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Foreword

Electrical grid services refer to a range of services requested by transmission and distribution system operators to maintain a reliable and balanced electrical power system. Penetration of intermittent renewables and distributed energy resources increases.
The IEA reports an average annual growth rate of wind power generation of 21.4% between 1990 and 2016 (IEA. 2017. Renewables Information Overview). It exceeds nuclear power and becomes the second largest low-carbon power source between 2035 and 2040. By 2040, the two intermittent sources of wind and photovoltaic's together will play the largest role in low-carbon generation in the EU, reaching 15-38% of the total electricity generation, based on a continued high annual growth rate of between 3.4% and 5.4% for the years 2016 to 2040 (IEA, 2018. World Energy Outlook). The same source assumes one-out-of-five cars sold in the world is electric by 2040, compared with one-out-of-hundred today (New Policies Scenario).
EU harmonization efforts for TSO grid service markets and national initiatives further affect the markets. In particular, ENTSO-E makes recommendations at EU level on how markets should be organised under the Guideline on Electricity Balancing (GLEB). Developments such as these opens up opportunities for more flexible generation and consumption, optimized capacity utilization and harmonized operations and trading.

GSM 2019 is the third edition of the international Grid Service Markets symposium. From 3 to 4 July 2019, 80 experts from various sectors of the power market shared their knowledge and experience in the field of grid services. The topics presented and discussed were wide-ranging and included international collaboration, technologies, operations, market developments and business potential. A rich program promoted the exchange between science and industry. 54% of the participants came from academia, 24% from industry, 11% from DSOs/TSOs and a further 11% from administration and associations.
The GSM 2019 audience was very international, with 75% of the participants coming from outside the host country: 19% from Germany, 9% from the United Kingdom, 8% from Italy, 6% from Denmark and France each, 4% from Netherlands and Belgium each. Austria, Croatia, Greece, Latvia, Norway, Slovenia and Sweden were also represented. 5% of the participants came from outside Europe.
The one and a half day GSM 2019 symposium offered 13 scientific presentations and 6 poster presentations from the academic world, as well as 16 top-class invited speeches, mainly from industry, administration and associations. The many lively discussions and Q&A sessions eventually brought together technicians and business experts, helping to bridge the gap between new, sustainable technologies and markets. The change of perspective helped to clarify the different points of view. In her welcome speech, Mirela Atanasiu, Head of Unit at the EU Fuel Cells and Hydrogen Joint Undertaking, stressed the importance of both the technical solution and the market readiness to meet the challenges of the transforming energy system.

Sincerely
Prof. Christoph Imboden & Dr. Michael Spirig
HSLU EFCF

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The following pages contain the paper contributions accepted by the IAB.

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- the Lucerne University of Applied Sciences and Arts UAS HSLU, www.HSLU.ch
- European Fuel Cell Forum AG, www.EFCF.com

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G0205

Assessing the impact of virtual qualified units on the Italian ancillary services market

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Abstract

Recent changes in the Italian regulation of the National Transmission Grid (NTG) demonstrate that the Italian Ancillary Services Market (ASM) is opening up to new subjects different from traditional producers, defined by the Italian grid code as “significant units” within a total power not less than 10 MVA. These new players are called Virtual Qualified Units (VQU, in Italian UVA “Unità Virtuali Abilitate”) consisting in non-significant producers, storage systems and loads. To cope with these changes to the regulation framework, the Italian TSO TERNA has launched few pilot projects to foster the participation in the Italian ASM of aggregators and demand response for providing balancing (up-ward and down-ward regulation) and reserves to the NTG.
In this context CESI has developed on behalf of TERNA an innovative simulation tool called MODIS that allows to quantitatively evaluate the impact on the ASM arising from a new transmission infrastructure, storage or a new VQU, in a planning perspective. Starting from the outcomes of the day-ahead market (DAM), this tool simulates the redispatching process of the ASM, minimizing market disbursement hour by hour over a whole year, necessary to ensure the fulfilment of the operational constraints.
This paper presents the methodology and a quantitative analysis to assess the economic benefit, that can be achieved by the VQU deployment in the NTG by 2025 and 2030. The economic benefit is quantified in terms of cost saving for providing regulating services and reserves in the Italian ASM. The methodology relies on scenario simulations and what-if analysis through the comparison of different simulations obtained using the MODIS model.

Introduction

In the transition to a low carbon economy Italy is facing a dramatic increase in Renewable Energy Sources (RES) penetration, which has been fostered by a strong support in terms of subsidies and incentives. Nowadays current policies are pushing the new RES generation to compete on equal basis with the conventional generation through appropriate schemes, mostly based on auctions.
The priority for the European Regulators and TSO's is nowadays to enhance harmonization of the rules for balancing and for exchanging ancillary services in order to implement an effective pan-European competition in the ASM markets and increase efficiency. To this aim, ACER, the European Association of Energy Regulators, has published Framework Guidelines on Electricity Balancing [1] that served as a basis for ENTSO-e to develop the Network Code on Electricity Balancing submitted for approval to the European Commission(EC). In November 2017 the EC has finally published the European Balancing Guideline [2].

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Following the new changes at European level also the Italian regulatory authority for energy, networks and the environment (Autorità di Regolazione per Energia Reti e Ambiente, ARERA) has legislated in order to foster the integration of new actors (different from traditional power producers) in the Italian ASM [3]. Consequently, the Italian TSO has established different pilot projects to start a testing phase able to experiment the participation of these new actors in the ancillary services market, in particular renewable, consumer and storage.
These changes in the regulation at national level demonstrate that the Italian ASM is opening up to new subjects different from traditional producers, defined by the Italian grid code as "significant units" within a total power not less than 10 MVA. These new players are called Virtual Qualified Units (VQUs, in Italian UVA "Unità Virtuali Abilitate") consisting in non-significant producers, storage systems and loads. To cope with these changes to the regulation framework, the Italian TSO TERNA has launched few pilot projects to foster the participation in the Italian ASM of aggregators and demand response for providing balancing (up-ward and down-ward regulation) and reserves to the NTG.
Annex 8 of the "2nd ENTSO-e Guideline for Cost Benefit Analysis(CBA) of Grid Development Projects" [4] mentions the assessment of ancillary services cost reduction as a potential benefit to be considered in the CBA for transmission investments. In this context CESI has developed on behalf of TERNA an innovative simulation tool called MODIS that allows to quantitatively evaluate the impact on the ASM arising from a new transmission infrastructure, storage or a new VQU, in a planning perspective. Starting from the outcomes of the day-ahead market (DAM), this tool, simulates the redispatching process of the ASM, minimizing market disbursement hour by hour over a whole year, necessary to ensure the fulfilment of the operational constraints.

The Italian Ancillary Market

This session describes few basic concepts about the Italian ASM functioning and its recent developments, to clarify which services are procured through the market and it introduces the main steps undertaken by the Italian Authority (ARERA) and the Italian TSO (TERNA) to increase market competitiveness opening up to new subjects, different from traditional power plant. Finally, a short overview about recent trend of the Italian ASM is given.

Italian ASM, brief description

The Italian ASM is an "Energy-Only" market, where all the services requested by the TSO to manage the NTG are procured at zonal level: all the submitted bids accepted in the ASM are valued at the offered price through pay-as-bid clearing mechanism.

The Italian TSO procures through the ASM the resources needed to:

- relieving intra-zonal congestions;
- procuring tertiary and secondary reserve;
- balancing the system in real-time.

The resources necessary to maintain the balance between injection and withdrawal are activated at different time starting from the day before real time (D-1) until the real-time, with two main stages:

- MSD Ex-Ante (hereafter named MSD) - in this phase the TSO relieves congestions and creates the secondary and tertiary reserve margin.

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- Balancing Market (hereafter named MB) – during the real-time operation the TSO clears the balancing offers (price and quantity) in order to restore the secondary and tertiary reserve margin and balancing the grid.

These two sessions are chronologically procured in sequential order after the day-ahead market (hereafter DAM). Each market participants qualified to participate into the ASM must provide all the residual margins after the DAM by means of specific bids/offers[1], and the offered volume should be consistent with the available margin of the power unit.

Procuring services from Virtual Qualified Units

Starting from 2017 the Italian electrical market opened toward new subjects different from traditional power producers, according to the following road-map:

- 5th May 2017 – ARERA approved the resolution (Delibera 300/2017 [3]) in which the Italian ASM should admit in the market new subjects such as demand and renewable and storage system.
- 30th May 2017 – TERNA published specific new rules (Regolamento UVAC MSD [5]) regulating the access to the ASM of consumption units;
- 25th September 2017 - TERNA published specific new rules (Regolamento UVAP MSD [6]) regulating the access to the ASM of non-significant producer unit;
- 19th June 2018 – TERNA published a new regulatory framework for the M-VQU (Regolamento UVAM MSD [7]) regulating the access of heterogeneous units (that could provide upward and downward regulation, including storage facilities).

The new regulatory framework has provided the foundation for aggregating different type of subjects into Virtual Qualified Units (VQU), classifying these new market actors according to the following categories:

- **C-VQU** – consumption virtual qualified unit, able to reduce consumption, with a minimum aggregation threshold between 10 MW to 1 MW.
- **P-VQU** – production virtual qualified unit, able to reduce or increase its injection toward the grid (reducing and increasing its production) with a minimum aggregation threshold between 5 MW to 1 MW.
- **M-VQU** – mixed virtual qualified unit, including P-VQU C-VQU and storage system. This virtual unit can modulate in both direction (upward and downward) their power level (injection or consumption). In this case the minimum aggregation threshold is 1 MW.
-

Italian ASM trends

As mentioned above, Italy is witnessing the deployment of a massive share of non-programmable, or variable, RES (hereafter NP-RES, mainly onshore wind and photovoltaic generation) which increased in the last decade from few GW to almost 30 GW. This non-negligible share of NP-RES has two main implications:

- It increases the amount of unbalance to be offset during real-time operation;

[1] Each bid/offer consists in a couple of value representing the quantity (in terms of energy) and the price.
[2] It simulates the ASM procurement of different services such as balancing, secondary and tertiary reserve.

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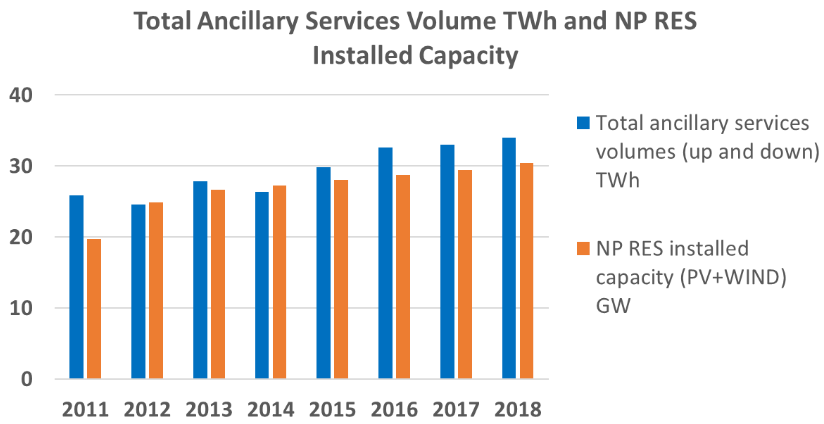
- It increases the amount of tertiary reserve (TR) needed to guarantee an adequate level of security to the NTG.

These two aspects call for a higher volume of services requested in the ASM, and consequently the costs related to the ASM disbursement increase. These costs are transferred to the consumer as highlighted in Figure 1-3;

Figure 1-3 – Italian ASM up/down volume and NP RES installed capacity.



Applied Methodology and Scenario Description

This section explains the numerical approach used to assess the potential impact of VQUs into the Italian ASM and the model used to carry out simulations and the results that have been obtained.

Introducing the simulation tools

Whereas for the DAM, a powerful and accurate simulator (PROMEDGRID) was developed and already applied in the previous national development plans considering the detailed model of the pan-European market [8], the yearly simulation of the impact of a new transmission project on the ASM was so far estimated in an approximated way, owing to the complexity of this market based on a pay-as-bid mechanism.

Thus, CESI in cooperation with TERNA has developed an ASM simulator, named MODIS, a multi-area market simulator, specifically tailored to the Italian ASM. MODIS reproduces all the balancing actions to ensure the security reserve margins[2], for a whole year with hourly discretization. Recently MODIS has been further strengthened by introducing a dedicated library for a detailed modeling of BESS (Battery Energy Storage System) technology [9], able to optimize e BESS operation[3] when operated to provide services into the ASM. Recently, the simulator was further improved and by adding a specific modelling procedure to replicate the VQUs behavior in the ASM.

MODIS emulates the real ASM behavior starting from the DAM final schedule and tries to ensure the offset between demand and supply, assuring the right reserve margin. For this reason, the deterministic model implemented in MODIS belongs to the class of “security constrained differential unit commitment problems”, where upward and downward regulation of the controllable variables are made starting from an initial status inherited from the DAM solution.

[2] It simulates the ASM procurement of different services such as balancing, secondary and tertiary reserve.
[3] Maximize usage of BESS and minimize the life-cycle cost of the electrochemical storage.

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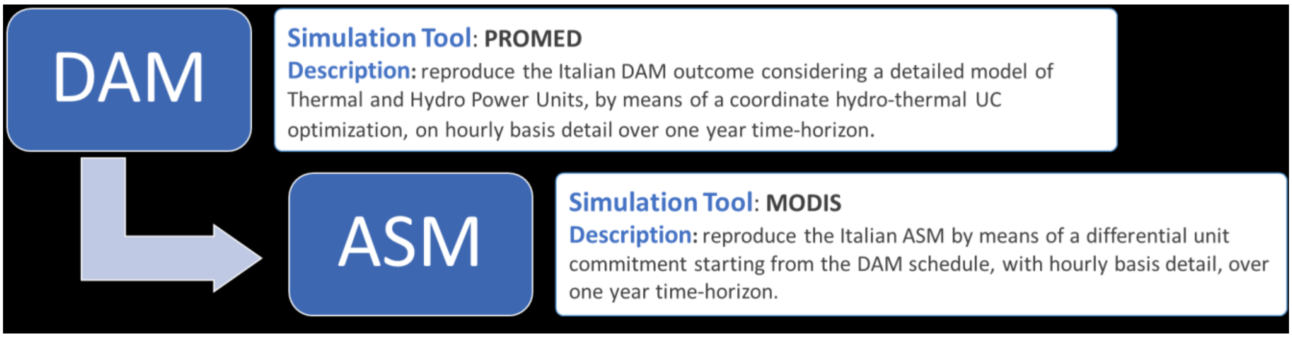
Simulation Approach

The results of the various market sessions are obtained by means of sequential simulations, coherently with the sequential order of the real Italian Power Market session.

Figure 2-1 – Sequential simulation process



Simulations are carried out to highlight the main benefit given by the new market players, i.e. the VQUs, competing in the market with the traditional power units, considering two different time horizons addressing the medium and long term (2025 and 2030).

Main benefits envisaged in this paper are:

- The ASM disbursement cost reduction: by tracking the cost of re-dispatching market process in each considered scenario, it is possible to assess the economic impact of VQUs.
- RES integration, quantified in terms of the avoided NP-RES curtailment thanks to VQUs participation into the ASM.

VQUs Modelling

In order to exemplify the heterogeneous characteristics of the VQUs, three main categories have been defined in the model as shown in Table 2-1.

Table 2-1 – VQUs modelled categories

Modelled Cluster	Cluster Description	Services
DSR, RES, DG (hereafter abbreviated in D-R-DG)	• **Demand Side Response**, intended as demand that can reduce consumption: this activation gives to the market upward regulation (balancing and if possible reserve). • **Renewable Generation,** that could provide downward regulation. • **Distributed Generation**, that could be moved upward or downward.	The mix of generation and controllable demand can participate into the market through upward and downward regulation.
Storage	Stationary storage system, mainly refers to electrochemical storage system. The option of future development of new pumping facilities is disregarded by this case studies	It participates into the market through upward and downward regulation
Electrical Vehicles (EV)	The transition from a century of mass-market dominance by the internal combustion to the EVs appears to be imminent. For this reason, this study also considers the impact of millions of EVs connected to the grid able support the ASM with regulating capacity.	It participates into the market through upward and downward regulation

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As mentioned before, the VQUs can compete with traditional generator on the basis of their bids, which are exogenous variables. For the purpose of this quantitative analysis the optimization of bid strategies is disregarded and VQUs are considered as most valuable resources than traditional power plant, and consequently their bids are less competitive than traditional units.

Case Studies

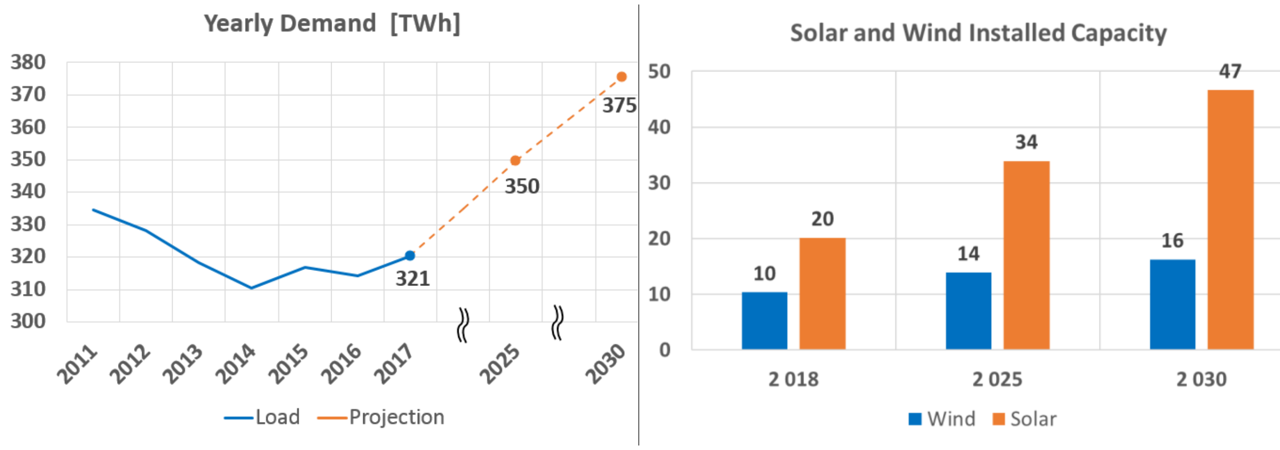
The application of the proposed methodology, implemented using MODIS, is exemplified with some case studies used to point out the benefits arising from considering VQUs participating into the Italian ASM. For the analysis a "what-if" approach (i.e. with and without VSUs participating into the market) has been adopted, to highlight possible beneficial effects given by those virtual units. All the adopted scenarios are based on a realistic description of the Italian ASM with the following problem size, 10 market areas,10 equivalent interconnections between areas, 244 thermal and hydro units.

Two different time horizons have been taken into account in this analysis, considering 2020 as short-term scenario, to represent the near future, and 2030 as long-term scenario.

The proposed scenarios have been voluntarily created with the purposes of emphasizing the effect of those new actors (distributed generation, DSR, small scale generation, storage facilities and EV) in scenarios with high penetration of NP-RES.

Load projections (in terms of yearly energy demand) and NP-RES installed capacity[4] considered in each scenario (2025 and 2030) are reported in the following Figure 2-2.

Figure 2-2 – Load projection to 2025 and 2030



In the proposed scenario VQUs are modelled according to the categories already described in Table 2-1, whereas the installed capacity is shown in the following figure (see Figure 2-3), where D-R-DG installed capacity is given by linear progression of observed amount of VQU participating into the ASM in the last months, whereas storage installed capacity is given by a policy target[5]. The draft document "the integrated plan for energy and climate (PNIEC)" [10] issued by the "Italian Minister of Infrastructures and Transport" marks out the new national energy strategy where storage is at the centre of the agenda to increase the flexibility necessary to expand the share of renewable energy in final energy consumption to 28% by 2030. According to this national energy plan the amount of storage expected at 2030 should be 6000 MW, allocated between stationary (pumping PP) and

[4] Load and NP-RES installed capacity are the main variables upon which depend the volume of tertiary reserve requested by the system and the amount of unbalance generated during real-time operation.
[5] Should be noted that electrochemical storage facilities, dedicated to grid regulating services, have been developed till today only through the form of pilot projects by the Italian TSO.

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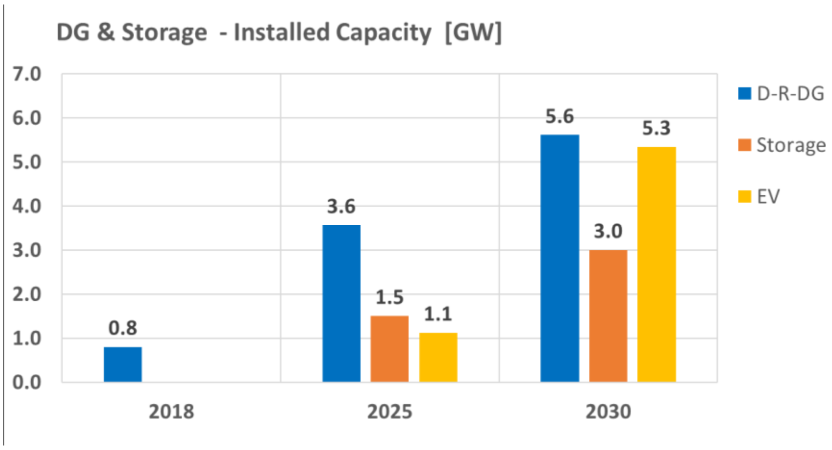
electrochemical. In this analysis we wanted go conservative taking half capacity by 2030, represented by the 3000 MW in Figure 2-3.

EVs installed capacity in participating in the Italian ASM is estimated taking into account the target of 6 million circulating EVs at 2030. The values shown in Figure 2-3 represent the average consumption value (1.1 GW at 2025 and 5.3 GW at 2030) which exemplifies the variable consumption given by the EV chargers during the simulation timeframe (one year, 8760 hours).

Figure 2-3 – VQUs installed capacity



What-if analysis

The basic methodological approach underlying the what-if analysis presented in current paper consist in comparing a scenario without having the VQUs participating into the ASM (Baseline scenario, BS), with a scenario where the VQUs actively bid into the market.

Another variable that at this point of the process to open the Italian ASM to VQUs, have an uncertain impact on the volume traded into the market is the contribution of the VQUs to the tertiary reserve requested into the ASM. Theoretically also VQUs could provide TR under some technical restrictions; in accordance with this assumption this analysis shows a comparison between the scenario where VQUs provide only upward and downward regulation with the scenario where VQUs provide also TR.

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Results and main findings

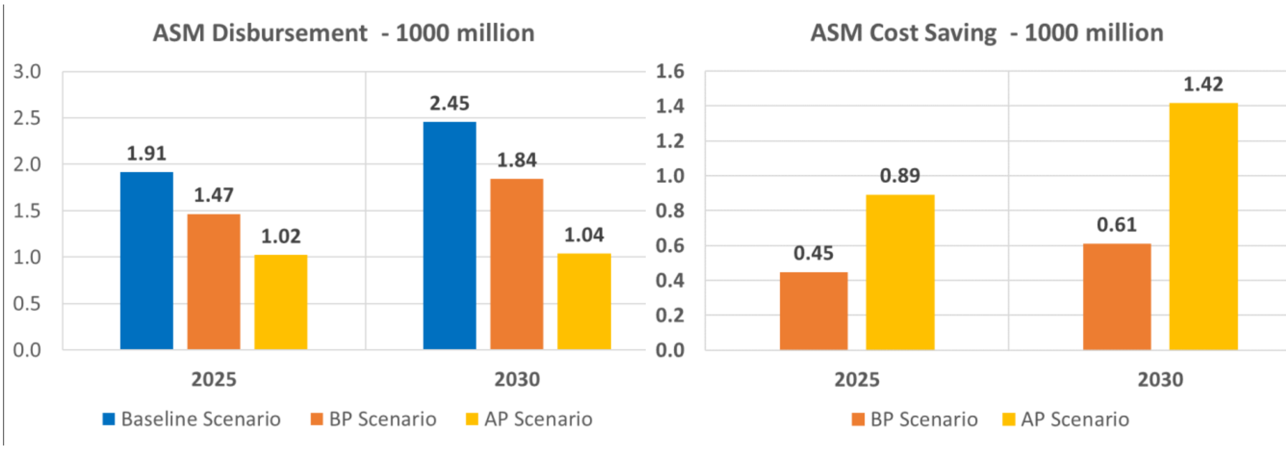
In the following session are presented the main findings of the analysis: all the results are collected starting from the hourly output given by the simulation tool. To summarize the main results, which are calculated with hourly detail, all the data have been collected and presented at country level, disregarding the zonal detail.

ASM cost assessment

In the following figure (see Figure 3-1) is reported the cost of the Italian ASM as result of the simulation (chart on the left) and the cost saving due VQUs which participate into the ASM[6]. Here below a brief explanation of the reported chart:

- Blue bar represents the cost for the Baseline Scenario (BS), where VQUs do not provide any ancillary services: these two scenarios represent the future snapshots under the assumptions VQUs are not participating into the ASM.
- The orange bar represents the Basic Procuring Scenario (BP), where VQUs are activated only for balancing purposes.
- The yellow bar represents the Advance Procuring Scenario (AP), where VQUs are activated for providing balancing and reserve[7].

Figure 3-1 – ASM disbursement and cost saving due VUs



In the BP scenario the cost saving due VQUs participating into the market and providing upward/downward regulation is about 450 million in 2025 (-23% respect to the BS cost) and 610 million in 2030 (-25% respect to the BS cost). For the AP scenario the high value of cost saving (-57% respect to the BS cost) is partially imputable to the advent of the VQUs, and partially related to the Italian ASM mechanism characteristics[8].

Figure 3-2 helps in understanding the way the model works: both figures represent upward and downward yearly activation in GWh, for 2025 and 2030 scenario, comparing the Baseline scenario result (red dotted line) with the BP scenario result (blue and orange colored area).

[6] this value is obtained as difference respect to the baseline ASM disbursement.
[7] It's important to stress that the AP scenario represent a pure academic exercise and it has been carried out only to exploit VQUs capacity in reducing the Italian ASM yearly expenditure. Probably in the coming years some of the VQUs will be able to provide TR, but not all of them, whereas in the proposed scenario all the VQUs are providing TR.
[8] In the Italian ASM TR is indirectly paid through the upward and downward regulation, and there is no reservation and remuneration of capacity. For this reason, in many hours VQUs are capable to provide reserve even without been directly committed by the TSO. In the AP scenario the reserve is taken from those unit for free, reducing the cost of the ASM of 46% in 2025 and 57% in 2030.

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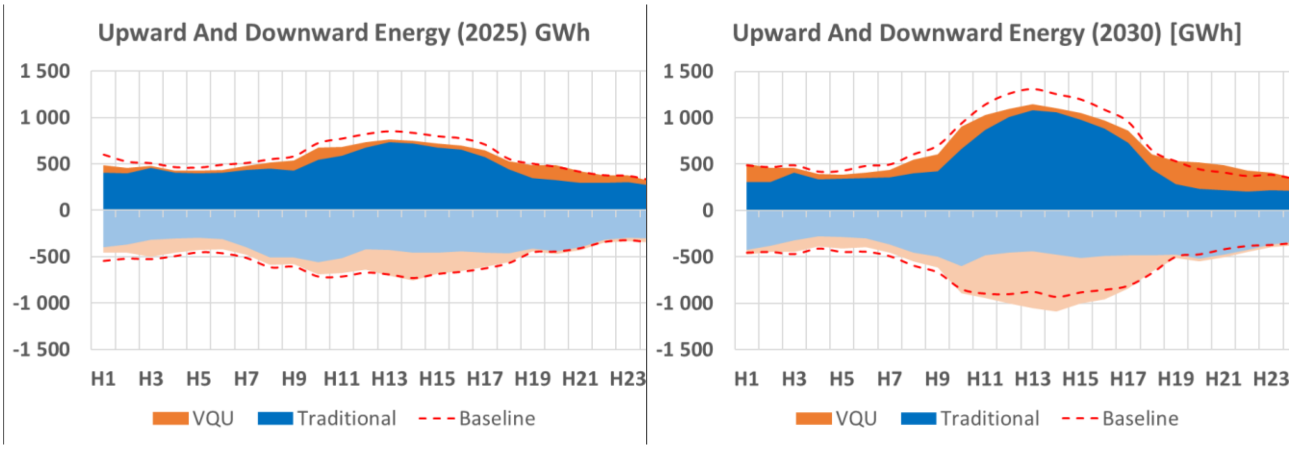
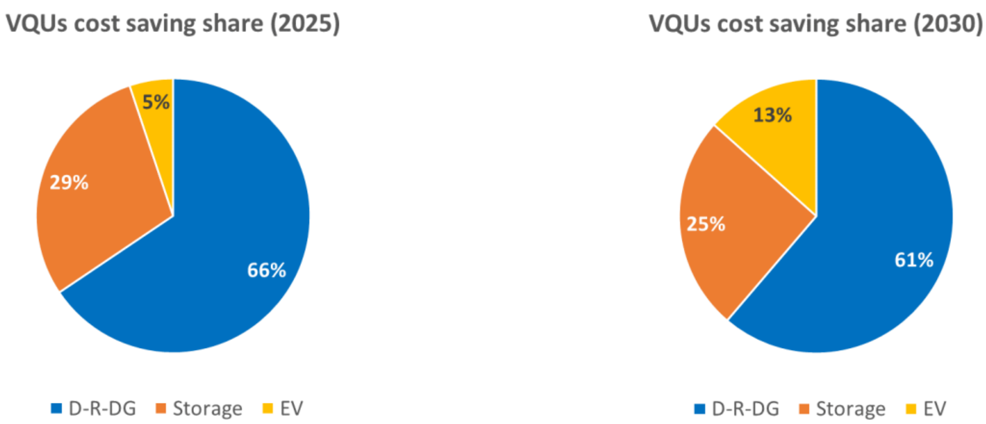
Figure 3-2 – ASM annual upward and downward volume (Baseline vs BP scenario)



The headroom between the red line and colored area in the positive side of the chart of Figure 3-2 indicates the avoided upward activation volume in the case VQUs are participating into the market. On the contrary, looking into the negative part of the chart, downward activation for BP scenario is greater than the quantity observed in the Baseline scenario. This result is consequent the augmented flexibility of the system given by the VQUs, which permits to integrate more NP-RES production (by increasing system capacity of providing downward regulation during solar hours).

Thanks to the MODIS simulation tool is possible to breakdown the cost saving due to a specific category of VQUs (see Figure 3-3). This figure refers to the BP scenario, and as noticeable in both years the greatest contribution in reducing the cost of the ASM is given by controllable demand, controllable renewable production, distributed generation and storage facilities. At 2025 the contribution in reducing the cost of the ASM given by the EVs is marginal (5%), it increases a little in 2030 contributing in reducing the ASM cost with a share of the total cost reduction of 13%[9].

Figure 3-3 – ASM cost saving breakdown by VQUs.



[9] under the assumption of 6 million EV circulating in the country.

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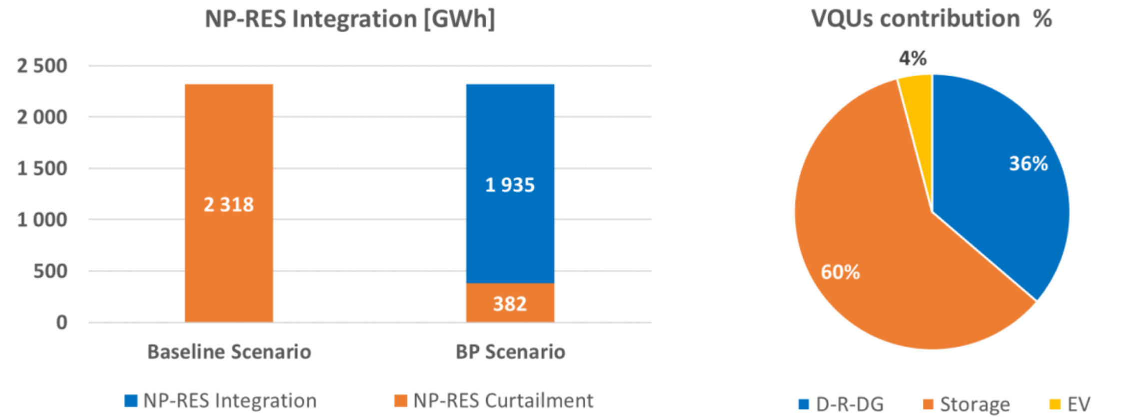
RES integration potential

VQUs are effective to prevent RES curtailment, also called overgeneration, which represent the amount of NP-RES production which cannot be integrated by the electrical system due the minimum power constraint of thermal units.
Calculation has shown that the amount of NP-RES curtailment, necessary to match the system reserve requirement, settles down to 973 GWh in 2025 and 2318 GWh in 2030 for the BS scenario. Particularly in the 2030 scenario, when the overgeneration is not negligible, the participation of VQUs into the market gives a huge effort in avoiding NP-RES curtailment (see Figure 3-4, figure on the left shows the amount of NP-RES curtailment in the Baseline scenario and in the BP scenario, whereas figure on the right indicates in which proportion VQUs are contributing to integrate 1935 GWh of overgeneration at 2030).

Figure 3-4 – NP-RES curtailment and NP-RES integration thanks to VQUs (year 2030)



The NP-RES curtailment is particularly evident during solar hours when PV production is at its maximum. This effect reveals just after DAM schedule, becoming relevant during the ASM in the moment it is necessary to start-up more thermoelectric power units in order to satisfy TR and SR constraints. Figure 3-5 show hourly concentration of NP-RES curtailment on yearly basis in the scenario at 2030 (figure on the left). This volume of overgeneration is then reduced thanks to VQUs (BP scenario on the right).

Figure 3-5 – NP-RES curtailment profile (Baseline scenario vs BP scenario, year 2030)

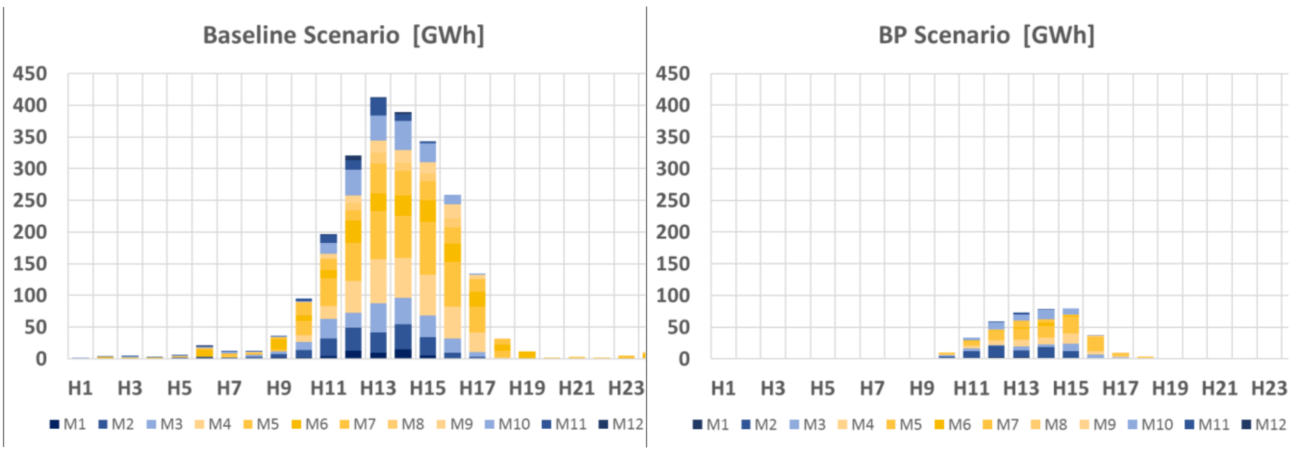


Figure 3-6 shows the avoided number of start-up of thermoelectric units over the 24 hours, for the whole year: the avoided start-ups indicates an increase of the flexibility of the system due the presence of VQUs.

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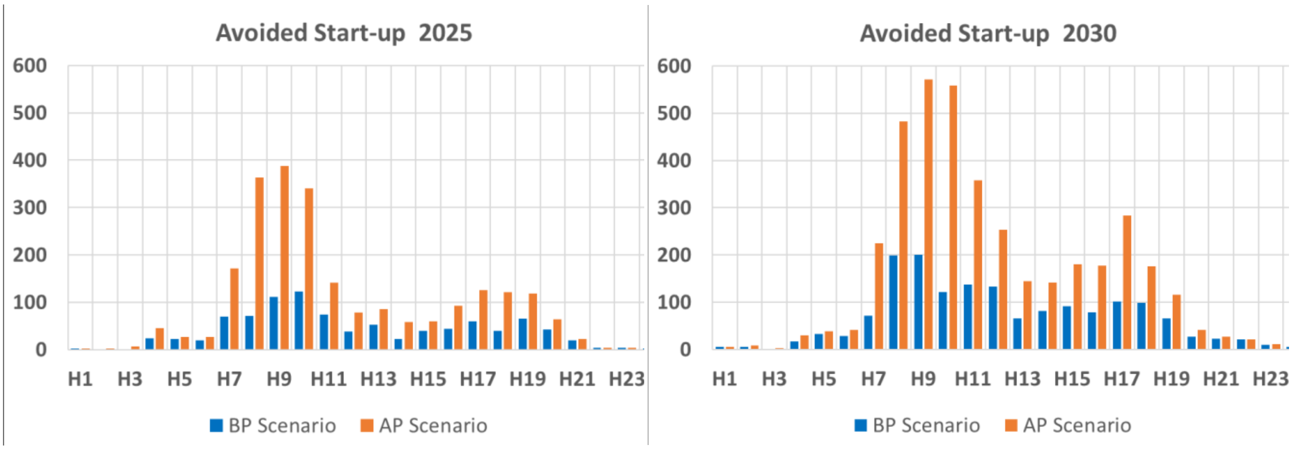
Figure 3-6 – Avoided start-up during ASM re-dispatching thanks to VQUs



List abbreviation and Acronyms

Acronym	Meaning
ARERA	Italian Regulatory Authority for Energy, Networks and Environment
ASM	Ancillary Services Market
BESS	Battery Energy Storage Systems
BS	Baseline Scenario, reference scenario used for comparison of sensitivities
C-VQU	Consumption Virtual Qualified Unit
DAM	Day Ahead Market
DG	Distributed Generation
DSR	Demand Side Response
EV	Electrical Vehicle
MSD	Italian acronym for the ancillary services market
M-VQU	Mixed Virtual Qualified Unit
NP-RES	Non-Programmable Renewable Energy Source
NTG	National Transmission Grid
PP	Power Plant
P-VQU	Production Virtual Qualified Unit
RES	Renewable Energy Source
SR	Secondary Reserve
TERNA	Italian Transmission System Operator
TR	Tertiary reserve
TSO	Transmission System Operator
VQU	Virtual Qualified Unit

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G03
FLEXIBLE UNITS &
DEVELOPMENTS IN GRID SERVICE MARKETS I

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G0301

Modelling and optimization of a flexible PEMFC power plant for grid balancing purposes

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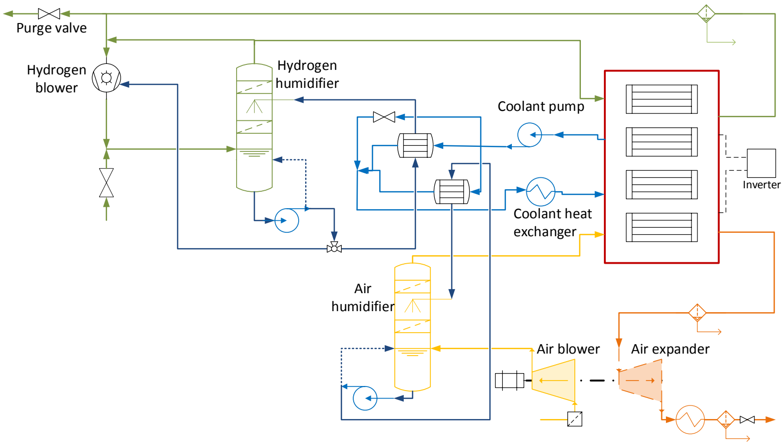
Abstract

Flexible power resources in the electric system, capable to rapidly ramp their electricity production or consumption, must compensate for the variability given by the increasing penetration of renewable energy sources. The EU project GRASSHOPPER[1] aims to setup and demonstrate a 100 kW_{el} PEM Fuel Cell Power Plant unit which is cost-effective, flexible in power output and scalable to MW-size, designed to provide grid support with a Demand Side Management program.
In this work, different layouts proposed for the pilot plant are simulated with Aspen Plus® for system performance evaluation, optimization of design and operating conditions. The system may operate at atmospheric or mild pressurised conditions (0.1-0.6 bar_g), using a compressor and optionally a turbine expander on the cathode exhaust side for energy recovery. The simulation includes a custom PEMFC model, reflecting the voltage dependence on pressure, relative humidity and gas composition. The main BoP components are also modelled in detail (see Figure). The increased voltage of the cell allows a slightly higher net system efficiency with pressurisation (taking into account increased BoP consumption) and the turbine adds nearly $2\%_{pt}$ of net electrical efficiency, reaching $45\%_{LHV}$.



Proposed layout for the 100 kW PEMFC pilot plant.

[1] This project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking under grant agreement No 779430. This Joint Undertaking receives support from the European Union's Horizon 2020 research and innovation programme, Hydrogen Europe and Hydrogen Europe research.

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Introduction

In Europe in the last years the share of renewable energy sources (RES) in the electricity production has grown according to the 20-20-20 targets [1] and is expected to grow even more to reach the ambitious targets specified in the EU 2030 Energy Policy Framework for climate change [2]. However, the increasing penetration of non-programmable RES may hinder the security and reliability of the transmission and the distribution grids, being their generation mainly uncertain and dispersed. To overcome these issues, it is necessary to evolve the system to more efficient networks. Many studies have investigated the effects that a high penetration of RES have in term of backup generation [3] and storage needs [4,5]; analysing options for grid improvement [6] and comparing introduction of storage systems as well as grid extension and repowering [7]. The concept of Smart Grid [8] is considered at international level, taking advantage of the increased intelligence and flexibility of the grid to facilitate the connection of DG units, increase the reliability and security of supply and allow the consumers to contribute in optimizing the operation of the system with Demand Response schemes.

Indeed, sufficient flexible resources [9], i.e. resources that can rapidly modify their electricity production or consumption to face an unbalance, must be present in the power system to cover the variability in net load. Within all the sources of flexibility, this work focuses on stationary Fuel Cells Power Plants (FCPP) based on low temperature Proton Exchange Membrane Fuel Cells (PEMFC). These plants, whose feasibility on a significantly large scale has been demonstrated in projects such as DEMCOMPEM-2MW [10,11], are seen as an essential technology for the future renewable based energy infrastructure [12] thanks to their very fast ramp rates and excellent load following capabilities that make them perfectly suited for grid balancing. It is therefore necessary to study how they can contribute to balancing the grid.

