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Swiss2Grid – Pilot- and Demonstration Project

An innovative concept for the decentralized management of distributed energy generation, storage and consumption

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Summary

The key question addressed by the S2G project was:

“To which extend is it possible to achieve a load management system based on local information from the grid, without an additional communication system, able to integrate decentralized energy generation, to reduce load peaks and to smoothly include self-consumption and storage devices on the one hand, and to omit grid infrastructure investments on the other?”

The S2G pilot and demonstration project could demonstrate, via thorough simulations and in-depth-analysis of measured voltages, that a decentralized, local-only voltage measurement approach can be safely adopted for demand side load management as long as there are enough flexible, local loads including batteries to handle also high local PV-infeed peaks and energy balancing over a full day.

Under these conditions, on the one hand, the absence of communication and/or centralized control does not result in bad decisions, i.e. no excessive load is put on the transformer. On the other hand, the algorithm systematically improves the stability of the network shifting loads where more appropriate.

We have further explored the potential of decentralized, local demand side load management when a non-pervasive communication infrastructure is present between control algorithms. We have investigated the benefits of the coordination - achieved via inter-algorithm communication - of control algorithms organized in subsets with as few as two peers. In light of this work we may conclude that the necessary investments to enable a massive coordination of control algorithms for voltage control only with a special communication infrastructure and centralized control mechanism may not be justified.

Resumé

La question clé abordée par le projet Swiss2Grid était:

“Jusqu’à quel niveau est-il possible de réaliser un système de gestion de la demande énergétique basé sur de l’information locale du réseau, sans un système additionnel de communication, capable d’intégrer la génération décentralisée d’énergie, de réduire les piques de réseau, et d’intégrer l’autoconsommation et les systèmes de stockage d’un côté, et de réduire les investissements en infrastructure de réseau d’un autre côté ?“

Le projet-pilote S2G démontre via des simulations et des analyses approfondies des tensions mesurées, qu’une approche de mesure décentralisée basée uniquement sur des mesures de tensions, peut être adoptée pour la gestion de la demande énergétique tant qu’il y a assez d’appareils locaux flexibles, y compris des batteries, capables de gérer les piques de production photovoltaïque et de balancer l’énergie pendant une journée entière.

Dans ces conditions, d'une part l'absence de communication et / ou d’un contrôle centralisé ne conduit pas à de mauvaises décisions, à savoir l'absence de charges excessives sur le transformateur. D'autre part, l'algorithme améliore systématiquement la stabilité du réseau en déplaçant la demande électrique.

Nous avons ensuite exploré le potentiel de la gestion locale de la demande décentralisée en présence d’une infrastructure de communication non-envahissante. Nous avons étudié les avantages de la coordination - réalisée via la communication inter-algorithme – de plusieurs groups d’appareils. À la lumière de ce travail, nous pouvons conclure que les investissements nécessaires pour permettre une coordination massive des algorithmes de contrôle avec une infrastructure de communication spécifique et des mécanismes de contrôle centralisés peuvent ne pas être justifiées.

Zusammenfassung

Im Zentrum des Projektes Swiss2Grid (S2G) stand die Frage:

“Inwiefern ist es möglich, ohne ein zusätzliches Kommunikations- und zentrales Steuerungssystem ein Lastmanagement zu betreiben, das auf lokalen Informationen aus dem Niederspannungsnetz basiert und gleichzeitig im Stande ist, die dezentrale Einspeisung von erneuerbaren Energien aufzunehmen, die Spitzenbelastungen von einzelnen Haushaltsgeräten zu glätten, den Eigenkonsum und die Speicher zu integrieren und gleichzeitig Infrastrukturinvestitionen zu verhindern?“ ¨

Das S2G Pilot- und Demonstrationsprojekt zeigt anhand von Simulationen und umfassenden Analysen von Spannungsmessungen, dass ein dezentraler Ansatz, der auf lokalen Messungen und intelligenten Algorithmen zur Steuerung von Haushaltsgeräten basiert, ohne Schwierigkeiten für das nachfrageseitige Lastmanagement verwendet werden kann. Voraussetzung dafür sind jedoch genügend flexible, lokale Lasten und Speicherkapazitäten wie Batterien zur Aufnahme von Einspeisespitzen aus Photovoltaikanlagen und zum Ausgleich des täglichen Energiebedarfs.

Unter diesen Gegebenheiten führt einerseits des Fehlen der für Smartgrids üblichen Kommunikationssysteme und/oder zentralen Steuerungseinheiten nicht zu falschen Lastverschiebungen, d.h. zu keiner Überbelastung am Transformator. Andererseits bewirkt der eigens für diesen Zweck entwickelte Algorithmus systematisch eine Verbesserung der Netzstabilität.

Im weiteren Verlauf des Projektes ist das Potenzial des dezentralen Lastmanagements unter Einbezug einer einfachen Kommunikationsinfrastruktur untersucht worden. Dabei sind die Vorteile sich über Kommunikation koordinierende Algorithmen auf den verschiedenen, gesteuerten Haushaltsgeräten untersucht worden. Auf Grund der erzielten Resultate kann die Schlussfolgerung gezogen werden, dass sich die Investitionen in eine Kommunikationsinfrastruktur zu einer intensiven Koordination der Steuerungsalgorithmen und in ein zentrales Steuerungs- und Kontrollsystems nicht rechtfertigen lassen.

1. Index

2. Initial position

The Swiss2Grid (S2G) Pilot and Demonstration project was initiated on the assumption of an increase of decentralized energy generation by the diffusion of photovoltaics, the electrification of mobility and heating, self-consumption and local storage systems. The gradual deployment of these technologies was supposed to change profoundly the structure and business model of the electricity sector and to raise new challenges in the management and distribution of electric energy. The experiences in neighboring countries proved that the development can be quite fast and solutions are needed much earlier than expected.

With the recent adoption of Swiss national energy strategy 2050 the role of renewable intermittent energy sources has been emphasized and the potential of PV is considerable. Moreover, is it taken for granted that the new energy scenario requires heavy investments in the grid infrastructure. However, the amount of investment and the question where and in which way to invest are still very open in the ongoing policy debate and can best be synthesized in the “more copper versus more intelligence” opposition.

The evolution of technical solutions in this field is breathtaking and it is not easy to follow the development. This is even more true considering the convergence of different areas such as Smart metering, Smart house and Smart grids. However, integrated solutions and business models are still in the making, and it is difficult to understand what kind of technological solutions is adopted by different stakeholders in the energy market value chain.

The rapid technological development is also influenced by the definition and adoption of a new regulatory environment. The technical solutions have to comply to new standards on the one hand, and standards are often lagging behind technological solutions or hinder innovative approaches on the other. The same is also true for the business model grown over decades and granting considerable revenues. The renewables with low to zero marginal costs are pushing traditional energy sources out of the market in the merit order regime. New business models are designed and the mainstream economic approach introduces the concept of flexible energy prices / grid tariffs for the management of intermittent energy generation.

In general, the challenges with the increase in distributed energy generations, distribution and local consumption are more and more perceived and a consensus is emerging that smart grid technologies, able to manage the load shifting in a completely new way, are needed. According to the mainstream the technological solution to this challenge is in the convergence of the electricity/energy grid with a new dedicated communication network. This network would be able to monitor single appliances and decentralized energy generators and control them from in a centralized way. This approach has gained a lot of attention in the last years and a lot of research funds have been invested in research, pilot and demonstration projects. Yet, the share amount of information to be handled in order to monitor and control simultaneously very large number of appliances rises new and challenging problems.

The S2G pilot and demonstration project was designed to question this mainstream approach and to investigate a different approach based on a decentralized perspective. The basic question at the beginning of the project was:

To which extend is it possible to achieve a load management system based on local information from the grid, without an additional communication system, able to integrate decentralized energy generation, to reduce load peaks and to smoothly include self-consumption and storage devices on the one hand, and to omit grid infrastructure investments on the other.

The core of this concept is a self-learning algorithm fed by information gathered at the local grid by a measurement device.

In order to proof the concept of such a decentralized approach to load management it was decided to set-up a pilot and demonstration project with 20 households equipped with measurement devices for the PV plants, hot water boiler, heat pumps, batteries as well as measurement equipment on the local distribution grid and LV transformer. This represents the real world and hardware part of the S2G project, from where all the data on the production, consumption and storage and the grid was collected.

At the same time the data was used in the simulation environment, which was created to investigate the behaviour of the algorithm and its impact on the local grid in the virtual part of the project, representing the households and the local distribution network. In this simulation environment it was also possible to scale – up the number of households up to 120 and to better understand the overall impact of the algorithm and to analyse different scenarios of coordination among the locally controlled devices.

These 20 households were selected in a public tender process in the catchment area of the DSO of Mendrisio (Aziende Industriali Mendrisio – AIM, supporting the project actively) and equipped with measurement devices. A measurement device was developed for the scope of this project including voltage, power and frequency and able to communicate the data to a central data base, where it could be analysed. The technical features of the so-called Home Appliance Controller (HAC) are described in detail in the first part of the project. The HAC device was designed to get as much as possible information from the local grid near the main switch of the different households and near the controlled household appliances. Since it was not clear, what was really needed as input for the algorithm and what was the resolution requested for the local information the devices were clearly over-engineered with respect to commercial measurement instruments.

The same was quite true for the measurement on the local grid, which was carried out with a high precision commercial instrument. Moreover to our surprise there are only few research projects dealing with the local energy grid, since it was taken for granted that it was generally over dimensioned and there was sufficient copper in the grid to accommodate further energy supply.

From the single HACs in the 20 households the data was gathered in a local computer with an interactive panel and send via a gateway to our database, where the analysis of the high precision data could be carried out. Through an intensive data analysis it could be concluded that the voltage changes and voltage drops represented the information for the locally functioning algorithm. The data analysis and its results, indicating a significant correlation between voltage at nodes in the grid and power at the local transformer are presented in details in this report.

The algorithms, integrated in the single HACs, are fed with the locally measured voltage changes and use the voltage history (last five days) in order to produce a forecast for the voltage for the next 24 hours. Based on this continuously up-dated forecast the algorithm plans a charging scheme/ functioning scheme for the specific appliance taking into account different objective functions, such as peak shaving, cost reduction, optimizing of self-consumption.

The interdisciplinary organized research team could proof the concept of a decentralized approach to the load management in the context of the S2G pilot and demonstration project. Moreover the P&D project was used as a test-bed for the development of further applications such as the intelligent or smart Home Charge Device for electric vehicles. The project also received the interest by a major player in the Swiss energy market, willing to bring the concept to a commercial level.

3. Goal of the Project

The Swiss2Grid project was designed to investigate and demonstrate an innovative approach to smart grids based on a decentralized load management with no central control and without a sophisticated communication infrastructure. The basic concept of the project was to use the local information on the grid (voltage drop) on the grid to feed the self-organizing and self-learning algorithm for the load management.

The key focus of the project was on the following aspects:

- production and testing of a household appliance controllers (HACs);
- simulation of different communication and tariff scenarios;
- mobile and stationary storage systems;
- load shifting on the principle household appliances;
- grid measurements and simulation on different levels (up-scaling).

The overall goal of the project was:

- to identify the information of the local grid to be used by the decentralized algorithm;
- to demonstrate the feasibility and the reliability of a decentralized algorithm and local-only measurement based load management;
- to account the amount of shiftable energy;
- to estimate the cost savings.

In terms of delineation of the approach pursued in this project, it …

- does NOT cut infeeds of renewable generators such as from PV to handle critical grid states such as too high voltages or currents;
- does NOT consider correcting the grid state when cables reach their maximum currents (this is implicitely avoided by assuming enough grid capacity for the most critical currents);
- does NOT need to use any type of communication of HAC-obtained local values with other HACs or with any central server;
- fundamentally assumes that the local grid at any time has enough flexible loads (including batteries) connected to handle the local balancing of all local infeeds (and via the transformer) including local battery feed-in thereby never overloading the grid.

Part 1 – Procedure / method

4. Set-up of the demonstration site and components

4.1. Selection of pilot and demonstration households

The goal to find 20 suitable households inside the relative small territory of Mendrisio municipality was not trivial. The inhabitants of this region had already been exposed to the electric mobility during the previous EV projects (VEL1, VEL2), but it was not clear how they would react to the topic of smart grids. The issues tackled by the project were challenging to explain to non-technical persons. In order to overcome these difficulties, it was decided to offer to the participants a photovoltaic system with an installed power of 1.5 kWp. The values of this offer, both from economic and sustainability point of view were very easy to understand. We organized a media strategy to promote the project and maximize participations results. The project public announcement was made in a public press conference with the most important representatives of Ticino media. Simultaneously a web portal (www.s2g.ch) was launched with all the information required to understand the focus and the objectives of the project and the participation formulary.

In order to be able to select the best candidates for the project a list of criteria was prepared.

Some criteria were mandatory and considered a prerequisite for participation:

- Household must be a private single family household
- Participant must be a house owner
- Household must be connected to AIM's electrical distribution grid
- Participant must accept a novel consumption metering for a period of three years

Other criteria were not mandatory but considered during the selection

- Desire to extend the own PV plant power
- Willingness to buy and use an EV
- Willingness to accept and install at the own house a battery system

Additionally the project had to consider the physical location of candidate's household, especially his connection to the neighborhood transformer. In order to maximize pilot houses effect on the grid, larger density of participants were preferred. Application results were remarkable, in less than two months (deadline was 15th of November 2010) 134 application forms were submitted. 103 of them were connected to AIM electrical grid and could be considered by the project.

The number of candidates is quite high if we consider that the total amount of energy meters in the AIM territory is 9151 (this number includes all kinds of users: apartments, industries, offices, etc…).

The majority of candidates were relatively young owners with houses of recent construction. Older people showed fewer propensities to a long term investment in such a PV system.

All type and level of instruction, and professional groups were represented; no predominant group has been identified. The following map shows the distribution of the candidates.

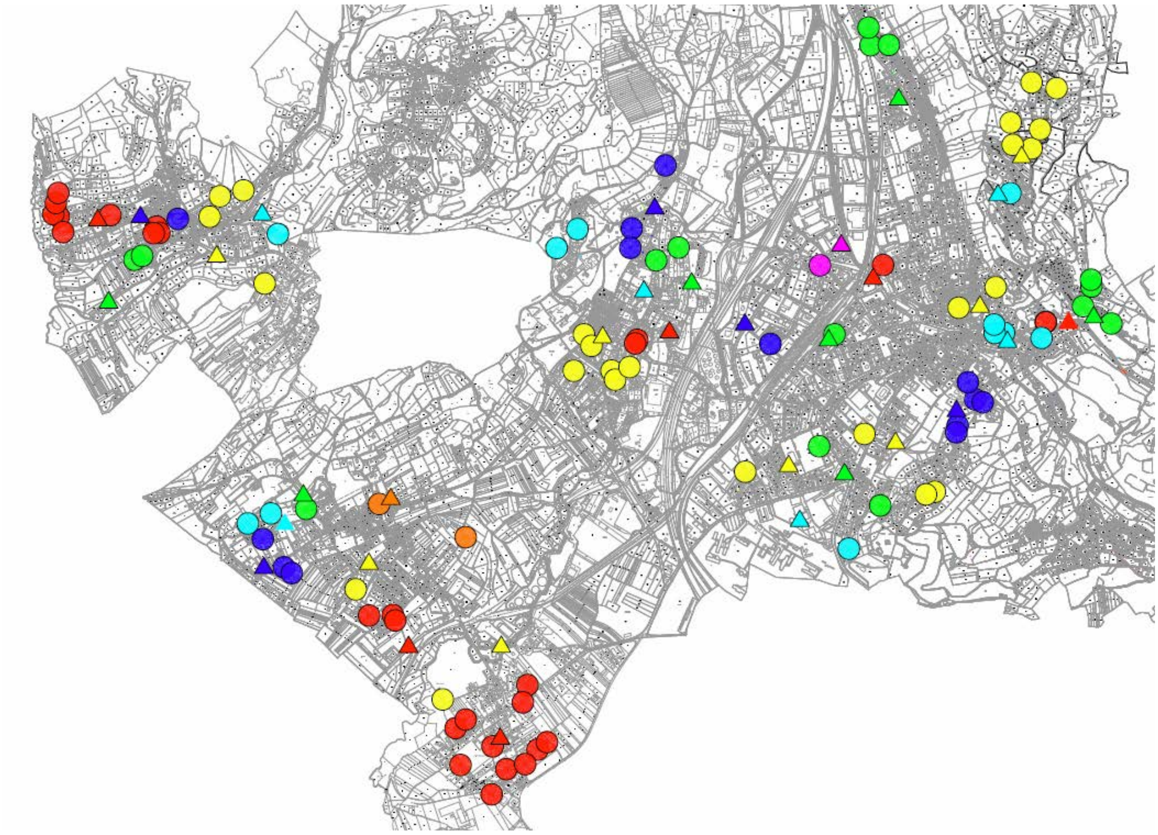


Figure 1: Map of the distribution area of AIM – Mendrisio

The next step was the preliminary interviews of the largest clusters, transformer “Asilo Genestrerio” (11 households) and transformer “Cimitero Arzo (9 households). The purpose of these interviews was:

- Explanation of the project, making sure the candidates understood what it would like to be a participant in S2G.
- Willingness to expand PV plant beyond the offered 1.5 kWp installed power, explanation of KEV incentives, current PV installation costs.
- Willingness to buy or lease an EV, explanation of current state of the art and prices.
- Technical assessment of the house, PV plant suitability and maximum installable power, household appliances inventory, pictures of the situation, etc.

After few days of interviews the following points were very clear:

- PV technology was not well known and easily confused with solar thermal collectors. After they were informed about of PV costs and KEV incentives, nearly everybody was eager to extend at least the PV plant to 3 kWp with an estimated personal investment of 10’000 CHF.
- Lot of candidates expressed in the interviews that they didn’t want at all to buy an EV, even if in the participation formulary the opposite was written.
- Confusion about EV technology was noticed too, several candidates expressed the desire to buy hybrid vehicle such as Toyota Prius confusing them with pure electric vehicle. Price expectations were not on pair with current market prices.

At the end of the process the following clusters were selected: the biggest neighborhood “Asilo Genestrerio” was retained because of his large size. Other two large neighborhoods “Posta Rancate” and “Casa del Bambino Mendrisio” were selected. The EV candidates were given the highest priority and could be part of the project even if they were the only ones connected to the local transformer.

Trafo	**Participants**	**EV**	**PV (kWp)**
Asilo Genestrerio	11	0	41.0

Posta Rancate	4	1	15.0
Casa del Bambino Mendrisio	3	0	13.0
Cimitero Arzo	1	1	4.5
Paolaccio Mendrisio	1	1	3.0

Table 1: The overall installed PV is over the double of the planned power

After the selection process an empirical investigation of customer behaviour, profiles and expectations was also executed. The overall impression of the investigation was satisfactory, in the sense that the sample of participants was really motivated in exploring the possible benefits of SGS, but with quite different expectations, sensitiveness and attitude toward the elements, the functioning and the effect of their specific domestic smart grid. In fact the participants could be easily clustered into three groups according to the motivation and expectations expressed during the interviews. The labels given to these groups are: (1) “Eco-Savers”, (2) “Carpe diem” and (3) “Green is better”. The first group included the 8 households which clearly stated that the financial support made the difference, more than a true ecologic attitude. The second and the third groups were equally represented with 6 observation but, while the “Carpe diem” were interested in being part of the game and experiment directly a new technology, the “Green is better” showed a strong inclination toward ecology.

As far as knowledge is concerned we observed a truly full array of answers, ranging from poor and superficial understanding of the changing electricity market to highly documented opinion on photovoltaic technology or nuclear and environmental problems. Surprisingly the “master of the topic” is not directly associated to the “green” intensity of the respondent.

The main problems cited were of course the exit from nuclear technology and the need of having a secure energy provision system. Both topics divided the opinions of the respondents with a large majority against nuclear production and no fear about the way energy will be supplied in the future. It is also important to note that a general confidence in technology improvement was perceived as well as the need of a strong commitment by the public sector as a guide in the energy change process. Many respondents identified responsibility also at micro level, that is to say the way we behave daily as consumers, workers, parents… .

As far as renewable sources are concerned, just few respondent did know about: the low actual share in energy production and/or the high cost for producing clean electricity and/or some of the other problems (intermitting production, NIMBY (not in my backyard), LCA (least cost approach),…) related to solar and wind power.

4.2. Components: Home appliance controller HAC

HAC (Home Appliance Controller) is an energy meter to be used on a three- or mono-phase 230VAC electrical network. His task is to measure the main electrical parameters (voltage, currents, power, cos(phi), frequency) and to send them to a concentrator device located in the same building where the measuring takes place, using the 230VAC distribution net as communication medium (powerline protocol). The concentrator device gathers the data and sends it via Ethernet to a remote database for research monitoring purpose.

The principal reasons for developing the HAC – which is an application specific device – instead of using a standard energy meter, are the following:

- Integration of the measuring data with their communication over the distribution net (powerline protocol), which is not supported by conventional domestic power meters
- Fulfilling of other specific Smart Grid tasks, such as measuring the line frequency with very high accuracy and the ability of switching on and off some household electrical appliances

In the pilot project up to 8 principal appliances were equipped with this control module. The HACs embed a communication node (based on any protocol), a switch and a power meter and was located between an electrical appliance and its outlet. The communication node ensured the connection to the monitoring system (a panel-PC) and to the home centralized decision maker, if it will be necessary; the power meter analyses the absorbed electric current and generates useful information (functional, statistical, diagnostic and energy consumption) related to the appliance itself and fed in the intelligent agent in the node. The connection to the panel-PC is based on Power Line Modem, but it could be any standard protocol, including ISM band RF wireless communication standard like the IEE 802.15.4 (ZigBee).

Figure 2: HAC prototype unit

4.2.1. Functions

The functionalities of the HAC device, highlighted in the project specifications, are listed below:

- Measuring the main electrical parameters: voltage, current, effective and reactive power
- Measuring the line frequency
- Sending the measured data to a data concentrator device within the same building

These tasks are accomplished by the following unities:

- ARM STM32F10X: The microcontroller running the firmware that manages the whole device, including the line frequency measurement
- PL3150: The microprocessor running the proprietary firmware (Echelon) that manages the powerline communication
- STPMC1 and STPMS1:Two application specific ICs which acquire and digitalize the electrical parameters, before sending them to the microcontroller through an SPI bus.

4.2.2. Specifications

Electrical measurements

The HAC was designed to measure the following electrical net parameters with the indicated precision. The HAC can be connected to a mono phase 230VAC or three phase 400VAC net as well.

Current:	from 0.1A to 25A, 0.1V resolution and accuracy
Voltage:	from 195 to 265V, 0.1V resolution, 0.2% accuracy
Energy:	0.1% Wh accuracy over temperature and 2000:1 range
Stability:	10ppm/°C (precision ultra-stable voltage reference)
Frequency:	from 49 to 51Hz, 1mHz resolution and accuracy
Phase:	from 0 to 360°

Microprocessors

Powerline communication:	Neuron chip PL3150 ANSI/EIA 709.2 (LON)
Data analysis :	32 bit ARM Cortex CPU with RTC

Memory

- ARM: 128KB Flash, 64KB SRAM
- PL3150: 64KB Flash, 2KB RAM
- SD Card: 2.0GB

Input/Output

- 1 ON/OFF switch (external)
- 1 reset button
- 3 signalization LEDs (red, green and yellow)
- 1 Normally Closed relay, contact current 20A
- 1 3-phase contactor (external)
- 10 free GPIOs
- 2 inputs from -10° to 70°C range for digital temperature sensors
- SPI interface
- UART interface
- CAN interface

Connectors

- Input: Phoenix screw clamp or similar, 25A
- Output: Phoenix screw clamp or similar, 25A
- Free I/Os: Standard header 2.54mm, 5x2 poles
- Temperature sensors: 2x Phoenix screw clamp, 3.81mm, 4 poles, with plug
- CAN: Phoenix screw clamp, 3.81mm, 4 poles, with plug
- UART: DB9 male
- SD Card: Standard connector, small size, plastic material (isolating)
- Relay: Phoenix screw clamp, 3.81, 3 poles

Power consumption

- Power consumption: less than 500mA
- Power supply: directly to 230VAC electrical net
- Super capacitor: guarantees a minimum life time of 4-6 hours to the microcontroller, in case of lack of current

Dimensions

- Case dimensions: 122 x 90 x 74mm

4.2.3. Hardware

The next figure gives an insight in the device architecture and summarizes the main functional blocks with their interconnections.

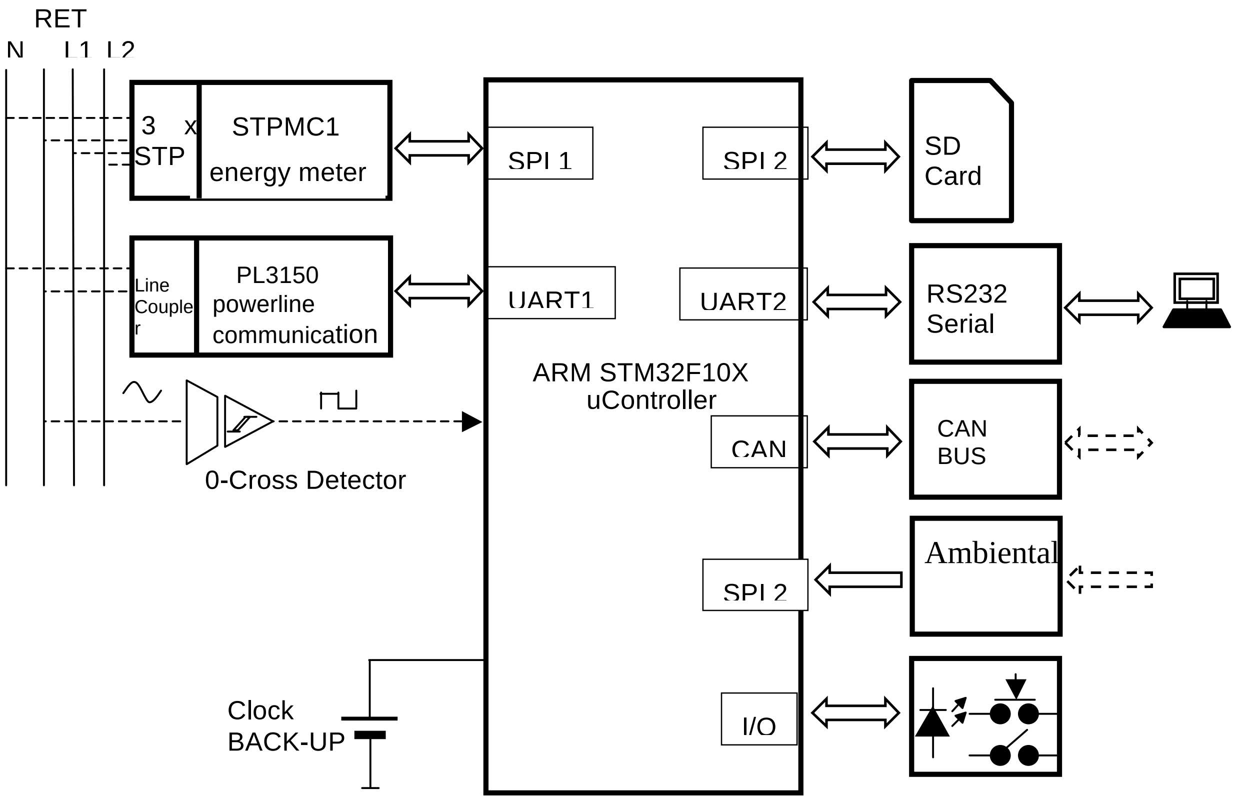


Figure 3: System sub units

CPU

The device is managed by a microcontroller belonging to the STM32F10X (ARM 32-bit CORTEX-M3) serie. This family features the adequate resources in terms of computation power, program and data memory and integrates all useful peripheral to interface the other system components and to perform many task directly by itself. The performance reserve and the family scalability of this processor make the system easily expandable for supplemental capabilities.

Data Communication

The data communication on the power grid leans to the Echelon LON established technology and employs a Power Line Smart Transceiver PL3150. This choice ensures compliance with ISO / IEC 14908.1 and 14908.3 and ANSI 709.1 and ANSI 709.3 as regards the data signaling on powerline. This technology is widely used both in the home automation and in the power management and enables the device to be integrated in more complex automation scenarios or in already existing installations. The interface with the microcontroller is established through an asynchronous serial channel (UART).

Electrical measurements

The electrical measurements are performed by a circuit based on the combination of the devices STPMC1 and STPMS1 that are specifically designed for power metering. This part of the system implements all the electrical measurements independently and makes them available through a synchronous serial channel (SPI).

Main frequency measurements

The measure of the line frequency is done directly by the microcontroller by means of an internal counter / timer. Prior to be processed, the signal is cleaned from noise with a selective bandpass filter and is shaped by a zero cross detector.

The Challenge

Measuring phase frequency at nominal 50Hz (20ms) with precision 1mHz with variation of the nominal value of 1Hz, hence with fmin=49Hz and fmax=51Hz.

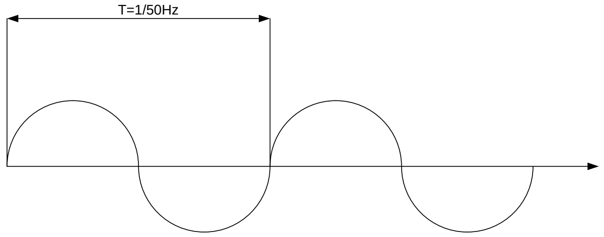


Figure 4: Phase frequency

Solution proposed

The phase signal should be first low pass filtered and then fed into a comparator. The resulting square signal can be directly input captured (the period counted) by a microcontroller timer.

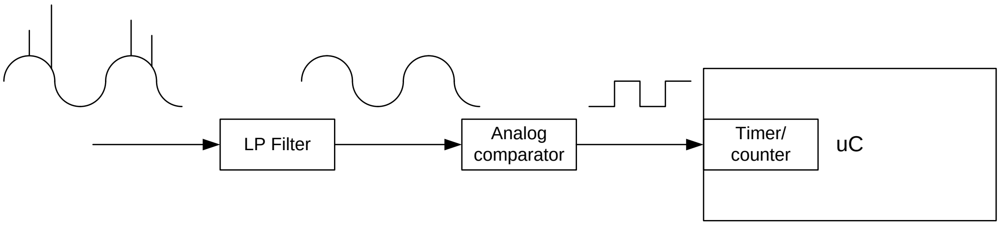


Figure 5: Frequency measurement solution

Counting the period length

Precision

We are interested in the precision p in time measurement to in order to assure frequency measurement precision of 1mHz. The difference between the measured frequency and the real frequency must be

$$\tilde{f} - f < 0.001 \rightarrow \frac{1}{T+p} - \frac{1}{T} < 0.001 \rightarrow p < \frac{0.001 \cdot T^2}{0.001 \cdot T + 1}$$

With a nominal period of T=20ms (50Hz) we get **p<400ns**.

The value of p for the fmin, fmax and fnom is shown in table below:

Tnom (fnom)	pnom=400ns
Tmin (fmax)	pmin=385ns
Tmax (fmin)	pmax=416ns

As expected we get the **lowest time quantization** for the highest frequency in the value of **385ns**.

Min counter frequency

We need a timer counting at least at the speed of **fc,min**=1/385ns=**2.6MHz**.

Max counter frequency

Using a 16-bit counter (65536 steps) in input capture mode we must ensure

$$\frac{Tmax}{Tc} < 65536 \rightarrow fc < 65536 \cdot fmin$$

With Tc and fc being counter period and frequency respectively. With fmin being 49Hz we get a max counter frequency of **fc,max**=65536*49=**3.21MHz**. In this case we would have a time precision p of 1/3.21MHz=311ns and a **frequency measurement precision** of

$$\tilde{f} - f = \frac{1}{Tmax + 311ns} - \frac{1}{Tmax} = \mathbf{0.75mHz}$$

This can be considered as the highest frequency measurement accuracy achievable using a 16-bit counter.

Variants

- In order to increase the timer frequency we can count over a half period. In this case, with Tmax being 1/49Hz/2=10.2ms, we get a double max counter frequency of 6.42MHz, a precision p in time domain of 1/6.68MHz=156ns, and a precision in the frequency domain of 1.5mHz, which is greater than the required threshold of 1mHz. We see that reducing time measurement in favor of greater counter frequency do not improve the measurement quality.
- The measure of the period length can be performed on more periods, from which a mean value can be obtained.

Counting the number of period over a given time

Instead of counting the period length we can count the number of period over a long time, let's say a time of 2 minute. If a period measures exactly 20ms, we'll get a counter value of 2*60/20e-3=6000. If we get a counter value of 6003, we will know that a period measures 2*60/6003=19.99ms.

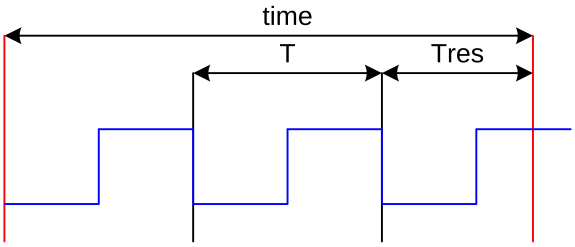


Figure 6: Period counting

In this case also we must ensure to fulfill our specification in the precision of the measurement. According to the figure above we get

$$\tilde{T} - T < \rightarrow \frac{time}{n} - \frac{time - Tres}{n} < 400ns \rightarrow \frac{Tres}{n} < 400ns \rightarrow n > \frac{Tres}{400ns}$$

With Tres being ca. 20ms in worst case (we assume time to be a multiple of 20ms), we get a min number of period counting of 50000, which yields a total integration time of 50000*20ms=1000s=16.667min (not really acceptable, even if counting every half period…).

Clock precision

From datasheet the HSE (High Speed External oscillator), which is more accurate than the internal, as duty cycle variable from 45% to 55%. On a 3.21MHz frequency (timer frequency) this means a variation

Nonvolatile memory

This memory allows to save locally the real time measurement data. The memory act as a buffer in the case of temporary interruption of the communication and enables the data stream to be resumed when the communication is established again preventing the system from losing data. In addition, long-term statistical data collection can be achieved locally, without the need for immediate data transfer. The media, an SD Card, can be removed from system and inserted in any FAT32 compatible computer for further data handling.

Real Time Clock Backup Battery

The battery allows to keep running the real time clock of the microcontroller even when the system is unpowered.

4.2.4. Electrical Design

Functional blocks

The figure below illustrates the functional blocks of the HAC.

The upper part of the figure depicts the 230VAC electrical net where the power meter, the power supply, the frequency calculator and the powerline communication blocks are connected to.

At the center of the figure one can see the microcontroller with its functional blocks interconnections.

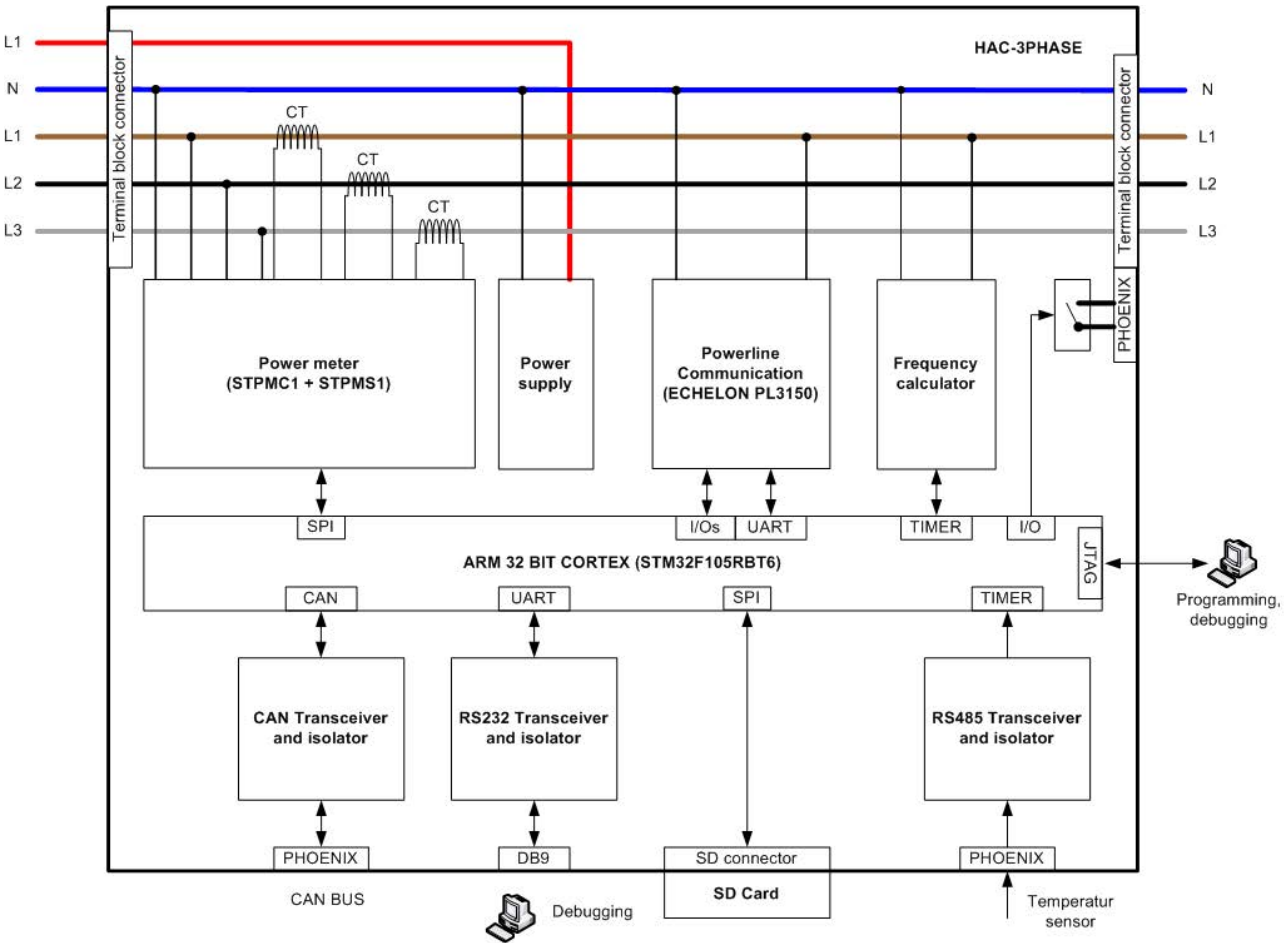


Figure 7: Functional blocks

Description of the functional blocks

Power meter

The Power meter block measures the actual net value of current and tension. The measuring process is overtaken by the STPMS1 integrated circuit, which digitalize the current and tension values, after they are properly scaled. There is one STPMS1 per phase (L1, L2, and L3).

The STPMC1 (one in the whole device) integrated circuit receives the digital data multiplexed in time from the STPMS1 and stores them in his registers, from which they are periodically read (once every second) by the microcontroller through an SPI bus.

Power supply

The power supply block generates, from the net at 230VAC, the necessary tensions (+5V, +3.3V, +12V and -5V) to supply the several blocks of the device circuit.

In order to provide the +12V, a switching transformer is used, for dimension reasons. From the +12V all the other tensions are produced, cascading linear voltage regulators.

The +5V feeds the Power meter block, the communication transceivers and the powerline communication digital part. The -5V is required by the frequency calculator block. The +3V is used by the microcontroller and by the SD card. The +12V is needed by the analog part of the powerline communication block.

Powerline communication

The powerline block is made up of a digital and an analogical section. The first integrates the Echelon reference design with the PL3150 IC, while the second includes three CPUs, running the proprietary firmware for the powerline communication. The analogical part, containing some big capacitors and coils, serves to interface the communication signals to the 230VAC net.

Frequency calculator

The frequency calculator block is responsible for measuring the line frequency with 1mHz resolution.

The next figure illustrates the path covered by the signal during its processing for the frequency calculation.

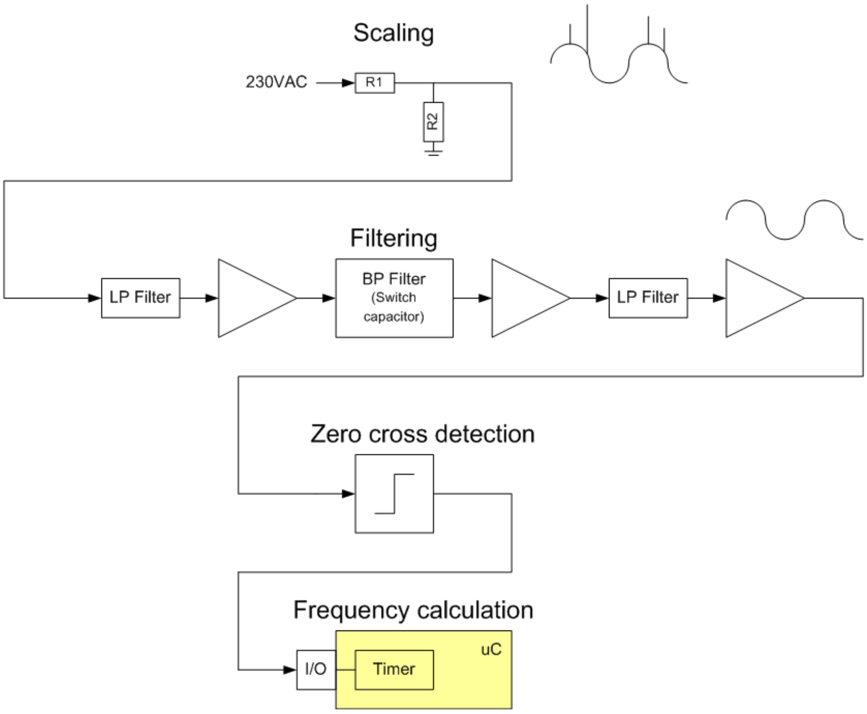


Figure 8: Frequency calculator

The measuring of the frequency takes place in four successive steps. First L1 is scaled, by means of a voltage divider, and brought to a level comprised within the range -1.5 and +1.5V. Then the signal is fed through a filtering chain, set up by a low pass, a band pass and a low pass filters. Between each filter a follower has been inserted, in order to create high impedance within the several filter stages. Then the signal enters a comparator, which detects its zero crossing, obtaining a square signal whose period equals that of line frequency. The microcontroller measures the length of several periods and calculated their average, obtaining a very accurate estimation.

Relay

A relay, controlled by the microcontroller, has been foreseen for two purposes:

- Directly disconnect one of the three 230VAC lines
- Activate an external contactor which, in turn, is able to disconnect all the net lines simultaneously

The relay is accessible through a 3-poles Phoenix connector, located in the front side of the electronics enclosure.

Microcontroller

The microcontroller is an ST 32 bit of the Connectivity line serie. Its characteristics are listed below:

- Core: ARM 32-bit Cortex™-M3 CPU
- Maximal frequency: 72 MHz
- Flash: 128KB
- SRAM: 64KB
- Pin: 64, almost all 5V tolerant
- Communication peripherals: 2x I2C, 5x USART, 3x SPI, 2x CAN, USB 2.0 full speed, 10/100 Ethernet MAC

The microcontroller, among the other peripherals, has an internal RTC as well as an internal power-down circuitry. The RTC is utilized by the firmware to trace the measuring time.

The power-down circuit is responsible for automatically switching to a specific power pin (VBAT), connected to the super capacitor, whenever the main power-supply is missing.

CAN

A CAN bus interface is required to interface with the battery loader of an electric vehicle.

The CAN is part of the microcontroller peripherals and is externally accessible through a 4-poles Phoenix connector.

RS232

An RS232 communication interface is required for debugging purposes.

SD Card

An SD card has is required for the following reasons:

- A removable storing device is needed to store data whenever the powerline channel is not at disposal (faults, blackout, software bugs,…)
- The specification of re-programming the microcontroller via powerline requires an independent memory support (the SD card in our case) to store the program data before rebooting the system

Temperature sensors

The digital temperature sensors served to provide the information whether a specific household appliance had to be turned on or off.

The temperature sensors we use (they are mounted on a dedicated small PCB, directly on the interesting part to measure) is the TMP03 sensor, of Analog Device. This digital sensor is particularly indicated for our application for the following reasons:

- High tolerance to noise (frequency signal)
- No need of further circuitry (as in case of analog temperature sensor)
- Minimization of processor pins (1 timer port per sensor)
- Low cost solution

JTAG

The JTAG connector serves to program the microcontroller and it is accessible through a 5x2 2.54mm standard header.

Other user interfaces

There are three buttons at user disposal:

- Reset : resets the device globally (master reset)
- Service: gives the user the possibility to interact with the PL3150
- Power-fail: the user can warn the system that the power-supply is going to fail (for example the user wants to turn off the device). This way the system can take the proper precautions, like aborting critical writing and entering a suitable state.

Three LEDs are also foreseen to quickly communicate the device state to the user.

4.2.5. Mechanical Design

Electronics Enclosure

The HAC has to be mounted inside domestic electrical panels, by means of standard DIN guides. The main requirements for its enclosure are:

- Compliance with standard DIN norm DIN 43880 and EN 60715
- Compact enclosure with enough space to place all the required circuitry
- Integrated connectors (separated from the PCB) specifically thought for current transformers (see component no. 19 in the figure below)

The electronics enclosure 7HMH68 of Italtronics meets the desired requirements, being conceived specifically for energy meters. It can contain up to three PCBs (see components no. 7, 11 and 16), two horizontal and one vertical, which provide a large surface for PBCs placing, in relationship to its quite low volume.

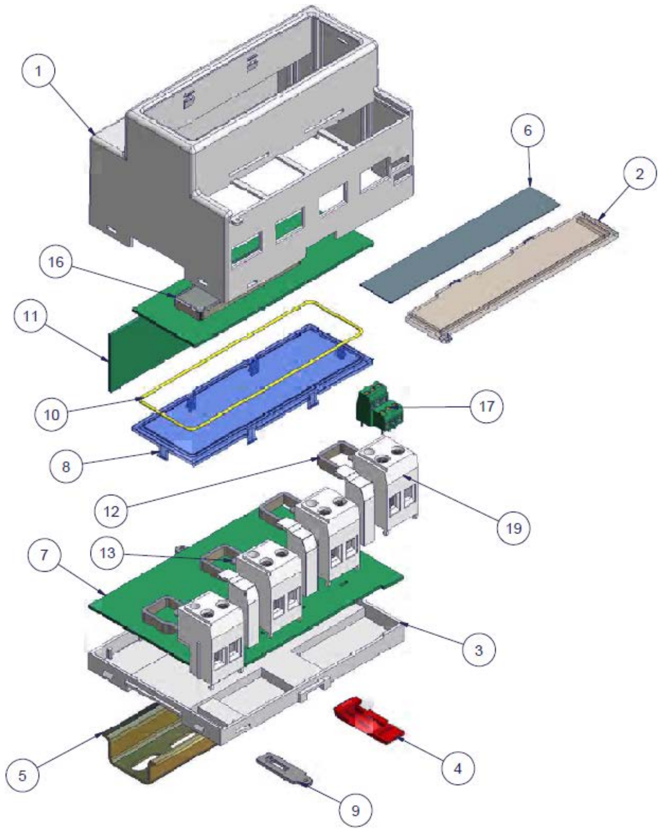


Figure 9: Module box 7HMH68, Italtronic

Printed circuit boards

Three printed circuit boards have been produced, connected to each other by means of standard flat cables with standard pitch 2.54 and 1.27mm.

The different blocks of the circuit have been separated on the different PCBs, basing on their functionalities.

HAC 3-Phase Bottom

HAC 3-Phase Bottom is the lower horizontal PCB. It comprises the power-supply, the power meter, the analog part of the powerline communication, the power connectors, the relay connector and circuitry, the flat cable connector to HAC 3-Phase Connectors and the flat cable connector to HAC 3-Phase digital.

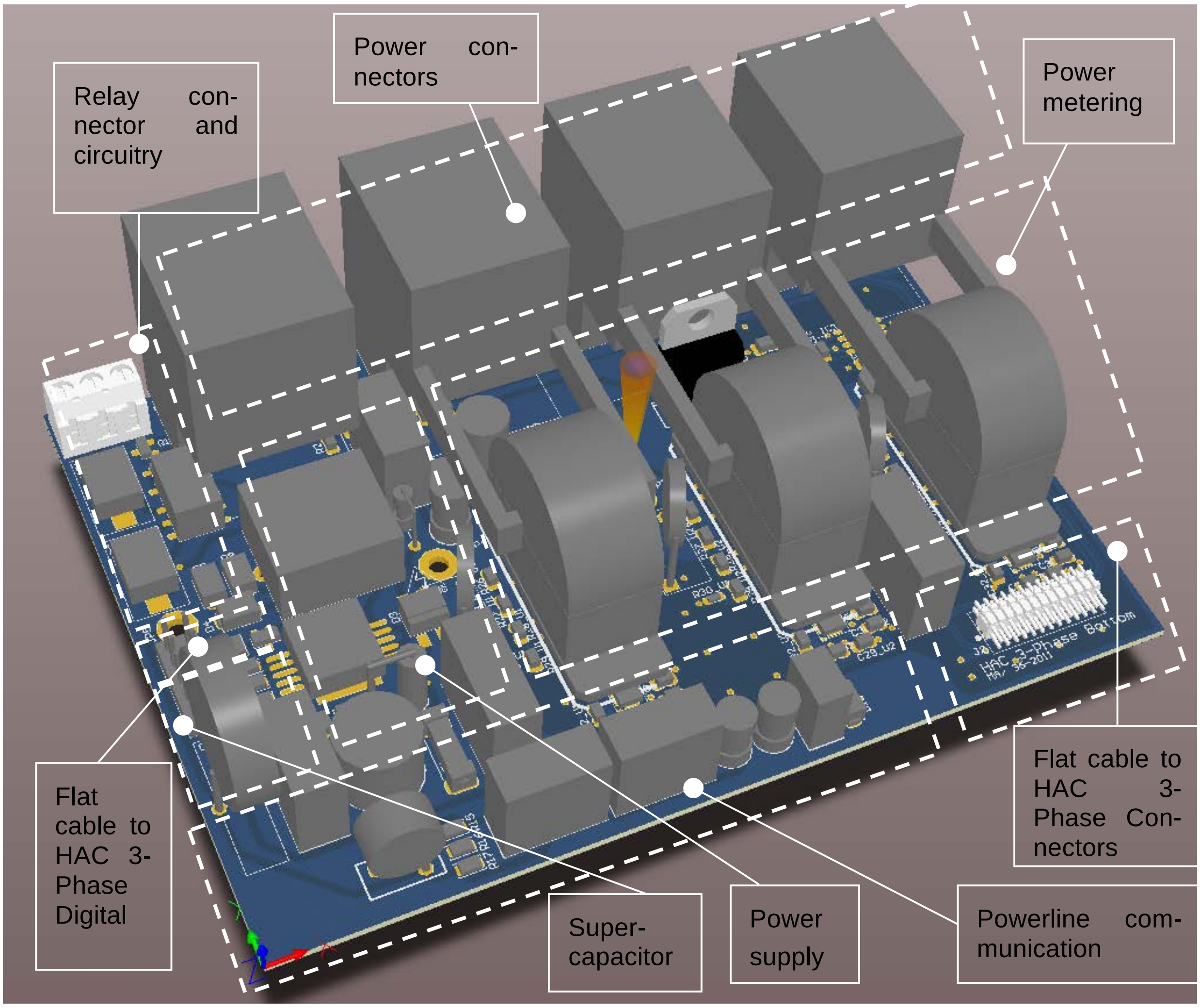


Figure 10: HAC 3-Phase Bottom

In the above figure one can see the different parts of the circuits. Particularly visible are the current transformers, characterized by their semi cylindrical section and pierced by the “U” shaped iron of the power connector.

HAC 3-Phase Connectors

HAC 3-Phase Connectors is the vertical circuit. It includes all the user connectors (RS232, CAN, Temperature and SD card) with their dedicated circuitry (basically transceivers and isolators).

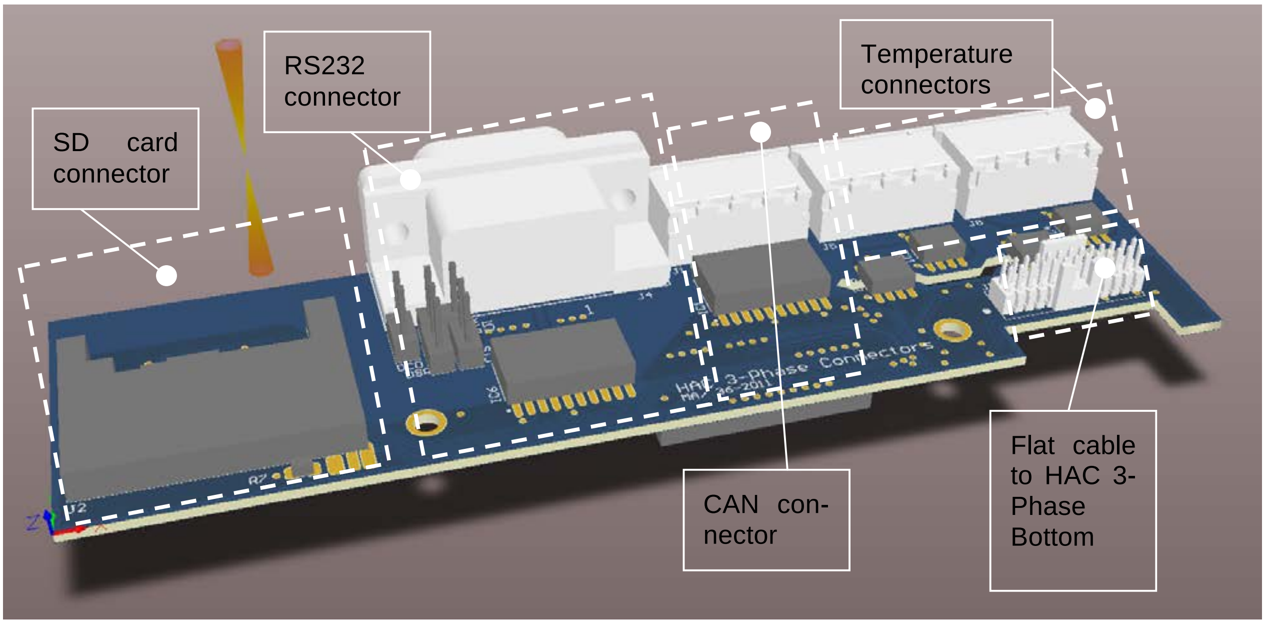


Figure 11: HAC 3-Phase Connectors

The connectors must be accessible from the user. In order to let them lean out of the electronics enclosure, a cave will be milled on the case.

HAC 3-Phase Digital

HAC 3-Phase Digital is the upper horizontal PCB. It contains the microcontroller, the digital part of the powerline communication (Reference design Echelon with the PL3150 IC), the frequency calculator, the user buttons, the free pins connector, the flat cable to the HAC 3-Phase Connectors PCB (on the PCB button, not visible in the figure), the user LEDs and the flat cable to the HAC 3-Phase Button PCB.

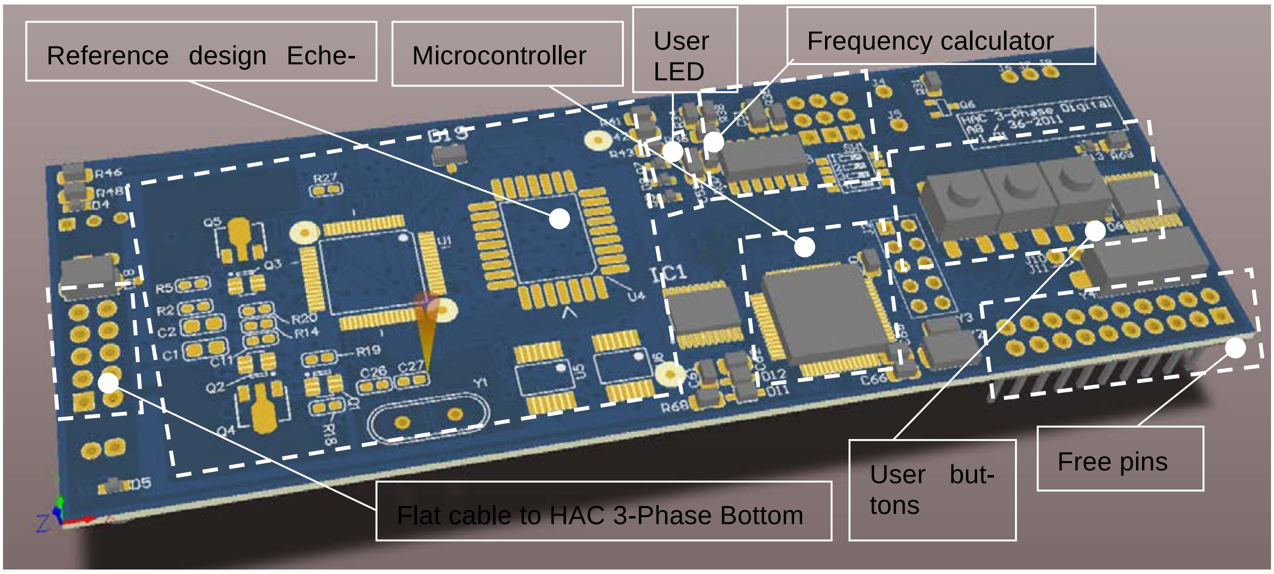


Figure 12: HAC 3-Phase Digital

To let the user buttons lean out of the electronics enclosure we will need to mill a slot through its plastic cover.

The switch capacitor filter itself is on a separate PCB, which connects to the HAC 3-Phase digital PCB through a standard header with 2.54mm pitch. This is done in order to ease any modifications of the filter.

Insulation

The HAC, being connected to the 230VAC electrical net, is exposed to potentially dangerous tension, for the user and for the electrical equipment connected to it as well. For this reason a suitable isolation had to be provided.

In this HAC version (a second release is already planned) the ground net of the circuit is connected directly to neutral line of the 230VAC net, the isolation is therefore applied at the user interface level (between the transceivers and the rest of the circuit).

A slot has been milled in the HAC 3-Phase Connectors PCB to guarantee the minimal physical distance, according to the CEI EN 60950 norm.

Table 2 illustrates the isolation, used for the different sensible part of the circuit.

	Component used	Description	Isolation type
SD Card	-	A plastic connector, not directly touchable by the user, has been used	Electrically non isolated
RS232	ADM3251E, Analog Device	RS232 Transceiver with integrated DC-DC	Galvanic, 2.5kV
CAN	ADM3053, Analog Device	RS232 Transceiver with integrated DC-DC	Galvanic, 2.5kV
Temperature sensors	ADUM5241, Analog Device	RS232 Transceiver with integrated DC-DC	Galvanic, 2.5kV

Table 2: Isolated parts of the circuit

The transceivers with integrated DC-DC were pretty expensive components, but they offer a functional and quick solution (in term of design) and they occupy a pretty small PCB surface (a standard DC-DC is very cumbersome in comparison).

An alternative solution would have been isolating the device at the switching transformer level, providing a separate ground for the whole circuit (apart from the power meter part, which needs to measure the tension value between line and neutral). This option will be taken into account in the next HAC release.

4.2.6. Software structure

The software was implemented in C language and made no usage of any operating system. The used development environment was a TrueSTUDIO/STM32 version 2.1.0 from Atollic AB. This development suite provides the tools for creating and managing the project, as well as the libraries supporting the usage of all resources integrated in the device. The following figure shows the architecture adopted for the implementation of software.

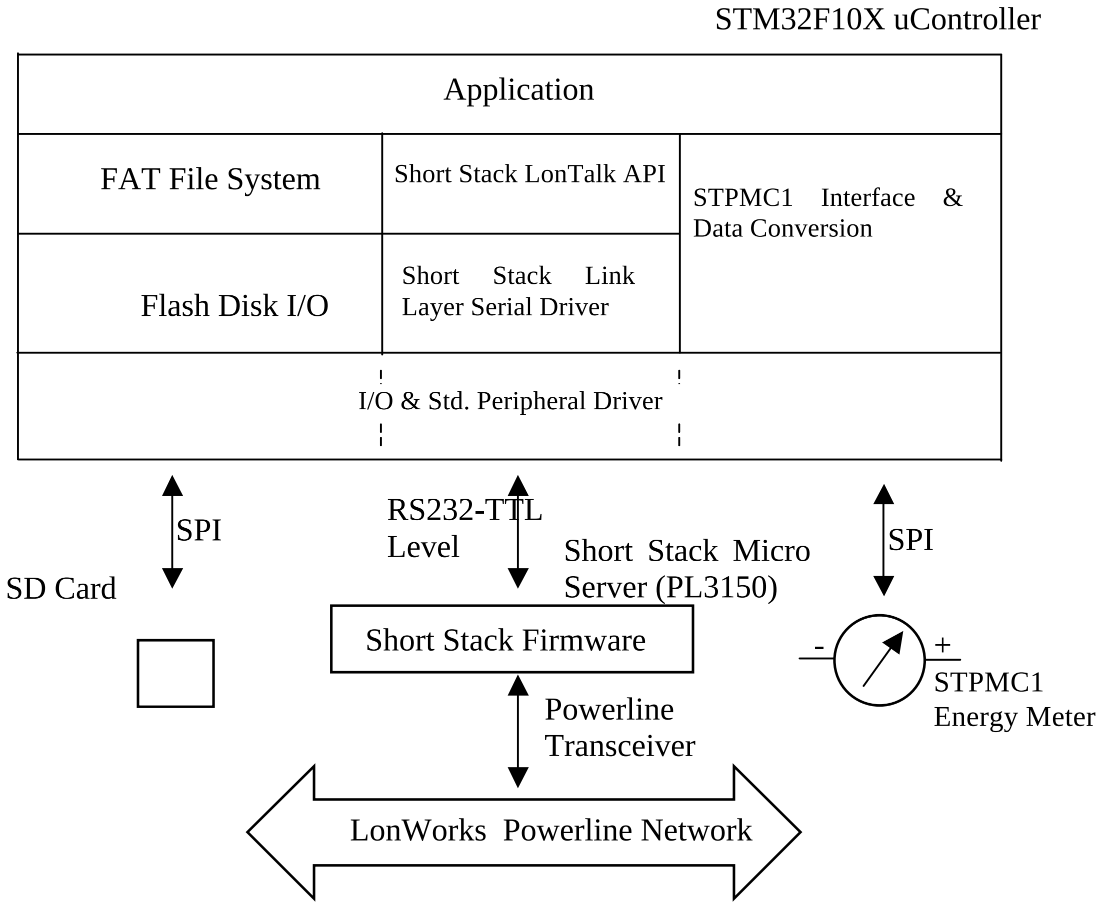


Figure 13: Software architecture

After the initialization phase, the program enters an infinite loop in which the function blocks are processed sequentially. To ensure a balanced distribution of the computing resource, the processing of more complex items or tasks requiring long response time will be broken in sub operations and distributed over successive iteration cycles of the loop. The following figure shows the principle of implemented processing.

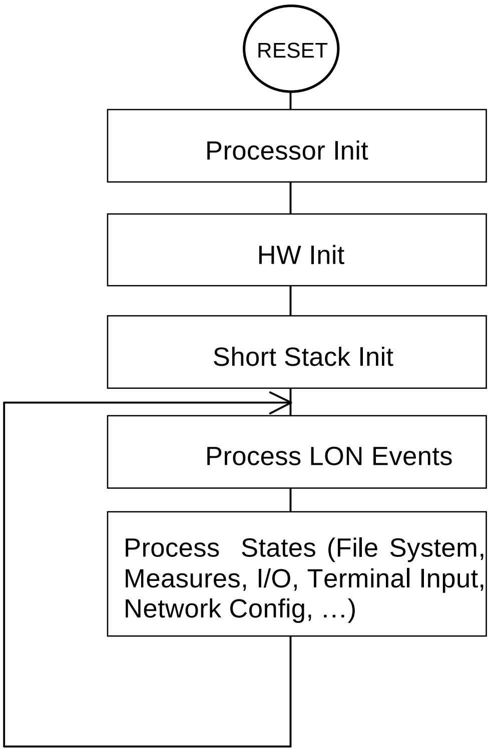


Figure 14: Main software structure

Electrical measures

The electrical measurements carried out by STPMC1 are available in its registers that are accessible through the SPI channel. In addition to the 2 lines for the data transfer, which are directly controlled by the SPI peripheral, 2 more software driven control lines are required.

Among the device measures, the following set (for each phase) is considered:

- U_{RMS}, integer format, data width = 12 bit.
- I_{RMS}, integer format, data width = 16 bit.
- $ENERGY_{ACTIVE}$, integer format, data width = 20 bit.
- $ENERGY_{REACTIVE}$, integer format, data width = 20 bit.

The electric power was not directly measured but was the result of a computation. The power meter increments continuously an energy meter, which is periodically read and transformed in power ($P(t) = \Delta E \,/\, \Delta T$) by the microcontroller. When the counter overflows it restarts at 0. The counter reading must be done often enough in order not to miss any of these transitions.

The conversion of the readings in physical units is a function of the dimensioning of the analog part of the measuring circuit. The component dimensioning to meet the design specifications results the following conversion factors:

Wh/bit = 6.02816E-06

V/bit = 0.10803

A/bit = 0.003142

With the maximum rated load of 5.5kW the energy meter rolls over in approximately 4.13 s. At the opposite, for a reading with an accuracy of 1 W, the integration time should be at least 22 ms. Implemented is a reading cycle of 1 s, which ensures an adequate system responsivity and avoids a data flooding of the power line communication channel.

All other electrical measures are read simultaneously with the energy meters and are grouped in a single data telegram also including the validity time stamp.

