Microgrid Field Trials in Sweden – The village of SIMRIS

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Introduction

Microgrids (MGs) are electricity distribution systems containing loads and Distributed Energy Resources (DER) that can be operated in a controlled, coordinated way, either while connected to the main power network and/or while islanded. MGs have been around for decades in the energy system. They can be commonly found in critical infrastructure building complexes such as military bases, hospitals and data centers.

With the challenges of the new energy world, network operators are starting to look into the technological solutions used in MGs (e.g., MG controllers) as an alternative to their so far conventionally utilized network technologies.

Microgrids status quo

For modern MG operation, a general hierarchical control structure has been developed, that separates control tasks into different levels and time horizons. Concepts are derived from the hierarchical control in transmission grids and are adjusted for the needs of Distribution System Operators (DSOs) and MGs in particular [1]. Just as in classic transmission systems, control is conceptually divided into a zero, primary, secondary and tertiary level. Time constant, resource interconnection and communication needs to increase along with the proposed layers. Figure 1 shows a simplified overview of the tasks of different control levels and an approximation of their respective time frames.

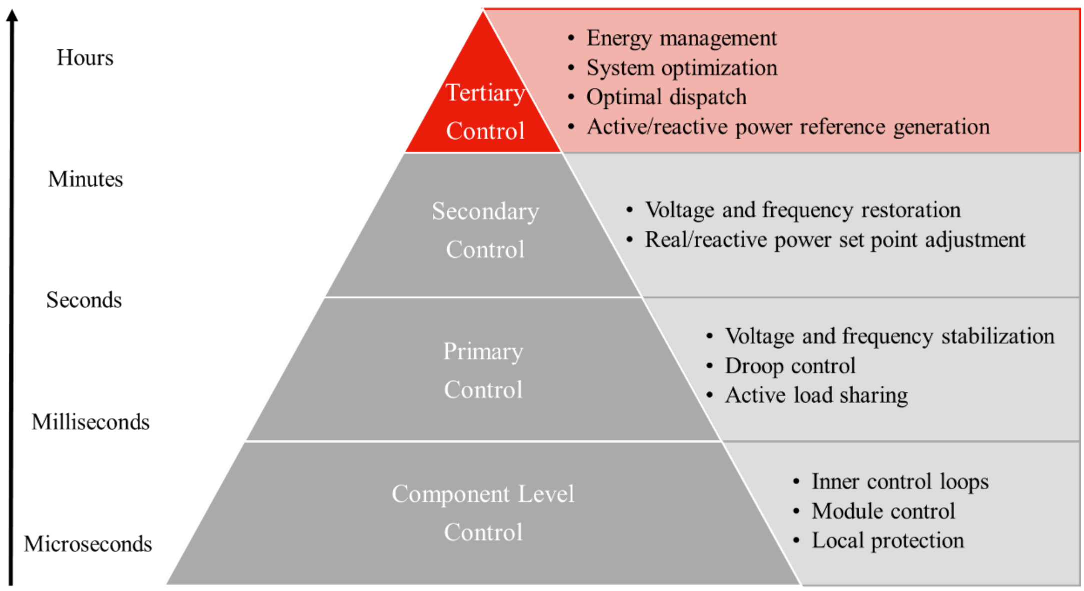

Figure 1: The MG hierarchical control architecture.

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Lower Level Control

The component control level comprises the internal control loops and protection of the employed DERs. This includes the control of classical generators and power electronic devices. The primary control provides amplitude and frequency references for those inner loops, using, e.g., droop control to stabilize the network and to prevent circulation of active and reactive power. Secondary control ensures that frequency and voltage deviations are kept within predefined limits and safeguard appropriate steady-state behavior. An overview of the related approaches can be found in [2].

Higher Level Control

The tertiary level of control is usually assumed as the highest level of technical control in MGs and works on time frames between several minutes and hours. Specifically, the tertiary level fulfills the tasks of steady-state operational planning, power flow control and optimal usage of all DERs. For this purpose, active and reactive power set points are calculated for all actively controlled DERs, based on the expectations about future behavior. An Energy Management System (EMS) is employed in this stage to find the optimum references under a combination of economic and technical objectives. An overview of some EMS strategies is provided in [3]. An important aspect of EMSs in MGs is the inherent uncertainty of the regarded problem. Not only is the behavior of Renewable Energy Sources (RESs) such as wind generators and Photovoltaics (PVs) not perfectly known for the future, the same holds true for the actual electric and thermal demands of consumers. Those tend to be particularly critical in the MG scenario, as the load is often constituted by a single consumer that is much more difficult to predict than larger load aggregations. The forecast of the operationally relevant parameters is therefore an indispensable aspect of high level MG control.

DSOs do not always utilize all the functionalities technically offered by a MG, e.g., switching between islanded and/or interconnected mode; hence network operators talk about Local Energy Systems (LESs). In this context MGs can be seen as a special subgroup of LESs.

Renewable energy sources projections in Europe – Uncertainty scenario for distribution system operators

RESs are a major component of the energy transition in Europe. The member states have set a new target goal for the European Union (EU) to cover at least 32% of gross final energy consumption from renewables by 2030. In the long term (year 2050), the share of RESs should exceed 80%.

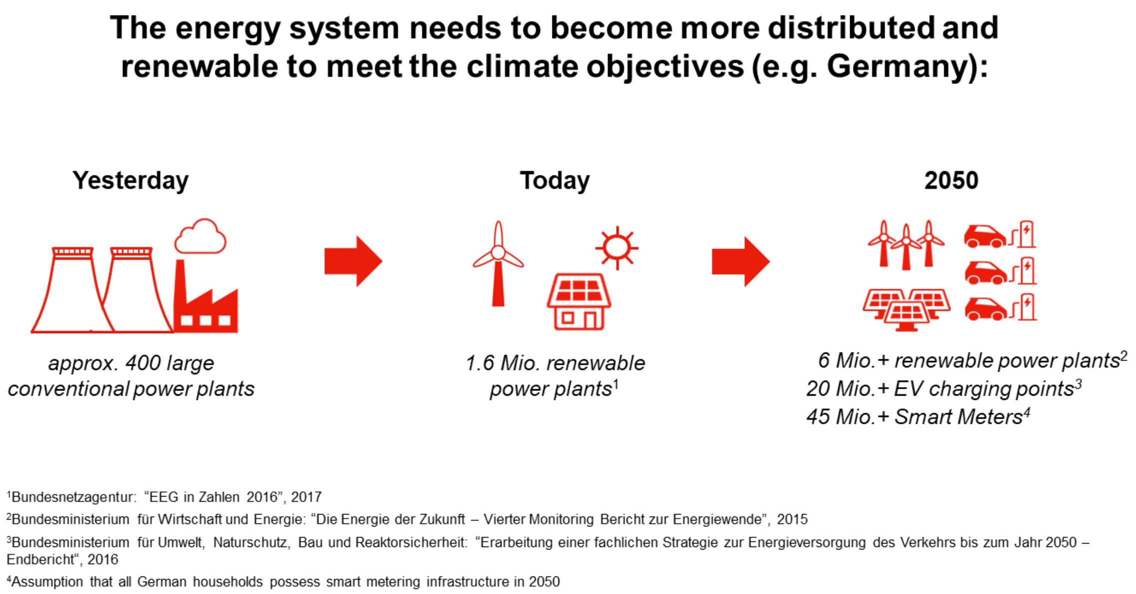

Figure 2: The power system evolution.

The rapid development of RESs induces high investments in distribution networks as the design of most of these networks (designed and deployed decades ago) was not meant and did not foresee the massive connection of DERs. Figure 2 illustrates this rapid evolution of the power system.

In some European countries, network tariffs paid by customers in areas with high penetration of renewables have risen to be the highest values of all national regions (up to 50% higher than the national average price), whereas electricity is consumed elsewhere in the country or beyond. Due to the current regulated business model of DSOs, the costs of renewable energy stay local, but the benefits do not**.** This means that local communities in rural areas do not benefit from RES development due to very high network costs.

The role of the DSO is to distribute power to the connected customers while keeping the power quality within the compliance limits. High network tariffs are caused by the high investment costs linked to RES integration, as new connections can overload the existing distribution assets, disrupt the voltage values at the distribution line or a combination of both. If these problems are not mitigated by the DSO, the protection devices installed at the distribution network, which are meant to protect the system, can therefore cause unwanted local blackout situations.