In this context, the EU project GRASSHOPPER [13] aims at analysing how distributed and fast-ramping fuel cell systems can be used to provide ancillary services and help balancing the grid. It will setup and demonstrate a 100 kW_{el} PEM FCPP unit which is cost-effective, flexible in power output and scalable to MW-size, designed to provide grid support with a Demand Side Management program.

1. Modelling Approach

In this work, two different layouts proposed for the GRASSHOPPER pilot plant (rated at 100 kW_{el} gross DC output) are simulated in order to support the decisional process for defining the plant layout, to support the plant design and engineering phase as well as to allow optimizing the plant expected operating conditions and evaluate its performance. The modelling activities are also relevant to investigate the behaviour of the system in off-design conditions, influencing the definition of an optimized plant control strategy.

A stationary model of the FCPP is developed in Aspen Plus®, building a network of components and calculating detailed mass and energy balances. The model includes the PEMFC and the main balance of plant components.

PEMFC model
A custom model is used for the PEMFC, considering a lumped-volume approach where the cell performances are dependent on the voltage-current polarisation curve. The polarisation behaviour is expressed through a semi-empirical equation, that simplifies the

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theoretical polarisation curve equation aiming at reproducing the real cell performances. The coefficients of this polarisation curve are regressed on the basis of experimental datasets. These data allow to evidence the influence on the performance of three operating parameters: stack backpressure, air ratio to stoichiometry and air relative humidity. The influence of the hydrogen stoichiometry is not included in the model since it is known from previous experiences that its influence on cells performances is low.

Equation *(1)* shows the polarisation curve formulation, whose coefficients are regressed with experimental data; the first two terms represent an apparent open circuit voltage and its change with pressure and air ratio to stoichiometry, the third term represents the ohmic losses and the last two terms represent the activation and the concentration losses respectively.

$$V_{cell} = OCV + K_{S_a,p}\, ln\left(x_{O_2} \cdot p\right) + i\,(R_{ohm,1} + R_{ohm,2}\left(1 - \frac{x_{H2O}}{x_{H2O,rif}}\right)^{G_{ohm}}) + K_{act}\, ln\left(1 + \frac{i}{i_0 \left(\frac{p}{p_{ref}}\right)^{G_{act}}}\right) + K_{conc}\, ln\left(1 - \frac{i}{(i_{L,1} + i_{L,2}\frac{x_{O_2}}{x_{O_2,rif}}) \left(\frac{p}{p_{ref}}\right)^{G_{conc}}}\right) \quad (1)$$

In this formulation, the effect of the air ratio to stoichiometry is included considering the dependence of the open circuit voltage and of the limiting current density on the oxygen molar fraction. On the contrary the dependence of the exchange current density on the oxygen molar fraction is not expressed because it resulted negligible. The effect of the backpressure is included in the open circuit voltage and in the activation and concentration overvoltage, since it influences both the exchange current density and the limiting current density. The voltage dependence on the air relative humidity is introduced in the ohmic resistance term, since the membrane conductivity is dependent on the number of water molecules that are present.

Figure 1 shows how the regressed polarisation curves fit the experimental data at different pressures. Relative errors are always below 8% and they remain below 3% in the common operating conditions, i.e. for currents below 1500 mA/cm^2. Regressions are made for a single cell.

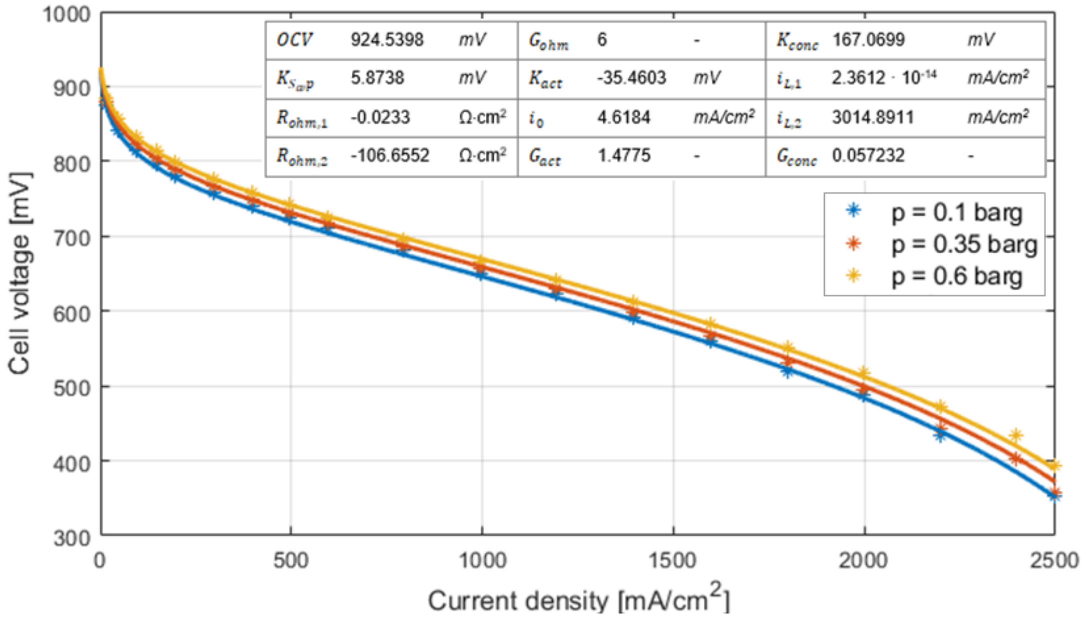

Figure 1 – Comparison between experimental and regressed curves.

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The model assumes that cells are electrically connected in series to form a stack and stacks are in turn connected in series to form a module (details are omitted here for confidentiality). The total number of cells is determined in order to be able to generate 100 kW of gross DC power at nominal operating conditions for the cells (see *Table 1*). The model computes then energy and mass balances to determine outlet gas conditions. Pressure drops in the channels are considered dependent on the volumetric gas flow rates.

Table 1 – Stack nominal operating conditions

Nominal operating conditions	
Nominal current density	1 A/cm^2
Air ratio to stoichiometry	2
Hydrogen ratio to stoichiometry	1.5
Air / H2 average RH over the stack	100 %
Stack backpressure	0.1 bar$_g$
Stack temperature	70 °C
Coolant temperature gain over the stack	10 °C

Main Balance of Plant (BoP) components

The main BoP components that are included in the model are shown in *Figure 2.*

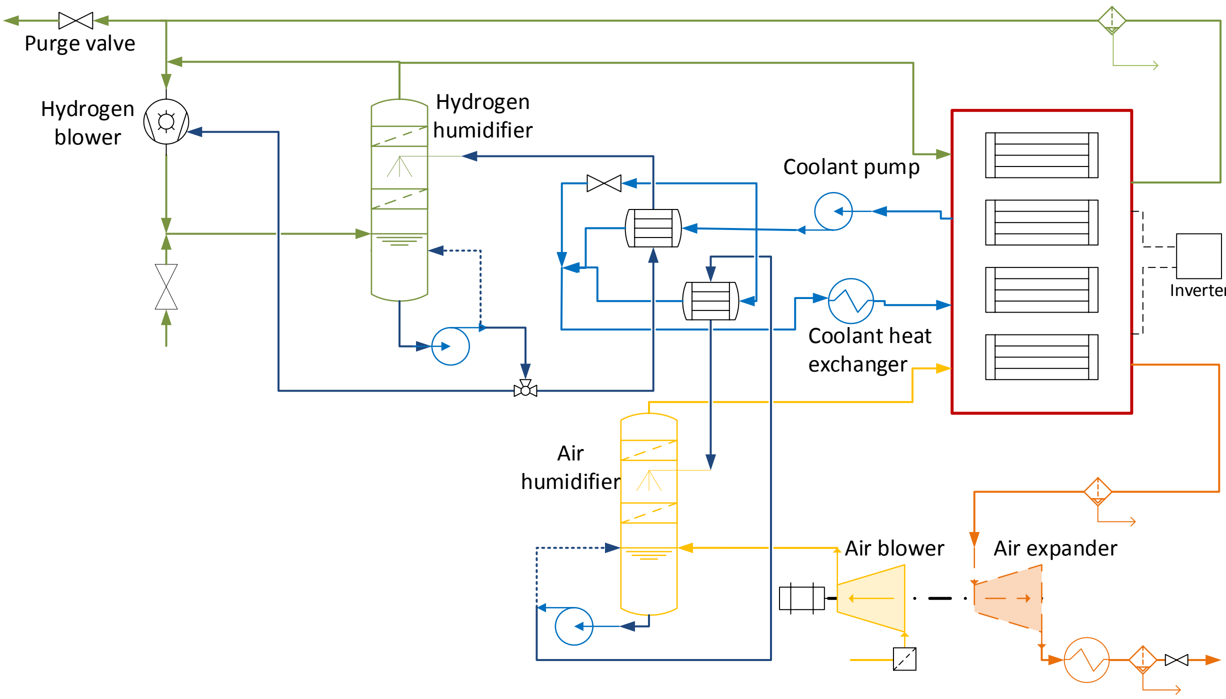

Figure 2 – Proposed layout for the 100 kW PEMFC pilot plant.

Fresh air is compressed, humidified and sent into the FC. A backpressure valve is then installed to keep the system pressurised and investigate the plant behaviour under mildly pressurized conditions. Two different options are considered:

- Option A: air exiting the cathode is cooled in order to condensate the water vapour. Air is then expelled into the atmosphere;
- Option B: air that exits from the cathode is sent into an expander in order to recover energy. Air is then cooled to condensate and separate the demineralized water and finally expelled.

Exhaust hydrogen is compressed to overcome the pressure drops, recirculated and mixed with pure hydrogen which is assumed to be available at the plant inlet at a minimum pressure of 2 bar. Hydrogen is then humidified with a dedicated loop. A small amount of water is continuously recirculated internally to the humidifier to be filtered. A purge valve on the hydrogen line is required to avoid inert gases build-up.

Both for air and hydrogen humidification, shower-type humidifiers are adopted. These humidifiers are water scrubbing units, that have also the function of removing possible pollutants from the inlet flows. These components are simulated by discretizing the columns along the direction of the flows in 4 sections and solving mass and energy balances assuming water-liquid equilibrium conditions in each discretization section. The reactants temperature at the humidifier outlet is controlled to obtain the relative humidity that is required in each operating condition. The heat necessary to control the humidifiers temperature is obtained from the hot side of the cooling circuit; the coolant fluid temperature is then further decreased to the desired stack inlet value in a heat exchanger dedicated to heat rejection. Heat exchangers are modelled considering the respective heat transfer areas and empirical correlations reproducing the dependence of global heat transfer coefficients and pressure drops on the flow rates (Table 2).

Table 2 – Heat exchanger characteristics

Heat exchanger	A [m^2]	$U_{nominal}$ [W/m^2K]	U dependence on flow rate
Coolant – air humidifier loop	1.530	3170	$U = U_{nominal}\left(\frac{\dot{m}}{\dot{m}_{nominal}}\right)^{\frac{4}{5}}$
Coolant – H_2 humidifier loop	0.105	6200	
Coolant heat exchanger	6.630	2960	

For hydrogen compression a liquid ring compressor is considered while for the incoming air a volumetric blower is adopted. For Option B, it is assumed that the expander is a volumetric machine coupled with the compressor on a single shaft. In this way, the expander directly provides part of the mechanical power requested by the compressor. The values of the efficiencies assumed in the simulations for compressors, the expander and pumps are reported in *Table 3*. The inverter efficiency is assumed equal to 95%.

Table 3 – Efficiencies of the BoP components

Auxiliary component	Isentropic efficiency	Mechanical efficiency
Pumps	70 %	90 %
Liquid ring compressor	9 %	85 %
Air blower	Functions of flow rate and pressure gain (*Figure 3*)	
Expander	80 %	90 %

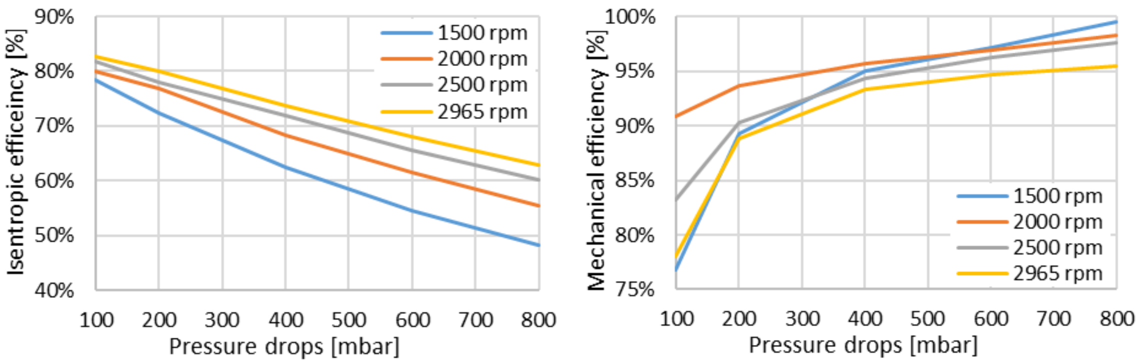

Figure 3 – Air blower efficiency curves

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2. Simulations

The FCPP model described in the previous chapter is used to compare the performances of the 100 kW plant in different operating conditions. Performances are express in term of gross and net electric efficiencies – Eq. (2) and (3) - where the first one represents the efficiency of the PEM fuel cell only and the second one, depurated from the DC/AC inverter losses and auxiliary power consumptions, represents the overall efficiency of the plant. The energy input to the system is computed according to the Lower Heating Value (LHV) of the hydrogen feed stream.

$$\eta_{GROSS} = \frac{P_{FC}}{m_{H_2} \cdot LHV} \tag{2}$$

$$\eta_{NET} = \frac{P_{FC} \cdot \eta_{inverter} - P_{auxiliaries}}{m_{H_2} \cdot LHV} = \frac{P_{NET}}{m_{H_2} \cdot LHV} \tag{3}$$

In the project perspective, coherently with the scope of offering ancillary services, the plant is expected to work most of the time at partial load conditions. Simulations should therefore analyse the plant performances not only at the nominal operating point but also in off-design conditions. For this purpose, simulations are run in correspondence of a range of currents between 20% and 150% of the nominal current value (i.e.1 A/cm^2).
The possibility of increasing the efficiency by working in mild pressurised conditions is also explored in the simulations. Simulations are performed both at ambient pressure and at slightly pressurised conditions (below 1 bar$_g$) to analyse how pressure influences the gross efficiency and the consumptions of the auxiliaries and how these effects are reflected on the plant net efficiency. For each chosen operating condition, plant simulations are performed with both layouts options A and B, allowing to understand under which operating conditions the introduction of the air expander may bring significant advantages.

Table 4 summarizes the simulation cases; air and fuel ratio to stoichiometry are always kept constant at the nominal values (2 and 1.5 respectively) by varying the reactants flow rates while changing the electric load. The coolant flow rate that passes through the cells is also varied: it is decreased with the load to avoid excessive low temperatures at FC outlet, and increased at high loads to limit the maximum temperature gain. This is possible by regulating the rotational speed of the dedicated pump. Ambient temperature is always assumed equal to 15°C.

Table 4: Summary of the simulation cases

Case 1	Case 2	Case 3	Case 4
Ambient pressure	Ambient pressure	Pressurised (0.6 bar$_g$)	Pressurised (0.6 bar$_g$)
Option A (no expander)	Option B (with expander)	Option A (no expander)	Option B (with expander)

3. Results

Simulation results show that the designed plant is fully controllable in term of temperature, flow rates and air relative humidity, able to reach the desired values for any current density and for both low and higher FC backpressure. Indeed, full controllability of these

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parameters is given by the inclusion of two separate circuits for air humidification and stacks cooling and by the arrangement of the coolant heat exchangers in parallel configuration with a bypass system. The possibility of using an ethylene glycol/water mixture to cool the stacks, allowed by the use of a separated coolant circuit, is also interesting for possible fully independent applications in cold climates.
On the contrary, in some cases it is not possible to fully control the hydrogen relative humidity, which - as a consequence of the hydrogen recirculation through a liquid ring compressor - can be higher than required. In such cases it would be therefore necessary to cool down the hydrogen humidifier.

Figure 3 shows the net power output and the corresponding gross and net efficiencies, obtained in each case by varying the current density from 20% to 150% of the nominal value. The higher gross efficiencies are reached at higher backpressures (Case 3 and Case 4) for any given net power output. On the net efficiency point of view, it can be highlighted that maximum net efficiency at full power is reached with Case 4, i.e. at max pressure with expander. The introduction of the air expander is instead obviously not attractive at low pressures (Case 2). At partial loads, the maximum net efficiency is reached at nearly 30kW at low pressure (Case 1 and 2), approaching 50% net; while it is reached at ~60 kW at higher pressure (Case 3 and 4), with Case 4 close to 48.5%.

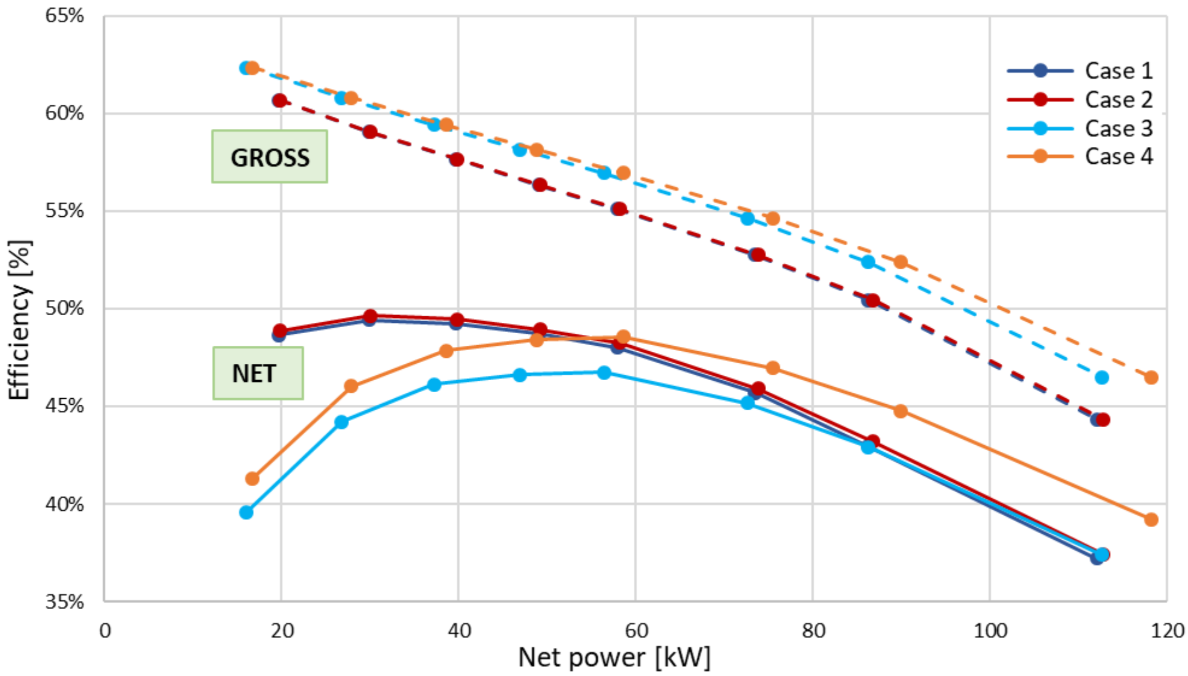

Figure 3 – Gross & net efficiency Vs net power

Figure 4 shows the total power consumed by the plant auxiliaries as a function of the net power. Auxiliaries consumptions always increase by increasing the net power except in Case 4, where in the range 20-60 kW they remain almost constant; in this range the additional power required by the auxiliaries when the load increases is perfectly counterbalanced by the additional power that the expander is able to provide by expanding air from 0.6 bar_g to ambient pressure.
Figure 5 shows the percentage gain in the net power output obtained with respect to the case at low pressure without expander (Case 1), at constant current density, i.e. at constant hydrogen consumption. It is clear that it is not effective to pressurize the stacks at low loads, where pressurisation leads to a net power loss higher than 15% with respect to the base case. Pressurisation becomes attractive at higher loads if an expander is also installed, giving the possibility of a 5% gain in net power output.

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A further gain in the net power output can be reached saving energy during compression by substituting the blower (assumed here to operate with the efficiency curves of Fig.3) with a more efficient machine, like a radial compressor. For such a system it is also more customary to have the compressor and turbine running on the same shaft, like in conventional turbochargers for the automotive industry, thus decreasing the electrical losses. The system envisaged would be in this case similar to units which are currently designed for mobility applications of PEM fuel cells.

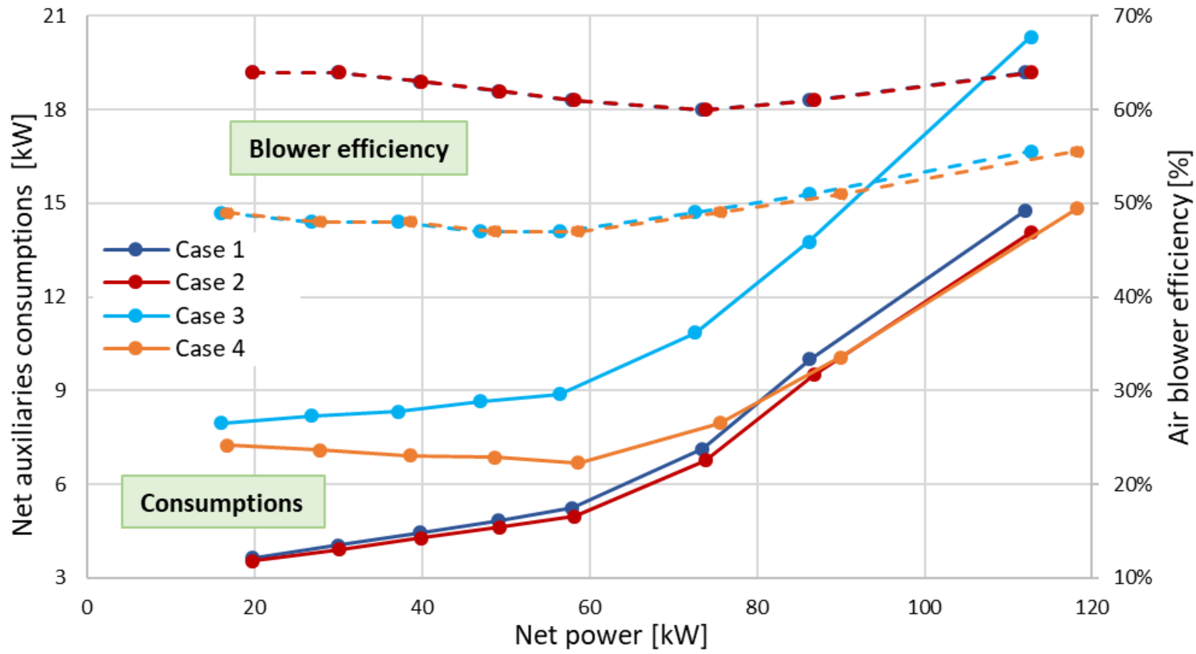

Figure 4 – Total auxiliaries consumptions and air blower efficiency Vs net power

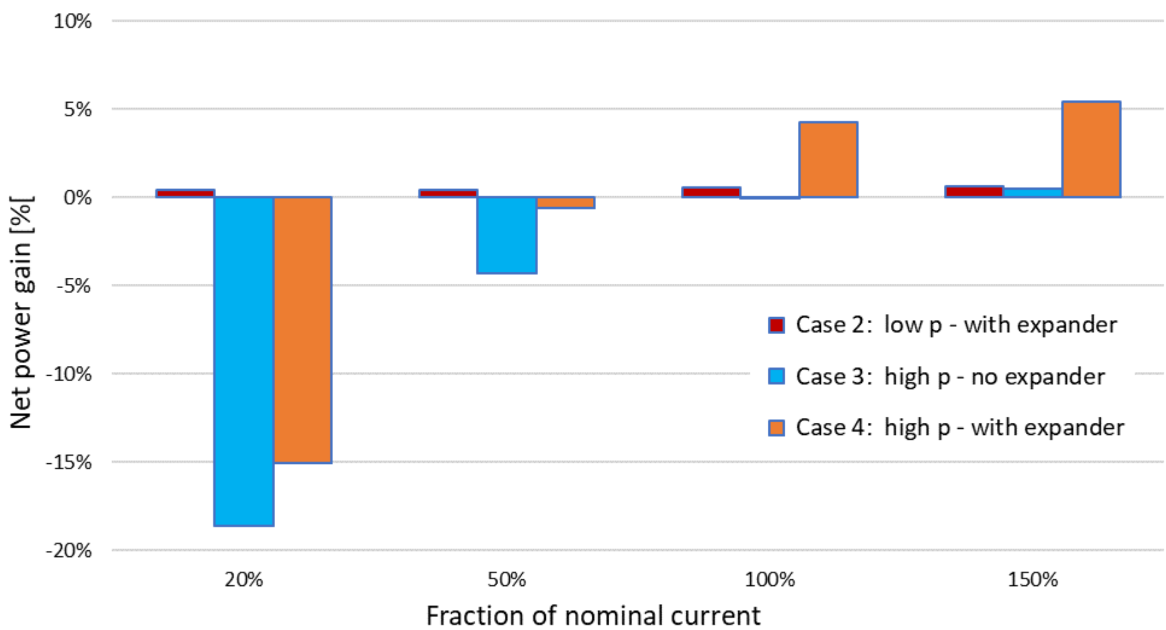

Figure 5 – Efficiency gain with respect to low pressure case without expander (Case 1).

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G0308

GRASSHOPPER project: Grid assisting modular hydrogen PEM power plant

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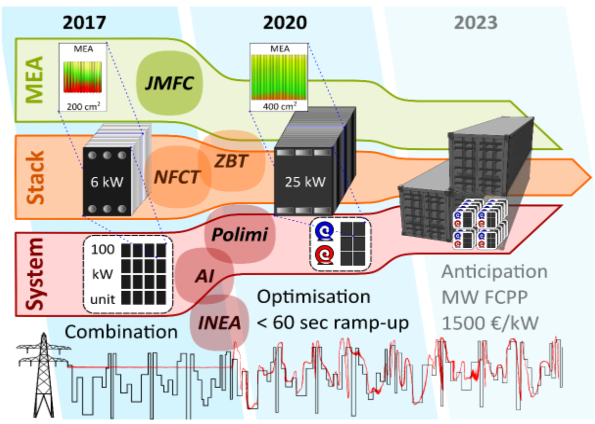
Abstract

The Fuel Cell Power Plant (FCPP) developed by the GRASSHOPPER[1] consortium will represent a next-generation MW-size PEM FCPP, more cost-effective and flexible in power output (estimated CAPEX below 1500€/kW$_e$ at a production rate of 25 MW$_e$ / year), designed for grid support and participation to flexibility trading and renewable energy markets.
The power plant will be demonstrated through a 100 kW sub-module pilot plant, implementing newly developed improved stacks, MEAs and BoP components, combining benefits of coherent design integration. This unit will be operated continuously for 8 months in industrially-relevant environment in Delfzijl (NL), engaging grid support modulation as part of an established on-site Demand Side Management (DSM) program. The flexible demand-driven operation will be demonstrated in the range 20-100 kW with a ramp-up rate delivering 50 kW within 20 seconds and 100 kW within 60 seconds. Innovative DSM programmes will be completed to establish the best path forward for commercialization of the technology for a fast response FCPP. A prototype software interface to be used as a tool for aggregating and trading flexibility for offering services to the grid will be developed and will particularly enable integration of flexible FCPP into the DSM portfolio.



Concept and project delineation

[1] This project has received funding from the Fuel Cells and Hydrogen 2 Joint Undertaking under grant agreement No 779430. This Joint Undertaking receives support from the European Union's Horizon 2020 research and innovation programme, Hydrogen Europe and Hydrogen Europe research

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Introduction

Renewable energy is at the core of Energy Union's priorities. According to the Energy Directive 2009/28/EC, the member states of the European Union (EU) have to produce at least 20% of their total energy consumptions using Renewable Energy Resources (RES) by 2020 [1]. Even more ambitious targets are specified in the EU 2030 Energy Policy Framework for climate change (the Clean Energy for All Europeans package) and the Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources includes a binding renewable energy target for the EU for 2030 of 32% [2].

To reach these targets, a key contribution is given by increasing the share of electricity production from RES. Anyway, these higher share of RESs production that is uncertain, irregular and often distributed, causes demand-supply imbalances, more frequent occurrence of grid congestion, volatility and increase in the wholesale electricity price. Furthermore, due to the low power factor of RES, costly investments are necessary to have a sufficient capacity to support generation at few hours of peak.
To overcome these issues, the Clean Energy for All European package [3] has introduced new electricity market design rules in order to help the energy markets to include more renewables, empower consumers, and better manage energy flows across the EU. With these new energy market rules, consumers are put at the heart of the transition, giving them more choice and greater protection. With Demand Response (DR) schemes and infrastructures they are enabled to participate actively in the energy market, varying its consumptions and/or production in response to price changes in order to profit from the optimal price conditions. In this way, prosumers (i.e. who both produces and consumes) makes the grid more efficient and contribute to the integration of RES.

In this framework, GRASSHOPPER project focuses on FCPP (Fuel Cell Power Plant) technologies as flexibility enabler for prosumers through the use of hydrogen. The implementation of the FCPP technologies on the market will benefits for the new energy market rules. The introduction of scarcity pricing and the possibility to produce and sell electricity to the market on the base of price signals, allows FCPP technologies to take advantage of instantaneous market remuneration, thus creating the opportunity for longer-term investment in this technology.

The plant layout that has been considered so far is shown in *Figure 1*

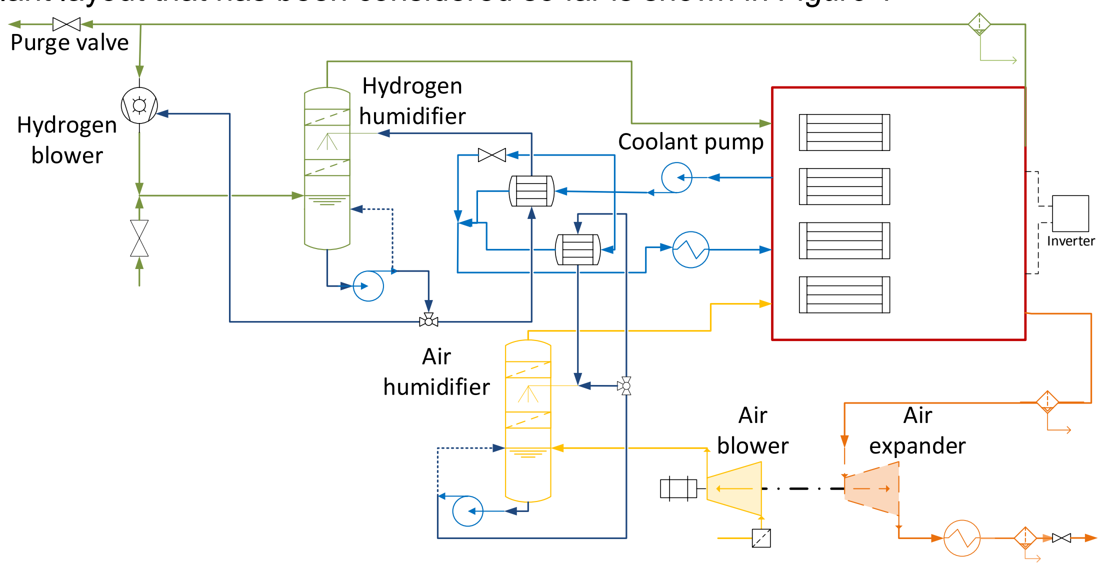

Figure 1 – 100 kW pilot plant Layout.

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1. Grasshopper project concept and delineation

The technical feasibility of large MW-size PEM Fuel Cell Power Plant (FCPP) has been well demonstrated, for example in the DEMCOPEM-2MW project (FCH-JU 2015) [4,5]. However, the cost assessment of this 2-MW power plant shows a too high Capex level (4175 €/kW). Furthermore, this plant was operated without dynamic operation features for grid support. Therefore, a major step in the reduction of fuel cell stacks and system costs is still needed, together with the dynamic operation capability that is a new necessary feature to participate in renewable energy markets.

The GRASSHOPPER (GRid ASsiSting modular HydrOgen Pem PowER plant) project, that has started the 1st of January 2018 and will last 36 months, tackles these issues in order to enable a controlled, renewables-based energy infrastructure.
The goal of GRASSHOPPER is to realise a major step change in the cost structure of existing FCPP, realizing the next-generation modular Fuel Cell Power Plant unit targeting stationary application in the MW scale (such as > 2 MW) grid stabilization.
The FCPP will be more cost-effective and flexible in power output, accomplishing an estimated CAPEX below 1500 €/kW$_e$ at a yearly production rate of 25 MW$_e$. This level is required to enter the markets as a competitive player.

Figure 2 shows the anticipated reduction of the CAPEX of multi-MW PEM FCPP, indicating the necessity of a major step change in cost reduction.

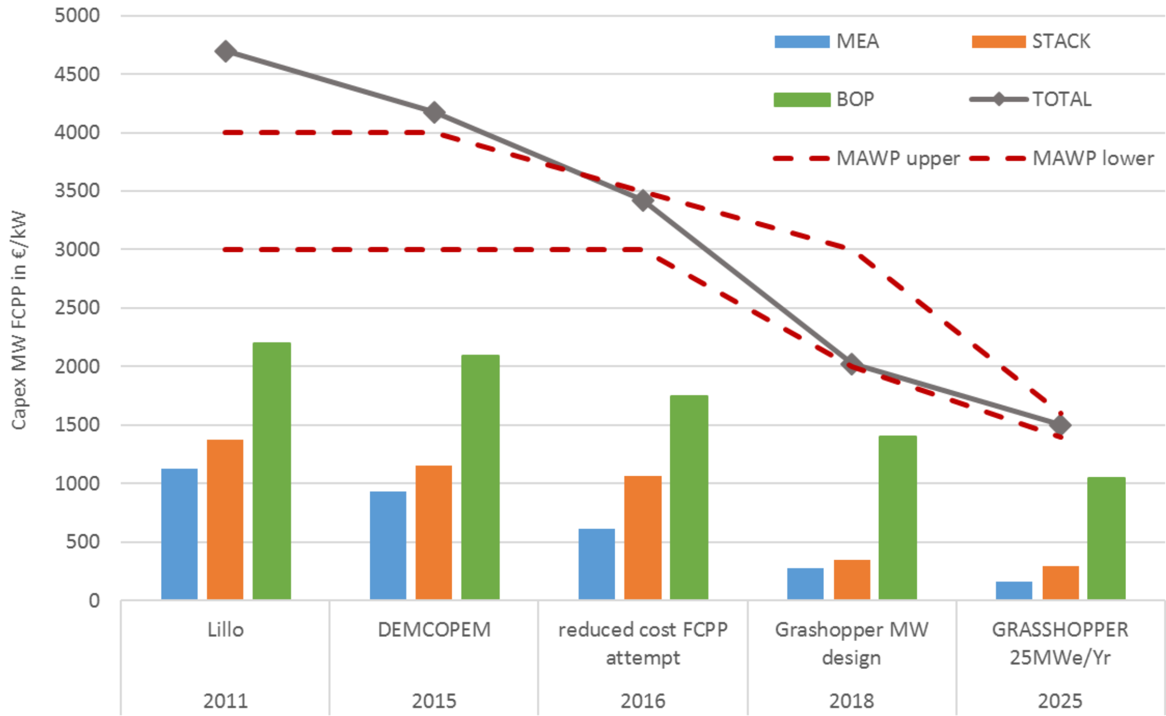

Figure 2 – Reduction of CAPEX in the multi-MW FCPP.

The consortium has the leading experience with building, operating and maintaining FCPP and hence a good understanding of what is needed to meet efficiency, performance and lifetime expectations. Scaling-up production volume alone is not sufficient to achieve 2023 target CAPEX costs of 1500 €/kW. First a design optimisation is proposed, coherently improving MEA, Stack and System together to realise a next-generation modular unit that does achieve the cost target when produced at scale. Thus, a first major step to

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approximate 2000 €/kWe will be made with the Grasshopper MW FCPP design and the target of 1500 €/kWe will be reached in the second stage via roll out to 25 MWe/year.

The MW-size FCPP unit will be based on the learnings from a 100 kW sub-module pilot plant, that will be demonstrated in the field. The 100 kW pilot plant will implement the design optimization; the power output will be increased from 6 to 25 kW_e to reduce system complexity and the operating pressures will be increased to improves the dynamic load range and flexibility. The 100 kW plant is large enough to implement cost savings and validate operation flexibility and grid stability capability via fast response.

The feature of flexibility and grid support functionality will be introduced by using a smart grid integration. The flexible demand driven operation will be demonstrated with a set point range between 20 kW and 100 kW and a ramp-up rate delivering 50 kW within 20 seconds and 100 kW within 60 seconds. This unit will be operated continuously for 8 months in industrially-relevant environment in Delfzijl, the Netherlands, for engaging grid support modulation as part of an established on-site Demand Side Management (DSM) programme. There is the intention of the consortium to keep the FCPP operating for 5 years after the project end. This will help to showcase the technology for interested parties, demonstrate the viability of the technology on medium term and serve as experimental validation of the operational costs for the system.

Project concept and delineation is summarized in *Figure 3.*

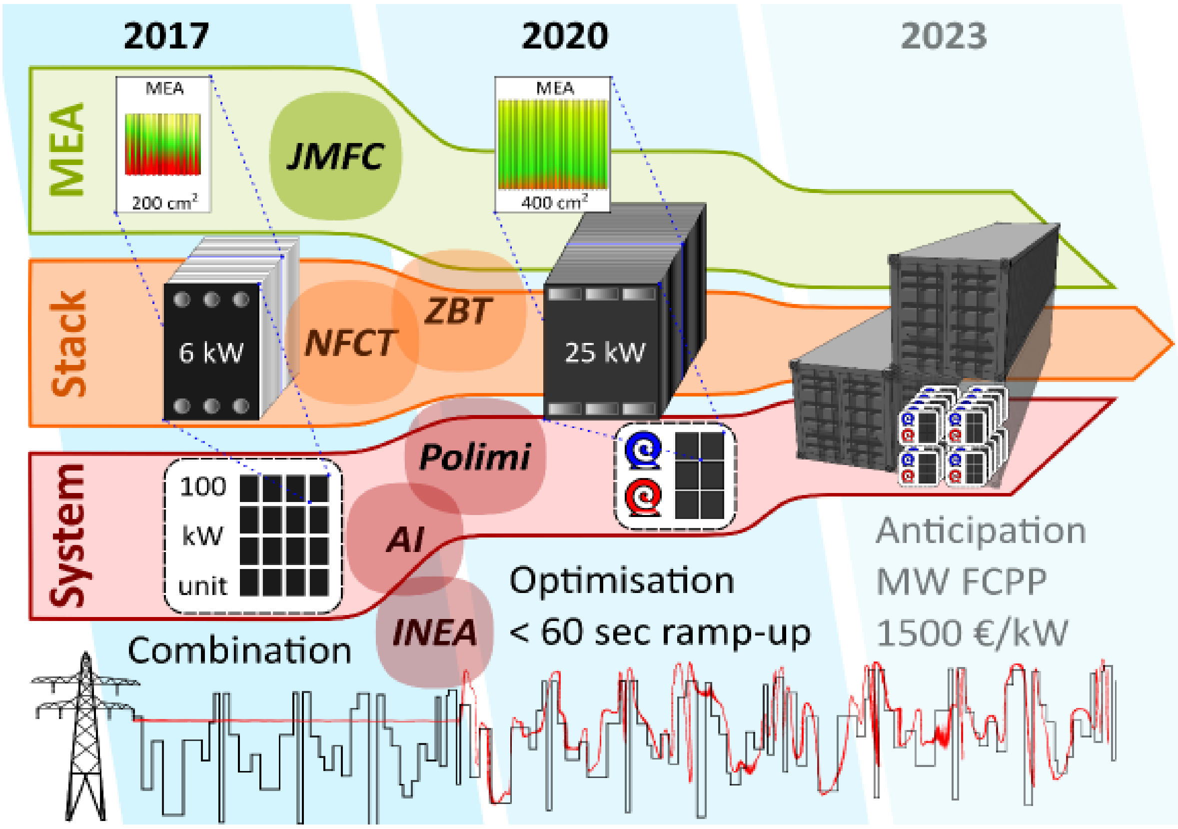

Figure 3 – Concept and project delineation

2. The project methodology and objective

Overall approach and methodology of the work plan consider a parallel approach, in which modelling activities and engineering activities for MEA, FC stack and FCPP are performed in parallel, with a continuous flow of information among the 6 members of the consortium.

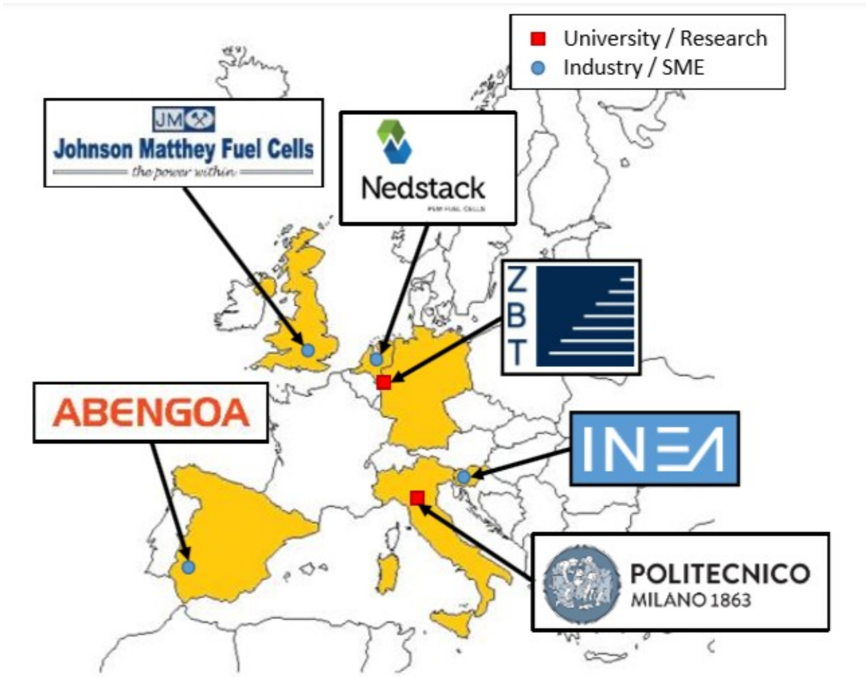

Figure 4 – Members of Grasshopper consortium

Taking DEMCOPEM-2MW in 2017 as the starting point, major cost reductions in MEA, stack and system need to be achieved by JMFC, NFCT and AI. This will be done for an important part by developing new stacks of larger sizes and higher power density, with improved MEAs and BoP system components. The step change in stack design is supported by modelling work from ZBT, which has extensive know-how on stack modelling and design. JMFC focuses on the MEA cost maintaining durability. POLIMI and AI focus on cost reduction of the FCPP BoP, using a wide knowledge of components of other industries such as AI manufacturing knowhow and POLIMI model of the overall system and component integration to reach optimal efficiency. In this way, the benefits of a coherent design integration will help to achieve cost and technical optimization. INEA will take care of the interface with the grid by bringing in the experience of the GOFLEX project; the feature of flexibility and grid support functionality will be introduced by using a smart grid integration.