The conversion factors of the telegram data are indicated below:

W/bit = 0.2 (-6553.6W .. 6553.4W)
VAr/bit = 0.2 (-6553.6VAr .. 6553.4VAr)
V/bit = 0.1 (0V .. 409.5V)
A/bit = 0.001 (0V .. 65.535A)

Structure of the data telegram with the electrical measures:

Field	Size	Meaning
Status	16-bit	Bit mask with several status flags
$U_{RMS}L1$	16-bit	U phase L1
$I_{RMS}L1$	16-bit	I phase L1
$P_{ACTIVE}L1$	16-bit	Active Power phase 1
$P_{REACTIVE}L1$	16-bit	Reactive Power phase 1
$U_{RMS}L2$	16-bit	U phase L2
$I_{RMS}L2$	16-bit	I phase L2
$P_{ACTIVE}L2$	16-bit	Active Power phase 2
$P_{REACTIVE}L2$	16-bit	Reactive Power phase 2
$U_{RMS}L3$	16-bit	U phase L3
$I_{RMS}L3$	16-bit	I phase L3
$P_{ACTIVE}L3$	16-bit	Active Power phase 3
$P_{REACTIVE}L3$	16-bit	Reactive Power phase 3
DateTime	32-bit	Seconds since 01.01.1970-00:00

Table 3: Data telegram structure for electrical measures

Measurements of the line frequency

The line frequency was directly measured using an internal microcontroller timer. This timer was programmed to count in steps of 1 µs and to automatically save a copy of the counter when a designated trigger signal changes state. The used 16-bit counter has enough reserve to process the 50Hz mains frequency being able to measure time periods up to 65.535 ms without rollover.

A complete frequency conversion is taken over 50 cycles corresponding to about a measure per second. A deviation of 0.001 Hz at the nominal frequency of 50Hz results in a difference of 20us over the measure cycle.

Structure of the data telegram with the frequency measures:

Field	Size	Comments
Status	16-bit	Bit mask with several status flags
Delta50Hz	16-bit	-32.768 Hz .. 32.767 Hz
DateTime	32-bit	Seconds since 01.01.1970-00:00

Table 4: Data telegram structure for line frequency

The Delta50Hz field represents the frequency difference in mHz from nominal value of 50Hz.

Powerline communication

The communication is based on the *Short Stack Version 2.1* source code library provided by Echelon. This library, together with the Smart Transceiver PL3150 running *Short Stack Micro Server* firmware, allows the device to be fully integrated as a node in a LonWorks network.

From the LON side the main communication characteristics are:

- Ability of auto configuring (ISI), without a network management tool.

- Use of network variables (NV) for the information exchange.

To port the library to the STM32F10x platform, the hardware dependent communication layer (i.e. the serial driver) as well as compiler and processor dependent settings has been adapted. To build and integrate the new network variable types, the Echelon tools *Node Builder Resource Editor* and *LonTalk Interface Developer* were used.

The following new user network variable types are defined:

UNVT_hac_uipqt:	electrical measures (output)
UNVT_hac_freqt:	line frequency measure (output)
UNVT_hac_cfg:	configuration (input)

The types *UNVT_hac_uipqt* e *UNVT_hac_freqt* correspond to the structures listed in previous chapters. The type *UNVT_hac_cfg* is used to send information to the device is defined as follows:

Field	Size	Comment
Configuration	16-bit	Defines the type of the parameter
Parameter	32-bit	Data

Table 5: Data telegram structure for HAC configuration

For example the command to update the date and time is:

Configuration = 1
Parameter = Seconds since 01.01.1970-00:00

The device will be connected to the network automatically in the installation phase as soon as it receives a connection request from control panel unit (*ISI-Controlled Enrollment*).

Local data storage / File system

The device is equipped with an SD card interface as a large capacity non-volatile memory. On this storage not only the measured data could be saved, but also configuration files or software updates can be stored. The File System is a derivation of the completely free package *FileFs* where the I/O components were customized for the used microprocessor platform. It handles FAT (16/32) formatted SD cards. The measures are stored in plain text CSV files named *DATA_nnn.TXT* where *nnn* is a numeric suffix progressively incremented. Each record represents a measure (power or frequency) and is tagged by a key (textual *'EL'* respectively *'FR'*). The time stamp of the record is explicit in the *form 'YYYY-MM-DD HH: MM: SS'*. When a file reaches the 100,000 records mark, it is closed and a new one is opened with an incremented index. To allow a safe card removal during operation a push button is present. Once activated, all pending write operations are closed and the card can be safely removed without any data loss or corruption.

Real Time Clock, Timer Tick

The processor has an internal real time clock that is kept working by an external back-up battery, even when the device is powered off. It is programmed to count the seconds and can be updated / synchronized at any time. The system is able to detect if the clock was never set, or if the time was lost.

The clock is used to give the time stamp to the measures and to set the creation date to the files on the SD card.

In addition to the RTC, another timer, the Core System Tick Timer is used to increment the software tick counter every 1 ms. This counter is used as base to build software time-outs and time measurements.

External sensors

The application was designed for the reading of 2 temperature sensors through the SPI serial channel. Actually this information was not used. These measurements could be easily integrated to those already defined for the communication and the file archiving.

Terminal connection

A terminal could be connected (9600,8, N, 1) to the RS232 serial port to interact with the device during development, installation or testing phase. At present no specific commands are defined, but only some commands for debugging purpose are recognized. Alternatively, this port can also be used to interface other serial devices.

CAN bus interface

The CAN transceiver is directly connected to one of the 2 CAN peripheral integrated in the microprocessor. At the time, no specific device is defined to be connected to the system, thus the application does not implement yet any CAN functionality.

Software update on the field

The update of the software is performed via powerline download. The new program is not transferred directly into the microcontroller memory but is temporarily buffered on the SD Card. This approach prevents from a potentially fatal programming disruption, due to a communication failure or loss. Once the download is successfully completed and the data is available on the local storage it can be safely transferred to the microcontroller memory. The programming file can also be transferred directly to the SD card on using a PC and then inserted in the device adapter for the update.

Led

There are 3 LEDs for the status reporting of the unit. Their function is summarized in the table below:

	LED 1	LED 2	LED 3
Off	Unconfigured		
On	Configured	Clock is set	Fatal error condition
Blinking fast			
Blinking slow	Configuring	Clock is not set	Measure acquired

Table 6: LED functions

Buttons

- Master Reset: reset di PL3150 and STMF3210X.
- Power Fail: safely remove the SD Card.
- Service Pin: send the *Service Pin* message on the LON Powerline network.

Switches

A group of 4 DIP switches is read by the program and allows to set several parameters (yet undefined) of the system.

	SW1	SW2	SW3	SW4
On	Triphase System			
Off	Monofase System			

Table 7: Switch function

4.3. Components: Touch Panel

This device was the gateway unit based on a fanless panel PC used as interface to monitor the powerline HACs network and was develop by **ISIN - SUPSI**. The device includes a powerline LON interface PL-22 and the standard Home automation SW application developed for home automation purpose. This software was modified and adapted according to the S2G requirement. Operating system is an open-source Linux distribution.

During the first phase of the project the purpose was only the monitoring of appliances, no user interface were active. In the second phase the user interface was activated and the participants were able to see the house consumption and actively interact with the intelligent energy management system.

The chosen unit has the following specifications:

LCD Size	10.2”
Max Resolution	1024 * 600
CPU	Intel® Atom™ 1.6GHz
Dimension (mm)	313.83 x 222.13 x 52.5
Net Weight	1.5 Kg

Figure 15: Touch panel unit

4.4. Components: DomoML

4.4.1. Interface between HAC communication protocol and algorithm via DomoML framework

The DomoML framework was interposed as an interface layer for connecting in a transparent way the software algorithm with the real devices, the HAC and the end user. Figure 14 shows its role within the whole system architecture: it let the Algorithm have all the consumption or parameter data of the HACs together with the user tasks, then it passes the scheduled activities to the HAC.

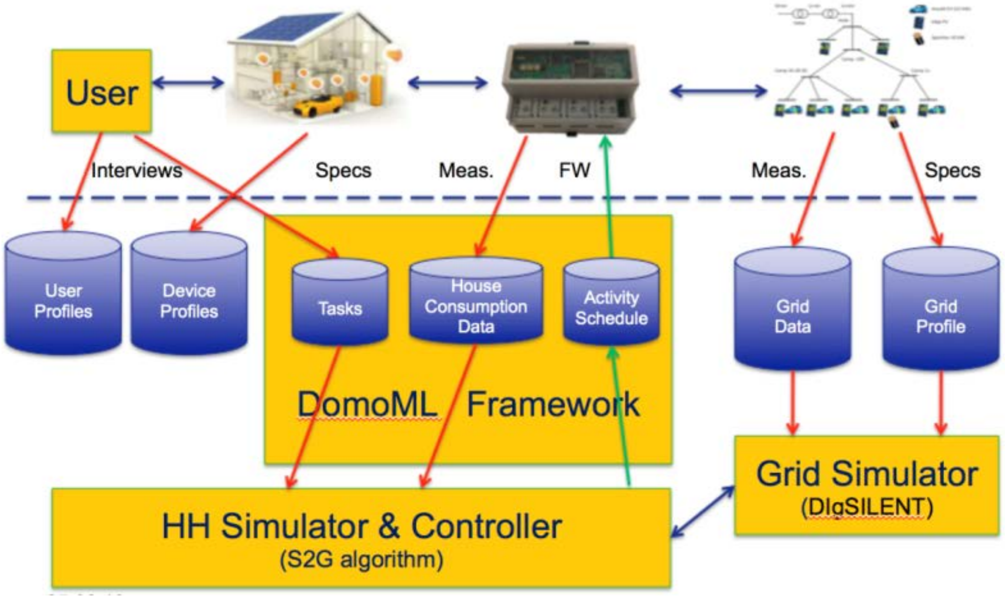


Figure 16: the DomoML framework interfacing User, Algorithm, and HAC within the system architecture

The communication between the algorithm and the household devices occurs through the DomoML Framework in the S2Gclient. For the interaction a protocol of possible requests and returned data has been established according to the algorithm needs and device restrictions.

S2GClient

Within the DomoML framework the S2GClient interfaced the Algorithm with HAC modules. The S2GClient is a web application that continuously listens for messages coming from the Algorithm and transforms these messages into commands for the DomoML framework.

The S2GClient supported also HAC devices that exposed a "relay=on/off" command. In the future, other commands could be supported.

Each HAC device has a field, named "label", in the DomoML framework. This field is important because DomoML relies on it to identify the different HAC device types and to build the corresponding tasks required by the Algorithm.

Beside timers and rules, S2GClient web application creates other objects, named Task, that are associated with HAC devices and are added to DomoML framework as virtual devices.

DomoML is also useful for the installation phase. When a HAC device is physically connected to the LON network for the first time, the lonbridge server usually auto-detects it and notifies it to DomoML.

Tasks request to DomoML

A list of the scheduled tasks associated to each device is obtained through an HTTP Get request to the DomoML Framework The default format of the response for the returned list is an XML document. In addition the list can be returned in JSON format.

There are 6 types of tasks:

- B2GTask
- HCDTask
- BoilerTask
- WashingMachineTask
- HeatPumpTask
- Task.

Each task is associated to an *Energy* HAC, or an *Energy1* HAC (in case of a single-phase HAC). These are connected to a b2g, hcd, boiler, washing machine or heatpump device.

Boiler and Heatpump

For **boiler** and **heatpump** devices the following <State> can be read:

- **active**: true/false shows if the task has been activated/inactivated by the user; if inactivated the algorithm is no more responsive on the device. The default value is true.
- **tmin**: minimum temperature the user can set. There is no default value, i.e. the <Value> tag has no default value.
- **tmax**: maximum temperature the user can set. There is no default value.

Washingmachine

For **washingmachine** devices the following <State> can be read:

- **active**: true/false shows if the task has been activated/inactivated by the user; if inactivated the algorithm is no more responsive on the device. The default value is true.
- **duration:** washing program duration, not yet available for user setting from the GUI. There is no default value.
- **endtime**: date and time of program ending. There is no default value, the user can set its value.
- **load**: loading profile, not yet available for user setting from the GUI. Possible values: low, medium, high. There is no default value.

B2G

For **b2g** devices the following <State> can be read:

- **active**: true/false shows if the task has been activated/inactivated by the user; if inactivated the algorithm is no more responsive on the device. The default value is true.
- **capacity**: battery capacity in J. The default value is 10E6.
- **maxchargepower**: maximum charging power in W. The default value is 1600.
- **maxinjectpower**: maximum charging power in W. The default value is 2000.

HCD

For **hcd** devices the following <State> can be read:

- **active**: true/false shows if the task has been activated/inactivated by the user; if inactivated the algorithm is no more responsive on the device. The default value is true.
- **capacity**: battery capacity in J. The default value is 58E6.
- **maxchargepower**: maximum charging power in W. The default value is 3000.

The other task **<State>** can be ignored by the algorithm because they contain the scheduling time list sent by the algorithm itself. The **<Function>** tags can be ignored too, because they are only used by the DomoML GUI to set the active, tmin, tmax, duration, endtime, load values.

Data storage implementation

Local and remote data persistence has been supported by means of a data logger module.

DataLogger is a web application developed for full data storage purpose within the DomoML framework. The energy data are immediately stored as soon as they arrive from HAC devices, they are zipped and sent to a remote server every 10 minutes. This mechanism of storing is currently running in 20 S2G installed households.

Long term aggregated data set has been also developed; the average of HAC measurement samples is stored every hour. This implementation will be installed after testing in all the households.

4.4.2. Interface and interaction design

After a preliminary user need analysis, some basic requirements had been defined, and will be refined according to real user needs during the tests in the households.

An interface has been developed in the form of an HTML5-CCS3 page targeted to run on different devices, such as tablets or touch panel PCs. This user interface has been implemented as a standard web technologies complaint web page, exploiting some graphic libraries for graph data display (HighStocks, www.highcharts.com).

The user interface was organized in a main view - home page, which can give access to all the other existing devices where the corresponding detailed view is presented. In addition, the user can access also some historical data and see some comparison between the mea

Main view

The main view offers an overview of the different devices such as boiler, battery, clothes dryer, washing machine, inverter, electric vehicle, heat pump and house.

The house ("casa") is a special device that collects data from the other devices and provides indications about their global consumption.

Each device of the house is represented as a hexagon with a descriptive icon and a label. Selecting one of these, the user can enter the detailed view. An "info" button is also present on the main view to show credits of the project with details about the project partners and the project itself.

In the initial design phase two different mock-ups were designed for the home page; the selected one is shown in Figure 17.

In the implementation phase the GUI has been maintained very similar. In the real installations the main view varies according to the devices that are installed in the specific apartment. Figure 18 shows an example of a currently running installation (s2g-hh01) with real data.

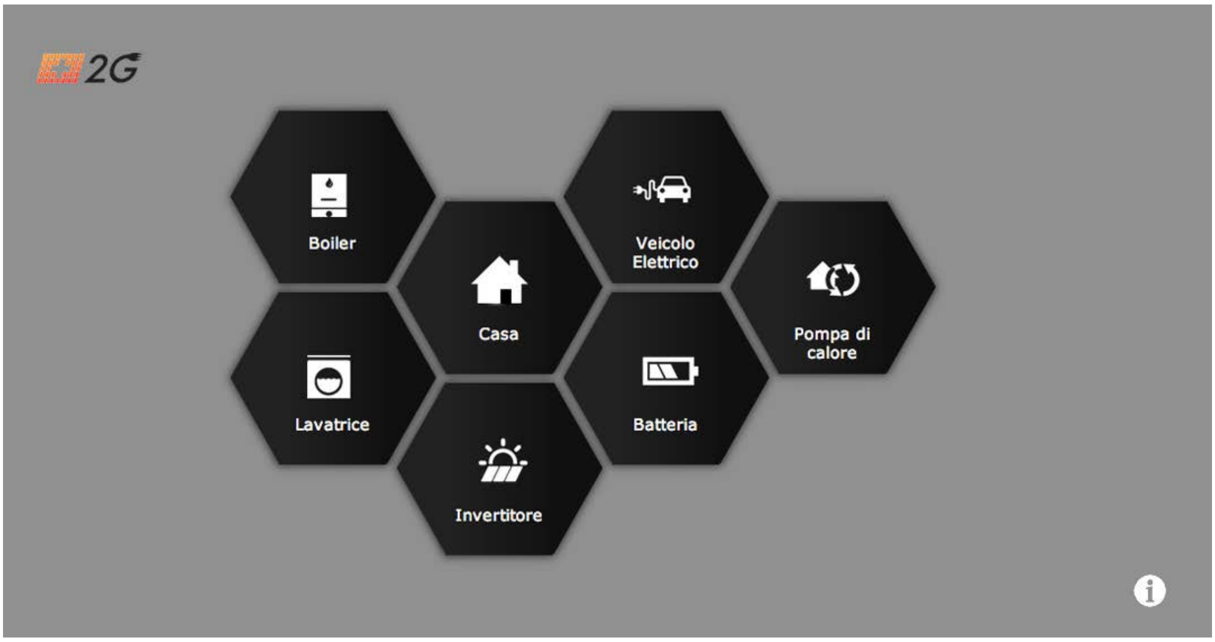


Figure 17: mock-up of the main view of the end user interface

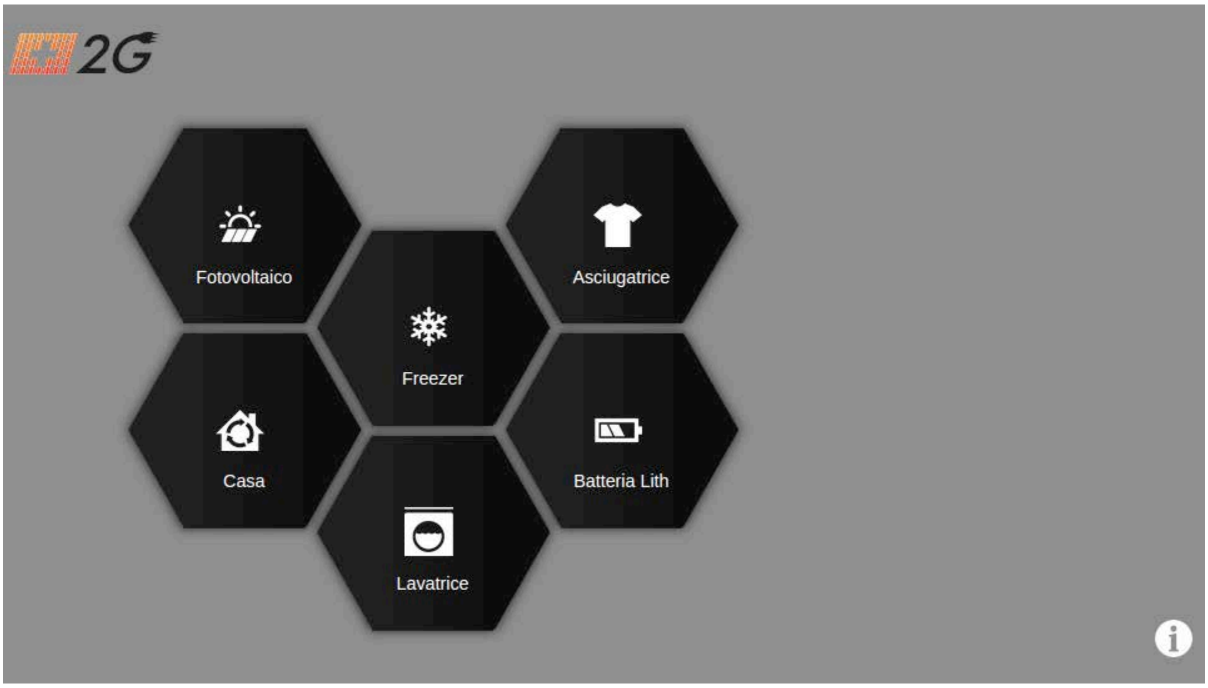


Figure 18: final user-interface of the main view

In the rest of the section examples of the detailed view of some devices will be described.

House view

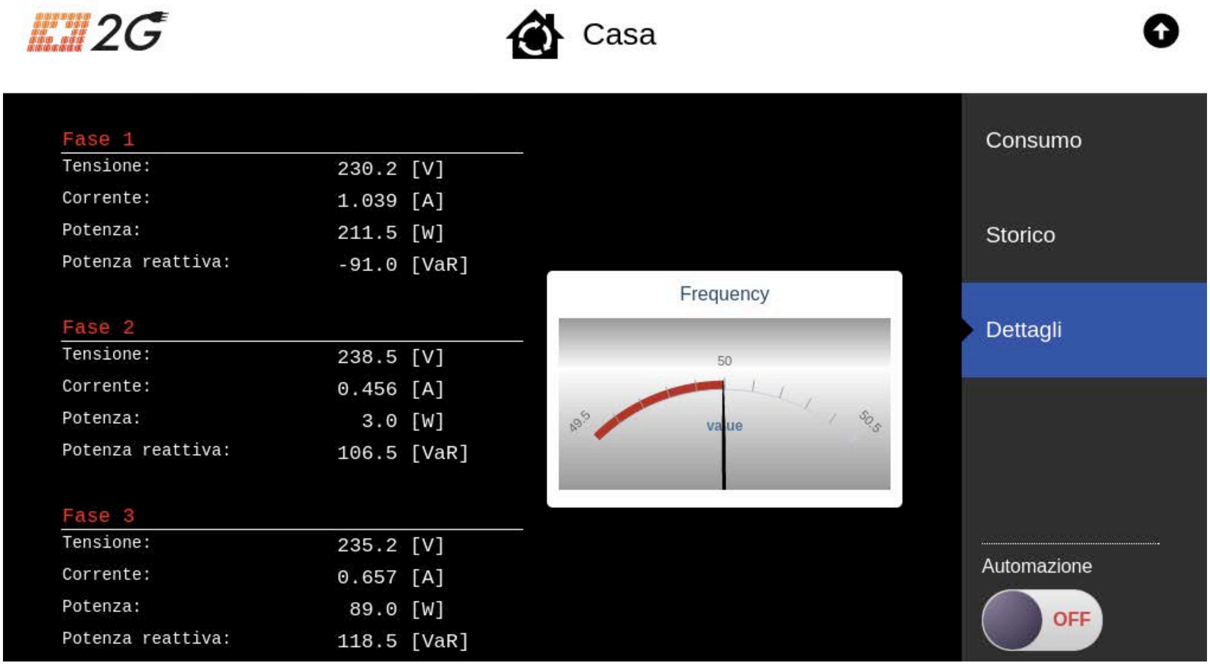
Each device view contains a menu displayed on the right side of the page. The house menu consists of the following items: *Consumption* (Consumo), *History* (Storico) and *Technical Details* (Dettagli).

An *up arrow* button is always provided to go back to the main view.

In addition, the user can decide whether to turn on or off the automatic control on the device itself by using the on/off button shown at the bottom-right corner of the page.

Figure 19 and Figure 20 present the user interface associated to the selection of two different menu items of the house. Figure 19 presents technical details about the device consumption: measures of voltage, active power and current together with a gauge displaying the actual frequency (last 30 secs average).

Figure 20 visualizes historical data about the whole house consumption.



Fase 1
Tensione: 230.2 [V]
Corrente: 1.039 [A]
Potenza: 211.5 [W]
Potenza reattiva: -91.0 [VaR]

Fase 2
Tensione: 238.5 [V]
Corrente: 0.456 [A]
Potenza: 3.0 [W]
Potenza reattiva: 106.5 [VaR]

Fase 3
Tensione: 235.2 [V]
Corrente: 0.657 [A]
Potenza: 89.0 [W]
Potenza reattiva: 118.5 [VaR]

Figure 19: house view (casa): details

Figure 20: house view (casa): history

Battery view

The battery (*Batteria lith*) menu includes the following items: Level of charge (*Stato di carica*), Consumption (*Consumi*), History (*Storico*), Technical Details (*Dettagli*), Scheduling (*Pianificazione*).

Figure 21 shows the result of the “level of charge” item selection.

The user-interface of the other menu items is similar to that of the devices already described.

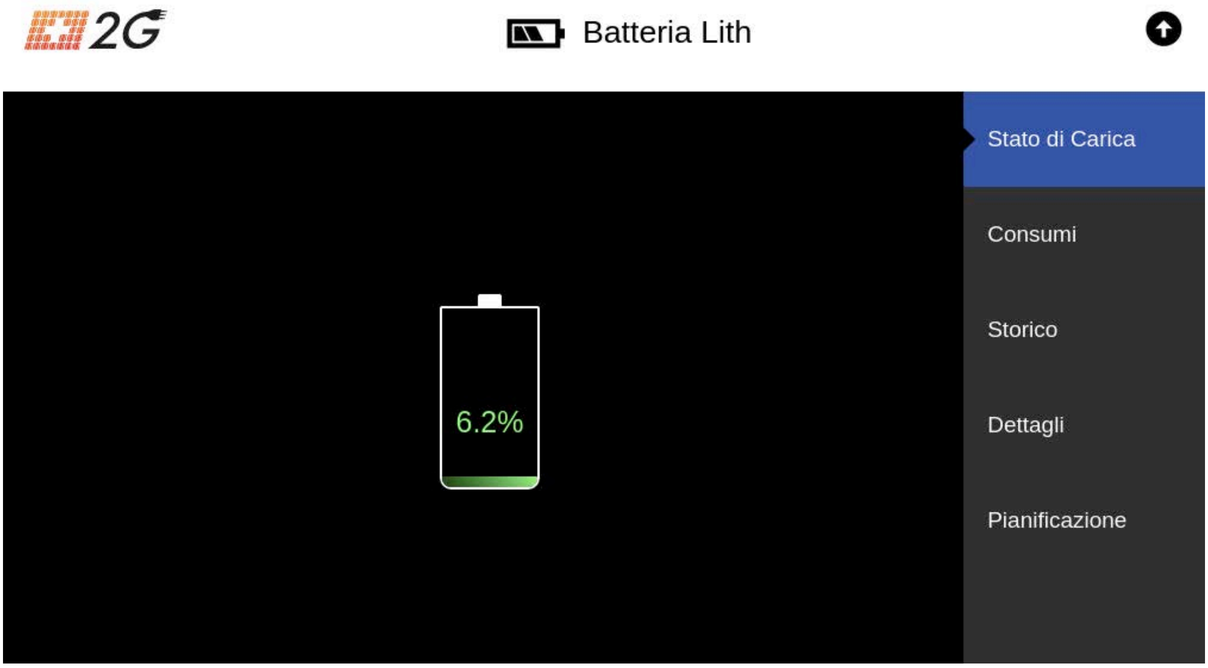


Figure 21: battery view: level of charge

Photovoltaic view

The Photovoltaic (*Fotovoltaico*) menu includes the following items: Energy (*Energia*), History (*Storico*), Technical Details (*Dettagli*).

Figure 22 shows the result of the “Energy” item selection. The graphic shows the active power in a four-hour interval.

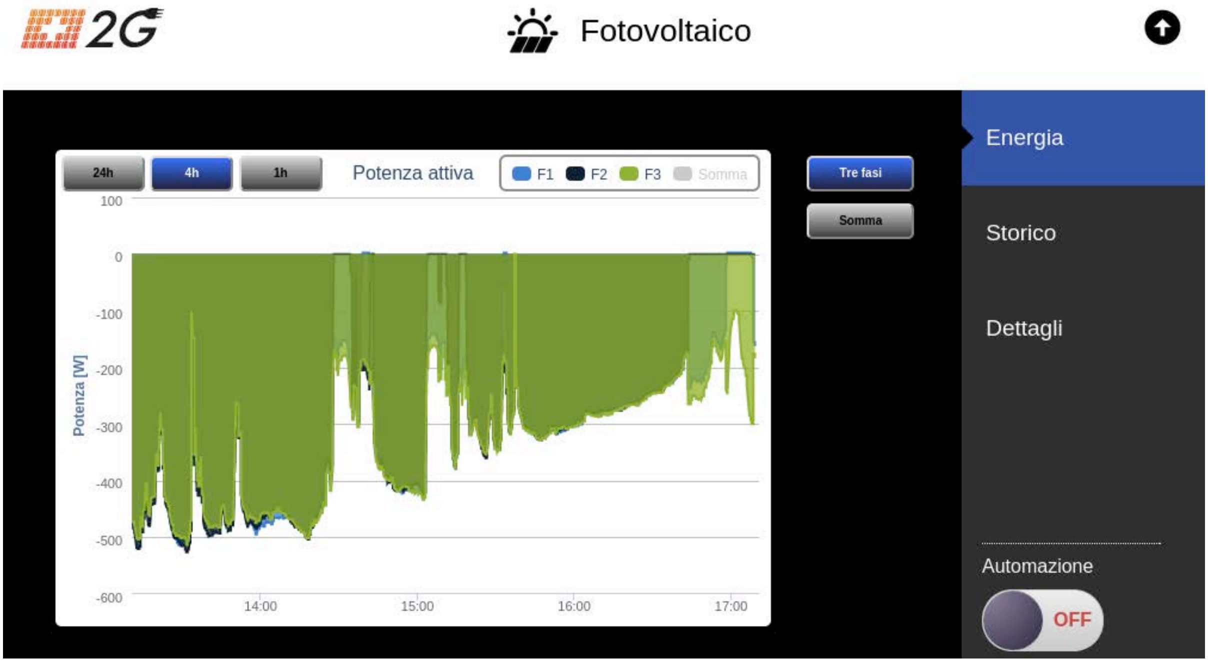


Figure 22: Photovoltaic view: energy

Heat pump view

The Heat pump menu includes the following items: Temperature (*Temperature*), Consumption (*Con-*

sumi), History (*Storico*), Technical Details (*Dettagli*) and Scheduling (*Pianificazione*).

Most of them are similar to the previous devices, except for temperature. Figure 23 shows the result of the selection of the “temperature” item of the menu. On the left side it shows a slider where the user can set the desired minimum and maximum temperature and at the centre the current temperature.

Figure 23: heat pump view: temperature

4.5. Components: Battery to grid system

We designed a **Battery-to-Grid (B2G) system** suitable for a household installation. The battery technology was selected to ensure a safe behavior in a domestic environment. In the S2G-Home we installed a 24V/200Ah Lithium-Iron-Phosphate (LiFePO4) battery and a 24V/300Ah Sealed-gel Lead-acid battery. The safety is especially critical for the Li-Ion battery pack. The chosen LiFePO$_4$ chemistry is one of the safest options. Moreover the battery pack embeds an industrial grade battery monitoring system (BMS) with an electronic safety switch. A block diagram of the realized B2G system is shown in Figure 24.

The battery is connected to a 2.4kW AC multi-functional grid-tied charger/inverter (Studer XTM 2400-24, Studer Innotec SA, Sion, Switzerland). We selected this inverter because it has a high level of customization and parameterization. We used this flexibility to adapt the charge modes and voltage levels to the Li-Ion battery chemistry. Moreover these parameters are externally accessible and modifiable via a RS232 serial line. We used this communication interface to drive the inverter from the HAC with the decentralized control algorithm. The BMS of the battery of the Lithium-Ion battery is also connected to the HAC by a CAN bus line, allowing to monitor the relevant parameters, in particular the state of charge of the battery.

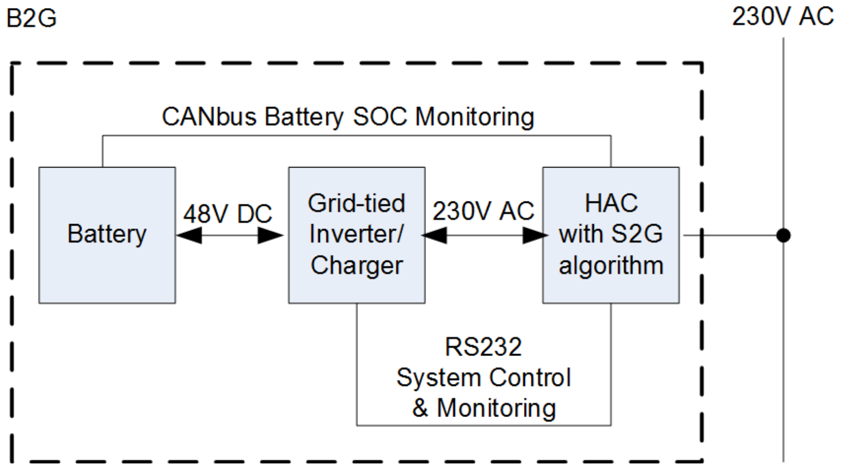


Figure 24: schematics of B2G system

We built two prototype of the system in the Trevano test facility. This permitted to verify the design and to perform tests by controlling the batteries with a software connected to the communication lines (CAN bus and RS232). The chosen Lithium-Ion battery was a 24V / 160Ah battery pack from Clayton Power. The other battery chosen was a sealed gel Pb-acid 4x6V / 300 Ah battery pack from Hoppecke.

By using the Lithium-Ion battery the system was able to achieve 3000 cycles of lifetime up to 70% DOD. The injected current to the grid can reach 10A and the charge current 7A.

Figure 25: detail of the prototype of battery systems

4.6. Components: Home Charge Device

One-way smart charge of electric vehicle

We have three electric vehicles available to the project:

- Trevano Test facility: Mitsubishi i-MiEV
- HH12: Peugeot iOn
- HH19: Renault Zoe (ordered by the participant, delivery first week of July)

In order to be able to control the charge in an intelligent way a home charge device (HCD) was provided by Protoscar. We modified this device by installing a HAC unit and connecting the HCD control board to the HAC via a RS232 line. The firmware of this device has been modified in order to enable interaction between the user and the S2G algorithm. By using the HCD interface (LCD + keypad) the user is able to confirm the desired due time for recharging and to enable/disable the algorithm. In the other way the algorithm was able to set the desired charging current. This charging current value was sent via the Mode 3 cable to the charging device of the electric vehicle. This system enabled us to start/stop the charging process and change the charging current from 6A to 15A (Mitsubishi MiEV) without any modification of the car.

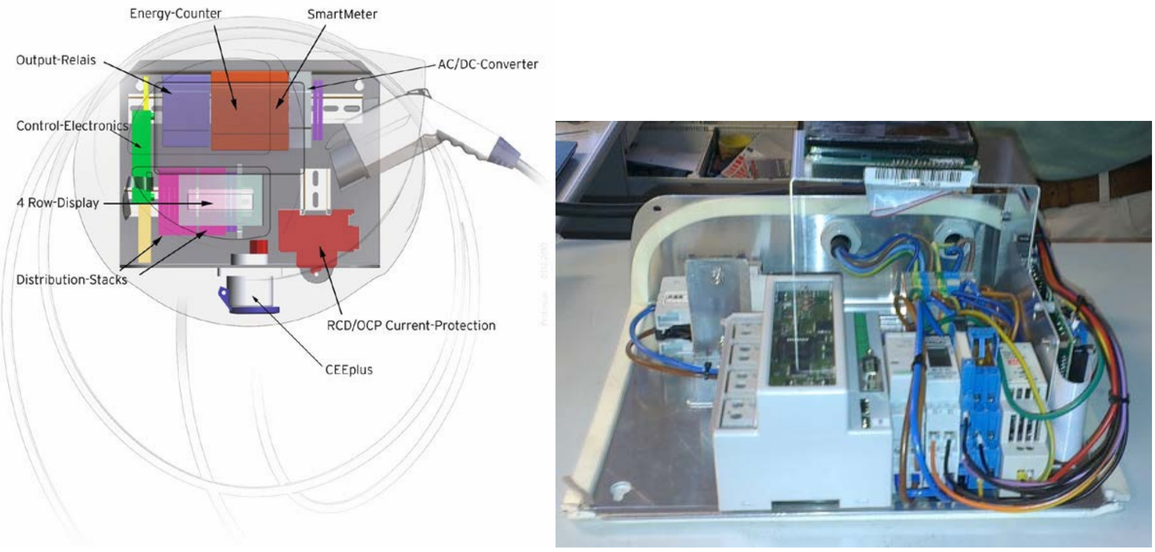


Figure 26: EV Home Charge Device (HCD) with an HAC

This functionality has been realized and tested at the Trevano test facility at the beginning of 2013. We currently installed a charger in HH12 and next month we plan to install another charge device at HH19 household. This household will use a Renault Zoe allowing us to test a 3-phase charger up to 11 kW controlled by the S2G algorithm.

4.7. S2G-Home Test Facility

The S2G team has realized a test facility on the SUPSI campus in Canobbio. The rationale behind this test facility is to allow preliminary testing on the hardware components and on the algorithm scenarios prepared by IDSIA.

The test facility had been named “S2G-home” and has the following components:

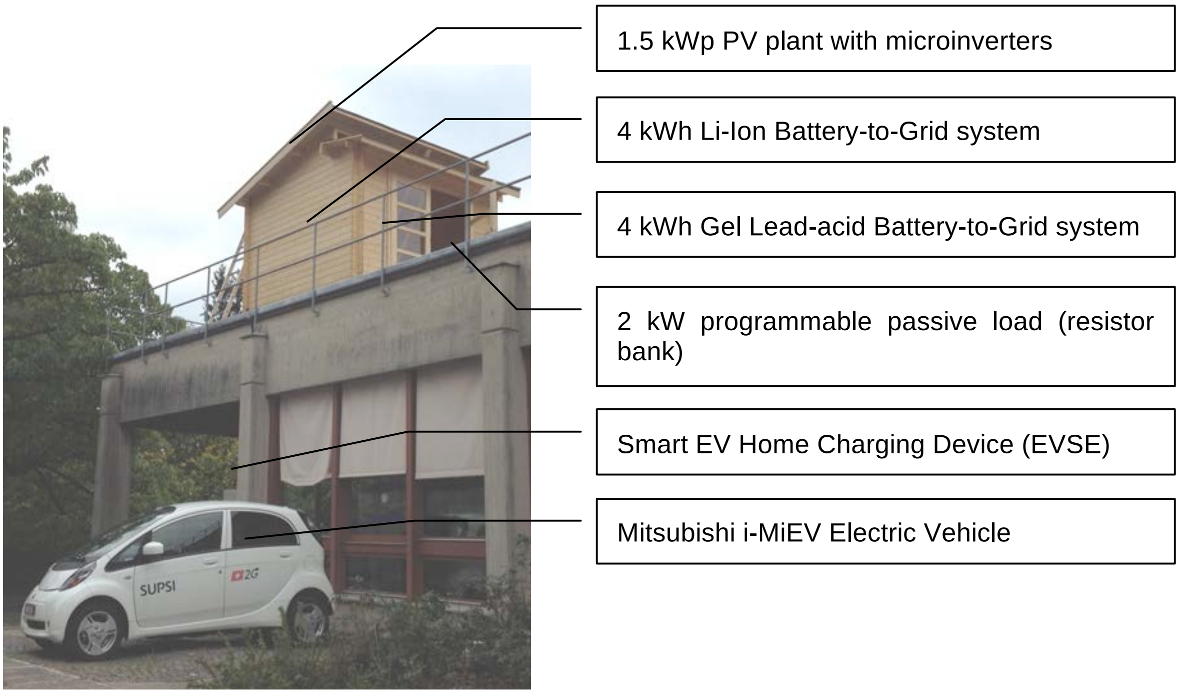


Figure 27: S2G-Home components and features

Synthetic load

We also planned to test two washing machines and two laundry drying machines. We evaluated the available devices on the market and we didn't found any appliance with a suitable domotic interface. We also contacted a Swiss manufacturer, which was interested to participate in the project but unfortunately, at the moment, he had only a hoven with a domotic interface, the washing machine and the laundry driers were planned in 2014 after the end of our project. We also analyzed the energy requirements of the devices current available on the market and we decided that the modern appliances are not interesting for energy shifting because of their increasing energy efficiency: 150 kWh/year for a washing machine and 200-300 kWh/year for a laundry drier (source: topten.ch). This low energy capability is also coupled with a requirement of user behaviour modification increasing the barrier for the algorithm acceptance.

For these reasons we decided not to tests all devices in the households. Anyway we found interesting to perform some hardware tests in our Trevano facility. We developed a programmable active load, which can be used to simulate any appliances of the house. This active load can go up to 2.5 kW power with 20W steps. We developed test software, which can be used to reproduce the load profile that we are monitoring in the project households.

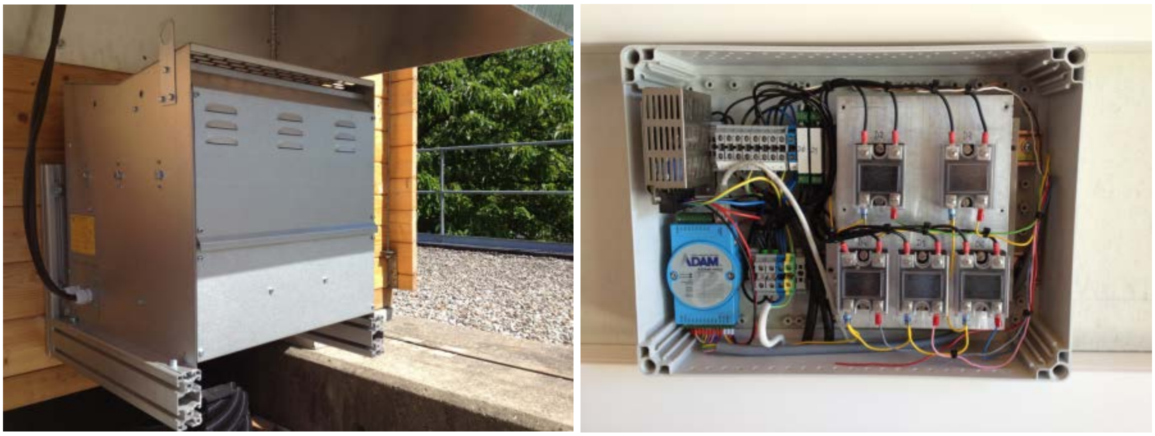


Figure 28: 2.5 kW programmable active load

Control software interface

We developed multiple interfacing options in order to maintain a single codebase for the algorithm and allow easy testing in different scenarios (simulation, S2G-Home test site, Mendrisio pilot households). This enables continuous improvements to the algorithm inner workings without affecting the finalized interfaces. The improvements of the algorithm can be simultaneously deployed in the simulation, the test facility and the pilot households.

4.8. Pilot installation

4.8.1. Calibration

After the HAC had been assembled, it was necessary to calibrate it in order to achieve the declared resolution. This was done in SUPSI in the ISEA Department. Fig. 1 shows the calibration of a 3ph HAC. The calibration process takes only 2 minutes and is partially automatic. The personal intervention was to connect and disconnect the HAC from the grid and the PC and to program the calculated calibration value in the HAC. It is possible in the future to do it completely automatically (in a mass production).

Figure 29: test and calibration of the 3phase HAC

4.8.2. Installation

In the next figure we display the 1-phase and 3-phase HAC ready to be installed.

Figure 30: 1-phase and 3-phases HACs

A typical installation setup is shown in the following figure.

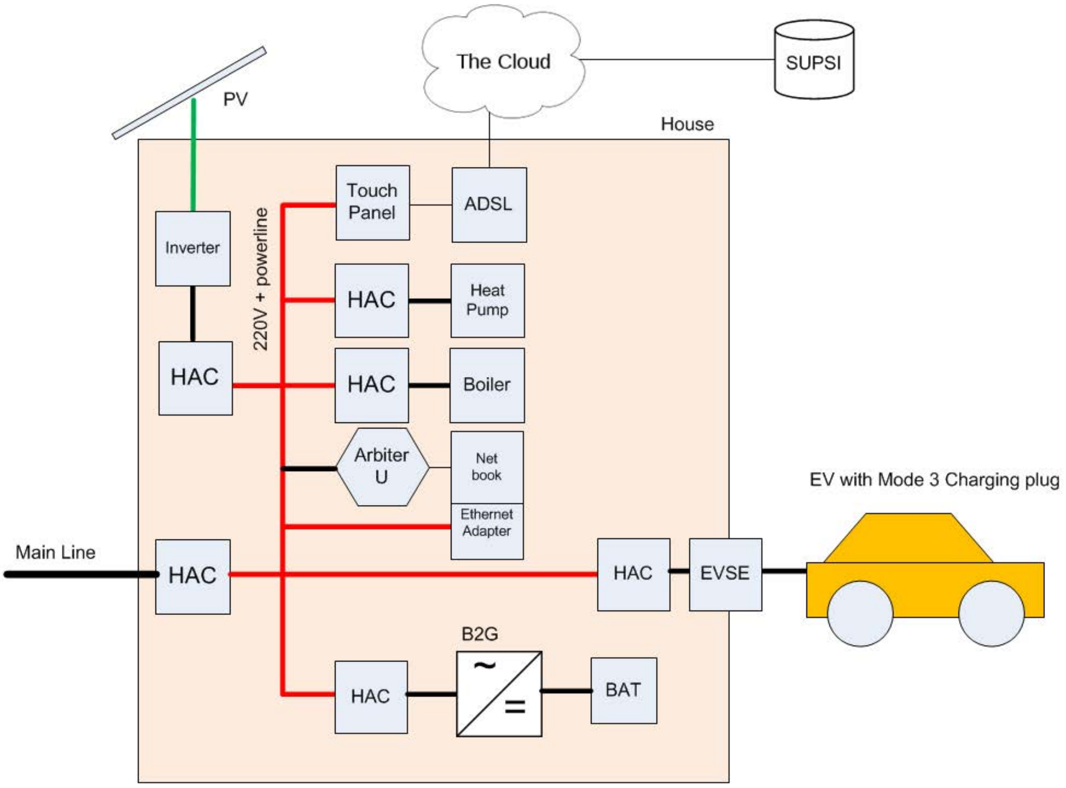


Figure 31: Typical installation setup of 1-phase and 3-phases HACs

At the beginning we installed the GRID and PV 3-phase HAC. The PV HAC measured the PV production and the GRID HAC measured the consumption of the whole household. The PV connection was in self-consumption mode, the energy produced by the PV system was used by the household and only the exceeding energy was injected into the grid. These HACs were typically installed in the main electric panel. Occasionally not enough space was available in the main panel unit and an additional cabinet had to be installed as shown in the next figure.

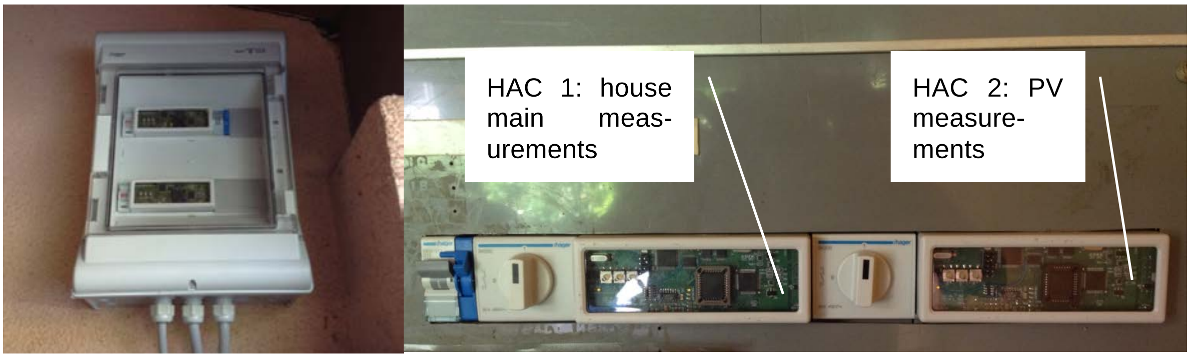


Figure 32: Example PV and Grid HAC installations

The Remote PC had been installed in every household in a location so that the users could see also information visualized by the user interface. During the first installation phase the Remote PC was used only as data concentrator for the acquisition system.

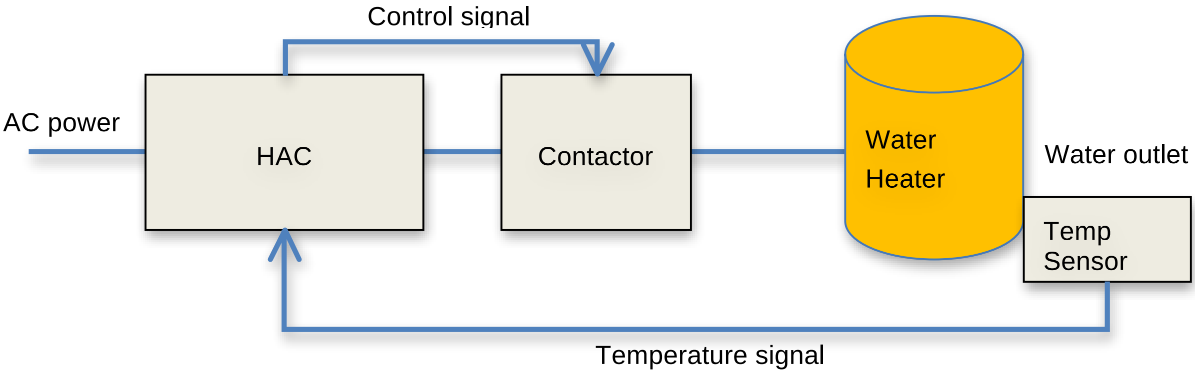
Figure 33: Remote PC unit installation

After this first installation phase we started to install the appliance HACs. Simple appliances like fridges, dishwashers and laundry machines were connected to the monophase HAC.

For the heat pumps and boiler a dedicated electrical cabinet was installed in the technical room. The 3-phases HAC were used to monitor these heating systems. With the help of the local DSO we identified the suitable houses. We chose the houses with night loads over 3kW (activated by the DSO remote control) and the houses equipped with heat pumps. The DSO gave us the permission to temporarily disable the remote control in order to give total freedom to the algorithm to control the loads.

The HAC were installed nearby the thermal buffers. With electrical water heaters the control are done by a contactor controlled by the HACs which will cut the power supply of the water heater for a limited amount of time. With the heat pumps the HAC is using his relay output to control the “EVU-Sperre” input of the heat pump. The signal disables the heat pumps in a proper and safe way. Temperature sensors were installed in order to monitor the water outlet temperature. This sensor was connected to the digital inputs of the HAC.

The figure shows the installation block schema:



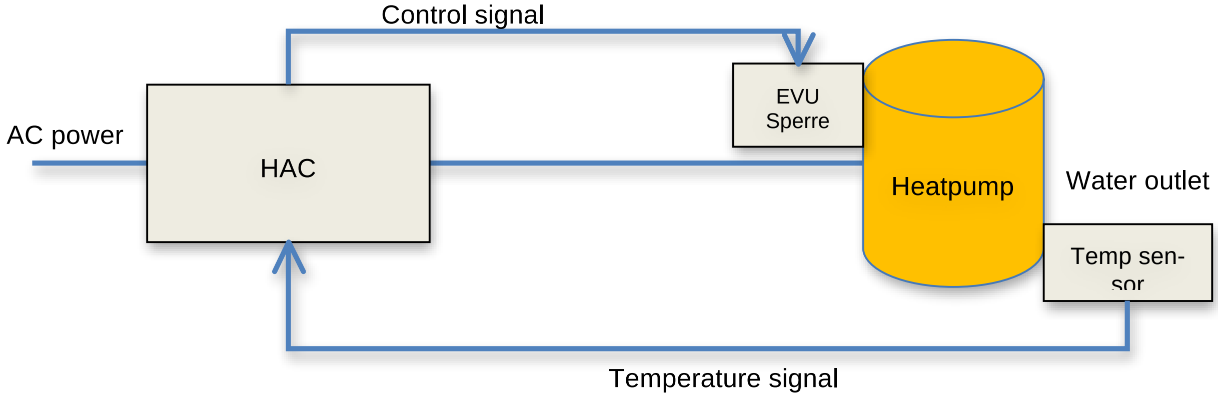


Figure 34: Cabling schema for monitoring and control of boiler and heat pumps

The following figure shows an example of the installation.

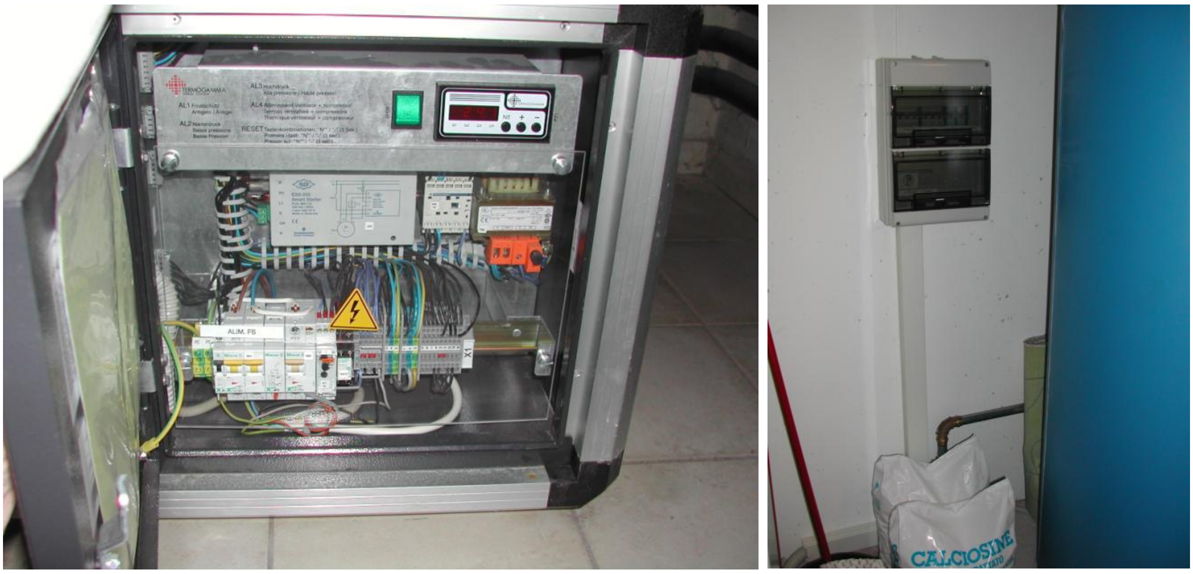


Figure 35: Heat pump control panel and HAC installation

Four households were also selected for the installation of a battery to grid system. The priority was given to the Asilo Genestrerio (neighborhood with higher density of participants). This transformer has also the advantage to be monitored by the grid meter from Bacher Energie AG. For this reason we preferred the house connected to the LV lines monitored at the transformer. The selected locations for the B2G installation are:

- HH01: connected to the Campagnola 100 LV line (monitored at the transformer)
- HH05: connected to the Pero 130 LV line (monitored at the transformer)
- HH06:
  - connected to the Campagnola 100 LV line (monitored at the transformer)
  - monitored by Arbiter grid measurements device (voltage local plug)
- HH09:
  - connected to the Pero 130 LV line (monitored at the transformer) monitored by Arbiter grid measurements device (voltage local plug)

The system was installed in an electrical cabinet, containing the battery, inverter, displays and safety switches. The cabinet was connected to a triphase plug of the households. The inverter is monophase but a triphase connection will permit to easily switch the connection phase during the test period and to test the algorithm performance with different situations at the same household. The HAC firmware has been updated in order to control and monitor the inverter and the battery. All the information were sent via powerline and exposed by the DomoML interface to the S2G algorithm.

Figure 36 shows the installation of the battery-to-grid system inside a household.

Figure 36: Battery-to-grid system installed in the households

4.8.3. Lessons learned

From the pilot part of the project several lessons can be learnt.

Household recruitment

During the households recruitment phase we setup a list of preferential options in order to guide the participant's selection. These options were the willingness to increase the PV plant size, to buy an electrical vehicle and to accept the installation of a battery in the house's technical room. After a preliminary selection we conducted interviews with the potential project candidates and we discovered inconsistencies between the data they previously input in the form and their real intentions. Sometimes this happened because of lack of technical knowledge, for example we saw lot of confusion between hybrid and electric cars.

Therefore we advise for pilot project involving private households to take in account that the candidates are not technical skilled and the information they provide has to be properly screened.

Installation with accredited technicians

The project pilot consisted in the installation of PV generators, monitoring and controlling equipment. During the project we discovered our installation plan was very optimistic both in time and finances. The installation in private households required the need to use different types of accredited technicians. For example in this project we needed low voltage electricians, PV installers, plumbers, carpenters, and antenna technicians. The interface between these technicians and the house owners was very time consuming. Moreover during the project additional interventions in the houses were needed adding extra costs in the installation budget.

We advise for these kind of projects to have lump sum agreement with these technicians in order to limit the financial risks in the project.

Lack of remote firmware update system

The HACs developed in the projected didn’t dispose of a remote firmware update feature because of time constraints and delays during the development. This required a physical intervention in the households in case of problems adding additional work during the monitoring phase. Moreover the need for software updates had an impact on the quality of the acquired data.

We advise that a software update capability should be a hard requirement before the installation of such hardware devices.

5. Swiss2Grid Algorithm

5.1. Development of algorithm scenarios with varying levels of communication

This section studies the performance implications of varying levels of communication between algorithms in different households.

In order to “proof” the concept of local measurement – no communication, a smooth path from “full communication” towards “no communication” was implemented and tested in simulation.

When a bidirectional communication infrastructure is in place, we defined the concept of *neighborhood* as the set of households able to communicate among each other. We defined the *full neighborhood* case as the scenario in which all households connected to the same MV-LV transformer can communicate among them. We also studied the scenario in which the households under a transformer are partitioned in a set of smaller, distinct neighborhoods, composed by as few as two households.

Every household computes its own forecast load for the next 24 hours, and broadcasts this information to its neighbors. The forecast load was computed by the households accounting for the contribution of both its controllable and non-controllable appliances.

Future loads of non-controllable appliances were predicted by considering the average load of such appliances as measured during the previous 3 months for the same time of the day and day of week.

Each controller repeatedly solved the S2G algorithm in a non-synchronized fashion. In our experiments, optimizations are triggered on average *52.4* times per day per household. It is important to remark that for a 24 hours horizon, using a common CPU, the solution of the household optimization problem takes less than 1s, such that computational aspects are not really an issue.

Communication infrastructure, requirements and protocol

Since communication can occur exclusively only among HAC controllers in the same neighborhood, no strict technological requirements were needed to be imposed on the characteristics of the communication infrastructure. Communication losses among controllers would result in a smooth degradation of system's load flattening performance: in the worst case, if all controllers lost communication abilities, the system would behave like in the baseline case (i.e. no communication at all). Remarkably, thanks to the fully decentralized model, the choice of communication infrastructure is flexible and can potentially be different for different neighborhoods.

The communication protocol uses a single message type, wherein a controller broadcasts its ID (assumed to be unique within the communication neighborhood), and its expected load for each *15*-minute timeslot in the next 24 hours.

In terms of bandwidth, when encoding the controller ID with 4 bytes and the expected load at each timeslot with 2 bytes, the size *L* of each message amounts to 4 + 2 x 24 x 4 bytes.

Additional payload might result from the characteristics of the technologies used to implement reliable local data communication in the network.

On average, each controller broadcasts a message twice per hour (i.e., after each rescheduling). Then, the total expected payload generated by a single controller amounts to about 10kBytes per day, i.e. roughly 1 bit per second (bps).

Our experience shows that up to relatively large values of number of households this amount of traffic can be reasonably handled by available powerline communication (PLC) or wireless technologies. For example, the set of narrow-band PLC standards promoted by the PRIME Alliance for metering provides a minimum throughput of *21.4* kbps http://www.prime-alliance.org/, whereas the G3-PLC specification http://www.g3-plc.com/, backed by several companies providing inexpensive, interoperable implementations, yields a *33.4* kbps data rate; similar performance can be expected from the P1901.2 standard being developed by the IEEE http://dx.doi.org/10.1109%2FMCOM.2008.4557044

Note that communication requirements only depend on the amount of households in each communication neighborhood, and are not affected by the total amount of neighborhoods. Therefore, the system is inherently scalable to huge deployments, provided that the size of each neighborhood does not exceed the specified limits.

Assessment of the results

We have performed several simulation experiments on a set of 120 households. All households are downstream a single MV-LV transformer.

Communication-free scenarios

Baseline: No demand side management.

Baseline-random: Appliances were managed by a controller that randomized their behavior, still meeting their operational constraints.

Cost: Controllers only implement the single-objective optimization of end used energy costs.

Cost-random: Controllers implement single-objective optimization of energy cost and randomization.

Communication scenarios

C-n: 120 households are divided in 120/n neighborhoods we analyze each scenario with n={2,3,4,5,6,8,10,20,60,120}. E.g scenario *C-2* implies that each pair of households are communicating among them, while *C-120* implies full communication between all simulated households.

Stability-120: stability is optimized with full communication.

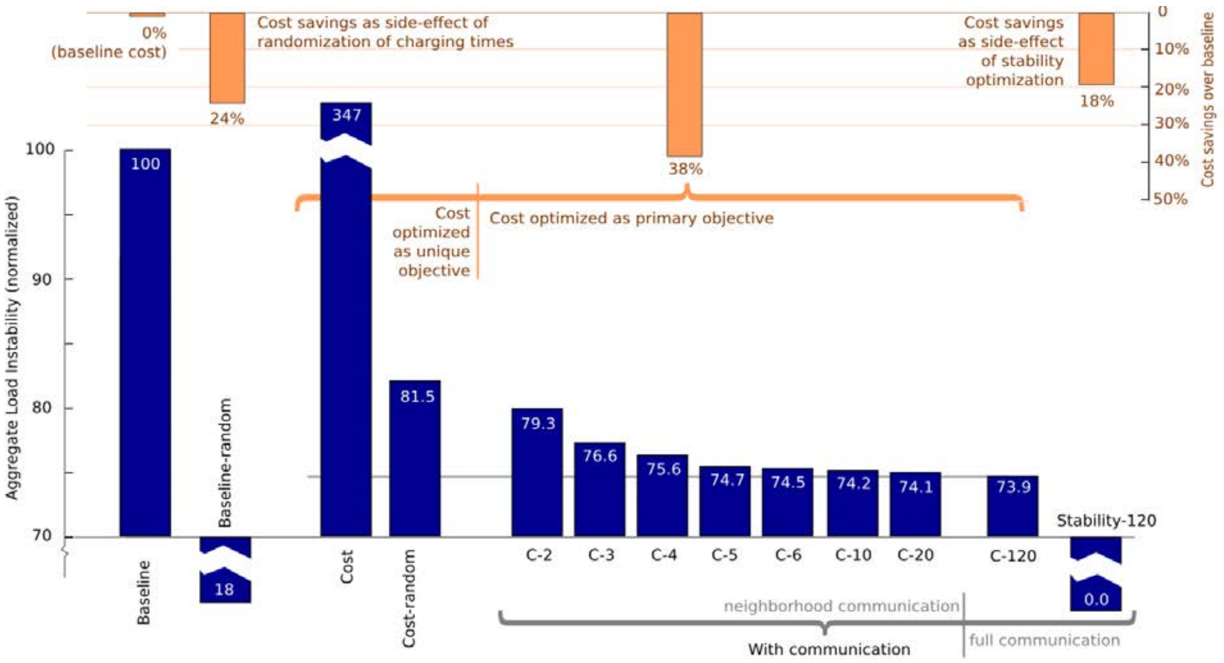


Figure 37: Summary of results for decentralized communication. Baseline case is normalized so that its costs represent 0% and stability performance amounts at 100%. Randomization helps in both reducing the costs and stabilizing the network. When cost savings are optimized at its maximum (i.e. maximum 38% cost savings), network stability (as defined in Giusti et al, 2014 referenced below) is severely deteriorated. When we enable network stabilization via communication we can ***still obtain optimal cost savings (38%)*** *while stabilizing the network with a performance lower than the 80%. We observe that pervasive communication does not help to improve more than 73.9%*

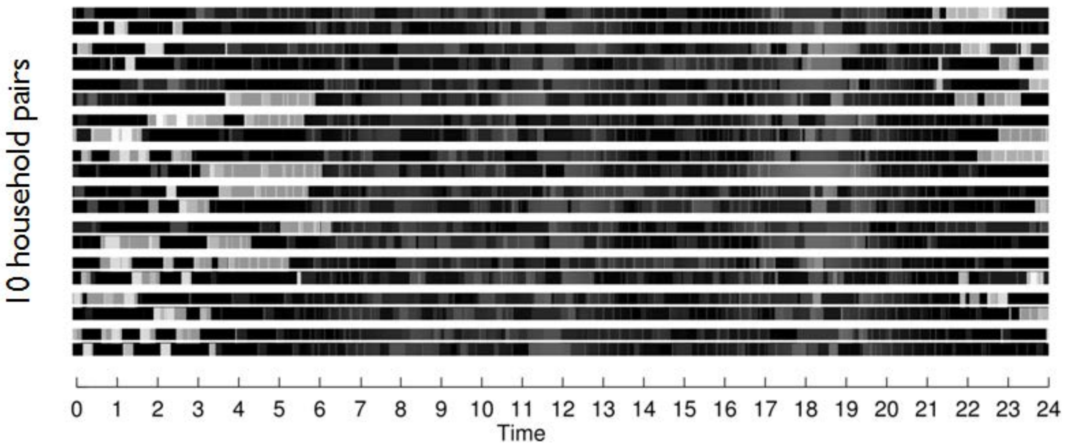


Figure 38: A detailed representation of a C-2 scenario, representing one day of simulation. Every row depicts the load of an household (bright: high load; black: no load). Rows are paired as pairs of households are enabled to communicate among them. We observe that high loads are rarely placed simultaneously by both households in the same neighborhood. More details in (Giusti et al., 2014).

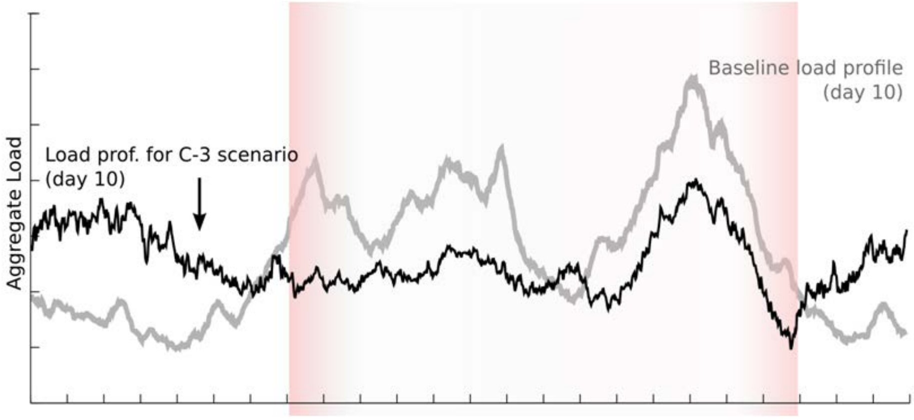


Figure 39: Detailed results for the Baseline and C-3 case. The overall network load at the MV-LV transformer is reported for day 10. The overall load is substantially flattened with a remarkable load shift towards periods with low price of energy.