Due to the nature of the DSO's business, regulation defines the solutions that the DSO can use for the mitigation of network problems. Currently, most of the European DSOs are bounded to invest only in copper (conductor and substation upgrade) or conventional voltage regulation devices (e.g., capacitor banks) instead of using the potential offered by LES flexibility and control. For this reason, high network investment cost in countries with the obligation to connect renewables regardless of the location is a common occurrence despite the uncertain development of RES in such local systems.

Typically, the short-term action of DSOs is to examine which specific types of bottlenecks, including network congestion, and/or voltage issues may occur. DSOs are required to plan appropriate network upgrades in order to remove such bottlenecks in accordance with national regulations. The entire process (planning, permitting and upgrading deployment) takes time, typically two to five years in most of the European member states. First and foremost, sizing the network upgrade faces huge uncertainties when it comes to additional renewable requirements in future involving the related bottleneck risks. In some cases, the uncertainty is so high that the network planners do not know whether the network capacity should be upgraded by three times the current capacity or not to be upgraded at all.

This uncertainty is given as sometimes new market incentives for renewable energy are published and their market uptake is very hard to predict. For example, in one project, new regulations from 2017 incentivized the installation of PV farms up to 500 kW and consequentially promoted customer investment in PV farms to be connected to a 24 km medium-voltage line. The first connection requests to this line have shown that the cost of a grid upgrade to mitigate the voltage disruption created by two distributed generation assets would be at least three times higher than the total investment value of the PV farms themselves. According to current regulation, this cost would then be distributed among all the customers connected in the region, leading to higher grid cost in the area.

Moreover, uncertainty is expected to increase as a wide range of up to 50 additional PV farms could possibly be added to the grid during the validity period of the regulatory incentive. Planning an upgrade to mitigate the problem caused by the two PV farms (reactive approach) might lead to an undersized solution which will need further upgrades in a short to medium term horizon. In contrast, planning for a number of connections which have not been confirmed yet (proactive approach) might lead to an oversized system (stranded investment), which will also generate higher grid fees.

Modular systems seem to be an appropriate answer to mitigate the inherent uncertainty given by the market uptake of RESs. After studies were done in the aforementioned project, it was realized that the use of some specific building blocks of a MG system, e.g. the Battery Energy Storage System (BESS) and the Power Conversion System (PCS), would be up to four time less costly than the alternative conventional grid upgrade when used for mitigating the electricity network disruptions such as voltage deviations caused by newly connected RES plants in a rural area. In addition, the nature of a LES and its modular approach would enable a faster and more cost-appropriate response of the DSO to the connection request of its customers.

Types of local energy systems

LESs can either be connected to existing distribution networks or deployed as off-grid systems. The former represents solutions for local energy communities where network operators already manage the public grid, referred to as *grid-connected* LESs. Grid-connected LESs have the opportunity to operate in an islanded mode meaning that they can be electrically disconnected from the distribution grid. The latter solutions are primarily designed for remote destinations, where no public grid is available, referred to as *off-grid* LESs. Off-grid LESs are characterized by genuine stand-alone networks, i.e., islanded networks. One must additionally distinguish between private and public microgrids as follows:

- **Grid-connected private LES:** The LES is operated by a small or low voltage DSO while satisfying the network codes agreed with the connected DSO. This means that the LES operator must satisfy the regulatory obligations for itself and its LES customers.
- **Grid-connected public LES:** The LES is operated by the connected DSO directly as a service, but possibly with different regulatory obligations for the LES.
- **Off-grid private LES:** The LES is operated by a small or low voltage DSO with or without regulation.
- **Off-grid public LES:** The LES is operated as a utility with or without regulation.

The E.ON project commissioned in the village of Simris, Sweden, is an example of a grid-connected public LES with the opportunity to operate in an islanded mode.

The Simris project

In 2015, E.ON decided to start the design and development of a technical pilot trial, motivated by the expected challenges associated with the increased integration of RESs. This trial will be able to demonstrate that an electrical system can host a penetration of up to 100% of power obtained from renewable sources (PV and a wind turbine) by using field-proven and market available innovative technologies.

For this pilot project, the small village of Simris in the south of Sweden can be connected and disconnected from the main grid in a seamless way while being sourced by times solely by renewably energy coming from a local wind turbine, a PV farm, and rooftop PV installations of the local households.

The LES Simris was created on top of an already existing grid. Within the Simris area, the existing 10 kV distribution system that forms the LES comprises seven substations of 10/0.4 kV of which five supply 150 customers. The feed in point to the LES is via a 20/10 kV substation from a 10 kV bay. The bay is equipped with a power breaker, voltage and current transformers, and relay protection devices.

Figure 3: The Simris energy system.

In addition to the existing grid and RESs, the main assets forming the LES are as follows:

- an intelligent EMS communicating with all power production units so that the LES delivers electricity within the conventional power quality limits.
- a main BESS of 333 kWh / 800 kW, which operates as the grid forming unit and which is in charge of the instantaneous balancing of the MG.
- a state of the art secondary substation (DER-substation), built next to the existing wind turbine and PV plant. The DER-substation is fully equipped with all the necessary communication devices, protective relay devices, and control system devices needed to run the LES.
- a bio-diesel backup generator of 480 kW rated power.
- a Demand Side Response (DSR) platform, which steers smart technologies (e.g., heat pumps, hot tap water boilers, electric vehicle charging stations) for supporting and balancing the MG.

Table 1 provides an overview of all the assets and energy systems present at Simris. Furthermore, Figure 3 shows the Simris energy system comprising the local wind turbine, the PV farm, and the containers hosting the BESS and the backup generator.

The Microgrid Controller: Energy Management System

The safe and reliable operation of the LES is realizable with a three layers energy management approach as shown in Figure 4.

Table 1: The overview on the installed assets and systems at Simris.

System	Description	Manufacturers
Central battery	333 kWh capacity, 830 kW charging, and discharging power	Samsung, Loccioni, TDE Macno
EMS	Controls the LES assets and holds load balancing responsibilities	Encorp
Wind turbine	500 kW nominal power	Enercon
PV plant	PV plant of size 442 kWp	SolarWorld, SMA Solar
Backup generator	480 kW, 4 500 liters bio-diesel tank	Scania, Coromatic
Substations	Interconnects the LES assets, the customers and the main grid	Holtab
DSR platform	Enables the access to distributed flexibility sources by steering smart technologies	ICONICS
Heat pumps	New heat pumps	Nibe
	Retrofit heat pumps	Ngenic
Water boiler	Retrofit device	MClimate
Residential PV and Battery	PV: 10 kWp Battery: 9.6 kWh capacity, 6.4 kW charging, and discharging power	Fronius Solar
E-mobility	Smart electric vehicle charging station	Ensto
Smart meter	Residential metering device	Comsel
Peer-to-peer platform	Visualizes customer energy data	Lumenaza
Local measurement units	Measurement of power, voltage, current, frequency, and other physical parameters	Janitza

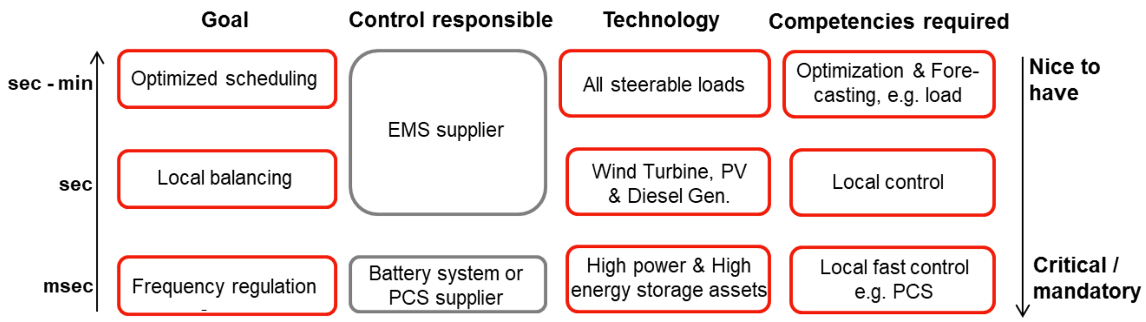

Figure 4: The three layers energy management approach.

The Simris EMS in charge of the load balancing responsibilities consists of industrial field-proven hardware, provided by the company Encorp, located in the BESS shelter, the DER-substation, and in the Simris primary substation. In each location, the EMS has access to relevant information, such as measurements from current and voltage transformers, indication of status from power breakers and disconnectors. In addition, the EMS has direct control over the power breaker at the Point of Common Coupling (PCC) so that it can command island mode by switching off the breaker when certain requirements are fulfilled.