The state of art and proposed improvements that will be realized in the project on MEA, stack and balance of plant are presented in the following paragraphs. Subsequently, the connection and integration with the local grid and local plant installation are described, as well as modelling, optimization and performance monitoring activities.

Targeted advances in PEM FC MEAs

Long lifetime PEMFC MEAs for large-scale stationary power generation applications require well over 20,000 hours of continuous operation, and thus have technical requirements which are very specific compared to automotive and small-scale stationary

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applications. The drive to reach higher power densities has not been the primary focus, whereas the requirement for stability and durability are of prime importance. The state of art MEA for large scale stationary application necessitate the use of a thicker membrane than automotive (up to 30 μm) to maintain durability, bonded catalysed substrate construction and high loaded cathode catalyst, which are incompatible with automotive type catalyst coated membrane (CCM) constructions.

Using a CCM MEA construction up to 75% lower Pt loading on a per unit power density basis than the current design is envisaged, thanks to thinner, higher quality printing, as well as reducing manufacturing costs by up to 65% on a cost per unit power basis, improving yield by 10% and providing the large scale stationary industry as a whole with a cost-effective MEA. The change to a CCM type process will also enable the use of cheaper gas diffusion substrate as the base-layer quality and porosity does not become the print quality limiting factor.

JMFC will mainly work on the realisation of improved MEAs with improved performance, no loss of durability and lower costs. The main activities are on the development of mechanically reinforced membranes, the integration of these membranes and catalyst layers to design and test CCMs, the scaling of CCM manufacturing to the volumes required for the stack validations and finally the integration of the CCMs within the new stack design.

Targeted advances in PEM FC stacks

Nedstack has shown long lifetimes and has successfully demonstrated its current stack technology for stationary MW-scale power plant applications (e.g. in the DEMCOPEM-2MW project). However, for successful future commercialization stack costs need to reduce drastically. This will be achieved mainly by step-increase in stack size and in power density.

Step-increase in stack size will be reached via a new cell plate design that will allow to increase the maximum cell count, reducing the stacks number and consequently the costs that are one-off per stack. The active area will be also increased and a new cell plate composition will allow for higher operating temperatures and lower cell plate thickness. Step-increase in power density will be achieved by running at higher current density, to fully utilize the stack power potential, and at different operating conditions, such as higher inlet pressures for hydrogen and air for stable operation at high current densities as well as fast dynamic responses. The stack housing design will be simplified and designed for mass production to reduce weight, volume and costs. Also a new gasket design will be required, as well as a different gasket material and gasket production process. This activity will be a joint development between NFCT and ZBT.

ZBT is responsible of the optimization of the fuel cell stacks flow field and of the operation point and operation strategy. A stepwise optimization of cell internal water management and cell operational uniformity linked to the external media conditioning and controls will lead to an optimized flow field and a streamlined operational strategy. Beside the most efficient working point, the operational stability of the new stack generation is in focus of numerical and experimental optimization both for the stack and the surrounding system and controls.

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Targeted advances in the Balance of Plant

Stationary FCPP consists primarily of the fuel cell stack and the balance of plant (BOP) components. The BOP includes items such as humidifiers, valves, compressors, pumps, wiring, piping, meters, controls, instrumentation, manifolds etc. that are associated with the complete operation of the fuel cell system. As can be evidenced from previous work [6] the BOP can actually be the dominant cost driver in FCPP's.

To reduce these costs, design efforts towards easy fabrication and modularity are necessary. Improvements for both cost reduction and system efficiency increase have been identified by ABENGOA.

Improvements in the power electronics can reduce significantly the costs since part of the cost of BOP is covered by power subsystem, mainly the inverter and the converter. The traditional inverters used for FC system are expensive and have efficiency in the range of 95-96%. There are low cost inverters in the market used for solar PV plant, with efficiency above 98%, and FC systems may be designed to have a voltage that matches these commercially available solar inverters. In this project, companies making these inverters will be approached to purchase inverter for 100 kW pilot plant and to evaluate the available options for MW sizes. Further reductions in power electronics costs are going to be addressed in the current project after careful analysis of different levels of centralization (e.g number of inverters for a specific power) without compromising system availability and serviceability. In case the FCPP has to be operated off grid, the system should be hybridized with battery/supercapacitors [7]. The main challenge in designing a fuel cell system for off-grid operation is matching the stack variable voltage over the desired load range with the battery system while keeping it in an acceptable range for the DC/AC inverter. The most straightforward design is to have a DC/DC converter between the fuel cell and battery bus to keep the stack output voltage in a proper range for the battery and the DC/AC inverter. However, a DC/DC converter adds a significant cost to the system. Another option is to use a three-port hybrid converter, an emerging technology designed and marketed for PV applications, that is more economical than discrete components.

The power increase per stack will reduce the number of connections, valves and other components, decreasing the manufacturing costs. Efficient compressors will contribute to the efficiency of the complete system while the use of standard instead of customized containers will significantly contribute to cost reduction.

Integration with the local grid and local installations

Promising solutions to overcome the issues that comes from the pervasive emerging of distributing non programmable RES have been proposed in a number of technological areas. The challenges of modernizing the electricity grids in Europe lie in enabling an increased flexibility of the European power system, efficiently providing increased transfer capacity and enabling an active participation of users and new market actors. Demand Response schemes and infrastructures offer various incentive frameworks and solutions for making a prosumer active, so it varies its electricity consumption and/or production in response to direct commands or economic rewards, for: offering ancillary services, e.g. to aggregators, balance responsible parties (BRPs), distribution system operators (DSOs); creation of microgrids and virtual power plants (VPPs), to exploit flexibility in demand and supply. On the market, there are many technologies enabling to integrate prosumers in DSM programmes. EU Commission with "Clean Energy for All Europeans" package

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(November, 2016) for clean energy transition is supporting new technologies and approaches to increase available prosumer's flexibility.

FCPP are to be competing with other available sources of flexibility. To showcase the benefits of FCPP for using its flexibility for grid support, for counter-balance peaks and drops in demand and supply, existing Demand Side Management (DSM) infrastructure will be adopted to integrate and validate FCPP as one of the key DSM enabling technologies on the side of prosumers. FCPP for grid support will target two groups of customers: a) Directly DSO or better aggregators with a goal to increase VPP (Virtual Power Plant) capacity and increased system stability, and b) Prosumers to enable them to participate in the market for flexibility and thus decrease their cost of electricity.

INEA will deal with power control and grid interaction, providing advanced solutions for gathering flexibilities on prosumer side. It will develop and validate prototype of FCPP to Grid interface as a tool to enable aggregators or Grid Operator to use FCPP flexibility for grid support services. Major roles will be to develop and validate a HW/SW tool that enables integration between FCPP and Distribution Grid Management System to be validated in an industrially relevant environment. On the other hand INEA will assess the business models and entrepreneurial strategies for integration of FCPP for grid support services and DSM programmes.

Modelling, optimization and performance monitoring

The modelling of mass and energy balances is an important step for identifying the reference theoretical performances of the system in terms of fuels consumption, electricity production, heat production and therefore of efficiency. This kind of analysis supports the improvement of system components and cost, identifying the most critical sections; on the other hand, also on-field measured values can be compared with results of simulations, identifying malfunctioning or unexpected operating conditions. The modelling activities are also relevant to investigate the behaviour of the system in off-design conditions (which are of large importance in the grid-support operation of the PEM plant), evaluating the technical viability in conditions that cannot be checked directly before real world application, supporting the exploitation process. A conceptual scheme of this approach is presented is Figure 5.

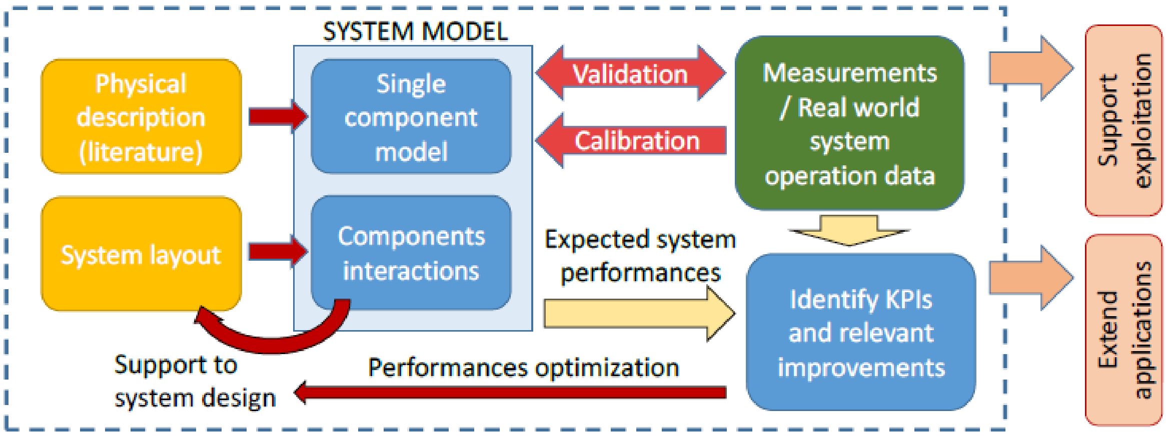

Figure 5 - Conceptual scheme of general modelling activities connected with field measurement and their impact on system performances optimization

POLIMI Energy Department has a long experience in the design, optimization and performance analysis of innovative energy system. In particular, in the field of hydrogen technologies several models have been designed related to both low and high temperature fuel cells and electrolysis systems, as well as for hydrogen production systems (steam reforming, membrane reforming, etc.). They make use of commercial (e.g. ASPEN), as well as in-house developed codes and are based on literature models for basic physics. Part-load operation of stacks at nominal temperatures can be simulated, as well as the influence of external conditions (e.g. environment temperature) and plant set-points (e.g. air excess).

An experimental section is also part of the experience of the group, focused on testing complete systems for cogeneration and fuel cell units at the POLIMI LMC (Micro-cogeneration Lab), laying also the basis for carrying out field tests on the systems once in operation, both during the FAT phase and during operation at the final installation site (e.g. specific measurements of reactant and cooling flows flow rate at inlet/outlet of groups of stacks), which are supporting the correct analysis of system performances. This activity, already performed in the previous project DEMCOPEM-2MW, allows to integrate the plant measurement system and to improve the accuracy in assessing the global performances of the system, where model results are compared with measurements for a mutual validation. Main challenges of the technical analysis of the PEM plant are related to the definition of a model sufficiently accurate to reproduce the different systems in order to support decisions in a) System layout optimization, b) Management of the plant in real world conditions; c) Identify possible improvements of operating strategies; d) Simulate the performance in conditions other with respect to the demonstration ones.

A sufficiently accurate and continuous flow of data will be guaranteed by the presence of the demonstration unit, operated in variable environmental conditions and subject to different loads. The identification by means of data analysis will be also a challenge of the project (i.e. optimal operation, possible presence of an electric energy storage).
The resulting tool will improve predictive capacities in terms of performance of the innovative system in different operating conditions and assist in the translation of pilot to MW FCPP. The models are expected to be improved both as benchmark for the current and future application, as well as to become a tool for estimating the impact of layout changes. The detail level in the description of part load and off-design conditions will be strongly improved and validated thanks to the large availability of data.

3. Conclusions

GRASSHOPPER project will develop a Fuel Cell Power Plant (FCPP) characterized by operation flexibility and grid stabilization capability. It will represent an example of the hydrogen-based electrical power generator with ability to participate in the automated flexibility trading market and to receive remuneration for providing ancillary services.

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REMOTE project: techno-economic analysis of H2-based energy storage systems in remote areas

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Abstract

The development of efficient and sustainable energy solutions and the attempt to reduce carbon dioxide emissions are leading to an increasing penetration of Renewable Energy Sources (RES). Effective Electrical Energy Storage (EES) solutions need therefore to be developed to deal with the issue of fitting locally available RES and loads. Hydrogen can become an interesting option because of its high energy density, long-term storage capability and modularity. In particular, in isolated micro-grid and off-grid remote areas, intermittent RES integrated with H_2-based storage systems can provide a reliable, cost-effective and decarbonized alternative to on-site electricity generation through diesel engines.

In this context, the EU REMOTE project aims at demonstrating the technical and economic feasibility of H_2-based energy storage solutions in remote locations: four demonstration sites have been selected in four different locations across Europe. According to the site, different RES sources are exploited: solar, wind, biomass or hydro. Their usage is optimized thanks to the operation of an H_2-based Power-To-Power (P2P) technology. In fact, surplus RES energy can be supplied to the electrolyzer for H_2 production. The fuel cell is then employed to generate electricity back during renewable power shortages. A battery bank is also adopted as complementary shorter-term electricity energy buffer. A centralized controller on-site will perform the management of the whole hybrid EES.

The aim of this study is to develop a preliminary techno-economic analysis and demonstrate the effectiveness of the hybrid H_2-battery Power-To-Power (P2P) solution in reducing the usage of external sources (e.g., diesel engines or grid) in a cost-effective way, with different load and environment conditions. The economic viability of the considered scenarios was outlined by computing the Levelized Cost Of Energy (LCOE). For each of the four sites, the innovative renewable configuration is compared with the current/alternative one. Main input data for the analysis were provided by the REMOTE project partners: techno-economic data from the technology suppliers, whereas electricity consumption and RES production values from the end users of the four isolated locations. Results from preliminary energy simulations revealed that the need for an external source is significantly reduced thanks to RES coupled with the hybrid storage system. Moreover, for all DEMOs the renewable solution was shown to be more profitable than the current or alternative one, either in the short term or in the longer term.

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Introduction

Renewable Energy Sources (RES) will represent the major asset in the future energy mix, addressing the problem of fossil fuel progressive depletion and mitigation of greenhouse gas emissions. However, well-known challenges have to be overcome to allow RES widespread diffusion. Effective Electrical Energy Storage (EES) systems are in fact required to deal with the problem of intermittency of electricity production from RES (e.g., wind and solar) [1]-[3]. Hydrogen, in particular, can represent an interesting storage solution because of its high energy density and long-term storage capability [4].
Concerning off-grid and micro-grid environments, diesel engines are the dominant technology for electricity generation with more than 23 GW of installed capacity [5], mostly in island and large territorial states, despite the related high production costs and pollution problems [6]. Exploiting local renewable energy could be an alternative. However, EES solutions need to be adopted to better optimize local RES management allowing to achieve higher RES penetration levels. Intermittent RES coupled with H_2-based energy storage systems can become an interesting choice [7]-[8] providing a reliable, cost-effective and decarbonized alternative to the common on-site electricity generation through diesel engines [9].
The presented work is performed within the framework of REMOTE (Remote area Energy supply Multiple Options for integrated hydrogen-based Technologies), a 4-year project (2018-2021) of the EU's Horizon 2020 program [10]. REMOTE objective is to demonstrate the techno-economic feasibility of hydrogen-based energy storage solutions in isolated micro-grids and off-grids remote areas, in the 5-200 kW range of fuel cell power [11]. As shown in Figure 1a, four DEMOs will be installed in four different locations across Europe: Ginostra (South of Italy), Agkistro (Greece), Ambornetti (North of Italy) and Froan Islands (Norway). The last DEMO will be temporarily host in the mainland in Rye (Norway) for a 2-year testing period before being moved to Froan. Each installation will complement locally available RES (i.e., solar, wind, biomass or hydro) with a hybrid energy storage system based on hydrogen and batteries, as schematically reported in Figure 1b. Stationary batteries are in fact commonly used to store energy on daily basis smoothing down the RES high-frequency variability [12]. However, when the energy storage is required for a longer period, batteries become expensive and the integration with H_2-Power-To-Power (P2P) systems with medium/long-term capabilities can be a viable and reliable option [13]. The adoption of a proper Energy Management Strategy (EMS) is thus essential for a correct interaction of the various sub-systems with the aim of achieving good energetic and economic performances [14]. However, the task is challenging because of the high number of technologies to be integrated (i.e., RES power systems, battery and hydrogen-based devices). During the course of the project, data from real-life experience will be made available giving the possibility to define specific control strategies for each DEMO and providing valuable information for the system modeling. The variety of the involved DEMO cases will allow to gain significant learning from integration with existing infrastructure in real sites paving the way for the deployment of the P2P storage system at large scale.
The aim of this study is to define the use cases of the four DEMOs, analyzing the technical solution proposed for each DEMO in order to evaluate how to improve the local situation. The various demonstration sites are described and the main technical data of the innovative RES + hybrid P2P system are presented. Preliminary energy simulations are carried out to demonstrate the effectiveness of the hybrid energy storage solution in reducing the usage of external sources (e.g., diesel engines). Finally, potential economic benefits are outlined comparing costs for the current or alternative and the suggested renewable solutions.

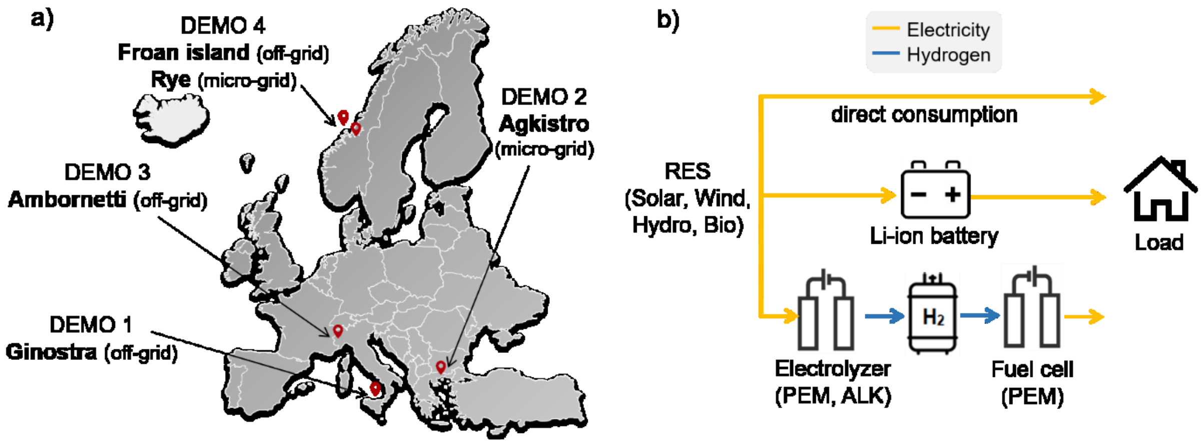

Figure 1. *a) Geographical location of the four demonstration sites. b) Operational sketch of the P2P system with H2 and batteries as energy storage mediums*

1. DEMO's description

A summary of the main components involved in the suggested innovative solution for each DEMO is reported in Table 1.

		1. Ginostra	2. Agkistro	3. Ambornetti	4. Rye
RES	Typology	PV	Hydro	PV + Biomass	PV + Wind
	Size	170 kW	0.9 MW	75 kW PV 49 kW Biomass	85 kW PV 225 kW Wind
P2P	Typology	Integrated	Integrated	Non-integrated	Non-integrated
	Supplier	ENGIE-EPS	ENGIE-EPS	BPSE, ENGIE-EPS	HYG, BPSE, POW
	P2G				
	Technology	Alkaline	Alkaline	Alkaline	PEM
	Rated Power	50 kW	25 kW	18 kW	55 kW
	G2P				
	Technology	PEM	PEM	PEM	PEM
	Rated Power	50 kW	50 kW	85 kW	100 kW
	H_2 storage				
	Gross energy (LHV)	1793 kWh	996 kWh	498 kWh	3333 kWh
	Battery				
	Technology	Li-ion	Li-ion	Li-ion	Li-ion
	Rated energy	600 kWh	92 kWh	92 kWh	550 kWh

Table 1. *Components of the RES+H_2-based storage solution*

1.1 DEMO 1: Ginostra

Ginostra is a village on the island of Stromboli in Southern Italy. The site is classified as off-grid since not connected to neither the Italian distribution and transmission grid nor the

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main Stromboli island micro-grid. All loads are residential and currently satisfied by employing one 160 kW and three 48 kW diesel generators. Because of the remoteness of the area, the fuel has to be transported in by helicopter leading to high costs for electricity generation. Enel Green Power (EGP) [15] is the final user of DEMO 1.
Main drivers to move to the PV + battery-H_2 P2P solution can be summed up as follows: 1) reducing current diesel consumption to lower the cost of electricity production and decrease the local pollution; 2) enhancing the reliability of the electricity service; 3) avoiding prohibitively high costs due to grid connection and 4) gaining experience from the P2P operation to replicate in other European islands.
Main technical specifications of the PV battery-H_2 system are set out below. Regarding the RES power plant, a 170 kW PV system from EGP will be installed. The hybrid energy storage system includes a 600 kWh Li-ion battery bank from EGP and an integrated hydrogen-based solution from Engie-Electro Power Systems (EPS) [16]. In particular, the H_2 system is composed of a 50 kW alkaline electrolyzer, a 50 kW PEM fuel cell (i.e., two 25 kW P2P modules) and a hydrogen storage with total capacity of 21.6 m^3. An oxygen storage of 10.8 m^3 is also present since the fuel cell is fed with pure O_2. Two 48 kW diesel generators will be maintained as a final back-up system.
The total annual electrical load, which is currently covered by diesel generator, is around 171.6 MWh. The new PV power plant is estimated to produce yearly about 273.2 MWh. Analyzing the hourly PV estimated energy production and load profiles along the year, it was seen that only slightly less than one third of the overall annual energy from PV, i.e., 82.4 MWh, can be directly consumed by the load. An energy storage system is therefore necessary to optimize the RES exploitation and store the remaining excess RES energy to use when a renewable energy deficit occurs, thus reducing or even avoiding the intervention of the diesel generator.

1.2 DEMO 2: Agkistro

Agkistro is a remote village situated in Serres region, North Greece closed to Bulgaria. At the DEMO site there is a hydroelectric plant, which is owned by Horizon SA (HOR) [17], with connection to the grid to sell the produced electricity. HOR company, which is the DEMO end user, aims at building an agri-food processing unit very close to its power plant. In order to connect the new facility to the grid, the company should create a separate line directly to a transformer 20 km away since the local one is full. In case of grid connection, besides the expensive and invasive work due to connection, the company would buy electricity from the grid at a price higher than the value of the sold hydropower energy.
The aim is therefore to make the new processing unit energy autonomous with no grid connection and relying only on the hydro plant and on the H_2-based P2P storage as a back-up system. Main drivers to move to this solution are thus: 1) avoiding the high expenses due to grid connection works; 2) improving the electrical supply reliability avoiding grid connection problems, i.e., instability and frequent outages due to the site remoteness; 3) avoiding to buy electricity from the grid at high prices and 4) gaining experience in the P2P storage solution for the replication in other remote areas.
The hydroelectric plant has a total capacity of 0.9 MW (with two turbines of 0.65 and 0.25 MW, respectively). Similarly to the Ginostra site, an integrated P2P system delivered by EPS is adopted. The hybrid storage solution includes a 92 kWh Li-ion battery bank, an alkaline electrolyzer and a PEM fuel cell with nominal sizes of 25 kW and 50 kW respectively and a 12 m^3 H_2 storage tank. An oxygen vessel with total capacity of 6 m^3 will be also installed to power the O_2-fed fuel cell. The minimum available electrolyzer size from the manufacturer, i.e., 25 kW, was chosen since the DEMO benefits from continuous availability of renewable source (hydro plant). Two fuel cell units of 25 kW were instead

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considered for the G2P section in order to cover the highest load request, which is around 40 kW.
Since the hydro plant works all year-round providing electricity to the main grid, RES electricity production is much higher than the load of the agri-food unit. Considering a medium year, the total annual production from the hydroelectric plant is in fact around 3166 MWh, whereas the total yearly electrical energy required by the new facility is estimated to be approximately 87 MWh. In a framework with high RES electricity generation and quite predictable and stable DEMO load, the P2P system is thus conceived as a backup unit in case of emergency or scheduled hydro plant downtime due to maintenance.

1.3 DEMO 3: Ambornetti

The mountain hamlet Ambornetti is an off-grid site located in North Italy, Piedmont. The aim is to turn this rural area into a completely energy autonomous community with neutral impact to the environment according to the object of a renovation project lead by IRIS [18], which is the DEMO end user.
Advantages and drivers related to the RES + P2P solutions are: 1) minimizing the overall lifecycle impact based on the renovation project aim; 2) avoiding expensive and invasive works and infrastructures for connection to the grid; 3) avoiding the employment of traditional fossil fuel generators and 4) gaining experience in the P2P storage solution for potential replication in other Alpine areas.
Concerning electrical production from local RES, a 75 kW PV power plant and a 49 kW biomass-based CHP generator will be installed to provide electricity to the off-grid community. The biomass system is able to work up to around 8500 hours per year providing approximately 41 kW of electric power (8 kW are self-consumed). Maintenance of the CHP plant is scheduled around every 300 hours. Biomass will be supplied from surrounding forests management and local agricultural waste. Regarding the storage system, a 18 kW alkaline electrolyzer from EPS and a 85 kW air-fed PEM fuel cell from Ballard Power Systems Europe (BPSE) [19] are adopted. The hydrogen tank has a volume of 6 m^3. Li-ion batteries with a total storage capacity of 92 kWh are also employed.
The annual electrical energy required by Ambornetti site is around 349 MWh. The total yearly energy produced by the PV system is estimated to be about 75.5 MWh; whereas the annual electrical energy coming from the biomass CHP system is around 345 MWh. The biomass plant periodically requires maintenance and needs to be shut down for approximately 10 hours each time. An energy storage system is thus necessary to complement the PV source during maintenance periods and allow the site to depend exclusively on local renewable sources.

1.4 DEMO 4: Froan/Rye

Froan is an archipelago of four islands located off the west coast of Norway, near Trondheim. The islands are currently interconnected by electric grid with one connection to the mainland through a sea cable, which is owned by the end user TrønderEnergi [20]. Since the cable is outdated, there is the urgency to replace it or consider other alternatives.
The exploitation of local RES sources, i.e., solar and wind, together with a H_2-battery storage system has been chosen as a solution. Main drivers to prefer this alternative are: 1) avoiding the high-priced and invasive replacement of the sea cable; 2) avoiding diesel power generation because of cost and polluting issues and 3) learning from the H_2-based system operation in Nordic countries climate and evaluating whether to propose it to other remote areas.

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The complete P2P system will be validated and tested at Rye on the mainland first, before shipping it to Froan. The farm site in Rye will be supplied by a 225 kW wind turbine and a 85 kW PV power plant. A non-integrated P2P solution with a 55 kW air-fed PEM electrolyzer from Hydrogenics (HYG) [21] and a 100 kW PEM fuel cell from BPSE has been considered. The hydrogen storage tank has about 100 kg of hydrogen capacity and is provided by Powidian (POW) [22]. A battery bank consisting of 5 racks of 110 kWh Li-ion is also adopted as a short term and quick-response storage. The whole system is integrated and managed by POW. Regarding the Froan site, the technical sizing of the RES and storage systems is still ongoing and depends on authorization issues.
The annual electrical consumption at Rye is about 126.8 MW. Concerning the wind and solar yearly production, around 209.7 MWh and 74.9 MWh have been estimated, respectively. The analysis of PV/wind production and load hourly profiles shows that about 81.6 MWh of the total RES production (i.e., PV + wind) are directly used to cover the farm load. The high amount of surplus RES energy can be thus stored through batteries and hydrogen and later used during the occurrence of energy shortages so as to maximize local solar and wind energy exploitation.

2. Method

2.1 Control strategy

A preliminary energy management strategy for the hybrid storage system has been defined in order to perform energy simulations (on yearly basis with 1-hour time step) and prove the usefulness of the proposed RES plus P2P solution in covering the electrical end-use demand. The control strategy integrates batteries as short-term storage system operating in first instance to absorb/provide electricity when necessary, and hydrogen as longer term storage medium working when the maximum and minimum operating limits of the battery are reached.
The State Of Charge (SOC) of the battery (SOC_{bat}) represents the main key decision factor for the EMS. The maximum and minimum battery SOC levels ($SOC_{max,bat}$ and $SOC_{min,bat}$, respectively) are considered as indicators to evaluate when switching on/off the fuel cell and the electrolyzer. When the battery SOC lies between its lower and upper boundary, priority is given to the battery component. During charging (RES power higher than the load demand), if SOC_{bat} has reached its maximum allowed level, the electrolyzer is switched on to convert the surplus RES energy into hydrogen. By contrast, during discharging (RES power lower than the load demand), the fuel cell is employed in order not to allow the battery SOC to go below $SOC_{min,bat}$. Information about the hydrogen SOC within the storage tank is also required: the electrolyzer can operate until the H_2 container is full and the fuel cell can produce electricity if enough hydrogen is present. Modulation ranges of electrolyzer and fuel cell need finally to be respected for the correct operation. The following constraints have therefore to be checked within the control strategy: 1) battery SOC limits, 2) modulation ranges of the electrochemical devices and 3) hydrogen storage SOC limits.

2.2 Economic analysis

Building on the data of the four DEMO sites, an economic analysis has been carried out in order to evaluate the economic viability of the scenario with RES coupled with H_2-based storage. Net present costs (NPC) for the current or alternative and renewable solutions were thus computed as follows:

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$$NPC = \sum_{i=1}^{n} \left[\frac{\mathrm{CAPEX}_i}{(1+d)^i} + \frac{\mathrm{OPEX}_i}{(1+d)^i} + \frac{\mathrm{RC}_i}{(1+d)^i} \right]$$

Where:

- n: analysis period, in years.
- d: corrected discount (considering an expected inflation rate).
- CAPEX_i: capital expenditures (including transport and installation costs) due to investments in the system in year i. It refers to the investment costs at the beginning of the strategic periods (for the first period $i = 1$).
- OPEX_i: operational and maintenance costs of the system in year i.
- RC_i: regeneration costs. They refer to the periodic reinvestment/regeneration to maintain the operation of the system. It includes all related transport and installation costs.

Levelized cost of energy (LCOE) is also defined to calculate unit costs of the NPC divided by the updated energy delivery with the discount rate:

$$\mathrm{LCOE} = \frac{\sum_{i=1}^{n} \left[\frac{\mathrm{CAPEX}_i}{(1+d)^i} + \frac{\mathrm{OPEX}_i}{(1+d)^i} + \frac{\mathrm{RC}_i}{(1+d)^i} \right]}{\sum_{i=1}^{n} \frac{\text{Energy delivery}_i}{(1+d)^i}}$$

NPCs and LCOEs were calculated over different time horizons: 10, 20, 25 and 30 years. The nominal discount rate was set equal to 7%. It was adjusted assuming an expected inflation rate of 2%, such that the real discount rate is 4.9%. Specific data about investment, replacement and operating costs were provided by the project partners.

3. Results

3.1 Energy simulation

Energy balance simulations on a yearly basis have been performed for DEMOs 1, 3 and 4 by implementing the operation strategy models described in Section 2.1. The hourly profile of RES production and load provided by the end-users of each DEMO were used. Main results are summarized in Table 2. For Agkistro site, a RES supply failure is instead simulated assuming the storage system at full capacity. Nominal values for equipment sizes and efficiencies from the technology suppliers were considered. The aim is to demonstrate the effectiveness of the H_2-based P2P solution in reducing the usage of external sources (e.g., diesel genset) by maximizing the exploitation of local RES.

In Ginostra, simulations show that the proposed hybrid P2P solution enables to drastically decrease the use of current operating diesel generators to a value of around 4.4% of the total yearly demand. When the RES power is not enough to satisfy the load, the shortage is mainly met by the battery (approximately 44.3%), acting as shorter term storage. The fuel cell instead only accounts for approximately 3.5% of the load; but its presence is required due to its longer term storage capability. The fuel cell is in fact mainly used in the summer period, which is characterized by a higher energy demand because of tourism. Figure 2a shows the hydrogen level within the storage to be sharply reduced in summer because of fuel cell operation.

Regarding Agkistro site, since the hydroelectric production is always much higher than the load demand, it is considered that the hybrid storage system is at full capacity all year long. Batteries and hydrogen have a function of back-up in the case of emergency (e.g., RES supply failure or maintenance). Electrical loads of the agri-food building present a seasonal variation. During winter and summer, the daily load required by the facility is around 400 kWh. During autumn and spring, instead, when there are no heating and cooling needs, the load demand to be covered each day is lower, approximately 170 kWh.

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Applying the control strategy for the discharging case previously reported, in case of RES failure (i.e., RES power set equal to zero), the storage system is found to be able to sustain the energy demand for slightly more than one day in the summer and winter period and for almost three days for the rest of the year.

In Ambornetti, considering a reference day (i.e., no biomass device maintenance) the biomass system working at rated power together with the PV plant are used to cover the electric load. The battery bank needs also to intervene daily during the morning and evening load peaks when renewable power (i.e., solar plus biomass) is not sufficient alone to satisfy all the electrical demand. Instead, in the presence of maintenance of the biomass generator, energy within the hydrogen storage system is also required. The battery component in fact quickly reaches its minimum SOC and the fuel cell has to be switched on consuming hydrogen. The fuel cell intervention is clearly shown in Figure 2b, where the H2 SOC periodically drops during maintenance of the biomass generator. Approximately 87.1% of the total load is directly provided by RES. The battery share accounts instead for around 11.7%. Batteries need in fact to operate on a daily basis during the load increment in the morning and evening. The remaining 1.2% is finally covered by the fuel cell. The hydrogen pathway does not intervene every day; but its function is essential as a backup medium to guarantee energy self-sufficiency during the periodic maintenance of the biomass plant.

In Rye, local RES coupled with the hydrogen/battery energy storage systems are effective at significantly decreasing the amount of energy required from external sources (e.g. fossil fuel generators or the grid) to a value lower than 5% of the annual load request. Wind and PV plants directly cover approximately 61.2 % of the total load. Batteries and fuel cells accounts instead for about 25.9% and 8.4%, respectively. The evolution throughout the year of the amount of hydrogen in the tank is represented in Figure 2c: the higher energy deficit in the first part of the year causes the hydrogen level to stay around low values. The reduced deficit in the summer period, together with a high surplus of RES energy, allows to fill the H2 storage, which is then gradually emptied in the second part of the year where an increase of the deficit occurs.

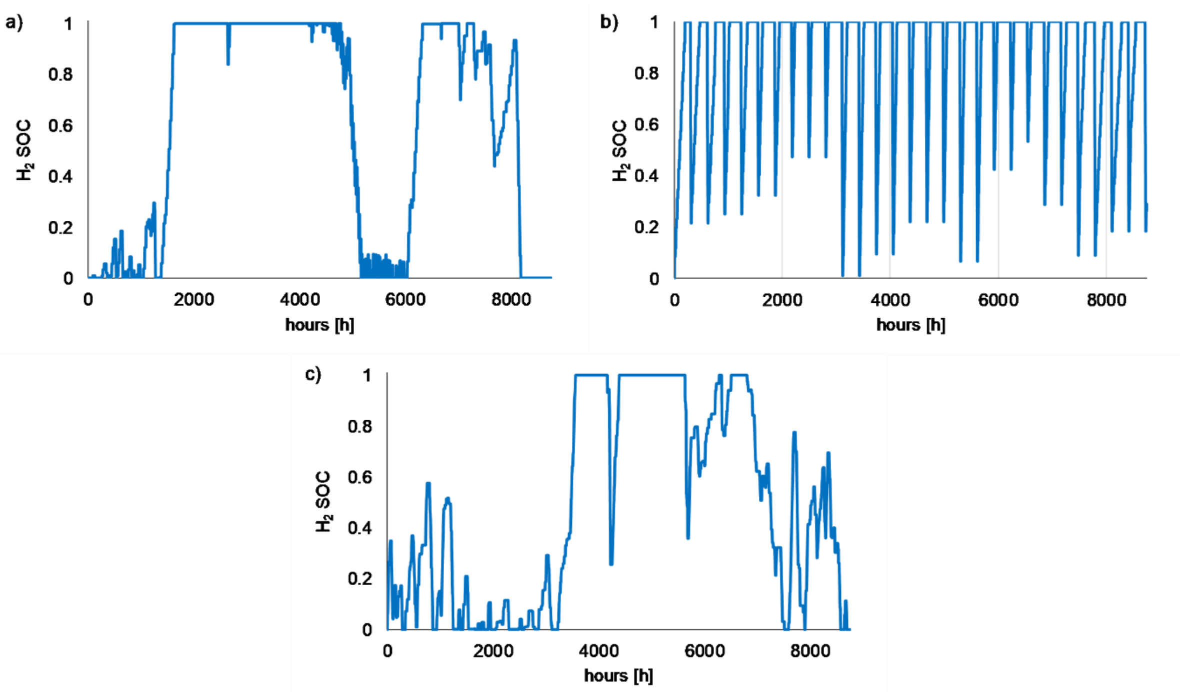

Figure 2. *H_2 state of charge over the year for a) Ginostra, b) Ambornetti and c) Rye*

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	DEMO 1		DEMO 3		DEMO 4	
Load directly covered by RES	82.0 MWh	47.8%	303.9 MWh	87.1%	77.6 MWh	61.2%
Load covered by P2P (battery + H_2)	82.0 MWh	47.8%	45.1 MWh	12.9%	43.5 MWh	34.3%
Load covered by external source	7.6 MWh	4.4%	0 MWh	0%	5.7 MWh	4.5%
Total load	171.6 MWh	100%	349 MWh	100 %	126.8 MWh	100%

Table 2. *Annual load coverage results*

3.2 Economic simulation

Regarding the economic analysis, for each site the following options are compared to the hydrogen-based one: usage of current diesel generators in Ginostra, connection to the grid in Agkistro, employment of a hypothetic diesel generator set in Ambornetti and replacement of the current sea cable in Froan. Figure 3 reports the LCOE values for each of the four DEMOs over different time horizons. According to the results, a renewable solution is more profitable than the current or alternative solution, either at short term (e.g., in Agkistro and Froan) or in the longer term (e.g., in Ginostra and Ambornetti where it is after around 10 and 20 years respectively when the RES solution yields lower NPC and LCOE). Concerning the RES configuration, the systems in Agkistro and Froan show values in the range 300-500 €/MWh (Froan is the largest demo and in Agkistro RES is available and thus investment costs are lower); whereas the LCOE is larger in the smaller demos of Ginostra and Ambornetti, between 700 and 1,100 €/MWh depending on the case and investment horizon. In particular, in Ginostra, the LCOE is strongly affected by the high costs for equipment transport and installation due to the remote location that can be reached only by helicopter and without the availability of heavy-work vehicles. It is also observed a steeper decrease in LCOE with investment horizon in the cases with grid connection due to the larger importance of the CAPEX; whereas in Ambornetti and Ginostra the solutions with diesel generators, which are characterized by large OPEX, cause the LCOE to be more constant in all investment horizons.

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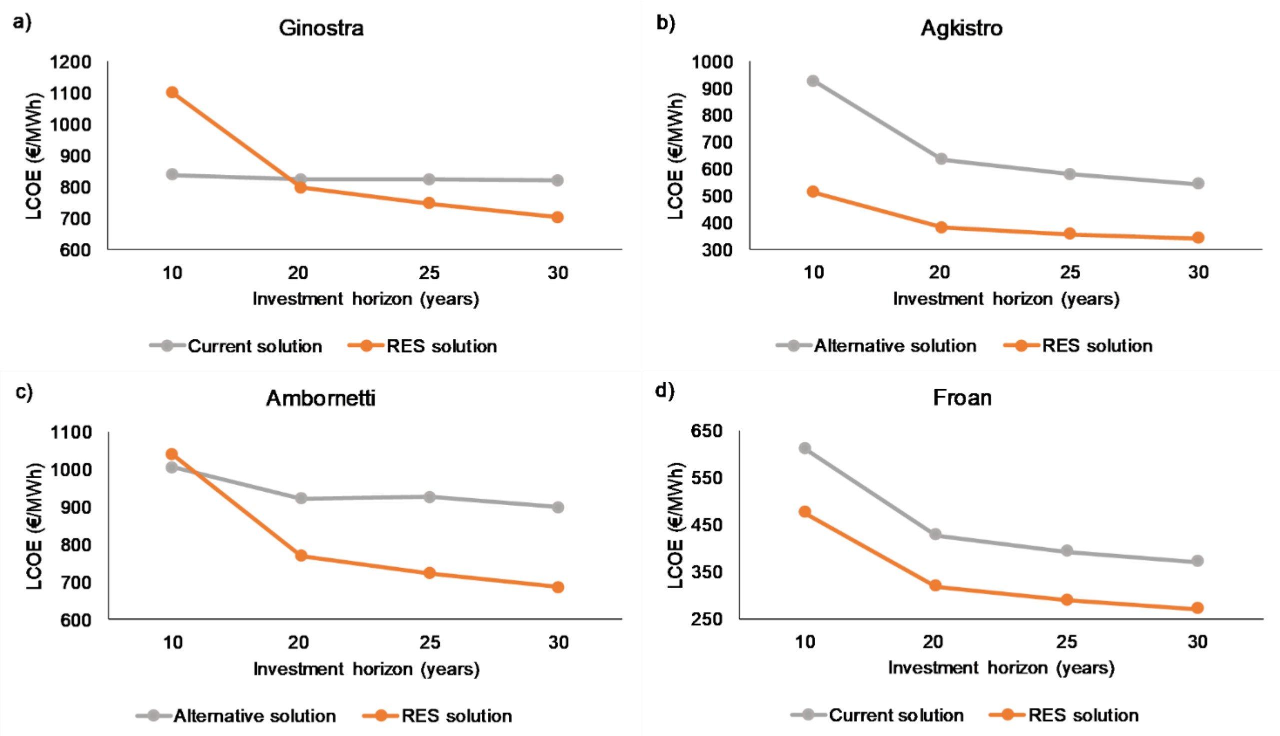

Figure 3. *LCOE values for the current/alternative solution and RES solution for the four DEMO cases of the project, (a) Ginostra, (b) Agkistro, (c) Ambornetti and (d) Froan.*

4. Conclusions

A preliminary EMS for the hybrid P2P system was developed in order to perform energy balance simulations over a reference year with 1 hour time step. Local RES coupled with a battery-H_2 storage system were shown to allow to significantly reduce or even eliminate the usage of external sources. In Ginostra, the renewable configuration enables to decrease the operation of current diesel generators to less than 5% of the total electrical demand of the local community. In Rye, only around 4.5% of the overall annual load has to be supplied by an external source. A completely energy autonomy was found to be possible in Ambornetti thanks to the exploitation of local solar and biomass sources. Finally, in Agkistro, the P2P configuration was verified to be effective as a backup solution, guaranteeing 1-3 days of energy autonomy in case of emergency or maintenance of the hydro plant. Generally, the hydrogen solution is useful for its longer term storage capability intervening mainly during maintenance, emergency or periods of the year with a higher electrical demand. A preliminary economic analysis was also performed for a comparison between the innovative configuration and the current/alternative one in terms of LCOE. For all the considered DEMOs, the exploitation of local renewables together with the adoption of a P2P system was proved to be more cost effective than traditional options either in the short or longer term. Outcomes of these preliminary simulations have thus shown the usefulness and economic viability of P2P systems. More detailed and refined results will be derived during the project, taking also advantage of real data from operation of the proposed storage solutions.