Communication

Above results have been published in the following paper:

Giusti, A; Salani, M.; Di Caro, G.A; Rizzoli, AE.; Gambardella, L.M., "Restricted Neighborhood Communication Improves Decentralized Demand-Side Load Management," Smart Grid, IEEE Transactions on , vol.5, no.1, pp.92,101, Jan. 2014 doi: 10.1109/TSG.2013.2267396

5.2. Development of algorithm for voltage forecasting

The section studies different algorithms for forecasting future voltages measured at the plug thereby fundamentally assuming that load (electricity consumption) behavior follows similar patterns. According to results obtained in the monitoring I work package of phase A in the grid of Mendrisio, a significant dependence is present at the MV-LV transformer between voltage and grid loading in given situations.

Prediction of voltage profiles

Extensive simulations with logged data in 2013 Jan-Sept have been performed to verify:

- predictability of voltage profiles
- regularity of voltage profiles in different days
- drifting of voltage patterns along different seasons
- correlations among voltages and powers

We have implemented a Voltage forecasting algorithm based on Exponential smoothing (see Chatfield, Chris. Time-series forecasting. CRC Press, 2002) with the following characteristics.

- Error compensation (short-term improvements)
- Holt-Winters seasonal components (season = day)
- No trending component

We verify that voltage is well predictable and that algorithm decisions match the observed voltage and power profiles.

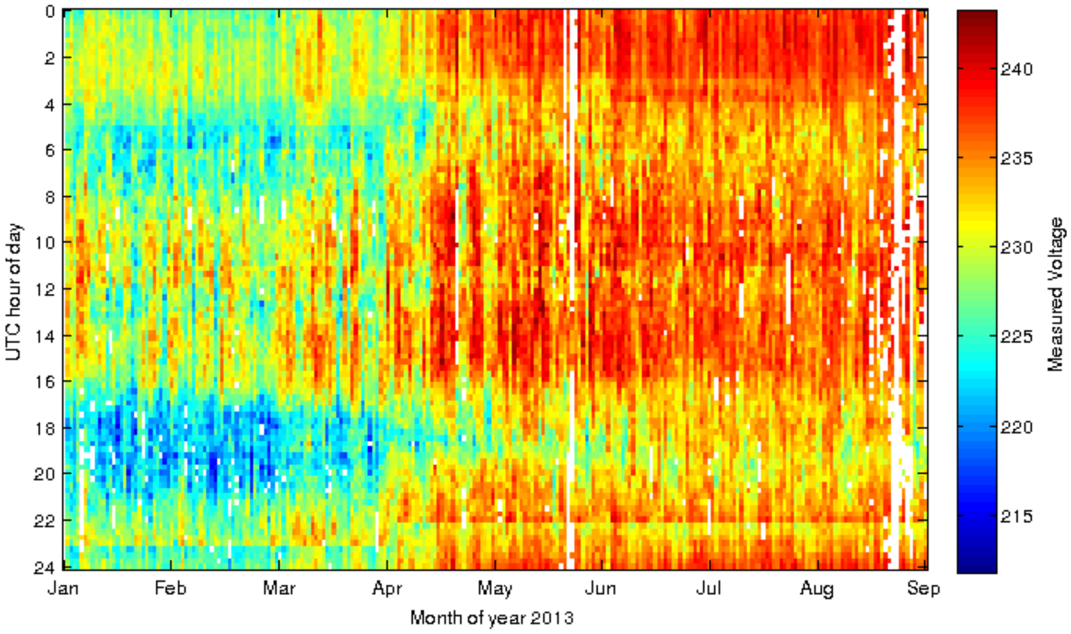


Figure 40: Pattern of measured voltage in Mendrisio household HH01 for different hours of day (y axis) and days of the year (x axis). Voltages are represented through the scale reported in the right colorbar.

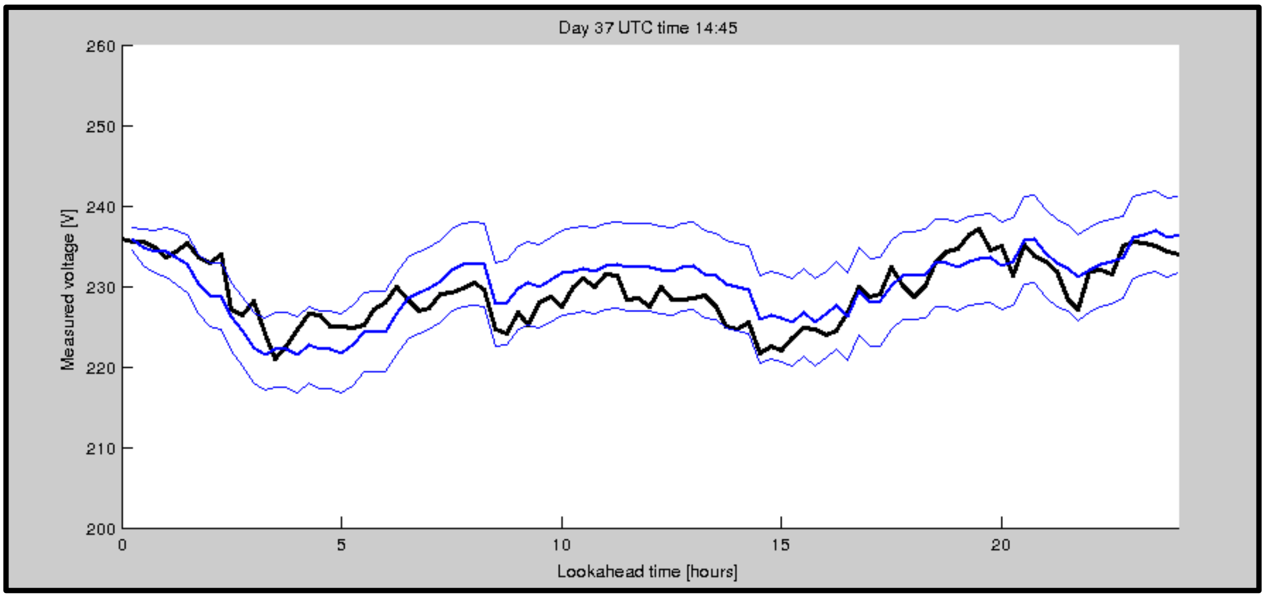


Figure 41: True voltage (black) and forecast voltage (blue) with 95% confidence interval (thin blue) after a 5-day training period. Household HH06, Mendrisio. February, 6 2013, 14h45 (Begin of Lookahead period)

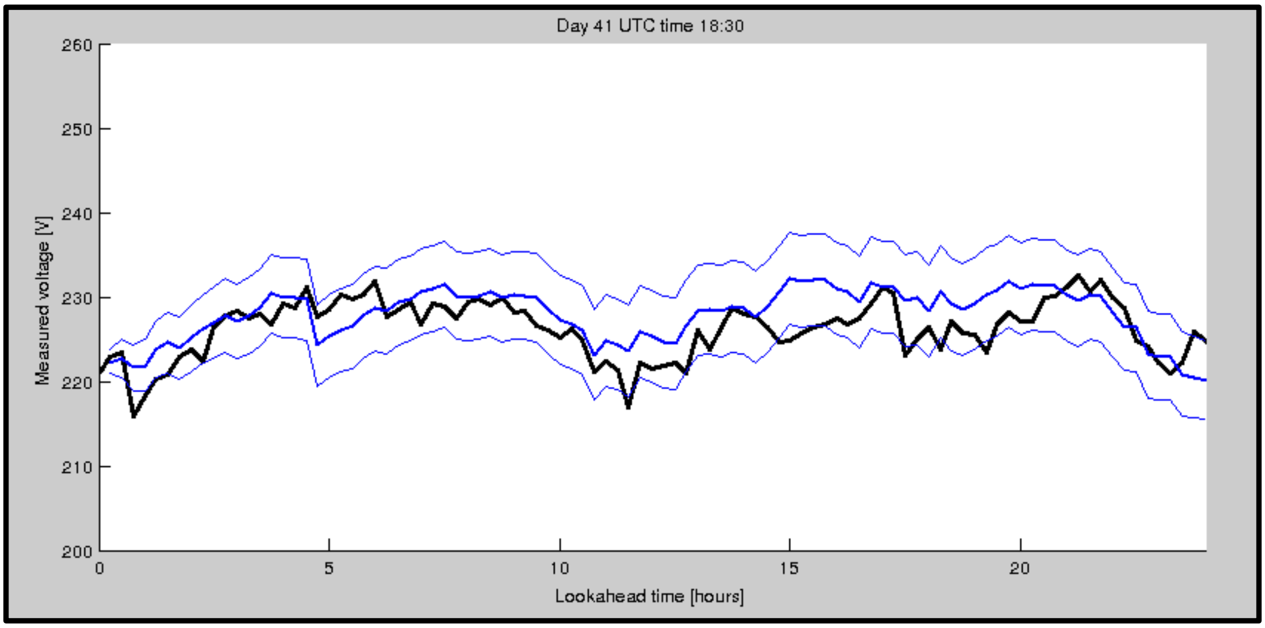


Figure 42: True voltage (black) and forecast voltage (blue) with 95% confidence interval (thin blue) after a 5-day training period. Household HH06, Mendrisio. February, 10 2013, 18h30 (Begin of Lookahead period)

Automated compensation of self-induced voltage drops

We observed, both in simulations and in field tests, that loads controlled by the S2G algorithm affect the measured voltage, causing a self-induced voltage fluctuation. We verified in simulation that considering such self-induced voltage fluctuation as an input for the algorithm decisions leads to a weak but measurable decrease in the algorithm's performance. Therefore, we implemented a method for automatically compensating voltage changes caused by controlled loads themselves.

The methodestimates the voltage change caused by a given load change by linear regression on historic data, considering measurements in the previous two months; the operation is implemented at every system startup and repeated every week; then, the corresponding correction factor is automatically used to correct measured voltage values to account for the voltage change due to the measured power value change.

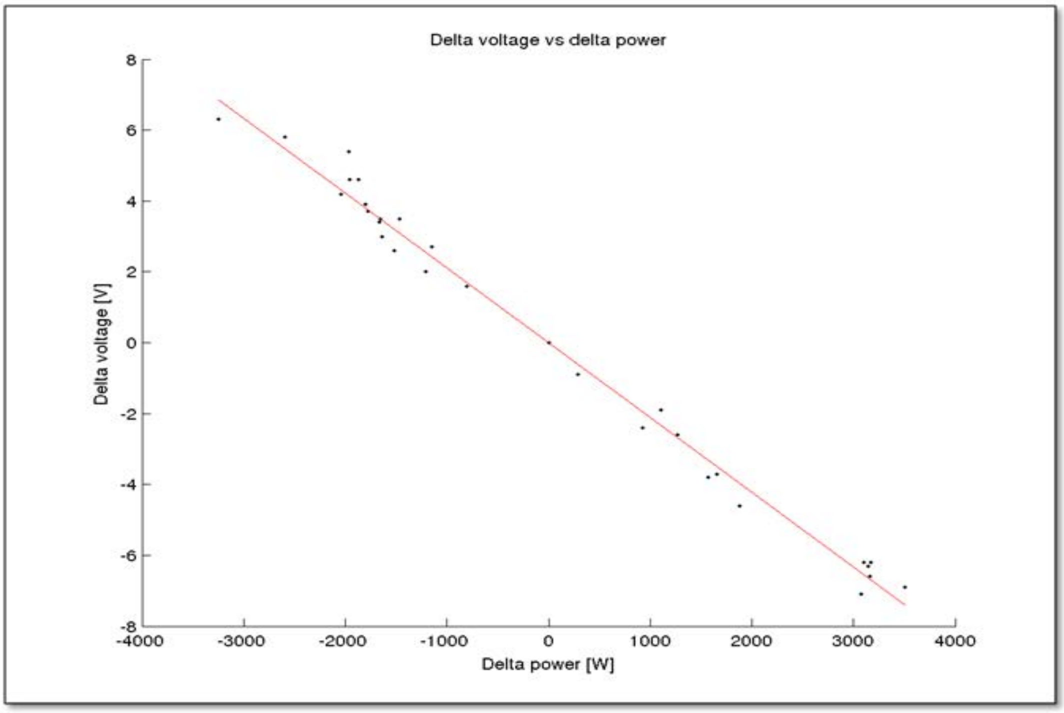


Figure 43: Voltage changes depending on differences in absorbed power. At this household location, the voltage changes by about 2 Volts per kW. We observed that different monitored households yield different correction factors.

Extra activity: preliminary study about more sophisticated machine learning approaches (with inconclusive results)

Because during algorithm testing it become apparent that the voltage forecasting techniques were a fundamental factor for performance, IDSIA extended this task in early 2014 with a preliminary analysis of more sophisticated forecasting algorithms based on machine learning. The core idea is that algorithms based on machine learning could be able to capture some complex patterns in the data, which cannot be handled by simpler algorithms implemented so far. For example: we expect that observing raised voltage during the first hours of daylight suggests that the weather is clear (and thus PV is producing energy), which should increase the probability of observing higher voltages later during the day due to expected continued sunshine; on the contrary, an overcast day (assuming that the sunshine intensity in the area remains the same for the day, scaled only by the time within the day)could also be detected before the end of the morning.

The analysis we performed is reported below. Different sophisticated forecasting techniques based on machine learning (FitNet, NAR) were tested and compared to forecasting techniques which are currently implemented in the S2G system (Exponential Smoothing, see above), as well as other classic forecasting methods (ARIMA, AR, SMA). These methods are described in the section below.

Methods

In this project, we aim to predict the future voltage data y_t, y_{t+1}, ..., y_{t+N-1} using the previous ones y_{t-m}, y_{t-m+1}, .., y_{t-1}, where M is the number of historical data used to forecast, and N is the number of future values being forecast. The forecasting effectiveness of different forecasting methods are tested, including simple methods and the complex models: simple moving average [3], a simple seasonal method with error correction [1], autoregressive model [4], autoregressive integrated moving average model [4], function fitting neural network [5], and nonlinear autoregressive neural network [6]. The details of these methods are presented in this section.

Simple moving average (SMA) is the simplest method to forecast the future values by simply computing the average value of a few previous data:

$$\hat{y}_{t+i} = \frac{\sum_{j=1}^{M} y_{t-j}}{M}, i = 0, 1, \ldots, N-1. \tag{3.1}$$

It is used as the comparison criterion.

A seasonal method with error correction is simply the average value of seasonally historical data followed by a simple error correction method. As mentioned before, the voltage has shown daily-seasonal patterns. Thus, this method predicts the future voltage value by averaging the values at the same time point in previous days. Let m be the period of the seasonality, $l = \frac{M}{m}$ be the number of available seasonal data, and the future values can be computed by:

$$\hat{y}'_{t+i} = \frac{\sum_{j=1}^{l} y_{t+i-jm}}{l}, i = 0, 1, \ldots, N-1. \tag{3.2}$$

The error correction is also easy. First, the last available voltage value (at the same time point on one day ago) is predicted using the average of data on previous days:

$$\hat{y}_{t+i-m} = \frac{\sum_{j=2}^{l} y_{t+i-jm}}{l-1}, i = 0, 1, \ldots, N-1, \tag{3.3}$$

and then the error between them can be estimated:

$$e_{t+i-m} = \hat{y}_{t+i-m} - y_{t+i-m}, i = 0, 1, \ldots, N-1. \tag{3.4}$$

Finally, the forecasting equation can be represented as:

$$\hat{y}_{t+i} = \hat{y}'_{t+i} - w_i e_{t+i-m}, i = 0, 1, \ldots, N-1, \tag{3.5}$$

where w_i is the weight of the error correction term, $w_i = 0{:}9 \times (i+1)^{-0.3}$, in our experiments. No training or parameters tuning is needed.

Autoregressive model of order m. We forecast the one-step future voltage value using a linear combination of the past data:

$$\hat{y}_t = c + \phi_0 y_{t-1} + \phi_1 y_{t-2} + \ldots + \phi_{M-1} y_{t-M}. \tag{3.6}$$

To apply multi-step forecasting, the forecast values can be used in the linear combination equation to forecast further steps. 14-day historical data is used as the training set. The difference between adjacent timeslot is predicted instead of the original voltage values.

Autoregressive integrated moving average model. In our experiments, we use the ARIMA (0, 0, 1) (0, 1, 1)$_{96}$ model. 14-day historical data is used as the training set. For better forecasting effectiveness, we map the voltage values to the range between -1 and 1.

Function fitting neural network. Here we suppose that the future m values can be estimated by the past m values, that is, there exists a relationship between past data and the future values. Thus, we aim to train a fitting neural network to represent this relationship f(.   ):

$$\{\hat{y}_{t+i}\} = f(\{y_{t-i-1}\}), i = 0, 1, \ldots, m-1, \quad (3.7)$$

and this neural network f to forecast the voltage. In the experiments, we use two hidden layers with 6 and 2 hidden neurons, separately. Furthermore, with different start timeslots, we train its own network, so there are in total m networks. 29-day historical data is used as the training set. The voltage values are mapped to the range between -1 and 1.

Nonlinear autoregressive neural network is a recurrent neural network, where the forecast values will be used as input (feedback) to forecast multi-step future values. We use one hidden layer with 10 hidden neurons. The inputs of the network is part of the past data at t-1, t-2, t-3, t-m, t-2m, t-3m, t-4m, and t-5m timeslots. 30-day historical data is used as the training set. The voltage values are mapped to the range between -1 and 1.

Results

In the experiments, the voltage values are averaged every 15 minutes, so we have 96-timeslot data in a day (that is, m = 96). To compare the performances of these methods, we plot the real voltage values and the forecast ones together. The root-mean-square errors are also computed to evaluate the performances quantitatively. An example is shown in the next figure. The abbreviations used in the figure are as below: simple moving average (SMA), a simple seasonal method with error correction (ES), autoregressive model (AR), autoregressive integrated moving average model (ARIMA), function fitting neural network (FitNet), and nonlinear autoregressive neural network (NAR).

From this figure - where time slot zero begins at midnight UTC - we can see that in general, all the other methods outperform the simple moving average, but there is not any method can predict the voltage accurately. For example, in the figure at the timeslots 45-60 (i.e. 11:15h-15:00h) and 80-90 (i.e. 20:00-22:30), all the methods do not forecast the voltage correctly. This may be due to the daily variance or due to exogenous reasons which are not predictable.

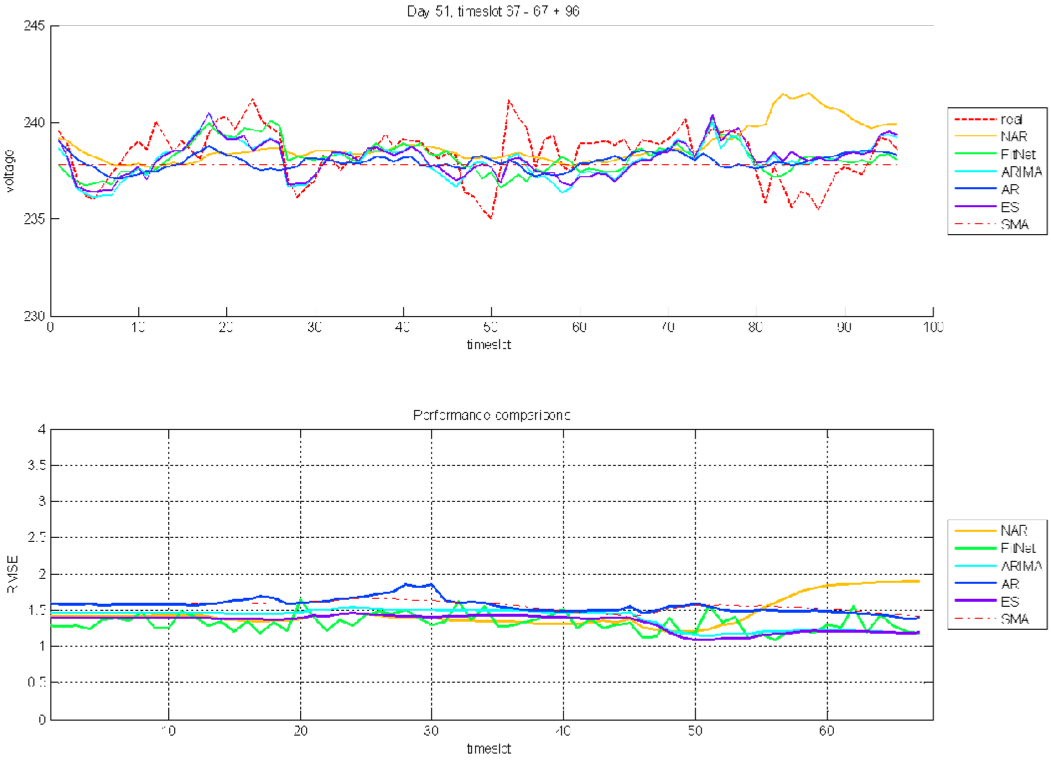


Figure 44: Qualitative and quantitative comparisons. The above image is the real voltage (in red dotted line) versus the forecast ones. The below figure is the change of rootmean-square-errors of these methods.

If we compare the ARIMA model versus the simple seasonal method (ES), as shown in Figure 45, it can be seen that they have quite similar patterns. It surprisingly indicates that the simple method can work as well as the complex model.

On the other hand, comparing the ARIMA model versus the AR model, as shown in Figure 46 the ARIMA model outperforms the AR model. Here we see that the forecast voltage is quite flat using AR model compared to using ARIMA model. In our parameter settings, the seasonal ARIMA model forecasts better than nonseasonal AR model. For example, at the timeslots 25-70 (06:16h-17:30h), most of the time the ARIMA model has similar output as the real data, but the AR model always underestimates or overestimates.

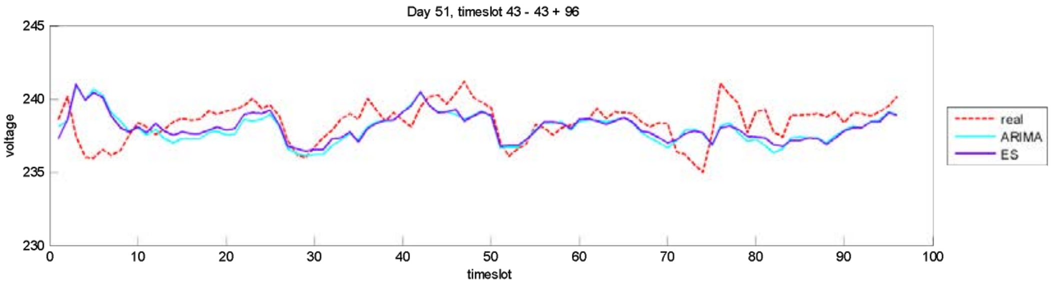


Figure 45: Comparison of the ARIMA model versus the simple seasonal method.

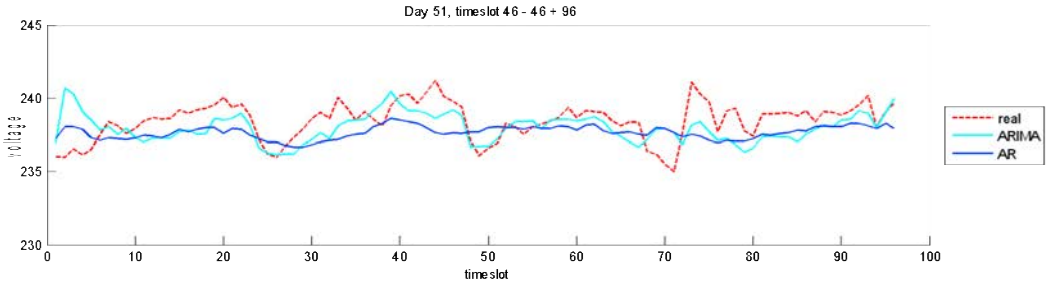


Figure 46: Comparison of the ARIMA model versus the AR model.

The performance of neural networks depends on the training stage. To prevent overfitting, we adapt early stopping. Thus, the initial weights of the neurons always affect the results. For example, after training the NAR again, the forecast voltage in Figure 45 is totally different from Figure 46; the same situation can be observed in Figure 47 and Figure 48 that the re-trained FitNet in the Figure 48 outperforms the Figure 47. In general, both of these two methods are unstable.

To compare the quantitative performances of these methods, we did the experiments on three phases of one dataset and on the 32nd and 51st days to start forecasting. Each time we forecast 96 timeslots (one day), 96 successive timeslots of voltage are forecast, and the 96 average root-mean-square-errors (RMSEs) are collected to depict the box plots. From the box plots, the most surprising discovery is that, the simple seasonal method is the most stable with the lowest RMSEs, even if it is so simple. As mentioned before, ARIMA model has the similar RMSEs but a bit higher than the simple method. The FitNet is quite unstable and always has bad performances. This may be explained with the lack of training data and the little relationships between the past 96 data points and the future 96 data points. The NAR is sometimes superior to others, but usually it does not forecast accurately. The AR model and the simple moving average always have bad performances.

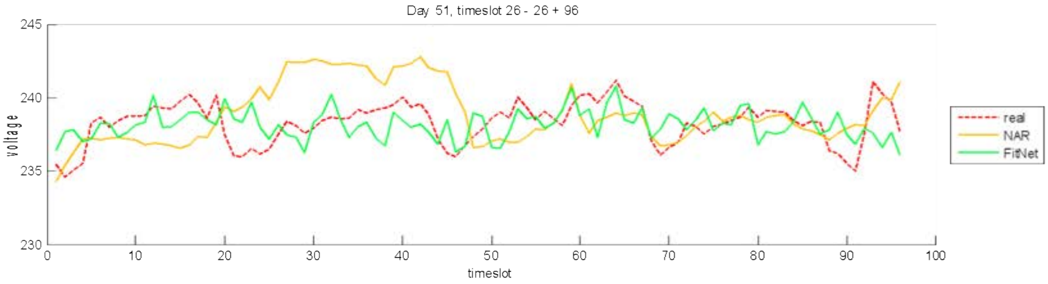


Figure 47: Comparison of the function fitting neural network (FitNet) and the nonlinear autoregressive neural network (NAR).

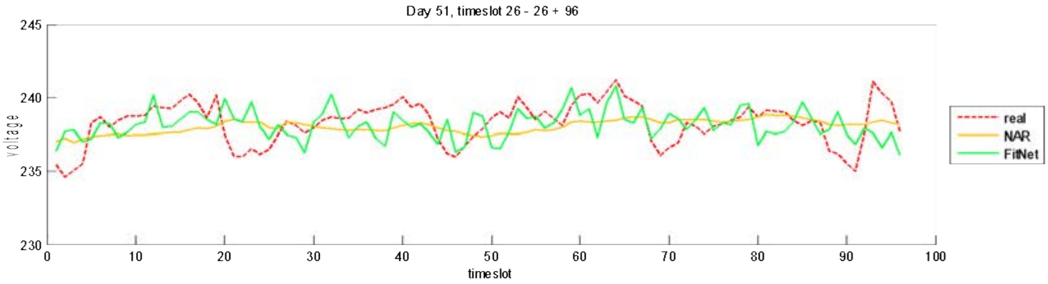


Figure 48: Comparison of the function fitting neural network (FitNet) and the nonlinear autoregressive neural network (NAR). Here the NAR is trained again, and we can see that the performance is worse than previous figure.

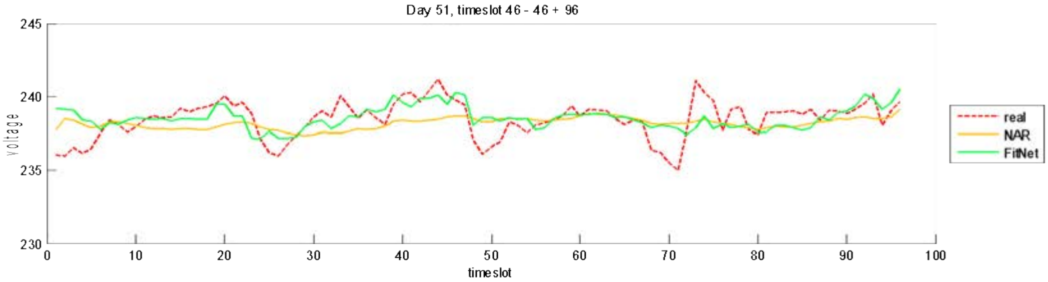


Figure 49: Comparison of the function fitting neural network (FitNet) and the nonlinear autoregressive neural network (NAR). Here the FitNet is trained again, and we can see that the performance is better than Figure 47.

The above results are for short future forecasting. The box plots of RMSEs forecasting 672 successive timeslots (7 days) are shown. For long future forecasting, the RMSEs are higher compared to forecasting only 96 timeslots, and ARIMA model and the simple seasonal method still outperform to other methods.

Conclusions

The preliminary study showed that the analyzed forecasting algorithms based on machine learning, despite being much more complex both in terms of implementation and of computational and memory requirements, did not perform better than baseline algorithms already implemented in the S2G system. Moreover, the analysis also shows that other standard forecasting methods not based on machine learning underperform compared to Exponential Smoothing. We conclude that the current voltage forecasting technique implemented in the S2Gg algorithm may not be further improved at the moment without a significant research effort.

6. Energy price and grid tariff scenarios with the decentralized S2G algorithm

The optimization or decision making behavior of the algorithm developed within the S2G project also depends on the tariff structure/price level that will be charged to end-users (mainly including energy services and network activities) and, in a wider perspective, on the development of an innovative and appropriate business model for the utilities (typically DSOs) involved.

The overall goal of the part of the project was to provide an optimal set of tariff/pricing scenarios useful to test many aspects of the optimization and simulation process, reflecting players' expectations about the future development of the electricity market (in Ticino).

From a practical point of view, we have conducted a qualitative analysis based on the expectations of the main players involved (AET, AIM Mendrisio, other DSOs, households/consumers).

The first step of this task is the analysis of the existing literature and field experience in order to understand the economic rationale and the technical/administrative problems behind a given tariff/pricing scheme.

For liberalized/competitive activities (upstream and downstream), according to the theory of efficient pricing and assuming that the only constraint is lossless balancing of production and consumption, consumers should face prices equal to marginal cost. In terms of rates structure, there is a wide spectrum of possible tariff schemes; with respect to time, the two main categories are time constant and time-varying. The latter could be more or less close to short run marginal cost and could also affect the behavior of consumers. The peak load matters. The load duration curve for most utilities is usually very peaky; the result is that, according to marginal cost pricing rule, the higher is the demand during the peak, the higher is the cost – and so the final price – for the service. Things could be different if also distributed generation is added. Therefore, is peak shaving could have an important economic impact, and costs related to this reduction could be overweighed by benefits. This means that, from a theoretical point of view, the optimal way for pricing electricity would be for regulators to institute time-varying rates.

Fields experiences had helped to understand constant and dynamic rates could affect firms' profitability, consumers' bills and investment level:

- Consumers similarly understand and respond to critical-peak pricing programs.
- The key point is represented by the peak to off peak price ratio. The higher it is, the more the peak reduction is significant. Nevertheless, for ratios higher than 10 the load shifting increases but at a decreasing rate.
- The presence of enabling technologies tend to incrementally boost price response.
- Low-income customers are price responsive_although not always as responsive as the average residential customer.
- If dynamic pricing become the default pricing scheme substantial benefits can accrue to customers;
- Smart Grids will potentially bring new options and needs for design and setting of network tariffs

As emerged, real time prices are, from a pure economic point of view and under the constraint of perfect markets (perfectly competitive and with complete consumer rationality), the most appropriate form of pricing scheme. Anyway, up to now they have not been widely adopted due to a series of issues that have to be considered in implementing this type of pricing scheme.

We will list and discuss them below:

- Elasticity of the demand
- Management of the risk
- Distributional impacts
- Mandatory vs voluntary implementation
- Variables that affect demand response

In the second step of the analysis we test several selected tariffs' schemes for most energy-intensive appliances (boiler and EVs):

1. Time of use (control group)

2. Time of use with dynamic rates
3. Flat rate
4. Flat rate with dynamic rates
5. Real time pricing.

Results could be summarised as follows:

- Most interesting price schemes seem to be ToU combined with dynamic rates (PTR) and Real Time Prices. In particular, RTPs seem to privilege boilers. Savings for EVs are remarkable; due to their strong flexibility in terms of use they could give back higher price advantages;
- Again, for EVs the incidence of PTR rewards is very relevant, in certain cases higher than for boiler;
- Monthly savings for boiler and actual usage of EVs seem in line with empirical evidence/pilot projects.
- A wider/total, diffusion of RTP could have consequences in terms of network congestion;
- At a first glance, pure flat rates could not be the best choice, but we have to keep in mind that they:
    - Could give to HAC the largest flexibility in terms of load shifting minimizing at the same time any possible problem in terms of network congestion;
    - Have the lowest cost in terms of invoice;
    - From DSO’s side represent an optimal choice because average revenues remain the same.
- Benchmarking and conclusions are obviously affected by the current gap between ToU/Flat rates and RTP and also by significant spot prices variability in the selected month;

Finally, we used all the information obtained to sketch a new business model for electric utilities (in detail: DSOs) aimed to valorise all the chances offered by the HAC.

We find that technological changes and economics challenges are at the same time a threat and an opportunity. The classic value chain has been disrupted, while a new one could be redefined with the goal to find where is now the value.

Considering results from theory and field experiences, market drivers and the potentialities of HAC the idea is that utilities, after rethinking to their organizational model (distributor and retailers, wires only, energy services only), should offer a variety of new value added services that could permit to:

- Increase/stabilize revenues, mitigating the risk of competitive pressures on retail market;
- Increase the firm’s profitability due to higher margins of additional, value added not-regulated services;
- Reduce the overall business risk;
- Increase customers loyalty;
- Reduce overall costs thanks to economies of scope.

6.1. Electricity service: pricing principles from economic theory

6.1.1. Relevant economic theory: basic concepts of tariff design

In this paragraph, classical economic theory for electricity prices is briefly reviewed as a background for studying network and energy tariff design options.

More detailed, the analysis of the literature concerning tariffs pricing for electricity will permit to highlight and examine the wide spectrum of retail pricing practices for regulated and unregulated energy services as well as the economic rationale at their base.

The optimal pricing rule. assumption and constraints

Any pricing system can be described as a way to communicate information regarding the cost of the service to the end-users. The service is the result of several connected activities.

In electricity, there exist quite a few actors and activities in the delivery chain. An electric power system can be broadly divided into three parts: generation (supply), transmission and distribution (network activities) and consumption (demand) (see Figure 50).

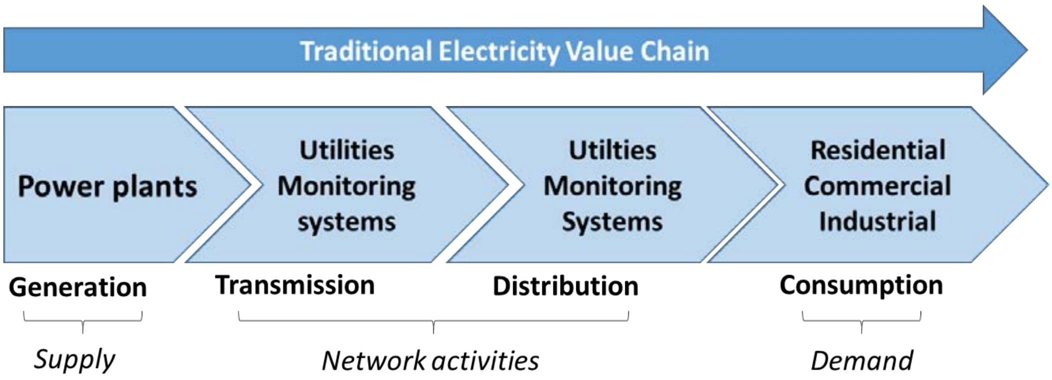


Figure 50: Traditional electricity value chain structure.

Generation includes thermal power, nuclear power, hydroelectric power, and other traditional centralized large-scale power plants, as well as wind power, solar power, geothermal power, and other forms of renewable energy sources (RES). Water pumping power plants and storage systems are examples of energy storage facilities that are included on the supply side.

The transmission and distribution side is broadly divided into the electric power transmission systems, that supply the electric power to distribution networks, the distribution systems, that distribute transmitted electric power to the consumers, and the load dispatching centers, that direct output from the traditional types of large-scale power generation and energy storage facilities, as well as the various control systems that make up the control and distribution management systems of these distribution facilities. The part of this side that is managed by the power company is also referred to in general terms as the “electric power system”.

Consumption includes everything that consumes electric power, including homes, offices, factories, and so on. The general term “consumer”, domestic or non-domestic, also refers to these homes, offices, factories, and devices that use electric power.

Each phase of the value chain has a specific cost; the sum of all those costs determines the amount due for the provision of the whole service by domestic or non-domestic consumers. More detailed, generation and consumption define the so-called “energy component”, while transmission, distribution and electric power system determine the “network component”. Usually, there are also other charges (taxes, VAT, RES financing system, etc..); sometimes their weight could be also very important[1] .

Once selected the categories of cost to be considered, it is necessary to delineate how to allocate the cost on different users.

According to the theory of efficient pricing, the so-called “optimal pricing rule”, consumers should face prices equal to marginal cost (MC) of the electricity service in order to make economically efficient energy-related decisions and maximise social welfare.

The marginal cost of an additional unit of output is the cost of the additional inputs needed to produce that output. More formally, the marginal cost is the derivative of total production costs with respect to the level of output. It is computed in situations where the breakeven point has been reached: the fixed costs have already been absorbed by the already produced items and only the direct (variable) costs have to be accounted for. The general economic theory of markets states that the equilibrium of supply and demand of products determines market price and the total amounts of products. The key result is that equilibrium prices reflecting marginal cost of production maximise the summed surpluses of consumers and producers. In other words, if prices are equal to marginal cost the quantity produced

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[1] For example, the average weight of RES’s financing in Italy in 2013 was about 40 €/MWh.

and sold maximize the benefit of consumers and producers resulting in a Pareto optimal situation[2].

In competitive markets, the favourability of marginal cost as an efficient price signal is based on the assumption of markets being perfect under perfect competition and no further restrictions within the grid; as we will see in the following pages, this could be at least true for generation and retail activities (where firms are currently price takers), but not for network activities. Again, in practice, all markets contain imperfections. In particular, due to the presence of externalities – mainly ascribable to the generation activity - private and social cost could not coincide and market prices could be lower than the (social) optimum[3] with consequences in terms of overconsumption.

Let us see how the optimal pricing rule works with different electricity cost components:

- ✓ Energy component

It remunerates the activity of generation with costs that vary over time and with relation to the fuel adopted. According to the above-mentioned theory, prices must be defined following the marginal cost pricing rule, in particular the short term marginal cost (STMC) of generation (in ctsCHF/kWh). The STMC is used when assuming that the capacity is fixed. In the long run it is possible to make investments in capacity and in this case the long run marginal cost is used. Usually the energy component includes also commercialization costs that remunerate the retailing activity. Wholesale trade of electricity has historically been taking place bilaterally, via over-the-counter transactions (bilateral contracts, usually long terms). With the liberalization process, various other means emerged in Europe. Nowadays, wholesale trade also takes place through the intermediary of traders or on power exchanges. The increasing role of spot markets, where electricity is traded on STMC, has contributed to improve the degree of the liquidity of the market reducing the volume of the over the counter negotiations.

Electricity spot markets play an important role in the liberalization of electricity industry. The advantages of wholesale markets are well known: they promote price transparency, efficient price signals and competition, with positive outcomes on both consumers and firms. Compared with long-term bilateral contracts, spot markets provide both consumers and generators with greater flexibility in their trading decisions, since traders can adjust their trading programs until the day before the trade, on the “day-ahead” market. However, all expected benefits of spot market crucially depends on the liquidity of the pool.

- ✓ Network component

It remunerates network services, typically transmission and distribution; they have two main characteristics:

- they are typically considered natural monopoly due to the high ratio of fixed to variable cost of supply; as a consequence, there are important increasing returns to scale[4];
- the so-called “*lumpiness*” of capacity[5]: in other words, one unit change in output may result little or no change in cost most of the time, but the same change will result in a very large jump in cost if it requires the installation of an expensive new lump of capacity[6].

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[2] According to Pareto, the first who articulates the idea of social optimum (also known as Pareto optimality) coincides with a situation where there are no ways to improve the lot of some without making other worse off. If market price is greater than marginal cost another unit of a certain good could be produced for someone willing to pay the cost of that additional unit, and that person would be better off since the marginal benefit is greater than the marginal cost and no one else would be worse off.

[3] Electricity generation could be based on different fuel mix; the presence of fossil fuels (oil, coal, gas, etc) could have important negative consequences on the environment, consequences that will not be included in the price for the commodity. Otherwise, electricity produced with fossil fuels must be more expensive.

[4] A given proportional change in all resources in the long run results in a proportional greater change in production. Increasing returns to scale exists if a firm increases all resources by a given proportion (say 10%) and output increases by more than this proportion (that is more than 10%).

[5] Rious 2008

[6] The expansion of capacity typically has to happen in greater steps, not in incremental small steps

The major implication of the above-mentioned characteristics on the optimal pricing theory is that the first best optimal rule (prices equal to marginal costs) usually cannot be directly applicable to network activities; in fact, due to substantial fixed costs, the average cost function is typically decreasing and higher than marginal cost (while in the short period typically coincide with the variation of variable costs). If prices are equal to marginal costs, the revenues of a producer fall short of total costs implicating financial losses; in other words, the marginal cost pricing rule applied to distribution and transmission activities would often implicate negative profits.

This involves a need for different approaches. A straightforward alternative would be to consider average costs as pricing method[7], so prices will be defined equal to the average cost for those phases of the value chain. Alternatives could be Ramsey prices, Two-part tariffs ad Fully Distributed Costs[8]. In any case, also for network activities, it could be applied the marginal cost pricing rule, but the presence of natural monopolies characteristics make necessary the presence of subsidies.

Because of the characteristics of natural monopoly, transmission and distribution are typically regulated activities. National Regulatory Authorities (NRAs) usually define regulatory guidelines network component included in the end-user electricity price.

NRAs lay down the rules about cost components that have to be considered in order to determine the average cost, in particular those concerning the cost of capital (Regulatory Asset Base, RAB). The regulator decides on the interest rate and often also on the depreciation method and period. The overall idea is that infrastructure and network costs (capital costs, CAPEX), operation and maintenance costs (OPEX), losses, ancillary services and congestion management have to be included in the pricing system following the principle of the cost-pass through (where costs are anyway controlled by NRAs).

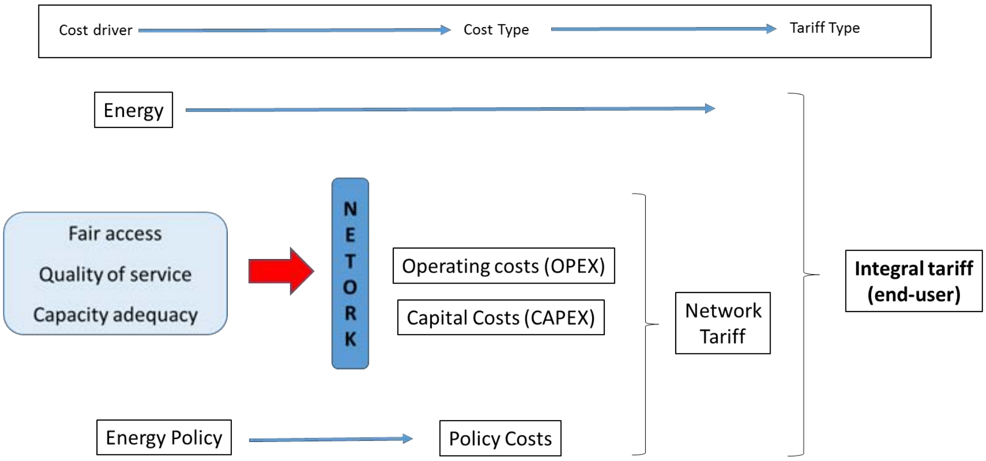

Figure 51: Relationship between network tariffs and integral (end users) tariffs

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(see Joskow and Tirole, 2005, for a discussion of the implications of so-called lumpy investments).When the capacity is to be expanded it can be profitable to build more capacity than the marginal demand for transmission capacity and price signals would imply.

[7] Average cost based pricing is widely used; its disadvantage is the welfare loss originated by potential economic inefficiency.

[8] With the Ramsey rule, prices and quantities are determined to a level that maximises the total surplus of producers and consumers subject to the breakeven constraints (second best prices); with two-part tariffs prices consist of a usage charge and a fixed entry fee, and the goal is to maximise the total surplus over all economics agents. Finally, the objective of the Fully Distributed Cost method is to allocate common costs according to a chosen criterion and then set prices so that each service just covers it’s fully distributed costs.

As is noted by Green (1997), an effective network pricing regime should:

- promote efficient operation of the wholesale electricity market;
- signal efficient investment in generation, load and transmission projects;
- compensate owners of existing transmission assets;
- be simple and transparent; and
- be politically implementable.

Network tariffs are determined in two major steps:

- Identification of cost drivers for cost of capital, operational costs and other, while identifying variable versus fixed costs;
- Determination of the rate scheme to recover the allowed revenue based on cost allocation to each customer category according to one or more of the following aspects:
    - Peak load problem;
    - Consumption patterns and size: load profiles/consumption pattern in each voltage level, size can be defined by the size of fuse, power of energy transfer;
    - Network structure: voltage levels and geographical areas;
    - Time: peak, off-peak, baseline, weekend etc..

All in all, the level of allowed revenues affects transmission and distributors’ investment behaviour as it has an impact on the recovery of network costs.

Nature of distribution network costs

Costs included in network tariffs depend on DSO roles and responsibilities. Network tariffs generally include the following direct network costs:

• *Capital costs:* incurred due to investments in assets necessary to provide the network service, including overhead lines and underground cables (km, kVA and voltage level as cost drivers), substations (kVA and voltage level based), control centers, ICT, metering systems; and other assets. Capital costs include depreciation and interest (depends on the RAB and the allowed rate of return).

• *O&M:* maintenance (km/ kVA/ voltage level based); operation including system services.

• *Procurement of network losses* (kWh based; where applicable). According to the survey, transmission and distribution losses constitute 5-14% of the total costs (depending on the power price, i.e. the price of the energy that is needed to cover the losses).

• *Customer service*: include metering services, invoicing and other administrative & commercial cost. Within these costs there are both capital cost (assets as meters, concentrators, communication devices, etc. and IT systems) and O&M costs. Both types of costs depend on the number of consumers. Mostly fixed regardless customer size/consumption.

• *Overhead costs*: Corporate costs not directly linked to the operation and maintenance of the network, but associated with network service delivery.

Overall, distribution network costs are mainly driven by power demand and less energy related. As we will see, network costs are recently driven also by the increasing role of distributed generation.

Source: Eurelectric 2013

- ✓ Network regulatory model in Switzerland

Around Europe today the dominant approach to regulation in energy sector is the RAB. The RAB has progressively replaced the “cost-plus” approach. With the last one regulators paid power companies based on their costs, plus a return to compensate for their activity. Today, only a very limited number of countries allow distribution and transmission system operators to automatically pass through costs in their tariffs. With the RAB NRAs approximate how much money a company has invested and pay it a return on that investment (the percentage is usually defined by WACC[9]). Various countries have adapted the RAB structure in different ways: the „incentive based“ and the „revenue cap“ models. With the first one the maximum limit (cap) is imposed on firm’s revenues, while with the second, according to Vogelsang (2002), the regulator delegates certain pricing decisions to the firm and the firm can reap profit increases from cost reduction[10]. The key point of RAB-based approach is the definition of authorized revenues, that coincide with the sum of:

1. Authorized OPEX: are usually defined by NRAs as the cost structure of an efficient system operator, enabling efficient management of the asset base. It is not a strict reference to any actual cost structure, as would be the case in a pure “cost plus” regulatory model.
2. Asset remuneration: is dictated by two distinct element: the RAB and the rate of return. First, NRAs assess the RAB using the accounting value of fixed assets, or a standard or inflation-linked value. They then apply a rate of return that may be pre or post-tax, nominal or real. The return on RAB is calculated with the WACC.
3. Depreciation: is linked to the RAB. Regulatory depreciation periods may differ from accounting periods, as they tend to match asset remuneration periods.

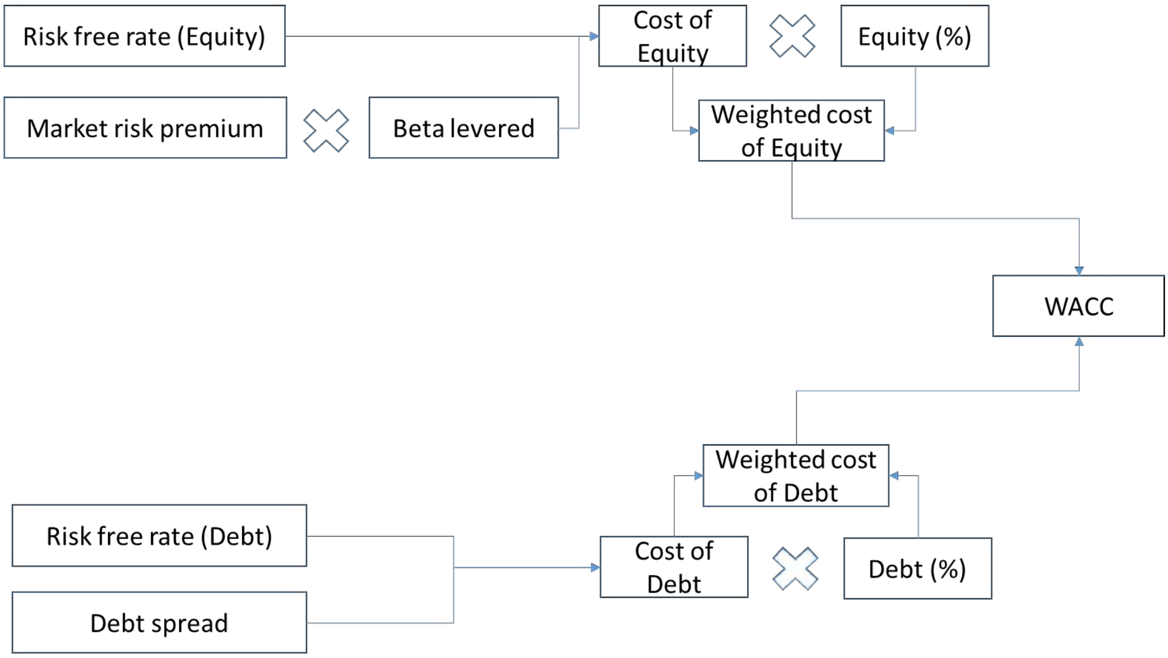

Figure 52: WACC for transmission and distribution in Switzerland: how to calculate it.

	2010	2011	2012	2013	2014	2015
WACC	4.55%	4.26%	4.14%	3.83%	4.70%	4.70%

Table 8: WACC for transmission and distribution in Switzerland: 2010 - 2015[11]

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[9] Weighted Average Cost of Capital.

[10] Incentive regulation aims to use the firm’s information advantage and profit motive to lead efficiency increase. In this way, regulator controls less behaviour but rather reward outcomes.

[11] The WACC allowed to Swiss firms is generally lower than the same figure for other European countries (except for Finland) because of lower risk free rate and spread as well as a limited tax rate. For example, in Germany the WACC in 2012 for transmission and distribution was 5.90%, in Poland 8.95%, in Finland 3.19% (distribution) and 3.06% (transmission), in Czech Republic 7.92%, in France 7.25% and in Slovakia 6.04%.

It is pretty clear that if a distributor could finance its investments mainly with equity capital or with advantageous debt rates he could benefit from the delta between the WACC and the actual cost of money used. This is what happened more or less in Tessin during the last decades because of the combination of the WACC, the efforts to increase efficiency (the cost of the network has decreased significantly) and the limited relevance of interests[12].

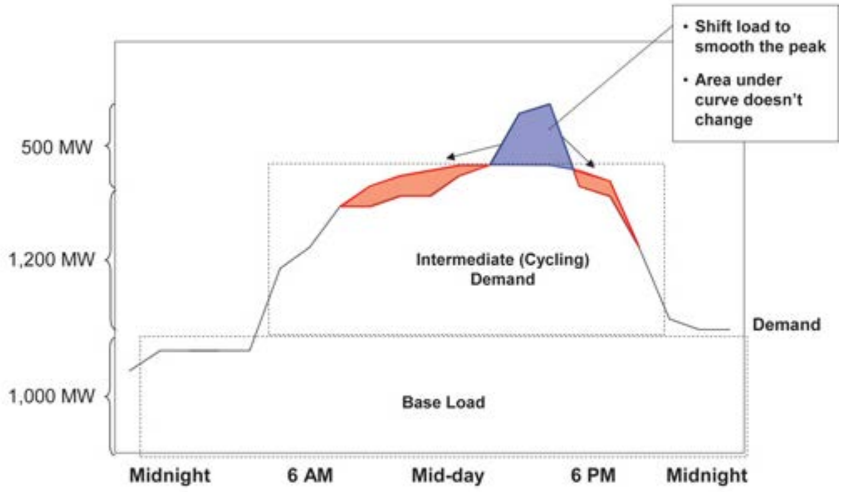
In any case, the idea is that the cost of capital is transferred into electricity tariffs and borne by end consumers, while the DSO could alternatively gain or lose money depending on its ability/capacity to manage investments' financial conditions.

Keeping this in mind, the possible reduction in investments resulting from a possible peak shaving/shifting it is not actually a benefit for the DSOs but only for final consumers. This enlarges the playing field for smart grids and smart meters, that have to be evaluated in terms of potential advantages (or disadvantages) not only from the supply side but also from demand side. More in depth, the overall impression is that strategies aimed to reduce or shave the peak load or potential reductions in peak capacity investments are more or less neutral for the DSOs that could pass through its costs to end users while could represent ad advantage for final consumers. This have to be considered in a) the (re) definition of the business model for DSOs, b) the identification of the most appropriate financing method approach for smart meters/smart grids.

- ✓ The peak load matter

The peak load concerns both generation and network services. Peak power occurs when demand for electricity "spikes". Spikes in electricity demand occur infrequently, less than 1% of the time or about 40 hours each year[13]; nevertheless, capacity in generation and networks is required to meet peak demand.

As demand increases, "dispatchable" generating capacity— first "base load," then "intermediate," then "peaking" capacity — with higher and higher marginal operating costs, is called to balance supply and demand (Turvey 1968; Boiteux 1964; Joskow and Tirole 2007). Therefore, generation and transmission/distribution networks are usually over-dimensioned due to the necessity to meet peak, with higher level of network tariffs (and higher end user prices). Again, peak load energy is more costly in terms of STMC; its volume determines an increase in the average price for electricity.



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[12] The figures for the Ebitda and Ebit cover ratios and for the ROD (Return on Debt) are quite limited and seem do not affect the firms' profitability. In any case, we can notice that this is particularly true for medium-large size firms while small and very small firms could face additional problems.

[13] The load duration curve for most utility systems is usually very peaky. Over time, as the penetration of central air conditioning systems has deepened, load factors have deteriorated and the peak loads have become more pronounced. It's very expensive to serve power during these critical periods and even a modest reduction in demand could be very cost-effective.

Figure 53: Baseload and peak load

On the other hand, the flatter is the demand, the lower is – or must be - the price for the service. Therefore, it's pretty clear that the peak shaving could has an important economic impact, and the cost of the reduction could be partially/totally overweighed by the benefits.

For the past century, electricity pricing has violated the optimality rule and been based on average cost. This has had the unfortunate effect of encouraging excessive consumption of electricity during the expensive peak-period hours and discouraging consumption during the inexpensive off-peak period hours, with important situations of cross subsidization between peaky and non-peaky consumers.

The peak demand is relevant in terms of cost for the electricity commodity and its pricing has been discussed quite extensively in the literature. Earlier authors[14] generally state that the off-peak customers should simply pay the marginal operating cost and the peak period customers should bear all the capacity costs. Later[15], the new insight is that the optimal price in each period should be equal to a weighted average of the marginal operating costs and the marginal outage cost. Therefore, not only the peak period customers but also the off-peak customers would pay a price higher than the marginal operating cost. There is a widespread consensus in the economics literature that such a shift in the pricing paradigm would increase both consumer surplus and producer surplus and raise societal welfare by lowering the average cost of electricity.

The peak load problem has been recently discussed together with the widespread of "demand management" measures aimed to reduce electricity used across all time periods or directed at reducing the peak or shifting the demand for electricity to non-peak periods.

This factor, in conjunction with the variation in marginal energy and capacity cost and the impossibility to store electricity in large quantities means that, from a theoretical point of view, the optimal way for pricing electricity would be for regulators to institute time-varying rates[16]. More detailed, prices during the off-peak period should be set equal to the marginal cost of energy and prices during the peak period should be set equal to the marginal cost of energy and capacity. If end-use consumers face retail prices that don't reflect these variations in marginal generation costs, they will consume too much when marginal costs are higher than retail rates, like during peak periods, and too little when marginal costs are lower than retail rates, likely during off-peak periods. Distortions in consumption could lead to distortions in investments and distortions in utilization of generation capacity.

- ✓ The peak load and the new role of Distributed Generation (DG)

An important development of the peak load matter is related to the huge amounts of investments in RES realized in the last decade combined with the substantial stability of the demand, currently still at a level lower than the pre-crisis period.

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[14] See Steiner (1957), Hirshleifer (1958), Williamson (1966), Boiteux (1964), Turvey (1968).

[15] Brown and Johnson (1969), Crew and Kleindorfer (1976, 1978), Anderson e Turvey (1977), Visscher (1973), Carlton (1977).

[16] The idea of moving from time-invariant electricity prices to „peak-load" pricing, where prices are more closely tied to variations in the marginal cost of generating electricity has been around for at least fifty years (e.g. Boiteaux, 1964; Kahn, 1970).

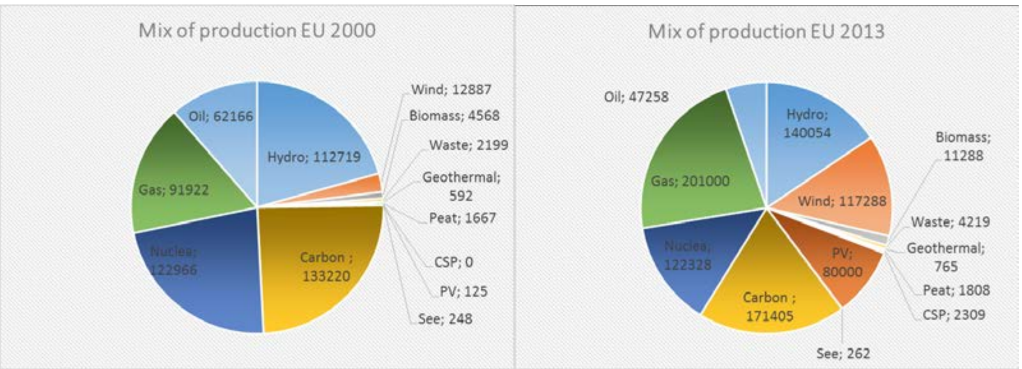


Figure 54: Mix of electricity’s production in Europe. Source: UE Commission, 2014

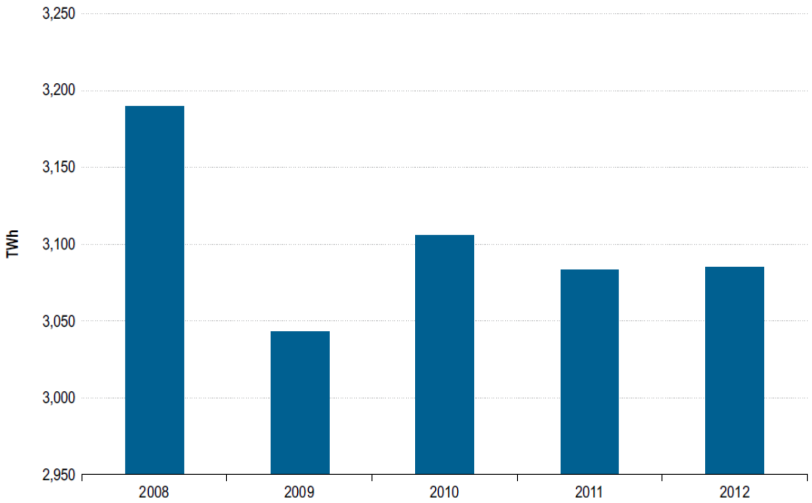


Figure 55: Electricity demand in Europe (2008 – 2012, TWh), source: Agici Consulting, 2013

It could happen that in certain hours of the day – typically around or after noon – RESs’ production is higher than consumption (Figure 56). This could stress the grid and several supports are needed.

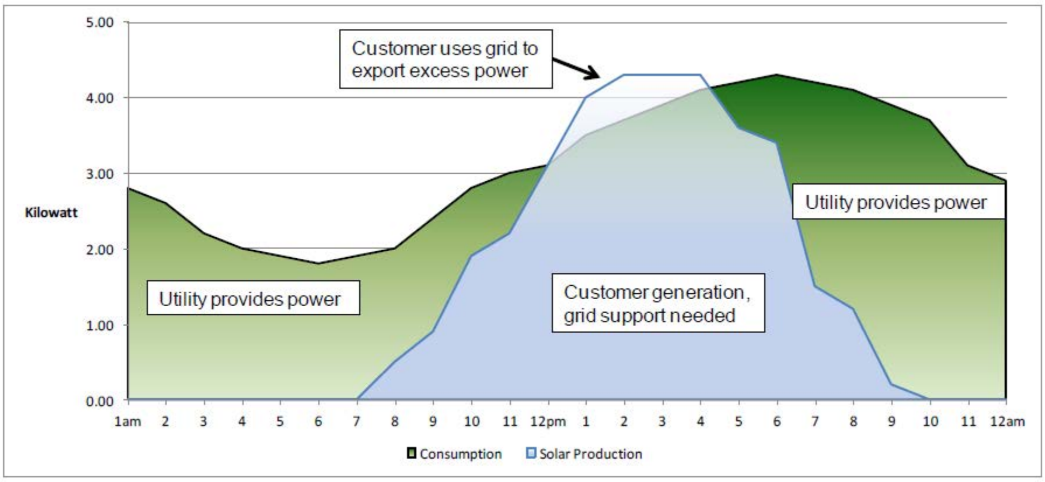


Figure 56: PV and overproduction

The overgeneration risk is better represented by the so-called “Duck chart” sketched in the Figure 57: it’s pretty clear that increasing RES generation (in particular: PV) paired with conventional base load resources that can’t be turned off (e.g. nuclear or natural gas) can cause over-generation in the afternoons during certain months in the next future.

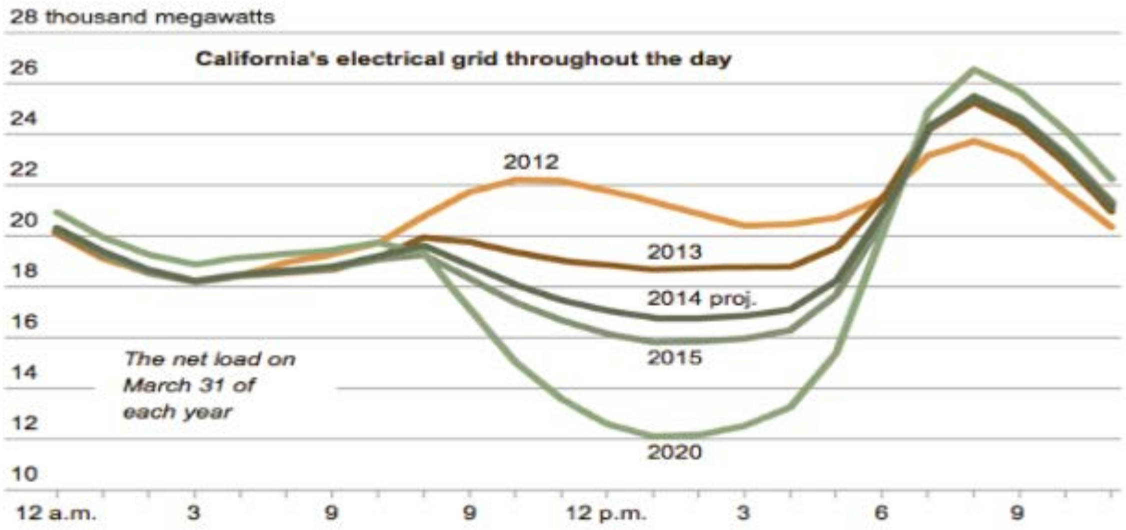


Figure 57: The Duck Chart: net load in California Grid in 2012-13. Forecast through 2020. Source CAISO

Until 2012, daily energy demand looked like a two-humped "camel," with peaks mid-morning and early evening. Utility operated power plants supplied most of the needed energy. But the substitution of local solar power to meet local energy needs affects the demand for mid-day energy from the grid. The daily demand curve transforms, from a camel (orange line) to a (forecast) "duck" (bottom green line). The utility companies crying "fowl" highlight a particular part of the duck chart: the dramatic ramp up in power generation on the light-green 2020 curve that happens in the late afternoon, as energy produced from solar wanes but energy demand rises. In the traditional grid operating model, accommodating this ramp-up in energy use requires a lot of standby power from expensive to operate, rapid-response power plants. Again, the necessity to increase rapidly the "classic" production in correspondence to the dramatic drop of RES production could have important consequences in terms of environment.

There are numerous strategies utilities can use to "flatten the duck" or "teach it to fly:"

- Target energy efficiency measures for the "ramp up" period
- Orient solar panels to the west to catch more late evening sun
- Substitute some solar thermal with storage for solar PV
- Allow the grid operator more demand management via electric water heating
- Require large new air conditioners to have two hours of thermal storage accessible to the utility
- Retire inflexible generating plants (read: coal and nuclear) that need to run constantly in off-peak periods
- Concentrate utility demand charges on the ramp up period.
- Deploy electricity storage into targeted areas, including electric vehicle-to-grid
- Implement aggressive demand response programs (subscribing more businesses and homes into programs to shed their energy demand at key periods)
- Use inter-regional power transactions
- Selectively curtail a small portion of solar power generation.