The RES generation is also controlled by the EMS which can demand the RESs to be curtailed if the BESS State of Charge (SoC) reaches certain levels. During times of high demand and low generation, the EMS can demand the combustion engine-driven backup generator to be activated and extend the time in island mode.

The EMS controls the operational mode of the battery system and sets the target voltage and frequency when operating as an island. An overview of the components and their dependencies is illustrated in Figure 5.

The Simris EMS can operate in different modes depending on the desired function, as presented later.

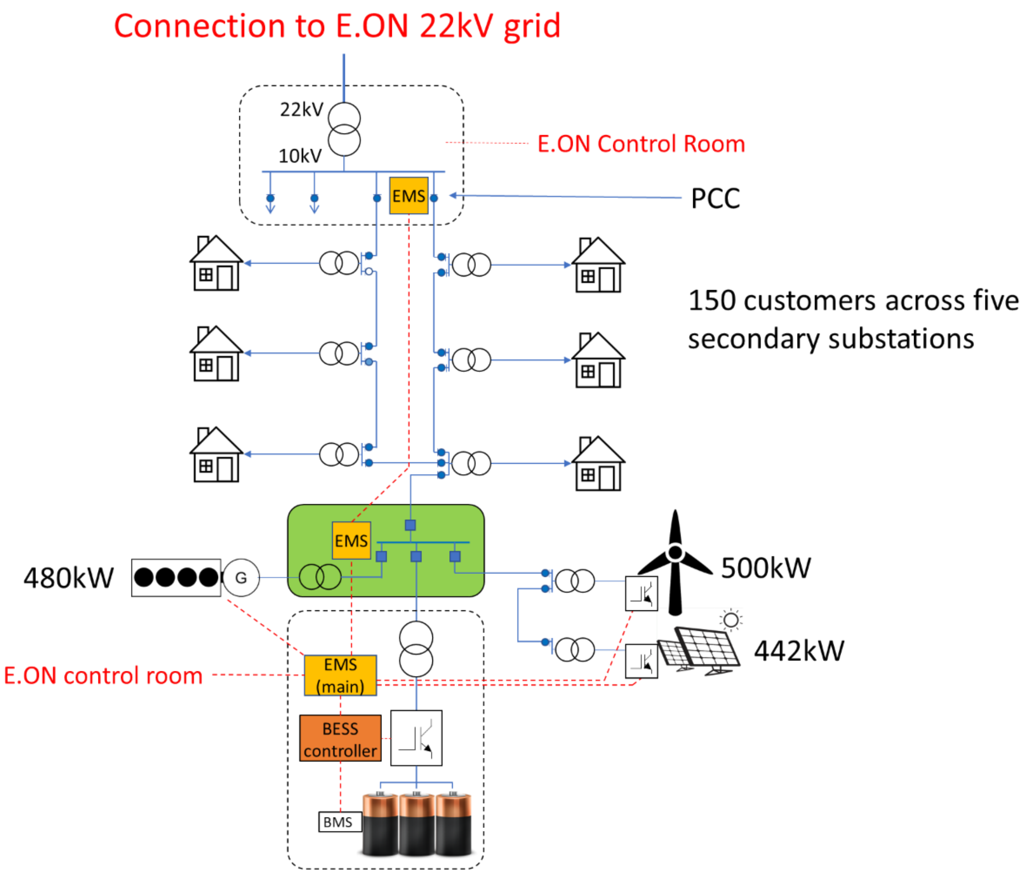

Figure 5: The system and component overview in Simris.

Virtual island mode

In Virtual Island mode, the EMS controls the active and reactive power set points to the BESS such that no exchange occurs over the PCC. In other words, in the virtual island mode, the PCS controller running in Current-source-inverter (Csi) mode operates as a grid-following unit. It is also possible to change the "exchange" set point over the PCC to any value, within the capabilities of the battery system and restrictions of the power system. Thus, the MG can either consume or inject active and reactive power to the overlying grid depending on current conditions and the state of the grid. This type of ancillary services could be of great value in future complex power systems. Balancing could be managed locally with several distributed LESs during peak load hours. In this scenario, LESs provide anciliary services to the overlying grid by adapting their power consumption and generation. This would increase the overall grid hosting capacity by keeping the voltage levels within limits, despite of the fast varying power flows given by the intermittance of RESs.

Intentional island mode

In the intentional island mode, the PCS controller running in the Voltage-source-inverter (Vsi) mode operates as the grid-forming unit in droop for both power as a function of frequency and reactive power as a function of voltage and allows the BESS to seamlessly transition between the grid-connected and islanded operating modes. To physically island the system, the EMS measures the real and reactive power across the PCC and sets the voltage and frequency targets for the battery system such that real and reactive power are near zero. The system is then ready to be islanded and the EMS triggers the circuit breaker to open. The battery system does not change operating mode, but assumes the responsibility for managing the island voltage and frequency. The EMS updates the voltage and frequency targets when islanded to maintain a constant 10.7 kV / 50 Hz as these will vary along the BESS droop curves with changing active and reactive power. However, the control in the EMS is relatively slow, such that a power imbalance allows the frequency and voltage to transiently change before being trimmed back.

To reconnect to the grid, the EMS controls the voltage and frequency to match the grid voltage and frequency, i.e., it synchronizes the systems. Once within prescribed limits, the EMS closes the circuit breaker.

In the diagram in Figure 6, the system was physically islanded, operating from the wind turbine, the PV farm, the backup generator and the BESS. At 11:08:30, the BESS SoC was low, triggering the EMS to start the backup generator, which ran up to a controlled 350 kW. During the power increase, the BESS allowed the frequency to increase along its droop curve, and the EMS subsequently trimmed the frequency back to nominal. At 11:11:40, the wind turbine tripped, and the BESS allowed the frequency to reduce along its droop curve. During this frequency reduction, the backup generator power contribution increased slightly due to the system inertia. The EMS subsequently updated the target frequency to return the system to a nominal 50 Hz. Customer supply was maintained within statutory limits throughout.

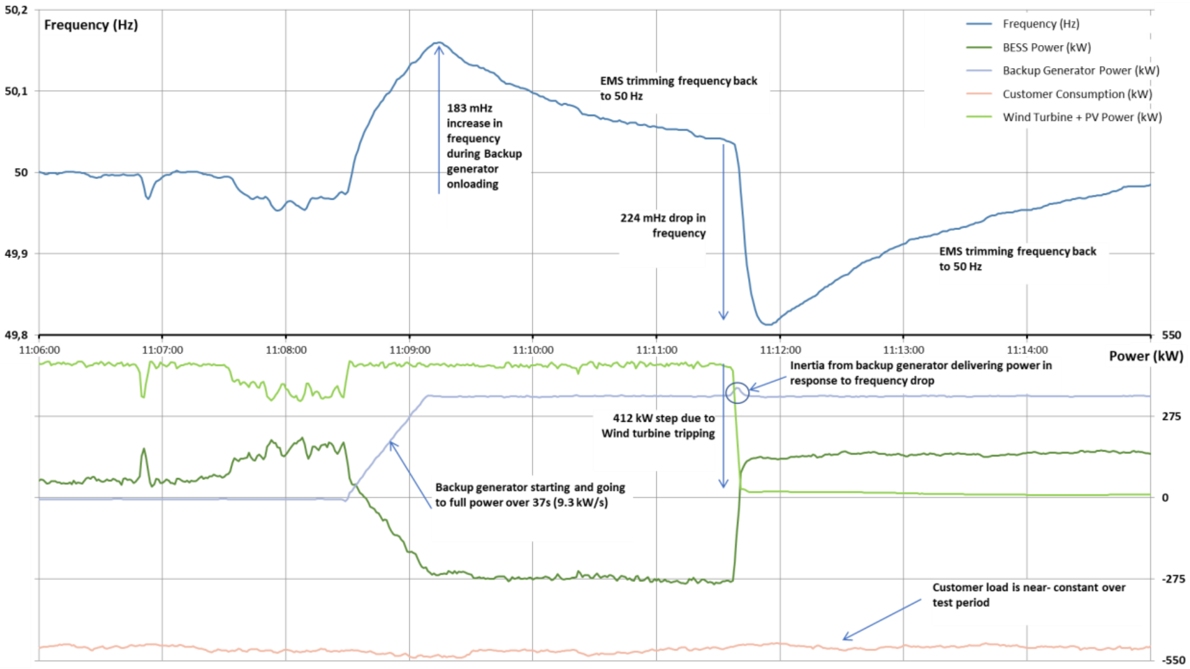

Figure 6: The frequency and powers during backup generator starting and the wind turbine tripping.