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Operating results of PEMEL, AEL and SOEC systems

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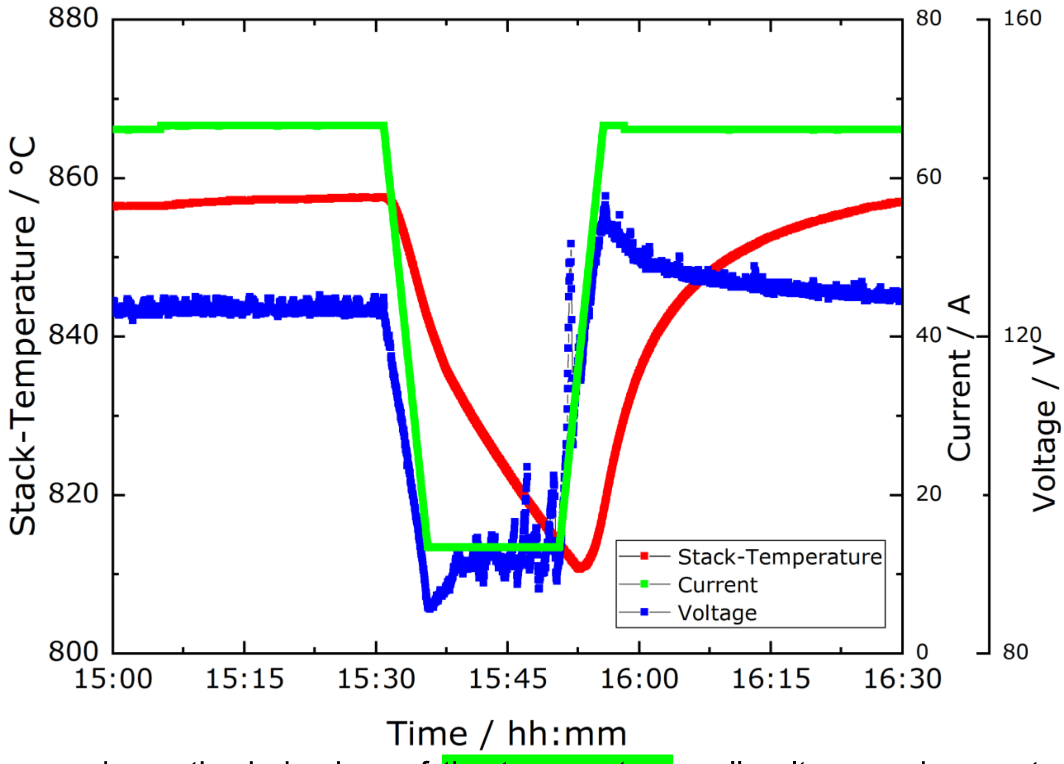
Abstract

Three commercially available stand-alone electrolyser systems are tested, covering the significant technologies alkaline water electrolysis, proton exchange membrane water electrolysis and high temperature steam electrolysis using solid oxide electrolysis cells. The hydrogen outputs of the systems are in the range between 5 to 10 $Nm^3\ h^{-1}$ hydrogen at delivery pressures between 10 and 35 bar. Each system comprises its own water purification, hydrogen purification, cooling units and safety systems.
Goal of the comparative study is to evaluate the systems regarding reaction time, stack stability, durability of Balance of Plant and maintenance effort under dynamic operation and grid supporting operation. Therefore different load profiles have been defined, simulating the shift between stationary and dynamic application. In this paper the results of the on-going test procedure up to this date are presented and discussed.



The diagram shows the behaviour of the temperature, cell voltage and current during a load change from 100% to 25% of the SOEC system.

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Introduction

In the Carbon2Chem project (03EK3038B), funded by the German Federal Ministry of Education and Research (BMBF), possible large energy-related applications processing exhaust gases from steel production to chemical raw materials are investigated [1]. The conversion uses the majority of the carbon dioxide within the steel mill exhaust gases and needs additional hydrogen that will be supplied by electrolysis. To reduce the carbon footprint of the process, the production of “green” hydrogen on the basis of regenerative energy sources is of significant importance. Additionally the supply of “green” hydrogen contributes to the transition from fossil to renewable energy sources as well as advances “carbon to chemicals” and “power to gas” applications [2]. For the production of “green” hydrogen, a dynamic operation of an electrolyser must be possible to operate according to the supply of regenerative energy and the regulations of the electrical grid. Furthermore, the influence of the dynamic operation on the electrolyser itself has to be investigated.

1. Scientific Approach

Today, three different electrolysis technologies are mainly applied to produce “green” hydrogen from water and renewable electric energy. These are Alkaline Water Electrolysis (AEL), Proton Exchange Membrane Water Electrolysis (PEMEL) and High Temperature Steam Electrolysis based on Solid Oxide Electrolysis Cells (HTSE or SOEC).

The most mature of these three technologies is the AEL. Systems with a power of hundreds of MW and thousands of $Nm^3\ h^{-1}$ production rate are already installed today [3]. The AEL operates at temperatures of about 50-80 °C using caustic aqueous KOH or NaOH with a concentration of 20-30 wt.% as electrolyte. In AEL the adjacent bipolar cells are connected while a diaphragm separates the electrodes of each cell [3]. At the cathode water is reduced to hydrogen and hydroxide. The latter passes the diaphragm and reacts to oxygen and water at the anode. As the environment is highly caustic, the components of the electrolyser need to have a high corrosion resistance. Therefore, mainly Ni-based alloys are used as electrode catalysts (e.g. Ni/Co/Fe as an anode catalyst and Ni/Co as a cathode catalyst), as porous transport layers and for the parts in contact with the electrolyte [4].

In PEMEL a proton conductive solid polymer membrane is used instead of a diaphragm. This offers the advantage of using de-ionized water, as no liquid electrolyte is required, as well as higher current densities up to 3 $A\ cm^{-2}$ or more [5]. The operating temperature compares to the temperature of the AEL technology. The PEMEL is as well constructed in a bipolar design. Water is split at the anode into protons and oxygen. The protons pass through the membrane and react with electrons to hydrogen at the cathode. In most cases the electrolyte membrane is made of a PFSA polymer, which is a super acidic ion exchange resin [5]. The high potential of up to 2.4 V at the anode in combination with the polymer leads to a highly corrosive environment. Hence, only highly corrosion resistant materials and catalysts, e.g. titanium and iridium/oxides can be used in PEMEL.

The HTSE based on SOEC operates in contrast to the both before mentioned electrolysis technologies at temperatures of about 500-950 °C. The water fed to the system is vaporized and split in the cells at voltages of 0.9 to 1.5 V [6]. At the cathode water is reduced to hydrogen and oxide ions. These ions pass the permeable ceramic membrane and react at the anode to oxygen. The downside of the high temperature, which leads to the desired low cell voltages, is a slower reaction to alterations in the operation conditions in comparison to the other two electrolysis technologies. This includes a significant longer

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start up and shut down procedure. While the HTSE is still under development first products are launched in the market.

ZBT is actively collaborating with the Joint Research Centre (JRC) of the European Commission and the leading institutions on the development of EU harmonized test and durability protocols for water electrolysis systems. Therefore, the experience gained with industry scale water electrolysers in the frame of the Carbon2Chem project will contribute to the development of the EU harmonized protocols in this topic.

2. Experiments/Calculations/Simulations

ZBT investigates the suitability and industrial operational capability of the three electrolysis technologies for dynamic operation. For this purpose, an AEL, a PEMEL and a SOEC system in the hydrogen production range of maximum 5 to 10 $Nm^3\ h^{-1}$ were procured and installed in the outside area of ZBT. All units are containerized standalone plants and are equipped with the necessary auxiliary devices like input water purification, cooling device for stacks, drying system for hydrogen quality, air conditioning and ventilation, as well as safety features.

The AEL system produces up to 10 $Nm^3\ h^{-1}$ hydrogen at a maximum pressure of about 12 bar. The PEMEL system provides up to 5 $Nm^3\ h^{-1}$ hydrogen with a pressure of 35 bar. The HTSE supplies a maximum of 5 $Nm^3\ h^{-1}$ hydrogen. The SOEC stacks operate at ambient pressure, but due to an inbuilt pressure swing adsorption the hydrogen can be delivered at a pressure of about 10 bar. In table 1, the main characteristics of the three electrolysis units are listed.

Table 1: Main characteristics of the three electrolysis systems [7]

	AEL	PEMEL	SOEC
Max H_2 production rate [$Nm^3\ h^{-1}$]	10	5	5
Output H_2 pressure [bar]	10	35	10 (after PSA)
Operation range of the nominal power [%]	25-100	20-125	20-120
Operating temperature [°C]	60-80	50-70	850-880

Aim of the testing is the investigation of the operation behaviour of the different electrolyser technologies under fluctuating power conditions. Hence, the systems are operated with different load profiles at their maximum output pressure. These load profiles represent the operation at constant current as well as at alternating current values based on various scenarios. In this extended abstract, the former will be referred to as stationary operation, while the latter is called dynamic operation.

The stationary tests were conducted at a production rate of hydrogen of 100%, to investigate the general behaviour and stability of the plant. The results were evaluated, also in the perspective of first signs of degradation of the electrolysis stacks. For the dynamic operation the production rate was increased and decreased within a period of 5 Minutes in reference to the secondary control power of the electrical power grid. In between the ramps, the hydrogen production was kept stable for 15 minutes.

As the PEMEL system was not ready for operation (see results) alternative measurements were realized. Thus, the before mentioned dynamic and stationary operation were carried out only with the AEL and the SOEC system.

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Figure 1 depicts the stationary operation of the AEL system in March 2019. The time frame covers 16 days.
The green line represents the current that is applied to both of the 2 stacks of the system. It starts from 0 A and rises to 109.25 A, which equals 100 % of the hydrogen production rate. While the current rises, the corresponding voltages of both stacks increase as well from 0 V to 265 V for stack A (upper blue line) and 266 V for stack B, respectively. Both voltages decrease over the course of the operation to a minimum of 254 V for stack A and to 251 V for stack B. A degradation of the stacks cannot be observed, as the voltages of both stacks decrease over time.

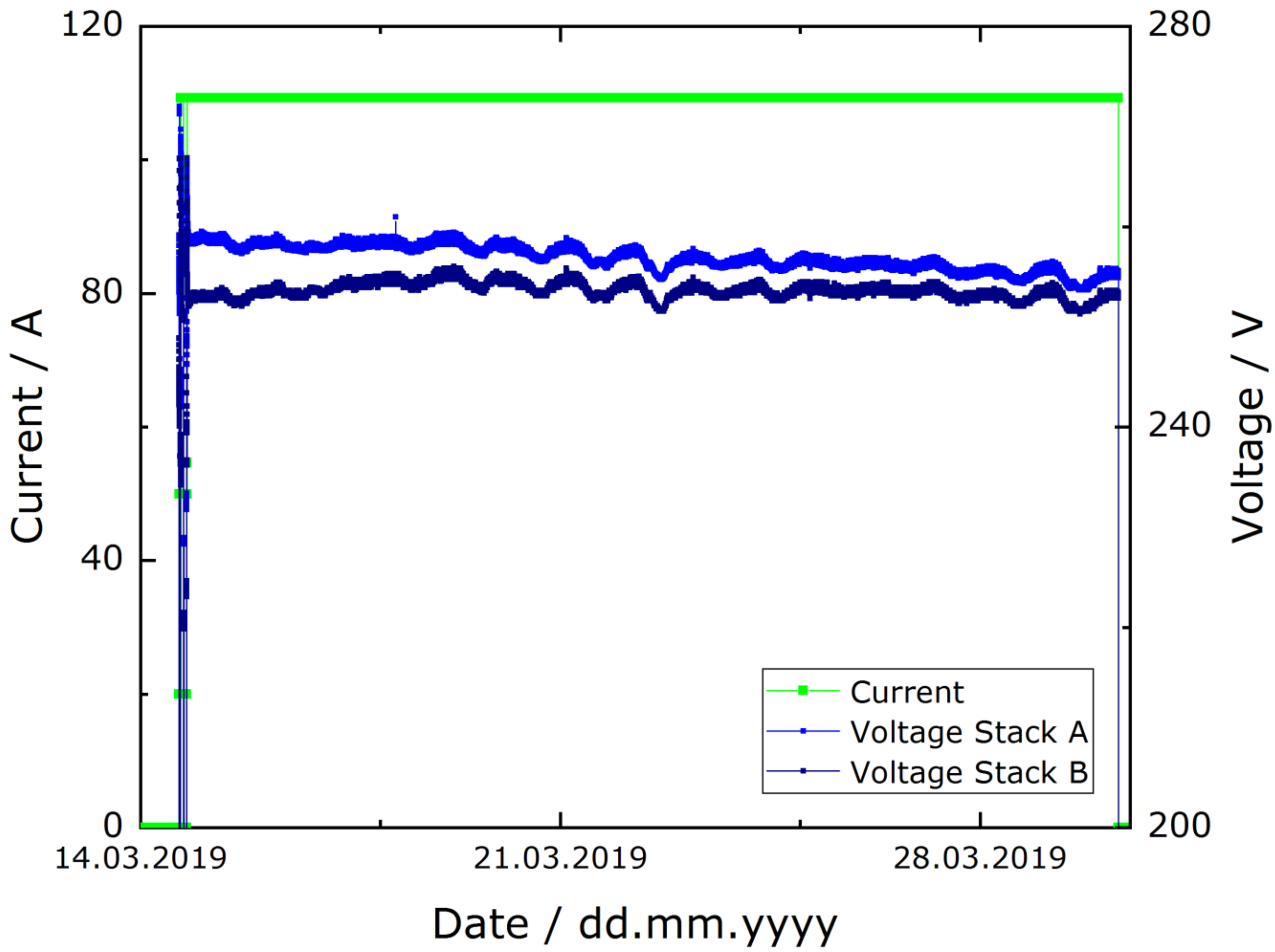

Figure 1: Stationary operation of the AEL

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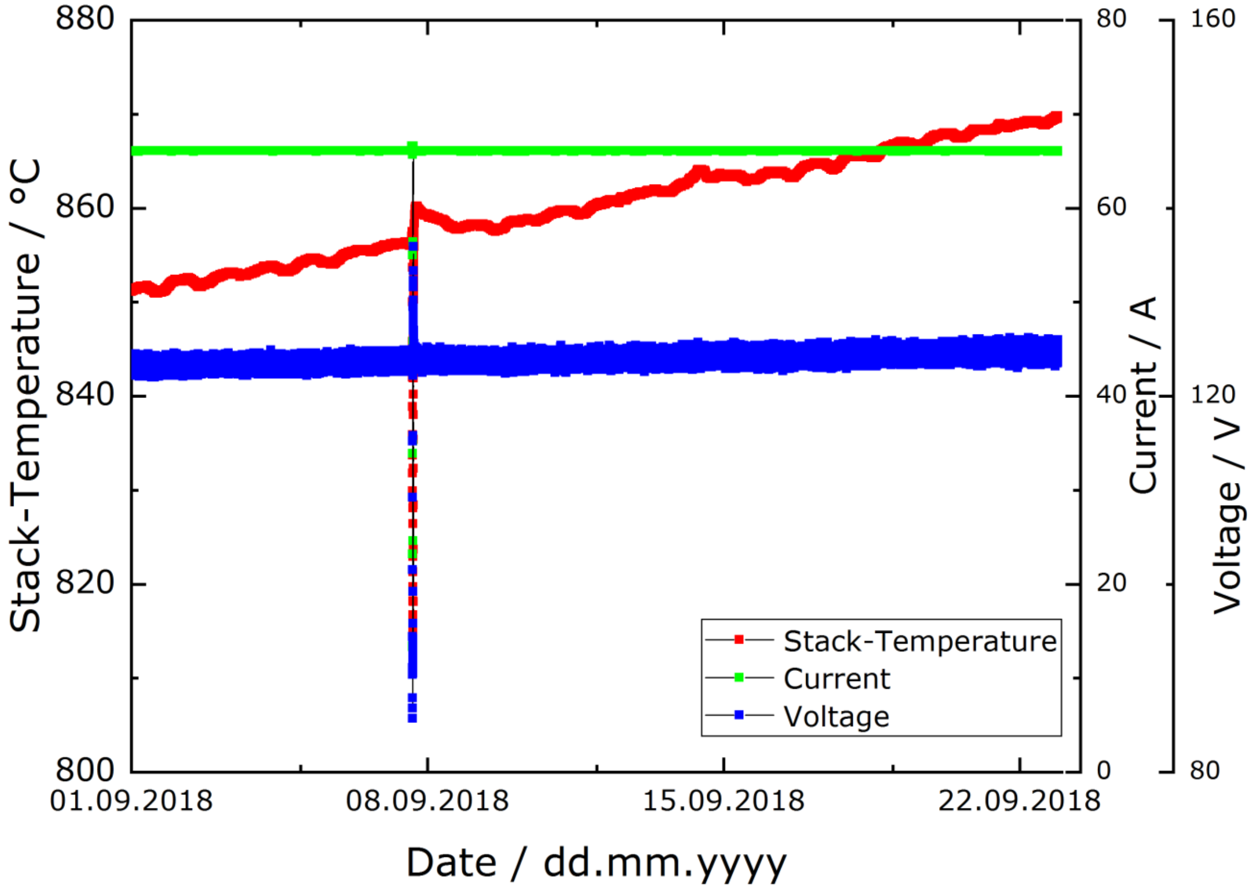

Figure 2: Stationary operation of SOEC

In figure 2, the stationary operation of the SOEC system is presented. The current, voltage and maximum stack-temperature for one of the modules of the plant, which consists out of 3 stacks, are shown. The current (green line) was set to 66.1 A, what corresponds to 100 % of the production rate of hydrogen. Over the course of the operation, the voltage of the module (blue line) rose from 122.7 V to 125 V, while the temperature (red line) increased from 851.1 °C to 870 °C.
As stack-temperature and voltage of an HTSE system can indicate degradation of the system, a quotient can be calculated for both of these factors. For the temperature, the degradation per day results in 0.83 °C/d. The quotient for the voltages is 102 mV/d.
On the 7th of September 2018, an exemplary dynamic profile was applied to the system, which is depicted in figure 2 as well as in figure 4.
Figure 3 shows the dynamic operation of the AEL. The currents of the 2 stacks are drawn in light (stack A) and dark (stack B) green, while the voltages are depicted as light blue (stack A) and dark blue (stack B). Both currents start at 100 % production rate (109.25 A). The hydrogen production rate is continuously lowered to 20 % over the course of 5 Minutes. The currents of the 2 stacks drop to 52 A each, which equals 50 % of the production rate. As the rate goes beneath 50 % and decreases to 20 %, stack A is turned off and the current of stack B rises at first to 96.14 A. The minimum current of 43.7 A is reached at 20% production rate. The minimal production is kept stable for 15 Minutes and raised again over the next 5 Minutes to 100 %. At 50 %, stack A is switched on again, what can be seen as current and voltage of stack B drop.
The voltage of stack A and B develop likewise, starting at 249 V and 247 V, respectively. At minimum production rate and over the course of the ramp up process, the voltages of stack A and B increase above the previously obtained value to 260 V for stack A and 263 V for stack B. At stable production at 100 %, each voltage returns to their initial value.

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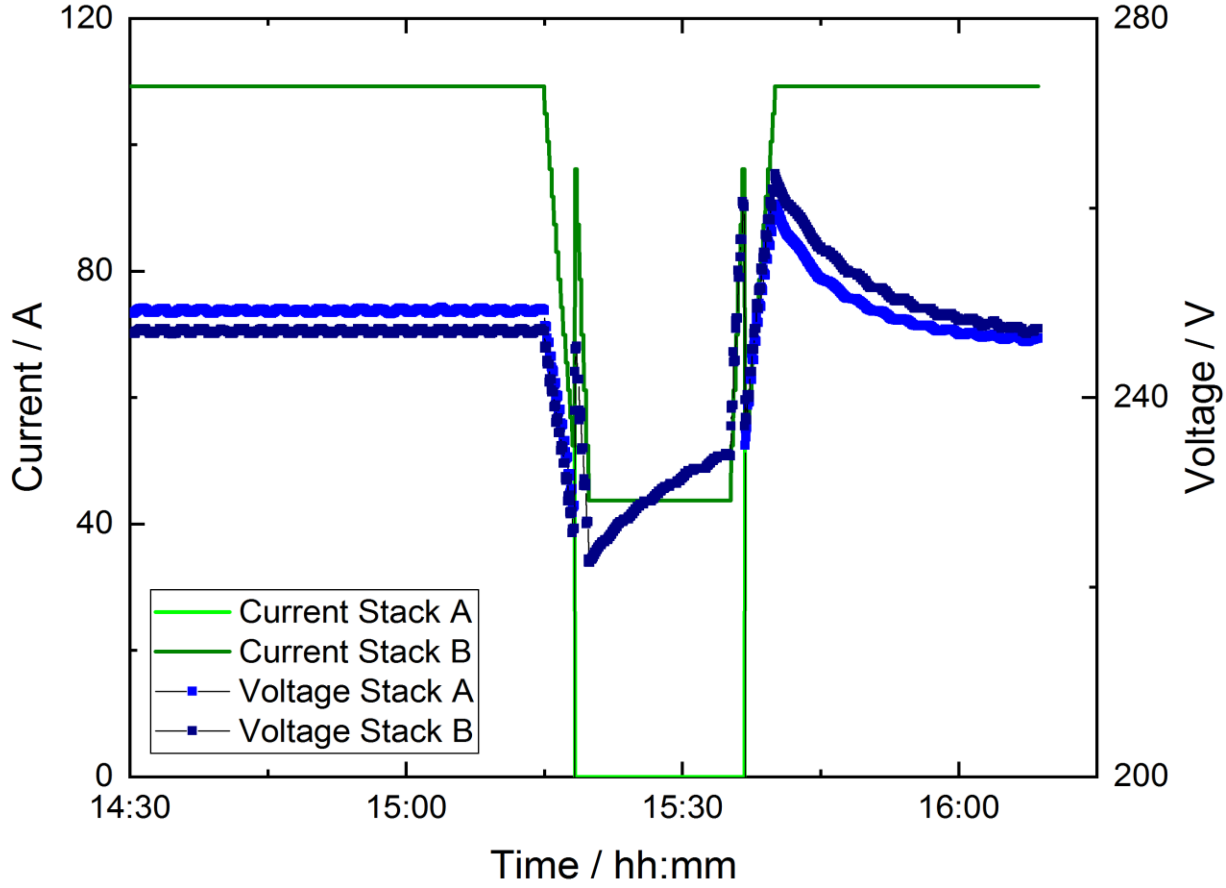

Figure 3: Dynamic operation of the AEL

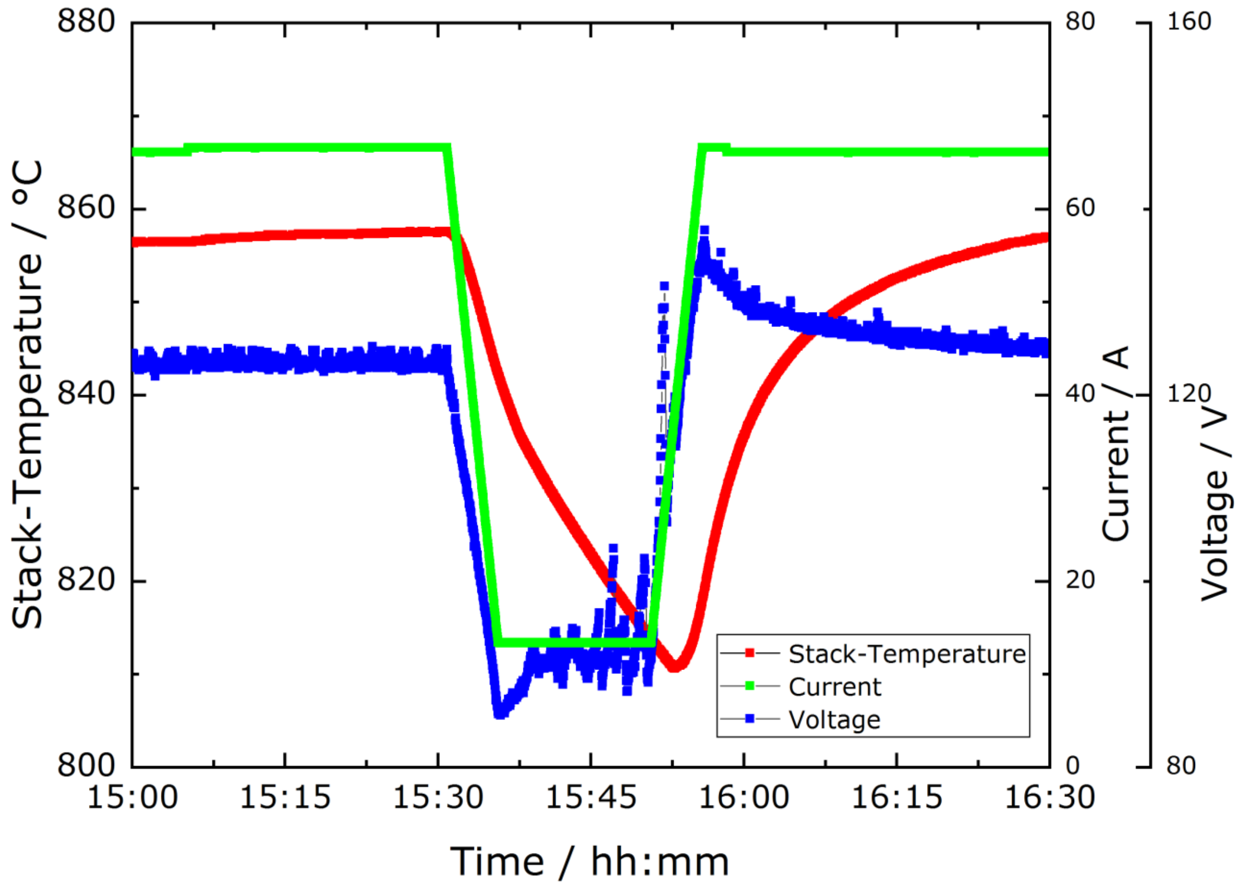

Figure 4: Dynamic operation of the SOEC

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Figure 4 presents the dynamic operation of the SOEC. The green graph depicts the current of one module, the blue graph shows the voltage and the red graph the temperature of the stacks. As the current decreases from 66 A to 13.4 A, voltage and temperature drop as well. After 15 minutes at 20 % production, the current increases again. This leads to an imminent rise of the voltage. The graph of the temperature follows this development with several minutes delay. It can be seen that the voltage exceeds the value obtained before the cycle (137 V) but reaches the old value (124 V) after the temperature rises to its original value (859 °C).

As the PEMEL system was not ready for operation alternative measurements were realized using a self-developed PEMEL test bench and commercially available PEMEL short stacks from American and German manufacturers. The test bench allows characterization of short stacks with up to 7 cells and an active area from about 25 cm² up to more than 500 cm². The possible electrical stack power is up to 40 kW with a maximum current of 2000 A. The test bench can be operated with a pressure of up to 35 bar, differential pressure as well as equal pressure on both electrode sides. The water feed can be realized on both sides. The operation is fully automated including an electrochemical impedance spectroscopy performed with a Gamry Reference 3000 AE Potentiostat / Galvanostat.
The following data show preliminary results of a short stack operated with highly dynamic load profiles changing the load from minimum to maximum and back to minimum within 10 seconds for several thousand cycles at different operation temperatures. Goal of this tests is to investigate the degradation of PEMEL stacks for highly dynamic operation on the one hand and on the other to develop in the near future Accelerated Stress Test (AST) protocols together with the industrial and scientific community which is united in the ANNEX 30 activities of the IEA and activities led by the JRC of the European Commission. Figure 5 shows such an experiment with about 8280 load changes for three different temperatures each.

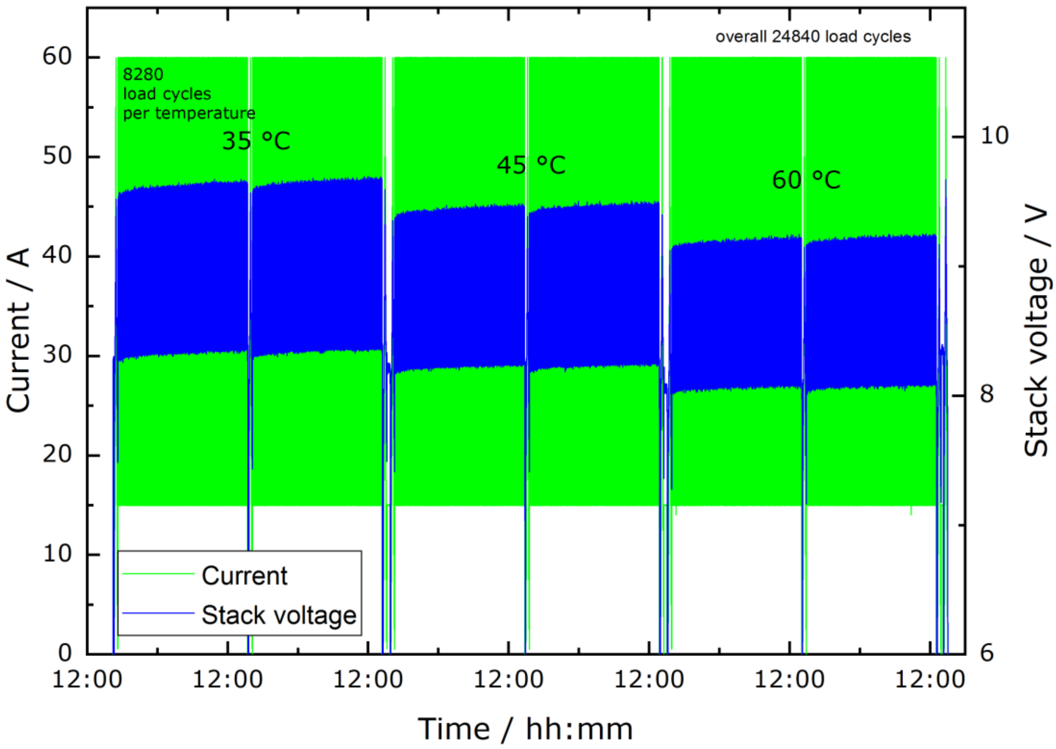

Figure 5: Highly dynamic operation of a PEM stack
The current is cycled between 15 and 60 A which are the minimum and the maximum operating current according to the manufacturer specifications. The temperatures of 35 °C

and 45 °C are also within the specifications while the temperature of 60 °C is higher than the manufacturer officially permits. Each temperature block contains three polarization curves and impedance measurements which are performed at the beginning, in the middle and at the end of the load cycling. The whole test ends with a reference measurement (polarization curve plus impedance measurement) at a temperature of 35 °C. As expected the stack voltage decreases with increasing temperature while it increases with operation time. As one can see the degradation is partially reversible. The stack voltage starts at a lower level after interruption of the dynamic operation. Figure 6 shows data from the previous figure but with a more detailed depiction of the stack voltage (right y-axis).

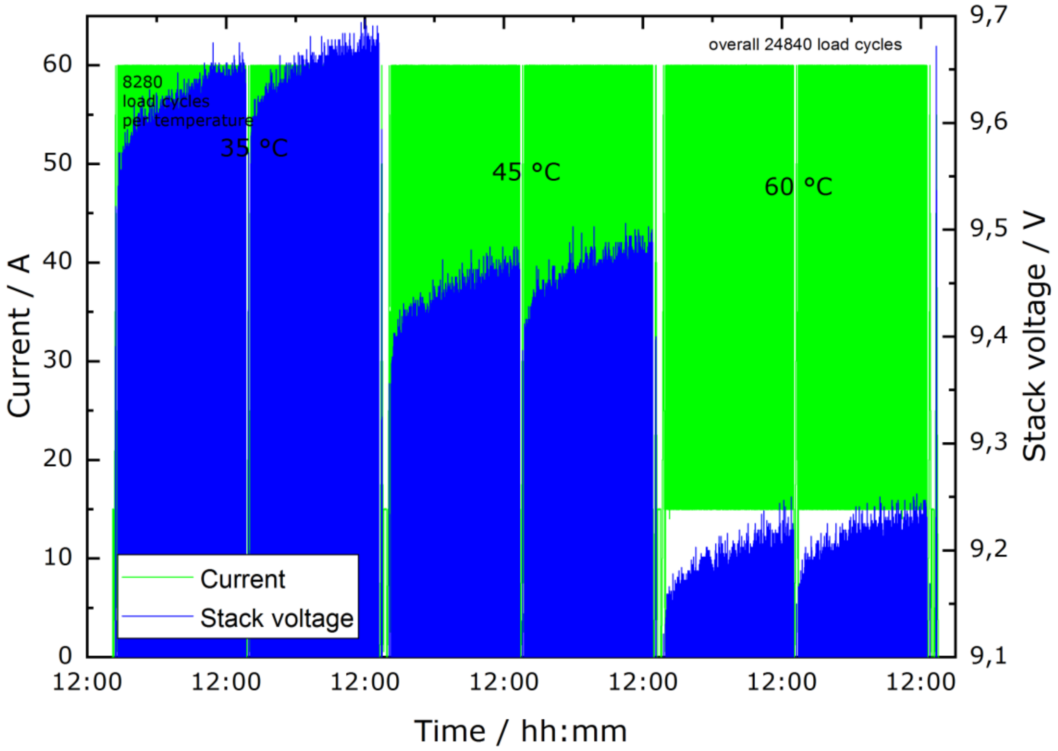

Figure 6: Highly dynamic operation of a PEM stack

Figure 7 shows the polarization curves which were recorded during the dynamic operation as discussed before. In order to determine the non-reversible degradation rate, the stack voltages of the first and the last measured polarization curve (both at a temperature of 35 °C) are compared. The stack voltage at the beginning is about 9.5 V at 60 A. This corresponds to a cell voltage of about 1.9 V. At the end of the test the stack voltage is about 9.64 V, corresponding to a cell voltage of ca. 1.928 V. This results in a degradation of about 28 mV during 140 h of operation. From this a degradation rate of about 200 µV/h can be calculated.

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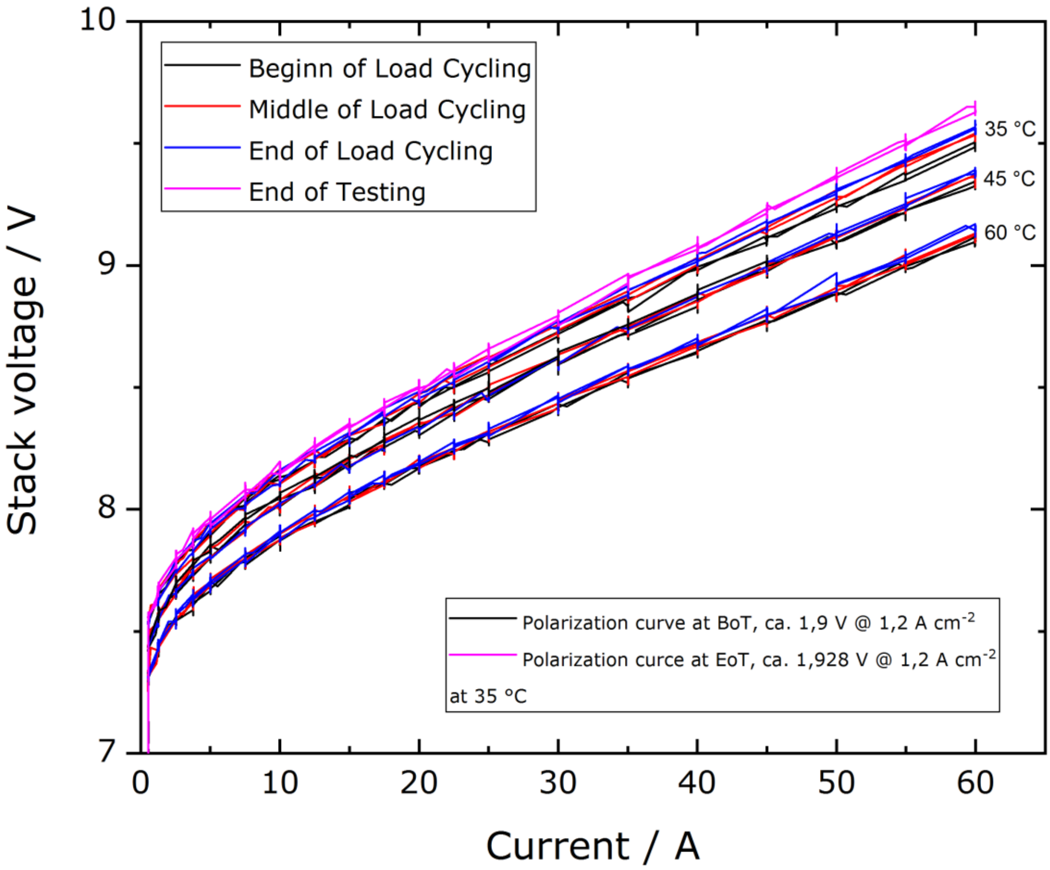

Figure 7: Polarization curve obtained at dynamic operation of a PEM stack at three different operation temperatures

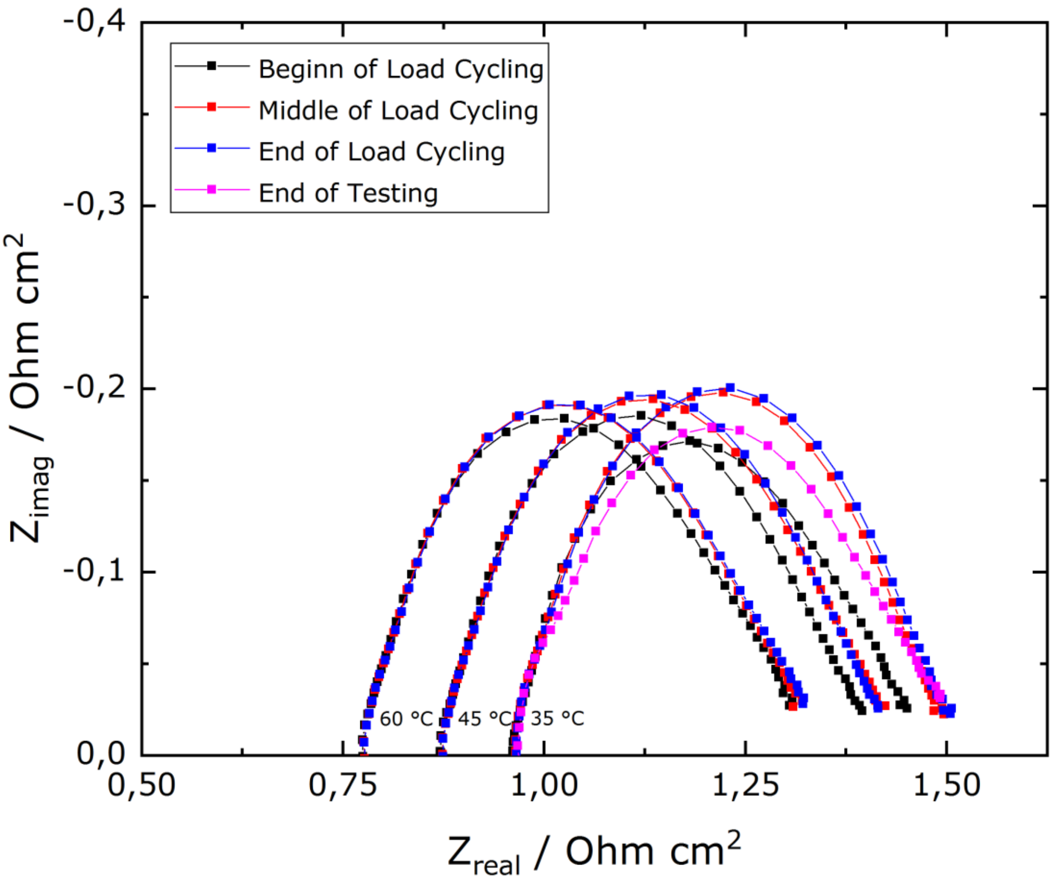

Figure 8: Corresponding Nyquist plots at different temperatures

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Additionally, as mentioned before impedance measurements were performed before, in the middle and at the end of load cycling in order to examine the degradation effects. Figure 8 shows the Nyquist plots of these measurements. As expected the impedance decreases with increasing temperature corresponding to the stack voltage. It can be seen that the operation has no impact on the left intercept point of the semi-circle with the x-axes. This means that the ohmic resistance remains stable for each temperature. Therefore, it can be assumed that there is no degradation regarding stack components like membrane, bipolar plates or porous transport layer which would increase the ohmic resistance of the stack. One can see a widening of the semi-circles with increasing number of load cycles so that it can be assumed that the degradation takes place in the catalyst layer.

3. Results

As seen in figure 1 and 2, stationary operation of both functional systems are possible. The AEL system shows no signs of degradation over the course of the experiment, while the increase of the operation temperature of the stacks in the SOEC indicates a significant degradation. The cause of this effect is not yet fully understood, but silicates in the feed water could contribute to this.
The dynamic behaviours of both plants shown in figure 3 and 4 have to be further investigated due to several, longer downtimes. Both systems tend to have a higher voltage after the dynamic profile than before. This can be explained by the decrease of the temperature, which leads to a lower efficiency of the electrolysis cells. As the temperature has a higher influence in the SOEC system, it is obvious that the voltage in the SOEC needs a longer time in comparison to the AEL to obtain its original value. A faster degradation due to dynamic operation could not be observed, but has to be investigated further.
The downtimes of the plants were mostly caused by the balance of plant of each system. Pumps, sensors and electrical components of the electrical cubicle malfunctioned and led to stop of operation for sometimes several weeks. Only in a few cases there were problems with the electrolysis stacks themselves.

Experiments could not be carried out on the PEMEL system, as it was not able to operate up to this day. After a long delay in delivery, problems with the certifications occurred on part of the manufacturer that made it impossible to conduct any testing with this system. The plant shall be tested as soon as these issues are resolved.

Regarding the PEMEL stacks figure 5 and 6 show that the degradation occurring over time are partial reversible. The results depicted in Figure 7 indicate a degradation rate of about 200 µV/h. The degradation rate one can often find in literature for the stationary operation of PEMEL stacks is in the range of 10-200 µV/h [8, 9]. While this is a preliminary result it needs further measurements in order to be approved.
Furthermore, the Nyquist plots of different temperatures shown in Figure 8 lead to the assumption that there is no degradation regarding stack components like membrane, bipolar plates or porous transport layer. It is likely that the degradation takes place in the catalyst layer. This assumption has to be investigated further with the help of ex-situ measurements.