In other words, the technical challenges of the duck are manageable, largely with existing technology.

The economic problems for utilities – stemming from an outdated business model – may not be so manageable.

More solar generation serving peak afternoon loads will out-bid competitors – utility-owned peaking gas power plants – because solar has zero fuel cost, so utilities will lose money even as customers save money. By 2020 in the California example, solar production at noon will also be sufficient to cut into power usually provided by so-called "baseload" power plants (e.g. coal) that are only economic when operated round-the-clock. The problem for utilities is that they have continued to pour money into a twentieth century grid system (inflexible, centralized power plants with long-distance transmission lines) even as the grid has been transformed by distributed, local renewable energy.

In terms of price signal, an excess of RES production with respect to demand will determine negative prices. At European level, Germany and Austria have been the first to face this situation (due to the rapid growing of RES production in the last decade). More recently, also France and Switzerland have faced the same problem (see Figure 58).

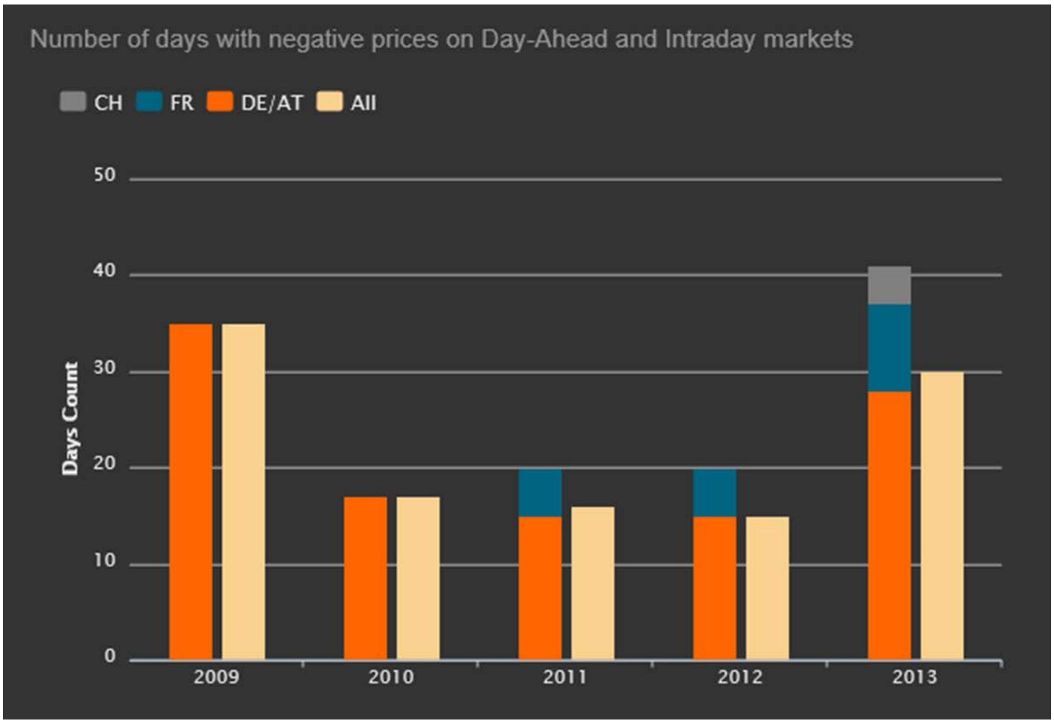


Figure 58: Number of days with negative prices on Day-ahead and Intraday markets

Negative prices are generally due to a combination of high production from RES and low demand. Moreover, they emerge when the power system as a whole is not flexible enough, so it is costly to adapt it to changing conditions. Negative prices could be important because they reduce the reward for RES generators: they take the incentive minus the market price, at least in countries where RES are subsidized through green certificates or feed-in premium schemes, where the green generator takes both the incentive and the market value of the energy that it produces. Under such circumstances, green producers give back to energy consumers at least a portion of the extra money they have been taking because of subsidies. At the same time, an implicit subsidy to “inflexible” capacity is removed. This increasing – and, it seems, not unstoppable – role of RES would in the next future has an impact on investments in new traditional plants while will impact too in terms of network charges.

There is an important question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid.

If we consider a residential or small commercial customer with solar PV panel on its rooftop we can observe that, during the day, customer’s consumption and generation are almost never equal; as a consequence, most of the time the customer is using the external power system to offset the difference between his consumption of electric energy and his on-site production. In most cases, the customer will be taking energy from the grid during many hours of the day.

Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency (i.e., regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer’s total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (i.e., backup service);

- provide voltage and frequency control services and maintain high AC waveform quality.

In most cases, self-generators productions variable and intermittent, as in the case of solar PVs, which means that they rely on the “grid” to balance their local consumption against variable generation. In other words, the grid acts as a “free battery”, absorbing the surplus generation while making up the shortfalls.

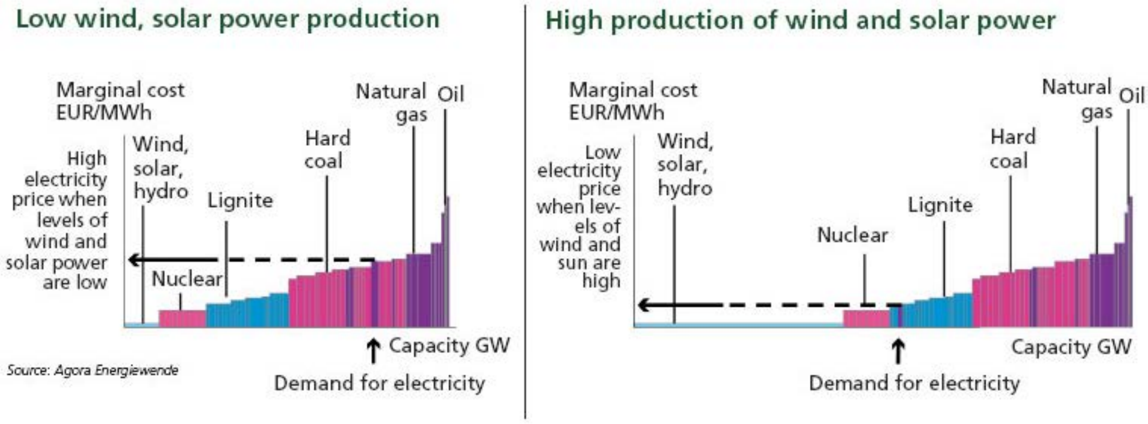
It’s pretty clear that DGs earn value from remaining connected to the grid. In fact, such customers are essentially free-riding on critical services provided by the grid. Yet, if the prevailing tariffs are based on net volumetric consumption, they end paying virtually nothing for grid’s vital services. This means that collecting revenues on a net volumetric basis, could be unfair and inequitable. The following table illustrates the non-energy – i.e. fixed – costs of serving a typical residential Swiss consumer.

Average Residential Customer: Non-Energy Charges as a % of Typical Monthly Bill	
Average Monthly Usage (kWh)*	375
Average Monthly Bill (CHF)	65
Typical Monthly Fixed Charges - Network Services	29
Fixed charges as a % of Monthly Bill	44%

*Table 9: Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff (Tessin, 2013) – without taxes. “*Based on Elcom data, 2013*

In terms of prices, the development of RES could influence power prices in both directions:

- Price decrease: with a lot of energy injection with low marginal cost such as RES plants with higher marginal cost (traditional plants) will be pushed out of the market, leading to a lowering of the spot price (seeFigure 59). Again, due to the direct impact on the consumption (demand reduction) of other primary energy sources there could be a reduction in non-renewable resources prices.
- Price increase: given the variability and intermittency of RES injection, when power is not available the injection has to be replaced by conventional power plants; this radically alter the running of this plants: start-up costs have to be spread over fewer hours and the marginal bidding price of these plants will increase in order to cover those costs over a shorter time period. This development is illustrated in the Figure 60: some plants are pushed out of the market while the electricity generated by the remaining plants will be offered at higher marginal costs, giving rise to a higher equilibrium price. This trend may be further accentuated if there is need to keep certain plants on line in order to have the required flexibility.



Source: Agora Energiewende

Figure 59: RES displace conventional energy from spot market: marginal price decrease

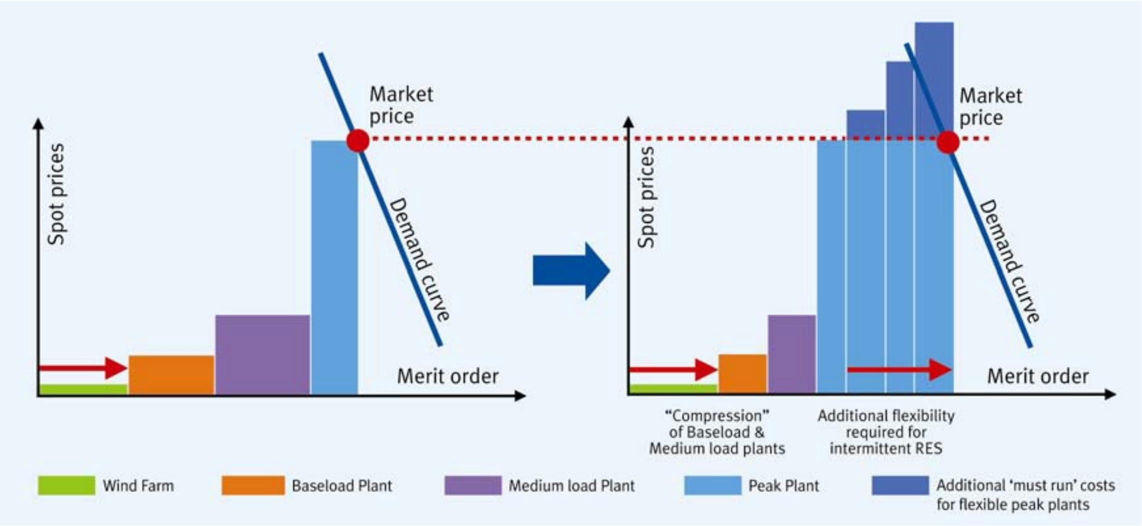


Figure 60: RES displace conventional energy from spot market: marginal price increase. Source: Agora EnergieWende

The overall conclusion is that high penetration of intermittent renewable energy sources will potentially causes short term price volatility in future electricity markets. This is specially the case in European countries that plan high penetration levels. This could have significant effects on tariff variations in case of RTP, and highlight the importance of hedging services.

Different conclusions for investments. According to a recent study of Eurelectric, every MW of wind capacity requires 1 MW of backup firm capacity to ensure 90% availability. This leads to an important conclusion: investments in wind generation – and, more generally, in RES – avoid fuel expenses but do not decrease in the same proportion the need to invest in firm capacity, which is still required.

The backup capacity could be provided either via lifetime prolongation of existing plants or by investment in new plants. Still concerning the need for backup capacity that RES require, other instruments outside the scope of generation activity might be mentioned. For instance the development of interconnection capacity in order to "import" backup capacity from abroad, "smart grids"; storage facilities, and the ability to (remotely) interrupt supply to customers (domestic or industrial) or any other DSM mechanism in general, can all be instrumental in balancing supply and demand.

6.2. Designing an efficient tariff: from tariff design to tariff structure

As already partially pointed out, tariffs for electricity services may have several objectives: cost recovery and financial sustainability, efficient allocation of scarce sector resources, income distribution and fiscal viability.

It is unlikely that all these objectives can be met, so even the most carefully designed tariff will require trade-offs. It will be a matter of policy goals to privilege a goal instead of another. Usually, at least from a theoretical point of view, efficiency is at first place.

If we focus on this topic, the basic classification is between time varying and time constant tariffs.

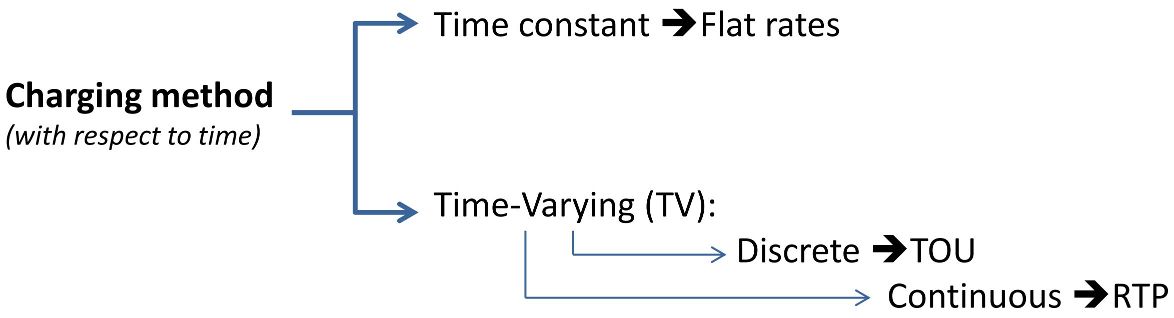


Figure 61: Different type of tariffs (with respect to time)

6.2.1. Time constant

The most popular time-invariant price is the flat rate.

It is the simplest type of tariff; each customer pays a fixed price per kWh no matter how much it costs to the utility to deliver it, no matter how much he will consume.

Referring to the economic analysis in the previous pages, we can identify two main cost components:

- Average delivery cost. The flat rate is not shaped on STMC but on the average cost, with consequences in terms of cross subsidization and possible “waste” or overconsumption of the commodity.
- Risk premium: consumers will pay a premium for locking in prices; the “spike risk” will be hedged by retailers (actually in most cases they will pass the relative cost to consumers following a cost-pass through approach).

For flat rates usually the risk premium incorporated is high due to the necessity for the utilities to hedge their risk on the long term.

Main disadvantages

A flat rate could:

- does not incentivize efficiency;
- be unfair as it incurs in high levels of risk premiums;
- favor customers having positively correlated loads with spot prices against negatively correlated ones. Equity is realized when no consumer subsidizes another consumer. If all consumers pay a flat rate, then those who use most of their electricity during the least expensive times of day are subsidizing those who use it mostly at the most expensive time of day (“peakier” consumers). In other words, flat rates create inequities among consumers.
- give generators the opportunity to exercise market power.

Main advantages

- Simplicity (for utilities and customers)
- Increasing of energy efficiency

- With several tiers (for example five) could give a most granular reflection of increasing costs (closer to the marginal cost pricing rule)
- Reduces the so-called “hassle factor”
- With a “fine tuning” process tiers and cutoff points could be periodically redefined in order to share possible gains with customers.

A flat rate could be in any case combined with other tariff schemes. One possible option for smart grids includes increasing block rates for energy efficiency and dynamic pricing rates for peak load management.

A variation of the “classic” flat rate is the increasing-block tariff, a ladder-like pricing mechanism where customers pay a low, fixed price until a consumption threshold is reached; after, they pay higher amount. There could also be more than one thresholds (tier) included in this tariff.

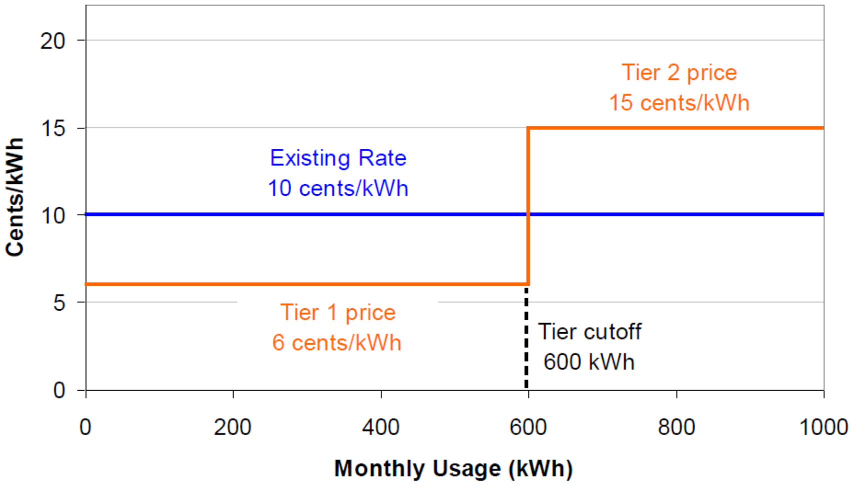


Figure 62: Increasing block rate structure

Designing an inclining block rate tariff structure is both an art and a science. In particular, difficulties are related to:

- Aligning prices with system costs;
- Establishing the number of tires;
- Determining cutoff points;
- Encouraging more efficient energy consumption;
- Promoting social objectives (e.g., income re-distribution)
- Ensuring bill stability or rate continuity

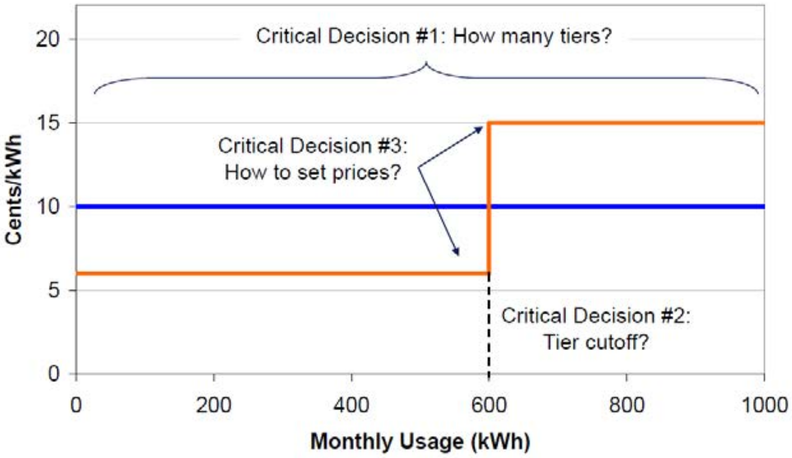


Figure 63: Increasing block rate: key decisions

6.2.2. Time-varying

Time-varying rates can be designed in a number of ways, depending on one's ratemaking objectives and the sophistication of the target market. The specific dimensions across which a time-varying rate design can vary and are summarized in Table 10.

Dimension	Description
Number of pricing periods	The price may change anywhere from once per day to once every hour (or even more frequently).
Timing of pricing Periods	The applicable hours of each pricing period are typically designed to coincide with load and price patterns of the service territory.
Price level	Time-varying rates are almost always cost-based and revenue neutral, but within these constraints there is some flexibility in establishing the price level for each pricing period, depending on how costs are determined.
Notification	The time elapses between when customers are informed of upcoming prices and the applicability of those prices (often on a day-ahead basis with many dynamic pricing developments, but ranging anywhere from near-instantaneous notification to fixed ToU prices (see below) that could remain unchanged for a multiyear period between rate cases).
Incentive	Time-varying rates can include incentive schemes involving high prices for high-cost hours and low prices for low-cost hours or, alternatively, rebate payments for targeted load reductions.
Combination	Time-varying rates can be combined with other rates (e.g., layered on top of an inclining block rate or flat rate).

Table 10: The Dimensions of Time-Varying Rate Design

There are several types of time-varying rates, starting from the less "granular" (time-of-use) to the most variant ones (real time prices).

6.2.3. Time-of-Use (ToU)

The majority of the electricity distribution companies have had a tradition of **Time-of-Use (ToU)** tariffs. A ToU rate could either be a time-of-day rate, in which the day is divided into time periods with varying rates, or a seasonal rate into which the year is divided into multiple seasons and different rates provided for different seasons. ToU rates are fixed by period and consequently offer certainty as to what the rate will be and when they will occur. In a time-of-day rate, a peak period might be usually defined as the period from 9 am to 9 pm on weekdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak period, possibly mirroring the variation in marginal costs by pricing period. ToU rates with three periods have also been offered. Such rate schemes include a shoulder (or mid-peak) period, where the cost of electricity is lower than peak period rates, but higher than off-peak period rates. Additionally, TOU rates may have two peak periods (such as a morning peak from 8 am to 10 am, and an afternoon peak from 2 pm to 6 pm). Prices for peak and off-peak periods are based on averages of historical prices. ToU retail pricing lacks both the granularity (they don't reflect the expected wholesale market variation) and the timeliness (they cannot capture the shorter-term variation in supply/demand balance) of RTP. Put differently, ToU prices, while giving greater advance notice of prices and offering less price volatility, do quite poorly in reflecting variation in wholesale prices; for this reason, they are often combined with a separate charge for peak usage.

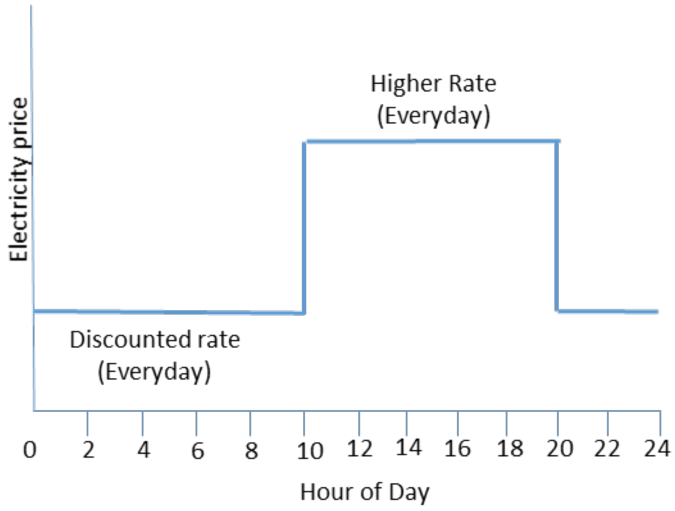


Figure 64: Time-of-Use rate

6.2.4. Critical Peak Price (CPP)

To overstep efficiency limits of classic ToU several demand charges could be applied. They are a way to charge for a customer peak usage, but the economic incentives that they establish are a proxy for the real economic cost imposed on the system, although imperfect.

The most popular is the **Critical Peak Price (CPP)** rate, by which customers pay higher peak period prices during the few days a year when wholesale prices are the highest (typically the top 10 to 15 days of the year which account for 10 to 20 percent of system peak load). This higher peak price should reflect both energy and capacity costs. In return, the customers pay a discounted off-peak price that more accurately reflects lower off-peak energy supply costs for the duration of the season (or year) or a ToU price. Customers are typically notified of an upcoming "critical peak event" one day in advance, but if enabling technologies are used, these rates can also be activated on a day-of basis[17].

The CPP rate is usually set as either four or five times the peak period rate. This is based on retailers' experience from their current trials that have observed diminishing returns (in relation to demand response) for CPP's in excess of 5 times the peak rate. Under CPP rates, if customers shift their electricity usage from the more expansive hours to the less expensive ones, with unchanged consumption,

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[17] CPP is similar to interruptible programs, where the system operator has the right to instruct the customer to cease consumption on a very short notice, but prices are not set so high as to cause most customers to reduce consumption to zero. In practice, interruptible programs are usually offered only to large customers, while CPP is envisioned to be used much more broadly.

they can reduce their electricity bills.

A more dynamic version of CPP is the **Variable Peak Price (VPP)** tariff, where consumers pay higher peak period prices during a few days a year when wholesale prices are highest. The main difference between this rate and a critical peak price is that the VPP varies from one event day to the next, as determined by market rates. On-peak prices generally vary each day based on day-ahead market prices. On non-event days, the VPP rate acts like a normal TOU rate, with fixed period prices

CPP rates and VPP rates usually determine a shift in energy consumption instead of a global reduction of the demand.

CPP has some of the advantages of RTP because retail prices are allowed to vary with the wholesale market. CPP has however two economic weaknesses: first, prices are limited and levels are preset for the peak period, based on historical consumption for the same period, therefore they can't be calibrated to move with the actual prices in the wholesale market; second, the number of critical peak hours that can be called in a year is limited. As a result, the utility protects customers against seeing very high prices, even only on a marginal purchases, for more than a fixed number of hours.

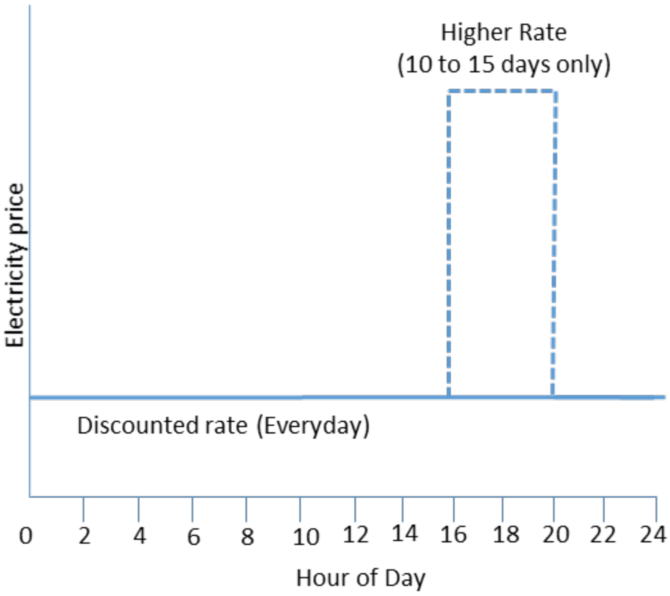

Figure 65: Critical Peak Price rate

6.2.5. Peak-Time Rebate (PTR)

If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of a **Peak-Time Rebate (PTR)**. Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed, the so-called baseline consumption). If customers do not wish to participate, they simply buy electricity through at the existing rate. There is no rate discount during non-event hours. PTR creates a “no lose” situation for all customers, while still providing the incentive to reduce peak usage. With a PTR, customers who don't respond by shifting load wind up paying the rebates to those customers that do respond.

PTR programs are demand-reduction programs: the attempt to recognize the idiosyncratic daily and hourly variation in system stress and give customers incentives to respond. In this way, they are the mirror image of CPP, with some significant weaknesses. The fundamental one is that there is no reliable baseline from which to pay for reduction. Usually it is defined on the past behavior of the customer and this create two serious problems:

- □ If the program is voluntary (opt-in) it will be joined disproportionately by the customers that already know they will have lower consumption relative to their assigned baseline[18].
- □ If the baseline can be affected by the customer, it will probably discourage conservation during times when the payments are not in effect.

Lastly, all the money that is paid out as “reward” has to come from somewhere; it most likely comes from higher general rates that would be necessary to reach the same revenue requirement under CPP or RTP.

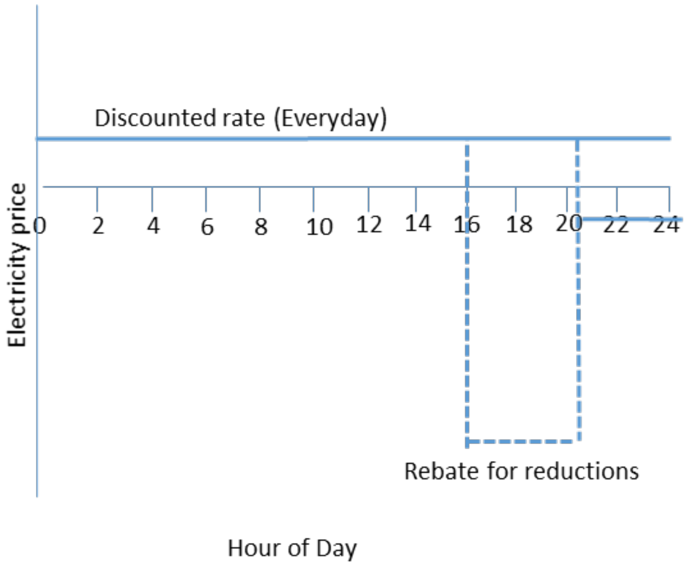

Figure 66: Peak Time Rebate rate

6.2.6. Real time pricing (RTP)

Participants in **Real-Time Pricing (RTP)** programs pay for energy at a rate that is linked to the current market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead (“real time”, indeed) basis. Typically, only the largest customers — above one megawatt of load — face hour-ahead prices. In terms of economic efficiency and incentives, RTP using real-time announced prices offers the greatest value. The marginal incentives of consumers facing such prices most closely reflect the actual supply/demand situation in the market. Borenstein[19] calculates how much is lost by using a day ahead price instead of a real time one and the result is that the day ahead system captures 45%-50% of the variation in the real time balancing price over a year or longer period. These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption at the most expensive times.

RTP constitute the purest form of dynamic pricing in that they are dispatched based on the changes in actual wholesale market prices.

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[18] For example, if the baseline uses last year’s consumption companies that have shrunk since last year will be the first to sign up: their consumption has fallen compared to the baseline for reasons having nothing to do with the program and the system operator ends up paying for a conservation that have occurred anyway. Differently, companies that have grown rapidly since the previous year simply won’t sign up.

[19] "Time-Varying Retail Electricity Prices: Theory and Practice," in Griffin and Puller, eds., Electricity Deregulation: Choices and Challenges, Chicago: University of Chicago Press, 2005.

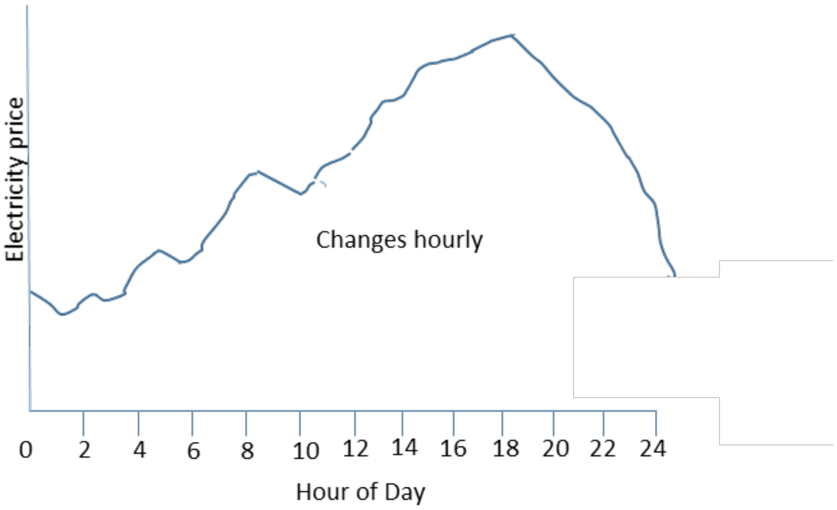

Figure 67: Real Time Price rate

6.2.7. Direct Load Control (DLC)

Direct Load Control (DLC) is the most widely offered residential demand response program in the U.S. Participation in this programs is typically voluntary and the reduction in demand/shift of load are controlled remotely by the utility via a switch on participants appliances (usually the most energy intensive ones). Most DLC programs offer a flat monthly incentive to allow the utility to control consumers' consumption. Although utility-based, DLC programs do result in demand response and have been effective in smoothing peak demand, they also raise equity concerns. Since participation is voluntary and the exact load reduction is not measured, participants who provide little load reduction are paid the same amount as those that provide significant load reduction. In general, because there is no direct relationship between the money value of system benefits actually achieved and the incentives paid to the participants, incentive payments can exceed system benefits; in this case, the non-participants bear the cost.

6.2.8. Issues in implementing Real-Time Pricing

As emerged, real time prices are, from a pure economical point of view and under the constraint of perfect markets (perfectly competitive and with complete consumer rationality), the most appropriate form of pricing scheme. Anyway, up to now they have not been widely adopted due to a series of several issues that have to be considered in implementing this type of pricing scheme.

We will list and discuss them below:

- ☐ Elasticity of the demand
- ☐ Management of the risk
- ☐ Distributional impacts
- ☐ Mandatory vs voluntary implementation
- ☐ Variables that affect demand response
- ☐ Elasticity of the demand

The price elasticity of demand for electricity contains important information on the demand response of consumers to a small price variation[20]. There are many studies on this topic; only a few parts consid-

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[20] Price elasticity of demand measures the responsiveness of demand to changes in price for a particular good. If the price elasticity of demand is equal to 0, demand is perfectly inelastic (i.e., demand

ers the presence of enabling technologies. Despite the importance, empirical estimates of the real-time elasticity are hardly available; the most popular time-varying tariff considered is the less variant one, the ToU. The majority of published studies estimated short-run and cross-price elasticities[21]. However, price responsiveness in a ToU rate framework can be much greater in the long-run when customers have the possibility to react to a price increase by purchasing more efficient appliances and equipment while in the short run residential customers can reduce usage only by forgoing consumption or by shifting consumption to off-peak periods.

The empirical literature suggests that demand elasticity for electricity is generally low; the real-time elasticity found in recent analysis is sometimes even lower. The values of own, cross-prices or substitution elasticities are highly variable, partly because of the differences in the model specifications such as data source and design of the experiment.

Generally, we can conclude from this empirical literature that in the short-term:

a) The demand for electricity by ToU is usually inelastic;
b) The elasticity of substitution and the cross-price elasticity are generally positive. In detail, the positive values of the short as well as the long run cross-price elasticities suggest that peak and off-peak electricity are substitutes;
c) The own-price elasticity for peak electricity demand is typically larger than the own-price elasticity for off-peak demand.

Author	**Type of model**	**Onw price elasticity**	**Cross price elasticity**
Aigner et al. (1994)	Generalized Leontief	Off-peak: -0.013/-0.049 Peak: -0.054/-0.158	Not reported
Boisvert et al. (2004)	Generalized Leontief	Peak: -0.05/-0.0675	
Filippini (1995)	Partial equilibrium model, loglinear demand	Off-peak: -2.30/-2.57 Peak: -1.25/-1.41	0.34/1.57
Filippini (2010)	Log-log	Short run Off-peak: -0.758/-0.652 Peak: -0.835/-0.778 Long run Off-peak: -1.273/-1.652 Peak: -1.608/-2.266	Short run Off-peak: 0.407/0.363 Peak: 0.917/0.793 Long run Off-peak: 0.684/0.919 Peak: 1.767/2.311
Ham et al. (1997)	Loglinear	Off-peak: -0.038/-0.050 Peak: -0.069/-0.091	Not significantly different from zero
King and Chatterjee 2003	Review on 35 studies	Short run -0.12/-0.35 Long run -0.6/-1.2	
Mountain and Lawson (1992)	Loglinear	Off-peak: -0.003/-0.036 Peak: -0.002/-0.0138	0.003/0.037

Table 11: Elasticity's literature review (time varying prices)

Focusing on more dynamic rates, in 2009 Faruqui et Sergei survey the evidence from the 15 most recent international experiments with dynamic pricing of electricity finding conclusive evidence that households (residential customers) respond to higher prices by lowering usage during peak periods while the overall price elasticity for RTP programs varying from -0.015 and -0.069.

In particular, if we compare the cost of smart meters with the increase in residential consumers' wel-

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does not change when price changes). Values between zero and one indicate that demand is inelastic (this occurs when the percent change in demand is less than the percent change in price). When price elasticity of demand equals one, demand is unit elastic (the percent change in demand is equal to the percent change in price). Finally, if the value is greater than one, demand is perfectly elastic (demand is affected to a greater degree by changes in price).

[21] Positive cross-price elasticity means that and increase in peak hours will determine a shift of consumption to non-peak hours. It is the response in the peak to off peak demand.

fare the result is not comforting; the net sum is in nearly all cases negative[22].

Recent advances in ‘‘Smart Grid’’ consumer energy management technologies can increase households’ price elasticities and reduce the cost of the advanced electricity meters required to record hourly consumption. This has increased the likelihood that real-time pricing would have positive net welfare effects, magnifying the business and policy interest in RTP.

□ Management of the risk

In the past, utilities were protected from price volatility and met their revenue requirements over the long run by adjusting rates, usually on a yearly base; they were also producers so the main risk was from fuel price changes. Currently, the majority of utilities are net buyers of power and the primary risk comes from the volatility in the wholesale price of power[23]. The risk of price volatility could be alternatively borne by retailers or by customers. With flat rate the risk is completely on utility, while with RTP prices the risk is on final user because the retailer set a price based on the wholesale market price[24].

Each of the pricing options represents different combination of risks and rewards for customers involved in the project. Generally, the higher is the reward, the higher is the risk in terms of wholesale price volatility. Depending on their risk preferences, consumers could self-select themselves into the appropriate rate design, thereby maximizing economic welfare. The set of pricing options can be plotted out in the risk-reward space, yielding the pricing possibilities frontier (see Figure 68).

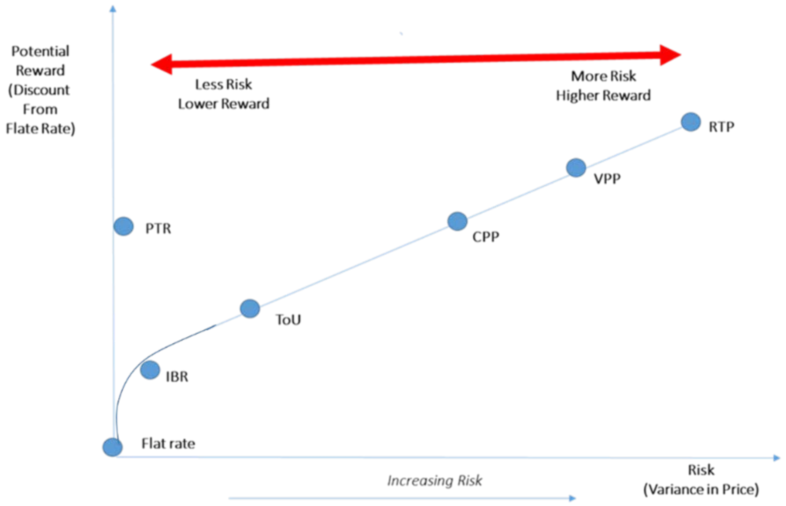

Figure 68: Conceptual Representation of the Risk-reward Trade-off in Time-Variyng Rates

With flat rates risks of price volatility are sustained by utilities that usually mitigate it with some kind of cross subsidization between people with low consumption and those with high consumption[25]; differently, with RTP risks (and potentially advantages) are completely borne by consumers while utilities are protected from price volatility.

The Figure 69 resumes prices for the period August 2013-August 2014 on the Swiss Day Ahead market (spot market).

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[22] This is the reason why RTP or strong time varying prices have usually been applied to industrial customers.

[23] In the last decade energy market prices have been extremely volatile. The main drivers of volatility include matching supply and demand, energy consumption, load profile, generator outages, fuel commodity prices and weather.

[24] If the retailer owns generation of its own or has other costs unrelated to wholesale power it will face risks in meeting its own revenue requirements.

[25] To the extent that the retailer hedges its wholesale (or fuel) price risk, the capital gains or losses associated with those sunk gains or losses are incorporated when the flat rate is changed.

Figure 69: Swiss spot market prices in the last year (€/MWh)

The volatility on the Swiss spot market sometimes could be significant: for example, in February 2013, the 11th, from 9 a.m. to 20 p.m. the wholesale price has varied from a minimum of 58 €/MWh to a peak of 75 €/MWh (+29%) (Figure 70). In 2014 for the same day the range was between 50 and 60 €/MWh (+20%)[26]. The average difference between peak and off-peak prices for Phelix futures is about 26%. With pure RTP this volatility will be borne by consumers that could yet decide to adjust their demand following market prices signals.

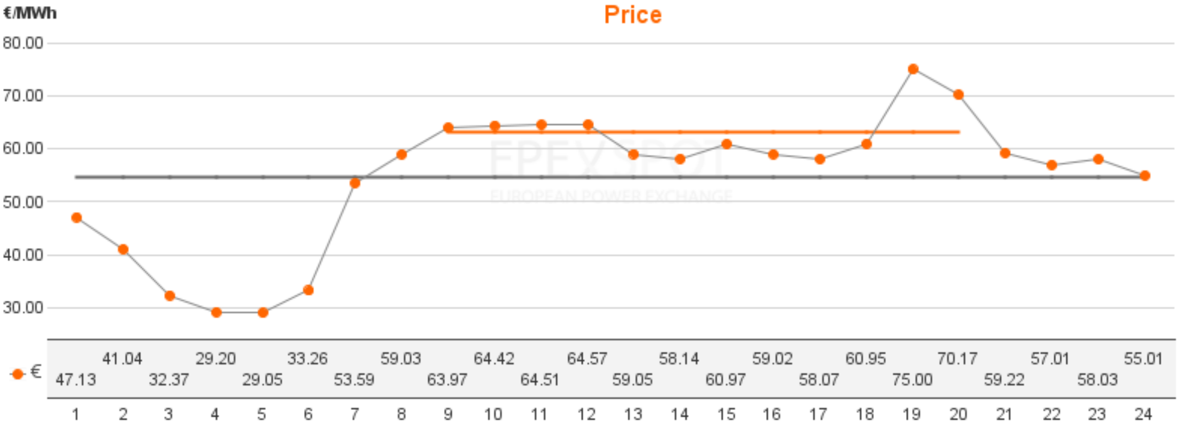

Figure 70: Swissix Day-Ahead Spot Price (11th of February, 2013)

There are several instruments that utilities or consumers could use for mitigating the volatility risk under the selected tariff scheme. There could be two main approaches:

- Retailer can carry out hedging on behalf of passive customers;
- Customer can actively participate in hedging of price risk.

The inclusion of price volatility management in pricing models has determined several variations of RTP scheme.

RTP with a Customer Baseline Load (CBL)

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[26] In certain cases if there is an opt-out dynamic pricing regime there could be some kind of “bill protection“ against an excessive price variation.

Sometimes utilities apply a two part RTP programs where each customer has a baseline consumption level that could be purchased at the regulated rate during each hour. The price the customer pays for its baseline consumption is usually the regulated TOU rate that the customer would otherwise face. Starting at the baseline, the customer then pays the real-time price for any consumption above its baseline level and receives a rebate based on the real-time price if its consumption falls below its baseline level. In financial terms, the baseline is just a forward contract for a quantity equal to the customers' baseline level, i.e., a hedge contract, which the customer has purchased at a price set by the regulatory process[27].

RTP with Build-Your-Own Baseline

A variation of this tariff scheme is a RTP with a build-your-own baseline. As the name suggests, customers take an active role in determining the extent to which they hedge price risk. Rather than being assigned a CBL for each hour of the year, the customer can purchase a baseline quantity, i.e., a forward contract, for each hour in order to hedge as much price risk as it wants. The key would be for the retailer to offer the baseline or forward contract for each hour at a price that equals the best forecast of that hour's future spot price. It is pretty clear that the concrete deployment of those pricing models is strictly related to new skills, both economical/financial and technical; this contribute to increase the complexity and the difficulty of such a pricing scheme.

RTP with Retailer Hedging on Behalf of Customers

Even if customers are on a simple RTP plan without any baseline and retailers are buying most of their power in the wholesale market, retailers can still stabilize RTP customers' bills by hedging on their behalf and using the profit or loss from such hedging to offset power price fluctuations. In this approach customers are completely passive, putting all hedging decisions in the hands of the retailer. To be more clear,

- if retailer does not engage itself in any hedging activity it will charges customers a fixed per-kWh transmission and distribution charge plus the spot price of energy in each hour. Customers' monthly bill and utilities' revenues will be (also significantly) variables;
- if retailer would obtain stability (of bills and revenues) has to sign long term contracts[28]. In this case, gains or losses could be distributed to customers with a constant surcharge or discount on each kWh sold during the billing period. The idea is to develop some kind of risk sharing between retailers and customers, strictly related to the ability of the firsts to hedging risks. It's important to note that with RTP and long term contracts customers will face the same volatility in prices as it would under RTP without hedging but prices could be shifted down by possible profits from long term contracts. The role of retailers is much more important in regulated markets, where consumers don't have the possibility to sign their own private contracts; in liberalized markets the retailer would serve as a broker of risk hedging service[29].

□ Distributional impact

Dynamic pricing and low income consumers

We found that there is a little dispute about the impact of dynamic pricing on customers in the aggregate; however, there is much disagreement about the impact of dynamic pricing on certain customer segments, most notably low income customers. Under a strong time variant pricing model customers with a relatively flat consumption will usually see the greater benefits, while customers with "peaky" profile will probably consume a disproportionate share of their power at the more expensive times; they might end up paying an average price higher the previous one.

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[27] Any two part RTP program will include an implicit transfer payment to or from the customer so long as the regulated price differs from the expected real-time price. Thus, baselines set by any regulatory process will be subject to intense lobbying and related influence activities.

[28] In the simplest way, the long term contract will be based on the same price for each hour. It's clear that he contract price could be higher or lower than the average spot price, so contracts will be cheaper or more expensive than spot prices. In other words, the long term contract could be considered as a financial investment.

[29] This service could be an important part of the new business model (see later).

Two competing forces are at work. Since low income customers use relatively less energy during the peak hours, their load profiles are flatter than those of the average residential customers; this would make them immediate beneficiaries of a rate that charges more during peak hours, and if they exhibit demand response by curtailing their usage during peak hours or shifting their usage to off-peak hours, they would gain even more. Others suggest that low income customers have little discretion in their power usage; this they have less to work with in terms of ability to shift load. The structure of consumption will affect results: if low consume income customers have an average load profile flatter than that of high ones.

□ Mandatory vs voluntary implementation

It is very important to keep in mind that the system is not driven by one customer's ability to conserve or shift energy consumption but by the ability of users in aggregate to lower demand at peak times, reducing in this way wholesale electricity prices and the risk of rolling blackouts. So, any appropriate pricing model aimed to optimize the aggregate load profile should be implemented and deployed in the largest way. In other words, policy makers have to decide between opt-in or opt-out/default programs. The firsts call for a voluntary subscription, while with second people who don't see any benefit after their first year on the program could go back to their previous rate. In order to mitigate the effect of a transition to a dynamic pricing scheme some kind of bill protection could be applied. An analysis dedicated to demand response, Faruqui highlight that the average dynamic pricing enrolment is 20% under default flat rates and 84% when dynamic prices are the default.

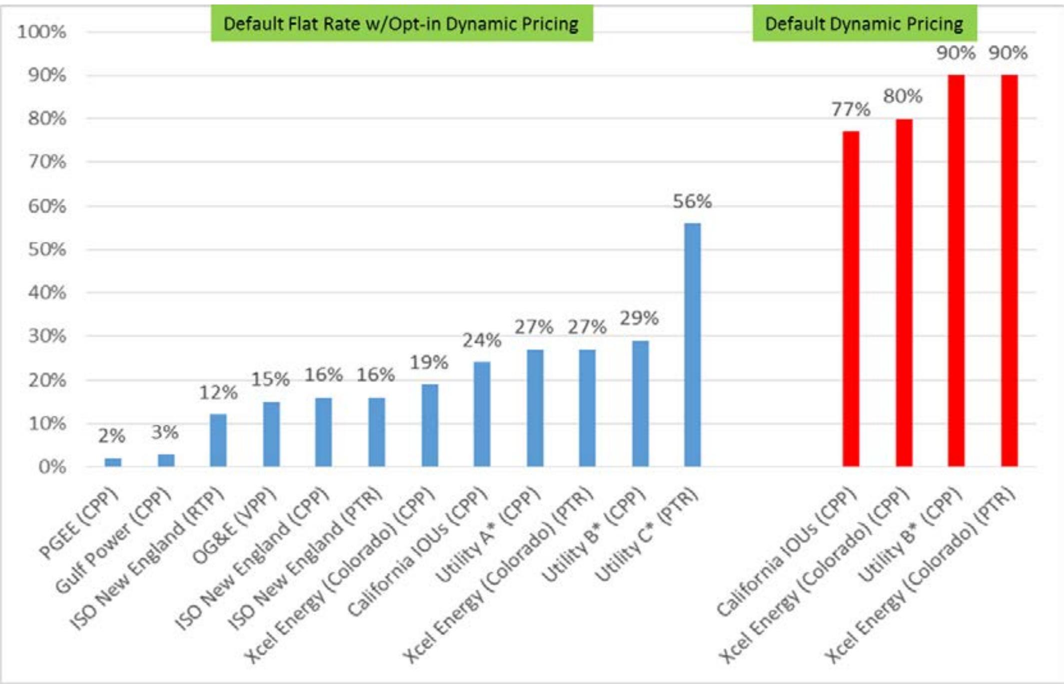
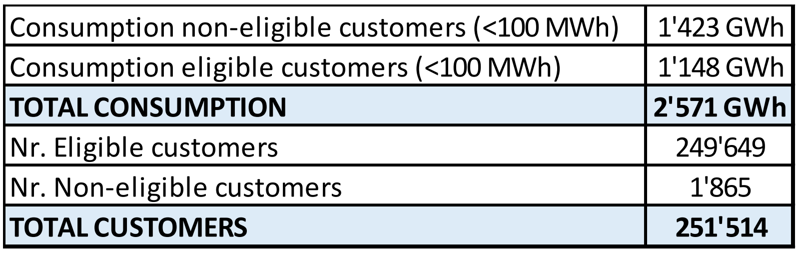


Figure 71: % of enrolment in dynamic pricing programs with opt-in or opt-out programs

□ Large consumers

Dynamic prices could be offered at the beginning to large customers; this has sense because: a) they are responsible for large share con power consumption and also because the cost of metering is trivial compared to potential efficiency gains. In the short run, changes in their consumption profile could determine a significant reduction in wholesale prices; on this base, some large consumer has suggested to be rewarded for its behavior. But if prices are set appropriately there is no need for further subsidization.



Consumption non-eligible customers (<100 MWh)	1'423 GWh
Consumption eligible customers (<100 MWh)	1'148 GWh
TOTAL CONSUMPTION	**2'571 GWh**
Nr. Eligible customers	249'649
Nr. Non-eligible customers	1'865
TOTAL CUSTOMERS	**251'514**

Table 12: Eligible and non-eligible customers in Tessin

□ Variables that affect demand response

In defining the most appropriate rate structure we have to keep in mind that consumer behavior in the long-term is affected by several variables, partly not manageable:

- Income: The reactivity of consumers depends on the weight of electricity total expenses on monthly/yearly expenses. If the incidence in negligible or extremely limited they will accept to change their behavior only in a partial way.
- Goals (of public authorities/public bodies, utilities, consumers): there could be some kind of trade-off between the aims of different stakeholders involved; for example utilities will try to increase their profits while consumers would reduce their bills.
- Distributed generation: we have already discussed how DG could affect consumers' behavior.
- The Hassle factor: the loss of economic welfare associated with shifting usage to a lower cost period.
- Marketing strategies: Changing the way electricity has been priced for decades will not be easy; several tools could facilitate the transition to time-varying rates. For example, an intensive research-based marketing and education effort will help customers to understand the benefits and opportunities that could be captured.
- Current structure and price of electricity: We have observed that main benefits of dynamic prices are related to the reduction of peak load; if costs are charged following the optimal pricing rule, this will imply a reduction in the energy and network component (transmission and distribution only). Now, if it's true that households under dynamic rates schemes would face lower bills, the matter is about the importance of this reduction. The risk is that the decrease/shifting of the peak will determine a limited bill's reduction, not perceived as a real benefit from final users (if compared to their effort in terms behavioral modification); the consequence could be medium-long terms effect of different sign.
- Degree of freedom of consumers' in their choices/behavior: with time-varying prices they can in any case decide to consume also in critical days while giving priority to their desiderata while, for example, with DLC they have to accept consumption's management by the utility.

Principles of smart tariffs

We have observed that, as electricity markets are liberalized, consumers become exposed to higher electricity prices and may decide to modify their demand to reduce their electricity costs. With the introduction of Smart Grid technology at distribution level, the consumer shall have an incentive to switch on their appliances time specific, to have the benefit of choice of low cost power.

One of the goals of the Smart Grid deployment is to develop grid modernization technologies, tools and techniques for demand response, helping the power industry to dynamically optimize grid operations and resources, and incorporate demand response and consumer participation. Demand response provides an opportunity for consumers to play a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. One advantage of smart grid application is the possibility to use time-based pricing, so customer who traditionally pay a fixed rate for consumed energy and requested peak load can set their threshold and adjust their usage to take advantage of fluctuating prices. This may require the use of an energy management system to control appliances and equipment.

As observed, in Tessin, about 44% of the bill covers charges related to the non-energy services provided by the grid. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or its entire fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In our case the fixed costs that the DG customer does not pay will be shifted to other retail customer[30].

The main conclusion is that DG customers should pay their fair share of the cost of the grid services that the host utility provides instead to behave as free riders.

Social advantages related to the possibility to defer investments in new plants to guarantee backup capacity could not be immediate and only possible; for networks (transmission and distribution) investment could remain unchanged due to the necessity to upgrade infrastructure for adapting them to the renewed production mix.

6.3. The empirical evidence. Fields experiences and pilot projects. What can we learn?

□ Tariff schemes and households response: an international survey

The system-wide deployment of smart meters and AMI creates a platform for providing “smart prices” to customers; such prices have the potential for including DR that would yield additional benefits in the form of cost savings associated with the reduced need for peaking generation capacity, lower peaking energy generation costs and power transmission and distribution cost. While there is wide support for dynamic pricing among academics and consultants, lingering doubts remain about its efficacy among utilities.

The optimality of peak load pricing of electricity is well established in the literature on public utility economics: to maximize the social surplus, prices during the off peak period should be set equal to the marginal cost of energy and prices during the peak period should be set equal to the marginal cost of energy and capacity. However, practice has vastly lagged theory.

The most recurrent critics are that residential customers do not respond to dynamic pricing, that dynamic pricing will hurt low-income customers who spend a lot of time at home and that customers simply don’t want to be placed in rates that fluctuate with market conditions because they are basically risk adverse.

It has been observed that practice lagged theory, creating a long-lasting paradox in the field of public utility regulation.

Articles analysed could be classified in:

- Papers/reports focused on the description of the magnitude of the effects of demand response programs, mainly consumption modification, elasticity and load shifting. In other words, the goal is to evaluate the primary benefit of the utility – intended as the money value resulting from DR and the primary short-term[31] benefit to the customers – which is the (probably) bill savings resulting from DR.
- Papers/reports focused on a more wide evaluation of pricing models: economic and financial cost-benefit analysis, effects on social welfare, effects on network costs, environmental effects

Elasticity and bill’s reduction estimates

The magnitude of possible positive spillover effects is tied to the answer to two questions:

- Customers will really respond to time-varying rates? In other words, do higher peak rates reduce demand?
- Would it have economic (and financial) sense to equip residential and SoHo[32] with AMI?

Trying to answer to these questions several countries have developed pilot projects; in the following

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[30] To put this into context, if 50% of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increase of up to 44%, from 65 to 94 CHF per month. Clearly this cost shift is substantial and simply not fair.

[31] In the long-run, the customer will derive additional benefits because utility cost will decline as customers are served more efficiently.

[32] Small Offices/Home Offices.

pages we will provide an overview of recent empirical assessments of dynamic pricing in the most important experiments realised.

Focusing on load shifting and demand response an interesting review of recent empirical assessments of dynamic pricing has been realized in 2013 and considers 163 experimental treatments in four continents and seven Countries[33].

In terms of tariff schemes, the experimental treatments analysed have adopted:

- Pricing-only experimental treatments
    - Time-of-Use
    - Critical Peak Pricing (with distinction between CPP high, CPP low and CPP pure – differentiated by the price level)
    - Variable Peak Pricing
    - Peak Time Rebate
- Price and enabling tech experimental treatments
    - Enabling technologies such as programmable thermostats and in-home displays (IHDs) can be offered with dynamic rates.

Figure 72sorts results concerning the peak reductions for each of the 163 experimental treatments, from lowest to highest. At a first glance, there is little consistency in the results: demand response varies from 0 percent to 58 percent. Some of the variation in demand response can be attributed to the different rate types tested, while the rest is potentially due to other factors such as differences in experimental design, socio-demographic characteristics, and climate conditions. Grouping the results by rate type slightly improves the resolution, but not by much.

Due to their tendency to have higher price ratios than ToU rates, the authors hypothesize that CPP and PTR rates tend to result in higher customer response; this could be primarily due to the use of high price ratios for these rates. By filtering by rate type and the use of enabling technologies we can see a clearer picture emerge from the data. The use of enabling technology appears to increase demand response to levels above pricing only observations for a given price ratio (Figure 73).

A previous study of the same author includes also RTP, with and without enabling technologies. Results are similar: they find conclusive evidence that households (residential customers) respond to higher prices by lowering usage during peak hours/periods. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. They also vary with the design of the studies, the tools used to analyse the data and the geography of the assessment.

In any case, it is interesting to notice that the most dynamic and theoretically efficient tariff scheme – RTP indeed – is not the most effective in terms of peak reduction; best results are obtained with pricing models that consider a huge peak/off peak price ratio. Peak reduction with RTP are even lower that those registered with ToU with enabling technology[34].

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[33] Faruqui, A. and Sanem S., “Arcturus: International Evidence on Dynamic Pricing,” The Electricity Journal, August/September 2013.

[34] This result have to be taken into consideration carefully because of the limited number of pilot projects based on RTP rates.

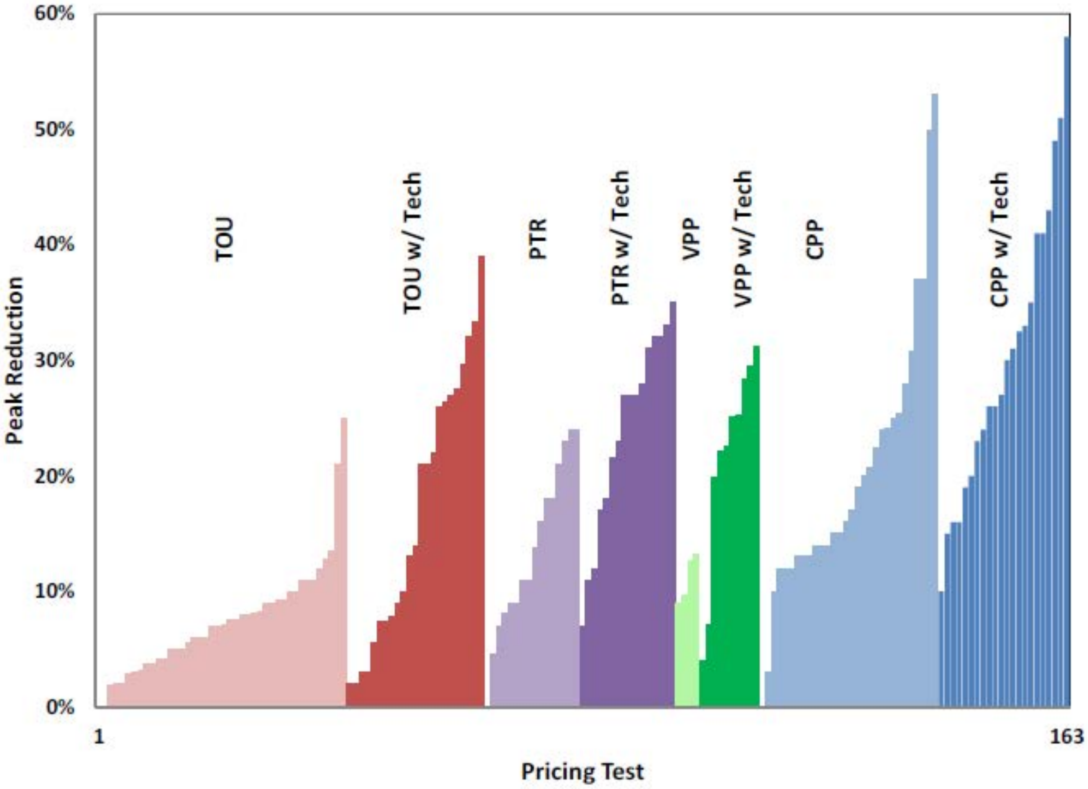


Figure 72: Impacts from Pricing Tests by Rate Type and Use of Enabling Technologies.

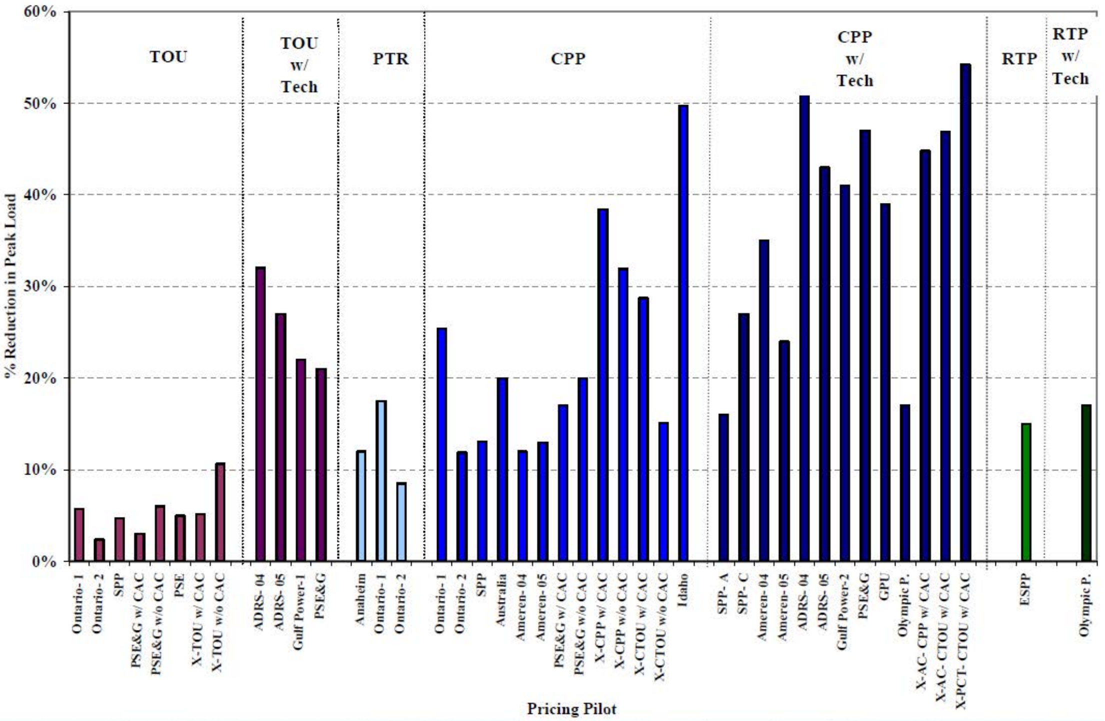
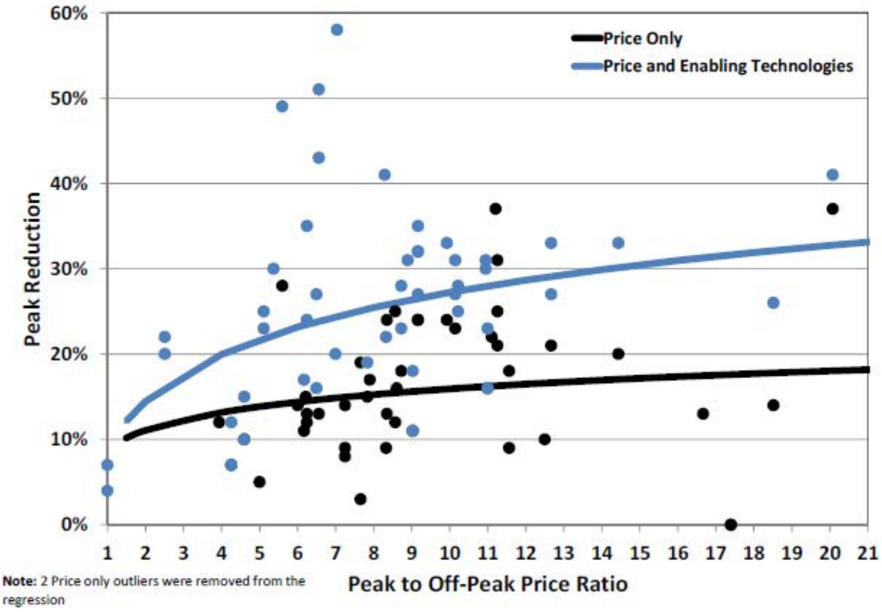


Figure 73: Impacts from Pricing Tests by Rate Type and Use of Enabling Technologies (with RTP).

As the peak-to-off-peak price ratio increases, the peak reduction also increases, although the relationship is weaker and less significant. However, the positive and significant relationship between peak reduction and the variable remains strong, and indicates that the use of enabling technology further boosts demand response.

The so-called “arcs of price responsiveness” (shown in Figure 74) can be used to make preliminary assessments about expected demand response from time-varying rates. For a price ratio of 5:1, the expected peak reduction in price-only and price-tech experimental treatments is 13.8 percent and 21.7 percent respectively. For a price ratio of 10:1, expected peak period reductions are 15.9 percent and 27.2 percent respectively.



Note: 2 Price only outliers were removed from the regression

Figure 74: The Arc of price responsiveness. Source: Faruqui et al. 2013

In terms of price elasticity, substitution elasticities from the experiments range from -0.07 to -0.40 while the own price elasticities range from -0.02 to -0.10. Availability of the enabling technologies, ownership of central air conditioning and the type of the days studies (weekend vs. weekday) are some of the factors that yield variations in the price elasticities. The following table summarizes the elasticities for some selected pilot programs.

Rate design	Sustitution elasticity	Onw price elasticity	Cross price elasticity
ToU		from -0.30 to -0.38	-0.07 (peak to shoulder) -0.04 (peak to off-peak)
CPP	From 0.063 to 0.154	from -0.027 to 0.054 (Daily)	
CPP w/Technology	From 0.295 to 0.306 (Peak to off peak) From 0.356 to 0.407 (Peak to off peak)		
RTP		-0.047 (Overall) -0.069 (Overall with AC cycling) -0.015 (Daytime) -0.026 (Late daytime/evening) -0.02 (Daytime + high price notification) -0.048 (Late daytime/evening+hig price notification)	

Table 13: Summary of the Experimental Elasticities

Utilities cost savings

From a general point of view, mains benefits related to the adoption of dynamic rates could be summarized as follow:

- Relative and absolute reductions in electricity demand;
- SRMC saving from peak demand shifting;
- Reduction in new plant investments;
- Reduction in backup reserve for emergencies/unforeseen events;
- Reduction in network investments as a consequence of congestion reduction.

In terms of cost-benefit analysis, several studies[35] provide estimates of the various costs and benefits for demand side response for electricity. The empirical evidence gives contradictory results: several experiences register a net benefit while others point out the prevalent weight of costs (in particular the cost of the adoption of smart meters/AMI, that permit to time-varying pricing to be actually implemented); in this case, authors suggest that the gap could be financed by some kind of system charge.