Longer term testing comparing the frequency, voltage, and Total Harmonic Distortion (THD) of the system when islanded to the same parameters for the local Nordic power system shows that the LES had better power quality when islanded than it would have had when grid-connected.

Figure 7, Figure 8 and Figure 9 show the comparison for islanding testing on 12 April 2018, where the system was islanded from 8:00 a.m. to 8:00 p.m. All figures show the results from the LES when in Intentional Island mode in the upper trace and the Nordic power system in the lower trace.

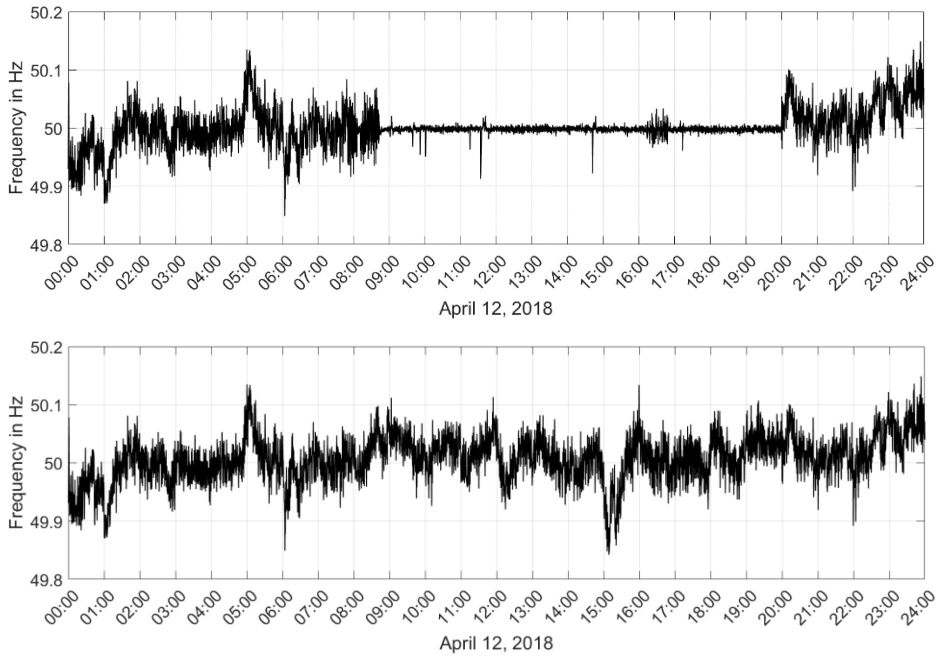

Figure 7: The frequency when islanded.

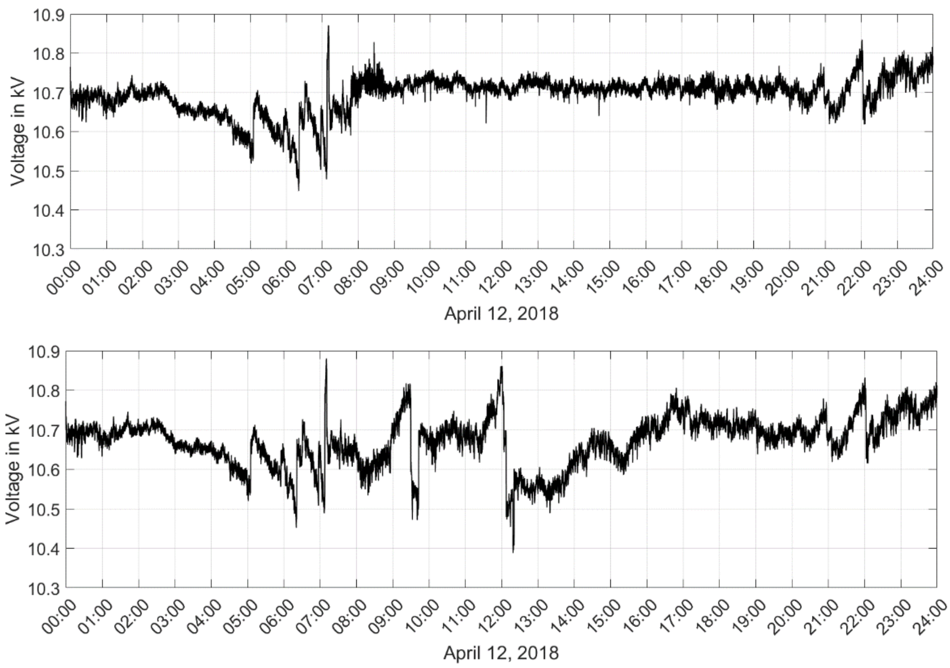

Figure 8: The voltage when islanded.

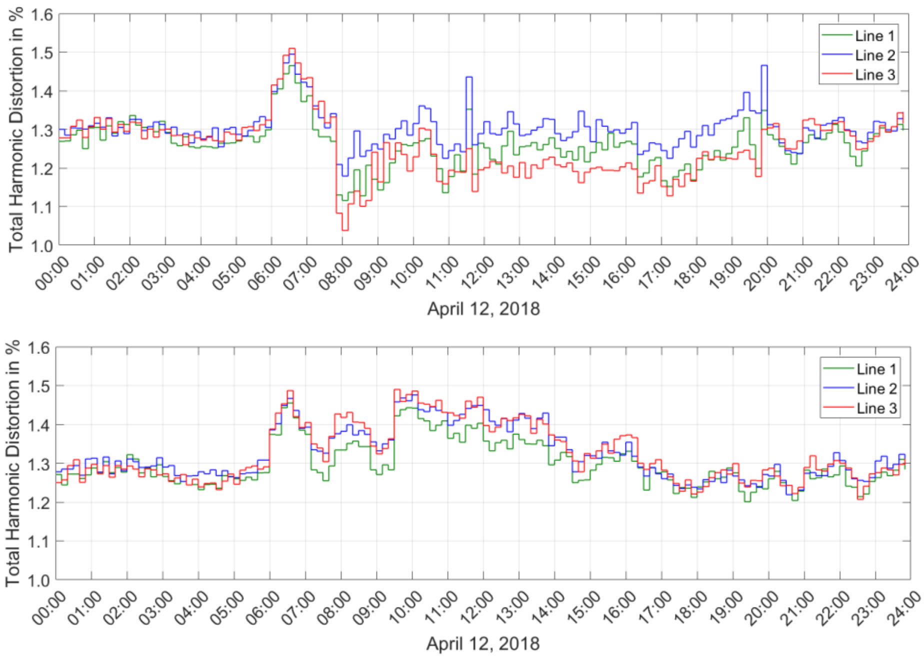

Figure 9: The total harmonic distortion when islanded.

Battery Energy Storage Systems

In the Simris project, the BESS is a core element of the LES. When islanded, it acts as the grid-forming unit and sets both the voltage amplitude and frequency.

The BESS selected for the project is characterized by a rated power of 800 kW, an energy capacity of 333 kWh and includes PCS functions allowing for islanding.

The BESS includes three key control components controlling the system operation:

1) the Battery Management System (BMS), responsible for SoC estimations and enforcing battery system limits
2) the PCS inverter control, responsible for the high-speed switching of the power electronics to manage the different operating modes
3) the battery system controller, including a state machine for different operating modes and manages transitions between states

A summary of the key components is shown in Figure 10. The BESS control system state flow diagram is shown in Figure 11.

The different states are requested by the EMS, and the BESS controller then implements the mode to the PCS. The previously described control structure allows the high-speed operation to be managed at a local level (inverter switching at 2.5 kHz), the BESS controller controlling the local interfaces and operating modes, and the EMS managing the system demands at around 1 Hz communication update.