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Feasibility analysis of off-grid hydrogen energy storage system for energy independent island in south Korea

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Abstract

Human beings are facing the great challenges of global warming and energy depletion, so many countries are making aggressive policies to solve the energy crisis and climate change.
The south Korea government has been promoting active policy supports for the development of renewable energy and actively fulfill the Paris Climate Change Accord to reduce carbon emissions. The aim is to increase renewable energy from 7% to 20% of the total generated energy and reduce carbon dioxide emissions by 37% of BAU value in South Korea by 2030. With the policy stimulation, Renewable energy sources have been greatly developed, especially large-scale solar, wind and hydro power plant. However, diesel engine power generation system is still widely used in many islands which is far from land. In these islands, the transportation supply of fuel is influenced by transport costs and fuel price fluctuation, also limited by weather factors. Furthermore, diesel power generation increase carbon dioxide emissions and pollutes the environment. In this study, hydrogen energy power generation system was studied for offering a zero-emission solution with renewable energy source in Gageodo Island. This system consisted PV panel, wind turbine, li-ion battery, three-phase converter, PEM water electrolysis, DI water generator, hydrogen storage tank and PEMFC. To determine the feasibility of the entire system, Homer software was used for optimization design and economic analysis.

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Introduction

Resource depletion, climate change and growing energy demand caused by fossil fuel emissions, the world has been focusing on the alternative energy sources that can replace fossil fuels [1], [2], [3]. The alternative energy sources for fossil fuels are biofuels, hydrogen, solar, geothermal, wind energy, hydro-power and so on. In these alternative energies, solar, wind, hydropower and biomass energy accounts for the highest proportion 74% in the total renewable energy use in South Korean by government policy support [4]. Even so, diesel power plants are still being used for many islands in South Korea. According to the statistics of KEPCO in 2012, There are still 63 islands that are powered by diesel power plants and it reported the status and deficits of the diesel power plants in island. It shows most of the diesel power plants are in a state of oversupply, the annual loss of these power plants is as high as million won [5]. To lowing the deficits of these diesel power plants and also reduce the carbon dioxide emission, a solution of HESS (hydrogen energy storage system) for green energy generation need to be developed. Only using solar and wind energy to generate electric power, both two have irregular electric power generation characteristics and the power output are heavily affected by the solar illumination index and wind speed therefore energy storage system is indispensable [6]. The device of energy storage system usually uses accumulator or battery, but these devices cannot store electric power for long time and the replacement costs of batteries are very expensive. In order to solve these problems, hydrogen energy storage system has been put forward in this project for giving a solution for continuous system which can provide extremely clean, stable power generation. Hydrogen, what is known is it can be produced by electrolysis using water. In this project, electrolysis produces clean hydrogen using renewable energy solar and wind turbine then the clean hydrogen is provided to the PEMFC to produce green electricity for providing electric to Gageodo Island in South Korea. Homer software was used to determine the entire system, the results are focused on the system optimization, electric production and carbon emission.

1. Scientific Approach

Optimize system and economic analysis is crucial for decision-design and improving design using Homer software. Many of studies on the renewable energy system in different countries. Abolfazl Shiroudi analyzed Technical-economic assessments for PV-Electrolyser-Fuel cell energy system at the Taleghan site in Iron in 2011, The results shows that the total net present cost (NPC) is around $115,034 and cost of energy (COE) of the proposed hydrogen system is $1.216/kWh [7]. Getachew Bekele studied feasibility of small-scale Hydro/PV/Wind based hybrid electric supply system in Ethiopia in 2011, as a final result, the cost of energy less than $0.16/kWh [8]. Abolfazl Shiroudi analyzed optimization and technoeconomic for Stand-alone PV-hydrogen energy system in Taleghan-Iran in 2013. The total initial capital cost, net present cost, and cost of electricity produced from this energy system are $193,563, $237,509 and $3.35/kWh, respectively [9]. Omar Hazem Mohammed studied the optimal design of a stand-alone hybrid PV/FC power system without battery storage in the city of Brest, Western Brittany in France in 2014, for the optimal design hybrid power system TNPC is $8,942,636 while its capital cost and cost of energy (COE) are $4,197,750, $0.12/kWh [10]. Kenneth E. Okedu are studied off grid micro system consisting of diesel generation, biogas, solar PV, wind turbine, micro-hydrogen plants and DC generator of fuel cell for five different renewable energy penetrations in Al-Zahia-Musandam of Oman in 2016, the results show that the optimize design for the NPC is $515,746 and COE is $0.47/kWh [11]. Anand Singh analyzed a solar PV, fuel cell and biomass gasifier hybrid energy system in Indian in 2016. It has been found the COE is Rs 15.064/kWh and complete net present cost Rs 51,89,003

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[12]. Tania Khadem studied hydrogen fuel cell system for irrigation in Bangladesh in 2017, the system is composed of PV array, electrolyser, hydrogen tank, fuel cell and DC pump. The results show that Per kg cost of hydrogen (COH) is $9.35 [13]. Himadry Shekhar Das studied the feasibility of hybrid renewable energy systems (photovoltaic arrays, batteries, and fuel cells) in Sarawak, East Malaysia in 2017, the results showed that the cost of electricity was $0.323/kWh [14]. Shoeleh Vahdatpour analyzed the potential of using a hybrid solar cell/wind turbine/biomass system for supplying the electricity demands of a residential building of Iran in 2018, climates (Total net present cost (NPC) and cost of electricity (COE) are $11,639 and $1.808/kWh) [15].
In line with the above research, even though many countries gave studies on Techno economic analysis for solar PV-hydrogen-FC renewable energy system, but there are few researches in South Korea for energy independent island. Therefore, the solar PV/wind-hydrogen-PEMFC renewable energy systems were studied for feasibility analysis in Gageodo Island using Homer software. The main components of the systems are shown in Figure 1.

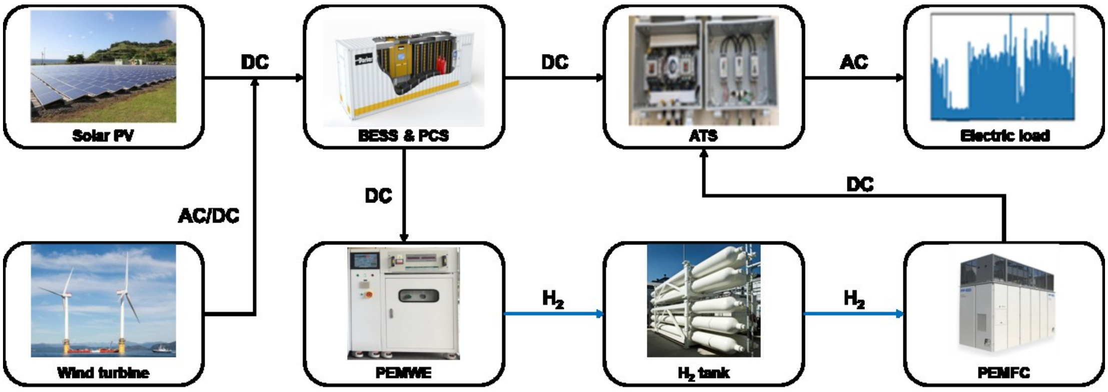

Figure 1: Main components of the hydrogen energy storage power generation system

2. Simulations

Study area
Gageodo island is far from mainland and located in southern region, South Korea (34º03' N, 125º07' E) as Figure 2 shows. There are 323 households in Gageodo Island. The reason for chosen this island is that diesel power plant is still being used. Currently three 250kW diesel engines and one 300kW diesel engine are alternately in operation and there are big losses every year due to electric over supply. Besides environmental pollution and carbon dioxide emissions are another reason which we considered.

Figure 2: Map of study area

Electric demand

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In this study, the most important objective was to assess whether the system's power resources could meet the load requirements. The scaled annual average of electric demand is 5,383kWh/day.

Solar source

The important factor of solar radiation data is needed to be provided for modeling solar PV system using HOMER software to calculate power generation. The solar radiation data input is based on solar source data from the NASA surface meteorology and solar energy from HOMER software in this study. The grid coordinates input to the HOMER is 34º03' N, 125º07' E of Gageodo Island. The annual average of solar average is 4.08 kWh/m^2/day and 5.88 kWh/m^2/day as shown in Fig. 3.

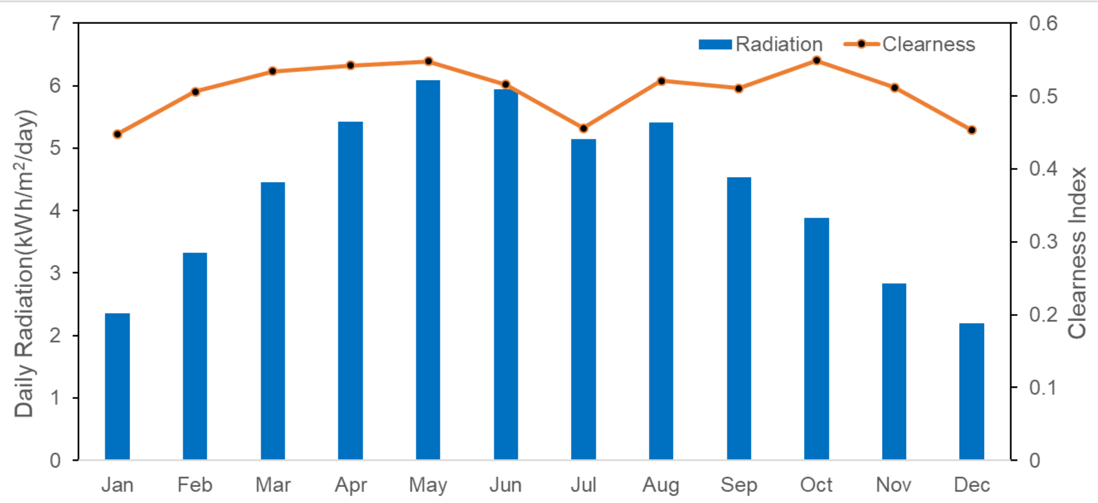

Figure 3: Solar source data at Gageodo Island

Wind Source

The wind turbine is scheduled to install in this solar PV-hydrogen-FC renewable energy system. Therefore, it needs to input wind resource data to HOMER with the grid coordinates of our site selection. The wind speeds are shown as Figure 4. at an anemometer height of 31.8 m Which provided by the NASA surface meteorology and Solar energy of HOMER software. The annual average of wind speed is 6.71m/s as shown in Fig. 4.

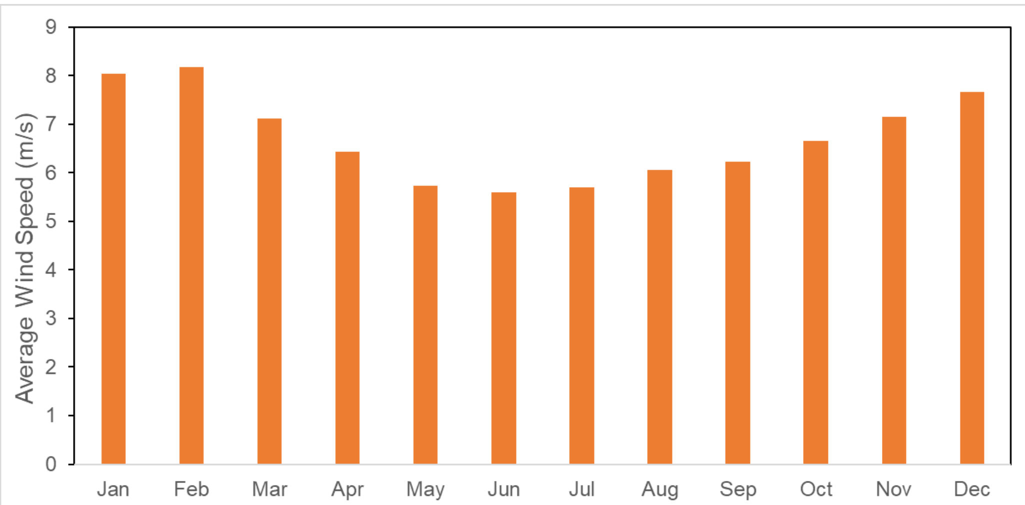

Figure 4: Wind source data at Gageodo Island

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Li-ion battery bank

Due to the fluctuation and insufficient certainty of renewable electricity generation (solar/wind energy), battery banks need to be used as energy storage system. Wind turbine is alternating current, it needs to be stored in direct current. The battery bank has consisted of 100kWh battery models with 600V, 167 Ah. The round trip of the battery bank is 90%.

Converter

In this study, the solar and wind energy is stored as direct current with battery bank. But the power supply of electrolyser is three-phase AC. Therefore, the three-phase invertor is need to convert one-phase DC to three-phase AC. The efficiently of invertor is 85% as we installed.

PEMWE

Electrical energy which was provided from solar and wind need to be produced as hydrogen energy. PEM electrolyser as its simplicity and high efficiency and simplicity was selected as hydrogen production system integrating with renewable energy system.

Hydrogen storage tank

The hydrogen which is produced by PEMWE need to be stored for PEMFC electricity production. In this study, Hydrogen production was calculated from PEMWE. The hydrogen gas is stored as 30 bar in the high-pressure hydrogen storage tank for high energy density.

PEMFC

The hydrogen which stored in the tank is used to supply PEMFC for electricity production. PEMFC generate electricity by a chemical reaction. PEMFC can continuously generate electricity as long as hydrogen is supplied. The PEMFC system is composed of fell cell stack, blower, humidifier, reformer, water reservoir, cooling pump.

Feasibility analysis

HOMER is applicable to feasibility analysis for economic analysis and optimization design for overall system. As the load demand, the PEMFC is simulated as 400, 500, 600 kW and the PEMWE is simulated as 450, 500, 550, 600, 650 kW. Solar PV, wind turbine, battery, converter is simulated as HOMER optimizer. The economic descriptions of all of components are shown in Table 1. The important metrics for the entire system are COE and NPC. The COE is the most important economic output for measuring the economic value. The NPC is the results to calculate the overall system cost.

Table 1: Input data on option costs, sizing and other parameters

Components	Capital ($/kW)	Replacement ($/kW)	O&M ($/kW/year)	Life time (year)	Capacity
Solar PV	1,800	1,800	25	20	Homer optimizer
Wind turbine	2,900	2,500	40	25	Homer optimizer
li-ion battery	146.875	146.875	0.1	15	Homer optimizer
PEMWE	1,345	1,000	20	15	450, 500, 550, 600, 650 [kW]
H2 tank(kg)	1,300	1,200	15	25	1,000,1,100, 1,200,1,300 [kg]
PEMFC	8,300	4,000	0.02	15	400,500,600 [kW]

Converter	800	750	150	15	Homer optimizer

3. Results

The system is composed of solar PV, wind turbine, battery, three-phase converter, PEMWE, hydrogen tank and PEMFC as shown in Fig.5. The Feasibility analysis of off-grid hydrogen energy storage system focus on the capacity design and economic evaluation. The capacity of PEMFC, hydrogen tank and PEMWE was designed as Table 1. Solar PV, wind turbine, battery, converter was simulated by Homer optimizer. There are 604,282 solutions were simulated, 581,939 were feasible to the load demand.

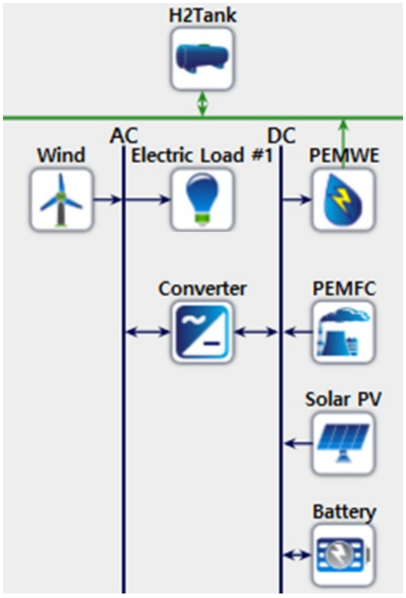

Figure 5: HOMER simulation model

The electricity production and quantity of system components are presented in Table 2. It can be seen that the power production of the solar PV is 900,338 kWh/year, wind turbine power production is 797,411 kWh/year and PEMFC power production is 35,015 kWh/year. Excess electricity is 58,987kWh/year with 1.48% unmet electrical load.
The Table 3, Table 4 shows the capital cost, replacement cost, O&M cost and total cost of the individual components for one year and for a lifetime of 25 years of the entire system.
The capital cost of simulation results is $10,872,750. The cost of PEMFC and li-ion battery bank are highest in total capital cost of the overall system.

Table 2: Electrical production and quantity of component in the system

Components	**Production (kWh/year)**	**Fraction**
Solar PV	900,338	52%
Wind turbine	797,411	46%
PEMFC	35,015	2%
Total	1,732,764	100%
Quantity	Value	Unit
Excess electricity	58,987	kWh/year
Unmet load	13,092	kWh/year

Renewable Fraction	100	%

Table 3: Annualized costs of the system ($/year)

Components	Capital	Replacement	O&M	Salvage	Total
Solar PV	85,701.24	39,707.57	18,750	-24,570.05	119,588.76
Wind turbine	73,639.59	0	16,000	0	89,639.59
li-ion battery	186,479.56	104,723.91	200	-23,761.16	267,642.30
PEMWE	38,422.72	16,042.81	4,500	-3,640.01	55,325.53
Hydrogen tank	82,527.12	0	1,000	0	83,527.12
PEMFC	210,761.58	0	2,800	-16,177.81	197,383.77
Converter	12,696.48	6,684.50	3,750	-1,516.67	21,614.32
System	690,228.30	167,158.79	47,000	-69,665.70	835,721.38

Table 4: Total net present cost of the system ($)

Components	Capital	Replacement	O&M	Salvage	Total
Solar PV	1,350,000	625,489.32	295,357.44	-387,037.19	1,883,809.57
Wind turbine	1,160,000	0	252,038.25	0	1,412,038.35
li-ion battery	2,937,500	1,649,652.51	3,150.48	-374,295.22	4,216,007.77
PEMWE	605,250	252,712.73	70,885.79	-57,338.84	871,509.67
Hydrogen tank	1,300,000	0	15,752.40	0	1,315,752.40
PEMFC	3,320,000	0	44,106.71	-254,839.30	3,109,267.41
Converter	200,000	105,296.97	59,071.49	-23,891.18	340,477.27
System	10,872,750	2,633,151.53	1,031,781.99	-1,097,401.74	13,440,281.78

4. Conclusion

This paper investigated the simulation of optimization and economic analysis on the solar PV/wind-hydrogen-PEMFC with renewable energy systems for electric supply at Gageodo island using HOMER software. The simulation results shows that cost of energy (COE) of the solar PV/wind-hydrogen-PEMFC with renewable energy is $0.957/kWh. The total net present cost (NPC) is $13.1M. The optimized size is 750 kW solar PV, 400 kW wind turbine, 2,000 kWh battery, 450 kW PEMWE, 1,000 kg hydrogen tank and 400 kW PEMFC. The excess electricity in the proposed system is found to be 58,987 kWh/year with 1.48% (13,092 kWh/year) unmet electrical load. So this optimized system can meet the load demand of Gageodo island for all seasons.

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DEVELOPMENTS IN GRID SERVICE MARKETS II

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G0402

Impact of short-term market sequences on bidding behavior of market participants

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Abstract

This study provides insights into the consequences of market actors' bidding strategies depending on market design changes, particularly the sequence and timing of different marketplaces. Balancing market bidding represents a complex decision problem for prequalified market participants as they could profit not only from reserving capacity but also from increasing or decreasing their output. At the same time, they face opportunity costs due to trading options in the wholesale markets. The bidding decisions are affected by the planned splitting of balancing capacity and balancing energy markets. Other factors that influence actors' strategies is the introduction of voluntary balancing energy bids and the gate closure time of the balancing capacity auction with respect to the day-ahead market. We investigate the impact of these changes by developing a theoretical bidding calculus for participants in multiple markets based on decision theory. We study the effect in which markets close and clear using three market design options. The business-as-usual option with a joint market is compared to split balancing capacity and energy markets with clearing for balancing capacity before or after the closure of the day-ahead market. The possibility of submitting voluntary balancing energy bids is explicitly considered in the bid formulation.

We find that the effect of splitting balancing capacity and energy markets will be marginal unless the timing of the balancing capacity market is also adjusted and voluntary balancing energy bids are introduced. From a theoretical standpoint, the procurement of balancing capacity day-ahead ensures that balancing providers with low opportunity costs are allocated to the balancing market leading to an efficient market equilibrium. The effect of the introduction of voluntary bids is twofold. It will on the one hand reign in high balancing energy prices but also create higher opportunity costs and, ergo, higher balancing capacity prices as bidders will attempt to compensate for the foregone profits from balancing energy by bidding higher for balancing capacity. Thereby the optimal bidding strategies between bidders using the regular combination of balancing capacity and balancing energy bid and bidders using solely voluntary bids differ.

1. Introduction

At present, European balancing markets are undergoing far-reaching reforms [1]. These auction-based markets need to cope efficiently with the changing system reality such as increasing volumes of variable renewable energy sources (vRES). On the other hand, new resources, such as flexible loads and distributed generation, are penetrating the system and the markets. Another important driver is the progressive integration of European electricity markets, which requires an adaptation of national marketplaces towards coordinated European marketplaces and a harmonized market design [1]-[3].

Market participants have a number of options to generate profits in liberalized electricity markets. They may trade energy at the spot markets, i.e. day-ahead (DA) market and intraday (ID) market, or offer flexibility in the balancing market to aid the transmission system operator (TSO) to keep generation and load in balance. From the perspective of market design, a crucial factor that determines the performance of balancing markets is the timing for the procurement of balancing capacity (BC) and balancing energy (BE). Timing changes in the spot markets have an effect on the balancing market and vice versa [4], [5]. The reason for this is that balancing service providers (BSPs) face tradeoffs when participating in the balancing markets or in the spot markets. Thus, the order of markets affects participants' cost structures and creates interdependencies between their strategies in different markets with regard to bid volumes and prices (e.g. [6], [7]).

In most European countries, BC and BE are procured jointly in a single auction ahead of the DA market[1] [9], [10]. A separate market for BE must be implemented in European balancing markets for automatically activated Frequency Restoration Reserve (aFRR) no later than 2021, pursuant to the EU Electricity Balancing Guideline (EBGL), the main EU regulation guiding the future balancing market design [1]. Furthermore, so-called voluntary BE bids must be introduced [1]. This implies that market participants who did not participate or were not awarded in the BC market may still submit BE bids without receiving remuneration for capacity. In this way, BSPs do not necessarily reserve their capacities in advance but aid system balancing on a more *ad hoc* basis, which is expected to improve market efficiency and boost competition [1].

Given the novelty of this regulatory change, to our knowledge, its implications have not yet been examined in the literature. Additionally, most balancing-market-related studies focused on BC reservation alone while the procurement of balancing energy was not investigated in its own right (e.g. [9], [11-[14]). To analyze the effect of the changes in the balancing market design on BSPs' bidding strategies, we pose three research questions in this study:

- What is the effect of splitting BC and BE markets on bidders' cost structures and bids in these markets?
- The EBGL only prescribes the temporal position of the BE market, yet the position of the BC market is not fixed. What effect does the position of the BC market with respect to the spot markets have on the cost structures of the bidders?
- What is the effect of the introduction of voluntary bids on BSPs' optimal bidding strategies in the balancing market?

In order to answer these questions, we contrast the presently most common balancing market design with several options for split BC and BE markets. We analyze the optimal bidding strategies that result from these options and discuss which option best fulfills the above-stated policy goals. We develop a theoretical bidding calculus for participants in multiple markets based on a decision-theoretical approach. We present a BSP's bidding calculus for each market design option and derive the profit maximizing bidding strategy.[2]

[1] One of the few exceptions to this rule is the Dutch balancing market design where BE is procured separately from BC. In the Nordic countries, in contrast, a BE-only product exists for mFRR, i.e., no BC is reserved in advance [8].
[2] Note that we do not apply a game-theoretical analysis. This would exceed the scope of this paper. For a game-theoretical model of the current Austrian-German and future harmonized European aFRR auction please refer to [15].

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2. Market design and market actors' cost structures

The fundamental goal of each market is different: the DA market is the primary market for energy trade, the ID market serves as the final option for "last-minute" schedule adjustments, the BC market represents an option market for possible future activation, and the BE market is the actual physical contribution for stabilizing system frequency. The BE market and the ID market serve similar purposes, i.e., addressing system imbalances: in the ID market, market participants attempt to minimize deviations from their submitted schedules (e.g. due to an updated forecast from renewables or unforeseen changes in demand), while in the BE market, the TSO alleviates system imbalances by BE activation.

The availability of different marketplaces determines the number of trading options for market actors and consequently their prospects for profit. This is illustrated in Figure 1 and discussed in the following. Market actors can be characterized by two important factors. Firstly, not all wholesale market participants can place bids in the balancing market due to the technical prequalification required for market entry. Prequalified market participants, BSPs, must decide whether to sell their capacities on one of the spot markets, where only energy delivery is remunerated, or on the balancing market, where profits from both the reservation of BC and the delivery of BE can be generated.

Secondly, based on their short-term marginal costs, a distinction is made between inframarginal and extramarginal market participants. Inframarginal participants' variable costs are lower than the marginal price in a given market. In contrast, variable costs of extramarginal participants are higher (e.g. [16]). This characteristic determines in which markets actors can offer their available capacity profitably as well as their cost structures. Considering the high observed empirical balancing prices [17], a market actor with high variable costs, e.g. a gas-fired power plant, is likely to be extramarginal in the spot markets but inframarginal in the BE market (see also [18]). In contrast, market actors operating coal-fired power plant, which is likely inframarginal in the DA market, must consider expected profits in different markets when formulating their trading decision ([6], [16], [18]). Finally, market actors with short-term flexibility (e.g. vRES) tend to bid in the ID market as they are most often not allowed to participate in the balancing market [19].

If the system is undersupplied, positive BE bids are required to increase generation (or reduce load) whereas in the case of undersupply negative BE bids are needed to lower generation levels (or increase load) in order to restore system balance. Following the merit-order in the positive and negative balancing market, bids are activated from the lowest to the highest bid. In the latter, a BSP generates savings by reducing its generation level, so in this market BE bids with the highest variable costs should be activated first. Figure 1 shows that the bids for the two regulation types imply different cost structures, which may or may not include opportunity costs.

Unlike technology-related costs, opportunity costs are largely dependent on a market sequence applied and limit market actors' strategy space. Market sequence also plays a role in determining whether BSPs that were not awarded in the balancing market can still offer their capacity in one of the spot markets. Their order is defined by a number of timing-related design variables, such as:

- the bidding frequency, i.e. how often a specific auction takes place,
- the bidding period, i.e. the timeframe when the order book is open, starting with gate opening time (GOT) and ending at the gate closure time (GCT) when no bids can any longer be modified or any new bids submitted and
- the frequency of market clearing, i.e. how often the market operator builds a respective merit order and determines the market clearing price.

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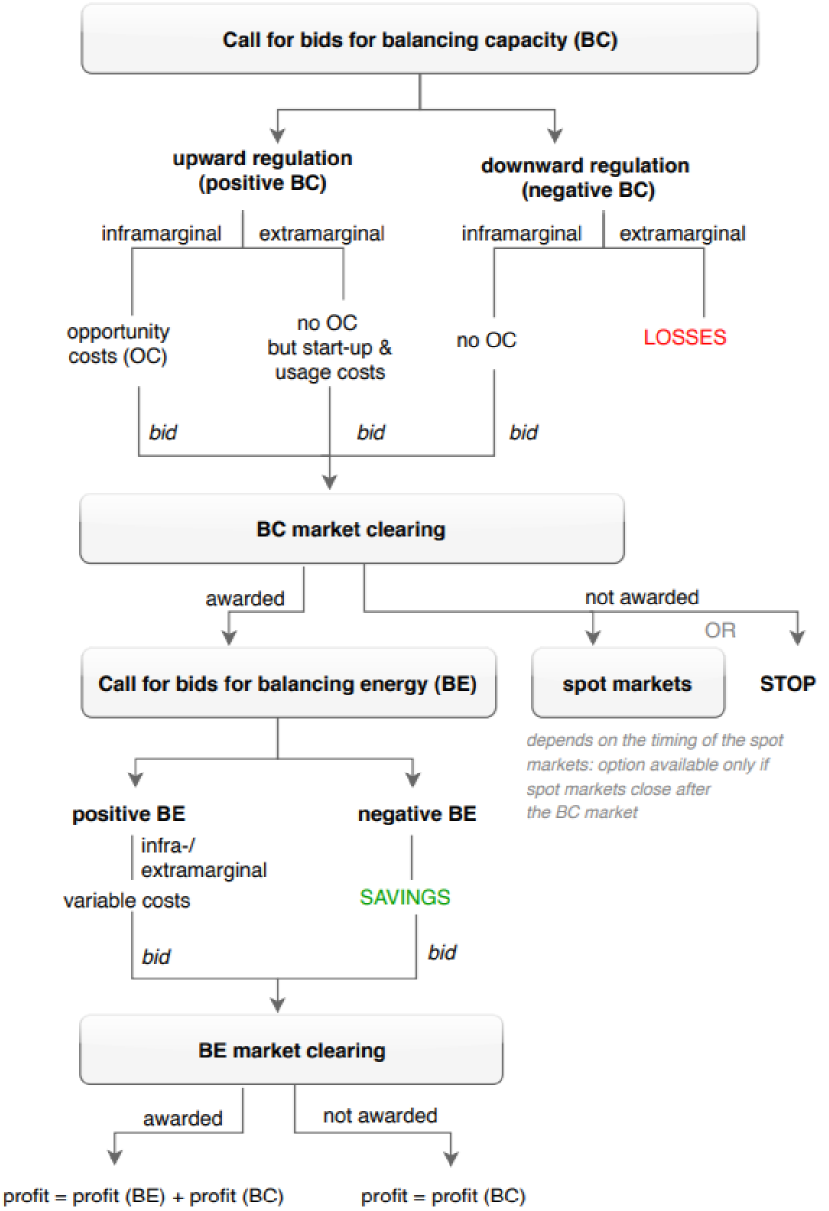

Figure 1. Trading options and associated costs for prequalified BSPs in the balancing market

Depending on the frequency of bidding, BC can be reserved for potential activation for different periods of time so that the reservation period during which BE can be activated can vary from a year to an hour or even less [10], [19]. Unlike the DA market and the ID market, in the balancing market bidding and clearing times can differ. For instance, if bids for BC and BE are submitted only once a week, i.e., the capacity market is cleared once a week, the energy market may be cleared every 15 minutes based on real-time system imbalances. Currently, fifteen minutes is the shortest settlement period applied in the European markets [9]. In contrast, if the two markets, for BC and for BE, are split, the frequency of bidding of BC and BE are not identical.

The spot markets and balancing market can be cleared either sequentially, a preferred way in the ENTSO-E area [9], [20], or simultaneously, for instance, as implemented in some US markets (e.g. PJM or CAISO). The markets are further characterized by different lead times, i.e., the time between GCT and bid execution, e.g. one day for the DA market and 60 to 5 minutes for the ID market (e.g. [21]). Finally, the markets in a sequence can be more spread out with longer time periods in between respective bidding periods or positioned compactly within a short timeframe, e.g. a day.

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Cost Structures

The underlying cost structures are crucial for the formulation of the bidding calculus. They consist of costs of capacity reservation (henceforth capacity costs) and costs of energy activation (henceforth calling costs).

Capacity Costs

Capacity costs include all costs of a BSP for reserving BC for the balancing market and are included in the BC bid in Euro/MW. For positive BC, the operator of an inframarginal power plant needs to consider opportunity costs. These arise due to sequential market clearing of the balancing and the spot markets so that the capacity committed to the balancing market cannot be sold in these other markets during the reservation period. The opportunity costs are given by the margin between the relevant market price and the variable costs, multiplied by the length of the reservation period (Figure 1). For negative BC, inframarginal power plants do not face opportunity costs: all the produced energy is sold at a profit because the operator must run the plant on a certain minimum load. For the operator of an extramarginal power plant several cost components are included in the capacity costs, such as start-up costs, usage costs or maintenance costs when providing upward regulation (Figure 1). However, these cost components are highly dependent on a specific power plant and, thus, are not considered in our theoretical analysis.

Calling Costs

Calling costs are assigned to the BE bid in Euro/MWh. The TSO incurs these costs in case BE is called. For positive BE and both inframarginal and extramarginal power plants, these costs are equal to the variable costs of generation. For negative BE, these costs are actual savings (Figure 1). The reason is that BSPs are still remunerated with the relevant market price. Recall, if negative BE is needed, there is too much energy supplied to the power system. Thus, a BSP does not need to produce traded energy with her power plant and also saves costs by reducing the load level of her power plant. Therefore, a BSP may be willing to pay the TSO for the delivery of negative BE, where the maximum willingness to pay is determined by the variable costs of the BSP's power plant.

3. Analysis of market design options

Current design: Joint market for BC and BE

This option is most frequently used in the European balancing markets (cf. [9]). BC bids and BE bids are submitted in the same bidding period, while the joint market is cleared only for BC. The scoring rule, i.e. the determination of winning bids, comprises solely BC bids. The BE bids in the merit order remain the same for the duration of the reservation period (from the GCT to real time). The GCT of the DA market and ID market take place after the GCT of the balancing market. Finally, the BE market is currently cleared every 15 minutes to one hour close to real time (Figure 2).

Figure 2: Joint market for BC and BE clearing before the DA market

The BSP's objective is to maximize her (expected) profit, which depends on her capacity costs c and calling costs k. The BSP's probability of being accepted with her BC bid b_C is described by function $H(b_C)$, which has a negative derivative, $h(bc) \leq 0$. A BSP's probability of being called for the delivery of BE on the basis of her BE bid b_E, is described by function $G(b_E)$. Since the calling probability $G(b_E)$ decreases with b_E, its

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derivative is less or equal to zero, $g(b_E) \leq 0$. The probabilities $G(b_E)$ and $H(b_C)$ are based on BSPs' subjective beliefs. The reservation period in hours is denoted by d and a BSP's capacity offer by q (i.e., her prequalified capacity). For the purpose of this analysis, we assume that a BSP submits only one BC bid and only one BE bid. If a BSP is awarded, her expected profit is given by (see also [14])

$$\pi(b_C, b_E) = H(b_C) \cdot q \cdot [(b_C - c) + (b_E - k) \cdot d \cdot G(b_E)]\,. \tag{1}$$

The first-order conditions for the maximization of (1) with respect to both bids b_C and b_E lead to the following conditions for optimal BC and BE bids b_C^* and b_E^*:

$$b_C^* = c - (b_E^* - k) \cdot d \cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)}, \tag{2}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}. \tag{3}$$

The optimal BC bid b_C^* depends on the capacity costs c. The term $(b_E - k) \cdot d \cdot G(b_E^*)$ in (1) reflects the expected profit of the BE bid per megawatt (MW) $\pi(b_E^*)$. That is, the expected profit of the optimal BE bid b_E^* is considered in the calculation of the optimal BC bid b_C^*. Since the term $H(b_C^*)/h(b_C^*)$ is negative, its absolute value is added to c. In our model the price rule pay-as-bid (PaB) is applied, i.e., awarded BSPs are remunerated with the bid figures they submitted.[3] This markup is due to the PaB rule and corresponds to a markdown in sale auctions, which is called "bid-shading" [23]. The optimal BE bid b_E^* is independent of the optimal BP bid b_C^* because the BC bid must be accepted first before any profits can be generated with the BE bid. The calling costs k are the basis of the optimal BP bid, to which – due to the PaB rule – the absolute value of $G(b_E^*)/g(b_E^*)$ is added as a markup.

From a theoretical perspective, this market sequence ensures overall market efficiency, i.e., minimizing overall costs. The reason for this is that winner determination is based on the submitted BC bids: BSPs with the highest variable cost and, thus, lowest opportunity cost incorporated in the BC bid, are awarded for the balancing market. This yields the efficient allocation that BSPs with low variable cost are not selected in the balancing market but run continuously on the spot market, while BSPs with high variable costs are selected for the balancing market in which they are activated discontinuously (based on the system imbalance) [16], [18].

Under the current design, the expected capacity costs c are given by

$$c = \max((p_{DA} - VC) + \varepsilon_{DA}; (p_{ID} - VC) + \varepsilon_{ID})\,, \tag{4}$$

where *VC* denotes the costs of power generation p_{DA} denotes the (expected) price of the DA market, and p_{ID} denotes the (expected) price of the ID market. Note that BSPs form beliefs about future DA and/or ID market prices since those are not known at the time of BC bid submission. To capture this price uncertainty of BSPs, we use the variables ε_{DA} and ε_{ID}, which can be interpreted as risk premiums with regard to expected opportunity costs. According to (4), capacity costs represent the maximum of the price spread of the DA market and a BSP's variable cost and the price spread of the ID market and a BSP's variable costs.

The magnitude of BSPs' expected opportunity costs is affected by how big the temporal gap between the GCT of the balancing market and that of the spot markets is. The farther

[3] The authors are aware that [1] foresees pay-as-cleared (uniform pricing) as price rule in the future, harmonized balancing markets. However, we decided to apply pay-as-bid in our analysis for three reasons. Firstly, the aim of this paper is the examination of effects on bidding strategies based on different market sequences, not based on different price rules. For an analysis of different price rules refer to [6], [22]. Secondly, [1] allows using pay-as-bid in balancing markets if it is proven that its application leads to a higher efficiency than pay-as-cleared. Thirdly, the theoretical analysis is more complex and less intuitive with pay-as-cleared as price rule (see [6], [26], i.e. exceeding the scope of this paper.

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the time of bid submission is from real time, the less precisely the expected opportunity costs can be estimated. As a result, market participants are more likely to place BE bids as close as possible to the maximum expected spot market prices to reduce the extent of missing out on profits from the spot markets [24]. A greater uncertainty produces higher risk premiums ε_{DA} and ε_{ID} as well as a risk for market inefficiency due to a higher probability of a distorted assignment of BSPs to the spot markets and balancing market. The size of the risk-premium depends also on the volatility of the spot market prices, i.e., the higher the volatility of the prices, the higher are the BSPs' risk premiums [25].

Thus, information availability largely depends on the time horizon of the balancing market. According to EBGL, "the contracting should be performed for not longer than one day before the provision of the balancing capacity and the reservation period shall have a maximum period of one day" ([1], Art. 5.9). Frequent bidding opportunities make it easier to evaluate the options closer to real time. However, the compression of GCTs may also lead to liquidity issues, particularly for daily timeframes [26], and to a much higher price volatility [5], thus increasing the magnitude of risk premiums ε_{DA} and ε_{ID}.

Alternative market design options: Split markets for BC and BE

Split markets for BC and BE imply that the BE market is independent of the BC market and both market clearing times and bidding frequencies differ. Furthermore, an additional factor is modelled: voluntary BE bids. As a result of their introduction, the bid components for existing BSPs change: an additional voluntary BE bid b_{VE} is added.

In our model, two distinct bidding options are considered. Firstly, if a BSP is awarded with the BC bid b_C, she submits her regular BE bid b_E, and if a BSP is not awarded with the BC bid, she can still submit her voluntary BE bid b_{VE}. Secondly, a BSP that did not participate in the BC market now also can still submit a voluntary BE bid (e.g. vRES plants that cannot reserve capacity upfront).

Note that in the first option the bidding strategy for the BC bid and the regular BE bid is not independent of the bidding strategy for the voluntary BE bid. The reasons for this is that bidders still have the chance to submit their voluntary BE bid if not awarded with the BC bid. This is not the case in the second bidding option: if a BSP did not participate in the BC market, she submits a voluntary BE bid exclusively. Further note that we assume that regular and voluntary BE bids form part of a single merit order.

Split BC and BE market with DA market cleared after BC market

In this design option capacity reservation takes place ahead of the DA market whereas the GCT of the DA market takes place prior to the opening of the market for BE, as is shown in Figure 3. Importantly, even if the BC and BE markets are formally split; bidders who commit their capacity in the first one will inevitably take the expected profit from the latter into account. In contrast to BC bids, different BE bids can be submitted each 15 minutes. The capacity costs correspond to (4).

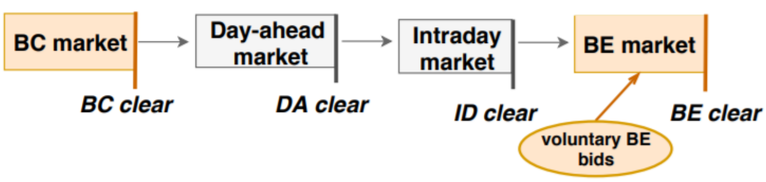

Figure 3. DA market cleared after BC market and before BE market

If voluntary bids are allowed, an additional element is considered in the expected profit function as the BSP who participates in the BC market takes both options for BE bid submission, regular and voluntary, into account. The expected joint profit is given by

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$$\pi(b_C, b_E, b_{VE}) = H(b_C) \cdot q \cdot [(b_C - c) + (b_E - k) \cdot d \cdot G(b_E)] + \\ + \big(1 - H(b_C)\big) \cdot G(b_{VE}) \cdot (b_{VE} - k) \cdot d \,. \tag{5}$$

The BSP is awarded with the BC bid b_C with probability $H(b_C)$ and, thus, generates profits with the BC bid and the regular BE bid, while with the probability $\big(1 - H(b_C)\big)$ a BSP is awarded with the voluntary BE bid b_{VE}. For maximizing (5), we compute the first-order conditions for the optimal BC bid b_C^*, regular BE bid b_E^* and voluntary BE bid b_{VE}^*, which lead to the following conditions:

$$b_C^* = c - (b_E^* - k) \cdot d \cdot G(b_E^*) - \frac{H(b_C^*)}{h(b_C^*)} + (b_{VE}^* - k) \cdot d \cdot G(b_{VE}^*), \tag{6}$$

$$b_E^* = k - \frac{G(b_E^*)}{g(b_E^*)}, \tag{7}$$

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)} \,. \tag{8}$$

Compared to (2), the optimal BC bid in (6) includes an additional markup corresponding to the opportunity costs given by the expected profit of voluntary BE bid. The optimal voluntary BE bid has the same structure as the optimal BE bid: the basis are the calling costs k plus the absolute value of the markup.

If the BSP did not participate in the BC market and is then awarded with the voluntary energy bid, her expected profit is given by

$$\pi_{VE}(b_{VE}) = G(b_{VE}) \cdot (b_{VE} - k) \cdot d \cdot q \,. \tag{9}$$

Note that in the case of non-acceptance with the voluntary BE bid, a BSP does not generate a profit at all because the DA market and ID market already cleared. The first-order condition for maximizing (9) leads to the condition for the optimal the voluntary BE bid b_{VE}^*:

$$b_{VE}^* = k - \frac{G(b_{VE}^*)}{g(b_{VE}^*)} \,. \tag{10}$$

Note that the voluntary BE bid is identical with the term in (8).

Split BC and BE market with DA market clearing before the BC market

In this option, BC is procured on a daily basis after the GCT of the DA market and BE is auctioned after the GCT of the ID market, as is illustrated in Figure 4.

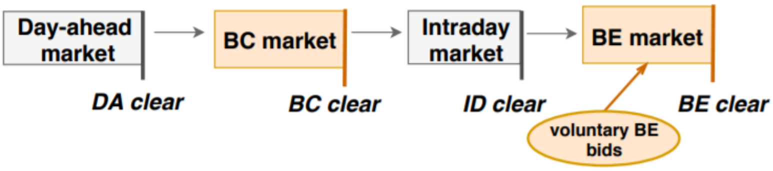

Figure 4. BC and BE markets clearing after the DA market

The opportunity cost reflect the expected foregone profit of the ID market:

$$c = (p_{ID} - VC) + \varepsilon_{ID} \,. \tag{11}$$

For both bidding options, the expected profit function is identical as in (5) and (9) and the first-order conditions for the optimal bids are identical as in (6)-(8) and in (10).