In 2008 Edison Electric Institute estimates the NPV of utility cost saving per customer over a period of 15 years. We can notice that capacity cost savings dominate the benefits to the utility.

	Utility capacity cost savings	**Utility energy cost savings**	**Utility transmission cost savings**	**Utility distribution cost savings**	**Total savings**
ToU high rate	$290	$40	$51	$41	$422
PTR rate	$520	$73	$91	$73	$756
Pure CPP rate	$581	$44	$101	$81	$807
CPP high rate	$594	$48	$104	$83	$829
CPP low rate	$460	$46	$80	$64	$651

Table 14: NPV of total utility cost savings per customers (over 15 years). Source: Edison Electric Institute, 2008

In terms of bill's reduction, the same study estimates that monthly bill savings could vary from a minimum of 3,94 $ for CPP low to a maximum of 8,08$ for CPP high (next figure).

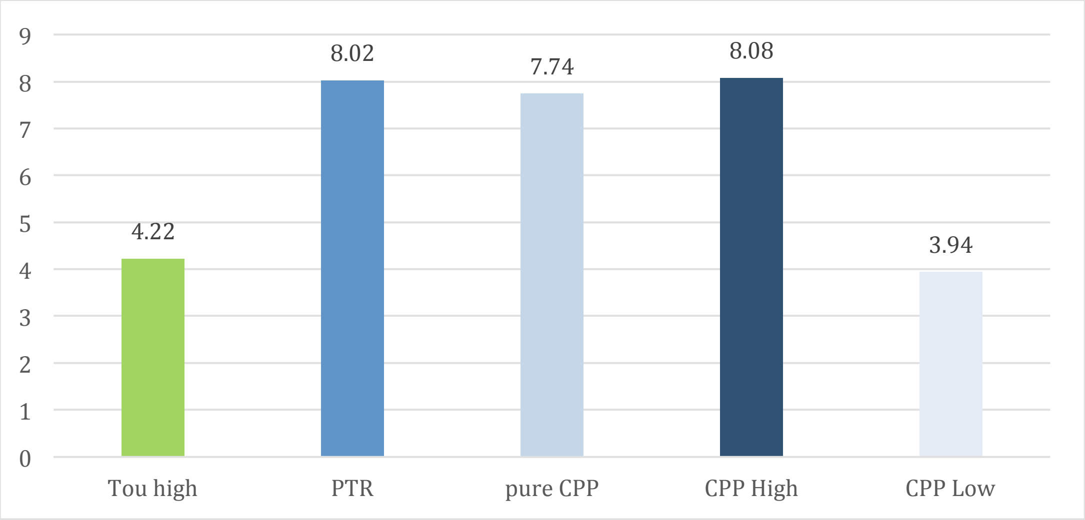


Figure 75: Average customer monthly bill savings by rate type ($). Source: Edison Electric Institute, 2008

Utilities cost savings, especially those related to the reduction of investments, don't necessary correspond to actual economic/financial advantages for the firms. As pointed out, with RAB regulation, the cost of new investments is remunerated with by end-users tariffs so, in some way, in the long run it's "neutral" for the utility[36]. In this case, the real benefits are at a social level, considering also possible

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[35] DECC (2011), Ofgem (2011), Strbac et al (2010), Ernst&Young, "Cost-benefit analysis for the comprehensive use of smart meters", NERA economic consulting, (2008) "Cost benefit analysis of smart metering and direct load control. Work Stream 4: Consumer impact", Edison Electrict Institute (2008) "Quantifying the Benefits of Dynamic Pricing in the Mass Market"

[36] Anyway, we have we have to keep in mind that investments represent an anticipated cash outlay,

reductions for customers' bills.

Overall results

- About rate design: larger differential between peak and off-peak rates leads to greater savings.
  - Higher values of CPP (so-called CPP high) provides a greater incentive to shift load during peak hours on critical days;
  - Comparing to CPP high rate to the PTR, the last one result in slightly less load shifting on critical days and no load shifting on non-critical days. But this is a per-customer result, and the primary issue with the PTR rate is how many customers will actually be aware of this rate since customers do not necessarily "join" a PTR program per se.
  - Comparing the CPP high with the pure CPP the last one produces results similar to the CPP high rate in terms of customer bill savings and energy savings during peak hour in critical peak days. However, on non-critical days the pure CPP rate results in more energy usage during peak hours because the peak price is lower than the CPP high price.
  - The ToU rate does shift load during peak hours but, on critical days it is only about half as effective as the CPP rates. This because under a ToU rate there is no additional incentive to modify behaviour on critical days (compared to non-critical ones).
  - Change in consumption during the critical peak and non-critical days with CPP high rate highlight that during the critical day's consumers tend to reduce their consumption while during non-critical days they simply shift their consumption from peak to off-peak hours.
- Results from recent pilot programs suggest that consumers similarly understand and respond to critical-peak pricing programs. Nevertheless, it is important to keep in mind that existing studies have focused on consumers who voluntary participate in dynamic pricing programs (self-selection process), so care must be taken before extrapolating to the entire population.
- If dynamic pricing become the default tariff substantial benefits can accrue to customers. If it's offered only as an optional tariff, benefits would be lower[37]. Actually, it is most likely that dynamic pricing programs will evolve slowly, and that most utilities will begin by allowing volunteers to opt on to alternatives tariffs while leaving flat-rate pricing the default option[38].
- Load shifting increases as the strength of the price signal increases, but at a decreasing rate.
- Low-income consumers have been found to be price responsive, although not always as responsive as the average residential customer.
- The presence of enabling technologies has been shown to incrementally boost price response.
- Results in terms of bill's reduction are, with some relevant exception, not so relevant and, in many cases, linked to energy consumption reduction.
- Targeting high consumption homes may be an effective strategy. The California Statewide Pricing Pilot from 2003 and 2004 demonstrated that CPP programs can be effective at reducing demand. That study also demonstrated, perhaps not surprisingly, that high-use customers decrease their demand the most on CPP event days (one additional note here is that those

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and they are financed alternatively with equity or debt; in the last case they will bear bank interest (and this could reduce their capital remuneration).

[37] According to Pfannenstiel and Faruqui (2008) benefits would be about a quarter to a tenth as large.

[38] Borenstein (2011) analyzes the impacts of allowing fewer than 20% of the customers to opt on to dynamic pricing. If customers whose demand is already flat are most likely to move away from flat rates, the cost of serving the households who remain on flat rates increases, since they will on average consume more during expensive peak periods. Borenstein (2011) finds that this effect is likely to be small. According to Joskow (2012) Borenstein does not model the offsetting effect, which is that as the first set of customers opt on to dynamic pricing and reduce their peak-period consumption, average prices fall, as do differences between peak and off-peak wholesale prices. This second effect suggests that the efficiency gains from forcing the remaining, unwilling customers onto dynamic pricing are smaller than the gains as the first customers move off flat-rate pricing.

people with the lowest demand benefited the most economically, in percentage terms, from the CPP program). As a result, a program targeting high-use customers may be more cost-effective than a rate targeting all customers because low-use customers do not exhibit a statistically significant reduction in energy use on CPP event days. It is important to differentiate between electricity usage and income level. While there may be a positive correlation between the two, it is important to highlight that response to CPP is consistent across income levels (i.e. low-income, high-usage customers respond identically to high-income, high-usage customers).

- Largest users saved the most amount of energy for the utility; customers using more than 15’000 kWh per month saved 5 times more energy than did users using less than 5’000 kWh.
- Smart Grids will potentially bring new options and needs for design and setting of network tariffs. The change brought by the new environment of SG concerns the use of electricity, elasticity of demand, mobile loads, large penetration of distributed generation and energy storages, etc. As the business logic of DSOs and TSOs is changed by SG, new structures for charging the customers and producers may be justified and emerge.

Smart grid projects: the role of consumers

- Increasing numbers of projects are focusing on consumer engagement; however consumer participation in the projects is still limited in size;
- Consumer resistance to participating in projects is still significant;
- Consumers participating in trials are typically volunteers (e.g. technology enthusiasts, green consumers, etc.), and are not representative of consumers in general;
- Lead organizations in projects focusing on consumer involvement are DSOs or DSO’s associated energy company. Aggregators and retailers, who should have the commercial role of interacting with consumers, seem to have a more limited role in these pilots;
- Denmark and Germany are the leading countries with projects focusing on consumer engagement;
- increasing numbers of multinational projects address consumer engagement as a key issue;
- The main factors used for motivating consumers are reduction of bill cost and environmental concerns.
- Many projects acknowledged a high level of consumers' skepticism and highlighted the importance of building trustful relationship with consumers

7. Part 2 – Results / findings

8. Experimental results

8.1. Grid measurements

8.1.1. Measurement infrastructure

The goal of this section is the acquisition of voltage metering data by various metering equipment in the demonstration region. With this metered data, the Swiss2Grid team had developed the Swiss2G algorithm, taking into account certain underlying statistical characteristics of the metered data.

Voltage amplitude measurements (11 equipment with amplitude voltage values; 4 additional equipment also using voltage and current phasor metering) have been obtained at 15 locations in the demonstration region during 2012-2014. The data has been captured and been converted into series with 30 seconds time difference between analyzed data points. Time was synchronized via internet time protocols and via GPS for the absolute phasor enabled meters. The data has been analyzed to determine patterns (correlations) between the voltages at the various metering points. The goal was to derive key parameters of statistical patterns together with local real-time voltage measurements to be able to derive local grid user actions in such a way that the voltage of each controlled node is within given voltage bands at all low voltage locations of the distribution grid. Figure 76 shows the measurements points in the Mendrisio neighborhood and the topology of the distribution grid which was analyzed.

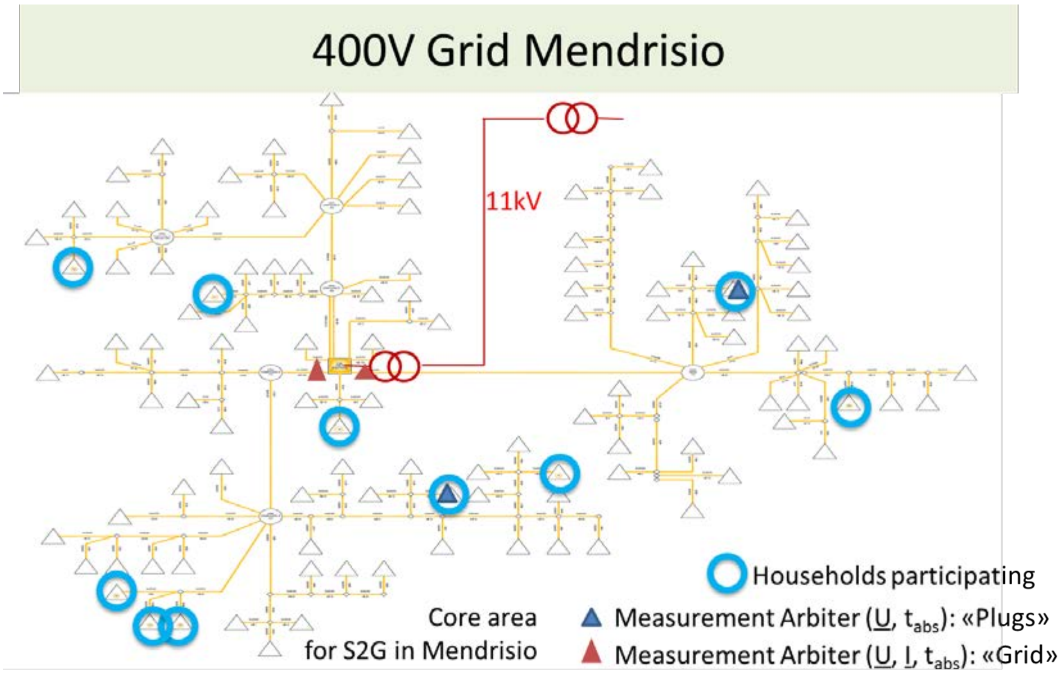


Figure 76: Measurements points in Mendrisio “Asilo Genestrerio” neighborhood (t_{abs}: absolute time, U, I: indicate absolute time (GPS-synchronized) measurements)

Every household has been fitted with two HACs (House appliance controllers) measuring:

- house connection point to the grid;
- PV inverter output.

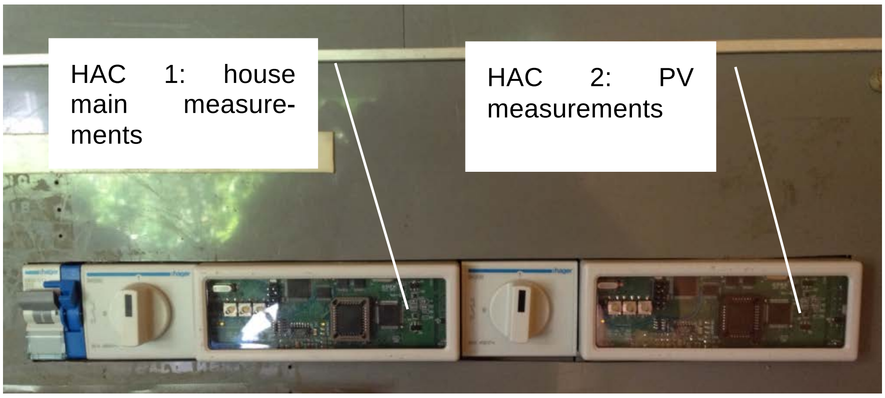


Figure 77: Example of a HAC installation

Figure 78: Example of a touch panel installation

All this collected data of the various monitoring equipment must be time-matched to be ready for parallel analysis and dependency analysis with the goal to get a full picture of the critical states of the grid in very short-term intervals. Time-accuracy has been reached and verified by using a combination of GPS time signals and Network Time Protocol (NTP) signals.

Since June 2012, data is being collected and permanently stored in second intervals in a MySQL database accessible via the Web, both by FTP and Web servers.

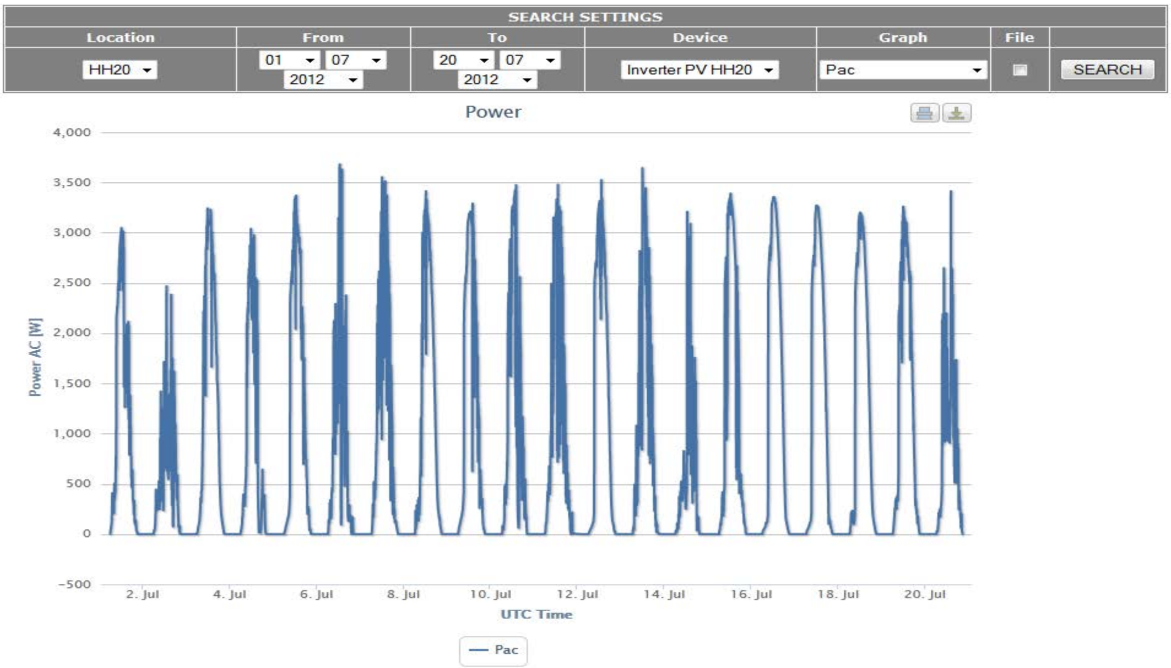
The current interface, with restricted access to the project team, is as follows. Figure 79 shows an example as the currents in each of the three phases at the transformer leaving towards the left hand side radial branch (i.e. towards HH06, shown above).

SEARCH SETTINGS

Type	Location	From	To	Device	Graph	File	
Grid Meter	Trafo-Asilo-Genestrerio	01 07 2012	20 07 2012	LV Line -> Arm. Campagnola	Current	☐	SEARCH

Figure 79: Example of current measurements at a transformer branch

The following picture shows – for one of the household marked as blue circle – the generated active power of a PV-panel, again for the same period as chosen above.



SEARCH SETTINGS

Location	From	To	Device	Graph	File	
HH20	01 07 2012	20 07 2012	Inverter PV HH20	Pac	☐	SEARCH

Figure 80: Example of a household measurement (PV system)

The web interface development has been an essential feature enabling to easily detect firmware glitches during the initial rollout. Moreover the team has implemented an automated daily data quality verification alerting by email the researcher about missing or incorrect data. This allows a reliable and effective support of the device operation.

Currently and going into 2014, data collection from the four Arbiter and HACs is continuing. After making all data ready to be used, the collected data will be analyzed and transferred to be used as input for the grid model based computations and algorithm development by Swiss2G partner BFH.

8.1.2. Correlation between voltage measured at the nodes and LV transformer power

A typical output of the captured voltage data is as follows:

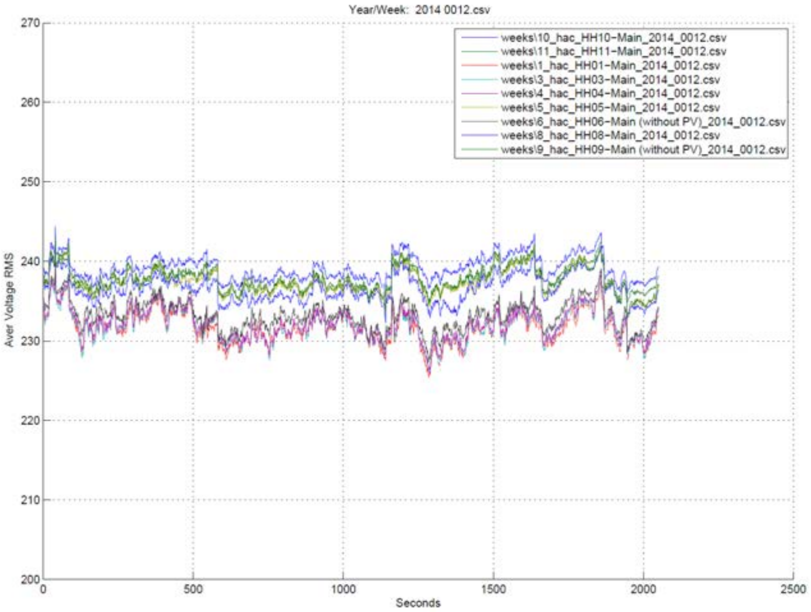


Figure 81: Typical voltage data profile (week 12 of the year 2014)

The graph shows for the time period week 12 (March) of the year 2014 the plot of metered voltage (amplitudes, RMS) at locations 10, 11, 1, 3, 4, 5, 6, 8 and 9. The plot contains data snapshots for every 30 seconds. Only those voltage magnitude data points are plotted where for each location, a valid data points has been acquired for all locations.

Another typical plot is the following for the summer season (week 28 of the year 2013):

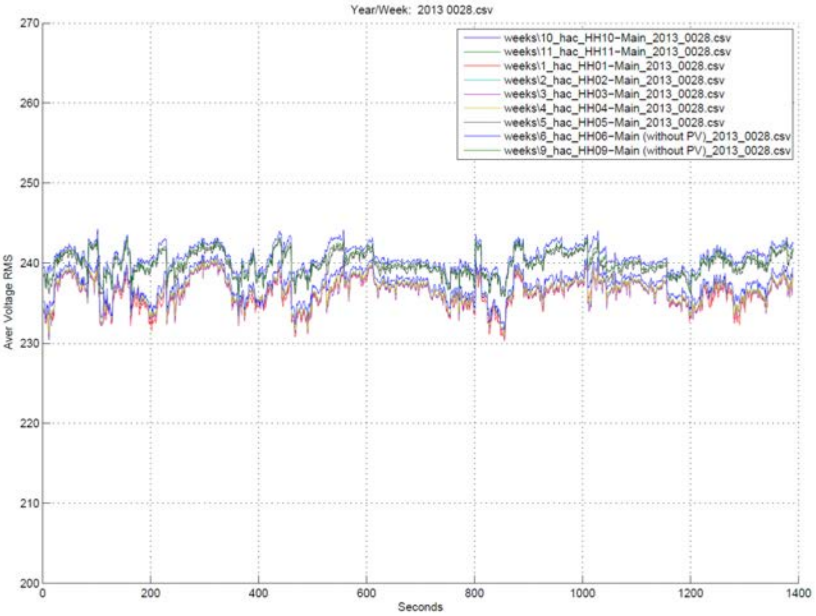


Figure 82: Voltage profile during summer season (week 28 of the year 2013)

Shown locations are 10, 11, 1, 2, 3, 4, 5, 6 and 9. The difference in acquired locations compared to the previous figure comes from the fact that several metering equipment had to be adjusted/updated during the project time and not always, the full set of acquired data was available. Overall, voltage data of this type has been obtained between 2012 and 2014.

Power fluctuations at the transformer radial branch can be predicted from local voltage measurements at the grid end nodes. In Fig. 2, in the case of HH5, the rms voltage at the HH main panelU_{main}, and the active power at the transformer radial branch P_{trafo} are plotted as a function of the time of day and the measurement day. The plotting shows a strong negative correlation between the two variables.

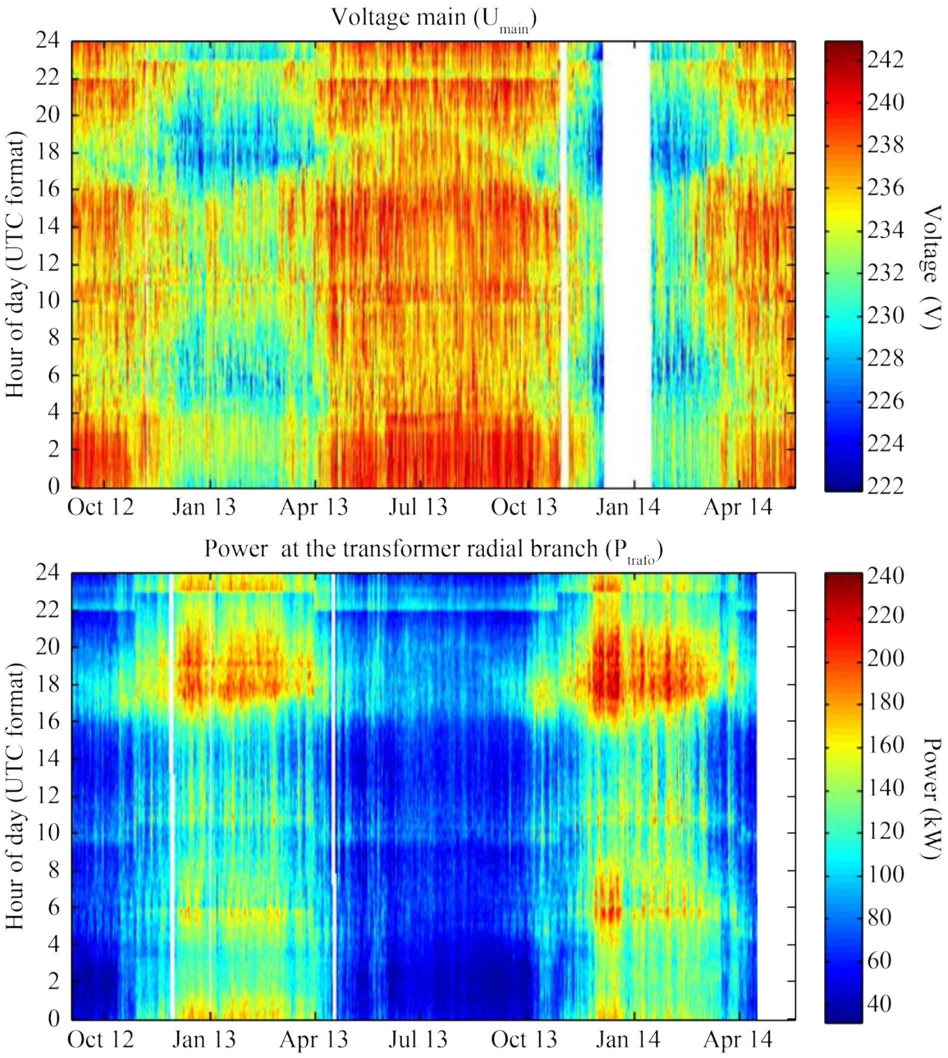


Figure 83: Voltage pattern measured at HH5 main panel U_main, and active power at the transformer radial branch P_trafo, at different hours of the day (y axis) and measurement days (x axis). 15 min averages of voltage and power are shown color coded. White background denotes missing data.

When plotting the active power at the transformer against the voltage measured at the HH main plug, we observe a linear relationship (Fig. 3), which can be modeled as:

$$\tilde{P}_{trafo} = k_1 U_{main} + k_0 \qquad (1)$$

where k_0 and k_1 are constants. We fitted (1) to the data of each HH using the least squares method (red line in Fig. 3). For each HH, Table I summarizes the extracted parameters k_0, k_1, with their respective 95% confidence intervals, as well as the correlation coefficient R and the rms error RMSE, expressed both as an absolute value in kW and as a percentage of the measured power range

$\max(P_{trafo}) - \min(P_{trafo})$. Households on the same radial branch of the transformer (HH1-5 and HH6-7) recorded similar values for the fitted parameters k0 and k1, as well as comparable correlation coefficients and RMSEs.

HH	Fit results				
	$\boldsymbol{k_0}$ (kW)	$\boldsymbol{k_1}$ (kW V^{-1})	R	RMSE (kW)	RMSE (%)
1	648.1±0.5	-2.642±0.002	-0.912	6.255	6.130
2	555.4±0.5	-2.241±0.002	-0.916	6.104	5.982
3	544.4±0.4	-2.195±0.002	-0.917	6.097	5.975
4	561.3±0.4	-2.265±0.002	-0.922	6.152	6.030
5	695.0±0.5	-2.827±0.002	-0.893	6.529	6.461
6	322.6±0.9	-1.308±0.004	-0.627	3.718	10.277
7	324.4±0.9	-1.318±0.004	-0.600	3.903	10.788

Table 15: Linear regression result

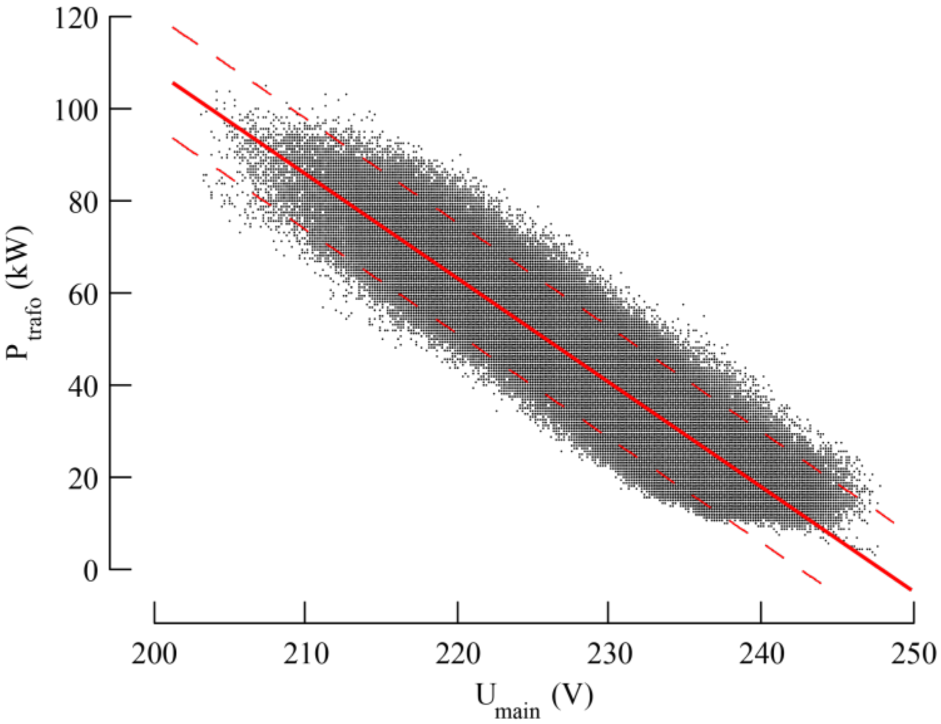


Figure 84: Correlation between U_main of HH4 and P_trafo measured on phase 1. Black dots: single measurement points. Solid red line: result of the linear regression defined by (1). Dashed red lines: 95% prediction interval.

8.1.3. Correlation between voltages measured on the LV grid

In order to conclude on statistical features of the local-voltage-only Swiss2G control algorithm, the captured data has been analyzed in several ways.

When modelling the transformer as an ideal voltage source, the dependency of the voltage at the HH main panel on the transformer power is expected to increase as a function of the impedance of the cables and of the number of HHs on the same branch. HHs at the far end of the grid should therefore yield higher correlation values. However, a detailed simulation would be required in order to assess this relationship more rigorously. We plan to address this problem in future studies. Nonetheless, by comparing the voltage correlation values of houses on the grid, it is possible to estimate their relative positions and even the grid topology itself [9]. The voltage time courses measured on the same radial branch of the transformer were also expected to be strongly correlated. In the case of the “Asilo Genestrerio” low voltage grid, we can easily identify neighboring HHs by looking at the correlation coefficient of the voltages measured at their mains (Fig. 4).

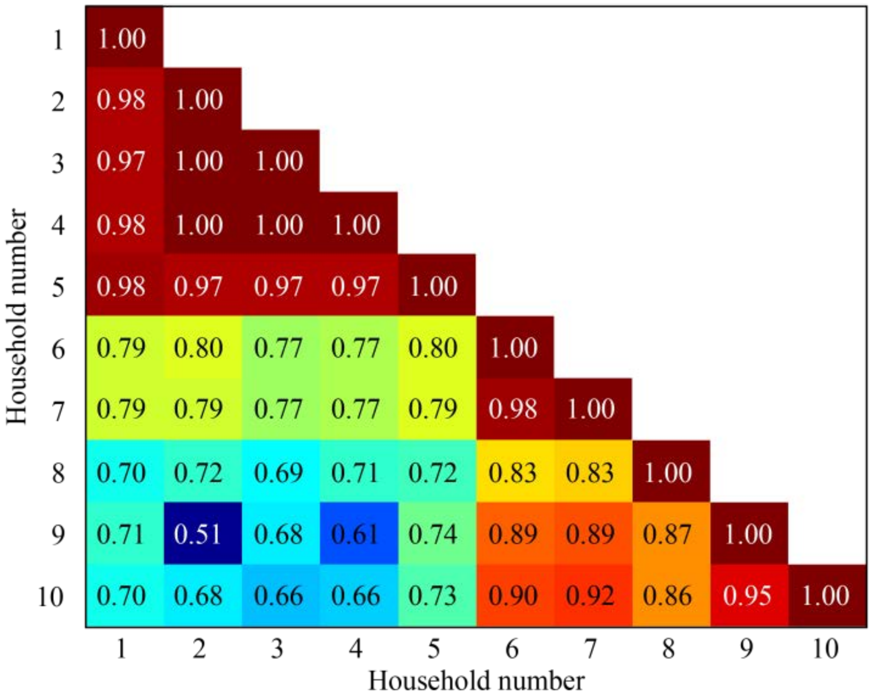


Figure 85: Correlation matrix of rms voltage on phase 1, measured at the main panel of the monitored HHs. Correlation coefficients are superimposed and color coded.

A more detailed analysis is shown in the following two figures:

The figures show the same voltages as displayed in the two figures before (i.e. time period week 12 of 2014 and week 28 of year 2013), but this time, each voltage is plotted against all other voltages in separate subplots. I.e. the subplot (1, 3) (third plot, first line) shows the plot of voltages captured a location 1 versus the voltages at location 2 and exact same time snap shots (each 30-seconds) during the week 12 of the year 2014 (next figure) and the week 28 of the year 2013 (over next figure).

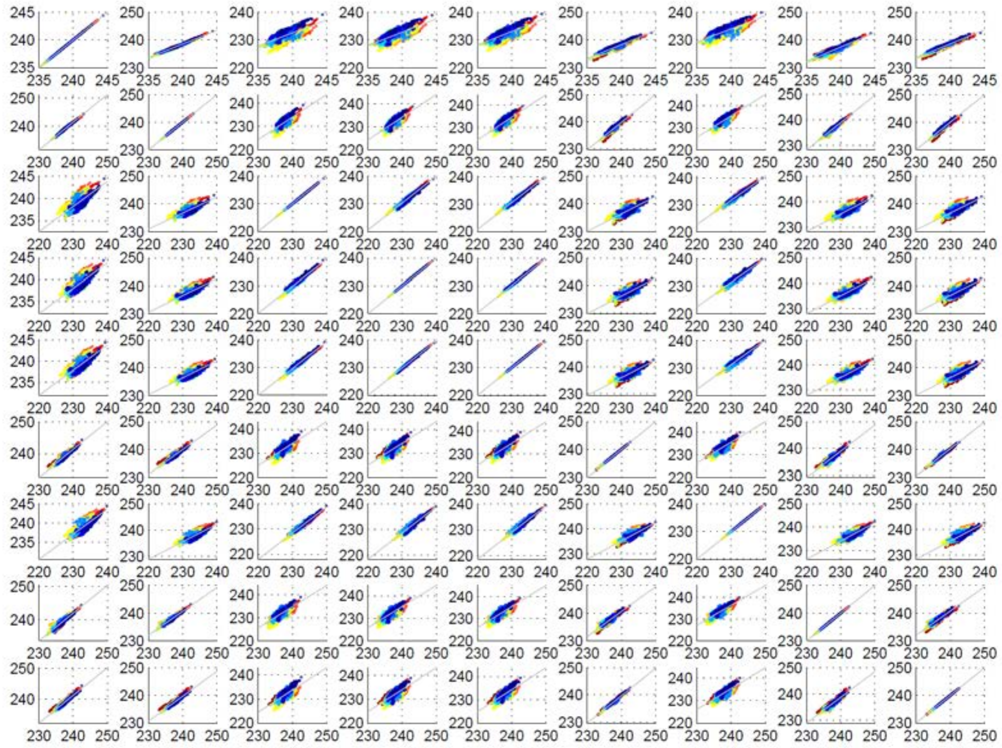


Figure 86: Time period week 12 of 2014 – Correlation of each node voltage versus all others

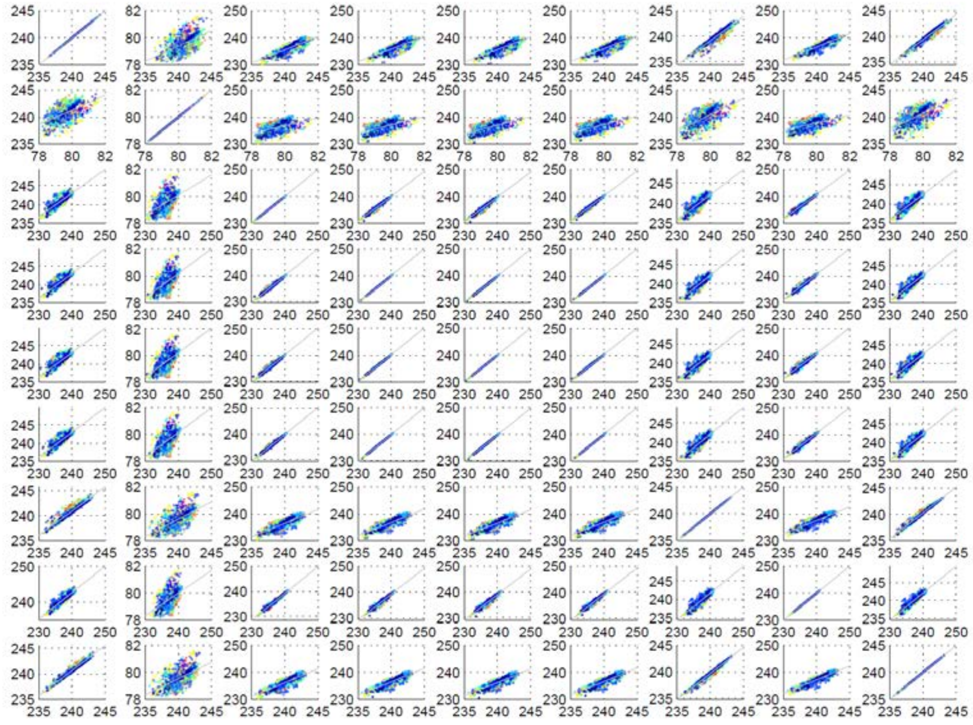


Figure 87: Time period week 28 of 2013 – Correlation of each node voltage versus all others

These scatter plots give a visual indication, how voltage (average of the measured phase voltages) captured during such two weeks of the year (in 30-second intervals; some data points (e.g. 2nd location) showed low average voltages because only two out of three phases were measured) correlated with the one of other locations in the same low voltage distribution grid and at same times during given weeks.

Clearly, these two figures show visually that some data points – for the given week of the year – have high correlations (very narrow point plots), other less (wider point plots). In the given distribution grid, voltages at the metered main household plugs never went outside of the norm voltage bands (230 plus/minus 10%).

The correlation analysis between any two metered household plugs has been done rigorously by taking the available metered data points per week in the metering time period. For each pair of metered voltages, the following analysis has been made:

- How many metering points have been successfully acquired?
- What is the correlation factor between the metered data points?
- What are the two coefficients for the linear approximation of the voltage data points (i.e. constant y-axis and slope of line)?

The data has be filtered by taking only those samples with high correlation (>0.95) and at least 100 metering points of the observed voltage metering locations / times for given individual week of the time period. From this, the plots obtained are as follows:

For each location (a household “main plug” nearest to the household meter; called “reference location”), we take the parameters describing the linear approximation (least-squares line) of the two voltages where a strong correlation is observed: R > 0.95 (R is a number between 0 and 1 to specify a confidence level of 95%). In the following, using the linear least squares approximation of highly correlated data sets, we compute and then plot the voltage changes on the y-axis. The x-axis number corresponds to the number of the “other voltage plug”. The ID/number of the reference location/household can be obtained from the title of each figure.

The following figure shows: The voltage at node 1 is perfectly correlated with itself, i.e. there is always a voltage change difference of zero with itself. The voltage at the other “household 2” shows three vertical distributions with respect to the voltage at reference node 1: The one at exactly tick “2” (meaning household 2) is marked with slightly larger filled circles. It shows the computed voltage difference of household 2 compared to a voltage of 230V at the reference household 1. The observed voltage range in the figure above is between approx. -1 and 5 Volts: The color of each point indicates the week of the year, in which the voltage difference is to be expected: Light colors indicate mid-year (summer) weeks (i.e. weeks 20-35). The darker the color, the more we approach winter weeks (i.e. 1-12 and 40-52).

In addition in the following figure, the smaller-dotted curve slightly to the left of tick 2 shows the expected (computed with derived linear regression curve) voltage difference at household 2 compared to the reference voltage (at node 1), assuming that the theoretical voltage at the reference node 1 (for this figure) is at the allowed minimum of 230-10% = 207V. The colored dots show that the voltage difference between node 2 and node 1 for such an extreme low voltage level at node 1 tends to go up, somewhere to a maximum change of around 7V and – due to light blue colors – in the early summer weeks 18-22 of the year. It is important to notice that only those weeks of the year are plotted in the figure where a high correlation > 0.95 has been observed between measured voltage pairs of nodes for a given week. All other weeks are disregarded.

It is also worth noting that the node voltages at pairs “reference node 1” and “other node 5 / node 8 / node 9” show high statistical correlation > 0.95 only in summer weeks of the metering period (light blue color dots). The voltage difference is then approx. 5 volts (=V at “other” node minus V at reference node 1) when assuming that the voltage at the reference node 1 is 230V.

The presented analysis focuses on the fact that the local Swiss2G algorithm can only assume facts derived from statistics say for weeks of a past year combined with information of local real-time voltage measurements. I.e. the analysis has shown that the local algorithm “running” at a node 1 can compute / guess for highly correlated weeks of the year the typical voltage difference at other nodes if the own voltage is between 207 and 253V. This assumes fundamentally that the local algorithm knows about the current week and time of the year.

One also observes (by the color range of dots) that voltages at reference node 1 and other nodes 2, 3, 4 and 6 are highly correlated throughout all weeks of the metering period. This is in contract to the mentioned “narrow” voltage correlation of reference node 1 with the other nodes 5, 8 and 9 for summer weeks only. Also, note that only low correlation (< 0.95) has been observed between voltages at reference nodes 1 and 10.

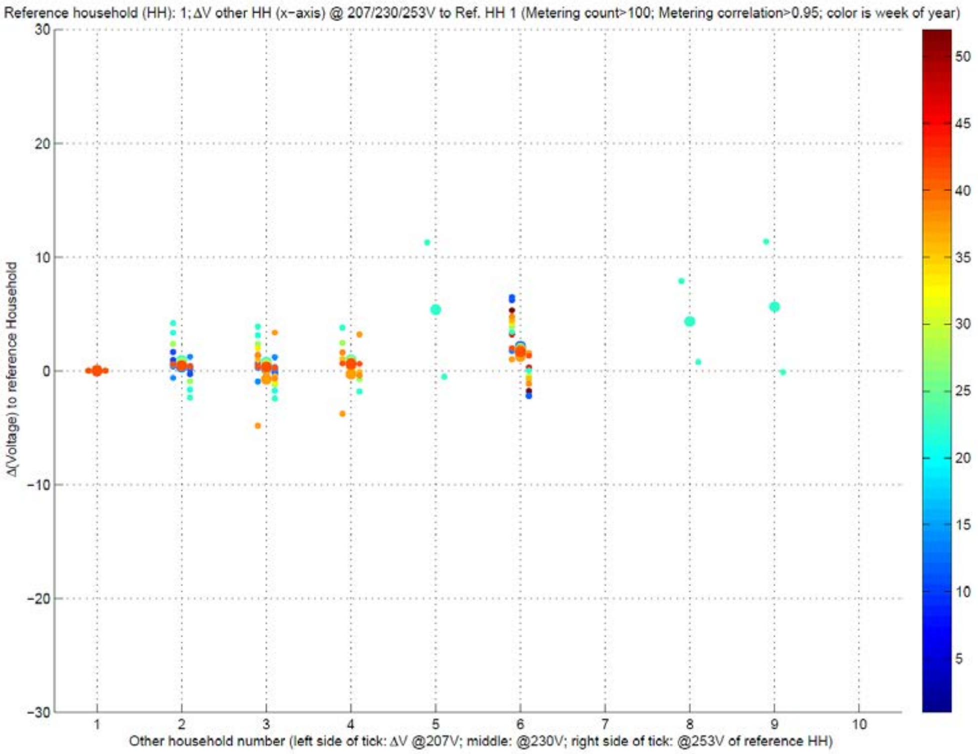


Figure 88: Correlation of voltages with reference node 1

To get better insights we now take node 6 as reference node. The following figure shows a high correlation for reference node 6 throughout the year compared with the voltages at nodes 1, 2, 3 and 4. Only in summer weeks (light blue color), a high correlation can be observed of node 6 towards the voltages at nodes 5, 8 and 9. No high voltage correlation is found between reference nodes 6 and the other nodes 7 and 10. If the voltage at reference node 6 is assumed to be very low (207V), the voltage at the other (correlated) nodes 1, 2, 3 and 4 can be expected to be approx. up to -7V lower (-7V in winter weeks). When assuming extremely high voltages (253V) at reference node 6, voltages at nodes 1, 2, 3, 4 would differ from this (very high) reference voltage between approx. -4V ... +3V, depending on the week of the year.

In order to have a “complete” analysis picture, the following figures show each of the nodes 1 – 10 as reference nodes and how their voltages correlated with each other based on the metered voltage values.

Reference node 6:

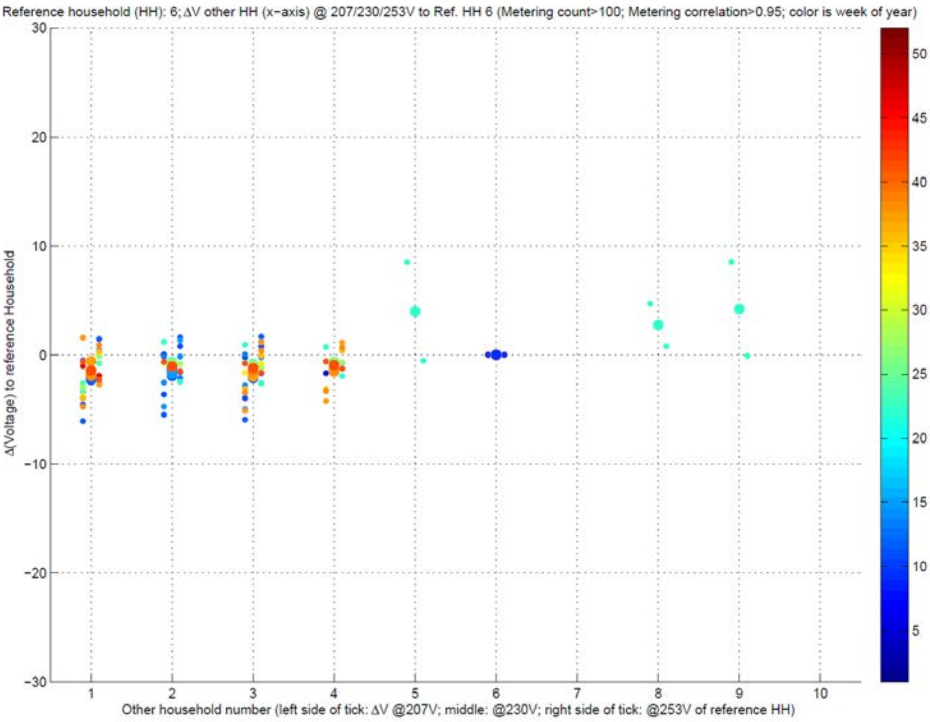


Figure 89: Correlation of voltages with reference node 6

In order to have a “complete” picture we also show in the following figures the voltage correlations of all other nodes.

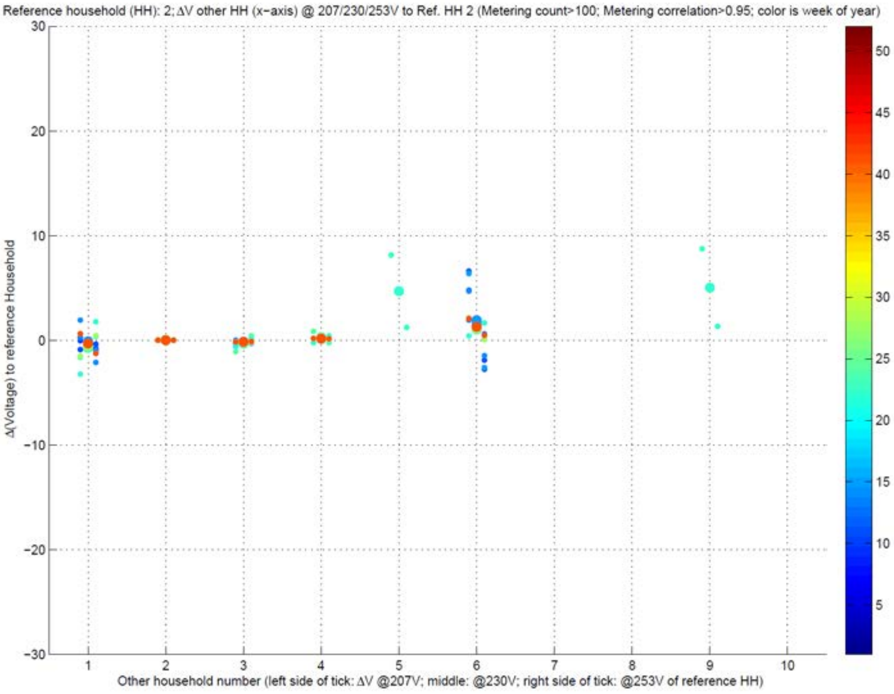


Figure 90: Correlation of voltages with reference node 2

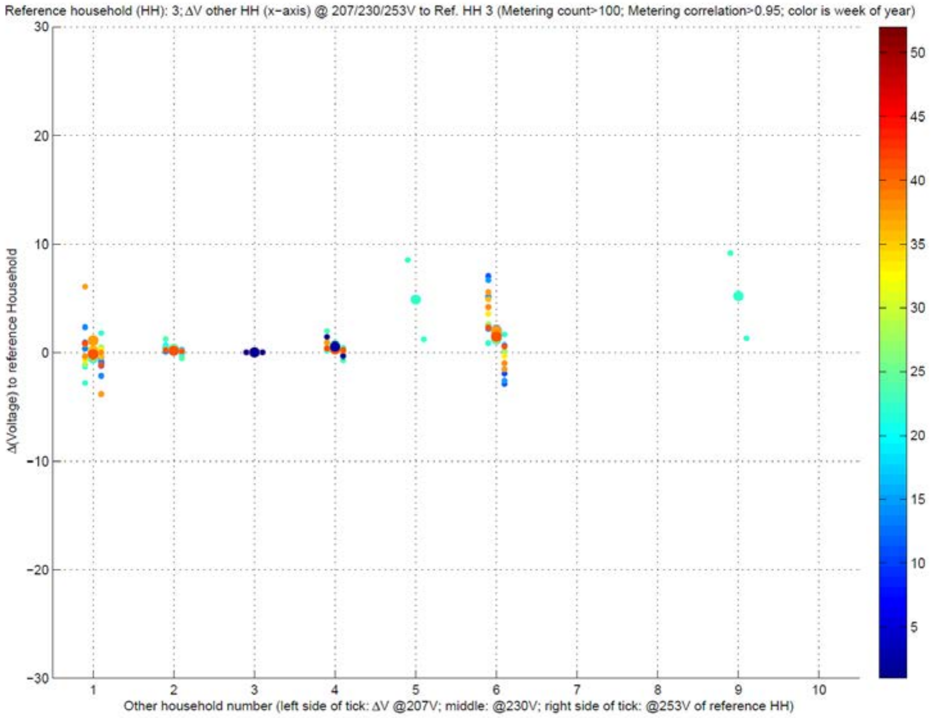


Figure 91: Correlation of voltages with reference node 3

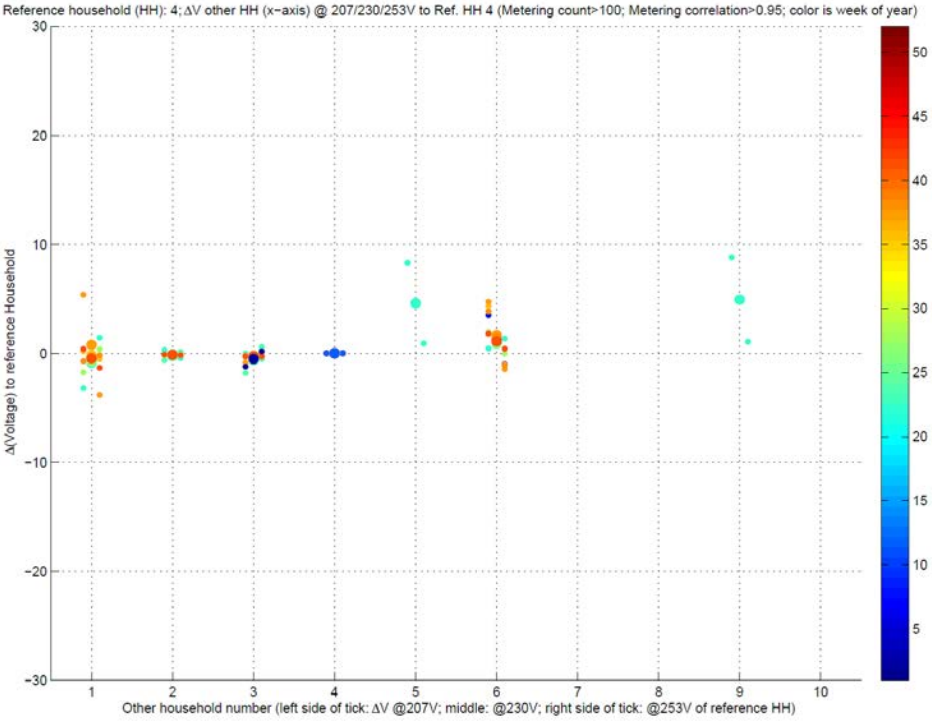


Figure 92: Correlation of voltages with reference node 4

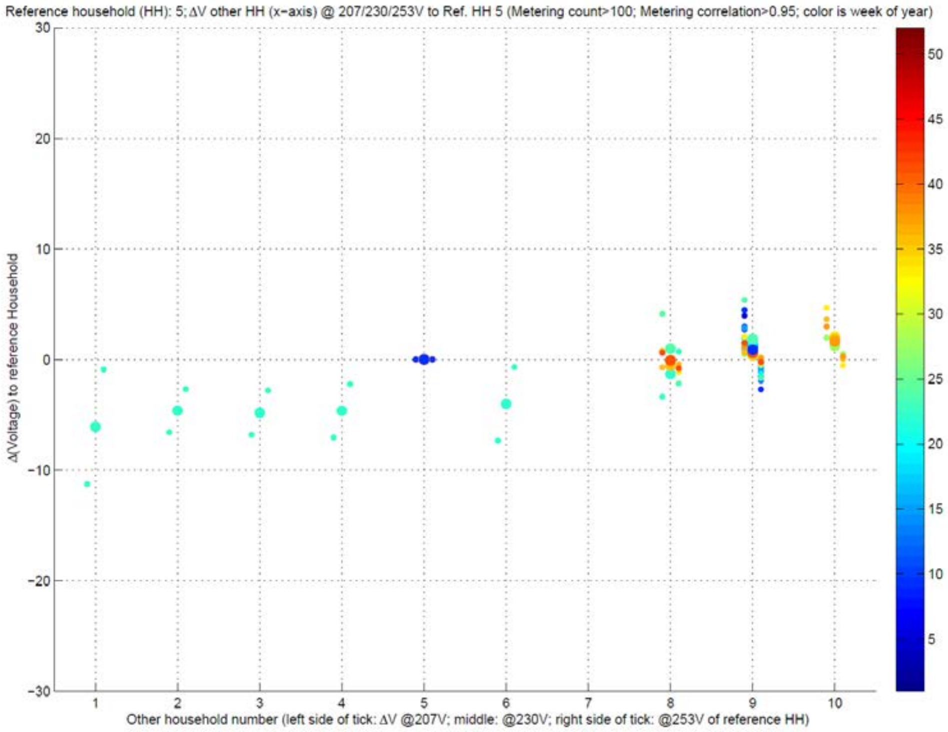


Figure 93: Correlation of voltages with reference node 5

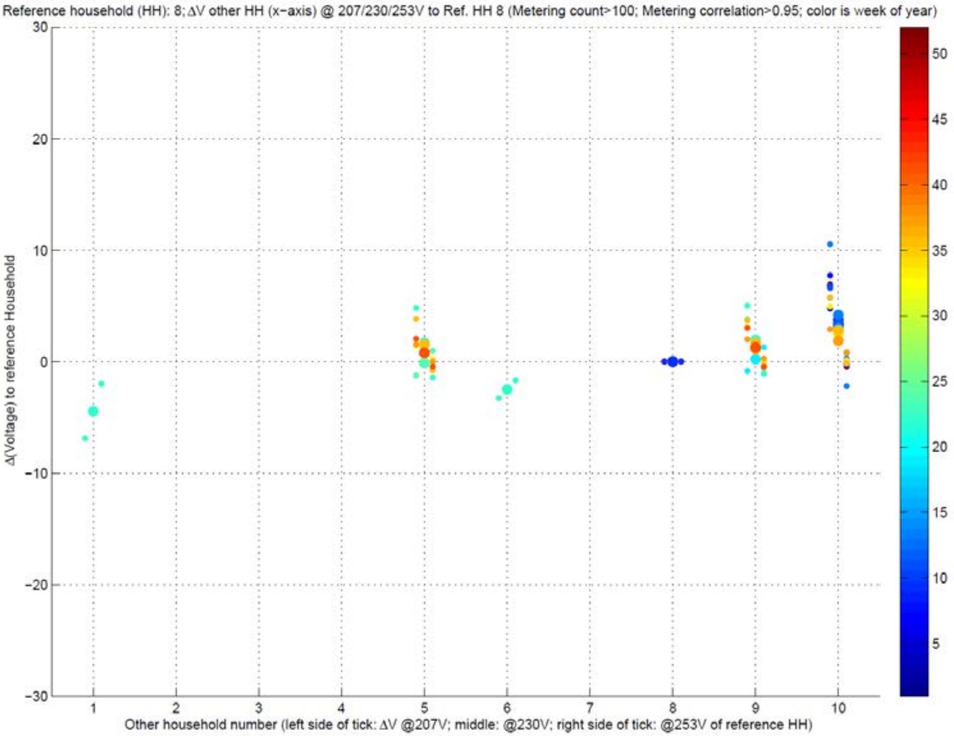


Figure 94: Correlation of voltages with reference node 8

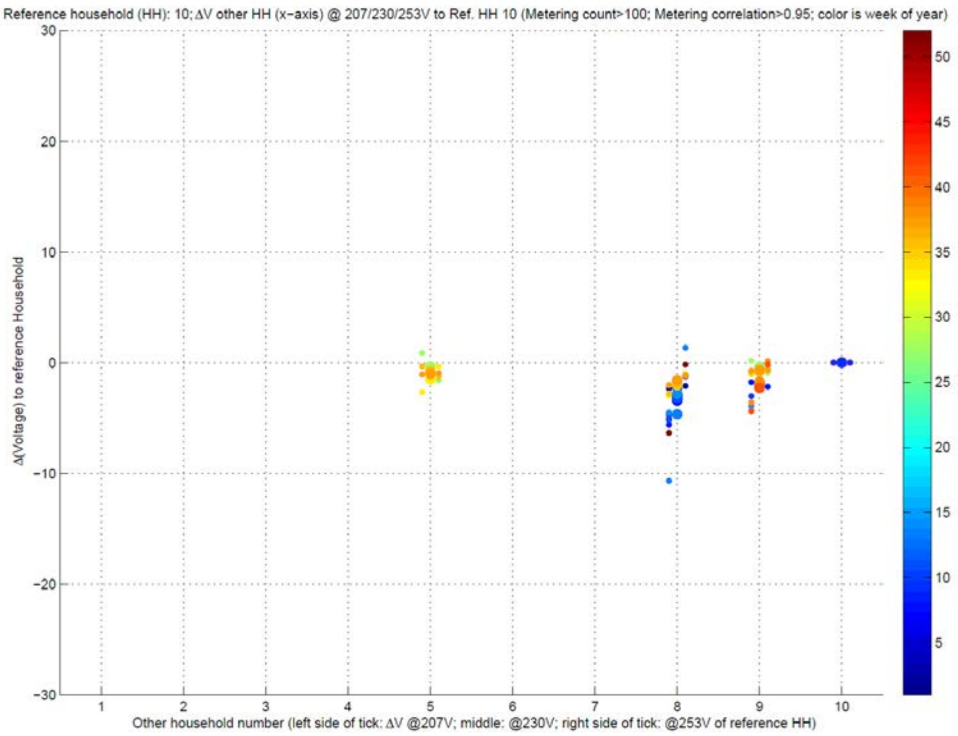


Figure 95: Correlation of voltages with reference node 10

We have presented some of the results of the Swiss2Grid measurement campaign performed on the selected LV grid. We have shown that the power fluctuations at the transformer radial branch can be predicted from local voltage measurements at the grid end nodes. We have shown that voltages measured on the same radial branch of the low voltage grid are usually strongly correlated. We can easily identify neighbouring HHs by computing the correlation of their voltage over time.

8.2. S2G algorithm field tests

8.2.1. Introduction

In this section we describe the tests performed with the algorithm on the field in the Mendrisio test households.

Algorithm-hardware interfacing

During the project, the S2G Algorithm has been interfaced to hardware (reading sensors, actuating devices) by means of the DomoML infrastructure. The DomoML-Algorithm interface was finalized and thoroughly tested before deployment. The developed software architecture allowed us to deploy and update the algorithm on the real hardware using the same code used for simulation (both for forecasting and scheduling modules).

Voltage measurements and forecasting

In all installed households, the algorithm could reliably receive voltage and power information from the DomoML framework. The voltage logging and forecasting subsystems of the s2g algorithms were tested and verified to be working fine as long as the underlying system was responsive.

Low level monitoring of actuation

A software infrastructure for updating and monitoring algorithms running in S2G households has also been implemented. To aid debugging, the system can plot the observed power profile by a device and compare it with the schedule requested by the algorithm.

In the figure below, the former is the blue line and the latter is the red line. The blue line tracks very well the red line, which implies that the software and hardware chain below the algorithm is correctly executing the algorithm's instructions.

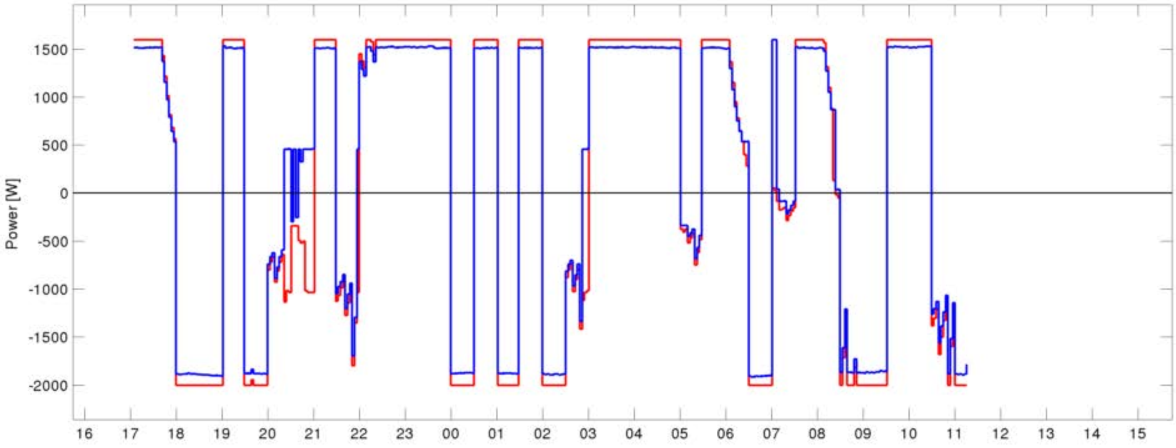


Figure 96: Low level monitoring for B2G control, HH21, 2014-Jan-08 → 2014-Jan-09 (Red: scheduled load; blue: observed load).

Controlled devices

Algorithms have been tested for controlling the following devices:

- B2G batteries (HH01, HH05, HH06, HH09, HH21)
- Boilers (HH02, HH05, HH09)
- HCD 1.5 devices

Difficulty in controlling boilers due to imprecise water temperature measurements

During the field tests, we observed that temperatures reported by sensors mounted on boilers did not correspond to the expected temperature of water within the tank. Because within this project the S2G algorithm requires to know the amount of energy stored in the boiler, this posed an important issue as it prevented the algorithm from effectively controlling the boiler. Different placement of temperature sensors within the boiler were attempted but none proved to be suitable. See for example the figure below, reporting measured temperature (blue line) and power used to heat water vs time (x axis).

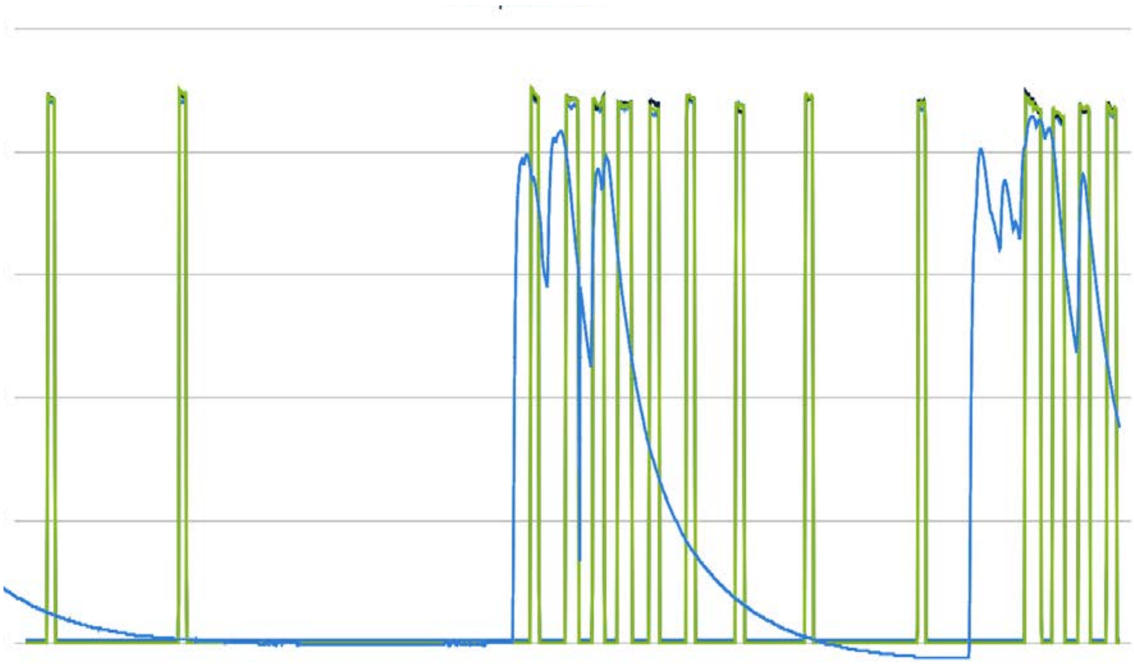


Figure 97: Control signals provided the S2G algorithm are reported in green, Temperature is reported in blue. Behaviour is unexpected as temperature does not change after the first two charging signals (left of the figure) and suddenly increase before the third charging signal. Possibly the temperature sensor is misplaced and the temperature is monitored on an outflow pipe far from the boiler.