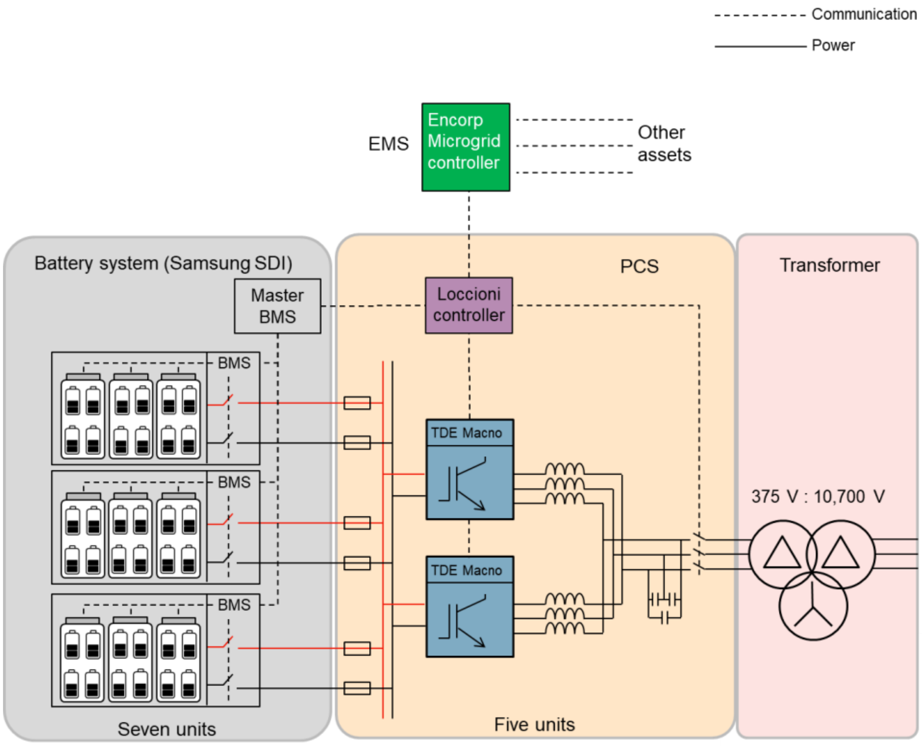

Figure 10: The overview of the BESS components.

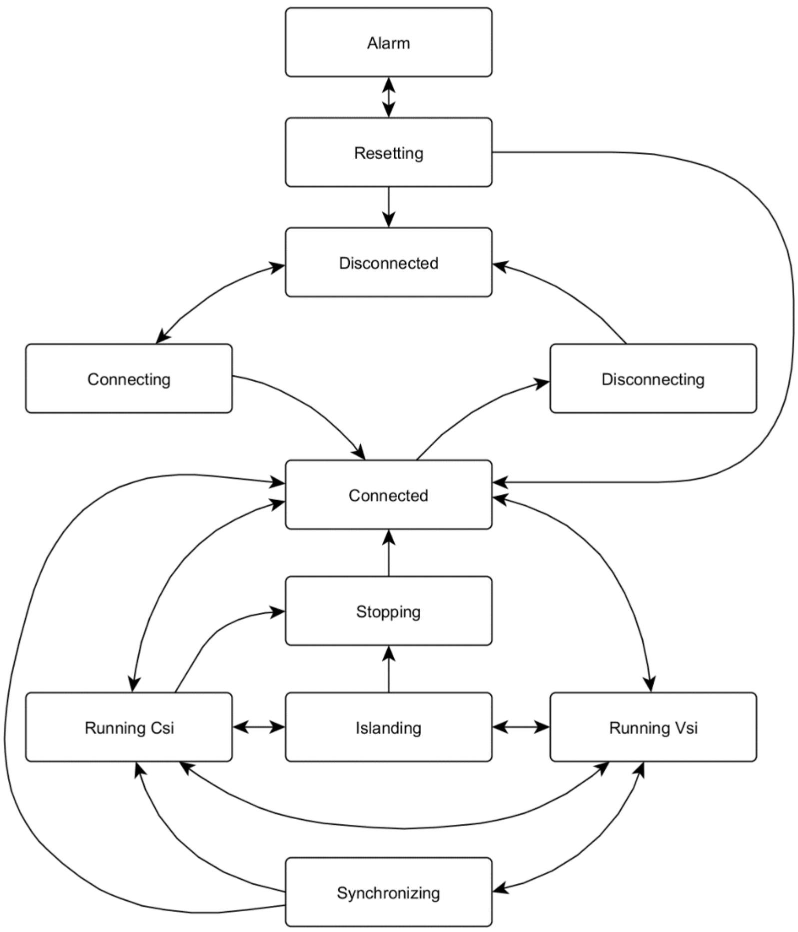

Figure 11: The BESS state controller.

Short-circuit operation was tested by introducing single-phase and three-phase faults to a low voltage circuit protected by 63 A fuses while islanded. Figure 12 shows the system voltage for a three-phase fault while operating on BESS only, where the battery system terminal voltage was reduced to 86% during fault clearance and nominal voltage was restored within 200 milliseconds.

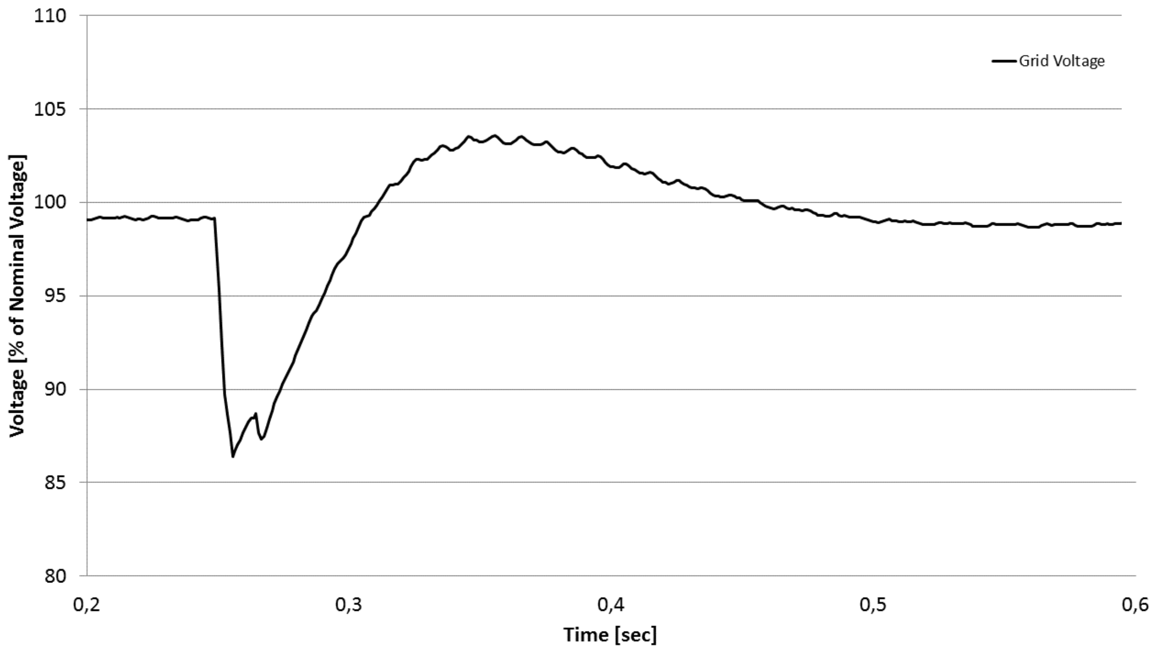

Figure 12: The voltage during short circuit testing.

Demand Side Response

A final balancing element connected to the EMS is the DSR platform. This platform enables the access to diverse distributed flexibility sources connected at the customer's premises.

The platform is capable of the following:

- deliver a real-time data platform for monitoring and control
- provide control loops to optimize energy usage in the LES
- offer real-time connectivity to assets and external platforms
- provide open connectivity to extend services to the system operator and flexibility marketplaces
- simplify integration of new asset types to expand the asset base
- visualize key performance indicators, monitor energy consumption, steer signals, and show user interaction (peer-to-peer platform)

As shown in Figure 13, the DSR technologies used in the Simris project are residential PVs and battery solutions, steerable heat pumps as well as hot tap water boilers, and an e-mobility charging station.

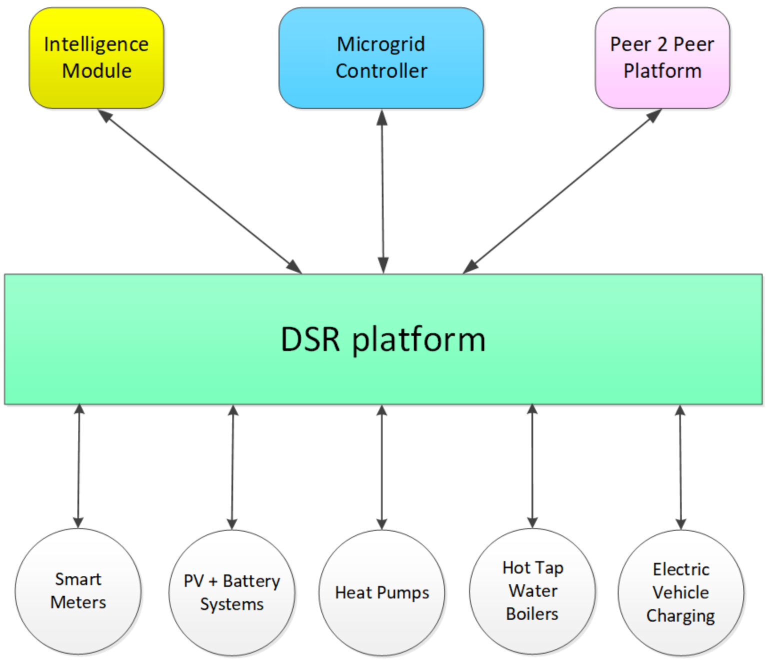

Figure 13: The DSR platform.