In practice, a BSP with a portfolio of units can allocate different portfolio shares to each market depending on their variable costs and, thus, maximize profits. Given that BSPs have the chance to generate higher profits in the subsequent balancing market, the DA market price now incorporates balancing market opportunity cost. Depending on the extent

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of which the DA price is influenced by these opportunity costs, the higher the DA market price, the less attractive is the balancing market option, and vice versa.

Yet, both from a theoretical standpoint (e.g. [15]) and confirmed by empirics [17], the balancing market offers higher profits, even as close as a day-ahead of delivery. Notably, in the BC market where capacities are reserved, BSPs do not face variable costs, unlike the DA market where participants incur costs for actual energy generation. Market participants, both those extramarginal in the DA market but also inframarginal, are thus incentivized to provide the maximum of their prequalified capacities as BC, potentially driving volumes away from the DA market.

Although technically feasible, this sequence is unpopular because of system security concerns, that is, if BC market is following the DA market, a supply shortage is more likely, endangering the system. The ultimate goal of system balancing consists in stabilizing frequency deviations, as a result, insufficient capacity available for activation would cause power outages. Therefore, safeguards such as a second auction or mandatory provision in case of danger to system stability must be in place. Another concern is that moving the balancing market so close to real time may affect market liquidity. This, however, should not necessarily be the case due to an offsetting effect of entry of renewables and distributed providers of flexibility into the market, which becomes possible thanks to shorter timeframes and improved forecasting.

Introduction of voluntary BE bids

If we set $G(b_E^*) = G(b_{VE}^*)$ for (5) to (8), two interesting observations can be made: firstly, the optimal regular BE bid and the optimal voluntary BE bid are identical, and secondly, the term for the optimal BC bid reduces to $c - H(b_C^*)/h(b_C^*)$. However, is it reasonable for a BSP to assume the same calling probability beliefs for both the regular BE bid and the voluntary BE bid? We argue that this is not the case. Recall that in the market equilibrium those BSPs are awarded with BC bids who have the lowest opportunity costs and, thus, (relatively) high variable costs. If a BSP is not awarded with the BC bid, she gains the additional information that her variable costs are lower than all of the variable costs of the BSPs who were awarded with the BC bid, i.e. those BSPs who form the initial merit-order of BE bids. This means that a BSP who was not awarded with the BC bid learns that she will compete with relatively “expensive” competitors for the positions in the merit order of BE bids. A rational BSP will include this information when formulating her voluntary BE bid: she will include a higher markup $G(b_{VE}^*)/g(b_{VE}^*)$ on her variable cost basis k and, thus, submit a higher voluntary BE bid compared to the regular BE bid.

The actual magnitude of the markup is a trade-off between additional profits and the position in the BE bid merit order: if a BSP exaggerates her markup, the BE bids of BSPs who were initially awarded with the BC bid, might still be lower than the voluntary BE bid. This would then result in a high position in the BE merit-order and, consequently, the BSP would deliver BE in a reduced number of cases. An additional factor that may limit her markup is that a number of voluntary bids that did not take part in the BC market will be placed in the BE market. These can be RES or small-scale producers whose bids will not necessarily have high variable costs and whose added volume it will be difficult to estimate. In other words, although BSPs that previously took part in the BC market obtain an information advantage, they do not get a similar advantage in the BE market as the bidding timeframe is the same for regular and voluntary bids and all the bidders are informed about the results of the BE market only *ex post*. Besides, according to the EBGL, no BE bids may be adjusted after the gate closure time of the BE market (Art. 24, [1]).

The empirical benefits of voluntary bids from the market perspective are illustrated by the experience from the Dutch market, where voluntary bids are already used. It shows that although the number of BC providers is very limited and they participate in the market repeatedly over an extended period of time, the balancing market still shows an efficient

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outcome as more BE providers take part in the market through voluntary bids (e.g. [21], [26]). Furthermore, opportunistic or collusive behavior that can arise from repeated BC auctions with a limited number of participants can be mitigated with the help of voluntary bids that seem to “cap” unreasonably high BE bids. As a result, voluntary bids can increase market liquidity and allocative efficiency making sure that the most cost-efficient units are used for the service.

4. Conclusion

By applying a decision-theoretical bidding calculus, we showed that the sequence in which markets close and clear has an effect on market actors’ cost structures and their optimal bidding strategies. An additional change is introduced if standalone voluntary BE bids, as mandated by the EBGL, are implemented. We analyzed these effects by comparing three balancing market designs.

An important conclusion from this study is that the splitting of BC and BE markets alone does not change BSP’s optimal bidding strategy unless the timing for the BC market is adjusted and voluntary BE bids are introduced. If these two aspects are disregarded, the effect of splitting will be marginal. The reason for that is that BSPs will still consider their costs and profits from both markets and the same bidders awarded in the BC market participate in the subsequent BE market. The additional short-term trading option in the form of voluntary BE bids generates additional opportunity costs, which leads to even higher BC prices. Especially if the BC market is situated far ahead of DA market, this can provoke substantial costs of capacity reservation borne by consumers. Thus, conducting the auctions for balancing capacity close to the DA market or even after its closure is likely to improve overall market efficiency.

Through voluntary BE bids, actors with short-term flexibility and low variable costs, e.g. new market entrants such as operators of renewables not participating in the BC market, can also compete for BE profits in the future. We show that their bidding strategy will differ from the one of incumbent BSPs that may use voluntary bids as a second chance to enter the merit order in the BE market. The introduction of voluntary bids in separate BE markets is likely reign in very high BE prices. A potential downside could be that the balancing market becomes so competitive that profit levels in the BE market as compared to the expected profits in the spot markets decrease to such an extent that it no longer appears profitable, driving capacities out of the balancing market.

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Appendix 1

List of abbreviations

aFRR	automatically activated frequency restoration reserve
BC	balancing capacity
BE	balancing energy
BSP	balancing service provider
DA	day-ahead
EBGL	Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (also known as 'Guideline on Electricity Balancing')
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	frequency containment reserve
GCT	gate closure time
GOT	gate opening time
ID	intraday
ISO	independent system operator
MCP	marginal clearing price
MW	megawatt
mFRR	manually activated frequency restoration reserve
PAB	pay-as-bid (pricing rule)
TSO	transmission system operator
vRES	variable renewable energy source

Notation used in this paper

π	BSP's (expected) profit [Euro].
VC	variable costs of a power station [Euro/MWh]
c	capacity costs [Euro/MW]
k	calling costs [Euro/MWh]
b_C	BC bid [Euro/MW]
b_E	BE bid [Euro/MWh]
b_{VE}	voluntary BE bid [Euro/MWh]
$H(b_C)$	BSP's probability of being awarded with BC bid
$h(b_C)$	derivative of the "acceptance probability"
$G(b_E)$	BSP's probability of being called for the delivery of BE based on BE bids
$g(b_E)$	derivative of the "calling probability"
d	reservation period [h]
q	BSP's power offer [MW]
p_{DA}	(expected) price of the DA market [Euro/MWh]
p_{ID}	(expected) price of the ID market [Euro/MWh]
ε_{DA}	price uncertainty related to the DA market
ε_{ID}	price uncertainty related to the ID market

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Architectures for Optimized Interactions between TSOs and DSOs: Experiences and learnings from SmartNet

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Abstract

Increased levels of Distributed Energy Resources (DERs) and their participation in provision of Ancillary Services (AS) at both transmission and distribution levels, call for a more advanced dispatching management of distribution networks to transform distribution from a “passive” into an “active” system. Moreover, new market architectures must be developed to enable participation of DERs in energy and AS markets. New operational and trading arrangements will also affect the interface between transmission and distribution networks, which will have to be managed in a coordinated manner between TSOs and DSOs in order to ensure the highest efficiency, effectiveness and security.

Evaluation and validation of the proposed schemes has been carried out both via simulations which have modelled market operation under different TSO-DSOs interactions, as well as in the laboratory and pilot project settings. This paper present experiences and learnings obtained during development and testing of the market clearing algorithm and simulator, including bidding by market participants and aggregation to provide flexibility used for ancillary services. It also discusses how solutions proposed in the SmartNet align with the present national and European policy goals and positions of the key industrial stakeholders, and also elaborate on the final guidelines and regulatory recommendations that result from the SmartNet project

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Introduction

To realize low-carbon electricity networks we need to increase levels of Renewable Energy Resources (RESs) connections, which then brings higher levels of generation uncertainty. Intermittency and variability of renewable generation, however, calls for additional instruments to increase flexibility of system operation so to facilitate integration of these resources. Thus, due to renewable generators' variable power outputs that are not easy to predict even for the next day, such resources are far from being "plug and play".

High penetration of renewables brings higher levels of generation uncertainty and, because of a need to balance demand and supply at any instant in time, will require additional support. New technology which can provide additional flexibility, with energy storage (including electric vehicles) and active demand participation are regarded as two major ways to provide this. They could be introduced at all voltage levels, but due to costs and available technologies, this is often considered at distribution levels, where larger number of smaller renewable generators, active demand side participation of smaller customers (e.g. commercial or domes-tic) and energy storage (including electric vehicles) are expected to be connected. These distributed devices are typically referred to as Distributed Energy Resources (DERs).

Since considerable share of RESs are connected at the distribution systems, it changes the nature of their operation whereby such networks are becoming more active, with possible changes in directions of power flows. One of the key approaches to help harness RESs in an efficient and cost-effective way is to utilize flexibility which can be provided by DERs. Some of the main aspects of the transition towards low-carbon energy systems envisioned by new European regulation and roadmaps [3] include market based provision of ancillary services by DERs that need to be give a level playing field to participate in all electricity/energy and ancillary services markets, at both transmission and distribution networks.

Therefore, procurement and activation of resources from distribution network for ancillary services, such as congestion management and voltage regulation, will require new grid organisation for ensuring and improving interaction between TSOs and DSOs, and defining their roles and responsibility under new operation regimes. In addition, operation of systems with high levels of DERs as well as design and operation of associated energy and ancillary services markets will need new tools and underpinning regulation and codes.

This paper discuses some of the regulatory aspects analysed within the EU H2020 project SmartNet [1] proposes five different architectures or coordination schemes (CSs) that each present a different way of organizing the coordination between transmission and distribution system operators (TSOs and DSOs), when distributed resources (production, storage or demand) are used for ancillary services [2]. Each coordination scheme is characterized by a specific set of roles, taken up by system operators and a detailed market design. These different schemes span from the situation of a complete centralized control over AS market to the creation of different local markets run by DSOs and one AS market run by the TSO.

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SmartNet in a Nutshell

This section briefly outlines the project - a set of coordination schemes, assumptions which were made for their implementation and the simulator used to assess and compare of these CSs.

SmartNet coordination schemes

SmartNet evaluates five coordination schemes (CSs), each presenting a different way of organizing the coordination between transmission and distribution system operators (TSOs and DSOs), when DERs participate in provision of ASs. Here, only a brief outline for each of the CSs is provided, while their detailed descriptions are provided and discussed in [2], while market aspects of the CSs are discussed in [4]. Each of the CSs is characterized by a specific set of roles assigned to TSOs and DSOs with a comprehensive operational rules and market designs. The main differences between different CSs are related to how, and by whom, coordination of DERs' participation in AS markets or local markets is managed.

The five proposed CSs, developed within the SmartNet, are as follows:

- *Centralized AS (CS-A) market model* where the TSO operates a market for resources connected both at transmission and distribution levels, without involvement of the DSO and without receiving any real-time information on distribution network status.
- *Local AS (CS-B) market model* where the DSO organizes a local market for resources connected at the DSO-grid and, after resolving local grid constraints, offers the remaining flexibility bids to the TSO for participation in AS markets.
- *Shared balancing responsibility (CS-C) model* where balancing and congestion management responsibilities are divided between TSO and DSO according to a predefined schedule. The DSO organizes a local market while respecting a schedule agreed with the TSO This does the same for the transmission grid.
- *Common TSO-DSO AS market (CS-D) model* where the TSO and the DSO have a common objective to decrease costs to satisfy the needs for resources by both the TSO and the DSO. This mutual objective could be realized by the joint operation of a common market operated by the TSO and the DSOs.
- *Integrated flexibility market (CS-E) model* where the market is open for both regulated and non- regulated market parties, having each a different goal to achieve (non-regulates parties would see this market as an extension of the intraday market, whereas the grid operators would procure services for the network). This scheme as not simulated because it was recognized it would pose a lot of problems (technical and regulatory) to work properly.

SmartNet simulator

To evaluate proposed Coordination Schemes (CSs), a large-scale simulator has been developed to realistically model the behavior of complex systems which include transmission and distribution networks, bidding and market processes, as well as fundamental physics behind each flexible device connected to the system. As illustrated in Figure 1, the SmartNet simulator comprises of three main layers:

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- *The Market layer*: is an optimization algorithm responsible for simulating the real-time balancing market clearing process and includes network representation, market products and arbitrage opportunities between day-ahead, intraday and ancillary services markets. It is designed to manage large optimization problems including the constraints of all the networks and the different TSO-DSO interaction models
- *The Bidding and dispatch layer*: It is assumed that a large number of relatively small dispatchable devices will participate in the market via third party aggregators, whose role is to aggregate devices and submit aggregated bid for participating in the ancillary services markets, and the to carry out a disaggregation process which depends on the results of the market clearing and sends activation/instruction signal to each of the participating devices. Bids for each of the devices should reflect flexibility costs and other constraints of particular technologies while also taking into account the potential arbitrage between different markets
- *The Physical layer*: The basis of the entire simulator is represented by the physics of the system components. The complex behaviour/characteristics of each network (transmission and distribution), loads, generators and flexible devices (storage, electric vehicles etc.) are simulated together with the automatic processes directed by grid operators (state estimation/forecasting, network asset management etc.). The processes include voltage regulation, reactive compensation, aFRR and network protections.

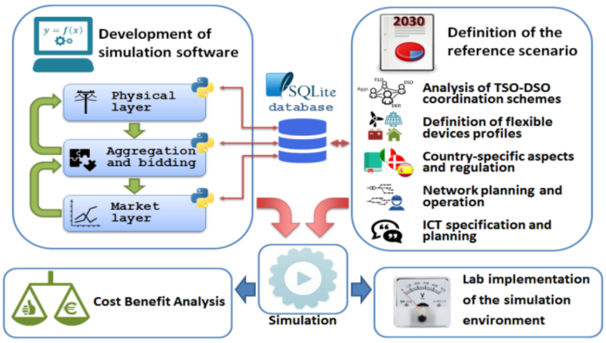

Figure 1 - Structure of the SmartNet simulation platform [5]

Implementation and Pilot Projects

In order to evaluate practical implementation of the concepts developed within SmartNet, in particular, regarding the different coordination schemes and the market models developed these were tested in three technological pilot projects, namely in Italy, Denmark and Spain. Each of the pilots is seeking to evaluate different parts/aspects of the TSO-DSO coordination value chain, as summarised in Table I [8].

Regulatory Analysis: Where does SmartNet Project fit and What does it Address

Two main aspects regarding regulatory analysis have been considered (i) how does a work carried out in the SmartNet fit within the current and emerging EC and national regulation, roadmaps and position papers of various stakeholders, and (ii) what important aspects should be considered when developing and implementing practical TSO-DSO coordination schemes, and how these issues have been addressed in the SmartNet project.

Table I – Summary of Technological Pilots

	Pilot A	Pilot B	Pilot C
Country	Italy	Denmark	Spain
Coordination scheme	Centralised Ancillary Services market	Common TSO-DSO Ancillary Services market	Shared balancing responsibility
Services to be gathered by TSO/DSO	- Aggregation of information for TSO - Voltage control for TSO - Frequency control for TSO	- DSO Congestion management - Frequency control for TSO	- DSO Congestion management - Frequency control for DSO
DER providing flexibility	Run-of-river hydro power plants	Impulsion pumps for heat water for indoor swimming pools in rental houses	Back-up batteries for radio base stations used in mobile phone communications
Main focus of the pilot	- TSO-DSO communication - TSO control - Assessment of DER capability to participate in markets	- Price-signals from aggregators to obtain DER flexibility - Communication chain from market to DER through aggregators	- Monitoring of distribution network - Creation and operation of local flexibility markets - Assessment of base station capability to provide services for grid support

The first question regarding current regulation, road maps and position papers has been addressed by firstly identifying main and critical issues that are associated with SmartNet models, assumptions and solutions. Then, comprehensive screening studies were carried out to evaluate how those issues fared in over 40 different documents that included legislation/regulation (EU Directives, Network guidelines, national regulatory Decisions), position papers, strategies, roadmaps, etc. Detail findings from these analyses are presented in [6].

In addition, similar approach has been used to gather learnings related to the similar critical issues associated with SmartNet models, assumptions and solutions used in the coordination schemes and in the simulators [7].

The following is a sample of these issues and associated analysis.

Market modelling and timelines

In the SmatNet market, the model developed and implemented sought to enable mechanisms which will help DERs trade their electric power and energy in ancillary services. Depending on the adopted coordination schemes, these services can be provided to TSO and/or DSO, and the simulator, and its market design, have been developed to handle DERs' trades with both TSO and DSO. The simulator is based on a hierarchical design formulated as standard constrained optimization problem that clears the market based on bids submitted by market participants [4].

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Due to the nature of the market and trades, i.e. intraday market for flexibility, as well as technical characteristics of the DERs, the following aspects of the market design and operation are important to consider:

- **Time step:** Considered time granularity for the market clearing. Activation decisions are made for each time step and the behaviour of the system and the flexibility assets inside each time step are considered constant at their average value.
- **Time horizon:** Overall time period considered for the market operation and clearing. The time horizon can be equal to or greater than the time step. However, it will typically be a multiple of the time step in order to model intertemporal constraints and to clear the market with some anticipation on the future time steps.
- **Frequency of clearing:** Defines how often the market is cleared. From a network balancing perspective, the market needs to be cleared sufficiently often in order to take into account the latest updated data from the system state. From an algorithmic perspective, the frequency of clearing needs to be sufficiently low, so that the optimization algorithm used to clear the market can generate (near) optimal solutions within the allowed time. If a higher frequency is required, e.g., for security reasons, an economically sub-optimal solution can be acceptable.

In the SmartNet simulator, time steps, time horizon and frequency of market clearing are parameters that are controlled by the user, providing necessary flexibility to adjust market operation and clearing for the particular conditions that will typically be dependent on regulatory settings.

Above explained screening analysis of various documents revealed a need for an overall harmonisation process across Europe. In addition, from 1st January 2025, the imbalance settlement period should be 15 minutes in all control areas. Since Market Operators (MOs) on the Day-ahead Market (DAM) and Intra-Day Market (IDM) shall provide the opportunity to trade energy in time intervals which are at least as short as the imbalance settlement, energy will be traded in at least 15min period from 2025. Finally, the trade should be moved as close as possible to operation, while it is important to ensure non-discriminatory access to the markets and creation of level-playing field.

Accounting for technical DER constraints in a market design

When deciding on modelling technical capabilities and responses from different DERs, it is important to consider how to include these into the market model. Thus, it is necessary to decide which constrains should be included in the market model, and how market participants should account for technical constraints of different DER technologies.

In SmartNet, five technology specific aggregation models, aimed at separate DER categories, have been used in order to reflect physical constraints of the devices being aggregated, as summarized in Table 2 (with more details provided in [9]. The physical approach (bottom-up) includes the physical constraints of each aggregated technology in the aggregation models, and assumes that that the aggregator knows the parameters of each individual device and its real time status. As indicated, in Table 2, the physical i.e. bottom-up, approach has been selected as the preferred aggregation option in the SmartNet market design [9]. Other aggregation approaches have been used only in two of the models due to physical characteristics of the aggregated devices, the number of the individual devices being aggregated and the availability of data. For example, in the case of atomic loads, which use load profiles and associated costs, rather than directly defined constraints, traces aggregation approach has been used, while justified approximation

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(hybrid) approach, which represents the entire population of aggregated devices by a single or a limited number of virtual devices has also been used for aggregation of TCLs.

Table 5 - Aggregation approaches, types of bids and units used for aggregation of different DERs [10, 9]

Models	Aggregation approach	Type of bid	Units used
Atomic Loads	• Traces	• Non-curtailable UNIT bid	• P [W], t [min], C [€]
Combined Heat and Power (CHP) Units	• Physical	• STEP curtailable Q-bid	• P [kW], t [h], C [€]
Thermostatically Controlled Loads (TCLs)	• Physical • Justified	• STEP non-curtailable Q-bid • STEP non-curtailable Qt-bid	• P [W], T [˚C], E [J], t [s], C [€]
Electric Energy Storage (EES) Units	• Physical	• STEP curtailable Q-bid • STEP curtailable Qt-bid	• P [kW], E [kWh], t [h], C [€]
Curtailable Generation and Curtailable Loads	• Physical	• STEP curtailable Q-bid	• P [kW], t [h], C [€]

It is also important to note that the way in which technical constraints of DERs are accounted for in the market design will directly influence the definition of bids, i.e. products, used by market participants, and in particular aggregators.
No present legal requirements for inclusion of device-related constraints, however, proposal for inclusion of certain requirements on portfolio-level are advanced by a number of stakeholders.

Management of voltage constraints

Voltage control is formally defined as non-frequency ancillary service [8] and thus shall be allowed to be procured by DSOs in market-based manner (both active and reactive power can be used for voltage control). According to common reports TSOs and DSOs should agree on voltage control parameters at the border of the networks.

Voltage control is one of the key aspects in managing power system stability, and it is becoming more challenging at the distribution level with the increase levels of DERs. In the SmartNet project, voltage management is considered one of the key aspects, with the DERs participating in provision of this service [2] both to DSO and to support the voltage at transmission network. Within SmartNet coordination schemes, this service is delivered in several coordination schemes: The Local AS market, Shared Balancing Responsibility, and Common TSO-DSO AS market.

Therefore, in addition to technical constrains of DERs, it is also important to include limitations of the power network into the market model. This, however, requires utilization of full AC network flow models, which introduce non-linear constraints, making optimization (i.e. market clearing), computationally challenging task, especially in the presence of binary variables. To enable utilization of existing solvers and provide computational tractability, modelling of the distribution network in the SmartNet simulator is based on Dist-flow model [4]. This has enabled inclusion of realistic physical models of the distribution system networks into a market clearing algorithm, providing more accurate market clearing solutions that respect physical constraints of networks and DERs .On the other hand, for transmission network linearized DC model is applied as it provide sufficient accuracy for those networks.

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Learnings from the SmartNet project

All the schemes of TSO-DSO coordination that have been assessed within the SmartNet project assume significantly higher levels of DSOs involvement and responsibility, in particular for the management of congestion and voltage constraints using DERs flexibility. This is in line with the EC package Clean Energy for All Europeans, which seeks to allow customers to provide become more actively engaged and also provide flexibility services at the level playing field with the participants connected to transmission networks (but, subject to secure system operation) However, this will require significant investments in monitoring and control systems, as well as good TSO-DSO coordination. To succeed, roles and responsibilities of both TSOs and DSOs should also be well defined.

Looking at the question of whether distribution constraints management should be shallow or deep, it is important to acknowledge the state and the capacity of the network. Traditional TSO-centric schemes could stay optimal if distribution networks don't show significant congestion. However, distribution grid planning was (and still is) affected by the fit-and-forget reinforcements policy, which may cause system operation issues.

More advanced centralized schemes incorporating distribution constraints show higher economic performances but their performance could be undermined by big forecasting errors: it is important that the gate closure is shifted as much as possible toward real time, market clearing frequency is increased and forecasting techniques are improved. However, although intraday markets should bring gate closure as close as possible to real time. It is not feasible to overlap a real-time session of intra-day market with a services market (CS-E): this solution would create uncertainty in the operators (TSO and DSO) in charge of purchasing network services because they would be no longer sure of how many resources are needed (i.e. the real amount of congestion and imbalance). This is a significant shortcoming of this coordination scheme.

Ensuring level playing field in the participation of distributed resources in the tertiary market will make it necessary to allow bidding, and thus market products, that will be able to reflect some of their technical characteristics, otherwise these technologies may be prevented from participating in the market. This could imply to enable complex bids or other sophisticated products.

Scarcity of liquidity, and potential impact of local market power (not investigated in SmartNet), along with extra constraints introduced to avoid counteracting actions between local congestion market and balancing market (e.g. increasing system imbalance while solving local congestion) furthermore negatively affect economic efficiency of decentralized schemes.

Local congestion markets should have a “reasonable” size and guarantee a sufficient number of actors are in competition in order to prevent scarcity of liquidity and exercise of local market power. Small DSOs may need to pool-up.

Reaction to commands coming from TSO or DSO in real time of the control loops which were initially planned for real time services provision can be too slow. So, a testing is needed to ensure compatibility with requested reaction times.

ICT is nearly never an issue: whatsoever TSO-DSO coordination scheme is implemented, the economic performance depends by wide and large on operational costs, being ICT costs mutually comparable between different CS and, in any case, one order of magnitude lower than operational costs (in our simulations: maximum 5% over operational costs).

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Offering water electrolysers' flexibility to European grid service markets

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Abstract

Sustainable production of hydrogen is a key element of the European energy transition agenda, especially for seasonal and mobile energy storage purposes. The technology is about to enter the market, as the economy of the solution has considerably improved over the years. The water electrolyzer (WE) as a key element of such hydrogen production can offer its high operational flexibility for grid services such as frequency control. Servicing those markets as a byproduct, the WE achieves a value that is relevant to bridge the gap towards market parity.

The article reports on best opportunities for European grid service markets to be served by WEs. The results of the research, supplemented by a survey amongst transmission system operators (TSO) and distribution system operators (DSO) conducted in 2017/2018, are summarized. Financial and business logic data is available for 25 European countries incl. Norway and Switzerland. 85 TSO grid services within 12 countries are commercially and technically feasible candidates.

With four such cases a more detailed economic analysis is made for a WE with daily storage capacity. Offering the WE's flexibility to the grid service markets can reduce the levelised cost of hydrogen at the WE outlet (LCOH) by up to 10% under ideal conditions, i.e. at a WE size of 500 kW and more operating at 6000 full load hours (FLH) or more, without sharing the margin between the balancing service provider (BSP) and the WE owner.

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Introduction

Aggregation of smaller scale, distributed renewable energy systems for the provision of grid services already is in place in a series of European countries. Others report to adapt their market rules in order to comply with the harmonization effort of the EU [1]. Thereby, opportunities open for water electrolyzers (WEs) to achieve an additional income from the provision of grid services. WEs, as a key element of sustainable hydrogen production, can offer high operational flexibility for grid services such as frequency control. Servicing those markets as a by-product, the WE achieves a value that is relevant to bridge the gap towards market parity. For the European project QualyGridS, the best opportunities for the European grid service markets to be served by WEs have been identified. Data is available for 25 European countries including Norway and Switzerland.

Balancing market survey

Due to a lack of reliable market data in the literature, a survey was conducted. The survey was based on written questionnaires, one specifically for TSOs, and a second one specifically for DSOs. The TSO questionnaire asked about grid service product information and prices for the year 2016. It was sent to 36 TSOs from 30 countries (28 EU countries plus Switzerland and Norway) and a selection of DSOs in winter 2017/2018.The results were cross-checked with available literature, mainly from [2], [3], and [4]. If necessary for clarification of the answers, the respondents of the survey were contacted multiple times during 2018. Results are summarized in Figure 1.

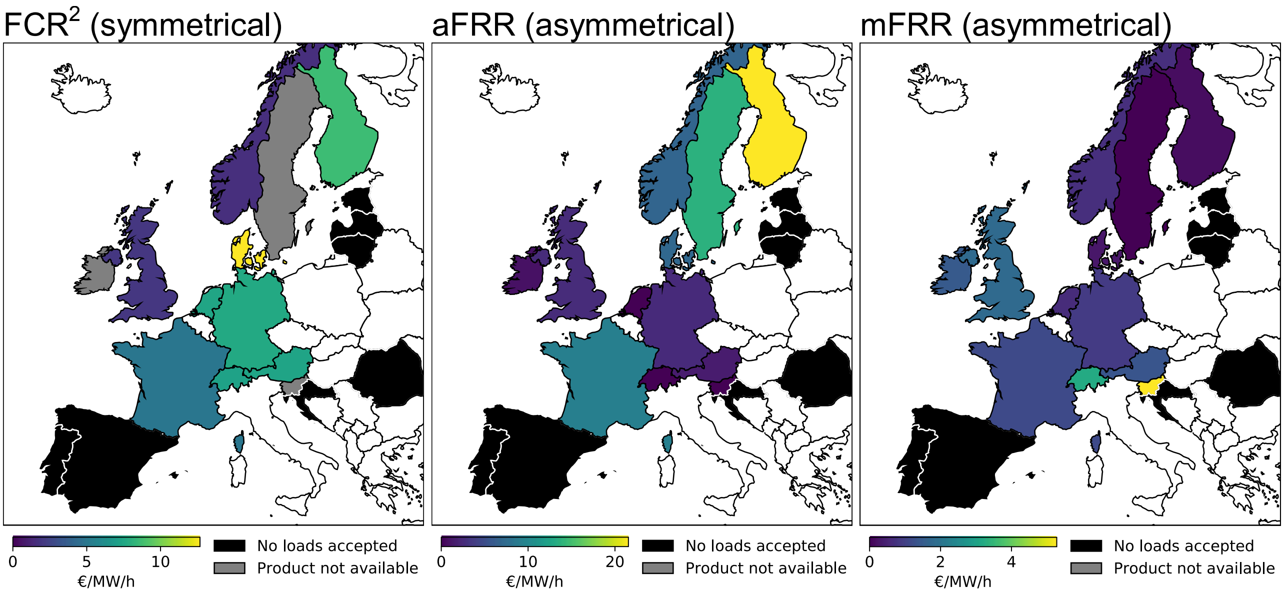

Figure 1: Results of the survey (average availablilty prices of 2016)

Evaluation of the most attractive grid services

Based on the survey results, a few attractive grid services are selected to be evaluated and compared in more detail. Therefore, the levelised cost of hydrogen at the WE outlet (LCOH) is calculated. As a base case, it is assumed that a WE operator buys the required electricity on the day-ahead market. He takes care to keep costs as low as possible and purchases electricity in the cheapest hours of the day. The next step is to formulate the influence of various network services on the WE operator's strategy. The aim of this

[2] Where FCR-N and FCR-D were available, FCR refers to FCR-N

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strategy is to minimize electricity cost. This allows for an evaluation of different grid services by examining the difference of the LCOH "grid services" and LCOH "base case" (no grid service).
Today's profitable WE business-cases[3] are characterized by a more or less stable hydrogen production target over the course of a few hours or days even. This restriction is considered in the following evaluation. The calculations for the base-case as well as for all grid service cases are based on historical data of the years 2016 and 2017.

Grid services overview

the following TSO grid service products are analyzed in more detail:
Positive and negative automatic frequency restoration reserve (+/- aFRR) in Germany (asymmetrical): The availability and utilization are paid as bid. If a tenderer[4] gets called for availability, he can, at a next stage, offer utilization. As for 2016 and 2017 there are two weekly products, an off-peak and a peak product [5].
Positive and negative manual frequency restoration reserve (+/- mFRR) in Germany (asymmetrical): The availability and utilization are paid as bid. Again, if a tenderer gets called for availability, he can, at a next stage, offer utilization. The products are characterized by a contract duration of 4 hours [5].
Frequency containment reserve (FCR) in Germany (symmetrical): The availability is paid as bid and traded as a weekly product.
Positive manual frequency restoration reserve (+mFRR) in Norway (asymmetrical): Availability (national name: RKOM) and utilization (national name: RK) are paid-as-cleared. There are two weekly availability products, an off-peak (12 pm – 6 am) and a peak (6 am – 12 pm) product. Furthermore, RKOM is split into RKOM-H and RKOM-B, where RKOM-H is characterized by stricter requirements regarding activation duration and flexibility [6].

Combining selected TSO grid services with WE applications

Today's profitable WE business-cases are characterized by a more or less stable hydrogen demand over the course of a few hours or days. Such cases could be identified in the application categories "industry with limited constant demand of hydrogen" and "distributed hydrogen fueling stations". [3] Hence, it can be assumed that the WE's flexibility is restricted with regard to daily production targets of hydrogen.
The impact of the grid service business for these two application categories is evaluated by considering the following cases:

- a base case in which the WE is operated without participation in the grid service business,
- offering asymmetric power reserve products (aFRR, mFRR) and
- offering a symmetric FCR product.

Changes in CAPEX and WE efficiency due to part- and over load resulting from the grid services are neglected. Further CAPEX/OPEX assumptions are depicted in Table 1. The calculations for the base-case as well as all grid service cases are based on historical data of the years 2016 and 2017. The following sections detail the conditions under which the respective calculations are based. Thereby asymmetric and symmetric products are considered separately, since the conditions under which a WE can provide these differ significantly.

[3] Other application categories such as "industry with high demand of hydrogen" and "power to gas connected to the natural gas grid" turn out to be unprofitable.
[4] A tenderer in this context refers to a Balancing Service Provider (BSP) that tenders grid service products to a TSO.

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Operation strategy without power reserve products (base case)

In the base case scenario, the WE operator is assumed to minimize the electricity cost without making use of the option to offer grid service products. The operator is assumed to follow a daily production target. The lowest electricity costs are achieved when the WE operates at nominal power during the hours with the lowest electricity prices. It is further assumed that the WE operator purchases electricity at the day-ahead-spot-market.

In order to calculate the electricity costs, historical hourly day-ahead-prices of the years 2016 and 2017 are used. These prices are available at EPEX SPOT SE [7] and Nord Pool AS [8] for Germany and Norway, respectively. In Norway's case, different bidding zones exist. In order to further minimize the electricity costs, it is assumed that the WE is located within the bidding zone with the lowest average price, which is NO 4 (Tromsø). The average price in this region in 2016 and 2017 was 25.39 €/MWh, whereas the average price in Germany with 31.58 €/MWh was about 6 €/MWh higher.

Operation strategy with asymmetric power reserve products (aFRR, mFRR)

The base case as described above is now extended by offering the WE's flexibility as asymmetric power reserve to the BSP. It is assumed that the BSP accepts quarter-hourly offers for aFRR as well as mFRR , and the WE operator offers positive power reserve products during operation (i.e. the WE reduces its power) and negative power reserve products during the stand-by time (i.e. the WE increases its power). The stand-by power consumption is neglected in this analysis. The impact of these grid service products on the electricity cost and the operation time is shown in Figure 2. The figure shows the sorted day-ahead prices of one day (in ascending order). The red hatched area represents the base case for which the WE does not profit from reduced energy costs due to the compensation for its availability and utilization offerings.

Positive power reserve products are offered for the hours scheduled for operating at nominal power. For those hours, the availability price ($P_{Availability}$) is interpreted as a reduction to the electricity cost. When positive reserve is called ('utilization of control reserve'), the costs are further decreased by a utilization compensation. However, the positive utilization reduces the operational time and as a result, lowers the hydrogen production accordingly. The actual net cost for electricity corresponds to the blue hatched area in Figure 2.

The negative products affect the net cost analogous to the positive products. However, a BSP, and therefore the WE operator too, usually pay the TSO for negative utilization. [5] As a result, the WE operator pays for the called utilization on the one hand, but increases the hydrogen production on the other hand.

The requirements imposed on WEs participating in these grid service markets, such as the minimum contract duration as well as the minimum power, are lowered by the BSP aggregating WEs in a virtual power plant (VPP). Hence, it is assumed that whenever the WE runs, it offers its nominal capacity for mFRR positive. In the high price hours however, when the WE is not operating, mFRR negative is offered at nominal power. In order to estimate the influence of utilization, German average utilization prices paid by the TSO as well as average utilization amounts (duration and frequency) are assumed. It is important to keep in mind that the amount of utilization varies depending on the bidding strategy, which in turn has an impact on the business case. However, the effect on the business case is expected to be minor since a higher utilization comes with lower revenues per MWh utilization (due to the merit-order principle of the pay as bid mechanism) and is therefore neglected.

[5] I.e. the BSP and with that the WE operator pay for the energy consumed. However, the price typically is lower than the regular market price, which makes the case commercially attractive.

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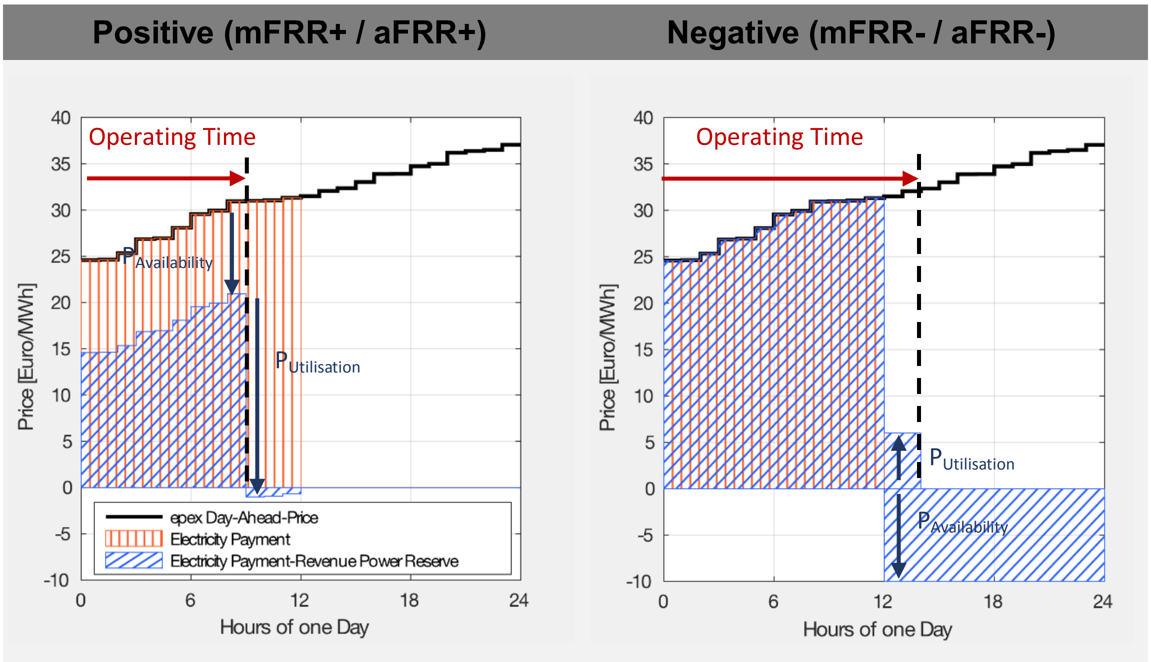

Figure 2: The effect of the asymmetric power reserve product on the business case (example of a nominal 12 hours operation schedule per day)

The impact of these power reserve products on the electricity cost is computed with historical ¼ - hourly values of 2016 and 2017. Regarding Germany, the relevant data is available from the Bundesnetzagentur [9]. The availability prices used for the analysis were derived from the published German average prices for availability in a given time-slot as €/MW/h.[6] In regard to utilization, these average values are used for the utilization price as well as for the amount. By dividing the total utilization (MWh/15min) by the total reserved capacity (MW) for each 15-minute slot, a relative utilization amount per 15-minute slot is derived. By knowing the reserved WE capacity and the relative utilization amount, the absolute average utilization of the WE can be estimated for every 15-minute slot.
Turning to Norway, mFRR is called Tertiærreserver. In the Nordic power supply system, the mFRR utilization is published by Nordpool, a common market place for energy trades. Nordpool refers to it as Regulating Power, while within the Norwegian TSO Statnett it's called Regulerkraftmarkedet (RK). As for availability (Regulerkraftopsjonsmarkedet, RKOM), data is published by Statnett [10]. Again, data for the period 2016, 2017 is being used. Please note that the time-series consists of weekly contracts only. Hence, seasonal contracts are neglected. Furthermore, the price for the negative availability is assumed to be zero. This is due to the fact that positive availability is traded only. In order to convert the availability prices to Euro, the official daily exchange rate time series from Nordpool is used [8]. As for utilization, a common market exists among all Nordpool zones [10]. Hence, the average utility price per ¼ hour is calculated by dividing the sum of all zones of the regulating bids volume by the sum of regulating volumes for each hour.
The value a WE provides to a BSP depends not only on speed, reliability and power, but also on the time of day or time of week at which the WE operator is willing to offer its services. This can be understood based on the following considerations:
mFRR (Germany) and aFRR (Germany) / mFRR (Norway) are traded as daily 4-hour and weekly off-peak/peak products, respectively. For any further analysis, and to make the cases comparable, it is assumed that the product delivery period is split into 15-minute slots by the aggregator, and that there is no minimal requirement regarding contracted power. The difference in the contract duration between the actual products and the

[6] Price in € per MW and hour of availability.

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assumed 15-minute duration plays a role when it comes to assessing the value of WEs providing these products. This is due to the fact that the day-ahead prices affect the tenderer's willingness to offer power reserve products [11]. The operator of a flexible power-plant, for example a storage hydro power plant or a gas power plant, usually plans its schedule to maximize its profit. Hence, the higher the day-ahead prices, the more attractive it gets to produce and sell electricity. As a result, the operator offers negative power reserve products for the time slots with high day-ahead prices (when the turbines run) and positive products for the slots with low prices. The willingness to offer negative power reserve during low price hours usually is low and therefore characterized by high offering prices and vice versa. Usually, weekend day-ahead energy prices are lower, due to a decreased demand of electricity.
However, aFRR and mFRR (Norway) are weekly products. Hence, a BSP gets compensated for a whole week (either for peak or off-peak hours) with one price. If a power plant operator offers a weekly product, let's assume aFRR negative, he commits to let the turbines run even during the unfavorable weekend hours. On the other hand, when evaluating the value of reserve offerings over shorter durations, in our case ¼ hours, the correlation between energy and flexibility prices should be considered.
For reasons of data availability, the effect of the contract duration on the value of power-reserve is estimated based on data from Germany. This is done by estimating the German mFRR (4-hour products) prices as if mFRR (Germany) had been traded as weekly products, assuming the effect is similar for mFRR and aFRR in Germany as well as in Norway:
The historical availability prices of mFRR (Germany) are aggregated over the same hours where aFRR products were traded. As there are two weekly products in Germany, this is done by calculating two average mFRR (Germany) availability prices for each week, a peak and an off-peak price. The impact on LCOH is then calculated for this synthetically aggregated mFRR (Germany) time-series as well as for the historical time-series with the 4-hour products. By comparing the relative savings on LCOH, we now are able to estimate the impact of this aggregation. By assuming that the impact was similar for Germany and Norway as well as for aFRR and mFRR, we can now calculate the reduction on relative LCOH savings on aFRR and mFRR (Norway) due to splitting the weekly product into 4-hour products and derive a more realistic result.
It is worth mentioning that we assume contract durations of 15 minutes, and therefore we are likely to still overestimate the revenues due to mFRR as well as aFRR. However, since there is no historical data available for neither mFRR nor aFRR with contract durations for less than 4 hours, this effect cannot easily be quantified.