These observations underlined the importance of adapting the algorithm for handling boilers even when the state of the boiler is not directly observable.

During the project, we implemented control of boilers on fixed time periods, in order to check that the underlying system was working correctly.

8.2.2. Tests in the S2G-Home facility

We previously demonstrated in a simulated environment that the local voltage measurements can be used as an input for a control algorithm [1,2]. In particular, the voltage measured at the socket can be used as a predictor of the state of the grid, as it inversely correlates with the power drawn from it. When the measured voltage is higher than average it means that a small amount of power is being drawn from the grid. It would therefore be favorable to turn on shiftable loads, as for example charge a battery or an EV. Conversely, when the voltage is low, it would be beneficial to the grid to turn off shiftable loads and to inject power from B2G systems. Based of the time-history of voltage, the S2G algorithm predicts the future state of the grid and by using a model predictive control strategy it re-schedules the activity of the shiftable loads, with the aim of optimizing the electricity costs and the grid stability in lexicographical order.

After the initial development of the algorithm, we performed several tests in the S2G-Home. Difficulties in building robust and reliable interfaces with the hardware devices were manifest, but were solved during the preliminary testing phase.

Figure 98 shows the behaviour of the algorithm controlling the B2G system over a period of three weeks.

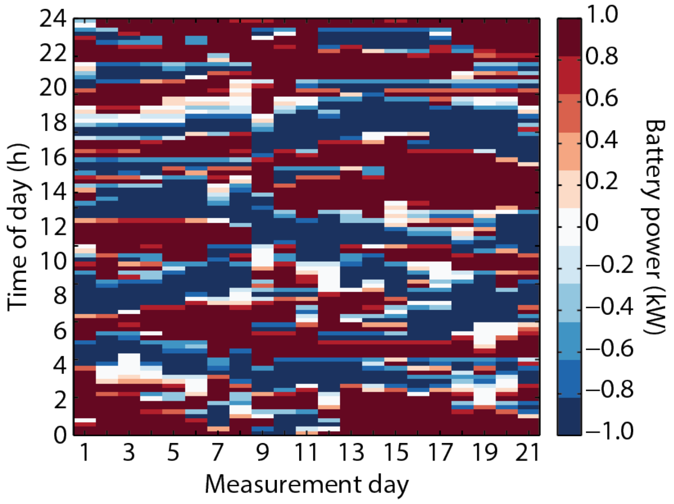


Figure 98: B2G behaviour. Power pattern of the battery measured at different hours of the day (y axis) and measurement days (x axis). 15 min averages of power are shown color coded; red values show charged power, blue values show injected power.

During this test we didn't set cycling constraints, the algorithm freely cycles the battery following the voltage fluctuations induced by the local PV generation and by the synthetic and real loads connected to the same grid.

In Figure 99 we show an example of the decisions performed by the algorithm on the battery bank during a 24 hours period. The algorithm used the voltage measured at the plug of the battery-to-grid system and estimated the voltage drop on the line caused by the battery itself using a linear regression on the time history of measured power and voltage changes. It then compensated for this effect and extracted a corrected voltage profile that represents the voltage fluctuations caused by the PV and the other loads in the low voltage grid.

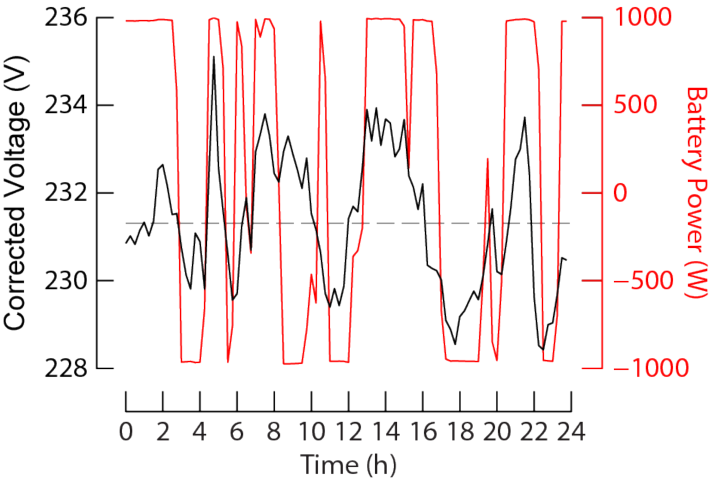


Figure 99: Example of the algorithm controlling the battery system for a 24h period. Black: corrected voltage measured at the battery-to-grid plug. Red: battery AC output power (positive: charging/negative: discharging).

Figure 100 shows the mean B2G power as a function of the corrected voltage for the three weeks of test of Figure 5. The voltage was normalized by dividing it by the mean voltage of the corresponding measurement day, in order to remove long term seasonal voltage fluctuations. As expected, at high voltages the battery gets charged while at low voltages power is injected into the grid. The relationship between the normalized corrected voltage and the mean battery power is highly linear, yielding a correlation coefficient of R=0.945 (red line in Figure 7). The linear fit does not cross the zero power line (dashed line on Figure 7) at normalized voltage equal one, as the efficiency of the B2G system is below 100%. As a consequence, the energy required to charge the battery is higher than the returned one. Over the three weeks of data, we measured an efficiency of 77.6% for the B2G system.

Qualitatively, the algorithm has shown to behave as expected when operating on real hardware. In the example we see that the control algorithm tends to charge the battery when the voltages are high (higher PV generation and/or lower consumption from other loads) and inject back the power when voltages are low (lower PV generation and/or higher consumption).

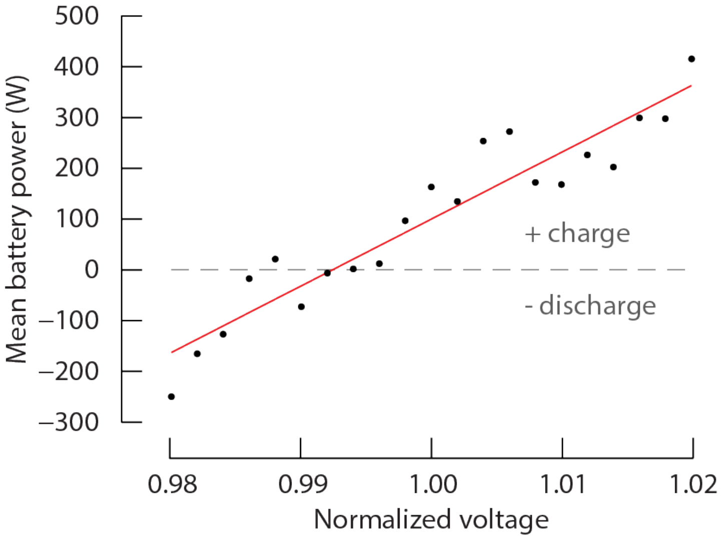


Figure 100: B2G mean power as a function of the normalized corrected voltage. Black dots: mean battery power, red line: linear regression.

8.2.3. Tests in the pilot households

This task reports on the analysis of the behavior of the algorithm in the field for households with b2g batteries.

B2G batteries have been installed in HH01, HH05, HH06, HH09, HH21, with the following characteristics:

- Capacity: 2918 Wh
- Self discharge: 3%/month = 0.12 W
- Charging efficiency: approximated to 0.9 [adimensional]
- Max charging power: 1.61 kW
- Discharging efficiency: approximated to 0.9 [adimensional]
- Max discharging power: 2.07 kW

On the field experiments have been conducted between October 2013 and April 2014.

After some preliminary experiments, the algorithm has been updated in order to limit the overall energy exchange from/to the battery in order to preserve the life-time of the accumulator.

An additional operational constraint has been added in the rolling horizon optimization framework implemented by the s2g control algorithm (see Task 2.6). Accounting for the overall energy exchange of **t** time periods in the past (tested with **t = 20**), the algorithm limits the total amount of exchanged energy to **k** times the battery capacity (**k = 2** in the experiments). This additional constraint was tested in simulation but not implemented on real deployments in order to stress the underlying implementation.

Analysis of B2G behavior

In the following we analyze the B2G behavior at households HH01 and HH06, which are both in the Campagnola branch of the Mendrisio network. We focus on the first 100 days of 2014 (starting at Jan, 1).

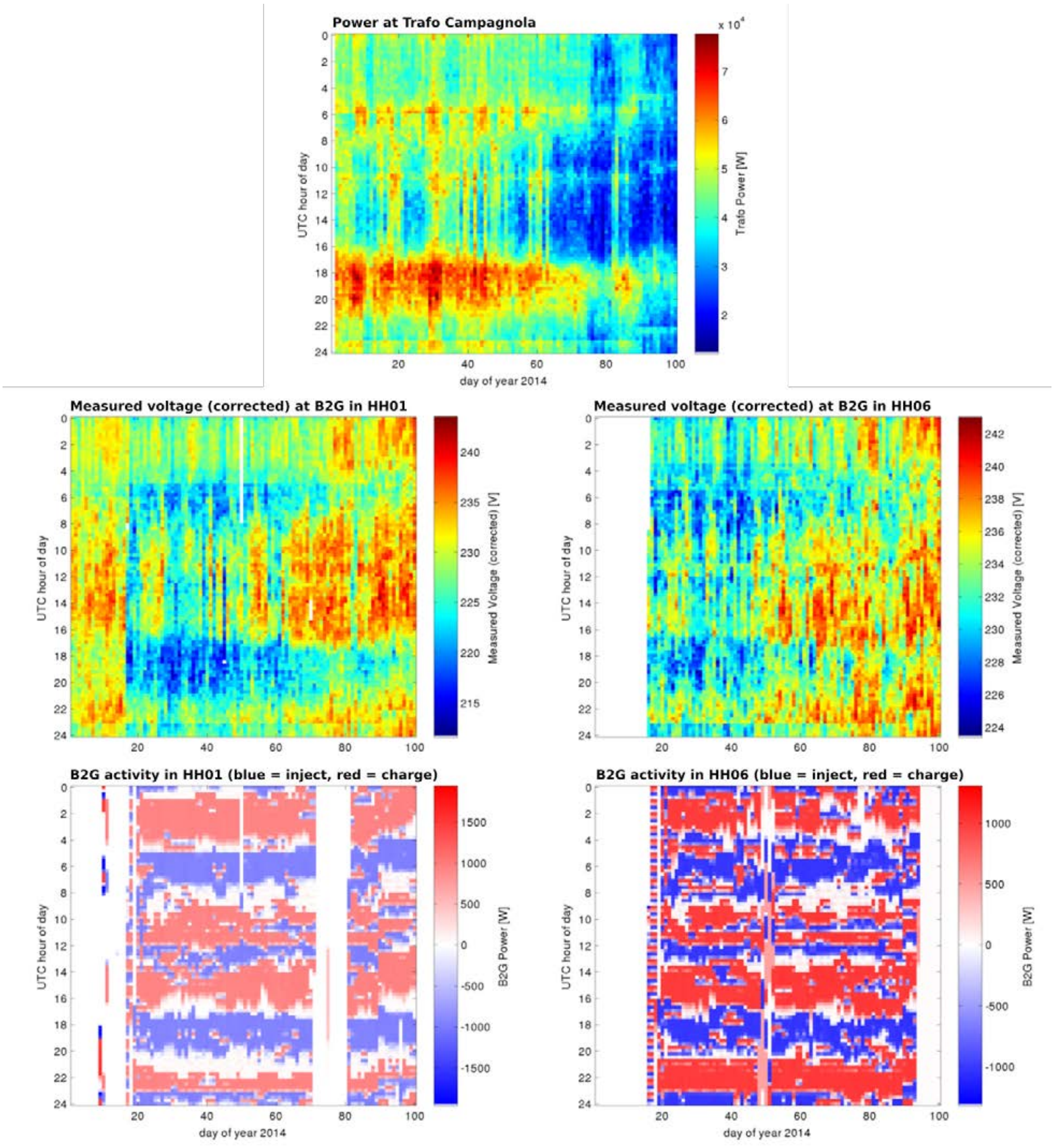


Figure 101: the figure reports the power at the transformer for the Campagnola branch of the Mendrisio network (top plot); below, we report measurements in HH01 (left) and HH06 (right), which both are connected to the same branch. First we report the corrected voltage measured at the B2G plug. Then, we report the power observed at the B2G plug, while the B2G is driven by the S2G algorithm. The algorithm is activated around day 20. Some interruptions are visible in days 70-80 for HH01 and after day 90 for HH06. The algorithm in HH01 is configured to charge/inject with at most 1000W of power, whereas the algorithm in HH06 can use at most +/- 1600W.

We visually observe that the corrected voltage is well-correlated to the power at the transformer, in both households. In particular, the period between h18 and h20 UTC is has low voltage and a high power at the transformer. There is an additional, very consistent peak of transformer power at 23h

UTC (22h UTC from day 90 when DST comes into effect) caused by remote activation of water heaters, which yields a corresponding drop in voltage measured at the households at the same time. Furthermore, we observe that power usage (and household voltages) are not stationary as the weeks pass and the outdoor temperatures increase, which affects power usage for space heating and PV outputs.

The B2G activity plots (third row), show that batteries (in both households) tend to inject power to the grid during the critical period at 18-20h UTC. Moreover, batteries tend to charge before 23h (in anticipation to the expected dip in voltage) and very consistently switch to injection exactly at that time. We can also observe that batteries tend to inject energy around the 6h period, which is a morning peak in the transformer plot. A subtler, but still noticeable peak is visible in the transformer plot at around 11h (10h from day 90 when DST comes into effect). Such peak is interesting because it occurs in a period which is otherwise characterized by relatively low load. We observe that the B2G behavior, expecially in HH06, reacts to this event by injecting energy for a short time, and restarting to charge as soon as the voltages increase.

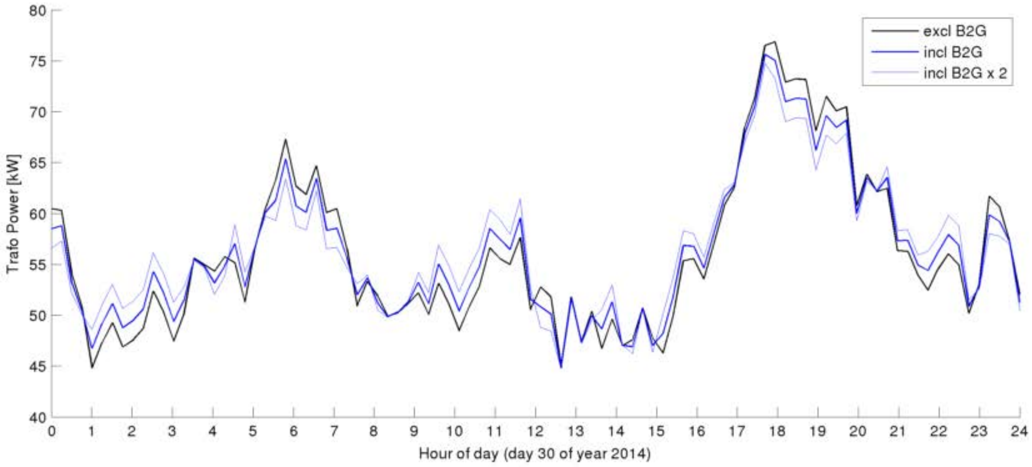
Analysis of B2G effect on power at the transformer

We consider the power at the branch Campagnola, and we isolate the contribution of the two algorithm-controlled B2G devices in households HH01 and HH06. In particular, we subtract the power exchanged by these two devices from the measured power at Campagnola; this gives us the power at Campagnola that would have been measured if the algorithm was not running. We plot these values in black in the following. Then, we compare the values, which were actually measured, that take into account the algorithm behavior in these two devices (dark blue). Finally, we also compute the power (thin blue line) that would be measured at Campagnola if each of the two B2G batteries exchanged twice the measured power.

In summary, for a given time t, if PC(t) is the power measured at Campagnola, P1(t) is the power measured at the B2G device of HH01 (positive = charge, negative = inject), and P6(t) is the power measured at the B2G device of HH06, we plot:

- PC(t) (blue line: measured data including B2G)
- PC(t)-(P1(t)+P6(t)) (black line: measured data excluding B2G)
- PC(t)-(P1(t)+P6(t))+2*(P1(t)+P6(t)) (thin light blue line: measured data counting B2G powers twice).

We report below these plots for several consecutive days in the considered period.



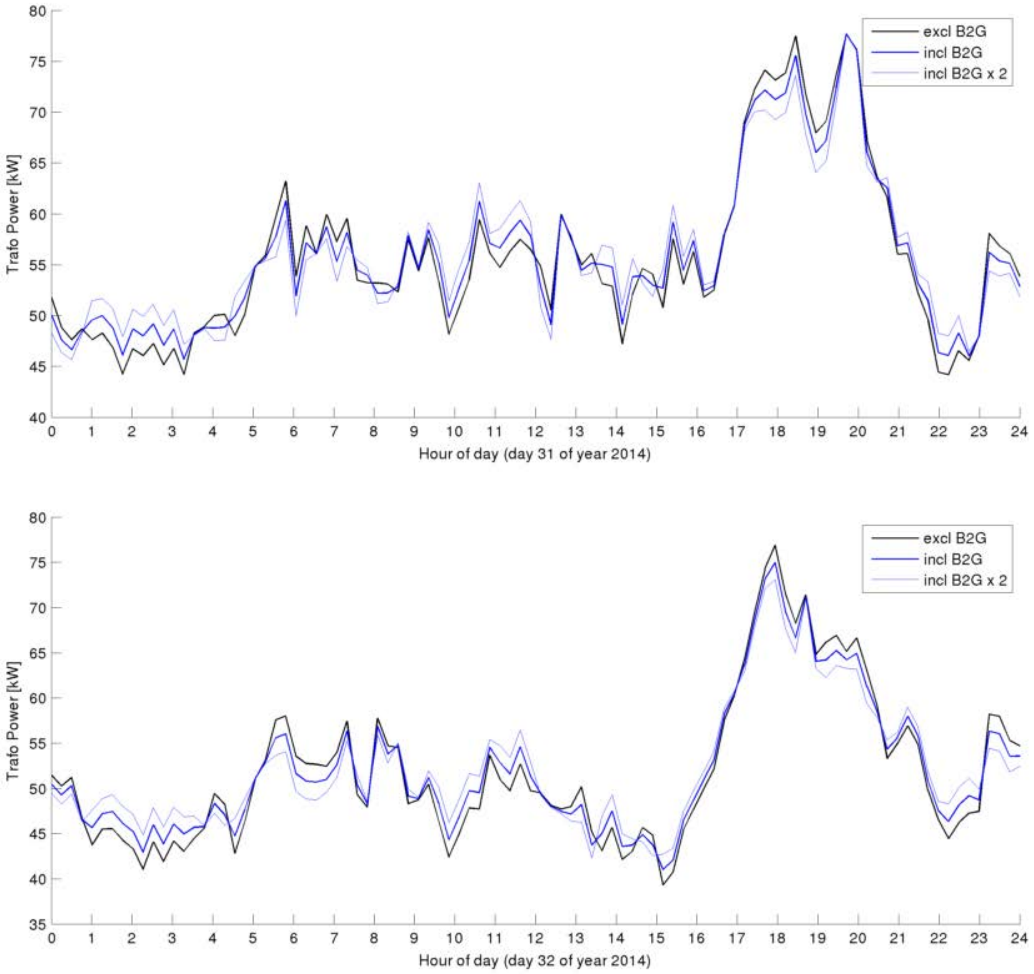


Figure 102: power at Campagnola excluding (black) and including (blue) algorithm-controlled B2G. Thin light blue line reports the power at Campagnola if the B2G contribution is counted twice.

We observe that algorithm-controlled B2G tends to flatten the power profile: where peaks are visible (e.g. around 18h UTC) the algorithm reduces the total load (by injecting power), whereas it increases the load (for charging the batteries) when the total load is very low. We remark that in these experiments the algorithm only used measured voltage as input.

We further report a statistical analysis of the data computed above, considering the period between day 20 and day 60, during which batteries in both HH01 and HH06 were running without interruptions. We report the histogram of the load measured at Campagnola for the three scenarios: measured load excl B2G (black); measured load incl B2G (blue); measured load counting the B2G contribution twice (light blue).

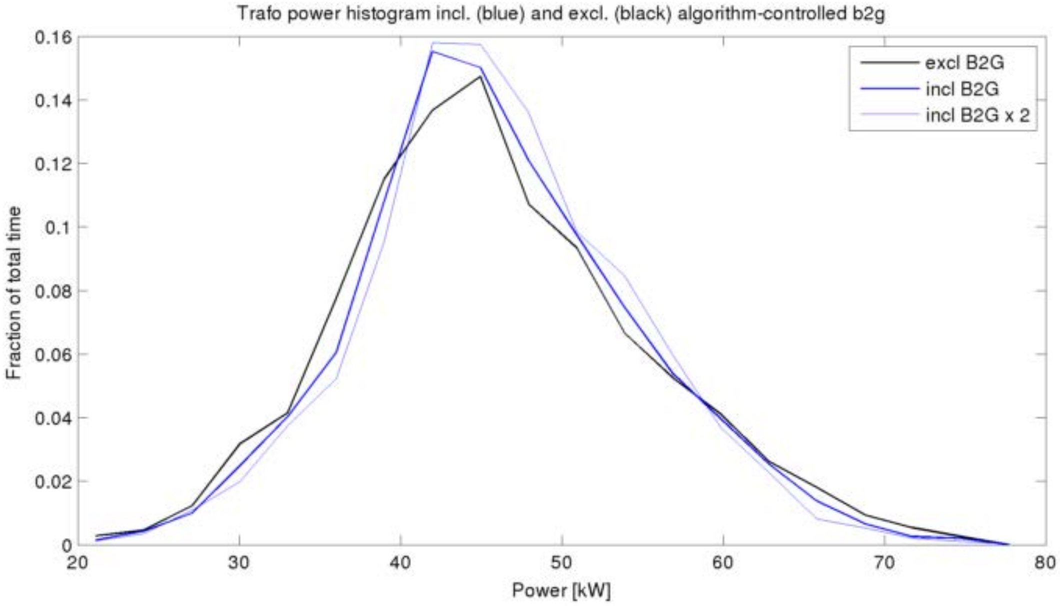


Figure 103: trafo power histogram

We observe that, as a consequence of the B2G effect, extreme loads (very small or very large) occur more rarely, whereas it’s more common to observe loads close to the average.

Effect of voltage correction

The voltage correction mechanism that automatically compensates self-induced voltage drops is implemented within the algorithm. In order to evaluate whether it is necessary, we report a visualization of the raw measured voltages for the same period as the figure above, compared to the corrected voltages. We observe that voltage patterns matching the power patterns at the transformer are much more apparent in the corrected values rather than in the raw values.

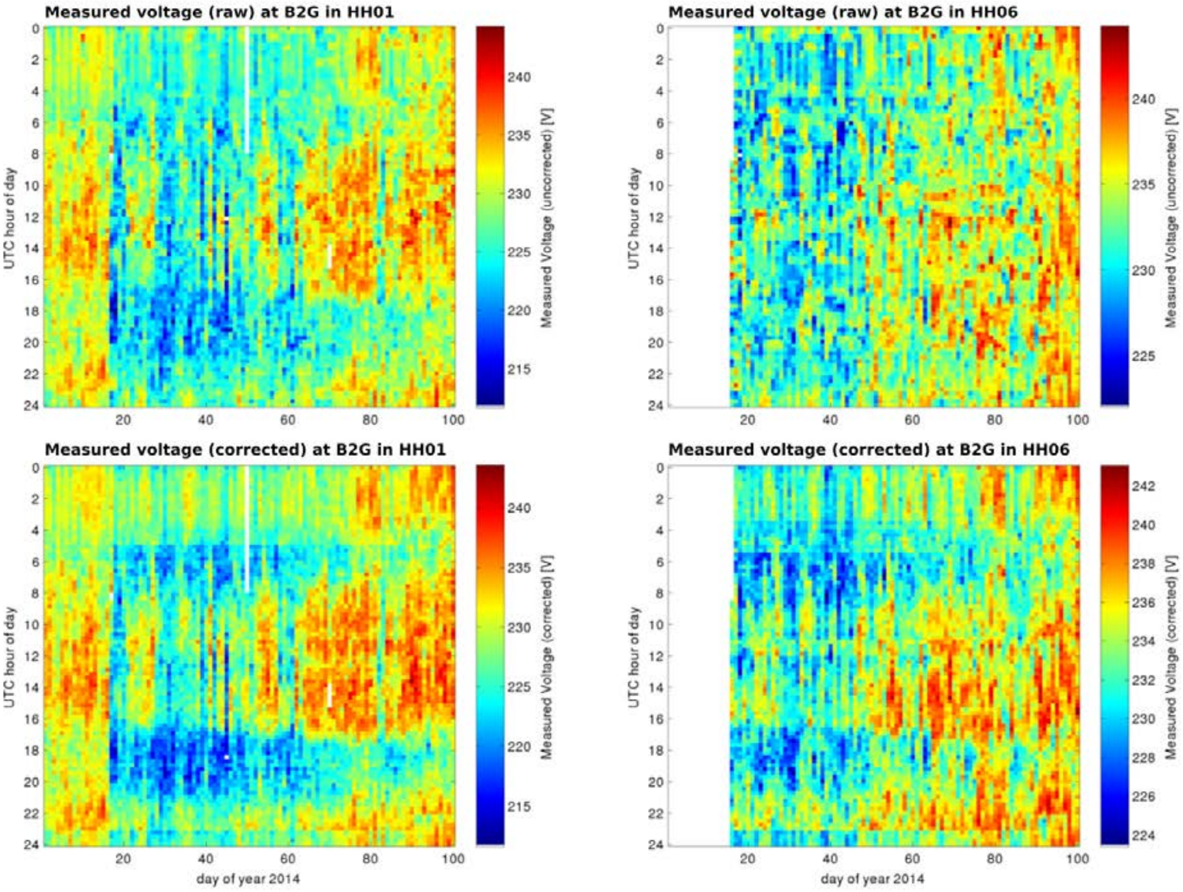


Figure 104: raw (first row) and corrected (second row) voltages measured at HH01 (first column) and HH06 (second column) during the first 100 days of 2014. Daily patterns are more visible in the second row, because the self-induced voltage drop (which is not regular and not related to load patterns at the transformer) is compensated.

9. Extended simulation results

9.1. Grid simulation setup

9.1.1. Introduction

In 2012 and 2013 the grid Mendrisio had been updated. The work had been described in the intermediate and annual reports. The influence of the Swiss2G-Algorithm on real LV-Grids and aggregated higher level grids have been shown by grid simulation. In spite of implementing of the algorithm direct as DSL-Model for households in the grid simulation tool DIgSILENT Power Factory (DPF) the project team decided to build up a separate smart household simulator (SHHS) as java applet for the calculation of the behaviour of smart households. The relevant data (voltage and active power) are exchanged between DPF and the SHHS automatic over a defined interface.

This so-called engine mode of DPF with a sequential running of the grid and household simulator and interrupts for the data exchange leads to very long simulation time. While on the other hand, the SHHS needs a long learning period of at least one week to be able to optimise the household behaviour.

IDSIA delivered several versions of the java applet and BFH run with the latest version (summer 2013) all the simulations. They also tested the reaction of the SHHS by unusual voltage curves showing a not optimal behaviour. The reason for this behaviour might be a non-realistic implementation of the algorithm in the java applet or a fundamental problem by using the applet (learning phase, ...). The results had been presented and discussed in a master thesis at BFH 2013 [1].

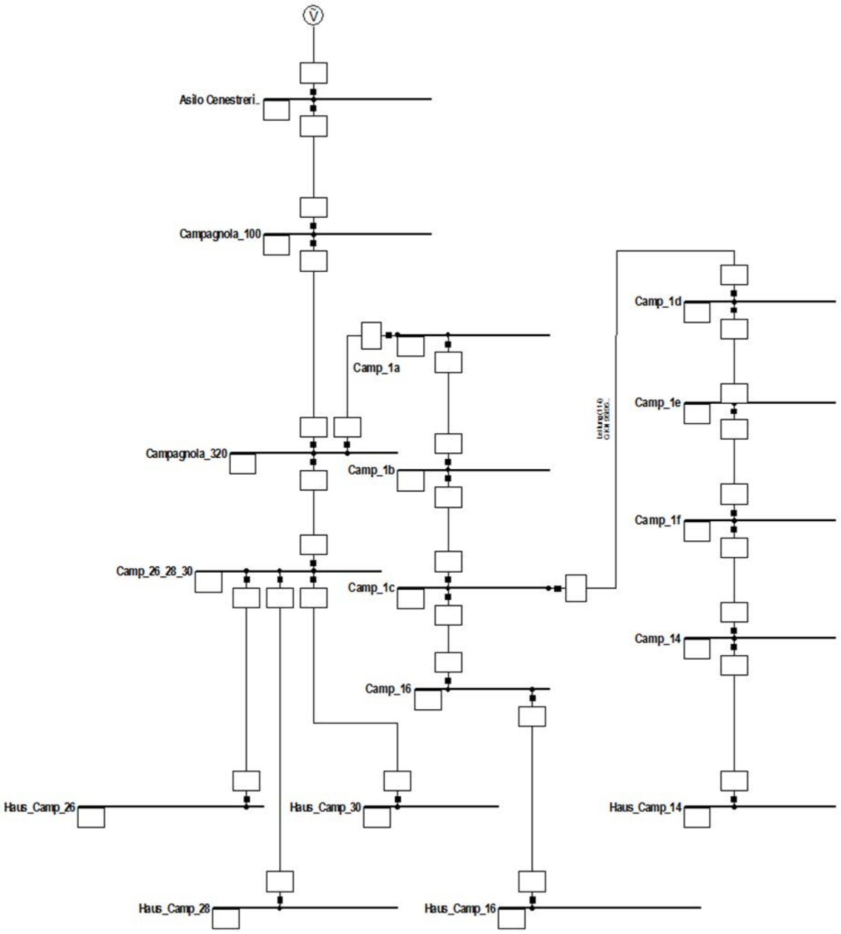


Figure 105: DIgSilent representation of the LV-Grid in Mendrisio, String Campagnola

9.1.2. New Approach: Grid Modelling within the HH-Simulator

While the reaction of the SHHS cannot be implemented in DPF in an efficient way, 2014 a new approach had been pursued to get the information about the behaviour of a huge mass of smart households. The SHHS was prepared to implement a simplified grid model to get the voltage information at the connection points of the smart household.

- The advantage of this simple approach is that the interaction between DIgSILENT and the SHHS is no longer required. This leads to short calculation times and allows an unlimited number of calculated scenarios.
- The disadvantage is the accuracy and that it is not possible to show effects on the higher grid levels directly.

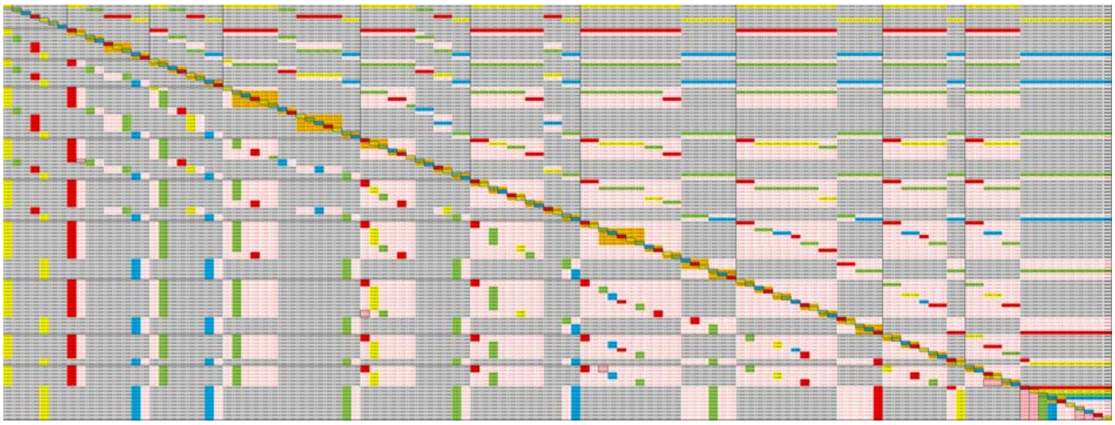


Figure 106: Excel-sheet for the complex grid topology (121x121)

BFH prepared two different LV topologies. A simple one-string topology was based on the LV-grid in Mendrisio from transformer Asilo Genestrerio to cabinet Campagnola 320. A more complex topology with parallel strings and about 120 grid nodes or points of common couplings (PCC) was derived from the grid data of a LV-Grid in the northern part of Switzerland. For both grids

- a grid matrix containing the resistance values (real part of the impedance) between the grid nodes,
- the real transformer measurement data over one week,
- and a synthetic production curve of PV installations

had been prepared, so that calculations can be performed in 1s steps over a hole week.

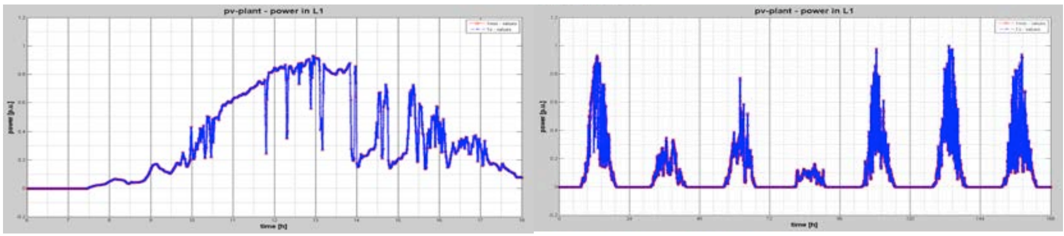


Figure 107: PV-Production at one day (left) and over one week (right)

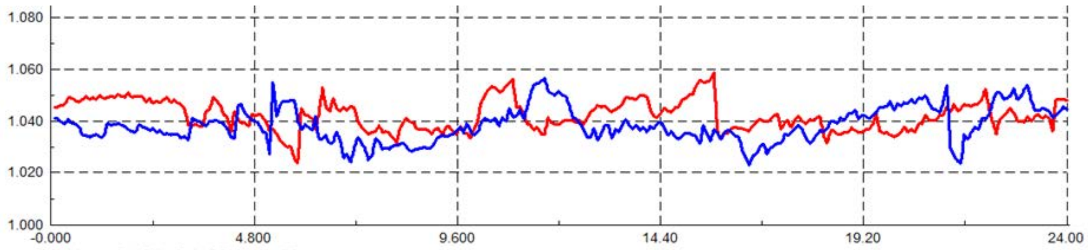
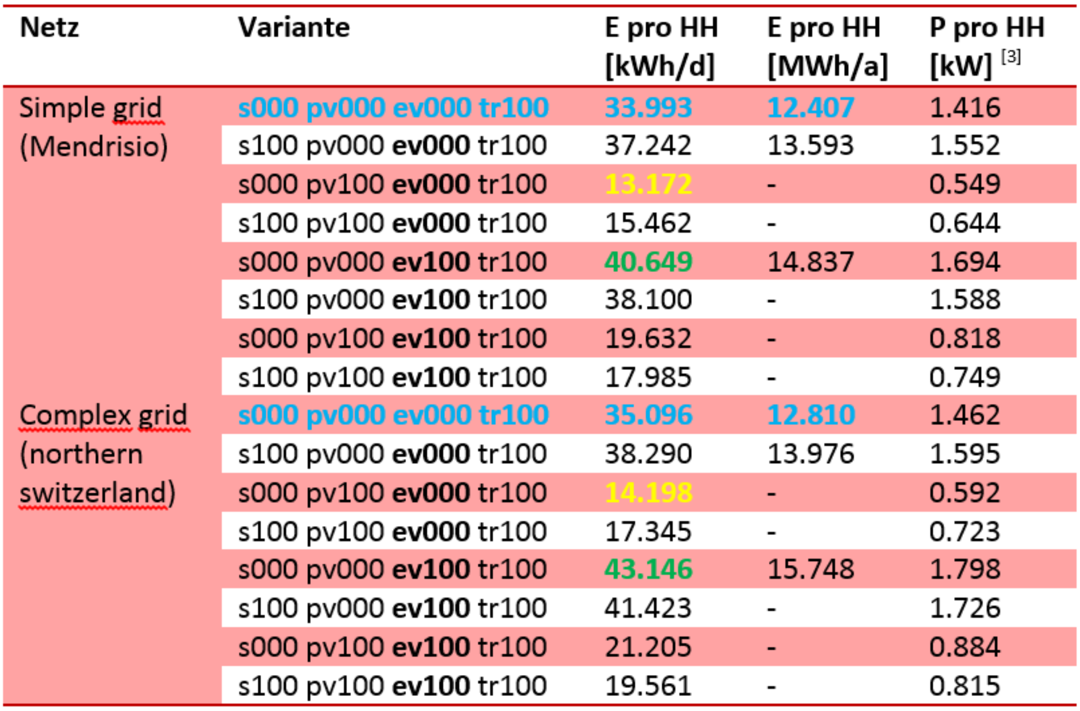


Figure 108: Voltage in p.u. at TS Asilo Genestrerio over 24 h (red – summer; blue – winter)

Nevertheless it is the only possible mode of modelling to get information of the reaction of the “real” algorithm to voltage variations in the low voltage grid. The applet calculates the active power consumption of SHHS in a defined LV-Grid. It takes into account that the voltage at the PCC depends on the two input parameters topology of the LV-grid and the voltage at the LV bus bar of the transformer. The amount of normal and smart households, PV installations and EV-use can be varied at each PCC. So the difference of power flow over the time in dependency of different penetrations can be shown.

IDSIA has implemented the matrices, calculated the scenario and sent back a result list including the voltage at each node and the power consumption of each group of households at each node (time steps are seconds) and the power flow over the transformer. 4 different scenarios with variation of the percentage of smart households (s000 and s100), the penetration of photovoltaic installations (pv0 and pv100) and the penetration of electric vehicles (ev000, 100) had been calculated. For each scenario, the voltage on the transformer LV-side had been varied based on the measurement values (tr100).



Netz	**Variante**	**E pro HH [kWh/d]**	**E pro HH [MWh/a]**	**P pro HH [kW]** [3]
Simple grid (Mendrisio)	**s000 pv000 ev000 tr100**	**33.993**	**12.407**	1.416
	s100 pv000 **ev000** tr100	37.242	13.593	1.552
	s000 pv100 **ev000** tr100	13.172	-	0.549
	s100 pv100 **ev000** tr100	15.462	-	0.644
	s000 pv000 **ev100** tr100	**40.649**	14.837	1.694
	s100 pv000 **ev100** tr100	38.100	-	1.588
	s000 pv100 **ev100** tr100	19.632	-	0.818
	s100 pv100 **ev100** tr100	17.985	-	0.749
Complex grid (northern switzerland)	**s000 pv000 ev000 tr100**	**35.096**	**12.810**	1.462
	s100 pv000 **ev000** tr100	38.290	13.976	1.595
	s000 pv100 **ev000** tr100	14.198	-	0.592
	s100 pv100 **ev000** tr100	17.345	-	0.723
	s000 pv000 **ev100** tr100	**43.146**	15.748	1.798
	s100 pv000 **ev100** tr100	41.423	-	1.726
	s000 pv100 **ev100** tr100	21.205	-	0.884
	s100 pv100 **ev100** tr100	19.561	-	0.815

Figure 109: Total Energy consumption per day or year (365xd) for the different scenarios

The above figure shows the results for the different scenarios calculated by the SHHS for both grids. The daily mean consumption of the simulated household is about 35 kWh/d. Assuming this load constant over the whole year, it seems to be related to a consumption of a big household with between 5 to 10 persons or to a multi-family house with two or three smaller households. The PV-installation delivers 20 kWh on a mostly sunny day, what is possible for a normal used roof for PV-generation (5kW$_p$).

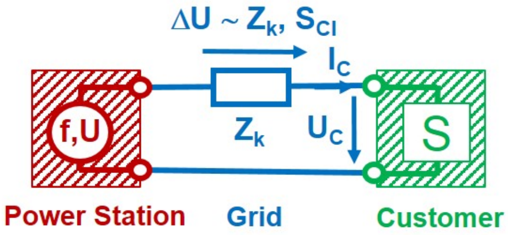
EV

S100 seems to have more consumption. This may be affected by shifting loads from next night to day.

Ev100 some charging is shifted to the morning of the next day and is not counted to the actual day.

9.1.3. Validation of the SHHS integrated Grid-modeling with DIgSILENT

Since this model is a DC-load flow model it does not take into account the reactive power flow, the reactances of the lines and the influence on frequency. The simplified model is also a constant current model, not taking into account that the current will be changed in dependency of the voltage variations at the PCC of the loads. The current is initially calculated from the power based on the nominal value for the voltage.



$$\underline{S}_C = P_C + jQ_C = \sqrt{3} \cdot \underline{U}_C \cdot \underline{I}_C^{\,*}; Z_k = R_k + jX_k$$

$$case\ \varphi_Z = 0° \Rightarrow I_{C_P} = \frac{P_C}{\sqrt{3}\,U_C}; I_{C_Q} = \frac{Q_C}{\sqrt{3}\,U_C}$$

$$\Delta\underline{U} = \sqrt{3} \cdot \underline{I}_C \cdot \underline{Z}_k \Rightarrow \Delta\underline{U} = \sqrt{3} \cdot (I_{C_P} + jI_{C_Q}) \cdot (R_k + jX_k)$$

$$\Delta\underline{U} / \sqrt{3} = (I_{C_P} \cdot R_k - I_{C_Q} \cdot X_k) + j(I_{C_Q} \cdot R_k + I_{C_P} \cdot X_k)$$

$$\Delta U \approx \frac{P_C \cdot R_k}{U_n} + \frac{Q_C \cdot X_k}{U_n}$$

Figure 110: Basic equations for the calculation of voltage drops

The above figure shows the theory for calculating the voltage drops in grids:

1. Neglecting the reactive power flow is possible if the grid impedance has a small reactive part or the reactive power flow is low. Both assumptions are normally true for low voltage grids.
2. The voltage drop is linear related to the current. When the power is given as constant, the current rises in case of a voltage drop. The voltage dependence of loads can be quite different. Usually, grid calculations are performed assuming constant power consumption. Neglecting the current change in decency of voltage variations can cause visible failures in case of high voltage variations.

The results for the current (= power) at each PCC had been implemented in the DIgSILENT grid model and the power and the voltage curves over one day had been compared to prove the calculation by the simplified grid model of the SHHS.

The deviation of the mean value over one week had been in all scenarios less than 1 per mill. While this difference can hardly be visible, a further scenario with 200% EV had been defined, and it gives the plots for this worst case scenario. A remarkable deviation appears while all the EV were charged in the evening, when no household is smart.

By analysing the failure sources, the results had been proved. The simplifications seem to be acceptable for the low voltage grid. This conclusion is only valid, if the transformer with its large inductance is not taken into account.

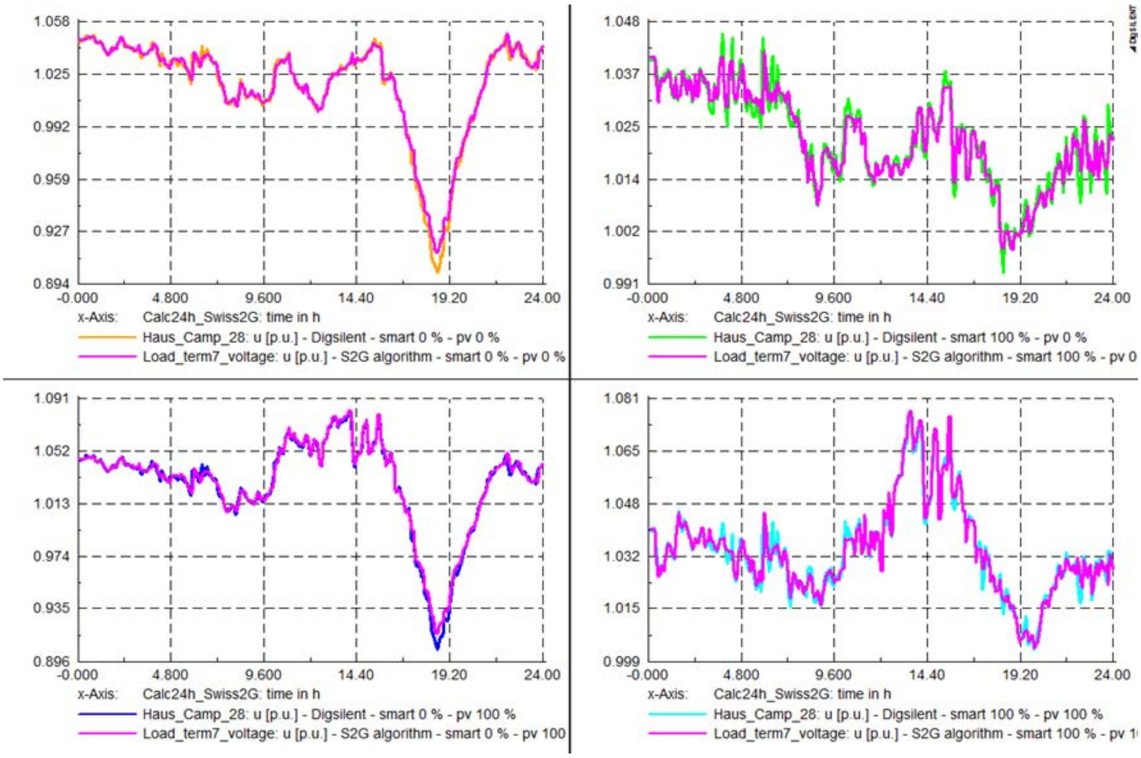


Figure 111: Voltage curves (purple is calculated by the SHHS) for different scenarios with massive (200%) EV; smart HH: left 0%, right 100%; PV: above 0%, below 100%)

9.2. Development of aggregate model for smart households

This part of the project was dedicated to the simulation approach implemented by IDSIA and BFH for efficiently simulating the LV distribution network after the attempts to use DIgSILENT failed due to interfacing difficulties and efficiency problems.

Previous attempts: using DIgSILENT for simulations

Various solutions have been attempted for reliably simulating a large amount of smart households for large-scale experiments, with full and bi-directional integration between algorithm and grid simulation. Unfortunately, these attempts were unsuccessful, mainly due to difficulties in efficiently interfacing the household/algorithm simulator and the grid simulator DIgSILENT at high resolution. As a result, it's not realistic to simulate the grid at intervals closer than 15 minutes, but at the same time reliable simulation of many algorithms -- even with an aggregate model -- requires a simulation step of at most 10 seconds. As a result, we will focus on fast and efficient simulation on the LV grid, as detailed below. As decided in the Nov, 2013 meeting in Biel between IDSIA and BFH, BFH will provide an analytic model of the LV grid in Mendrisio. This model is integrated in the household/algorithm simulator in order to quickly simulate the LV net with a short enough timestep.

Implemented solution: LV network simulation integrated with Java household simulator

We implemented a simplified simulator for the LV net with a linear model. A LV net is composed by an ordered list of N terminals. Any number of households and PV power can be connected at any terminal. The LV simulation is called at every timestep with the following inputs and outputs.

Inputs:

- power at each of the N terminals
- voltage at the transformer

Outputs:

- voltage measured in the next timestep at each of the N terminals.

The model is defined by a matrix with N rows and N+1 columns. The outputs are computed by multiplying such matrix by a column vector with N+1 elements obtained as the concatenation of the voltage at the transformer and the power at each of the N terminals.

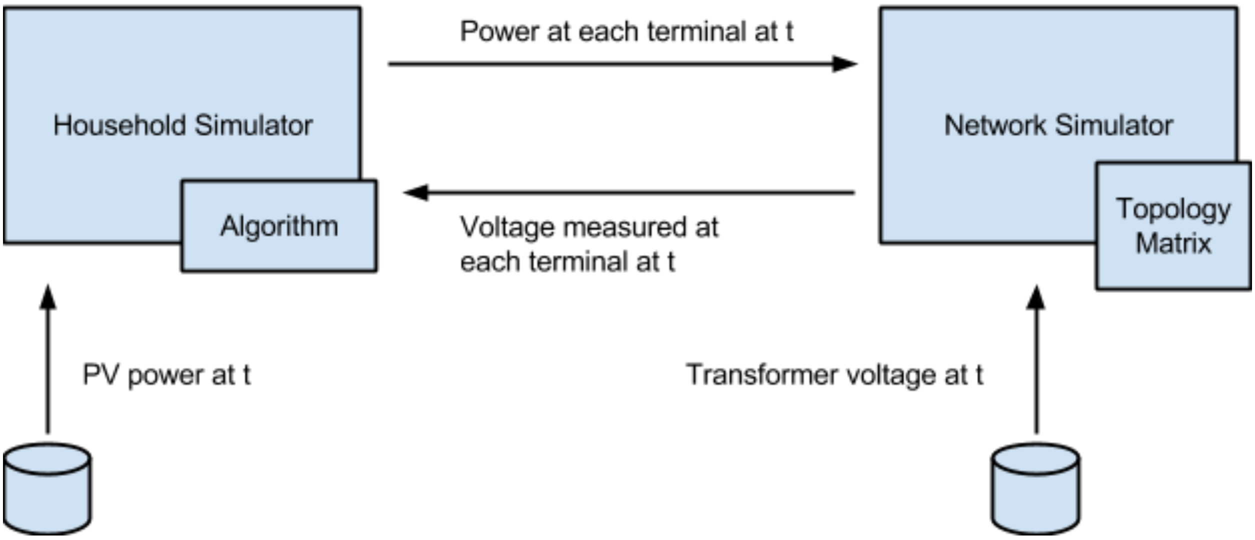


Figure 112: overview of new simulation architecture. All modules are implemented in Java by IDSIA and integrated in a single JVM.

Results

The implemented approach has been shown to be very efficient. Simulation timesteps of 10s can be adopted with minimal performance penalty. Running a 1-week simulation for a network with 121 terminals and 114 households, 114 EV requires few seconds of computation time (plus the time required for algorithm evaluation, which is not dependent on the choice of the simulation model).

The architecture outlined above has been used to run the simulations reported in task T8.5.

9.2.1. Algorithm parameters

The algorithm behavior is controlled by three parameters, whose impact on performance when multiple algorithms are working together has been evaluated in simulation studies. Parameters have then been fixed before the final simulations, as described below.

Algorithm re-evaluation interval (key for simulations: **ss###** where ### represents the amount of minutes between algorithm re-evaluations)

The algorithm is re-evaluated periodically in order to account for latest information (e.g. updated voltage forecasts, updated measurements). The period between re-evaluations is an important parameter for determining the performance of the algorithms, especially in highly dynamic cases, such as when voltages change unpredictably due to high PV penetration and partially cloudy skies, or in presence of variable transformer voltages (i.e. tap changers). We observed that setting this parameter to large values reduces the algorithms' responsiveness to these unforeseeable cases. Values larger than 60 minutes yield heavily degraded performance. Performance improves steadily with shorter times, with diminishing returns below 15 minutes. Times shorter than 5 minutes were not tested in simulations. Recommended values for deployment range from 3 to 15 minutes, depending on the appliance. Simulations are fixed to **ss015** (15 minutes).

Short-term forecast error correction (key for simulations: **ia###** where ### represents the error correction percentage [000 → 100]).

Future voltage forecasts are computed with Exponential Smoothing (see T2.2) with seasonal components (capturing day-to-day patterns) and short-term error correction. Error correction consists in comparing the voltage estimated for the current time using data from previous days, with the voltage actually measured at this moment. This error is corrected with a linearly decreasing weight, as shown in the picture below.

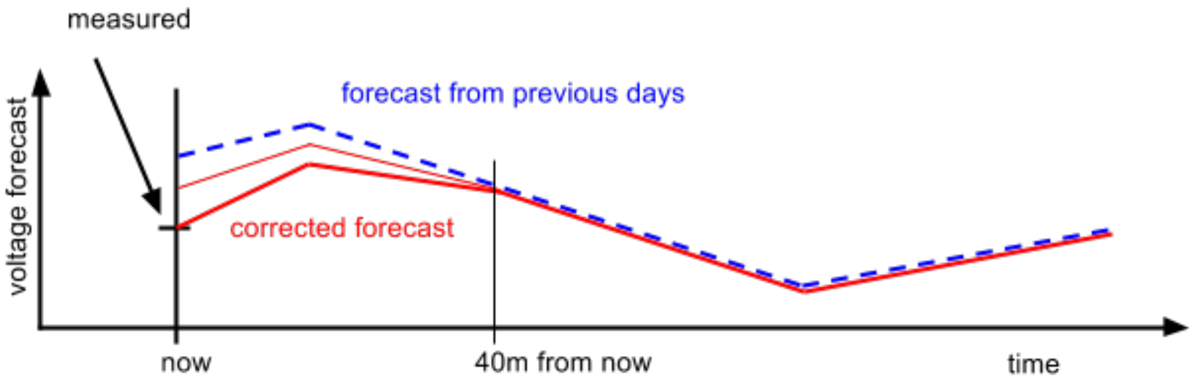


Figure 113: blue dashed line shows forecast computed from historic data. Measured voltage for current time is lower than predicted: the error is propagated with linearly diminishing weight, reaching 0 at 40 minutes in the future. Figure reports corrected forecast for ia100 (thick red line) and for ia050 (thin red line). Corrected forecast for ia000 corresponds to dashed line (i.e. no correction).

The parameter is fixed to **ia100** (100% correction) in simulations and deployments, which has been found in preliminary simulations to yield the best performance. The choice of the time threshold has been found to have a very limited effect on performance, with best results obtained between 10 and 120 minutes. 40 minutes has been chosen and fixed as a reasonable middle ground.

Forecaster standard deviation multiplier (key for simulations: **dm###** where ### represents the multiplier in percent points [000 → 999]).

This parameter is used to randomizeforecasts in order to avoid that many households with very similar measurements have identical forecasts which would lead to identical decisions. The randomization amount is expressed as a fraction of the voltage signal's standard deviation. For every 15 minute slot, the forecast voltage is corrupted with a gaussian pseudorandom variable with standard deviation equal to $\sigma \times dm$where σrepresents the standard deviation of the voltage signal.

Based on simulation results, recommended values for deployment range from 005 to 030. Simulations are fixed to **dm015**.

9.3. Algorithm testing

We consider two network models provided by BFH:

- lineCampagnola_16terms (16 terminals, 13 households, 13 EVs, 65 kW PV).
- rheinfelden (121 terminals, 114 households, 114 EVs, 570kW PV).

9.3.1. Simulation settings

Each network can be simulated with different parameters, each of which is identified by a short code:

- **s###**. Percentage of smart households/EVs (0 to 100). In this document we focus on the extreme cases: all households and EVs are dumb (**s000**); all households and EVs are smart (**s100**). Intermediate cases can also be simulated.
- **pv###**. Percentage of PV installed with respect to values specified in the network model. **pv000** means no PV installed; **pv100** means PV installed as specified in the network model. Other multipliers can also be simulated (e.g. **pv050** means half of the specified PV power, **pv200** twice of that). We focus on **pv000** and **pv100**.
- **tr###**. Multiplier (percentage) modulating voltage fluctuations at transformer. **tr100** means that voltage at transformer follows the profile specified in the network model. **tr000** means that voltage at transformer is fixed to 1 p.u.. Other multipliers are possible (e.g. **tr050** means that voltage changes around 1 p.u. following the specified profile but with half width, i.e. voltage = ((specified_voltage - 1) * 0.5 + 1) p.u.. We focus on **tr000** and **tr100**.
- **en###**. Multiplier (percentage) for the number of simulated entities (households and EVs). **en100** simulates the amount of entities specified in the network model. Other multipliers are possible, and also affect the amount of pv (e.g. en200 will simulate twice as many households, EVs, and PV power).

9.3.2. Algorithm settings

Simulations are tagged with the algorithm internal parameters used for that simulation. A discussion of these parameters is outside the scope of this document. All simulations in this round use the same parameters (also see Task T6.3):

- **dm020**: forecaster standard deviation multiplier = 0.2
- **ia100**: short-term forecast error correction = 100%
- **ss015**: algorithm is reevaluated every 15 simulated minutes (plus every time an EV is plugged).

9.3.3. Household and EV models

Each household is equipped with:

- One stochastic uncontrollable load summarizing all uncontrollable loads in the household. For each timestep (10 seconds), the load is generated by the following algorithm:
    - with 99% chance, keep the power used in the previous timestep
    - with 1% chance, switch to a new power, computed as r*p(t), where r is a random real number in the interval [0 2], and p(t) is the value at this time of a "baseline" profile which depends on the minute of the day and is represented below
- One controllable boiler (7kW, 700L Boiler with 200L/day hot water consumption evenly distributed along the day). Temperature is kept in the range 57-63 deg C.
- One controllable bidirectional battery (same characteristics as the batteries installed in Trevano: Capacity 2918 Wh, 1610 W charging power, 2070 W discharging power).

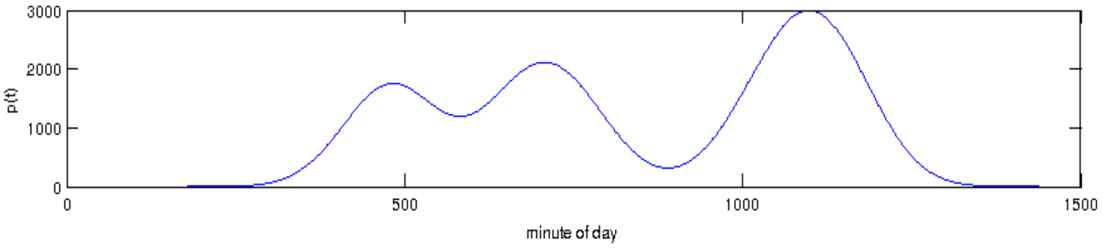


Figure 114: uncontrolled loads profile

Each EV has the same characteristics of the MiEV: 11.1 kWh capacity, 0.9 charging efficiency, negligible self-discharge, 3kW charging power. The usage model of the EV is a simple stochastic model where every day the EV is unplugged at a time chosen from an uniform probability distribution between 7:00 and 9:00, and plugged back at a time chosen from an uniform probability distribution between 16:00 and 18:00, with a state of charge randomly chosen from an uniform probability distribution [50% 70%]. The next unplug time is known to the algorithm when the car is plugged.

9.3.4. Control policies

When controlled by the algorithm (“smart”), the boiler, bidir battery and EV behave as requested by the algorithm. Else (“dumb”):

- the boiler follows a threshold with hysteresis controller (57-63 deg C).
- the bidirectional battery is kept idle
- the EV is fully charged as soon as it is plugged.

Safeguards are in place to ensure that the algorithm maintains all devices within the required operational state, i.e.: boiler temperature kept within 57-63 deg C; EV fully charged at unplug time. In case of a violation, the system emits a warning.

9.3.5. Simulations

For each of the two networks, we report results for **s000** and **s100** (all dumb entities and all smart entities), for each of the following four cases:

- **pv100**,**tr100** (100% PV, transformer voltage as specified)
- **pv000**,**tr100** (no PV, transformer voltage as specified)
- **pv100**,**tr000** (100% PV, transformer voltage flat at 1 p.u.)
- **pv000**,**tr000** (no PV, transformer voltage flat at 1 p.u.)

All simulations last for 7 days (initialized Jan 7 at 00:00, ending Jan 15 at 00:00).

Format

The csv file in each directory contain power and voltage values per each terminal (same order as specified in households.txt and topology matrix rows) sampled every 5 minutes (averages over the 5 minutes are reported, not instantaneous values).

Visualization

For every pair of simulations (**s000** and **s100**) we report a number of visualizations, exemplified here for the lineCampagnola_16terms network with pv100, tr100 (100% PV, transformer voltage as specified).

For each day of the simulation (here shown for day 6): profile of the average voltage over all terminals; (blue line: **s100**, black line: **s000**).

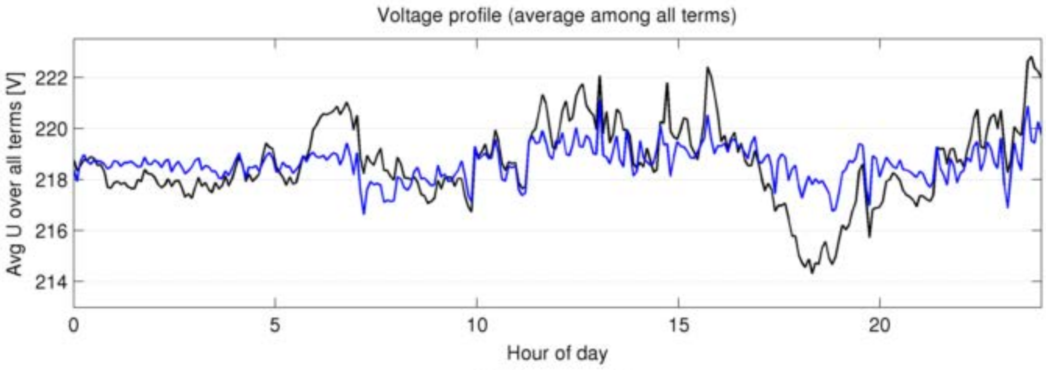


Figure 115: day 6 – voltage profile

For each day of the simulation (here shown for day 6): profile of the total power (as measured at the transformer); (blue line: **s100**, black line: **s000**).

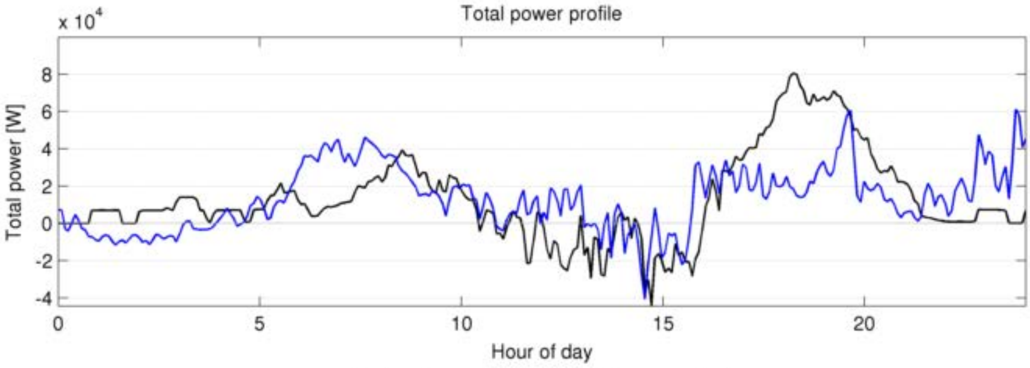


Figure 116: day 6 – power profile

For each day of the simulation (here shown for day 6): profile of the PV output (red line), and profile of the total power by all smart devices in the s100 case (blue line).

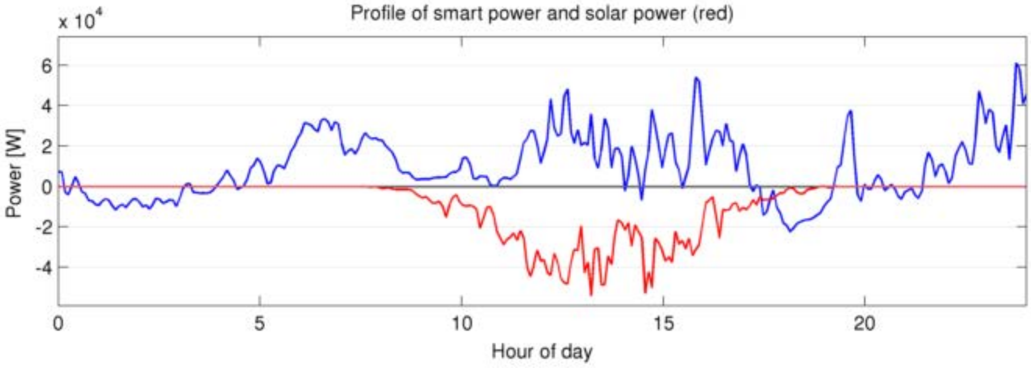


Figure 117: day 6 – smart abd solar power profile

voltage-histogram.png: For the whole simulation: histogram of the voltages measured at all terminals (blue line: **s100**, black line: **s000**).

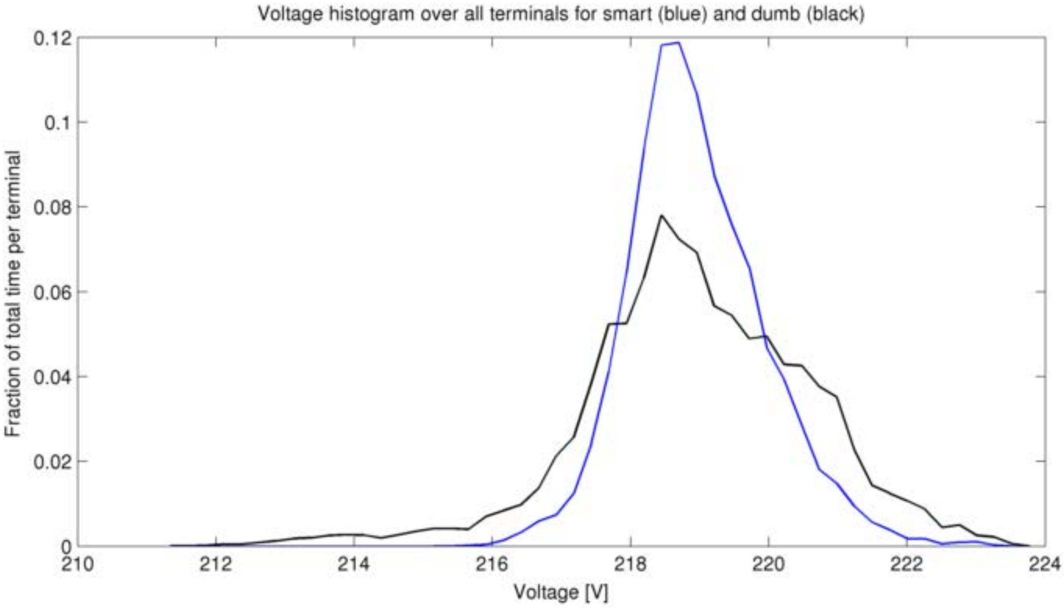


Figure 118: voltage histogram

For example, this image shows that a voltage of 214V is never observed at any terminal in the s100 case, whereas it is observed for a small fraction of time at some terminals in the s000 case.