Photovoltaics and battery systems

PVs and battery systems enable the customers to be more self-reliant and to reduce the feed-in from the grid. Roof-top installed PV panels produce energy in the daytime and the battery allows excess energy to be stored. In case the overall load demand exceeds the PV generation, the battery is discharged allowing the stored energy to be utilized for either self-consumption or auxiliary grid balancing services. As the market penetration for this solution is increasing and due to the versatility of the battery, it is expected to become a vital part of the future energy system.

One general concern regarding battery storage in MGs is how much flexibility it will be able to provide. At a brief glance, the PVs and battery systems seem to be a great source of flexibility for the LES. However, when the LES is characterized by an excess of energy, due to high power generation in the central PV power plant, the batteries are likely to be charged by the household solar power generation alone since the residential PV would also provide maximum output. Hence, there might be little additional storage capacity left to utilize for grid balancing services through DSR. Likewise, a lack of solar power production yields an energy deficit in the system while at the same time it is unlikely for the batteries to have stored enough energy to support the grid during those times.

One of the DSR strategies is based on residential battery power control. Every five minutes, a set point is sent from the DSR platform to each of the residential batteries. An example of one of the control approaches can be seen in Figure 14, where the residential battery power set points to be sent out by the DSR platform are a result of the current main battery's SoC. The control strategy is intended to support the operation of the main battery in cases it suffers from low or high SoC levels. In the former case, the residential batteries are requested to discharge, whereas in the latter case the residential batteries are requested to charge. Elsewise, i.e., between a 30% and 70% main battery SoC deadband, the residential batteries can operate in their usual operation modes as defined by the customers.

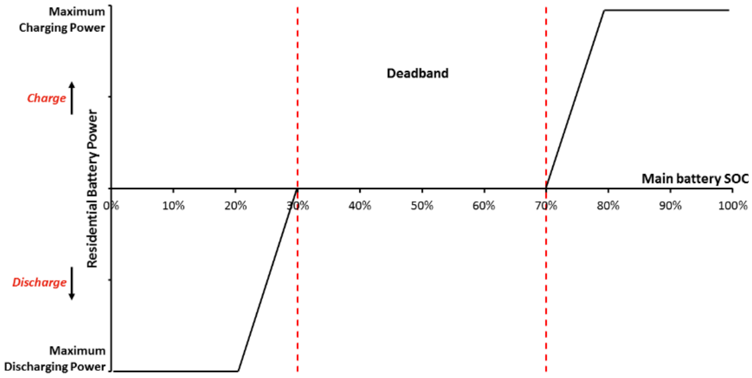

Figure 14: The residential battery control.

Heat pumps

Electrical heat pumps are a common source of heating for Swedish households and are major electricity consumers relative to other appliances in a residence. In Sweden, around 60% of the total household energy consumption is allocated to meet heating demands. In addition, due to the thermal inertia of buildings, it is possible to turn a heat pump off for a long period of time without the indoor temperature dropping more than 1 °C from the initial temperature. For these reasons, electrical heat pumps offer an opportunity to help balancing the power demand and supply in the grid. An estimation of the overall Swedish flexibility potential in heat pumps is in the size of gigawatts, thus providing an excellent foundation for scalability.

Heat pumps can provide both negative and positive flexibility since it is possible to both increase and decrease heating demand. However, the available flexibility is largely dependent on the outdoor temperature as represented in Table 2. The specific temperatures are dependent on the heat pump technology installed and other factors such as wind, sun, heat generation from internal electrical loads, and people.

During warm weather, there is a theoretical potential for flexibility but as temperatures exceed 15 °C, the heat pump is often turned off as there is enough thermal energy to keep a comfortable indoor climate. At colder temperatures, around -15 °C and below, the heat pump most likely operates at maximum capacity, unless the heat pump is over-dimensioned, and therefore it is only possible to decrease the power output. In-between, it is possible to both increase and decrease the demand. By how much depends on the current outdoor temperature.

Rather than a signal based on the power in kW, the DSR platform creates a steering signal in percentage, based on the main battery SoC in a range between 100% (maximum power increase) and -100% (maximum power decrease). To ensure that customer comfort is always maintained, a boundary control is implemented, disabling DSR control if the indoor temperature deviates by more than ±1 °C from the customer-set indoor comfort temperature range.

Table 2: The flexibility potential based on the outdoor temperature.

Outdoor temperature	Flexibility potential
> 15 °C	No flexibility
0 °C	Increase/decrease heat demand
< -15 °C	Decrease heat demand

Hot tap water boilers

Hot tap water boilers offer a cheap opportunity to increase the flexibility in a household. Since the energy is stored as heat and cannot be converted back to electricity, it is however less versatile than a battery. During excess energy production in the LES, the hot water tanks can be heated reducing the need to heat water at other times such as when the system has a deficit of energy production. Additionally, one might also think about the option to stop the hot tap water boilers from heating as usual but in a way to not disturb customer comfort. However, since the heating patterns of a boiler tend to be highly sporadic, the risk of a negative impact on customer comfort, by not having hot water when needed, is considered within the project, for which reason a remote control will only manage heating water during excess energy generation. The introduced control system, therefore, does never affect the customer comfort.

By monitoring the household consumption patterns, the hot tap water boiler device will know when and how much water will be consumed and will minimize the boiler's hot water tank heat losses by pre-heating it just in time. For this purpose, temperature measurements to the inlet and outlet pipes of the water tank are necessary. The local hot tap water boiler's steering device will receive steering signals from the DSR platform using smart meter technology and thus the water tanks will be managed by remotely setting the heating mode.

Electric vehicles

Electric vehicles connected to a smart charging station can be a source of flexibility to support the penetration of renewable energy, by controlling the steerable Electric Vehicle Supply Equipment (EVSE) current output in response to the fluctuating balancing requirements of the system. A EVSE is integrated in the project at Simris and connected to the DSR platform. The DSR platform is able to send periodic steering signals to the EVSE via a back-end, limiting the amount of energy the charging station is providing over time. A graphical view of the control logic for the abovementioned example is shown in Figure 15.

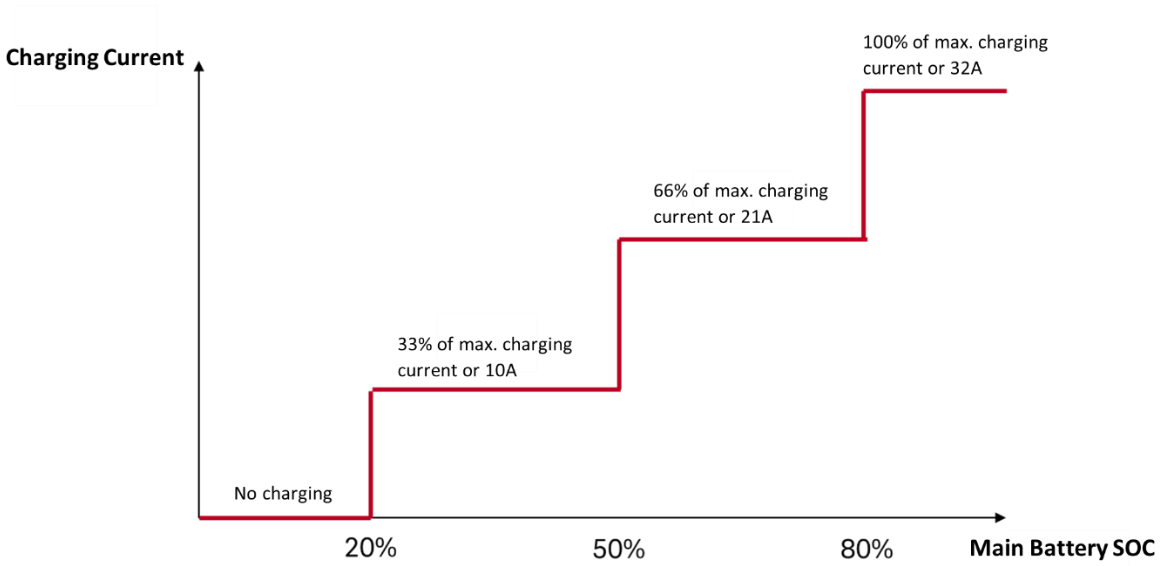

Figure 15: The electric vehicle charging control.