Operation strategy with symmetrical power reserve product (FCR)

As next, the base case as described above is extended by offering the WE's flexibility as FCR, which is a symmetric power reserve product. In order to evaluate the economic potential of the symmetrical FCR product, the full capacity of the WE can be used for the provision of FCR. In that case, as the WE operator has to guarantee the symmetrical power reserve, the WE can maximally operate at half of its maximum power, which then is considered its nominal power.
Offering FCR not only is generating an additional revenue, but also yielding opportunity costs. These opportunity costs are caused by the fact that the WE has to operate on part-load while selling the symmetrical grid service product. As a result, the WE gives up the opportunity to produce hydrogen at maximum power during the best day-ahead price hours. This reduction needs to be compensated by operating at more expensive hours[7] that originally were not scheduled for operation.

[7] Operating at 50% of nominal power.

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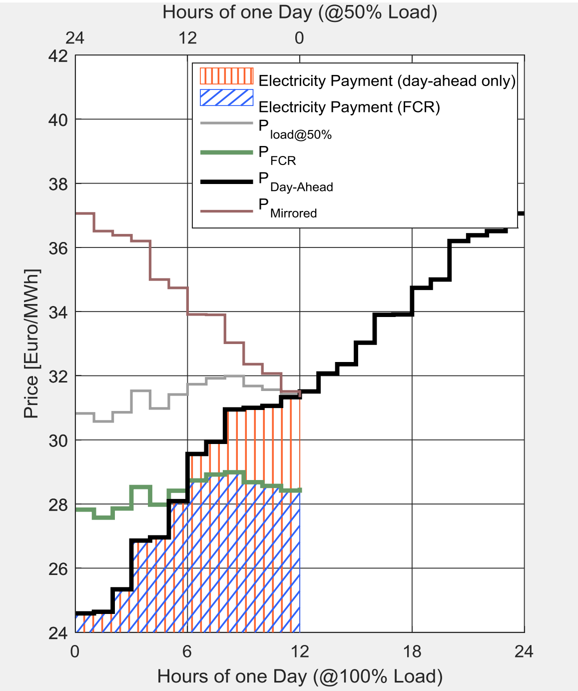

Figure 3: The effect of the symmetric power reserve product FCR (example of a 12 hours operation schedule per day at nominal power)

With this mechanism in mind, a procedure is derived in order to identify the hours, in which an FCR offering is advantageous while operating the WE on part-load. This procedure as well as the impact on the cost of electricity is depicted in Figure 3. The figure again shows the sorted day-ahead prices of one day (in ascending order). As an example, if the WE operator intends to offer FCR for 2 hours a day, the two hours during which FCR is most advantageous consist of the hour with the highest day-ahead-price that was at the same time scheduled for operation in the base-case (not offering GS) and the hour with the lowest price that was originally not scheduled for operation. In the example of Figure 3, these hours would be hour 11-12 and hour 12-13. This is due to the fact that the difference between the average day ahead price during these two hours (50% load) and the day ahead price for hour 11-12 (100% load) is the lowest possible difference, and therefore causes the minimal opportunity cost. To operate at 50% load during the two hours 11-13, the cost for electricity equals to the average price of these two hours multiplied by the two hours of 50%-load:

$$P_{load@50\%}(t) = \left(P_{Mirrored}(t) + P_{Day\ Ahead}(t)\right)/2$$

These costs $P_{load@50\%}$ are represented by the grey line in Figure 3 (electricity price if the load is operated at 50% and the missing production must be made up at a time with the next cheapest energy price). The opportunity-costs can now be derived by looking at the difference between the grey line and the bold black line (day-ahead price). As can be seen, for the example of a 12 hours base operation schedule with 2 hours of FCR offering,[8] the lowest opportunity costs are found in hour 11-12 and increase towards the left side. I.e. the more FCR hours are to be offered, the higher the opportunity costs are. If we now subtract the revenue of FCR-availability, the actual electricity price (green line) of offering FCR is obtained. Lower values of the green line, as compared to the day-ahead-curve, imply that an FCR offering is advantageous. In the example of Figure 3, with an FCR availability compensation of 3 €/MW/h, this is the case if the day-ahead-price is in the range from 29 to 34 €/MWh. If the day-ahead-price is lower than 29 €/MWh, the opportunity costs are too high and it is more advantageous to operate the WE at nominal power instead of offering FCR. The cost reduction due to FCR is reflected by the difference between the red and the blue area in Figure 3.

Deriving the levelised cost of hydrogen

Deriving the LCOH produced by a WE in Germany, no EEG surcharge is considered. The costs for water are assumed to be 0.03 € per kg hydrogen [12]. Further assumptions for the Alkaline as well as PEM WEs are based on [13] and depicted in Table 1.

[8] In this example 12 hours means operation as base case, i.e. operation without FCR. Offering FCR for 2 hours in fact extends the effective operation time to 13 hours: 11 hours at P_{nom} plus 2 hours at $P_{nom}/2$. The number of hours in which the WE operates at 50% load and offers FCR is indicated in the upper x-axis.

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	ALK	PEM
Nominal Power	1MW	
Maximal Power	1MW	
Maximal Power (Positive Sensitivity)	1MW	2MW
Power Consumption	58 kWh_e/kg	63 kWh_e/kg
Lifetime - System	20 Years	
Stack - Lifetime	80'000 h	40'000 h
Degradation	not considered	
CAPEX - System	1'200€/kW	1'500€/kW
CAPEX - Stack replacement	420 €/kW	525 €/kW
OPEX	4%/CAPEX	
Weighted average cost of capital (WACC)	8%	

Table 1: Assumptions

The costs for electricity are calculated according to the assumptions and methodology described above and implemented in a discounted cash flow model. In order to avoid unrealistic price jumps between different full load hour (FLH) scenarios, stack-replacement costs are calculated as annuity costs.[9] Based on the annuity payment equation and the present value of constant perpetuity, the annual payment due to stack replacement of a fictional WE with infinite operation years can be calculated as:

$$PV = \frac{S_c}{r} \qquad \text{Eq. 1 [14]}$$

$$PV = \frac{S_c}{(1+WACC)^k - 1} \qquad \text{Eq. 2}$$

Where: $k = \frac{S_r}{flh}$ Eq.3

$$Annuity\ Payment = PV \cdot \frac{WACC}{1-(1+WACC)^{-n}} \qquad \text{Eq. 4 [15]}$$

$$if\ n \to \infty$$

$$Annuity\ Payment = PV \cdot WACC \qquad \text{Eq. 5}$$

$$Annuity\ Payment = \frac{S_c}{(1+WACC)^{\frac{S_r}{flh}} - 1} \cdot WACC \qquad \text{Eq. 6}$$

k =replacement period in years
$WACC$ =Weighted Average Cost of Capital
r =interest of stack replacement period
PV =Present value of stack replacements over n years (Euro)
S_c =Stack replacement costs (Euro)
S_r =Replacement rate (hours)
flh =Full-Load-Hours a year (hours)
n =years of annuity

In order to evaluate the impact of grid services, the LCOH is calculated.[10] By forming the difference of the LCOH derived from the base-case (optimal scheduling without grid

[9] This corresponds to the amount the WE-operator has to spend every year in order to keep the stack in new-like-condition.
[10] Only the cost in Table 1 were considered and any other costs for the storage and its ancillary (compressor and so on) are neglected.

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services) and cases with grid services, the cost reduction due to the grid services can be expressed as savings on LCOH, where LCOH is defined by:

$$LCOH = \frac{\sum_{t=0}^{n} \frac{C_t}{(1+WACC)^t}}{\sum_{t=0}^{n} \frac{H_t}{(1+WACC)^t}} \qquad \text{Eq. 7} \quad [15]$$

$WACC$ =Weighted Average Cost of Capital
C_t =Costs in year t (Euro)
H_t =Hydrogen production in year t

Results

By implementing the procedures and model assumptions defined above and testing them on the historical data for 2016 and 2017, it is possible to derive the costs of hydrogen production depending on different setups. The influence of different grid services can best be examined by looking at the LCOH savings shown in Figure 4.

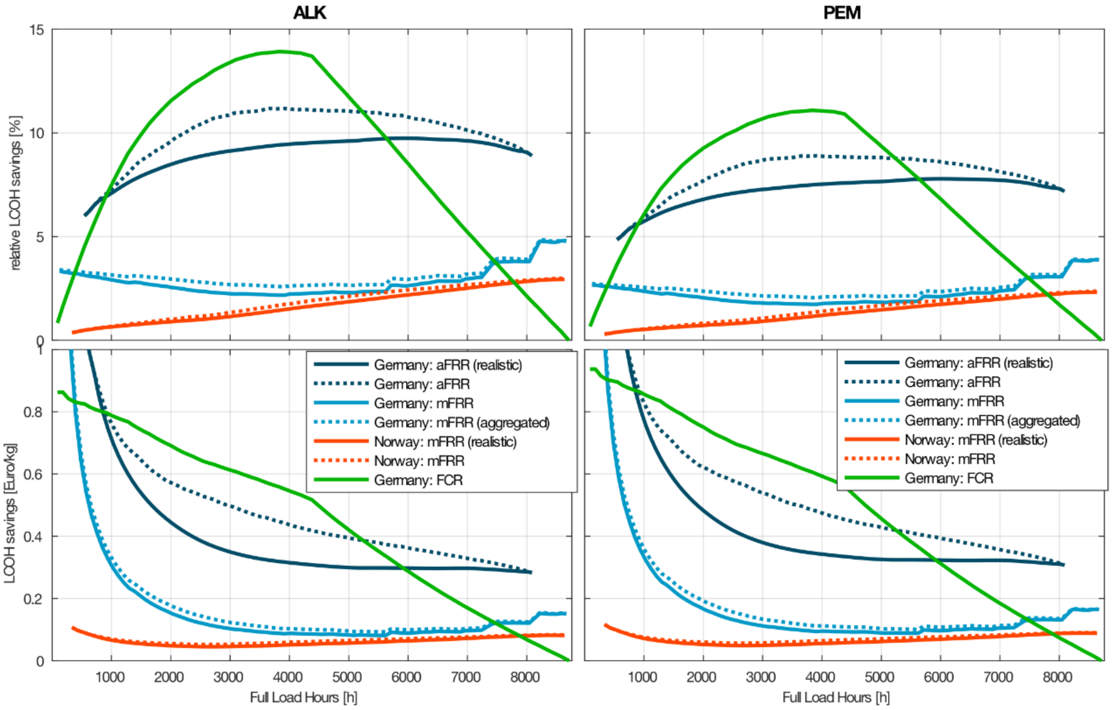

Figure 4: Relative LCOH-savings (upper) and absolute LCOH-savings (lower) due to grid services for ALK-WE (left) and PEM-WE (right). The cases “realistic” refer to the synthetically calculated 4-hour contracts, which consider the effect of contract duration on the value of GS, as explained in section Operation strategy with asymmetric power reserve products (aFRR, mFRR). Full load hours are to be understood as annual full load hours, where it’s assumed they are equally mapped to daily full load hours.

Looking at the absolute FCR savings in Germany, the highest impact is found at low FLH scenarios (for the lowest FLH scenario 0.94 €/kg (PEM) and 0.86 €/kg (ALK)). As the operating hours increase, this value decreases steadily and reaches 0.56 (PEM) and 0.52 (ALK) €/kg at the 4380 FLH scenario. This decrease is caused by the opportunity costs of not having the possibility to concentrate the production during the lowest price hours. If the FLH are further increased, the number of hours available for part load (50% of nominal power) declines and restricts therefore the revenues of FCR even more. As a result, an even steeper decrease can be observed for FLH higher than 4380.

More constant relative savings over all possible FLH scenarios can be observed for aFRR and mFRR in Germany. Over all FLH, the average savings are with 7.2% (PEM) and 9.0% (ALK) substantially higher for aFRR than for mFRR (Germany) with 2.3% (PEM) and 2.8% (ALK).
Due to the inexistence of a negative mFRR availability market in Norway, the relative savings of mFRR (Norway) steadily increase from almost zero for low FLH scenarios to 2.4% and 2.7% for PEM and ALK-WE for high FLH, respectively.
As can be seen for PEM as well as for ALK WEs, the least promising grid services are mFRR (Germany) and mFRR (Norway). At less than 1000 FLH, aFRR shows the highest saving potentials with about 7% and 5% of savings on LCOH for ALK and PEM WEs, respectively. Above 1000 FLH, FCR influences the LCOH even more and reaches relative savings of 13% and 11% on LCOH for 4380 FLH. Between 5700 and 8760 FLH aFRR is the dominant grid service product in terms of saving potential.

Conclusion

Providing services to the grid service markets, WE operators can reduce their LCOH in many European markets. Detailed calculations show that especially German aFRR and FCR are suitable products with which WEs can reduce production costs considerably. It is worth mentioning here, that many effects, which limit savings from grid services, could not be considered at this stage of the analysis. These effects include the costs of additional storage facilities and lower availability revenues due to the temporal splitting of availability contracts (4-hour contracts have to be split into 15-min contracts). Furthermore, the WE operator has to offer grid service products through an aggregator who has to be compensated for its services, too. Hence, the results show an optimistic picture and should only be used to compare the grid service products relative to each other.

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Power Alliance – Extending Power Grid Capacity on the Medium Voltage Level by Incentivizing a New Class of Emerging Flexible Loads

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Abstract

The electrification of the energy system introduces new loads with high simultaneity, such as new storage technologies, sector coupling technologies or electric cars. This effect, together with the penetration of renewable energy sources causes an increased likelihood of grid congestions in times of high production or demand, which in turn entails an increased need of costly physical grid expansion. Demand flexibilities and dynamic load management solutions can be used to counter this effect. However, demand flexibilities are limited particularly in the industry sector, because market-based incentives to support the macro-economic goal of optimizing existing grid capacities are missing. The paper proposes a novel market-based approach to employing dynamic load management in the mid-voltage grid that overcome these hurdles. A smart method to utilize redundant grid capacity for a new class of loads called "conditional loads" is combined with an attractive tariff scheme for customers and incentives for DSOs that help increase competitiveness of electricity vs. fossil combustibles.

Introduction

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In order to mitigate the risks of climate change an extensive energy system decarbonization needs to be realized until mid of this century. If the installation of renewable generation assets continues at the necessary high rates, the system will increasingly exhibit an excess power production, increased simultaneity of production and demand, and resulting grid congestions on all voltage levels. A means to avoid or mitigate costly physical grid expansions in the future are the utilization of demand flexibilities and dynamic load management solutions. However, a shift of demand towards times of abundant wind and solar power is rarely happening today: while a top-down enforcement of necessary measures is politically not desirable, market-based solutions are difficult to implement, because the demand is largely inelastic due to technical, regulatory and economical hurdles.
The paper proposes a market-based approach to utilizing demand side flexibilities on the mid-voltage (MV) grid, overcoming the existing hurdles. The approach consists of three main ideas: 1. We utilize the currently unused grid capacity reserved for n-1 security of supply for a special class of flexibilities called “conditional loads”, which are assumed to be the main drivers of future grid congestions. These loads are used by a "Regional Load Shifting" system to automatically resolve grid bottlenecks. 2. We propose a novel tariffication scheme for end customers that significantly reduces energy prices, grid fees, and taxes and levies for conditional loads. 3. We provide incentives for distribution system operators (DSOs) to offer conditional loads to their customers. We describe two new processes that are needed to implement the proposed scheme, and sketch the underlying technical solution, including a proof of concepts of technical and economic feasibility.
The proposed approach was developed as part of the EU project "Power Alliance", that involves research and industry partners from Austria, Germany and Switzerland. Participating DSOs contributed real data from pilot customers of power consumption and production as well as related auxiliary measurements. Here, an existing smart metering and load management solution has been adapted to implement a practical prove of concept for the "Power Alliance approach" presented here.
The paper is structured as follows: Section 1 discusses existing business models and principles that aim at avoiding future grid congestion. Section 2 discusses increased simultaneity as an effect of decarbonization, and section 3 discusses the main hurdles that are in place today that impede the use of demand flexibilities to mitigate grid congestions. In section 4, the Power Alliance approach is introduced as a solution to this problem. The paper concludes with a summary of proposed concepts and results.

1. Flexibilities to Mitigate Grid Congestion

The electric power system is undergoing a profound change driven by the continuously growing penetration of renewable energies, and the expected electrification of the transportation and industrial sectors. These two major trends increase the need for flexibility to avoid bottlenecks and blackouts at the distribution grid level.
In order to respond to these new challenges, the present grid technologies, business models and regulations need to be updated (Giordano & Fulli, 2012). This is particularly important for DSOs, who are in charge of accommodating decentralized energy generation even though this technology endanger their current business model. DSOs are highly regulated entities, and thus the regulatory framework must be adapted to facilitate the implementation of new business models and incentivizes DSOs to try innovative solutions in order to keep the quality of supply at lower cost (Colle et al., 2019).
Presently, DSOs charge fees using the classic electricity tariff, which is based on the amount of energy transmitted. Consequently, the DSO revenues are largely affected when

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end-users start to require less energy due to the increase of distributed generation technologies (Honkapuro et al., 2014; Jansen et al., 2007; Picciariello et al., 2015).
Furthermore, even with lower revenues, a DSO is still compelled to keep the security and reliability of the electric supply with an aging infrastructure (Honkapuro et al., 2014). As a consequence, DSOs are in the need to find new ways of creating and capturing value. The use of information technologies in smart grid application opens large opportunities for new business models that benefit several stakeholders, including DSOs. The proposed "Power Alliance" provides such a business model, and particularly provides incentives also for DSOs.
The literature mentions mainly 3 types of business models that are enabled by smart grids: Vehicle to grid (or grid to vehicle), demand response and renewable energy integration. Among other benefits, these business models can help DSOs to reduce system costs, lower investment cost and grid capacity requirements (Niesten & Alkemade, 2016). The paper introduces a novel market-based approach to respond to above listed challenges that combines demand response for the MV grid with renewable energy integration with the allocation of currently unused grid capacity.

2. Decarbonization Entails High Simultaneity

The electrification of transport and heating that is necessary for decarbonization entails new loads that exhibit high simultaneity. This in turn amplifies an already existing lack of flexibilities available for grid capacity optimization.
Today low wholesale prices appear on the spot market when renewable production is high and power demand is low. With the increase of renewable power production, it is likely that we will experience situations in which - even during high load periods - wholesale prices will remain low, if only renewable production is high enough. Scenarios for a decarbonized power supply in Germany (Graichen, 2017) expect that, e.g. for solar photovoltaic (PV) production alone, an installed capacity in the order of 250 GW is necessary in a decarbonized energy system. Wind generation capacity onshore and offshore ranges in the same order of magnitude. Today the overall maximum grid load in Germany is in the order of 80 GW (Klobasa et al. 2013).
With the penetration of new storage technology, power-to-x technologies as well as electric cars, the maximum grid load has the potential to increase quite substantially. For example, if only 1 Mio. electric cars would charge simultaneously at a rate of 11 kW, the German grid load would increase by 11 GW already. While the average charging will likely be much lower than that, other, additional factors will contribute. E.g.,

- the number of passenger cars registered in 2019 amounts to approximately 47 Mio., some of which will likely be fueled by renewable hydrogen. This in turn - amongst other applications - drives the number of installations for electrolysers.
- the number of fossil fueled room heating systems is in the order of 15 Mio. units, which in majority need to be replaced by heat pumps or direct heating systems.
- with the phase-out of feed in tariffs for approximately 1.6 Mio existing solar generators, a substantial share will be upgraded with stationary batteries. The majority of new PV installations in the private and commercial sector dispose of a battery already .

With a penetration of smart meters and smart charging technologies these new loads will draw electricity from the grid, preferably during periods of low price, i.e., during periods of high renewable generation. These new loads therefore will exhibit a very high simultaneity and thus have the potential of becoming the main source of stress to the electricity grid on all voltage levels.

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3. Main Hurdles for Exploiting Demand Side Flexibility to Counter Simultaneity Effects

Demand side flexibilities, together with dynamic load management solutions can provide a means to avoid grid congestions at times of high simultaneity. Yet, from a practical point of view, significant hurdles exist towards their implementation.

Hurdles in the household segment. In the *household segment* today, there is very little capacity installed which technically could be shifted. Apart from electrical water heaters, which in some cases follow a ripple control signal, most other appliances, e.g. cooking, washing, lighting, communication, etc. are nearly inelastic.
From a technical point of view the penetration of electric cars and solar storage systems as well as the substitution of fossil room heating systems through heat pumps will offer significant technical load shifting potential in the future.
From an economical point of view it is obvious that the cost of implementing and maintaining an energy management system including smart metering and communication can hardly be refinanced by the relatively little savings achievable through load shifting today. The household customer electricity predominantly consists of fixed charges for grid use and taxes and levies. The fraction for energy on the overall bill, e.g., in Germany is 30% or lower on average. Any gains through load shifting towards periods of lower prices thus only slightly affect the overall bill. In Switzerland the fraction the of energy is somewhat higher though, but in turn, the absolute price for electricity is lower than in Germany, and electricity in the overall household budget is mostly not an issue of concern.
The European Union is pushing for a mandatory rollout of smart meters for a long time, in an effort to let household customer participate in flexible rate schemes. In Germany this leads to the adoption of the Law for the Digitization of the Energy System Transformation ("Gesetz zur Digitalisierung der Energiewende", Bundesregierung 2016) which foresees a mandatory installation of smart meters for households over 6.000 kWh of annual consumption. This obligation however only enters into force as soon as a minimum of 3 independent suppliers of certified smart metering systems are certified by the state. Today only one such system is on the market due to the complexity of the data security prerequisites laid out in the law.

Hurdles in the industrial & commercial segment. In the *industrial and commercial segment*, practically all significant consumers are obliged to monitor their energy consumption electronically. From a technical-economical point of view several studies have shown that the available potential today is relatively small (Klobasa et al. 2013). The underlying reason for this is the fact that in industrial production the cost of electricity in the overall production for most companies is relatively low. The average share is around 5% on average only. Hence cost saving measures on other parameters e.g. labor, capital etc. have a significantly bigger impact. In addition, the opportunity cost of permanently shifting planned production cycles into variable periods of lower energy costs will overcompensate the savings on the energy bill.
In those cases where the energy bill is a significant portion of the overall production cost, i.e. the basic materials industry, a number of policy related subventions are in place in order to keep production local in a global market (carbon leakage, local employment). One example is companies with baseload offtake profile (>7000h/a) in Germany will receive grid tariff discounts of 80 to 90 %. load shifting measures would compromise the offtake profile and hence jeopardize these very significant grid savings.

As a conclusion it can be stated that flexible loads for the energy system today are practically insignificant.

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4. The Power Alliance Approach

The Power Alliance approach proposes a technical and economical scheme that allows to overcome the existing hurdles for utilizing demand side flexibilities to avoid grid congestions in future scenarios of increased electrification. It thereby supports the underlying macro-economic goals of avoiding negative prices for electric power, avoiding the shut- down of excess generation, and mitigating a future need for costly physical grid expansion.
To overcome the hurdles for utilizing flexibilities towards these goals, demand side load management is applied only to a specific class of new flexible loads, the so-called "*conditional loads*", which mainly emerge from sector coupling applications. For these loads, the currently redundant grid capacity used to provide today's high level of security of supply - the "*n-1 security*" – is utilized, thereby allocating additional capacity in the existing grid infrastructure. Conditional loads are subject to a simple security of supply, while n-1 security is maintained for all other loads.
Incentives for grid customers to declare suitable loads as conditional loads with the DSO comprise 1. significantly reduced grid fees for conditional loads (the "*Power Alliance Tariff*"), and 2. an automated dynamic load management solution (the "*Regional Load Shaping*" solution) that minimizes the customers' energy costs for conditional loads according to stock prices whenever regional grid capacity constraints admit it.
Power Alliance also advocates reduces taxes and levies for conditional loads: to support the long-term goal of significantly increasing competitiveness of electricity vs. fossil combustibles, it is necessary that electricity – wherever it is in competition with fossil energy carriers - is not burdened with associated costs as much as it is the case today.
The main incentives for DSOs to participate in the Power Alliance scheme are a better plannability and control over their grid, as well as more detailed insights into grid flows, which allows them to offer attractive products of choice to their customers.

4.1 Unconditional and Conditional loads

The Power Alliance approach distinguishes two classes of loads according their respective requirements regarding security of supply:

Unconditional loads are loads are price inelastic within the normal range of price fluctuations. These loads only depend on the demand of the respective energy service. Examples are loads in industrial production, household appliances, lighting, communication etc. For unconditional loads, a supply outage would incur significant costs. The customer is willing to pay an adequate price for n-1 security of supply. As it is the case today, unconditional loads are supplied through the normal n-1 secure capacity band of the MV grid (cf. Figure 1).

Conditional loads are new emerging loads that are either connected directly to the MV grid or belong to premises that have their own grid level 6 transformer stations (e.g industrial sites or residential microgrids). They have *two defining characteristics*:

1. They can tolerate a lower security of supply compared to unconditional loads. This means that the (rare) event of an outage would *not* incur an unacceptably high financial damage.
2. They exhibit a significant price elasticity during a larger number of timesteps within a 24-hour period or longer.

Typical examples for conditional loads are industrial power-to-heat installations to substitute fossil-based combustibles, industrial electrolysers for hydrogen production (including synthetic fuel), electric cars charged at work, as well as buffer batteries that are used for PV-based self-consumption or for peak shaving in industry and in local micro-grids. Conditional loads are supplied through the redundant grid capacity that is today reserved for n-1 security (cf. Figure 1).

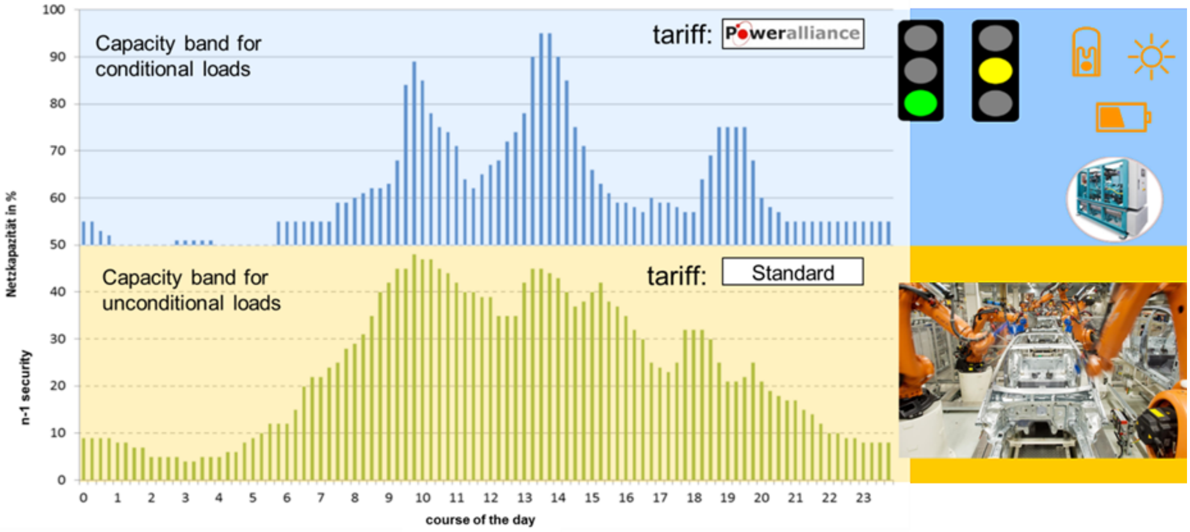

Figure 1: Conditional and unconditional loads

4.2 Incentives and Obligations for Stakeholders

The goal of Power Alliance is to provide a market-based scheme and corresponding incentives to stakeholder to support the macro-economic goal of avoiding costly physical grid expansion. Besides national economies, there are two main stakeholders participating in the Power Alliance scheme, namely grid customers on MV level, and DSOs.

The grid customer perspective. For *unconditional* loads, today's normal grid tariffication stays unaltered and is called the "*Standard Tariff*" (ST). For *conditional* loads we introduce a new tariff that is significantly lower than the ST, and we refer to it as "*Power Alliance Tariff*" (PAT). The PAT effects all three price categories of power supply, namely *grid fees, energy price*, and *taxes & levies*.

- **Grid fees.** The PAT for conditional loads offers customers significantly reduced grid fees compared to the ST, e.g., a reduction by -90%. In return, customers must guarantee that their conditional loads are either connected and controlled by separate electrical wiring, or that they are integrated in an energy management system that allows for an individual metering and control in relation to the signals which result from the Power Alliance system. They accept for their conditional loads a simple security of supply instead of the usual n-1 security of supply. I.e., in case of a grid capacity bottleneck, conditional loads are automatically shedded to ensure n-1 security of supply for unconditional loads. In addition, the customer (or its energy supplier/service provider) has the obligation to send daily schedules not only to the transmission system operator (TSO), but also to the DSO, thereby providing the DSO with better insights in their grid flows.
- **Energy prices.** The PAT allows end customers to participate in the spot market. Thereby they can leverage the spot market's demand flexibility for conditional loads, profiting from the daily energy price volatility it offers. The is achieved by applying a smart mechanism based on dynamic load management, the *Regional Load Shaping* (RLS) system (Christen et al., 2019). The RLS automatically shifts conditional loads to times of minimal spot prices, respecting the customer's technical and procedural

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constraints. Only if the available capacity limit for unconditional loads (i.e., the capacity of the n-a band) is reached at a certain time slot, grid customers are competing among each other for this time slot. Here, every individual customer is curtailed according to their individual allowance. A customer's allowance in turn is derived from a prioritization of customers according to their PAT scheme: The more customers are willing to pay for PAT, the higher is their prioritization in a competition setting. Thus, the Power Alliance approach utilizes the willingness to pay principle by creating scarcity-based market prices for grid use. To limit the energy price risk for conditional loads, customers are given the option to agree on price caps with their power suppliers. To mitigate the price risk for unconditional loads, customers directly use the ST to hedge the energy price under a full supply regime.

- **Taxes & Levies.** The PAT offers a significant reduction in taxes and levies compared to the ST (e.g., -50%). The Power Alliance approach uses this instrument to additionally incentivize the build-up of loads for decarbonisation through sector coupling and storage technologies.

Since reduced fees are only applied to conditional loads, the overall income situation of the energy system is not affected in a negative way.

The DSO perspective: Incentives and Obligations. In offering the PAT, DSOs can increase the distribution grid capacity of their MV grids without costly physical grid upgrade, increasing their income. They also gain more detailed insights into their grid flows, because Power Alliance customers are obliged to submit their daily schedules to them. This allows for a better plannability and control, and also helps DSOs to strengthen their customer relationships by offering attractive products of choice. Furthermore, the DSO is offering its unconditional and conditional capacity products to its customers on a regular basis e.g. annually or monthly.
In return, DSOs accept the obligation to monitor critical grid nodes, and to automatically submit respective measurements to Power Alliance. This enables Power Alliance to monitor grid capacity at bottlenecks, and, in case of excess demand of conditional loads, curtail them semi-automatically. More specifically, in case the daily ordered capacity demand of conditional loads exceeds the available n-1 capacity reserved for security of supply at a critical node, the Regional Load Shaping (RLS) system automatically curtails customer loads according to their individual allowance under the Power alliance tariff scheme. I.e., in contrast to *local* load management solutions, the RLS combines *regiona*l grid capacity optimization for DSOs with *local* load shifting for energy price optimization for end customers within the respective grid branch (Christen et al., 2019). After curtailing, the RSL sends a suggestion to customers for shifting the curtailed portion of their loads to a time slot with the "next best" spot price. Customers are then given the option to accept or reject the automatic suggestion, and, in case of rejection, resubmit an adapted schedule suggestion to RSL, which again is checked automatically by RSL for compliance with the grid constraints at bottlenecks. The process is iterated for every customer until the customer accepts a schedule or until a temporal deadline is reached.
In open ring topologies grid bottlenecks usually appear on grid level 4 at the transformer stations from the high voltage transmission grid to the MV distribution grid - loads are highest at this point in the grid whenever no significant production is located within the local distribution grid.

4.3 New Processes

In order to practically implement the Power Alliance scheme, two additional processes must be devised and implemented.

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The capacity purchase process.

- Grid customers purchase conditional and unconditional grid capacity from their DSOs on a regular basis (e.g., monthly or yearly) according to their needs. Curtailments might occur during high capacity demand, i.e., in times of low or negative energy prices. In this case, customer loads are curtailed in proportion to their capacity limit. In order to achieve a higher prioritization in case of curtailment, customers have the option to buy more unconditional grid capacity than they actually need (*willingness-to-pay principle*).
- The DSO sells unconditional capacity rights only to the extend such that he can meet all required unconditional schedules at all times.
- For the sale of conditional capacity no limit is stipulated. Grid customers are free to purchase as much as they need in order to improve their individual situation in case of possible curtailments.

The daily capacity nomination process. Customers (or their service providers) are submitting to their DSOs two day-ahead schedules on a daily basis:

1. The **schedule for their unconditional loads** is based on a normal day-ahead forecasting process that reflects their needs. Schedules for unconditional loads do not need to be approved by the DSO, since the DSO is obliged to fulfill them in any case as long as they do not exceed the contracted limit.
2. The **schedule for their conditional loads** results from automated stock price optimization by the RLS load management software. After the reception of all schedules well before the given deadline, the DSO is checking grid capacity constraints and accepts or rejects them. In case of rejection, the RLS software automatically suggests a revised schedule that complies with grid constraints and provides to all customers second best time-slots for their excess loads with respect to stock prices. The customer in turn can accept the suggested schedule revision or provide their own revised schedule. The process is iterated until a temporal deadline is reached.

The technical implementation of the capacity nomination processes comprises two components: the "*energy manager*" is a local energy management system installed at the customers' premises; the regional "grid manager" software system is installed at the DSO's premises and aggregates the individual day-ahead schedules (of unconditional and conditional loads) of all customers attached to a grid branch and checks each critical node in the branch against the available capacity limit. Energy manager and grid manager units are technically separated to comply with the requirement of the European Union of ownership unbundling.

4.4 Proof of concept

Technical feasibility. Even though conditional loads are not significant in capacity today, it is assumed that the emergence and penetration of such loads in a decarbonized energy system will be the primary driver of grid extension needs. In order to demonstrate the feasibility and the practical use of the Power Alliance approach, simulations have been performed that are based on real data from pilot customers projected to a one year period in 2035 (Christen et al., 2019). It could be shown that today's redundant grid capacity can be put into service for conditional loads without compromising n-1 security for unconditional loads. I.e., crucial consumers and processes are not effected by the Power Alliance scheme in case of an outage.

Economic feasibility. The successful implementation of the Power Alliance scheme and business models for stakeholders largely depends on several external factors such as the future electricity and gas prices as well as the price of the studied technologies. To assess the feasibility, simulations of future market scenarios have been performed.

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According to Graichen et al. (2015) the wholesale electricity price will increase in the following years, from 3.8 cEUR per kWh in 2016 to 8.3 cEUR per kWh in 2035. Therefore, it is expected that the EEG Subvention decreases from 6.1 cEUR per kWh in 2016 to 2.2 cEUR per kWh in 2035. This means that the resulting retail electricity price in 2035 will be 6% larger than the electricity price in 2016. Regarding the end user gas and oil price, the forecasted scenarios show a rise in the next years due to an increase in the CO2- Price. As a result, according to (Swiss Federal Office of Energy, 2012) with very strong environmental policies, the gas price could reach the value of 13.5 EUR/kWh in the year 2035. This means an almost 30% growth in 15 years.
Furthermore, due to the learning effect the cost of the technology such as batteries and PtoH2 will significantly decrease. According to the projection of (Pleßmann & Blechinger, 2017) the capital cost of batteries will drastically decrease from 1192 EUR/kWh in 2016 to 289 EUR/kWh in 2035. At the same time, it is likely that the cost of the Polymer electrolyte membrane electrolyser sink from 2000 EUR/kW in 2016 to 530 EUR/kW in 2035 (Estermann et al., 2017).

Conclusions

Continuing the way of decarbonization with renewable energy sources will lead to congestions in Europeans electrical power grid. Causes are the penetration of renewable energy sources, progress in sector coupling but also the missing flexibility in loads. However, the missing flexibility is mainly related to the industry where no incentive is given from the economical point of view. The paper proposed a market-based approach to solving this problem for the MV grid. The approach utilizes the currently unused grid capacity reserved for n-1 security of supply for a special class of flexibilities called “conditional loads”, which are assumed to be the main drivers of future grid congestions. While conditional loads are only equipped with simple security of supply, n-1 security is guaranteed for all other loads. A novel tariffication scheme is introduced that economically incentivizes the adoption of conditional loads for end customers and DSOs, and an automated "Regional Load Shaping" system shifts conditional loads to resolve grid capacity bottlenecks if needed. We described the new processes necessary to implement the "Power Alliance" scheme practically, and sketched the underlying technical solution, including a proof of concepts of technical and economic feasibility.

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A Market Data Clustering Aimed to the Economic Analysis of an ESS-based Power Plant providing Ancillary Services

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Abstract

The increasing use of Non-Programmable Renewable Energy Sources (NP-RES) in power systems determines very strong effects on the grid. The intrinsic uncertainty of the NP-RES causes strong power unbalance problems with consequent repercussions on the frequency and voltage stability; this requires greater use of balancing resources and Ancillary Services. One of the most promising solution to face the issues related to the spread of NP-RES is the use of Energy Storage Systems (ESSs), but their high cost makes ESSs still not very widespread, limiting its use to pilot plants. However, there may be particular market conditions that make it right to use the ESS to support the network.

In this paper, a hierarchical clustering method for the offers accepted on the electricity market is used to evaluate the affordability of ESSs able to provide ancillary services in different market areas. The proposed approach is applied to a historic series of Ancillary Services ex-ante market data, by using the Pearson coefficient to highlight the similarities between the historical sub-series of months. Then, by applying the Ward method, similar months are grouped together in order to extract the market characteristics of interest such as average price and share of hours of supply of resource in the market.

The presented methodology, formalized in a general way, is applied to a case study based on real data of the dispatching services market of the Southern Italy area where the penetration of NP-RES is particularly high.

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Introduction

The new paradigm of the power system is based on increasingly widespread use of Non-Programmable Renewable Energy Sources (NP-RES) to replace carbon-intensive power sources reducing significantly global warming emission. Europe leads this process: for instance, in Italy from 2008 to 2017, photovoltaic (PV) and wind power plants have shown an average annual growth of 50% and 43%, respectively, [1], reaching at the end of 2017 more than 774.000 PV units (19.683 MW rated power) and 5.600 wind power units (9.766 MW rated power).
However, the growing development of NP-RES has also introduced significant issues in power system management, especially in the areas with high penetration of wind and solar power plant, changing the classical concept of the power system management, [2]. The traditional *one-directional* system (production → transmission → distribution → loads) is now being replaced by a more complex and integrated system characterized by *multi-directional power flows*, high volatility and low predictability [3].
To ensure the safe, reliable and resilient operation of the grid, it is necessary to guarantee, instant by instant, the balancing between the power generated by the production units and the power absorbed by the loads. The intrinsic uncertainty of NP-RES, highly dependent on weather conditions, and the impossibility of modulating their power produced leads to power imbalances that threaten the safe operation of the power grid. In fact, variability and uncertainty of renewable energy generation increase the cost of maintaining the short-term energy balance in power systems and, therefore, the increase of power regulation (*up reserve* and *down reserve*) used by the Transmission System Operator (TSO) [4], determining an economic impact that is evident from the prices of the Dispatching Services Market (DSM).
This situation determines very strong effects on the grid requiring a more efficient management and a wider use of Ancillary Services, especially in the areas with high penetration of wind and solar power plant [5, 6].
One of the most promising solution to face the issues related to the spread of NP-RES is the use of Energy Storage System (ESS). In fact, ESSs can provide multiple services and features to improve safety and reliability of power systems.
The installation of ESSs in areas of the country where the penetration of NP-RES is high, could be mitigating the volatility of renewable energy production and maintain the security and overall efficiency of the national electricity system, [7]. However, in order to select the proper storage technology able to support network services, it is advisable to analyze the characteristics of the ancillary services market. In fact, the large amount of available data and the dependence on non-recurring weather conditions that are very difficult to forecast, requires a careful pre-analysis.
In this paper, a clustering algorithm for the ancillary services market ex-ante, based on the Ward methodology, is proposed.
The proposed approach is applied on a historic series of ancillary service ex-ante market data, by using the Pearson coefficient to highlight the similarities between the historical sub-series of the months of the year. Then, by applying the Ward method, similar months are grouped together to extract the market characteristics of interest such as, average price and share of hours of supply of resource in the market.
The proposed methodology has been applied to evaluate the economic feasibility of ESS power plant by using real data of the Italian Ancillary Services Market ex-ante of Central South and South Italian areas.

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1. The Electricity Market in Italy

The electricity market, namely the place where transactions involving electricity are conducted, was set up in Italy as a result of Law no. 79 dated March 16, 1999 ("*Bersani Decree*") as part of the implementation of the EU directive on the creation of an internal energy market (Directive 96/92/EC repealed by Directive 2003/54/EC), [8].
The electricity market is divided into:

1. Day-Ahead Market (DAM)
2. Intra-Day Market (IDM)
3. Dispatching Services Market (DSM)

In the DAM and IDM - also referred to Energy Markets - producers, wholesalers and end customers, together with network operators, such as in Italy *Acquirente Unico* (AU) and *Gestore dei Servizi Energetici* (GSE), buy and sell wholesale quantities of electricity for the next day. These markets, which are managed by *Gestore dei Mercati Energetici* (GME), define system marginal prices at which the energy is traded. Whereas in DAM are defined the preliminary programs of production and withdrawal of each offer point for the next day, in the IDM market operators negotiate the offers to purchase and sell electricity for each hour of the following day, for the purpose of modifying the injection and withdrawal programs defined to satisfy new requirements not foreseen in the DAM.
In the DSM, the Italian TSO, *TERNA*, procures the resources it needs to manage and control the national electric system (solving intra-national congestions, creating energy reserves, real-time balancing, etc.), accepting bids/offers from market participants related to different reserve and balancing services [8].

The DSM is divided into:

- ex-ante DSM: 6 sub-sessions, where *TERNA* trades energy and balancing services in order to release congestions and to create reserve margins (secondary and tertiary reserve);
- Balancing Market (BM): 6 sub-sessions, where *TERNA* trades real-time balancing services to restore secondary/tertiary reserve and to maintain the grid balancing.

The DSM is divided into market zones defined considering:

- the transport capacity of the lines
- the location of the power production and absorption, [8].

In Italy the market areas have been redefined starting from Jan, 1th 2019 to consider new connections to Malta (already operational) and to Montenegro (under construction). However, the paper refers to market areas active until Dec 31th 2018 described in Table 1.

Table 1 - The Italian market zones as defined up to December 31th 2018.

Acronym	**Market Zone Name**	**Geographical Area**
NORD	Northern	Valle D'Aosta, Piemonte Liguria, Lombardia, Trentino Alto Adige, Veneto, Friuli Venezia Giulia, Emilia Romagna
CNOR	Centre - North	Toscana, Umbria, Marche
CSUD	Centre - South	Lazio, Abruzzo, Campania
SARD	Sardinia	
SUD	Southern	Molise, Puglia, Basilicata, Calabria
FOGN	Foggia	
BRNN	Brindisi	
ROSN	Rossano	
SICI	Sicily	
PRGP	Priolo G.	