Similarly, a voltage of 220 V is observed roughly as often in the s000 and s100 cases. A system capable of fixing the voltage of all terminals to the same fixed value would generate a graph which is 0 everywhere and 1 at one point.

power-histogram.png:For the whole simulation: histogram of the powers measured at the transformer (i.e. sum of all powers at all terminals) (blue line: **s100**, black line: **s000**).

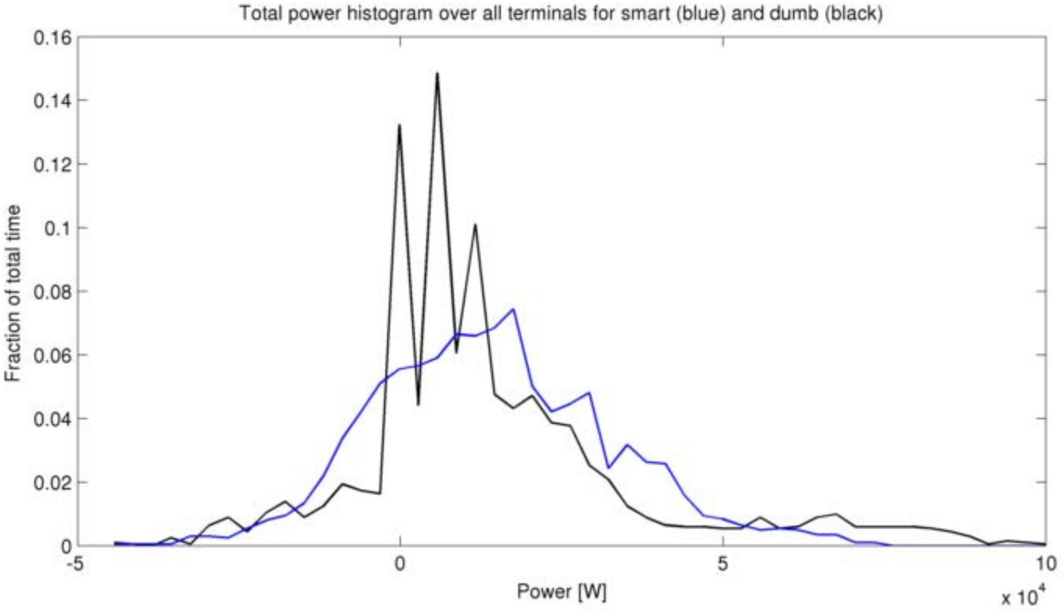


Figure 119: power hystogram

For example, this image shows that the total power at the transformer is around 0W for about 13% of the time in the s000 case and 5% of the time in the s100 case. We see that in the s100 case powers larger than 70kW are never observed, whereas they are sometimes observed in the s000 case.

voltage-scatter.png: For the whole simulation: scatter plot of the voltage values measured in s100 at any terminal (y axis) vs the voltage measured in s000 (x axis) at the same time in the same terminal.

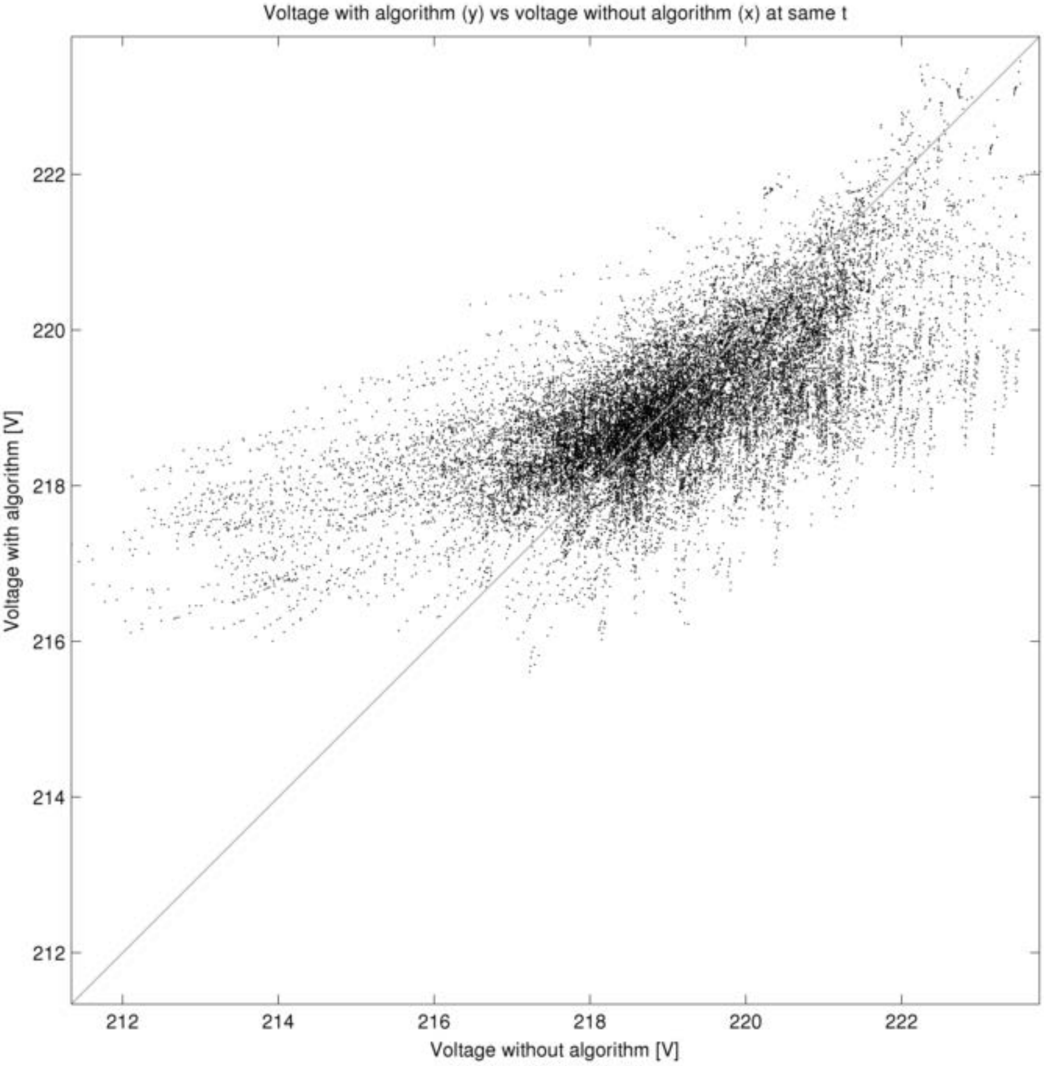


Figure 120: voltage without vs with algorithm

A system capable of fixing the voltage of all terminals to the same fixed value would generate a graph on which all points lie on the same horizontal line (i.e., for every voltage observed in s000, you would have the same fixed voltage at the same time and terminal in s100). A system which does not affect measured voltages would generate points lying on the diagonal. A point on the leftmost part of the plot (i.e. around x=212, y=217) means that at a given time and terminal, one could measure a voltage of 212 V in the s000 case; at the same time and terminal, one measured a voltage of 217 V in the s100 case.

voltage-violations.png: For the whole simulation: plot of the fraction of the total time and terminals for which the voltage measured at a terminal is outside the range [230-m 230+m] V, plotted versus the value of m. (blue line: **s100**, black line: **s000**). Note that the plot is focused on the bottom part of the y axis.

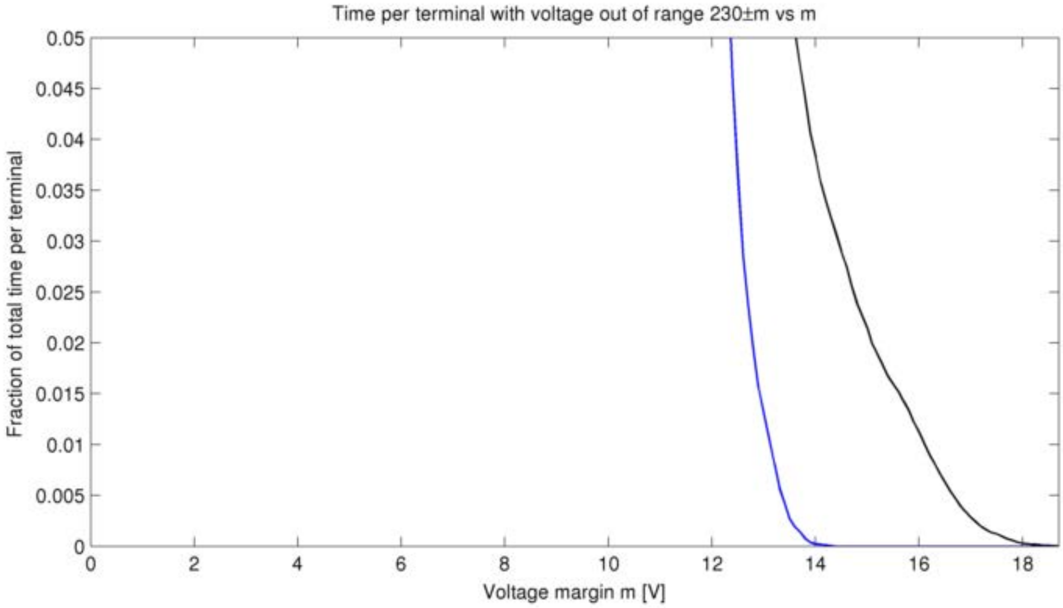


Figure 121: voltage violations frequency

This plot shows that in the s100 case one never observed a voltage outside the range 230±14 V at any terminal; whereas in the s000 case one observes a voltage outside such range for 3% of the time/terminals. More precisely, that could mean 3% of the terminals for 100% of the time, or 3% of the time on all terminals, or anything in the middle.

This plot should represent the most robust and effective approach to evaluate whether the algorithm is effective at stabilizing voltages in the distribution network (more specifically, one expects the blue line to lie on the left of the black line).

9.4. Simulation results

Complete results are reported in the attached archive, one directory per scenario. Below we report just the **voltage-violations.png** file for each scenario.

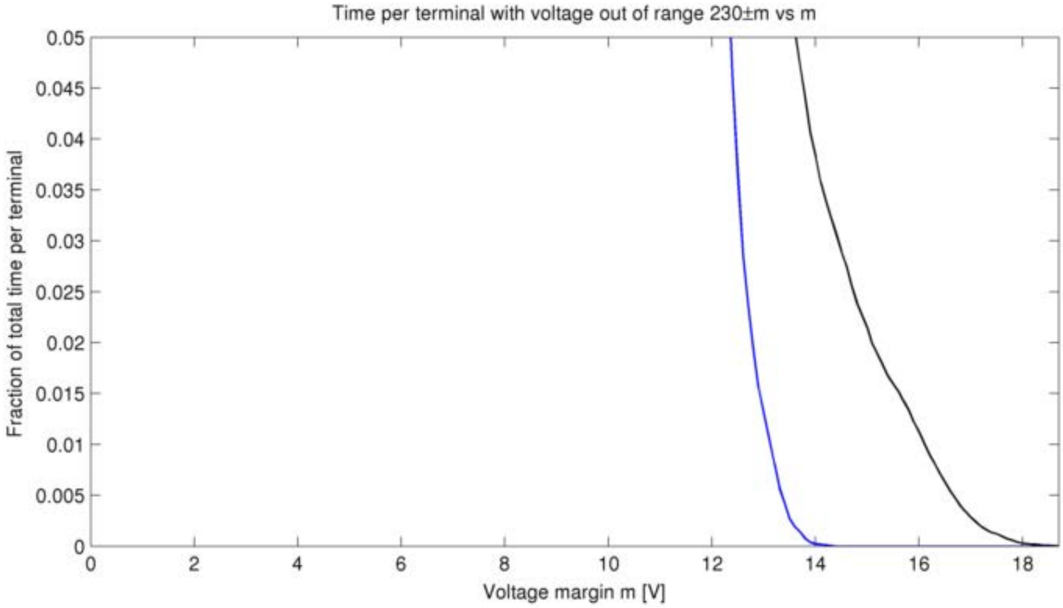


Figure 122: lineCampagnola_16terms_pv100_dm020_ia100_ss015_tr100_en100

(100% PV, transformer voltage as specified)

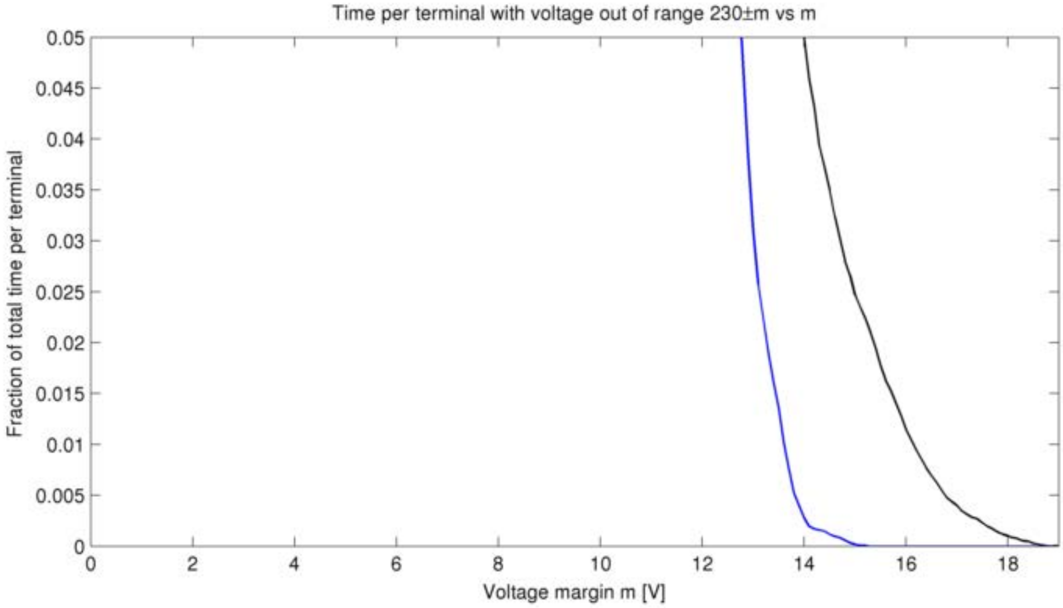


Figure 123: lineCampagnola_16terms_pv000_dm020_ia100_ss015_tr100_en100

(no PV, transformer voltage as specified)

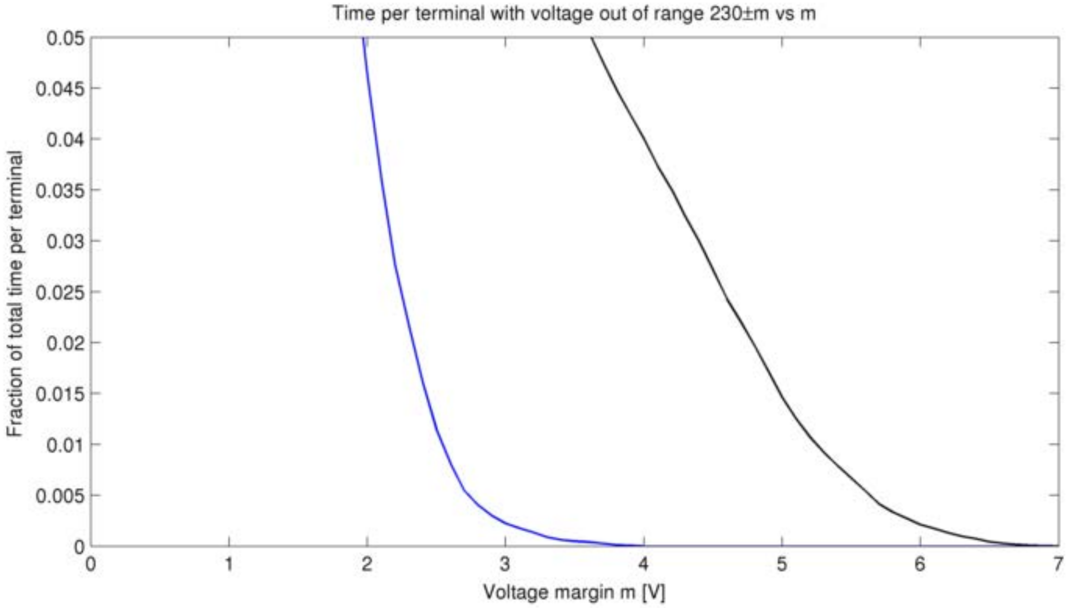


Figure 124: lineCampagnola_16terms_pv000_dm020_ia100_ss015_tr100_en100

(no PV, transformer voltage as specified)

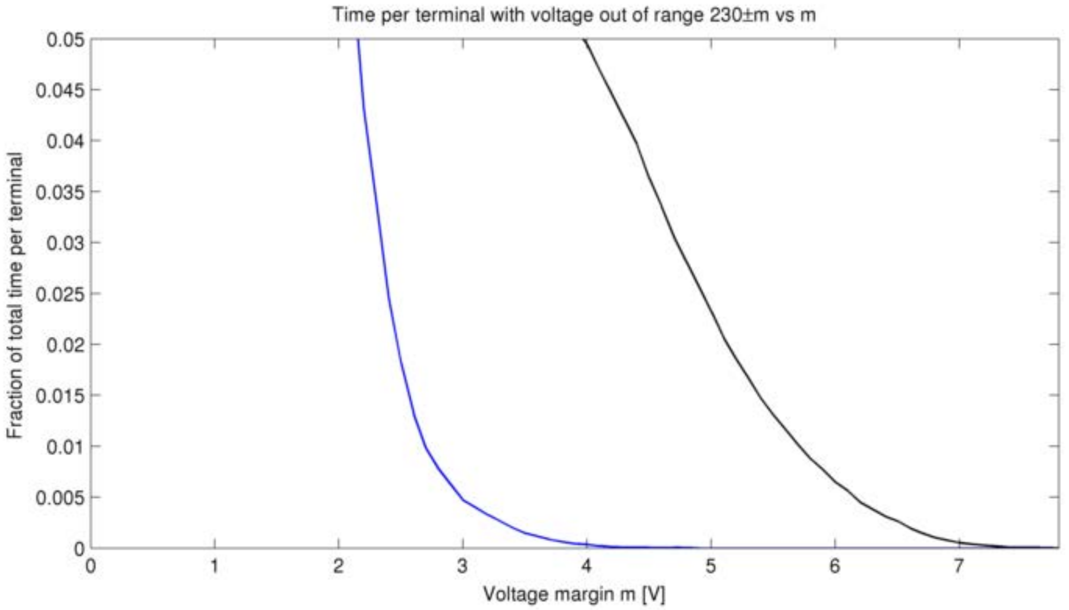


Figure 125: lineCampagnola_16terms_pv000_dm020_ia100_ss015_tr000_en100

(no PV, transformer voltage fixed at 1 p.u.)

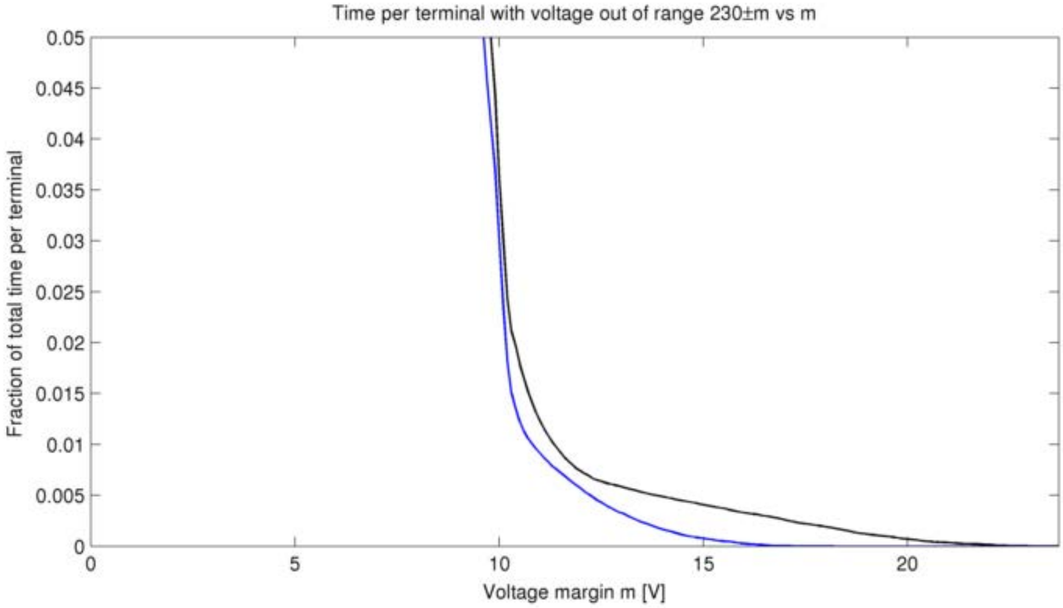


Figure 126: rheinfelden_pv100_dm020_ia100_ss015_tr100_en100
(100% PV, transformer voltage as specified)

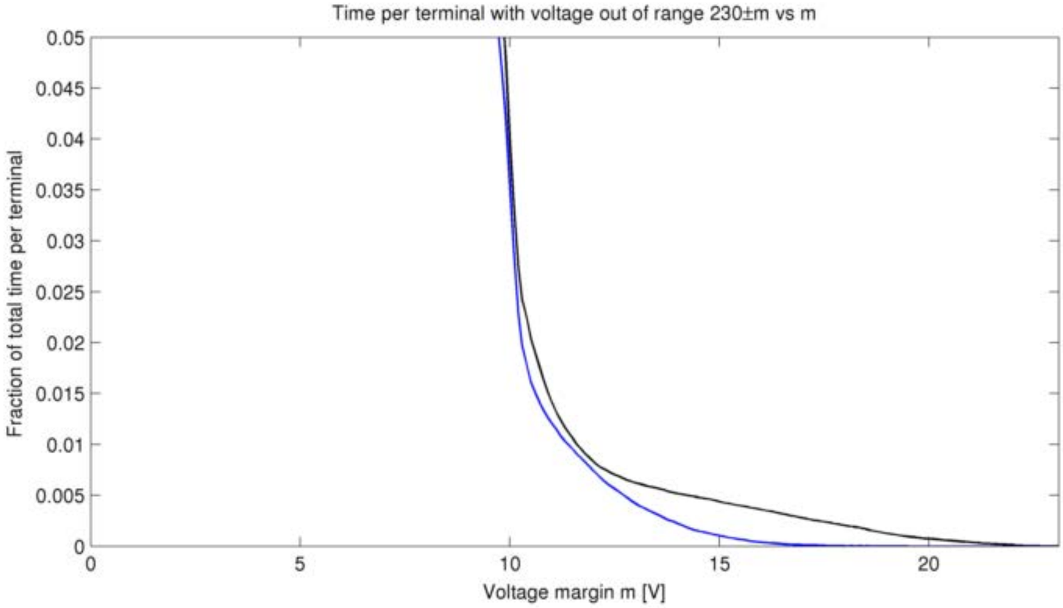


Figure 127: rheinfelden_pv000_dm020_ia100_ss015_tr100_en100
(no PV, transformer voltage as specified)

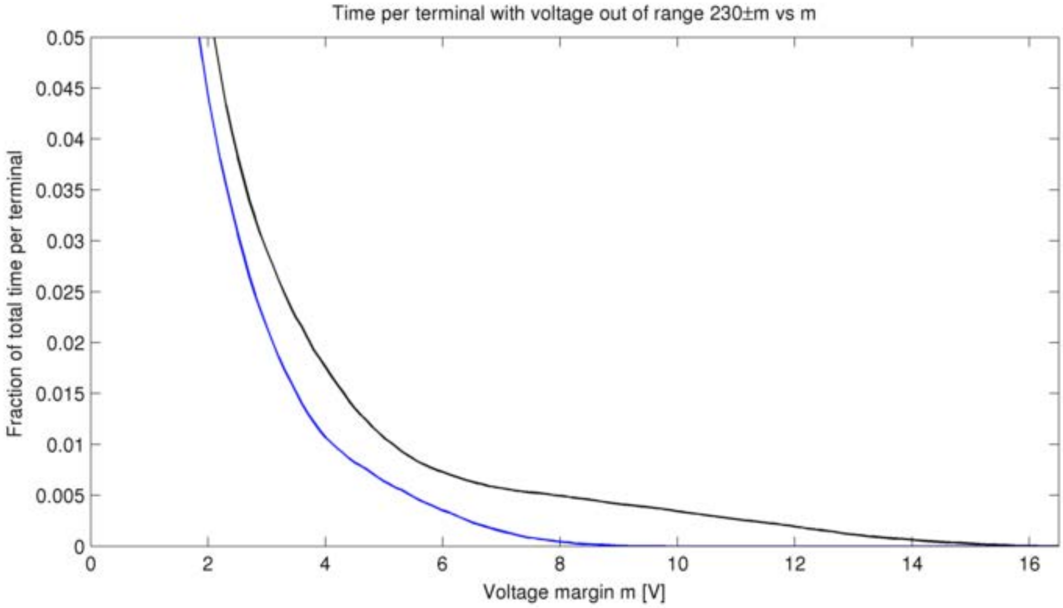


Figure 128: rheinfelden_pv100_dm020_ia100_ss015_tr000_en100

(100% PV, transformer voltage fixed at 1 p.u.)

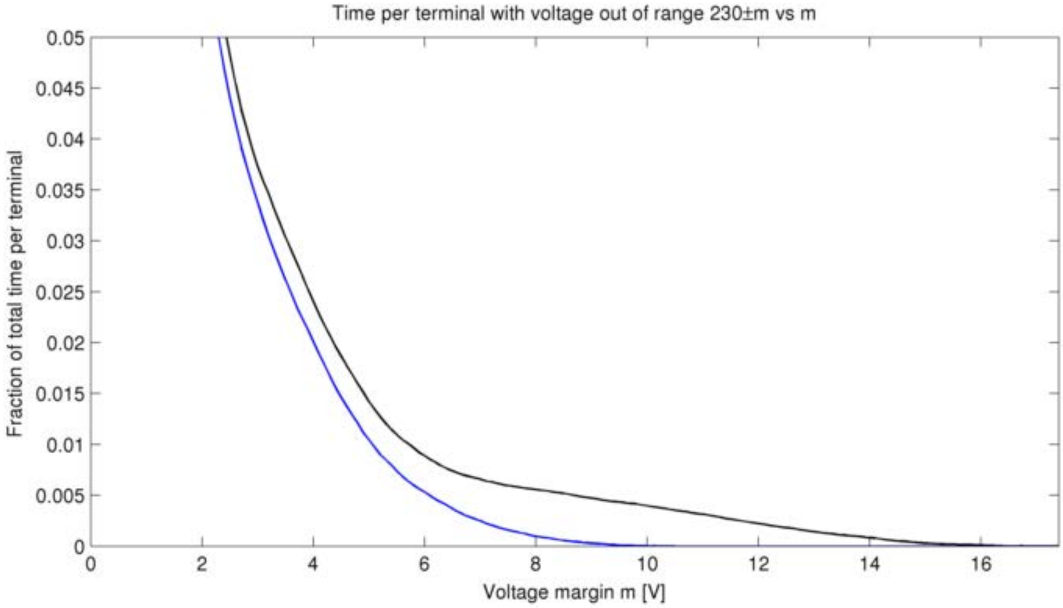


Figure 129: rheinfelden_pv000_dm020_ia100_ss015_tr000_en100

(no PV, transformer voltage fixed at 1 p.u.)u.)

To prove the global results of power consumption of the models, the power flow in winter and summer over the distribution grid transformer in the real grid had been compared with the results from the basic model without PV and EV. The simulated total energy consumption for one day (W_{day}=1.36 MWh) seems to be close to the real consumption which is measured in summertime (W_{day}=1.72 MWh). The winter (W_{day}=2.83 MWh) curve is much higher, especially in off-peak time. The differences could be explained with a lower consumption for electrical heating for the simulated households and with the real PV feed in, which is not taken into account in this scenario.

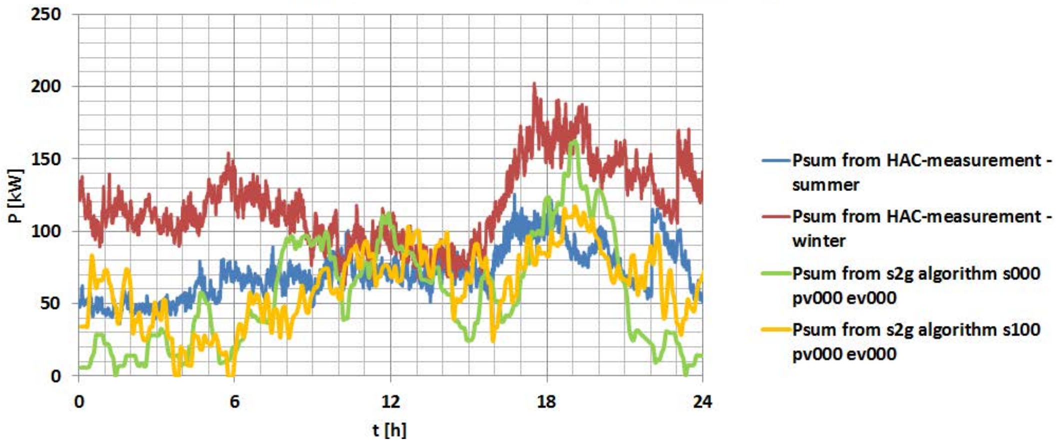
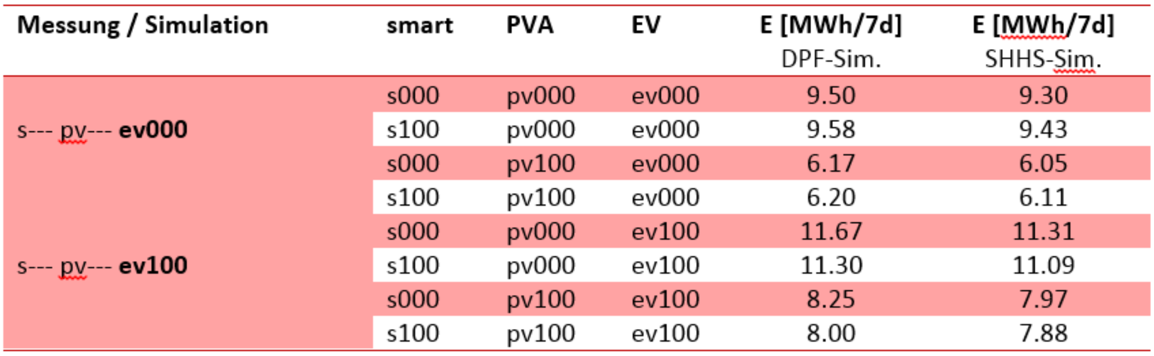


Figure 130: Power flow over the transformer to the LV-Grid: Measurements in winter (red) and summer (blue) and simulation without PV and EV; 0% smart (green); 100% smart (yellow)

While implementing the PV installations and the EV load, the volume and the load curve of the whole grid is influenced in dependency of the chosen scenario. It is important to know, that the total consumption can vary a little bit due to the shifting of loads in the smart scenario. Loads can be shifted from evening to morning next day or week and can fall out of consideration. The next figure compares the weekly consumption for 8 scenario with different ev and pv penetration. The numbers in the second row are calculated with the Smart Household Simulator, adding the consumptions of all households over one week. The numbers in the first row are calculated with DIgSILENT Power Factory (DPF) representing the total energy flow over the transformer. The difference represents the grid losses (some percent).



Messung / Simulation	**smart**	**PVA**	**EV**	**E [MWh/7d]** DPF-Sim.	**E [MWh/7d]** SHHS-Sim.
s--- pv--- **ev000**	s000	pv000	ev000	9.50	9.30
	s100	pv000	ev000	9.58	9.43
	s000	pv100	ev000	6.17	6.05
	s100	pv100	ev000	6.20	6.11
s--- pv--- **ev100**	s000	pv000	ev100	11.67	11.31
	s100	pv000	ev100	11.30	11.09
	s000	pv100	ev100	8.25	7.97
	s100	pv100	ev100	8.00	7.88

Figure 131: Total Energy delivered to (DPF) or consumed in (SHHS) the LV-Grid over one week in different scenarios

9.5. Testing under extreme conditions

In order to validate whether the algorithms help stabilizing voltages in distribution networks subject to extreme conditions (e.g. large amounts of PV or EV loads), we run a further simulation campaign with large values for pv and ev parameters.

The simulation setup matches the setup described above, focused on the mendrisio-campagnola network.

We tested PV ranges from 100% to 600% and EV ranges from 100% to 300%.

In the considered scenarios:

Total household loads (uncontrollable loads + boilers) amount to 9300 kWh in the week;

PV100 corresponds to -3200 kWh in the week;

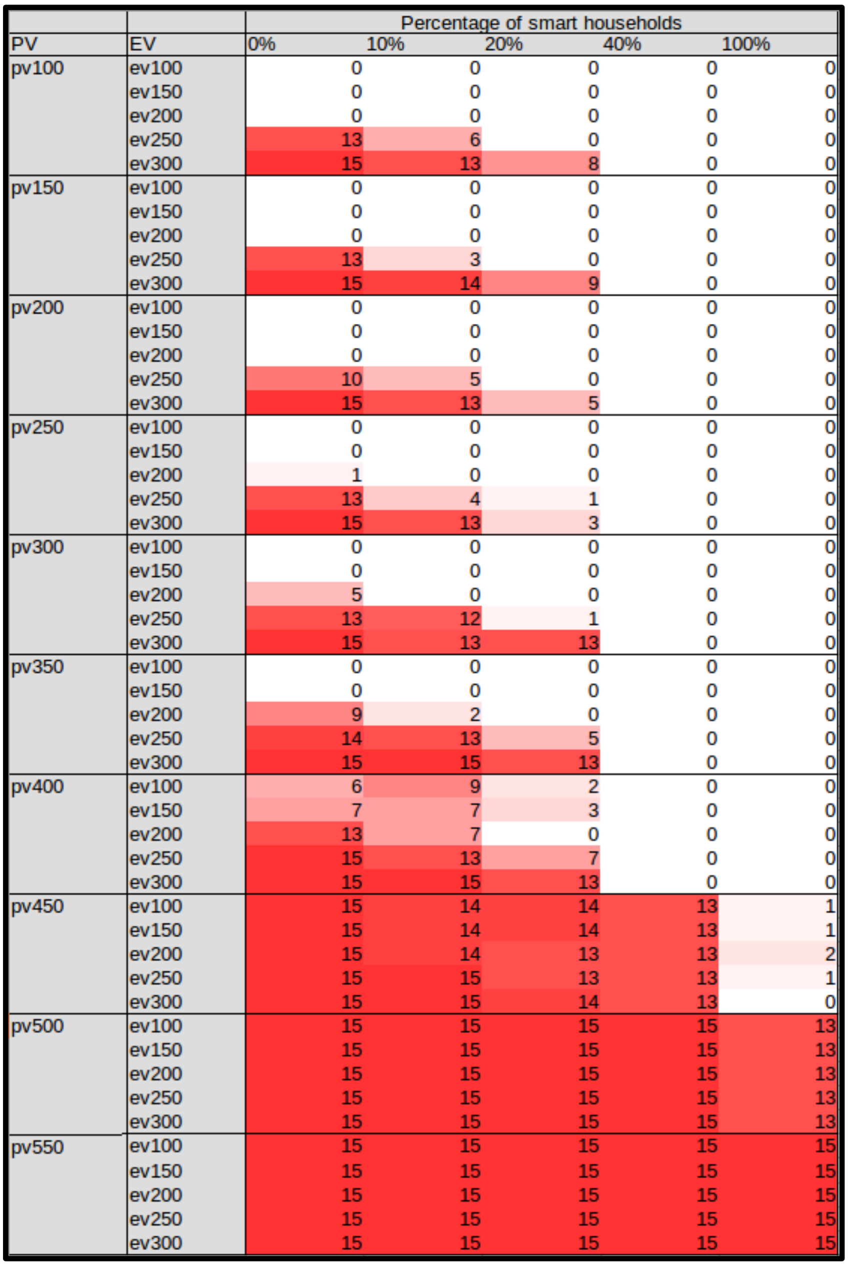
EV100 corresponds to 1900 kWh in the week.

Performance measures

For every scenario, we simulate different amounts of algorithm penetration: 0%, 10%, 20%, 40%, 100%. For every amount of algorithm penetration, we compute the number of terminals which violate the voltage limits in **EN50160**; a terminal violates such limits if and only if the voltage (averaged over 10 minute slots) is outside the range [230-10% 230+10%] for at least 5% of the time in whole the simulated week.

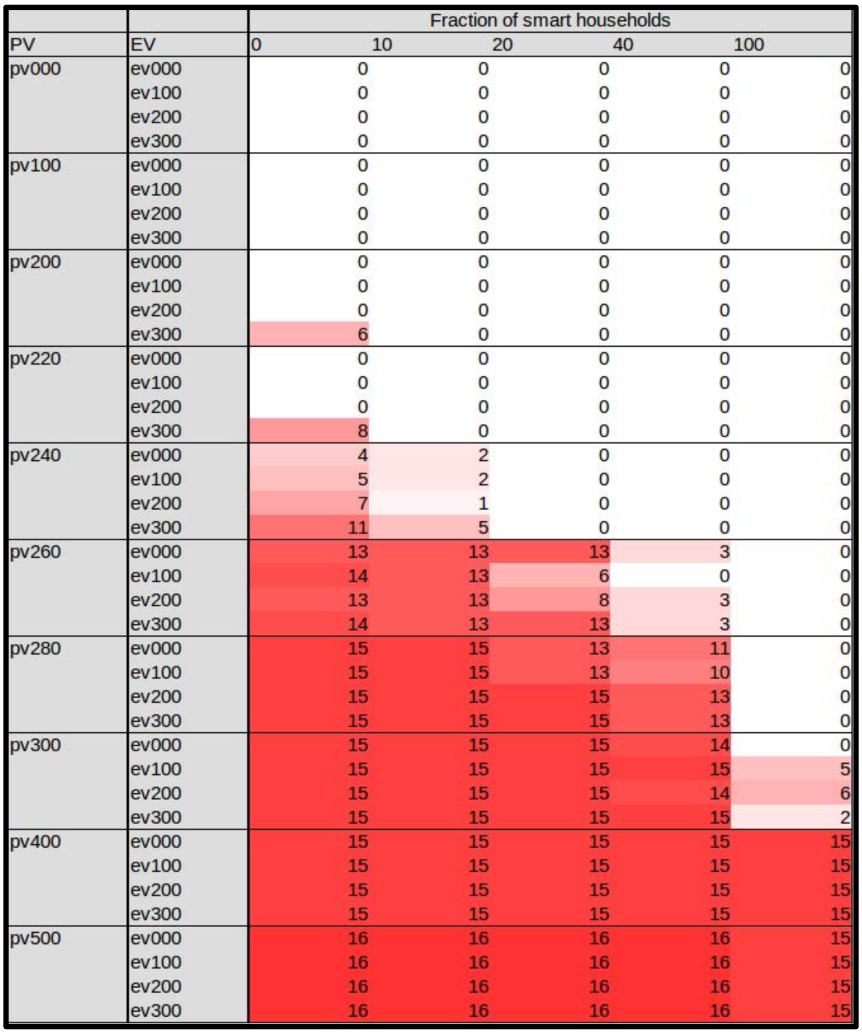
Summary results

The tables reported below summarize the number of violating terminals vs the scenario (rows) for different penetration amounts of algorithms (columns).



		Percentage of smart households				
PV	EV	0%	10%	20%	40%	100%
pv100	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	0	0	0	0	0
	ev250	13	6	0	0	0
	ev300	15	13	8	0	0
pv150	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	0	0	0	0	0
	ev250	13	3	0	0	0
	ev300	15	14	9	0	0
pv200	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	0	0	0	0	0
	ev250	10	5	0	0	0
	ev300	15	13	5	0	0
pv250	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	1	0	0	0	0
	ev250	13	4	1	0	0
	ev300	15	13	3	0	0
pv300	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	5	0	0	0	0
	ev250	13	12	1	0	0
	ev300	15	13	13	0	0
pv350	ev100	0	0	0	0	0
	ev150	0	0	0	0	0
	ev200	9	2	0	0	0
	ev250	14	13	5	0	0
	ev300	15	15	13	0	0
pv400	ev100	6	9	2	0	0
	ev150	7	7	3	0	0
	ev200	13	7	0	0	0
	ev250	15	13	7	0	0
	ev300	15	15	13	0	0
pv450	ev100	15	14	14	13	1
	ev150	15	14	14	13	1
	ev200	15	14	13	13	2
	ev250	15	15	13	13	1
	ev300	15	15	14	13	0
pv500	ev100	15	15	15	15	13
	ev150	15	15	15	15	13
	ev200	15	15	15	15	13
	ev250	15	15	15	15	13
	ev300	15	15	15	15	13
pv550	ev100	15	15	15	15	15
	ev150	15	15	15	15	15
	ev200	15	15	15	15	15
	ev250	15	15	15	15	15
	ev300	15	15	15	15	15

Figure 132: Summary results for the tr000 case



PV	EV	Fraction of smart households				
		0	10	20	40	100
pv000	ev000	0	0	0	0	0
	ev100	0	0	0	0	0
	ev200	0	0	0	0	0
	ev300	0	0	0	0	0
pv100	ev000	0	0	0	0	0
	ev100	0	0	0	0	0
	ev200	0	0	0	0	0
	ev300	0	0	0	0	0
pv200	ev000	0	0	0	0	0
	ev100	0	0	0	0	0
	ev200	0	0	0	0	0
	ev300	6	0	0	0	0
pv220	ev000	0	0	0	0	0
	ev100	0	0	0	0	0
	ev200	0	0	0	0	0
	ev300	8	0	0	0	0
pv240	ev000	4	2	0	0	0
	ev100	5	2	0	0	0
	ev200	7	1	0	0	0
	ev300	11	5	0	0	0
pv260	ev000	13	13	13	3	0
	ev100	14	13	6	0	0
	ev200	13	13	8	3	0
	ev300	14	13	13	3	0
pv280	ev000	15	15	13	11	0
	ev100	15	15	13	10	0
	ev200	15	15	15	13	0
	ev300	15	15	15	13	0
pv300	ev000	15	15	15	14	0
	ev100	15	15	15	15	5
	ev200	15	15	15	14	6
	ev300	15	15	15	15	2
pv400	ev000	15	15	15	15	15
	ev100	15	15	15	15	15
	ev200	15	15	15	15	15
	ev300	15	15	15	15	15
pv500	ev000	16	16	16	16	15
	ev100	16	16	16	16	15
	ev200	16	16	16	16	15
	ev300	16	16	16	16	15

Figure 133: Summary results for the tr100 case

Detailed results (for further analysis)

The attached CSV file reports one line for each scenario. For each scenario, the following columns are reported.

- Network (Campagnola)
- PV (scenario parameter)
- DM (algorithm parameter, fixed)
- IA (algorithm parameter, fixed)
- SS (algorithm parameter, fixed)
- TR (fixed to tr000)
- EN (fixed to en100)
- EV (scenario parameter)
- Simulation outcome: total energy [kWh]
- Simulation outcome: EV energy [kWh]
- Simulation outcome: PV energy [kWh]
- Simulation outcome: Uncontrollable energy [kWh]
- Simulation outcome: Boiler energy [kWh]
- Simulation outcome: Other energy [kWh]
- Smart fraction i.e. algorithm penetration (simulation parameter: {0%, 10%, 20%, 40%, 100%})
- Definition of voltage margin (fixed to 23V = 10% of 230V for EN50160 computation), reported because it's used to compute the two fields below
- Simulation outcome: #terms violating margin above 1% of time

- Simulation outcome: #terms violating 5% of time (sed for performance measure computation)
- The last columns of the file (one per terminal) report the fraction of time that each terminal was outside of the range [230-margin 230+margin].

9.6. Testing with a more complex grid

The results from the more complex gird were similar to those or the grid Mendrisio besides of two remarkable deviations between both implementations:

- The run of the load over the day calculated by the SHHS for the more complex grid seems to have more deviation to the measured total load curve at the transformer.
- The more complex grid seems to be charged closer to the limits.

The following figure shows the daily run of the charge of the transformer for the scenarios with ev and pv. It is obvious that the ev load in the evening, which is not shifted by the smart household algorithm leads to transformer loads near the absolute limits. The only possibility to meet this problem is a coordination of the loads by an algorithm.

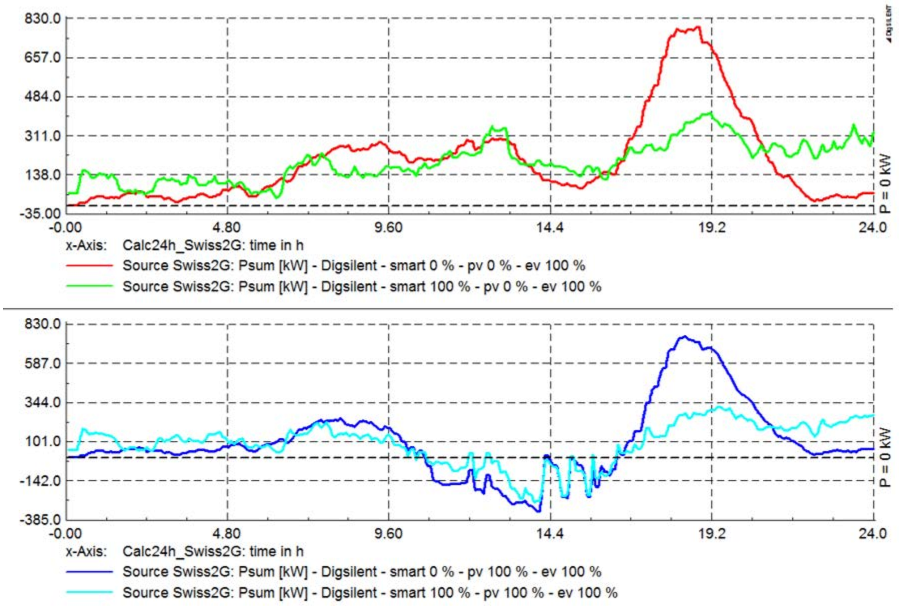


Figure 134: Total transformer load for selected scenarios

As a consequence also the voltage variation in the grid is very high. One illustrative example for voltage deviation is given in Figure 135 for a point of common coupling far away from the transformer. The voltage in the pv scenario rise up to 1.05 p.u. and drops down 0.85 p.u., which is 5% under the allowed limit.

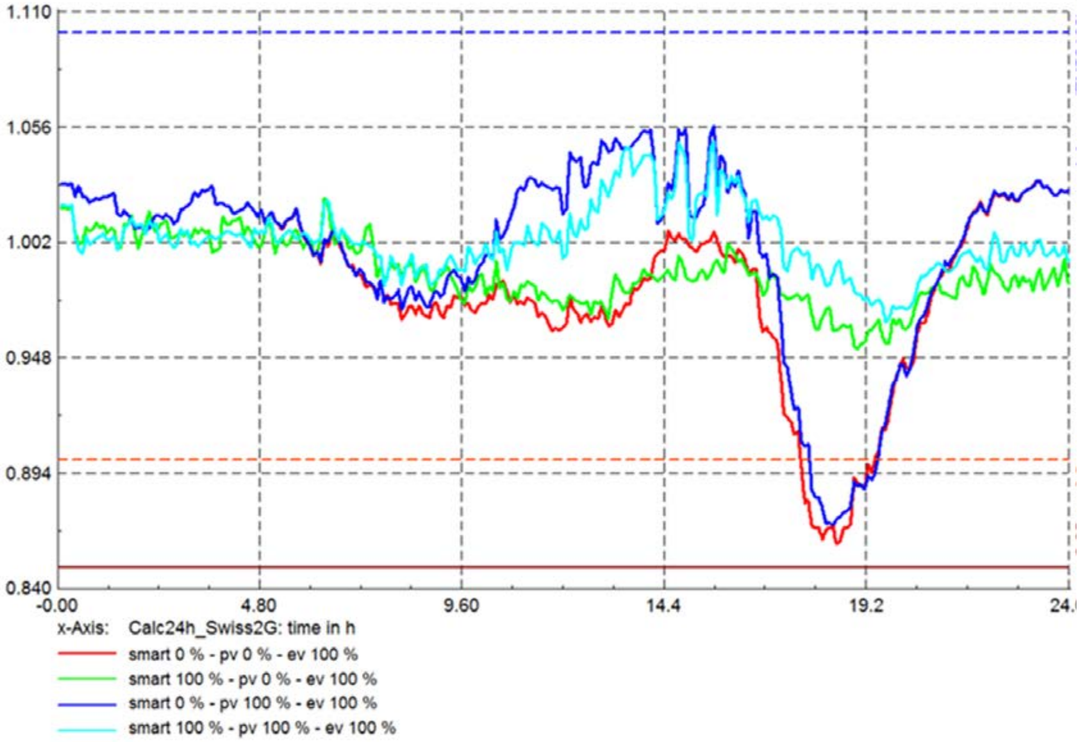
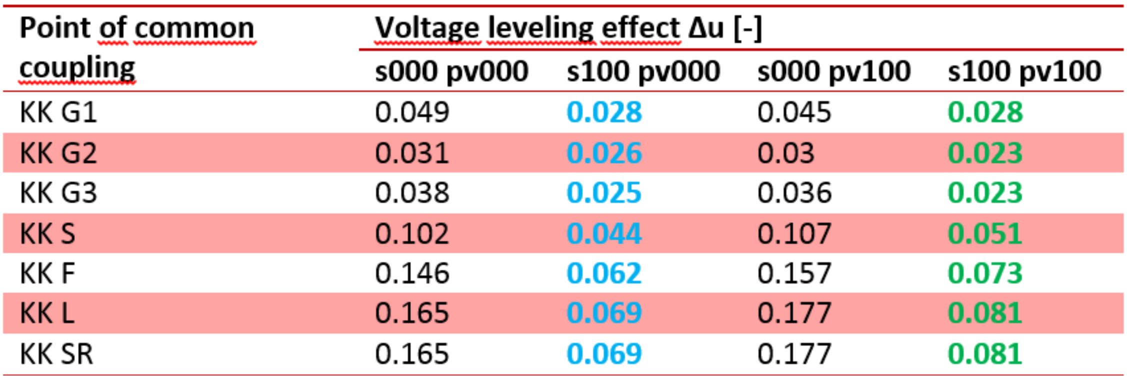


Figure 135: Voltage over a day at a PCC far away from the transformer for different scenario in the complex grid

The positive influence of the smart algorithm on the voltage seems even higher for the more complex grid. The relation between the levelling numbers of the smart (blue/green) and the not smart (black) scenario can rise up to 2.5.



Point of common coupling	**Voltage leveling effect Δu [-]**			
	s000 pv000	**s100 pv000**	**s000 pv100**	**s100 pv100**
KK G1	0.049	**0.028**	0.045	**0.028**
KK G2	0.031	**0.026**	0.03	**0.023**
KK G3	0.038	**0.025**	0.036	**0.023**
KK S	0.102	**0.044**	0.107	**0.051**
KK F	0.146	**0.062**	0.157	**0.073**
KK L	0.165	**0.069**	0.177	**0.081**
KK SR	0.165	**0.069**	0.177	**0.081**

Figure 136: Voltage levelling effect in the more complex grid

9.7. Effects on higher level grid

The task would have been to interpret the results and derive conclusion to the higher level grids based upon the existing simulation results. Since in the new approach to simulate the influence of the algorithm, the direct interaction between the household simulator and the network analyse tool DIgSILENT has been given up, no simulation results are available for this topic.

The shown diagram should serve for a rough analysis of the possible effects. Frequency stability is a question of the work together in the whole West European Transmission grid. Power stations, which are activated by their transmission grid operators (TSO) for primary regulation, provide a grid power factor of 3 GW, which has to be guaranteed in case of a frequency deviation of 200mHz. As they are blocked within a small band of +/- 20 mHz, a change of some hundred MW of load, which is activated by decentralized algorithms will not affect the regulation. Therefore, any interaction of smart households with the frequency regulation may not be probable.

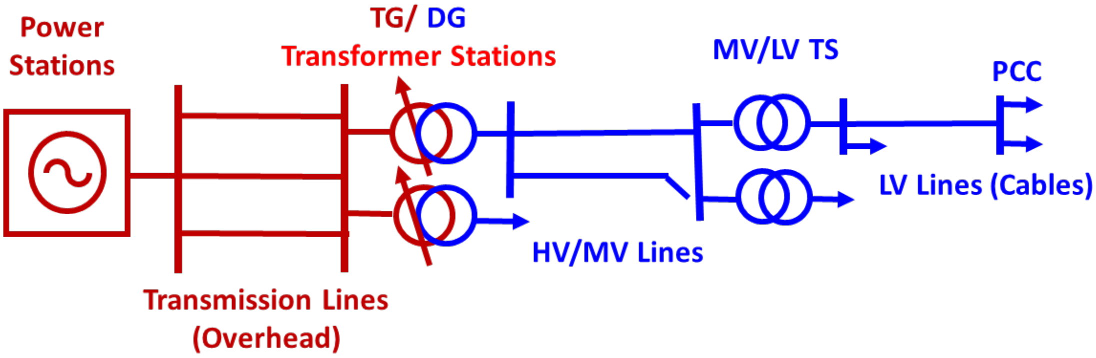


Figure 137: Schematic overview of the whole grid constellation

Voltage regulation is a local task. The bigger power stations have an obligation to keep a predefined voltage level at their connection point to the transmission grid. In combination with the voltage regulation, also the needs for reactive power are covered. This regulation in combination with some local measures in the transmission grid performed by the TSO assures the distribution grid companies a voltage level at their connecting points to the transmission grid normally more than 1 p.u. (e.g. 100%). The regulation is very fast with time constants of less than a second. Transformers in the grid normally have an automatic tap changer, which allows local voltage adaptions. To save lifetime, the regulator for tap changers is delayed so that the minimum frequency of switching is more than one minute. An interaction between local algorithms and the voltage regulators is possible and according measures should be regarded. Some simulations about this item have been performed and documented in [1].

The influence of reactive power flow in the LV-grid is very low due to the low inductive part of the grid impedance and can be neglected. Transformers have a big inductance and the impedance angle of power lines rises with increasing voltage levels up to nearly 90°. Therefore in transmission grids voltage oscillations are depending of reactive power flow. As a consequence, the influence of the active power flow on the voltage gets less important for voltage stability in upper level grids. Taking into account that regional voltage regulation by transformers decouples voltage and power flow, the influence of active power algorithms on the upper level grid will be low.

The conclusion is, that isolated simulations in LV-grids may be accurate enough to get the needed information about voltage stability in case of decentralized active power algorithms.

9.8. Algorithm testing with different tariff scenarios

9.8.1. Selected tariffs' schemes

We have carefully considered the main key points emerged in the literature analysis, the conclusions of pilot projects and the structure and the functioning of the S2G algorithm HAC; after all, we decide to test 5 different tariffs' schemes:

1. Time of use (control group)
2. Time of use with dynamic rates (PTR)
3. Flat rate
4. Flat rate with dynamic rates (PTR)
5. Real time pricing.

The empirical test has been developed under several technical and economical hypotheses:

- Appliances tested will be the most energy intensive ones: boiler and electric vehicles (EVs):
  - Bolier_1: Average Boiler, 5kW, 500 L with 100L7day hot water consumption (uniform usage). Thermal conductance 2W/K, heating efficiency 100%. Temperature range: 57 to 63 degC, ambient temperature 20 degC;
  - Boiler_2: Average/Large Boiler, 7kW, 700L with ~200L/day hot water consumption (uniform usage). Thermal conductance 2W/K, heating efficiency 100%. Temperature range: 57 to 63 degC.
  - EV_1: Electric Vehicle used every day from 7 am to 17 pm, plugged in with a state of charge of 30%;
  - EV_2: Electric Vehicle used only on working days; it is unplugged from 7 am to 9 am and plugged in from 4 pm and 6 pm with a state of charge between 50% and 70%;
  - EV_3: is the Electric Vehicle currently in use at ISAAC; simulation will use data of actual use made by the institute.

- The goal of the algorithm will be:
  - Monthly bill expenses minimization;
  - Load optimization (load shifting, not energy consumption reduction).

- Where necessary, rates have been defined under the revenue neutrality constraint.

- Rates have been tested on one single house, with the above mentioned appliances and solar panels. In our opinion it is not necessary to extend the simulation to a larger number of houses because the optimization process works independently for each of them. For the price test we selected the month of March 2013 as benchmark for the definition of critical event days baseline (CED) and for RTP - spot prices (Swiss Day Ahead market)[39].

- CED definition: in order to quantify (and monetize) the shift in consumption during critical days for PTR we have had to define the baseline and the value of the reward (credit) allowed:

  - Baseline: the incentive is paid based on the difference between metered load during the peak period on event days and an estimate of what the customer would have use during the same period if the PTR event had not occurred. This estimate is referred to as baseline load. The accuracy and magnitude of incentive payments is dependent on the accuracy of the baseline estimate. The payment is made as a credit on the customer's bill.
  - Value of the credit: following the empirical evidence – in particular the arc of responsiveness – we decide to reward virtuous customers with a credit of 1.- for each kWh not consumed/shifted.

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[39] We have analysed all the spot prices for 2013 and we have observed that months with higher prices in rush hours were February, March and December.

        - We identify critical hours in 5 different critical days; on a yearly base this means 60 hours of possible “spike” prices. This could be a high level of criticality, so a possible reduction of CED should be considered.

- The degree of freedom for the HAC affects the results:
    - Bills’ reduction will be overriding if the cost of smart meter is borne by consumers; the second if distributors/retailers will install – and pay - the meter;
    - If prices will increase for very limited periods, such as for example one hour, the HAC will shift consumption for this selected ; if in doing so could benefit of the maximum freedom (flat rate or ToU rate with extended ranges) there will not be problems in terms of congestion.

- Giving this couple of objectives to the HAC, the algorithm will decide to change consumption consumers’ behaviour in the best way possible considering load profile and the amount of money to pay. In this sense, the HAC that works alone should reflect the behaviour of the “optimal” customer, shifting consumption from more expensive hours to less ones.

- Also the share of enrolment is relevant: if the HAC manage consumption for example of the 10% of residential customers there will not be congestion problems; otherwise, with a deeper penetration, the congestion matter will increase is importance. In this case, the degree of freedom of HAC in shifting load will have a primary relevance: if tariffs are structured as ToU with extended pricing periods or as flat rates the algorithm will shift consumption for critical hours to non-critical ones without significant problems in terms of congestion. This is one the (main) reason why we decided to include in our analysis also a flat rate, pure or “corrected” with a dynamic rate.

- We consider only shifting and non-reductions of consumption.

- Considering our project, it is our opinion that the most appropriate dynamic price in terms of reward for customers could be the PTR. With this rate customers that modify their behave consumption (or, better, with an HAC that will do this change) could benefit of a reduction in their bills holding the same demand. In other words, PTR is a rewarded strategy that will permit to increase the percentage of enrolment in case of opt-in strategy or will not be penalise customers in case of opt-out approach (in the last case it could be the default rate). This is the reason why PTR is the dynamic rate that has determined the higher percentage of enrolment (see project pilots); it is also characterized by a relevant volume of savings (from customers’ side and from utility/society side).

- Due to the nature and the structure of the algorithm, from an economic point of view its activity seem to be quite similar to the direct load control made by the utility whereas, in our project, customers conserve the possibility to define their own consumption profile, in certain cases in contrast with load optimization activity. Again, is more fair than DLC because the amount of the reward is linked to the actual amount of load shifting/load optimization (while with DLC all consumers will receive the same contribution no matter what is the volume of load shifted/reduced).

- Selected tariffs don’t include taxes, VAT, RIC, etc…

The following figure resumes the details of selected tariffs.

Tariff	Type	Peak	Off Peak	Dynamic Rates	
				amount	when
1	Time-of-Use	14,40	11,10		
2	Time-of-Use with Peak Time Rebate	14,40	11,10	1 CHF/kWh	5 CED – from 7 pm to 8 pm
3	Flat Rate	12,90			
4	Flat Rate with Peak Time Rebate	12,90		1 CHF/kWh	5 CED – from 7 pm to 8 pm
5	Real Time Prices	Spot market prices (energy) and network prices			

Table 16: Details of selected tariffs.

In detail, the above-mentioned tariffs have the following characteristics:

- Time of use: Prices of AIM Mendrisio (local electricity distributor/retailer) for 2014 – domestic customers. Peak tariff: 14.40 cts/kWh (5.50 network + 8.90 energy), Monday-Wednesday, 8.00 a.m., 8.00 p.m. Off-peak tariff: 11.10 cts/kWh (3.90 network + 7.20 energy), Monday-Wednesday, 8.00 a.m., 8.00 p.m. Saturday-Sunday, all the day.
- Time of use with Peak Time Rebate. If end users shift their consumption during CED they will obtain a credit/reward; otherwise, there will be no penalty and the price will be the usual ToU rate. It is clear that the crucial point is the definition of customer specific baseline user and the amount of reward. According to the results of pilot projects and with the arc of responsiveness we decide to define a credit of 1.- per kWh saved (shifted).
- Flat rate: the price is the same for each kWh used, at last up to a fixed amount of consumption.
- Flat rate with Peak time Rebate: is a flat rate with the possibility to obtain a credit (or a gift or something else) if end users reduce their consumption during the above-mentioned critical days.
- Real Time Prices: the reference for the level of energy component is represented by electricity spot prices (www.eepx.com) with a +8% as mark up for local distributors/retailers. For network component, due to the impossibility to calculate the real time rates following the optimal pricing rule theory we decided to use the same rates of ToU.

9.8.2. The price test: results

- If we consider the percentage reduction in monthly bills we can observe that for boiler devices better results in terms of savings seems to be related to the adoption of a RTP pricing system: -28.91% with boiler 1, -26.67% with boiler 2. Differently, if we consider EVs higher saving seems to be obtained with a ToU + PTR price structure, mainly for the incidence of PTR credits on final bills. Anyway, also in this case RTPs seem to be interesting.
- This kind of comparison does not consider pure flat rate (tariff 3): in this case, in effects, there are no effective savings because price paid is fixed and time-invariant.
- Same results if we consider the absolute value of monthly bills. For our analysis, at least in this step, it seems to be much more interesting to reason about percentage savings because this permit to better understand the real weight of load shifting.
- If we focus on EVs we can notice that EV_1 (used every day from 7 am to 17 pm, plugged in with a state of charge of 30%) is interesting and also EV_3 (repeating ISAAC use) register remarkable reductions. We remind that EV_2 usage profile seems to be quite unrealistic.