RWTH Aachen University's Contribution to the Project with the Study and Simulation of an Advanced Control Strategy

The RWTH Aachen University has closely collaborated with the E.ON team in defining alternative ways to control MG systems. This project activities of RWTH Aachen University are aimed particularly at providing a long-term evaluation of EMS optimization for MGs in a more general way. Special focus is on the ability to switch to and to continuously stay in islanded operation mode. Furthermore, the effects of active control on the predictability of MG behavior are examined. This includes the following aspects:

- Developing a central EMS and showing its viability for MGs other than the Simris LES but based on some of the Simris up-to-date measures. In particular, the full inclusion of an exact relaxation of the power flow equations is used to make best use of reactive power capabilities and to take equipment constraints into account.
- Comparing the effects of different operational objectives on a larger scale simulation based on the developed test system and the EMS. A whole year of simulated operation, based on measurements obtained from the Simris field trial site, is evaluated. This also allows to show some trade-offs to be made and critical disadvantages in the focus on certain objectives.
- Performing a comprehensive analysis of the maximum possible time-frame for islanding operation under different operational objectives.
- Developing data science-based forecasting methods to predict the behavior of the generation and loads in a MG.
- Analyzing the behavior of a MG and its EMS when it is only seen as a single point of load connected at the PCC. The main focus of the analysis is to show how the effects of active control by an EMS deteriorates with reduced forecasting accuracy. It is analyzed how different operational objectives also result in different behavioral patterns, which pose a varying degree of difficulty in the prediction.

One of the possible approaches for MG control is a hierarchical control structure as used in the Simris project. The optimization problem is solved by a single entity for all parameters. Therefore, all relevant data has to be gathered by the central system and schedules are then distributed to all entities after the computation is finished. The RWTH Aachen University considers these controls' capabilities and their master/slave communication model.

A general form of an optimization-based EMS is described by a set of generic equations. A desired objective function C is minimized over a certain time period T with a timestep length Δt considering the system state $x(t)$ at a time t (for example system voltages, current, stored energy, and others), the inputs $u(t)$ at a time, which in our case are the real and reactive power references and set points, and the cost or fitness $f(x(t), u(t))$ at the time t. This objective function can be subject to various boundary conditions including:

- model equations (e.g., power flow equations, equipment constraints, and so on)
- energy limits
- power and voltage limits

$$argmin_{\boldsymbol{u}}\, C(\boldsymbol{x}(t), \boldsymbol{u}(t)) = \sum_{t=1}^{T} f(\boldsymbol{x}(t), \boldsymbol{u}(t))$$

In EMSs, a simple distinction can be made between sub-classes of convex problems solved with classic-, gradient- or Hessian-based methods and non-classic methods that may not be convex and include heuristics. If peak shaving of, e.g., power consumption is considered [4], objectives tend to be quadratic, leading to a Quadratic Problem (QP). Recently, Second Order Cone Programming (SOCP) [5] and Semi Definite Programming (SDP) [6] formulations have also become popular, as they allow the exact relaxation of grid constraints for radial networks. Another important aspect is whether binary variables (or integer variables in more general terms) are considered. These require additional Mixed-Integer Programming (MIP) solving methods, that increase computation time and make the distribution of the control problem challenging to solve it in a limited time horizon. Mixed-integer formulations are often employed because they allow an easy inclusion of varying behavior patterns for single resources. This becomes relevant for the inclusion of generator start-up constraints, piece-wise linear approximations of non-linear cost functions or reconfigurable switches in the network.

An optimization-based EMS can be operated both in an open- and closed-loop form referring to control theory terminology. Early approaches usually adopt the concept of day-ahead scheduling, i.e., a single optimization and implementation of set points, based on the prediction for a whole day [7]. Most concurrent approaches, however, make use of a receding horizon implementation, which includes a feedback-loop for MG states and re-optimizes the behavior at every time step. Optimization is performed for a discrete time step length that requires averaging of behavior for that period, forecasted values of future behavior, and possibly simplified models.

The proposed developed controller uses the concept of Model Predictive Control (MPC) that has become an interesting approach for energy management purposes in MGs in recent years. The MPC provides set points for the energy storage charging/discharging power as well as set points for the curtailment of renewables and their reactive power output. The state of the system consists of the SoC of the energy storage devices. One time step within the calculations is one hour. The MPC is designed, for instance, to minimize the exchange of energy with the main grid, covering demand of the customers, and fulfilling the energy balance. This approach could potentially prolong the islanding mode of the microgrid but was shown to have an adverse effect on islanding based on actual implementation [8].

Model predictive control

A MPC is an advanced control technique for multivariable control problems. MPCs use an internal model of a system to generate predictions of the system's future behavior. The designed MPC finds an optimal plan for running the assets (by defining control set points) for each time step over the prediction horizon starting at the current time step. The optimization is based on predictions of the upcoming demand, production from RESs and prediction for the state of the system. A general depiction of the methodology is presented in Figure 16.

For the optimization, only the first control input is implemented, and subsequently the time horizon is shifted by one time step. At the next time step, the new state of the system is measured or estimated, and a new optimization is performed while considering the new information. This approach is called a rolling horizon control.

The control horizon can be chosen to be lower than the prediction horizon within the formulation to deal with the time lag of computational intensive calculations. If the control horizon is set to be lower than the prediction horizon, it could be assumed that the last calculated control variables remain the same until the end of the prediction horizon. The predictions needed for the application of MPC could be assumed as perfect in the MPC statement, i.e., not affected by errors, as the consistent set point recalculation will already provide a means of disturbance rejection. Extensions to robust or stochastic optimization approaches [9] are, however, possible.

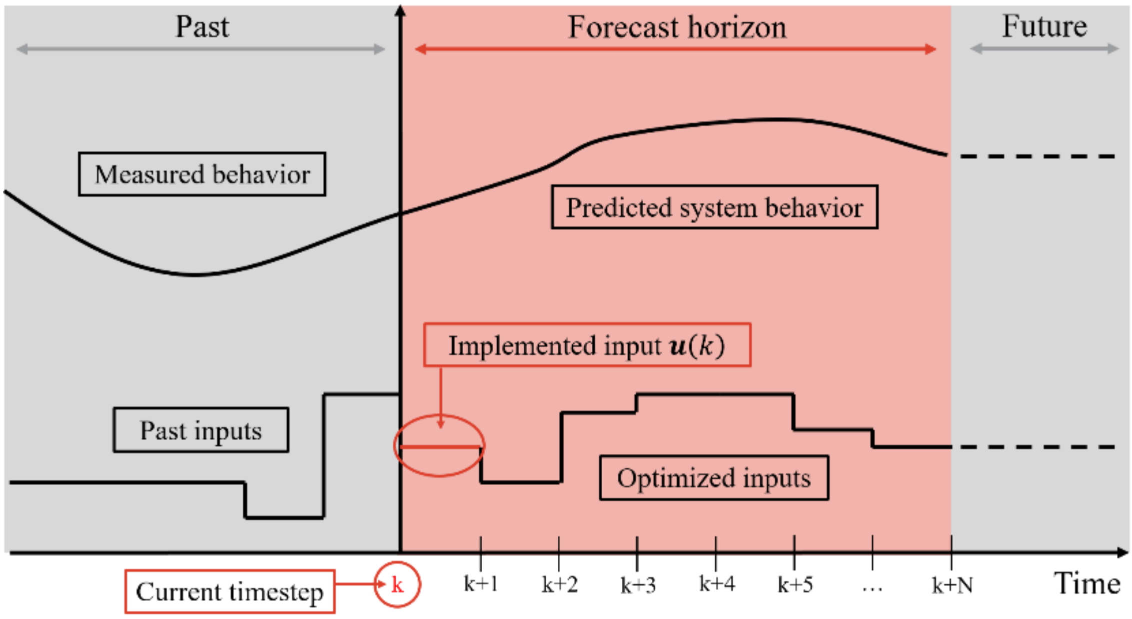

Figure 16: The MPC prediction and control horizon.