		Final price Without algorithm	Final price With Algorithm	Savings due to algorithm
BOILER_1				
	Tariff 1	25,46	23,13	-9,15%
	Tariff 2	25,46	20,89	-17,95%
	Tariff 3	26,79	26,79	0,00%
	Tariff 4	26,79	25,56	-4,59%
	Tariff 5	24,77	17,61	-28,91%
		Final price Without algorithm	Final price With Algorithm	
BOILER_2				
	Tariff 1	43,95	40,27	-8,37%
	Tariff 2	43,95	36,86	-16,13%
	Tariff 3	46,05	46,05	0,00%
	Tariff 4	46,05	43,00	-6,62%
	Tariff 5	42,30	31,02	-26,67%

Table 17: Monthly bill with and without the algorithm: Boiler

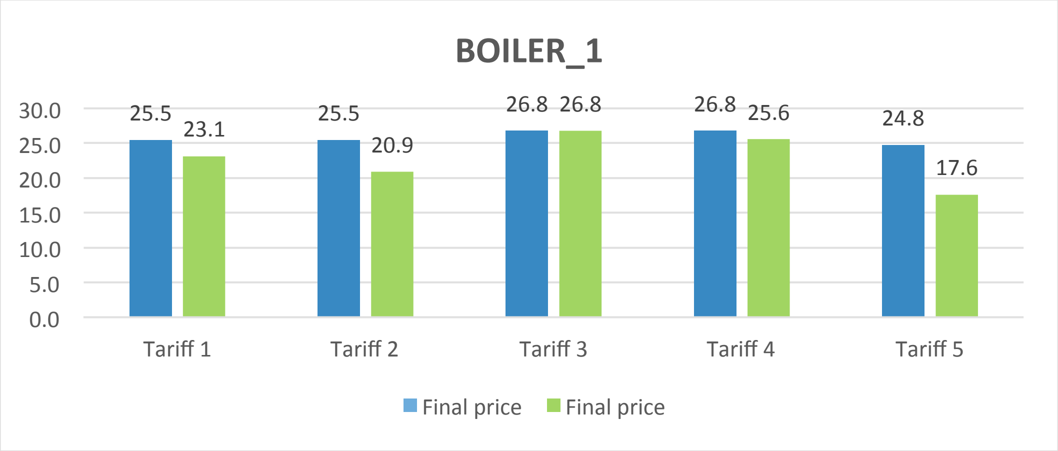

Figure 138: 36. Boiler_1

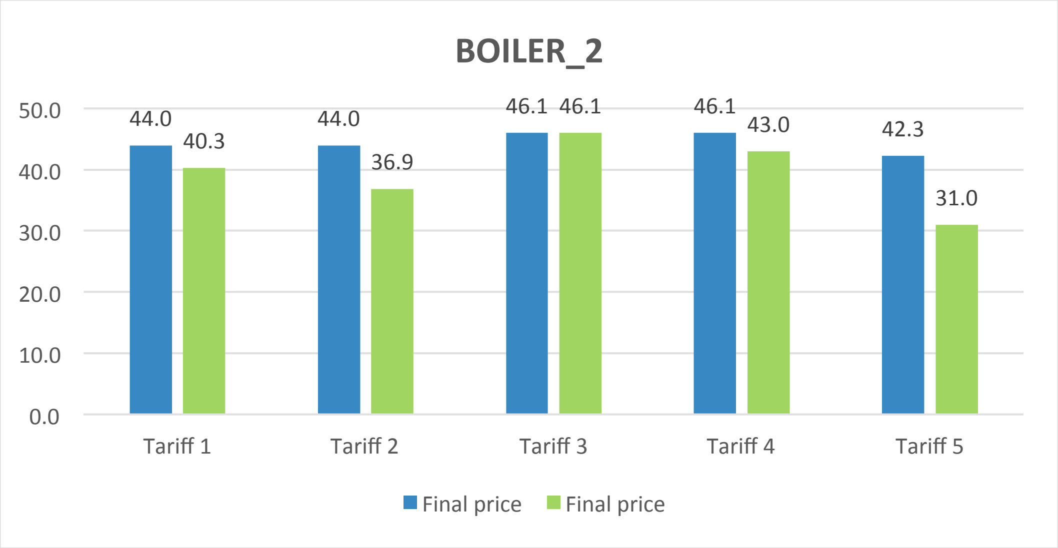

Figure 139: Boiler_2

		Final price Without algorithm	Final price With Algorithm	Savings due to algorithm
EV_1				
	Tariff 1	58,7	38,9	-33,76%
	Tariff 2	49,7	28,1	-43,32%
	Tariff 3	50,1	50,1	0,00%
	Tariff 4	50,1	35,2	-29,67%
	Tariff 5	56,1	30,5	-45,60%
EV_2	Tariff 1	20,8	17,0	-18,46%
	Tariff 2	20,8	9,1	-56,20%
	Tariff 3	19,7	19,7	0,00%
	Tariff 4	19,7	13,3	-32,34%
	Tariff 5	22,9	12,1	-47,05%
EV_3	Tariff 1	13,84	12,62	-8,82%
	Tariff 2	13,84	7,44	-46,24%
	Tariff 3	13,38	13,38	0,00%
	Tariff 4	13,38	8,55	-36,10%
	Tariff 5	14,76	10,33	-30,01%

Table 18: Monthly bill with and without the algorithm: EVs

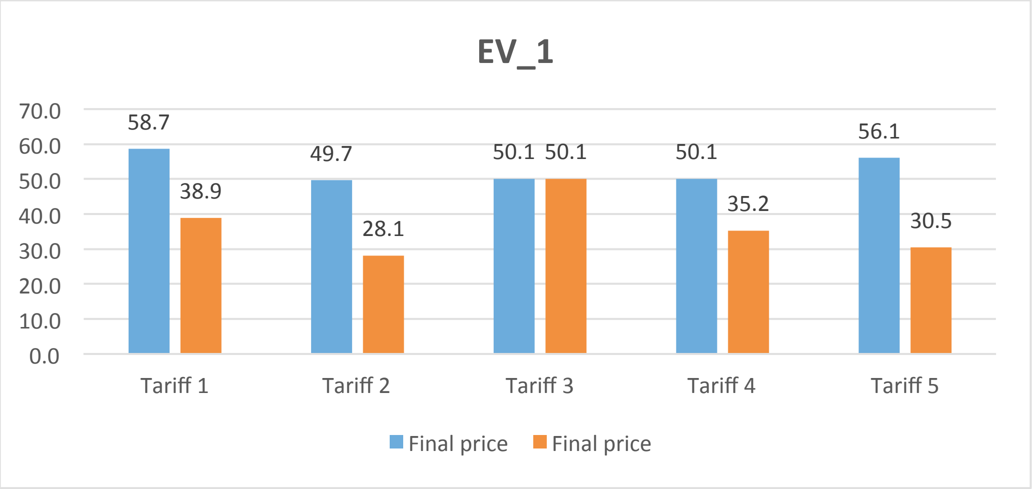

Figure 140: EV_1

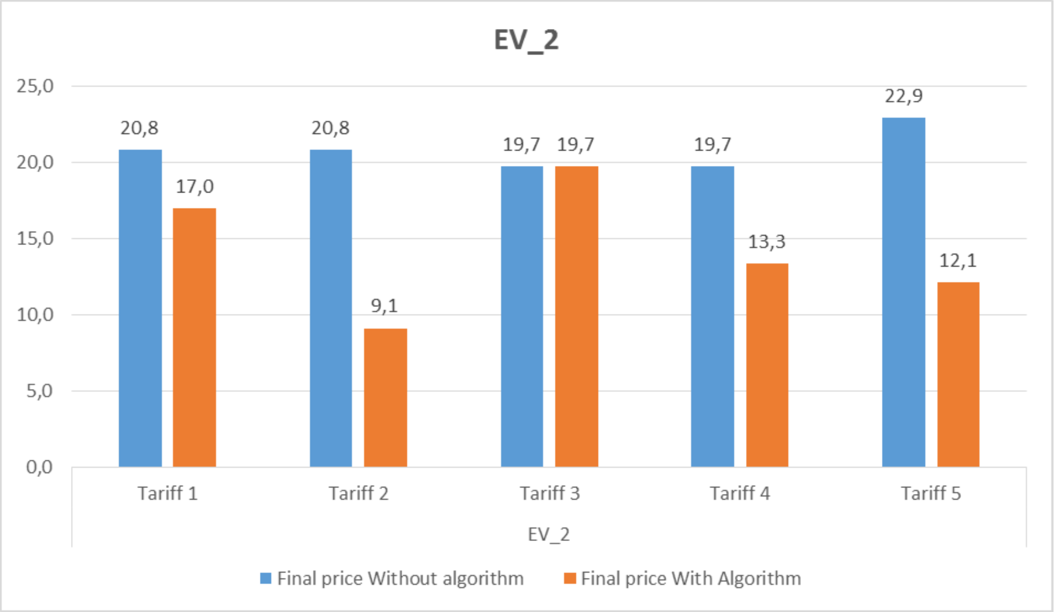

Figure 141: EV_2

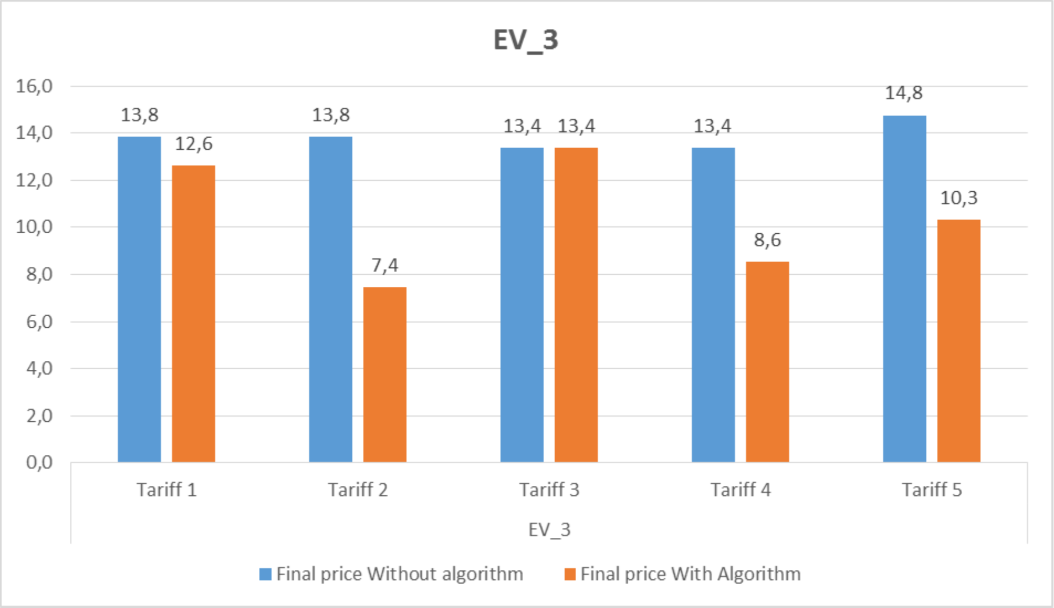

Figure 142: EV_3

- We can compare final price with algorithm with minimum price of current ToU price structure (11,10 ctsCHF/kWh, red line). We can point out that in several cases the first is pretty close to the second; in certain cases is also lower due to the incidence of credit rewards or to the possibility to shift consumption during hours with minimal rates (i.e. nigh) in case of RTP.
- Higher savings in terms of price could be obtained with an appropriate management of EVs charging.

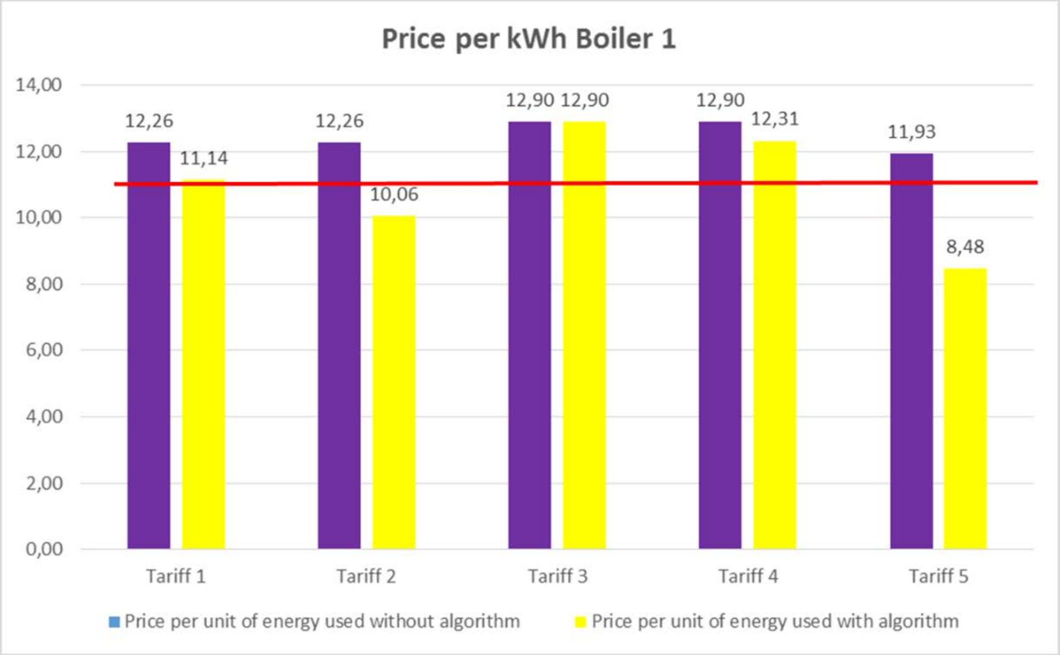

Figure 143: Price per energy used with and without the algorithm: Boiler_1

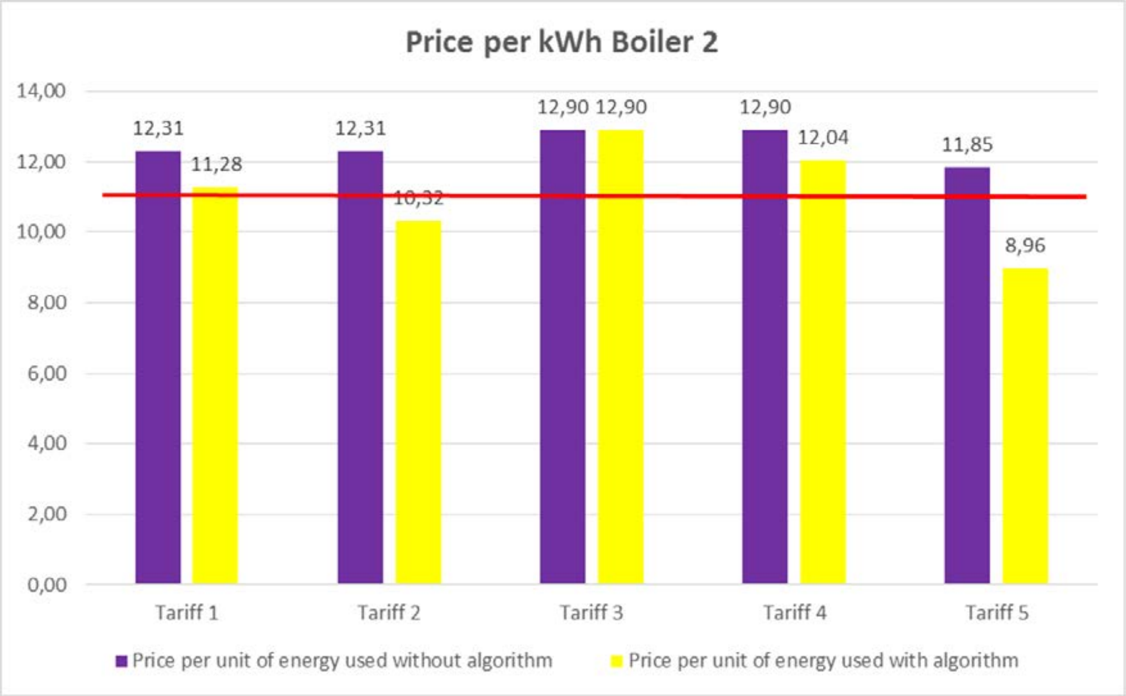

Figure 144: Price per energy used with and without the algorithm: Boiler_2

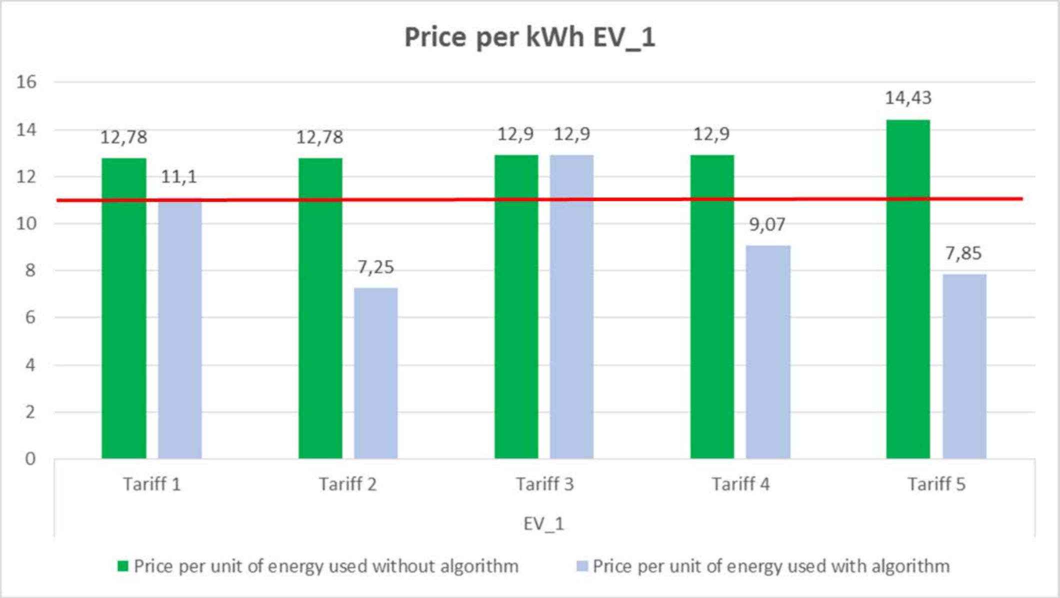

Figure 145: Price per energy used with and without the algorithm: EV_1

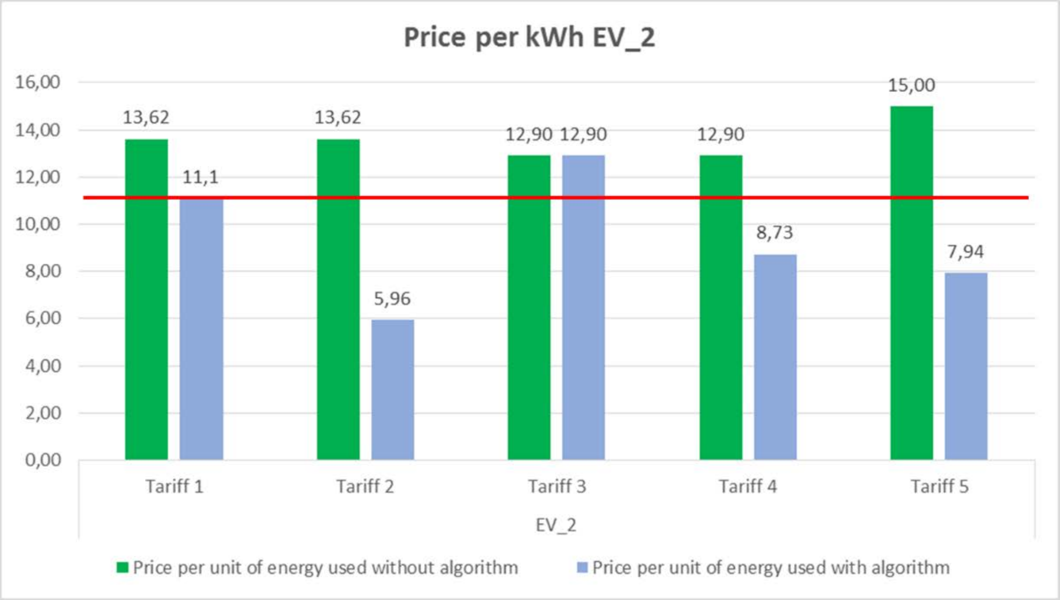

Figure 146: Price per energy used with and without the algorithm: EV_2

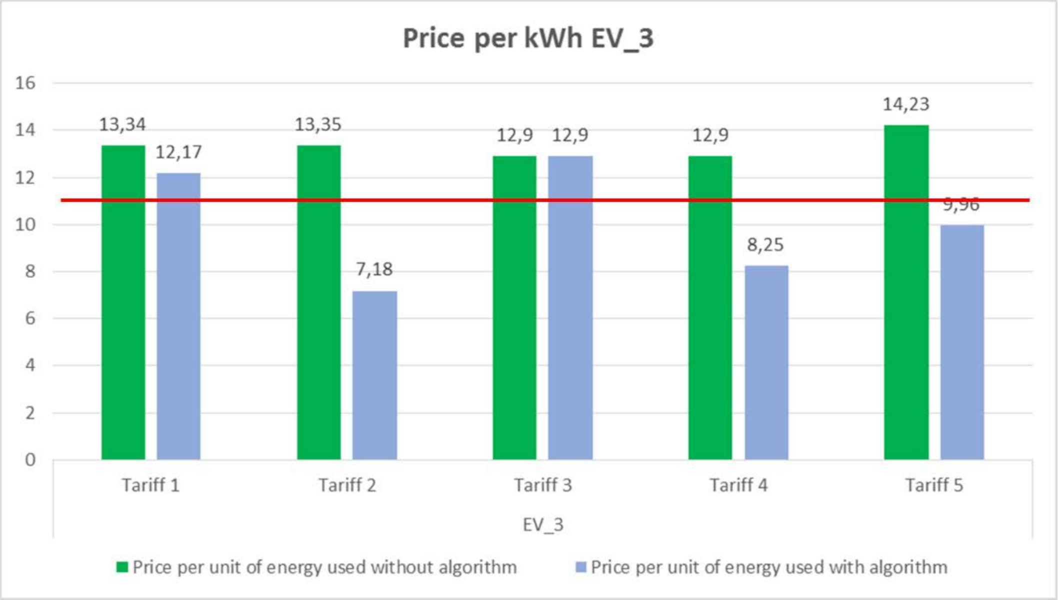

Figure 147: Price per energy used with and without the algorithm: EV_3

- Monthly savings for PTR rates are similar to those registered in the pilot projects analyzed.

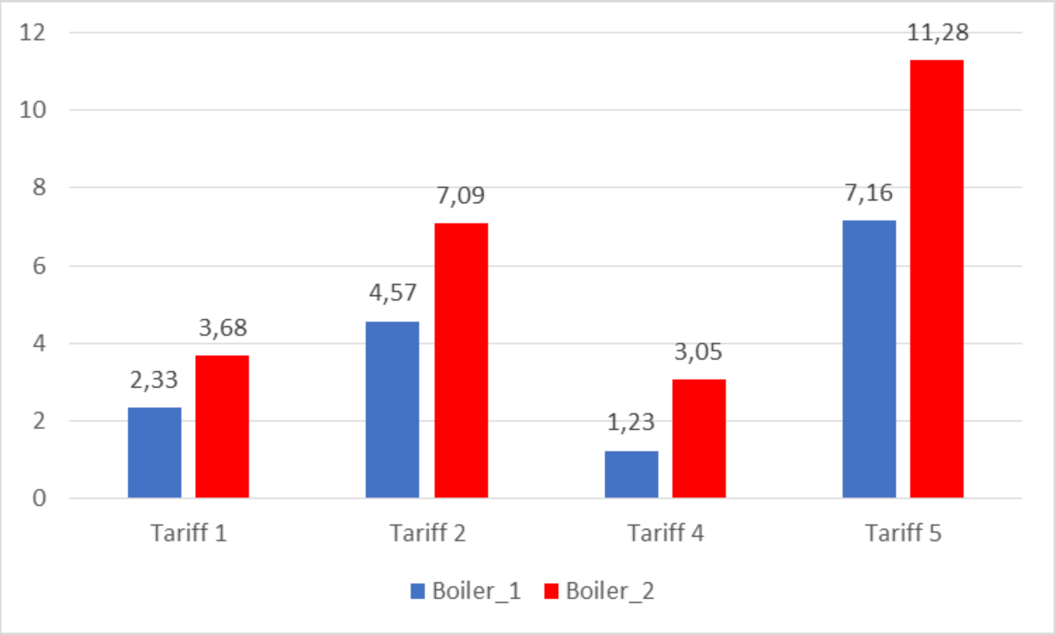

Figure 148: Monthly savings: Boiler

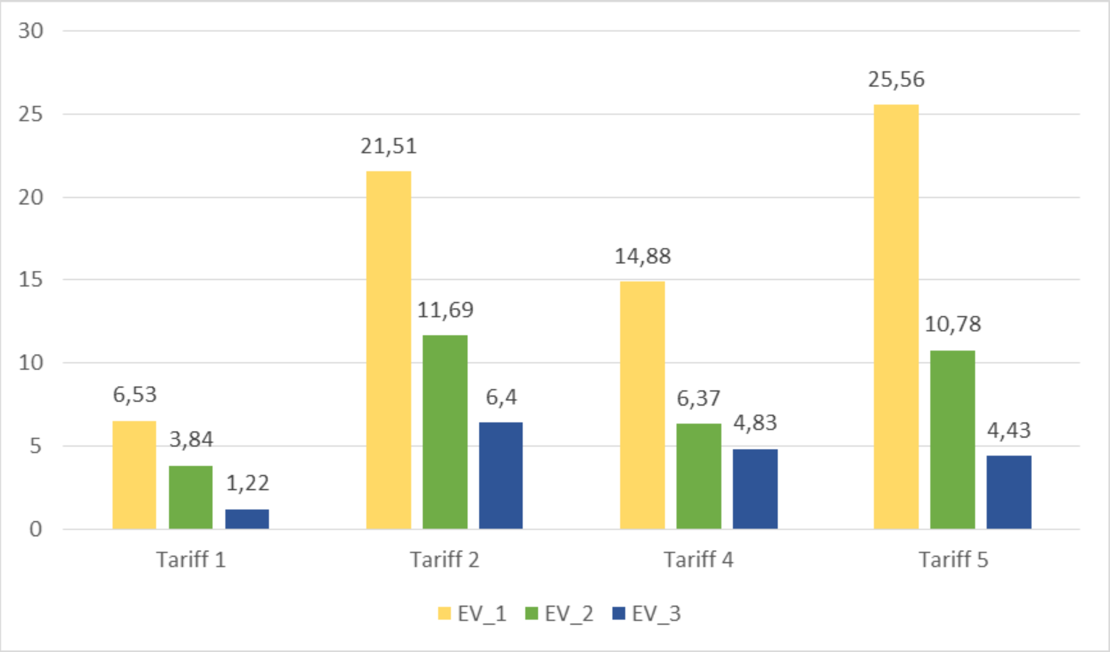

Figure 149: Monthly savings: EVs

9.8.3. Conclusions

- In general, results could be a little underestimated due to the invariance in total consumption;
- Most interesting price schemes seem to be ToU combined with dynamic rates (PTR) and Real Time Prices;
- In particular, RTPs seem to privilege boilers. Savings for EVs are remarkable; due to their strong flexibility in terms of use they could give back higher price advantages;
- Again, for EVs the incidence of PTR rewards is very relevant, in certain cases higher than for boiler; this because at 7 p.m. EVs without algorithm are usually plugged in. The baseline is so very high as much potential savings with HAC.
- Monthly savings for boiler and actual usage of EVs seem in line with empirical evidence/pilot projects.

- Shifting from the end-user perspective to DSO one the problem is to understand if reductions/savings in bills could be counterbalanced by advantages/benefits in terms of:
    - Cheaper/more profitable electricity supply (flatter profile);
    - Increasing/new revenues/higher marginality from other services (energy and non-energy);
    - Reduction of planned investments (probably not in the short period);
    - We have also to consider the amortization of HAC cost.
- The test has been conducted on usage data for the month of March 2013. Total hours with CED are 5 (5 critical days, 1 hour each – from 7 to 8 p.m.). This means 60 hours per year (usually spikes concerns 40 – 50 hours per year). It could be appropriate to consider a reduction of CED.
- A wider/total, diffusion of RTP could have consequences in terms of network congestion[40].
- At a first glance, pure flat rates could not be the best choice, but we have to keep in mind that they:
    - Could give to HAC the largest flexibility in terms of load shifting minimizing at the same time any possible problem in terms of network congestion. To mitigate effects in terms of inequality or inefficiency flat rates could be redefined after two or three years following some kind of profit sharing approach;
    - Have the lowest cost in terms of invoice;
    - From DSO’s side represent an optimal choice because average revenues remain the same.

Benchmarking and conclusions are obviously affected by the current gap between ToU/Flat rates and RTP and also by significant spot prices variability in the selected month. In detail, ToU and flat rates are in certain cases significantly higher than RTP due to the presence of risk hedging that permits to the utility to define fixed amount of rates for a fixed time period (in nearly all cases one year). If we decide to totally transfer this risk on consumers prices will be lower but volatility could determine also “peak” in their bills.

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[40] See M. Salani, A. Giusti, G. Di Caro, A. Rizzoli, L. Gambardella “Lexicographic Multi-objective Optimization for the Unit Commitment Problem and Economic Dispatch in a Microgrid”. Proc. of IEEE-PES International Conference on Smart Grid Technology (ISGT), 2011.

10. Discussion and appraisal of the results

10.1. Grid measurements

The Swiss2G algorithm has the goal to control flexible grid devices (water boilers, batteries, etc.) based on local voltage measurements only. The analysis had shown that often, voltages measured at individual locations of a distribution grid (i.e. below the MV/LV transformer) are correlated during certain weeks / intervals of the year. Knowing about a high correlation for given weeks of the year allows the derivation of knowledge about how voltages at (correlated) nodes change with known real-time voltage measurements at the own local node. Such a statistical knowledge needs the preceding statistically meaningful and continuous measurement of voltages at nodes and times considered critical ("hot spots locations" at "hot time spots").

The analysis showed that significant voltage correlations occurred in critical periods such as winter weeks and summer weeks - where most extreme grid states (lowest and highest voltages) could be observed. They can be detected with the analysis of voltage measurements over a longer period (year).

The analysis indicates that there is strong evidence of correlation between voltages under certain conditions. These conditions depend on the grid topology, the model parameters of the grid elements, the patterns and quantities by which electricity is fed into and taken out of the grid. For example we could prove that voltages measured on the same radial branch of the low voltage grid are strongly correlated. We can identify neighbouring HHs by computing the correlation of their voltage over time .

The correlation between voltage at the appliance and power at the transformer can be further improved by compensating the voltage drops caused by local load.

The analysis indicates that there is high chance that a local voltage-measurement-only algorithm can be applied successfully during known periods (weeks) of the year using only statistical information and real-time metered voltage values.

10.2. Algorithm

We summarize our major findings related to the S2G control algorithm and the results of field tests and simulations. We jointly draw some remarks and observations.

We demonstrated empirically that local voltage magnitude at the low voltage level can be successfully used as a driving signal to load shifting. The analysis of collected data revealed a statistically significant (weak in some cases) correlation between the local voltage and the power at the transformer. Therefore, the voltage signal can be safely used, subject to some elementary processing (i.e. smoothing and randomization), to provide locally a relatively accurate picture of the current status of the LV network.

We have proposed a decentralized control algorithm based on three major characteristics:

- Voltage profile forecasting
- Model predictive control scheme
- Lexicographic multi-objective optimization

Voltage profile forecasting: accurate voltage profile forecasting is crucial to improve the performances of the control algorithm, therefore we have intensified our research efforts and concluded that a relatively simple approach, i.e. Exponential Smoothing, is currently the more effective forecasting techniques that can be used in our context. We found beneficial for the overall performances of the algorithm to identify and discount from the voltage readings the self-induced voltage drops.

Model predictive control scheme: the control algorithm features a simplified model of the systems on which control actions are projected for the next 24 hours. The algorithm is run iteratively every 15 minutes (but shorter periods can be used as well) so that sudden changes in the status of the system are accounted. We found this approach quite effective as the optimization of a simplified model does not rise computational issues and the iterative approach can effectively consider the dynamics of the system.

Lexicographic multi-objective optimization: since the beginning of the project we decided that users' convenience should be one of the objectives to be optimized. An additional, possibly contrasting, objective is to stabilize the low voltage network in terms of power quality (e.g. flatness of the load profile). We have proposed a lexicographic approach to account for both objectives in a hierarchical way: we first optimize the users' convenience and then the network stability. Thanks to this approach, we found that almost flat energy tariffs should be preferred over more dynamic ones in order to avoid massive synchronization of load requests.

11. Conclusions and outlook of the project

The key question of the project S2G was:

"To which extend is it possible to achieve a load management system based on local information from the grid, without an additional communication system, able to integrate decentralized energy generation, to reduce load peaks and to smoothly include self-consumption and storage devices on the one hand, and to omit grid infrastructure investments on the other."

The S2G pilot and demonstration project could demonstrate, via thorough simulations and in-depth-analysis of measured voltages, that a decentralized, local-only voltage measurement approach can be safely adopted for demand side load management as long as there are enough flexible, local loads including batteries to handle also high local PV-infeed peaks and energy balancing over a full day. Under these conditions, on the one hand, the absence of communication and/or centralized control does not result in bad decisions, i.e. no excessive load is put on the transformer. On the other hand, the algorithm systematically improves the stability of the network shifting loads where more appropriate. Stability here is defined as the maximum smoothing of the voltage during the hours of the day.

We have further explored the potential of decentralized, local demand side load management when a non-pervasive communication infrastructure is present between control algorithms. We have investigated the benefits of the coordination - achieved via inter-algorithm communication - of control algorithms organized in subsets with as few as two peers. We found that the overall benefits of massive communication are negligible however better than those obtained with the coordination of as few as two or three control algorithms. In the light of these results we may conclude that the necessary investments to enable a massive coordination of control algorithms for voltage control only (assuming enough flexible local load to handle local PV-infeeds) with a special communication infrastructure and centralized control mechanism may not be justified.

These conclusions are the outcome of a challenging project with ambitious goals related to flexible load management, combining empirical data with sophisticated simulations and algorithms. From a scientific point of view the analysis of the measurement data, the development of the self-learning and self-organizing algorithms and their application to the demand side load management have to be considered as key innovative parts of the project. However, the results would not have been achieved without a considerable effort to develop the measurement devices and to equip the 20 households with them. It is well worth to remind that many technical problems had to be resolved and that without the implementation in a demonstration site, the results and conclusions of the simulations would be much less relevant. The efforts necessary for the development of the technical measurement equipment were underestimated at the beginning of the project and in future need much more attention, as long as data from real-world conditions are considered essential for the investigation and testing of innovative ideas and approaches.

The project was not only a combination of hardware equipment, voltage measurement analysis and software algorithms but also a combination of different technical and scientific disciplines. From the beginning the emerging topic of smart grids was conceived by the whole team as a very interesting field of interdisciplinary research. Yet it proved to be much more difficult to understand each other than expected and the whole project turned out a truly learning process for each member of the team. This learning process is an important outcome and result of the project. It allowed the whole research team to open up new research perspectives in a field with a great potential for further research results. The project team members look forward to the challenges and problems linked to such interdisciplinary projects and endeavors.

In fact, the S2G pilot and demonstration project proved to be a fruitful laboratory for the development of new ideas and projects. Although not all the initiated projects are fully integrated in the S2G households and catchment area, the spirit of the S2G approach is maintained. SUPSI is preparing a follow-up project Swiss4Grid with the goal to keep the existing locations from Swiss2Grid and RiParTI 2.0 increasing the density of EV, PV and stationary batteries and extensively test the industrial solution in development with Alpiq.

Besides the direct results of the project, discussed in the previous chapter, the S2G project was also an important door opener for new projects. The proof of the concept of the decentralized approach and the results allowed the project team to participate in new P&D and industrial projects and to further develop the algorithm.

Ongoing projects

CTI Project - HCD 2.0

A CTI-project was granted. “HCD 2.0 is an innovative and smart EV home charging system equipped with self-learning algorithms that optimizes energy consumption patterns and electrical network stability." (CTI no. 14982.1 PFIW-IW). Within this CTI the S2G algorithm has been implemented in an EV charging equipment. The CTI project is ending in 2014.

Industrial Project with Alpiq – GridSense

SUPSI is collaborating with Alpiq in order to develop a commercial S2G algorithm under the GridSense trademark. The algorithm will be embedded in heat pumps, water heaters, EV stations, PV inverters and stationary batteries.

P&D - RiParTI 2.0 – Private Charging

Infovel Mendrisio is coordinating the following P&D project in collaboration with SUPSI “Evaluation des Ladeverhaltens des Swiss2Grid Algorithmus und des Nutzerverhaltens mittels einer intelligenten Heimladestation” (TP Nr. 8100053-01). Within this project we are testing the EV algorithm with a prototype hardware with 30 EVs in private locations (companies and private households in Ticino. This project is ending in 2014.

P&D Project - Pufferbatterien

Infovel Mendrisio is coordinating the following P&D project in collaboration with SUPSI: “Pufferbatterien für die maximale Nutzung lokal erzeugter erneuerbarer Energie insbesonders in E-Autos” (SI/501006-01). Within this project the S2G algorithm is embedded in a bidirectional fast-charge station for electric vehicles. This project started in 2013 and will end in 2016.

SCCER – Furies

Thanks to the development in the S2G P&D project part of the research team succeeded to enter the Swiss Competence Center on Energy Research for future energy grid infrastructure in January 2012. Mendrisio with its 20 households represents the most advanced pilot project for the demand side load management. The results and conclusion can be introduced in a very competent environment and in the Swiss policy debate on future grid development.

12. Dissemination activities

12.1. Publications

Kriett, P.O., Salani, M. “Optimal control of a residential microgrid”. (2012). Energy 42(1):321-330. doi:10.1016/j.energy.2012.03.049

M. Salani, A. Giusti, G. Di Caro, A. Rizzoli, L. Gambardella. “Lexicographic Multi-objective Optimization for the Unit Commitment Problem and Economic Dispatch in a Microgrid”. Proc. of IEEE-PES International Conference on Smart Grid Technology (ISGT), 2011.

A. Giusti, M. Salani, G. Di Caro, A. Rizzoli, L. Gambardella: "Restricted Neighborhood Communication Improves Decentralized Demand-Side Load Management". 2012. Accepted on IEEE Transactions on Smart Grid.

M. Höckel, T. Häni, S. Eberhart: “Elektromobilität in Verteilnetzen”, Messung, Modellierung und Simulation von Netzen mit dezentralen Erzeugungsanlagen, Speichern und Elektroautos, VSE Bulletin, 9/2012

D. Rivola, A. Giusti, M. Salani, A. Rizzoli, R. Rudel and L. Gambardella, “A decentralized approach to demand side load management: the Swiss2Grid project”, 2013, Published and presented at Energieinformatik 2013, IEEE IECON13

D. Rivola, M. Marzoli, Matteo, D. Chianese and R. Rudel, “High Penetration of Photovoltaic Systems in Residential District: an Innovative Project for the Decentralized Management of the Distributed Generation”, 2013, 28th European PV Solar Energy Conference.

Baggi, Shalako and Rivola, Davide and Medici, Vasco and Corbellini, Gianluca and Strepparava, Davide and Rudel, Roman (2014) Modeling and Simulation of a Residential Neighborhood with Photovoltaic Systems Coupled to Energy Storage Systems. In: EUPVSEC 2014, 29th European PV Solar Energy Conference, 20-25.09.2014, Amsterdam, The Netherlands. (In Press)

Rivola, Davide and Medici, Vasco and Giusti, Alessandro and Rudel, Roman (2014) A Residential Smart Grid Facility for Testing and Evaluation of Decentralized Load Management Strategies. In: EUPVSEC 2014, 29th European PV Solar Energy Conference, 20-25.09.2014, Amsterdam, The Netherlands

12.2. Conferences and meetings

- IEEE-PES International Conference on Smart Grid Technology (ISGT) 2011 - Manchester
- 28th European Photovoltaic Solar Energy Conference – September 2013 – Paris
- Swiss Grid Day - October 2013
- Energieinformatiktagung - November 2013 - Vienna
- ERA-Net plus Tagung - Oktober 2013 – Salzburg
- PV Tagung 2014 – Lausanne
- Brenet Status Seminar 2014 – Zurich
- 29th European Photovoltaic Solar Energy Conference – September 2013 – Amsterdam
- Science Brunch – Netzkonvergenz – zentrale versus dezentrale Intelligenz, FSM Forschungsstitung, Juni 2014, Zürich,
- Powertage, Juni 2014, Zürich
- Energieinformatiktagung - November 2014 - Zürich

12.3. European Label

GRID+ is a Coordination and Support Action which has been created for providing operational support for the development of the European Electricity Grids Initiative (EEGI). The EEGI is one of the European Industrial Initiatives under the Strategic Energy Technology Plan (SET-Plan) which proposes a 9-year European research, development, and demonstration program to accelerate innovation and the development of the electricity networks of the future in Europe.

The Swiss2Grid project received the EEGI Grid+ label, acknowledging that a specific project is in line with the spirit of the EEGI (i.e. knowledge sharing of results, system level innovation, etc.) and an EEGI Functional Objective as specified in the EEGI Research and Innovation Roadmap.

13. References

[1] Swiss2Grid: Simulation eines über Netzgrössen beeinflussten Algorithmus, Masterthesis Syril Eberhart Okt.‘13

[2] DIN EN50160-2010; Voltage characteristics of electricity supplied by public distribution networks

[3] Technical rules for the assessment of network disturbances D-A-CH-CZ 2007

14. Appendix 1: Electrical Utilities and technological changes and challenges: toward a new Business Model

14.1. The disruption of the classic Business Model

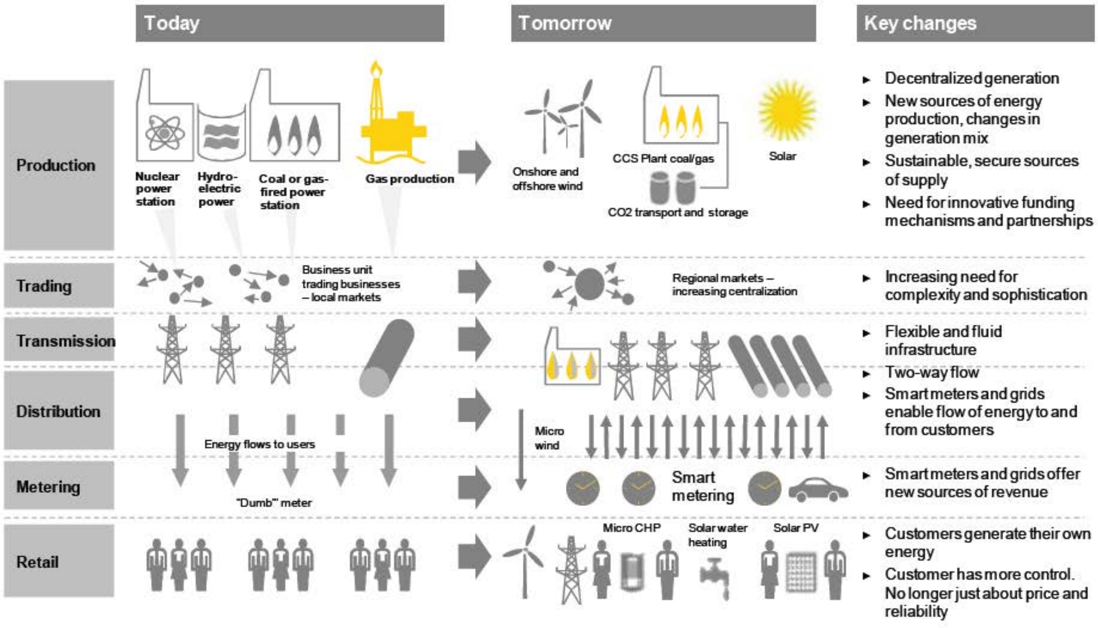
As already pointed out, smart grid investments in local distribution networks offer a variety of potential gains. At the same time is true that full transformation of local distribution systems will take many years and a lot of capital investment; in other words, utilities should be ready to face in the next future significant volumes of expenses.

However, as Joskow (2012) highlight, are the benefits likely to exceed the costs? Does DSOs/retailers will found economically advantageous to adopt smart meters/enabling technologies? Again, is the cost for each kWh saved/shifted recovered by the DSO/retailer?

It (widely) depends on the possibility for utilities involved to develop a new business model, tailored on the new technological and economics dimension. Changes and evolution of technology will affect this business model: firms should be equipped for the new challenges, in particular those related to distributed generation and their consequences on infrastructure and retail business.

- Threats from technological challenges

In the traditional electricity value chain, energy and information flow in one direction, and all but the largest of customers play a passive role. The introduction of smart grid technologies will add complexity to the network, moving power and information in multiple directions and enabling a host of new participants and business model. DG, plug-in electric vehicles and energy storage will extend the value chain to include assets operated closer to the end user. End users themselves, who may be capable of providing some combination of demand response, power or energy storage to the system will also be an integral part of the new value chain.



Source: Ernst & Young

Figure 150: Current and future value chain structure

Growth of DE will force change on utilities' business models. Some of their most profitable customers will reduce their regular power consumption from the central grid in favor of locally produced power. These customers may still depend on the central grid for their emergency or peak use, so utilities will have to maintain their costly infrastructure and power-generating capabilities even as revenues from consumption decline. In many markets, utilities are working with regulators to adapt to this structural change by promoting a pricing model based more on connectivity and capacity and less on usage.

To thrive in this new dynamic, utility executives will need to understand the value chain of distributed energy and related business opportunities. They may need to develop or acquire new capabilities, as well as secure regulatory support, as they move from a focus on centralized generation to models that rely on more customer interaction, commercial and energy services, and information management.

Utilities have to react to those challenges because technology changes will impact on their profitability, basically reducing their revenues from usage-based rates. This situation could be further complicated with the complete market liberalization (retail market included): in this case a progressive reduction in classic business commercial margin will be added to the above mentioned challenges (see also next paragraph).

New opportunities are large, but sometimes traditional utilities are not able to capture them, unlike pure energy services firms. In detail, non-utility entities are actively seeking entry into serving customer electric needs by carving out services traditionally supplied by the monopoly utility This is why there is the necessity to rethink the business model.

- Opportunities from technological challenges

As already pointed out, smart grid investments in local distribution networks offer a variety of potential gains:

- to reduce operation and maintenance costs (goodbye meter readers, manual disconnects, and responses to nonexistent network outages);
- to improve reliability and responses to outages;
- to improve power quality (for example, to eliminate very short disruptions in voltage or frequency);
- to integrate distributed renewable energy sources, especially solar photovoltaic systems installed at customer locations that produce power intermittently and can lead to rapid and wide variations in the (net) demand placed on the distribution network;
- to accommodate demands for recharging of the electric vehicle of the future; to deploy “smart meters” that can measure customers’ real-time consumption and allow for dynamic pricing that reflects wholesale prices; and

to expand the range of products that competing retail suppliers of electricity can offer to customers in those states that have adopted retail competition models.

14.2. The reconstruction of the New Business Model

- Main electricity market drivers and electrical utilities models

As anticipated, the market for electricity is currently changing, facing several challenges/pressures.

- Strongest retail market competition.

The increasing liberalization of the energy market has been accompanied by a parallel intensification of market pressure in the downstream market. Industrial customers first, residential ones then, have exploited their possibility to switch supplier looking for the most economic/efficient one. The main consequence is the stress on prices that, with progressive reduction of inefficiencies and extra-profits, are converging toward the efficient level, at national and international level.

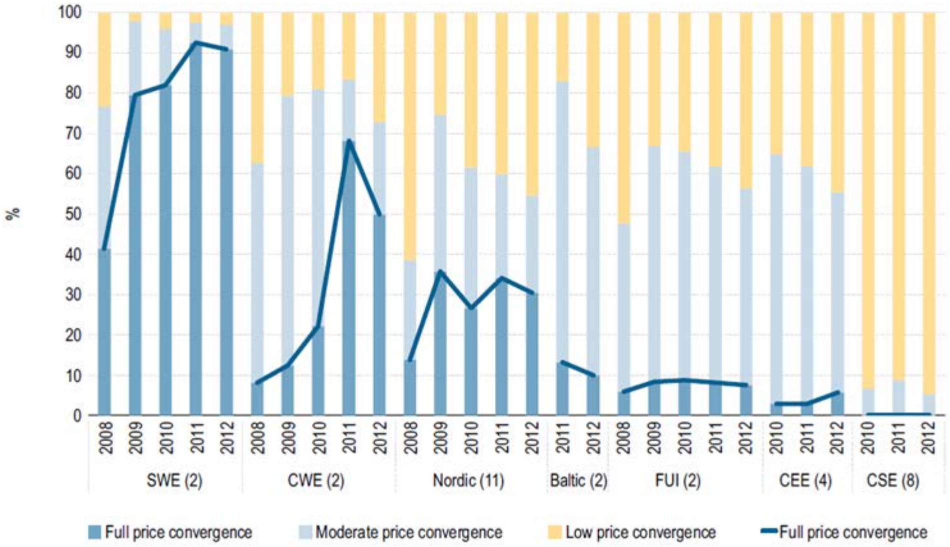
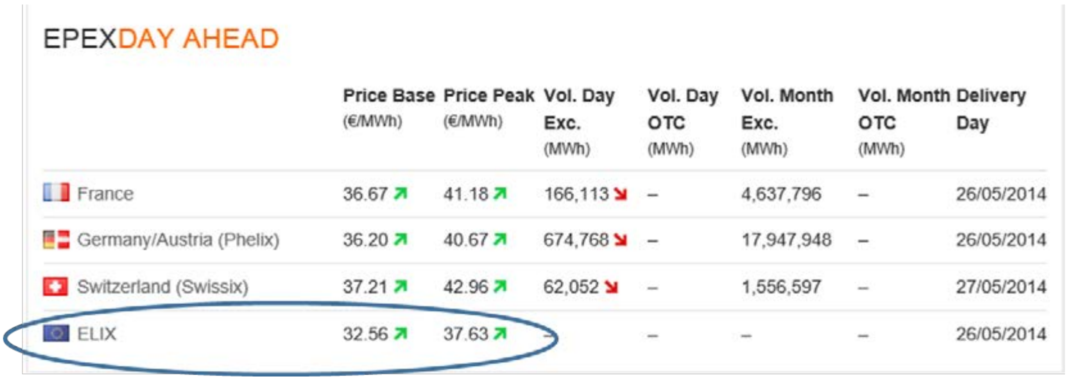


Figure 151: Degree of convergence for prices in European' regions (2008-2012, %).

The efficient level of prices could be represented by the so-called ELIX index, that synthesize the price that could be obtained matching demand and supply in a completely integrated market41. As we can see from the next figure, is lower than all the other spot prices.



EPEXDAY AHEAD

	Price Base (€/MWh)	Price Peak (€/MWh)	Vol. Day Exc. (MWh)	Vol. Day OTC (MWh)	Vol. Month Exc. (MWh)	Vol. Month OTC (MWh)	Delivery Day
France	36.67 ↗	41.18 ↗	166,113 ↘	–	4,637,796	–	26/05/2014
Germany/Austria (Phelix)	36.20 ↗	40.67 ↗	674,768 ↘	–	17,947,948	–	26/05/2014
Switzerland (Swissix)	37.21 ↗	42.96 ↗	62,052 ↘	–	1,556,597	–	27/05/2014
ELIX	32.56 ↗	37.63 ↗	–	–	–	–	26/05/2014

Figure 152: Spot prices and ELIX index. Source: EEX, 04/24/2014

Wholesale prices seems to be still declining, at least up to 2018; a slow growth is forecasted only in 2019.

Phelix future	Cal - 15	Cal- 16	Cal - 17	Cal - 18	Cal - 18	Cal - 20
Base	34,99	34,43	34,00	34,55	35,00	35,73
Peak	44,75	44,12	43,65	44,68	45,93	47,20
Off peak	29,56	29,06	28,66	28,91	28,92	29,34

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[41] ELIX refers to the European Electricity Index; it is calculated and published as ELIX Base and ELIX Peak. ELIX is calculated on the basis of aggregated bid and offer curves for every single hour of the day-ahead auction and according to the rules of spot market. For aggregation of bid and offer curves, market areas Germany, Austria, France and Switzerland are taken into account under the assumption of uncongested transmission capacities between those market areas.

Figure 153: Phelix futures 2015-2020 (€/MWh). Source: European Energy Exchange – EEX – May 2014

As already anticipated, another consequence of liberalization is about retailers‘ commercial margin from supply activity: as the liberalization increase, the margin will decline; sometimes, it could be near to zero or even negative (usually in case of industrial customers portfolio). In this case, not unbundled operators (retailers and distributors) usually compensate this reduction following a cross-subsidization approach: the decrease in profits is partially waged with a stable – sometimes increasing – return on (regulated) network activities.

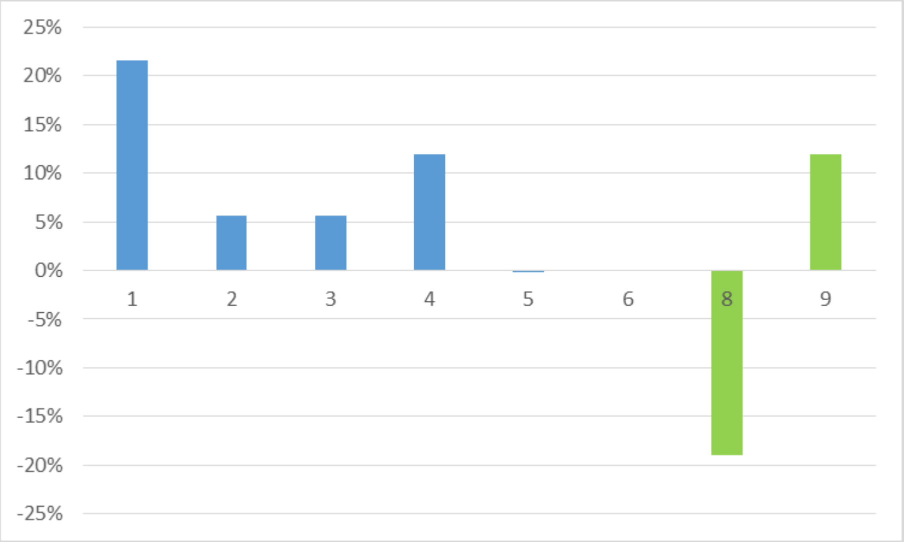

Figure 154: Tessin: Local distributors‘ commercial margin (2012, %). Source: our elaboration on local distributors' data, 2014

The offered services‘ ridefinition will become the key business variable for utilities: they will try to compensate reduction in commercial margin due to a strong increase in price competition with other services, for example energy efficiency, consultancy, financial services.

- Marketing activity

Today's energy and utility companies face intense market and competitive pressures. Companies are challenged with commodity price volatility, government deregulation and asset privatization. Managing these industry cycles is paramount to building shareholder value. Continued industry consolidation and business globalization will require companies to be proactive in capitalizing on new market opportunities. Strong leadership will be the driving force behind the successful company. In the renewed scenario, utilities should invest money and effort in strong market activity in order to increase their base of customers (in particular residential, that give back higher profits). One of the key points is to promote customer loyalty, to segment clients, offering them new value added and tailored services.

- Offering extension

The declining in prices and the observed progressive reduction of the profitability of “classic” electricity business gives room to the development and supply of new services. With this business model, utilities will offer energy and non-energy services.

Retailers are now offering a wider range of products and services in an effort to leverage off their relationship with the customer and build brand loyalty. They usually also collaborate with provider of other services (for example, ICT).

If a utility decide to extend its offer it could obtain several benefits:

- Increase/stabilize revenues, mitigating the risk of competitive pressures on retail market;
- Increase the firm’s profitability due to higher margins of additional, value added not-regulated services;
- Reduce the overall business risk;

- Increase customers loyalty;
- Reduce overall costs thanks to economies of scope.

In terms of revenues impact, the offering extension could increase figures in a range between 1 and 5%. At a first glance it could seem a limited percentage but we have to keep in mind that:

- Those strategies are still at the beginning;
- They could permit to keep customers‘ portfolio
- They present a high marginality (from 10% to 20% on average).

- The role of renewables and distributed generation

Growth of DG will force change on utilities’ business models. Some of their most profitable customers will reduce their regular power consumption from the central grid in favor of locally produced power. These customers may still depend on the central grid for their emergency or peak use, so utilities will have to maintain their costly infrastructure and power-generating capabilities even as revenues from consumption decline. In many markets, utilities are working with regulators to adapt to this structural change by promoting a pricing model based more on connectivity and capacity and less on usage. To thrive in this new dynamic, utility executives will need to understand the value chain of distributed energy and related business opportunities. They may need to develop or acquire new capabilities, as well as secure regulatory support, as they move from a focus on centralized generation to models that rely on more customer interaction, commercial and energy services, and information management.

- Drop in demand electricity growth/Energy efficiency

Efficiency could be an opportunity for utilities and be profitable. Energy efficiency is a way of managing and restraining the growth in energy consumption. Something is more energy efficient if it delivers more services for the same energy input, or the same services for less energy input.

There is potential threat that energy efficiency and “distributed generation,” like rooftop solar could pose to the traditional utility business model. Those “disruptive technologies“ allow consumers to generate their own electricity and reduce their energy consumption might affect utilities themselves. Under utilities’ traditional business models, customer-owned generation and increased energy efficiency reduce the revenue a utility earns. That lost revenue causes the rates other customers pay to increase in order to recoup the cost for the utility’s fixed assets (transmission and distribution wires, power plants, etc.).

Increasing rates consequently improve the value proposition of energy efficiency and consumer-owned generation for the remaining customers, causing more and more people to invest in efficiency and rooftop solar. A vicious cycle begins, resulting in additional lost revenues for the utility and higher rates for the customer base that cannot afford to participate. If the utility industry will not adapt their business models in response to these trends or else they will risk the same fate as the landline telephone industry as cell phones grew in popularity.

The above-mentioned drivers and key issues have shaped recent changes of business models for electric utilities. To deal with the renewed energy market utilities can pursue several strategies; this means that they can operate as:

- ✓ Distribution and services
- ✓ Wires only
- ✓ Services only (ESCOs)

Differences between the above mentioned models are pretty clear. With the first one utilities operate both in the distribution and retail activities, with the second the focus in on infrastructures while the last are new companies providing energy services to final energy users, including the supply and installations of energy efficient equipment; they can also finance or arrange financing for the operation and their remuneration is directly tied to the energy savings achieved.

The details of the new business model could be also linked to the industry structure: for example, a vertically integrated model or a model based on some form of contractual relationship between producers and distributors/retailers could result very attractive. This because:

- o A more integrated firm could invest new risk capital in the development of its business;

    - It could better manage opportunities offered by the supply of ancillary services (see following pages).

- Tariff scheme strategy

A number of variables, both from retailers' and customers' point of view, are likely to influence the uptake and the deployment of new different energy business model for the utilities, able to take up the challenges. In detail, we have already discussed the most interesting pricing schemes, pointing out advantages and disadvantages. Focusing on their relationship with the business model, we may give further considerations.

We observed that, from customers' perspective, new tariffs' schemes and the introduction of new (smart) technologies could determine interesting savings giving at the same time many other opportunities (consumption control, information, etc…).

The key issue for retailers is whether offering new "smart" technologies is going to assist in enhancing or maintaining margins.
In detail, concerning tariffs retailers and distributors have to consider several important aspects such as:

- The majority of the benefits will in the first instance flow to customers (at least for those who are currently being subsidised). In a wider perspective, the overall general impression, based also on the literature and fields experiences, is that the economic and financial convenience with smart meters/AMI seems to be positive if estimated at a global (private and social) level. This because the most important benefits are at a social level (investments' reduction and bills' savings). The result is that in many cases the cost of the meters should be recovered (totally or partially) with systems charges (cross subsidization between "smart consumers" and "not smart");
- The benefits for retailers are primarily about retailing existing customers and winning new (profitable) type of customer (with flatter loads). Overall, the majority of new tariff schemes are unlikely to be particularly margin enhancing for the retailers;
- The cost of the implementation of the technology could be so recovered by revenues from value added services supplied by retailers/DSOs and with a "better quality" of energy purchased from producers/traders (flatter consumption profiles usually correspond to higher profitability);
- Empirical evidence highlight that it would be reasonable that:
    - For bill savings of greater than about 10% a majority of customers will be prepared to move and thus create a competitive threat to the incumbent retailers;
    - For bill savings of between 5%-10% a significant minority of customers will be prepared to move;
    - For bill savings of between 0%-5% a minority of customers will be prepared to move.
    - The same figures could be considered in order to incentive customers to change current tariff rates.

From a general point of view, if customers perceive the risk that they may have to pay more if they change their behaviour this, combined with how little knowledge they generally have of their energy use, is likely to create considerable inertia. This could be a good reason to privilege a PTR approach instead of a RTP one, considering also that results in terms of peak reduction are not very different.

In case of not liberalized/regulated retail domestic market, such as in Switzerland, incumbent doesn't have any threat/pressure from other operators so the decision to adopt different tariffs or new technologies depends more or less exclusively from their profitability (current and future); in any case, they could decide to invest in this new strategies considering the future development of the legislative and regulatory framework toward a completely open and competitive market. This will permit them to be leader instead of followers.

About investments, the main advantage is the reduction of those aimed to increase/maintain the peak capacity. But it's true that a) they do not represent the major part of investment currently planned in Switzerland, b) in any case, from DSOs perspective, their cost could be recovered by final tariff (remunerated with RAB method). In any case, if they don't invest, benefits could be connected to the possibility to not increase the leverage/debt capital.

- Services and new businesses

Research from IBM, Accenture, the Smart Grid Consumer Collaborative and other sources confirms that customers increasingly want energy services. For instance, they want a deeper look at where they are using power, not just a lump sum bill. And they want different rate plan options. Customers' appetite for energy services will grow stronger over the next decade.

In general, utilities will experience expansion into energy services and behind-the-meter assets, either on their own or with third-party partners. Customers increasingly want value-added energy services such as consumption information, consumption controls (load shifting), green energy, demand response, higher reliability, and "energy bundles" -- electricity combined with other products and services (rooftop solar owned by the utility, free air conditioner maintenance if enrolled in demand response, a special rate for electric vehicle owners, and so on.

As those services become more widespread and well-known, consumers will come to expect them from every utility, regardless of the regulatory model under which it operates. In the following pages we’ll present possible services specifically related to smart grids/AMI development.

- Behind the meter services
  Expansion into energy services and behind-the-meter assets, either on their own or with third-party partners. Customers increasingly want value-added energy services such as consumption information, consumption controls (load shifting), green energy, demand response, higher reliability, and "energy bundles" -- electricity combined with other products and services (rooftop solar owned by the utility, free air conditioner maintenance if enrolled in demand response, a special rate for electric vehicle owners, and so on.

- Integrated contracts
  The utility could offers services such as planning, installation, operations and maintenance, load management or demand management. For example, utilities could act as a contractor to manage the energy efficiency of residential buildings, hotels, hospitals or industrial facilities. This could be easier with the help of smart grid and smart meters.

- Energy efficiency solutions
  Contractors often share in the savings from the energy conservation measures they put in place. Dalkia and GETEC Energie offer these kinds of services, and some larger utilities are entering these high-growth businesses, too. For example, E.ON is ramping up its distributed business, having announced investments of nearly €1.4 billion in that area. With a PTR tariff’s scheme credit earned by consumers could be used to buy more energy efficiency appliances[42].

- Big data management

Utilities could process information from smart meters/HAC to reduce risk management, for more sophisticate forecast and, more generally, to make the supply chain more efficient.

- Energy services and ICT
  An increasing number of companies from different sectors (particularly ICT companies) are getting involved in smart grids. These companies still do not play a leading role in most of the projects, but they are setting up new cooperation links which might bring innovation and changes to established business and operational practices (e.g. need for new ICT competencies within DSOs/utilities);
  This result confirms the increasing role of ICT in this sector and the progressive shift of the business model of energy utilities towards a more mixed, hybrid model (utilities as services’ suppliers).

- ▪ Opportunities from DG

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[42] Ofgem states that “we expect suppliers to increasingly develop product offerings in this area in response to government’s climate change commitments and as metering technology evolves”.

There could be main opportunities for utilities in DG: helping customers generate their own energy supply, managing end-user demand for energy and controlling the distribution and consumption of energy.

> The opportunities in this part of the value chain include planning, building, installing and operating the physical assets, as well as the commercial opportunities in financing and managing risk. Many companies are exploring contractor models in which they buy, install and maintain equipment, leasing the supply of electricity to customers (see also financial services).

- Ancillary services

To deal with intermittency and RES forecast errors there is an increasing need for ancillary services. Ancillary services markets should be developed so that customers and generators with flexible consumption or production can "offer" such flexibility to system operators and other market participants. More detailed:

  - Energy produced by RES in peak time (overproduction): when prices are negative, it could be interesting to give TSO/DSOs the possibility to sell to local producers (AET, Ofima and Ofible) energy from RES at a competitive (positive) price for water re-pumping instead of turn-off plant;
  - Market for energy balancing. The possibility to manage/shift load could permit to DSOs to use potential saving in electricity due to the flattering of consume profiles to increase gains participating on the market for balancing/regulation. In case of a relevant number of decentralized producers, the utility could collect the energy and help them to participate as actors on the market for balancing/regulation (pooling regulation).

- Storage programs

  Utilities can invest in storage programs, maybe in collaboration with generation companies (in Tessin this could mean local retailers/distribution together with local producer, AET).

Energy storage systems such as batteries can reduce the need for building peaking power plants. By storing energy during off-peak hours (usually after midnight) and releasing the stored energy during peak hours (usually afternoon), battery storage systems help distribute the load more evenly throughout the day and to reduce peak power demand of buildings. Depending on the capacity, loss factor (charging efficiency), and discharge rate, batteries can be used for energy storage or to supplement power demand.

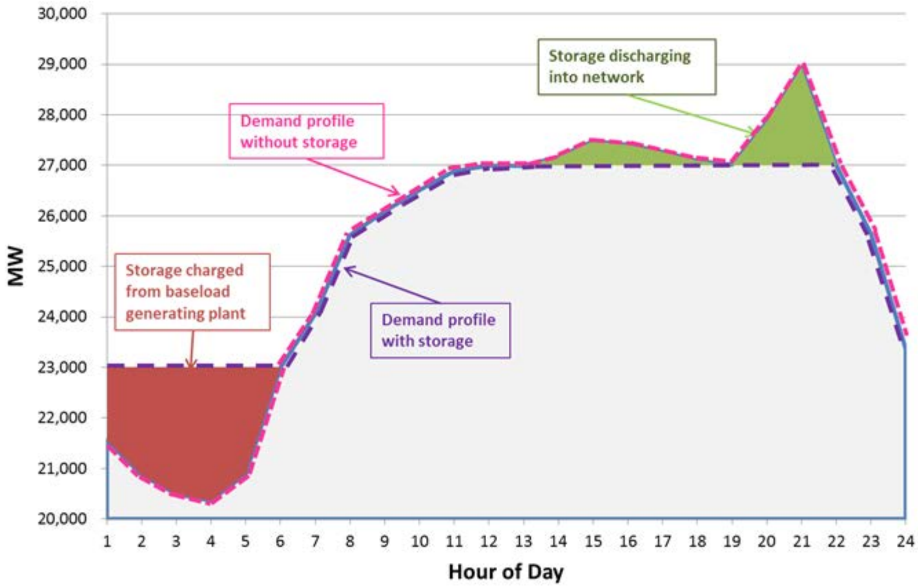

Figure 155: Potentiality from battery storage. Source: Energy Storage Association, 2012.

Some research even points to electric vehicles as potential peak shaving devices. When consumers plug in their cars, the vehicle battery can serve as short-term energy storage, supplying utilities with short bursts of electricity when and if necessary. Denmark has become a leader in this vehicle-to-grid (V2G) technology due to its advanced grid ability to handle renewables — the country has more than twice the amount of renewables on the grid than any other nation and a goal to be fossil fuel free by 2050. In September 2011, a pilot project consisting of 30 EVs will be placed into effect, with hopes to add more quickly. According to a press release about the project, EV owners who enroll in the program will be allowed to sell power back to the grid through their EV batteries and earn up to about $10,000 over the lifespan of the car in compensation. Researchers hope this aspect will serve as an incentive to encourage consumers to purchase EVs and sign up for the V2G program.

Utilities can also offer their own recharge stations for EVs.

- Management of the risk/Financial services

In an increasingly liberalized energy market with opportunities related to new competitive pressures there is room for an innovative role for utilities in terms of supplier of financial services. In particular, they could be active in the hedging activity, in the way already explored in the previous chapter dedicated to the time-varying pricing models.

High penetration of intermittent renewable energy sources will potentially causes short term price volatility in future electricity markets. One of the most critical concerns that customers have voiced in the debate over RTP is that they would be exposed to risk from fluctuations in their electricity cost. The concern seems to be that a customer could find itself consuming a large quantity of power on the day that prices skyrocket, resulting in a high monthly bill. Well, this risk could be eliminated through various straightforward financial instruments (i.e. hedging strategies).

Otherwise, the utility could operate as a provider for financial services (for example, borrowing leasing for the installation of RES plants).