In the current LES Simris activities and beyond, RWTH Aachen University is evaluating a combination of the following objective functions (compare Table 3):

- the minimization of the summed costs of all assets J_c
- the minimization of the energy losses J_l
- the maximization of local energy use in order to satisfy the local self-consumption desire of certain local energy systems J_p
- the minimization of the grid-connected time while avoiding consecutive connection and disconnection from the grid J_δ

These four objective functions are evaluated in three cases:

- Case A: Economic value – minimizing the operation costs for the MG which combines the operation cost minimization and the loss minimization
- Case B: Local use of energy which is a weighted function of the exchanges with the power grid and the losses
- Case C: Potential Islanding Time (PIT) maximization, which sets the PIT as a primary objective meanwhile the secondary objective is the pure cost minimization.

Table 3: The objective functions evaluated by RWTH Aachen University.

Operational cost minimization	Loss minimization
$J_c = \sum_{t=1}^{T} \text{cost of power import at time } t - \sum_{t=1}^{T} \text{revenue of power export at time } t + \sum_{t=1}^{T} \text{cost of all assets at time } t$	$J_l = \sum_{t=1}^{T} \sum_{(i,j)\in\mathcal{E}} P_{i,j,loss}$
Minimization of power exchange with the main grid	**Maximization of possible islanding time (PIT) after t_{island}**
$J_p = \sum_{t=1}^{T} P_{imp}(t) - P_{exp}(t)$	$J_\delta = \sum_{t=t_{island}}^{T} \delta_{PCC}(t)$ $s.t. \quad \delta_{PCC}(t+1) \geq \delta_{PCC}(t)$

The evaluation of one year of operation in a test, shown in Figure 17, shows how the different operational strategies impact operation costs, the energy exchange, and the line losses. Obviously, direct minimization of operational costs (case A) or energy exchange with the main grid (case B) allowed the best results concerning their respective objective. Yet, it is interesting to note how maximization of PIT (case C) achieves similar results in terms of energy exchange with the main grid, compared to a pure cost optimization, while incurring significantly higher energy losses. This indicates high currents, specifically fast charging, and discharging events of energy storage in preparation of an islanding event, as further explained in [8].

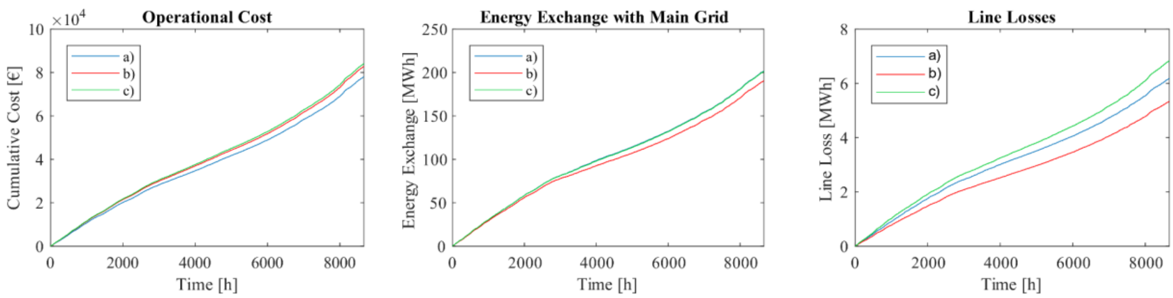

Figure 17: The annual cumulation for (a) operational cost, (b) energy exchange with the main grid, and (c) line losses employing the operation strategies A-C.

Resource forecast

To apply the control strategy as described above, PV and wind production as well as the consumer load need to be forecast.

In order to create forecasts for the unknown variables, RWTH Aachen University applies state-of-the-art Recurrent Neural Networks (RNNs) in an encoder-decoder setup to derive these values. This RNN setup (Figure 18) uses historical values in the encoder as a starting point to produce an outlook into the future in the decoder. The RNNs are based on Long Short-Term Memory (LSTM) cells that possesses cyclic, self-feeding connections. These cycles are capable of capturing time-series dependencies and their dynamic behavior over a sequence of time steps. Furthermore, they include exogenous features at each forecasted time step to further improve prediction accuracy. For the upcoming 24 hours, this type of forecasting algorithm is capable to forecast wind and PV production as well as electrical loads. Exogenous variables for all these forecasts comprise meteorological values in applicable combinations, e.g., temperature, air pressure, solar irradiation, wind speed and direction, cloud coverage, and others. They are collectively assumed to be known for the forecast time steps, suggesting the availability of highly accurate meteorological forecasts. In a real-life application, the forecast accuracy of the desired target variables is expected to degrade slightly with ever so slightly imperfect meteorological forecasts. Further, the developed approach considers calendar variables such as weekday, time of day, month, national holiday, and others to also account for consumer behavior for the electrical load forecasts.

Figure 18 shows the setup of the RNN architecture [8]. As it can be seen, an encoder-decoder setup is used that takes the historical sequence to encode this within a so-called hidden state (a collection of memory vectors), which then provides the starting point for the decoder that derives the forecasts. In Figure 18, l presents labels, i.e., target values, y indicates the forecasted (output) value and f denotes the respective set of exogenous variables.

Encoder as well as decoder use a combination of the label (forecasted value) of the previous time step and the features of the current time step. This lagged use of the previous time step for inferring the current time step further focuses the forecasting algorithm to exploit the strong auto-correlation that is inherent of the time-series of question.

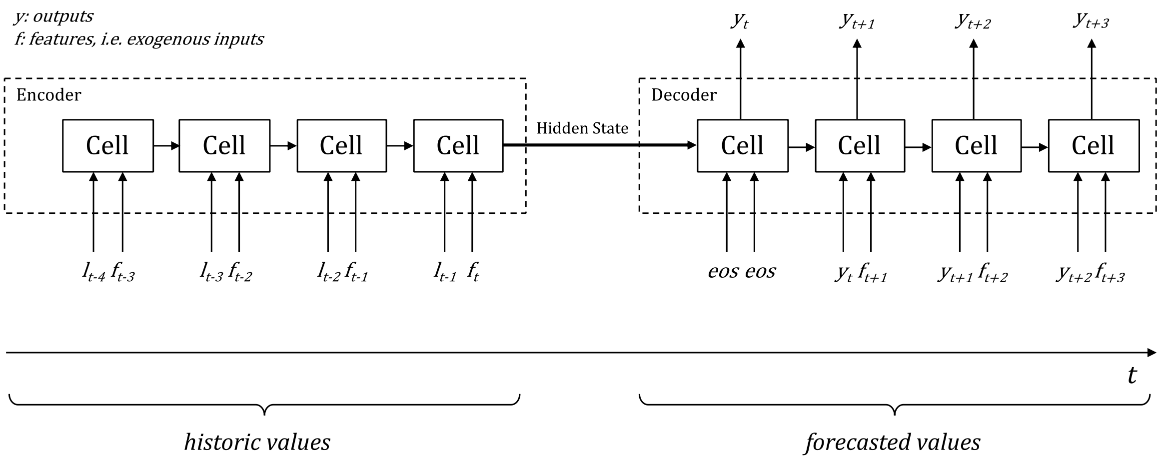

Figure 18: The setup of the forecasting algorithm.

Using this algorithm, RWTH Aachen University was able to produce reasonably accurate results for 24 h forecasts on synthetic load data from Simris. Afterward, these forecasts were used as inputs to the MPC. It turned out that the evolved forecasting architecture outperforms similarly employed encoder-decoder RNN-based forecasting techniques.

On this basis, the simulation results of the RWTH Aachen University showed that the combination of a carefully designed MPC approach as described above in combination with a tailored forecast algorithm could provide an improvement (self-consumption increase) of over 10% [10]. This initial simulation results are to be validated with tests to be performed during the remaining project lifetime.

Conclusions

E.ON and its partners believe that LESs could become an important and powerful opportunity for the energy industry to be available to guarantee a cost-effective integration of renewables in those cases where conventional solutions are clearly not the appropriate ones. The work on LESs continues and the development of future solutions is being built up on the lessons learned obtained in the first years in that area.

On top, the new upcoming regulation coming out of the European Commission's Clean Energy Package for all Europeans (published in 2016) [13] will provide an opportunity for the European member states to define a national regulatory framework which will allow LESs to become the technical enablers for the creation of local energy communities. Such local energy communities will support the transition towards a European energy system that combines sustainability and security of supply with competitiveness and citizens at its core.

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