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To assess the cost of dispatching services in a market zone, it is useful to observe the differential price, namely the difference between rising prices (*TERNA*'s energy purchase price) and falling prices (*TERNA*'s energy sale price). In general, the more the difference is high, the more the situation is economically unfavorable since the energy that *TERNA* buys has a very high price compared to the price with it is sold; this condition shows a suffering of the network generally connected to a poor regulation power offered by the groups in production, as when the production from renewable is very high and variable.
All this is confirmed by the data [9]: for example, with reference to the annual average price of the offers accepted on the ex-ante DSM in the period October 2015 - September 2018 reported in Figure 1, it is shown how in the CSUD, BRNN, FOGN and SOUTH areas, where most of the NP-RES energy production is installed, the differential price is very high, with a peak value in the CSUD area of 209 € per MWh, approximately the double of the average value of the other areas.

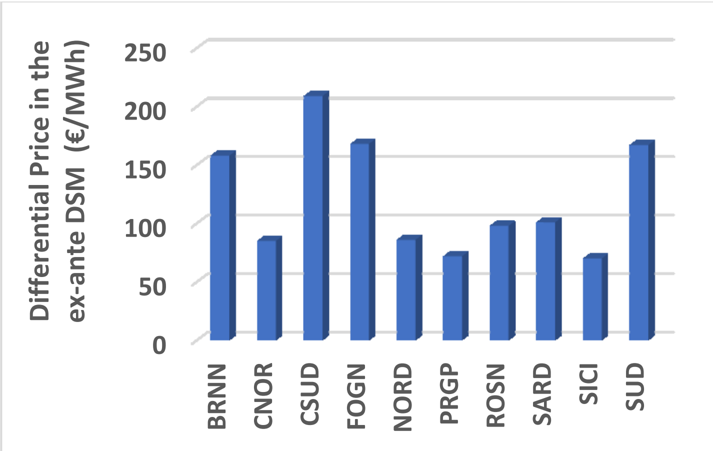

Figure 1 - Average Differential Price in the ex-ante DSM for the different market zones.

2. The Proposed Methodology

In this Section, the proposed methodology will be defined. In order to develop a procedure useful for assessing the sustainability of an investment in storage systems for network service erection based on the analysis of ex-ante DSM market data, considering the large amount of data to be analysed, the proposed approach achieves data clusterisation with the aim of aggregating similar market periods for each of which it makes sense to use an average price.

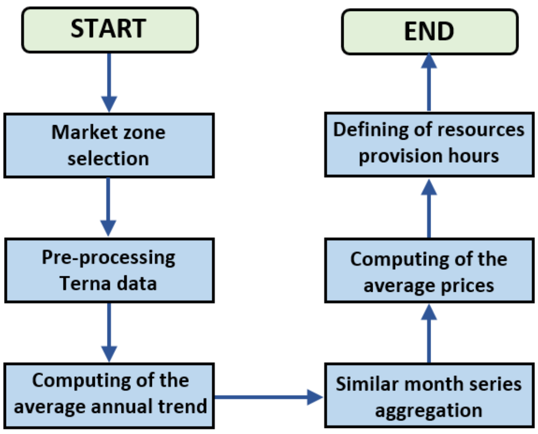

Figure 2 - The flowchart of the poposed methodology.

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Figure 2 shows the flowchart of our procedure applied to the time series of the offers accepted on the ex-ante DSM. The procedure can be applied for one or more market areas in order to identify the different average prices of the offers and the hours of resource provision in the market. In such a way, it is possible to economically evaluate ESS investments and their profitability in each market zone.
After the market zones selection, the input time series are filtered removing noise by smoothing. In particular, in the second step, starting from *TERNA* data, the input time series of the offers accepted on the ex-ante DSM, are pre-processed through a moving average algorithm. In particular, a 3-period moving average is used, [10]:

$$x_j^* = \frac{x_{j-1} + x_j + x_{j+1}}{3} \quad \forall j = 2, \ldots, d$$

where *d* is the length of the input time series and x_j^* is the *j*-th element of the filtered one.
In the third step, the aim is to obtain the average year trend of the offers accepted on the ex-ante DSM through similarity assessment between the times series. Very often, the Pearson coefficients (or correlation coefficients) are used. Given two time series:

$$^1X = \{ ^1X_1, ^1X_2, \ldots ^1X_T\} \text{ and } ^2X = \{ ^2X_1, ^2X_2, \ldots ^2X_T\}$$

the Pearson coefficient is defined as [10]:

$$R(^1X, ^2X) = \frac{\sum_{t=1}^{T}(^1X_t - ^1X_m)(^2X_t - ^2X_m)}{\sqrt{\sum_{t=1}^{T}(^1X_t - ^1X_m)^2}\sqrt{\sum_{t=1}^{T}(^2X_t - ^2X_m)^2}}$$

where ^1X_m and ^2X_m are the average value of the first and second data series, respectively:

$$^1X_m = \frac{1}{T}\sum_{t=1}^{T} {^1X_t} \text{ and } ^2X_m = \frac{1}{T}\sum_{t=1}^{T} {^2X_t}$$

It is worth to note that the Pearson coefficient can only assume values between -1 and +1: in particular, the positive sign indicates that the two variables increase or decrease together (positive linear relationship), while the negative sign indicates that with the increase of a variable the other decreases and vice versa.
In the proposed methodology, we indicate as S_i the annual time series of the offers accepted on the ex-ante DSM related to the year *i* = 1, 2, ..., *n*; each time series S_i, therefore, consists of the month time series $\boldsymbol{G_n}$, $\boldsymbol{F_n}$, …, $\boldsymbol{D_n}$ (January, February, ..., December) of the *n*-th year.

$$S_1 = \{G_1, F_1, \ldots, D_1\}, S_2 = \{G_2, F_2, \ldots, D_2\}, \ldots, S_n = \{G_n, F_n, \ldots, D_n\}$$

To obtain the average annual trend of the offers accepted on the ex-ante DSM, (step 3 of Figure 3) it is necessary to assess the dissimilarity between identical months belonging to different years. For instance, considering the January time series for different years, the related Pearson coefficients matrix $\boldsymbol{R_G}$ is defined as follow:

$$\boldsymbol{R_G} = \begin{pmatrix} 1 & R(\boldsymbol{G}_1, \boldsymbol{G}_2) & R(\boldsymbol{G}_1, \boldsymbol{G}_3) & \ldots & R(\boldsymbol{G}_1, \boldsymbol{G}_n) \\ R(\boldsymbol{G}_2, \boldsymbol{G}_1) & 1 & R(\boldsymbol{G}_2, \boldsymbol{G}_3) & \ldots & R(\boldsymbol{G}_2, \boldsymbol{G}_n) \\ \ldots & \ldots & \ldots & & \ldots \\ R(\boldsymbol{G}_n, \boldsymbol{G}_1) & R(\boldsymbol{G}_n, \boldsymbol{G}_2) & R(\boldsymbol{G}_n, \boldsymbol{G}_3) & \ldots & 1 \end{pmatrix}$$

Then, the January's average month $\boldsymbol{G_M}$ is defined as follow:

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$$\boldsymbol{G}_M = \frac{1}{n}(\boldsymbol{G}_{1,M} + \boldsymbol{G}_{2,M} + \cdots + \boldsymbol{G}_{n,M})$$

where the terms $\boldsymbol{G}_{i,M}$ are the pairs that have maximum Pearson coefficients along the line. Finally, by repeating this procedure for each month, the average year trend is obtained:

$$Year_{avg} = \{\boldsymbol{G}_M, \boldsymbol{F}_M, \dots, \boldsymbol{D}_M\}$$

The following step is the clustering procedure aimed to group similar month time series within the average annual trend. In this paper, we use the hierarchical clustering approach proposed in [11~~9~~] consisting in a four-step procedure to identify different clusters:

1. identification and union of the most similar elements, i.e. those at the smallest distance in the distance matrix (according to the *Ward method*), so as to form the first group. At this point, there are *n-1* groups, in which, one is formed by two objects and the others *n-2* by a single object;
2. determination of a new distance matrix (the new matrix dimension is reduced by 1), obtained by calculating the distance of the obtained group with respect to the other groups;
3. identification of the couple with the smallest distance (according to the *Ward method)* and grouping in a single cluster;
4. repetition of steps 2) and 3) until all the elements are united in a single cluster.

It is important to define a measure of similarity between the objects. However, the Pearson coefficients are not a similarity measure; in order to obtain a distance measure, starting from the Pearson coefficients, it is possible to use the relationship defined by Golay et al., [12]:

$$D({}^1X, {}^2X) = \sqrt{2[1 - R({}^1X, {}^2X)]}$$

At each iteration of the clustering procedure, we have different clustering solutions: in order to define the proper cluster number and quantify the goodness of the obtained clustering solution, it is necessary to compute the Silhouette coefficient as defined in the following. Considering the time series X_i within the cluster C_k, a measure of the intra-cluster variance $a(X_i)$ is obtained by measuring the average distance of X_i from the other time series of the cluster. The separation between different clusters is defined by measuring the minimum mean distance $b(X_i)$ between X_i from the other clusters, [10]. More in detail:

$$a(X_i) = \frac{1}{n_k - 1}\sum_{j=1, j\neq i}^{n_k} D(X_i, X_j) \qquad b(X_i) = \min_{k'\neq k}\left\{\frac{1}{n_k}\sum_{j\in C_{k'}} D(X_i, X_j)\right\}$$

where n_k is the element number in the cluster C_k. The Silhouette coefficient for each series is defined below, and it ranges from -1 to +1.

$$S(X_i) = \frac{b(X_i) - a(X_i)}{\min\{a(X_i), b(X_i)\}}$$

The higher is the Silhouette coefficient the more the time series belongs to a given cluster. Finally, through the calculation of the average Silhouette value, it is possible to have a global indication of the goodness of the obtained clustering solution.

$$S = \frac{1}{K}\sum_{K=1}^{K}\frac{1}{n_k}\sum_{i\in C_k} S(X_i)$$

The clustering procedure is implemented in an iterative algorithm that stops when the Silhouette coefficient computed at the current iteration is equal to the silhouette coefficient computed at previous iteration. The clustering procedure ends when this condition is achieved, then the cluster number and their elements are defined.
In order to apply this clustering procedure for the zone market prices application, consider the month time series in the average year trend:

$$G_M = \{G_1, G_2, ..., G_{31}\}, F_M = \{F_1, F_2, ..., F_{28}\}, \mathrm{K}, D_M = \{D_1, D_2, ..., D_{31}\}$$

Each time series consist of a number of points coinciding with the number of days in the same month time series. In order to apply the clustering procedure, it is necessary to calculate the Pearson coefficients matrix $\boldsymbol{R_T}$:

$$\boldsymbol{R_T} = \begin{pmatrix} 1 & R(\boldsymbol{G}_M, \boldsymbol{F}_M) & R(\boldsymbol{G}_M, \boldsymbol{M}_M) & \dots & R(\boldsymbol{G}_M, \boldsymbol{D}_M) \\ R(\boldsymbol{F}_M, \boldsymbol{G}_M) & 1 & R(\boldsymbol{F}_M, \boldsymbol{M}_M) & \dots & R(\boldsymbol{F}_M, \boldsymbol{D}_M) \\ \dots & \dots & \dots & & \dots \\ R(\boldsymbol{D}_M, \boldsymbol{G}_M) & R(\boldsymbol{D}_M, \boldsymbol{F}_M) & R(\boldsymbol{D}_M, \boldsymbol{M}_M) & \dots & 1 \end{pmatrix}$$

Starting from the $\boldsymbol{R_T}$ matrix and by applying the Xavier-Golay relationship, we calculate the dissimilarity matrix for grouping the most similar month time series.
After the clustering procedure, in the fifth step we proceed with the identification of the average offer price in each cluster: we compute the average value of all offers related to the same day of different months within a single cluster. After that, the average value of the results obtained for a single day are computed to find a single representative price of the cluster.
Finally, we have computed the hours of resources provision in the DSM: they can be directly calculated from the data available on the *TERNA* website.
An hourly offer day can be modeled in a vector of 24 points, where each element represents a price. In particular, if there have been no resources provisioning at the *i*-th hour, the *i*-th cell of the vector is empty. Therefore, by calculating the number of no-empty cells, the resources provision hours within a day can be calculated.

3. Case Study

We use as input time series of the proposed cluster methodology the offers accepted on the ex-ante DSM from October 2015 to September 2018, [9]. Moreover, in order to verify the effectiveness of the proposed methodology, we choose the Internal Rate of Return (IRR) as metric to evaluate the economic profitability of four different ESS battery technologies located in market areas where the penetration of NP-RES is higher. Table 2 compare the most relevant features for the four considered ESS technologies, [13, 14]. ESS rated power and energy values, used for the economic analysis, are extracted from TERNA public reports related to the first and second year of ESS experimentation in south of Italy, [13].

3.1. Clustering Results and Economic Analysis

Clustering analysis have highlighted that market areas where the penetration of NP-RES is higher, and thus the investment for ESS could be the more profitable, are CSUD, SUD and FOGN. Hence, in this Section, we summarize obtained results only for these market zones.

CSUD market zone: the proposed procedure allows obtaining four clusters characterized by Silhouette coefficient equal to 0,94, as showed in Table 3. A clustering solution with five clusters shows lower performance with a Silhouette coefficient equal to 0,86

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Table 2 - Comparison between ESS battery technologies.

Technology	Lead-Acid	NaS	Lithium-ions	Flow Battery
Rated energy [MWh]	80			
Rated power [MW]	12			
Batteries lifetime [cycles]	750	4500	2750	12000
Charging time [hours]	10			
Discharging time [hours]	7,5			
ESS lifetime [years]	15			
Annual charging/discharging cycles [cycles]	50	300	183,3	800
Annual ESS charging hours [hours]	500	3000	1833,3	8000
Annual ESS discharging hours [hours]	375	2250	1375	6000
Average charging power [MW]	8			
Average discharging power [MW]	10,67			
ESS cost [€/kWh]	264	688	1320	506
Total investment cost [€]	21.120.000	55.000.000	105.600.000	40.480.000

Table 3, - Clustering results for the CSUD area.

Clusters	Month	Average price [€/MWh]		Resources provision hour [%]
		Go up	Go down	
1	June	268,73	20,42	64
2	October	151,65	16,67	47
3	January, April, March, August	212,72	15,27	61
4	February, May, July, September, November, December	200,85	16,67	55

Table 4 - Economic analysis for the CSUD area.

	Lead-Acid	NaS	Lithium-ions	Flow Battery
Annual revenue [€]	993.240	4.870.208	3.151.195	6.787.075
O&M cost [€]	6006			
IRR	**-4%**	**4%**	**-9%**	**15%**

Table 5 - Clustering results for the FOGN area.

Clusters	Months	Average price [€/MWh]		Resources provision hour [%]
		Go up	Go down	
1	July	123,59	13,93	22
2	August, September	122,49	23,65	13
3	June	290,25	22,78	38
4	January, March, April, May, October, November and December	132,25	21,03	34
5	February	156,15	17,22	35

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FOGN market zone: the proposed procedure allows obtaining four clusters characterized by Silhouette coefficient equal to 0,84, as showed in Table 5. A clustering solution with five clusters shows lower performance with a Silhouette coefficient equal to 0,78.

Table 6 - Economic analysis for the FOGN area.

	Lead-Acid	NaS	Lithium-ions	Flow Battery
Annual revenue [€]	931.399,57	3.195.409,4	2.157.353,07	3.602.976,53
O&M cost [€]	6006			
IRR	**-5%**	**-2%**	**-12%**	**4%**

SUD market zone: the proposed procedure allows obtaining four clusters characterized by Silhouette coefficient equal to 0,92, as showed in Table 7. A clustering solution with five clusters shows lower performance with a Silhouette coefficient equal to 0,81

Table 7 - Clustering results for the SUD area.

Clusters	Months	Average price [€/MWh]		Resources provision hours [%]
		Go up	Go down	
1	October	217,51	0,88	20%
2	December	201,24	0,03	28%
3	January, February	150,89	0,03	31%
4	March, June, July e August	129,25	0,06	30%
5	April, May, September and November	158,10	1,32	38%

Table 8 - Economic analysis for the SUD area.

	Lead-Acid	NaS	Lithium-ions	Flow Battery
Annual revenue [€]	817.973,44	3.822.701,6	2.037.094,7	4.562.701,97
O&M cost [€]	6006			
IRR	**-6%**	**1%**	**-13%**	**7%**

Obtained results show that the CSUD area is characterized by the higher resources provision hours supplied and the purchased energy than other areas, while the SUD area is characterized by having very low sales prices. Therefore, the economic analysis showed that the lead-acid and lithium-ion storage battery based ESSs present a negative IRR in all the considered market areas. The NaS battery based ESS, instead, is characterized by positive IRR in the CSUD and SUD areas while it is negative in the FOGN area. Finally, the flow battery based ESS, due to the highest operating cycle number, allows having positive IRR in all the market zones.

4. Conclusions

A methodology for the technical and economic evaluation of ESSs able to provide ancillary services within the Italian electricity market is presented. In order to identify the most economically convenient ESS technology in different market areas, the features of the DSM market have been analyzed through a hierarchical clustering procedure. This approach, using the Pearson coefficient matrix, has been applied to 2015-2018 time series of the ex-ante DSM data.

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Results of the clustering procedure are used to evaluate the economic feasibility of lead-acid, NaS, lithium-ions, and flow battery based ESSs in the CSUD, FOGN and SUD market areas, where the penetration of NP-RES is higher. Assuming, a fifteen-year investment lifetime, results has been show that lead-acid and lithium-ion based ESSs present a negative IRR for all the market areas, whereas NaS and flow battery based ESSs are characterized by positive IRR due to the high number of operating cycles.

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G0502

Unified and Standardized qualifying tests of electrolysers for grid services

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Abstract

Some grid services available for loads are well established in several European countries with the services and prequalification tests quite similar however with differences. In the future process of decarbonisation of the electricity but also other sectors hydrogen produced from renewable electricity in water electrolysers is believed to play an important role. However to be part of the grid service market electrolysers have to pass the prequalification tests. In order to ease the market entry of electrolysers demonstration of the capability of electrolysers to cope with these requirements should be helpful.
For this purpose the project QualyGridS establishes standardized testing protocols for electrolysers to perform electricity grid services. Protocols are trying to unify the different tests needed for different European countries. Some general basic qualification tests are defined from which the suitability of the system for any grid service can be derived. More specificially adapted to some well-established services like e.g. FCR, a-FRR (positive and negative) tests are defined integrating the requirements for Germany, France, Switzerland and other countries.
The protocols are validated for both alkaline and PEM electrolyser systems, respectively, using electrolyser sizes from 25 kW to 300 kW within the project showing the capabilities of today's state of the art systems and extrapolation to larger systems. Testing protocols also include the review of existing and possibly set-up of new Key Performance Indicators (KPI) for electrolysers.

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Introduction

With more and more renewable energy fed into electricity grids to achieve the goal of electricity decarbonisation high fluctuations of power input have to be equilibrated with measures for grid stabilisation like electricity grid services. These services apply in different European countries in in similar however still varying way.
Decarbonisation also has to be achieved in other sectors like mobility and heating and industrial applications. Hydrogen could be in the near future a vehicle to achieve this decarbonisation across the sectors. Hydrogen can be produced by water electrolysers using renewable energy or surplus electricity from the grid. Being flexible electricity consumers in the megawatt range electrolysers can also offer electricity grid services to improve their revenues.
Electrolysers are still in the process of being developed to meet the need: large capacity, low costs, high efficiency of energy transformation, highly dynamic operation. An overview of the present and future development status of water electrolysers is given in [1].
As a contribution to stronger market entry of water electrolysers combined with grid services the project QualyGridS works out testing protocols for electrolysers that perform grid services. The purpose of these testing protocols is to give the manufacturers and customers of electrolysers the reassurance that the electrolyser will be able to meet the grid services requirements.

1. Technical Requirements and Prequalifications for loads performing Grid Services

An overview of electricity grid services that might be accessible to water electrolysers was conducted collecting the technical requirements and prequalification procedures [2]. Loads are not in all EU countries permitted to participate in grid services. The grid services in the market are similar in most EU countries, however the exact technical specifications and prequalification procedures are defined by every country and show some variations.
The most common grid services are FCR (Frequency containment reserve, a-FRR (automated Frequency Restoration Reserve) and m-FRR (manually activated FRR). As an example of variations in the technical requirements the requested evaluation procedures for FCR in Germany, France and Switzerland are shown in figures 1-3. FCR is in most countries a symmetrical service requesting increase and decrease of power, the capacity requested is in the range of 1 MW and the maximum power change must usually be reached after less than 30 seconds. Some countries allow aggregation of several technical devices performing grid services together. By this the requirements for the single technical can be less demanding.
The grid services a-FRR and m-FRR are usually requesting higher capacity than 1 MW. In many cases they are assymmetrical, only requesting power increase or decrease. The power change rates for these services are less uniform across the countries. Again many countries allow for aggregation of technical devices.

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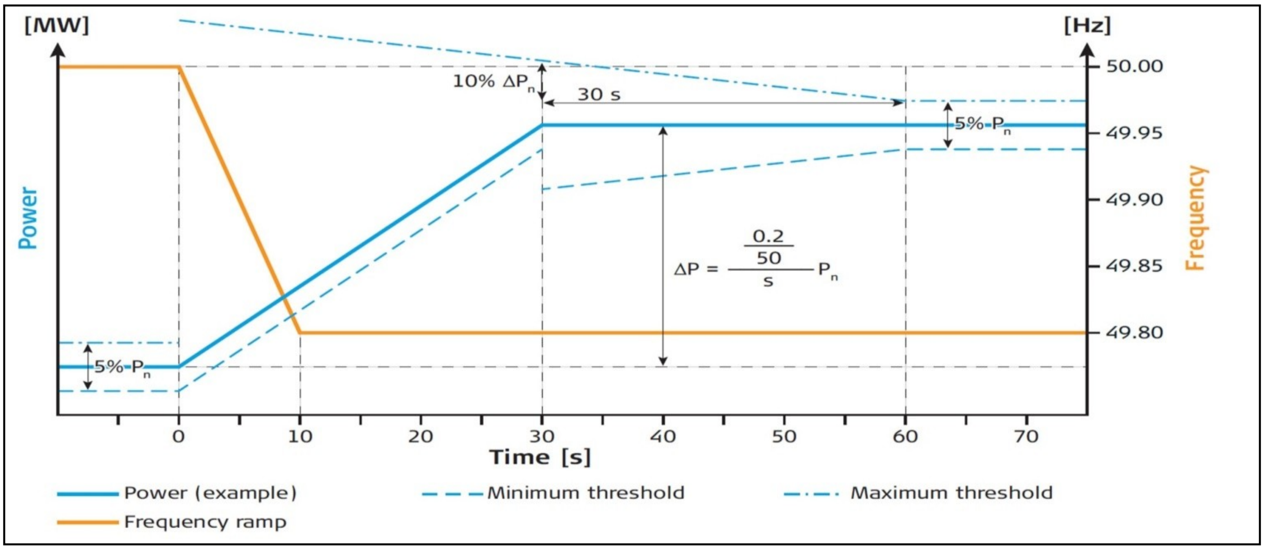

Fig. 1: FCR requirements Switzerland [3]

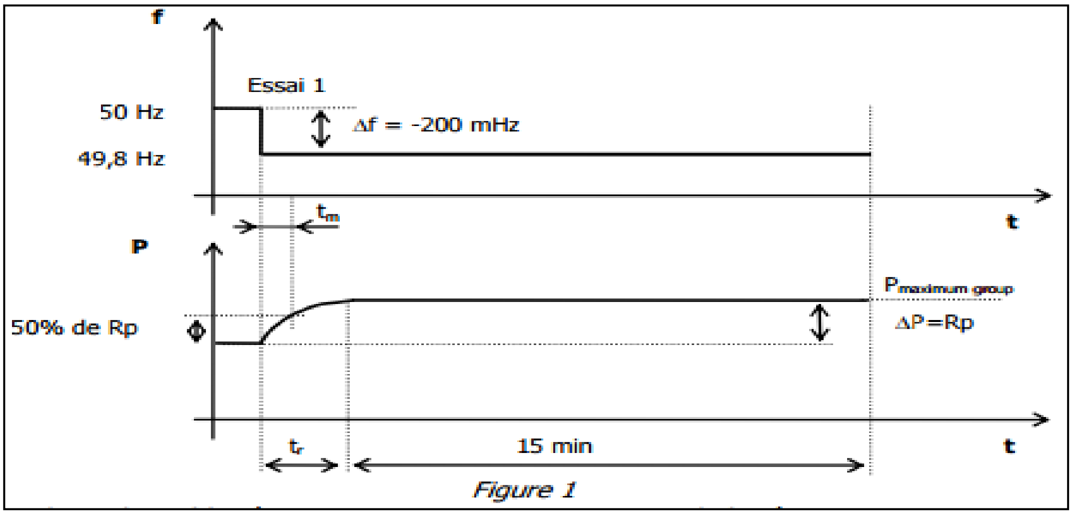

Fig. 2: FCR requirements in France [4] The pass criteria are: Non oscillating waveform, response time t_r < 30 sec, time t_m < 15 sec, the variation $\Delta P = R_p$ maintained for 15 min (after t_r)

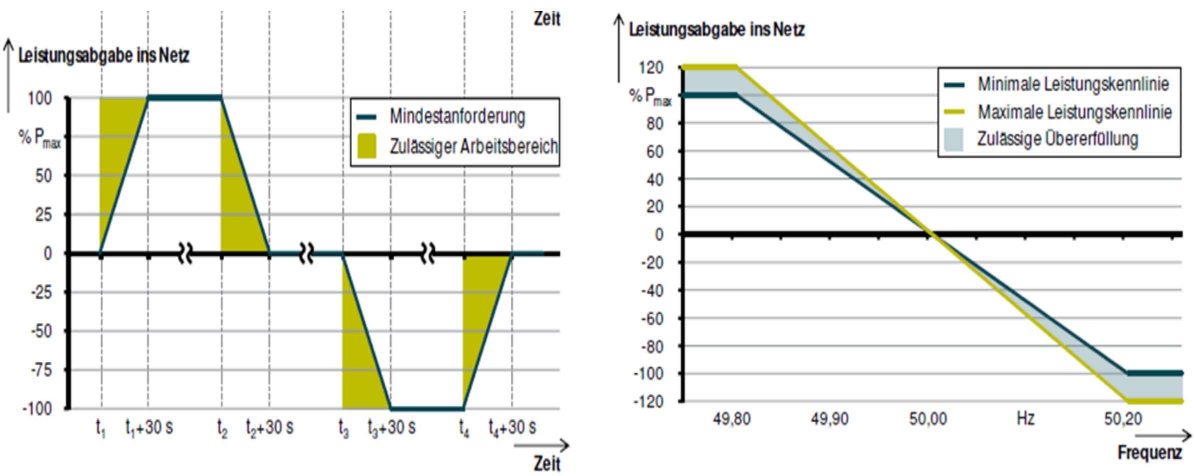

Fig. 3: FCR requirements for Germany [5]. The power must remain in the green respectively grey area

2. Unified Qualification tests

The purpose of the project QualyGridS is to establish standardized testing protocols for electrolysers to perform electricity grid services. Due to the variations between countries the protocols are trying to unify the different technical requirements.
Some general basic qualification tests are defined from which the suitability of the system for any grid service can be derived. These tests determine the available power range of the electrolyser, the dynamics between the different states as well as the power stability in constant operation. From this it can be found which grid service could possibly be performed and subsequently the specific testing protocol of this grid service can be applied. For the most common grid services testing protocols and evaluation procedures are defined integrating the requirements for Germany, France, Switzerland and other countries. A device passing these tests should pass also the specific test of a single country because the pass criteria defined are defined in a range suitable for all the considered countries. On the other hand a device not passing the test might still be capable of performing grid services in some but not all EU countries.
The 2017 status of available documents on technical requirements and prequalification tests was taken as basis.
Examples of testing protocols and evaluation procedure suggested for unified FCR testing are shown in Figure 4. In a corresponding way protocols are suggested for a-FRR, m-FRR and RR (replacement reserve).

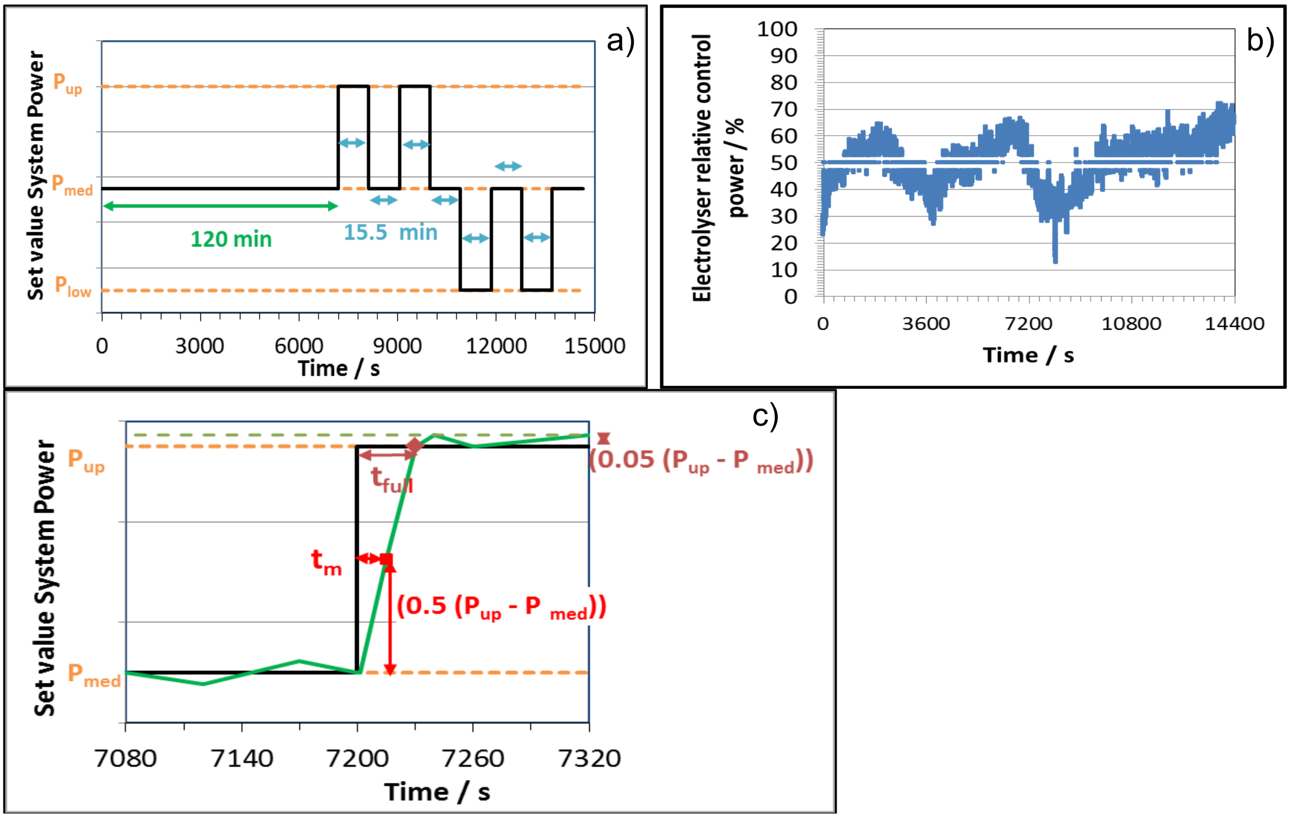

Fig. 4 QualyGridS suggested unified FCR testing protocols and evaluation. a) Testing protocol part 1 derived from prequalification procedures; b) Testing protocol part 2 derived from a real case of grid frequency input; c) Evaluation of activation times and stability. Pass criteria: t_m. ≤ 15 sec, t_{full} ≤ 30 sec, stability ≤ 0.05 (P_{up}-P_{med})).

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3. Electrolyser Properties

Large scale water electrolysers available on the market today are usually alkaline electrolysers, a well established technique that has been used for producing industrial hydrogen for decades, however did not have to meet the requirement of dynamic operation. Recently the PEM (polymer electrolyte membrane) electrolyser technique has reached maturity to the megawatt range. These electrolysers usually show a higher efficiency, more dynamic operation and a smaller footprint. However today still every large scale electrolyser is made to the customer's application specific requirements. By adapting the BOP (Balance of plant) components requirements like dynamics, power stability, control strategy, gas purity etc. can be varied in a significant range. Besides the mentioned water electrolyser technologies also the high temperature electrolyser SOEC (Solid oxide electrolyser cell) is developed for hydrogen production. This technique with a high efficiency has to date not been demonstrated in the megawatt range, the development is continuing.

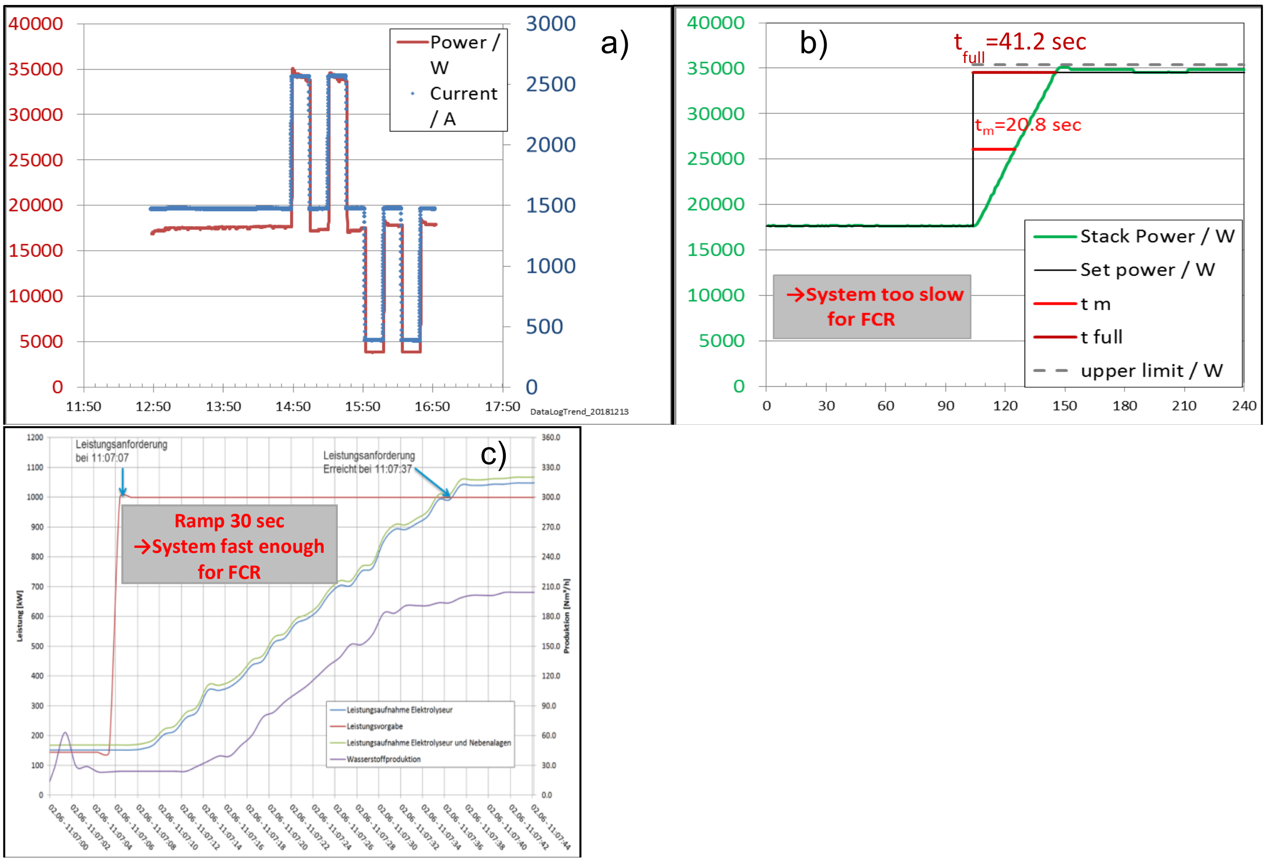

Figure 5: Ramp dynamics evaluation with PEM electrolysers with different power but same stack cell size: 50 kW experimental electrolyser at DLR, not designed for high dynamics and efficiency FCR testing protocol result, b) ramp analysis of the same electrolyser. c) 1.5 MW PEM electrolyser of Uniper, Hamburg designed for power to gas application with limited dynamics [6]

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Within the QualyGridS project the suggested testing protocols are validated on both alkaline and PEM electrolyser systems, using electrolyser sizes from 25 kW to 300 kW. Thereby the project is showing the capabilities of today's state of the art systems with extrapolation to larger systems. Figure 5 shows as some testing result from the project results for an experimental PEM electrolyser system of 50 kW. For this system that was not designed for a very high dynamical behaviour and also not for high efficiency the dynamics would not be high enough for FCR but sufficient for FRR. Also the power stability for this system is not good enough due to many auxiliary devices with rather high power consumption being switched on and off during operation. However looking at the power increase ramp of a technical system, the 1.5 MW electrolyser installed in Hamburg Reitbrook, it can be seen that this system, also not being designed for high dyamics, meets the criteria for ramping speed and power stability. Other PEM electrolysers tested in the project also showed a reaction to power change requests within few seconds and would be capable of doing FCR. Also the tested 300 kW alkaline electrolyser at NEL that was specially adapted to high dynamics operation showed power changes within few seconds. Therefore with a suitable setup in BOP and control electrolysers are capable of doing all tested electricity grid services.

4. Conclusion / Outlook

As next steps the QualyGridS testing protocols will be updated with recent changes in the technical requirements and prequalifications published in the countries since 2017 (e.g. Germany [7]). A lot of changes are going on due to increasing shares of renewable energies in electricity, due to the EU decarbonisation requests as well as the ENTSO-E (European network of transmission system operators for electricity) [8] activities for unifying and opening the electricity grid markets in the EU.
The QualyGridS electrolyser testing protocols will be worked out as a technical standard and submitted to a standardisation organisation. The testing protocol curves are not necessarily specific to electrolysers. They could just as well be applied by other loads desiring to prequalify for a grid service. Therefore the use of these unified testing protocols also for other loads will be discussed.

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G0707

Efficient preparation of TSOs for the integration of Capacity Calculation Regions (CCRs) in terms of security and welfare

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Abstract

For each Capacity Calculation Region (CCR)1, a coordinated capacity calculator needs to be established to define cross-zonal capacities for day-ahead, intraday timeframes and long-term timeframes. The CCRs have to be adopted to comply with the legal requirements of the CACM Regulation in order to reflect a better coordination of capacity calculators and the progressive introduction of flow-based approaches. Forced by Article 29(9) of the CACM Regulation, the goal of coordinated congestion management methods between the neighboring regions requires cooperation between coordinated capacity calculators for exchanges and confirming information on interdependency. This dynamic approach is in line with Regulation (EC) No 714/2009, which requires Member States to promote cooperation and monitor the effectiveness of the network at the regional level. That cooperation at regional level is compatible with the progress towards a competitive and efficient internal market in electricity. It is anticipated that the CCRs of CWE and CEE (under Core project) will be the first adjacent regions to implement the flow based capacity calculation methodology, and thus as the first CCRs are obliged to submit a proposal for a common flow based capacity calculation methodology. When this common flow based capacity calculation methodology is implemented, it should in practice bring merging of the CCRs for capacity calculation purposes.

This integration needs to ensure smooth and sufficiently fast enough integration of CCRs as well as consequently adequate preparation of TSOs according to future demands. Also, the cooperation of CCRs leads to less reliance on assumptions, higher transparency and efficiency in flow determination, market efficiency and possible higher capacity for exchanges. It is also anticipated that as the current level of interconnection increases. In the near future, the level of interaction between CCRs needs to be re-evaluated in terms of security, and welfare should also be increased. As it is known, these interconnections must be properly modelled and considered to work successfully in the internal European market coupling.

1 **https://www.entsoe.eu/network_codes/ccr-regions/**

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Introduction

CACM Regulation defines the capacity calculation region as the geographic area in which coordinated capacity calculation is applied. It means that, as stated in article 20(2) of CACM, within each capacity calculation region, TSOs have to calculate cross border capacity according to a common methodology. A CCRs configuration is a set of regions where each bidding zone border belongs to one and only one region. It is worth noting that the same bidding zone may belong to many different regions. Only once a configuration has been established it does become possible to develop a methodology to calculate the capacity on each border. Thus the CCR configuration is one of the pillars of the whole mechanism designed by CACM.

It should be noted that there are two approaches for capacity calculation taken into account in CACM:

- Flow Based (FB)
- Available Transmission Capacity (ATC)

FB is the main approach and ATC can apply only as an exception (art 20). However, for each of the two approaches, different methodologies can be developed, so it is possible to have, at least in principle, different regions applying different methodologies within the scope of the same approach. In order to avoid inconsistencies, CACM prescribes that if two adjacent regions implement a capacity calculation methodology based on FB, they have to be considered as one region or, in other words, they need to merge (art. 20(5)). TSOs belonging to these regions have to submit a proposal for applying a common capacity calculation methodology, specifying the implementation date.

Since 20 May 2015, in CWE region a FB market coupling has been operating for the Day Ahead time-frame. So far, in CEE the FB project has not yet been delivered. If two different methodologies are going to be developed it will be much more difficult to converge to a common calculation methodology. In order to prevent such envisaged difficulties, NRAs asked for an immediate merge. [1]The main drivers to start merging process of CWE and CEE regions were following:

- Efficiency: In both regions, grids are highly meshed, so in both regions cross border capacity needs to be calculated according to a FB methodology. In CWE this is already the case and in the near future FB will apply also in CEE. It is more efficient to use the same methodology from the very beginning.
- Certainty: If two different methodologies are being developed, the merging process might be delayed because of technical problems.

During the year 2016., sixteen TSOs started to follow a decision of the Agency for the Cooperation of Energy Regulators (ACER) to combine the existing regional initiatives of former Central Eastern Europe and Central Western Europe to the enlarged European Core region (Decision 06/2016 of November 17, 2016).
In accordance, these TSOs will also design and implement common capacity calculation methodologies for intraday and long-term time-frames.
The countries within the Core region are located in the heart of Europe which is reason why the Core CCR Project has a substantial importance for the further European market integration. [2]

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1. Requirements for Capacity Calculation Regions

All TSOs in each CCR must develop a capacity calculation methodology based on a flow-based approach (or coordinated NTC approach with justification), as specified in Article 20 CACM. This is only the first step in the process, as Article 21 further requires that CCR's capacity calculation methodology should be harmonised by 31 December 2020.

During 2017, CCRs (Figure 1) put their proposals to public consultation and submitted them to the relevant NRAs[2]. Not all CCRs' proposed capacity calculation methodologies have been approved yet, because some NRAs have requested amendments. Approval of the methodology triggers a four months delay for TSOs of the concerned CCR to jointly set up the coordinated capacity calculators needed for the deployment of the Common Grid Model.

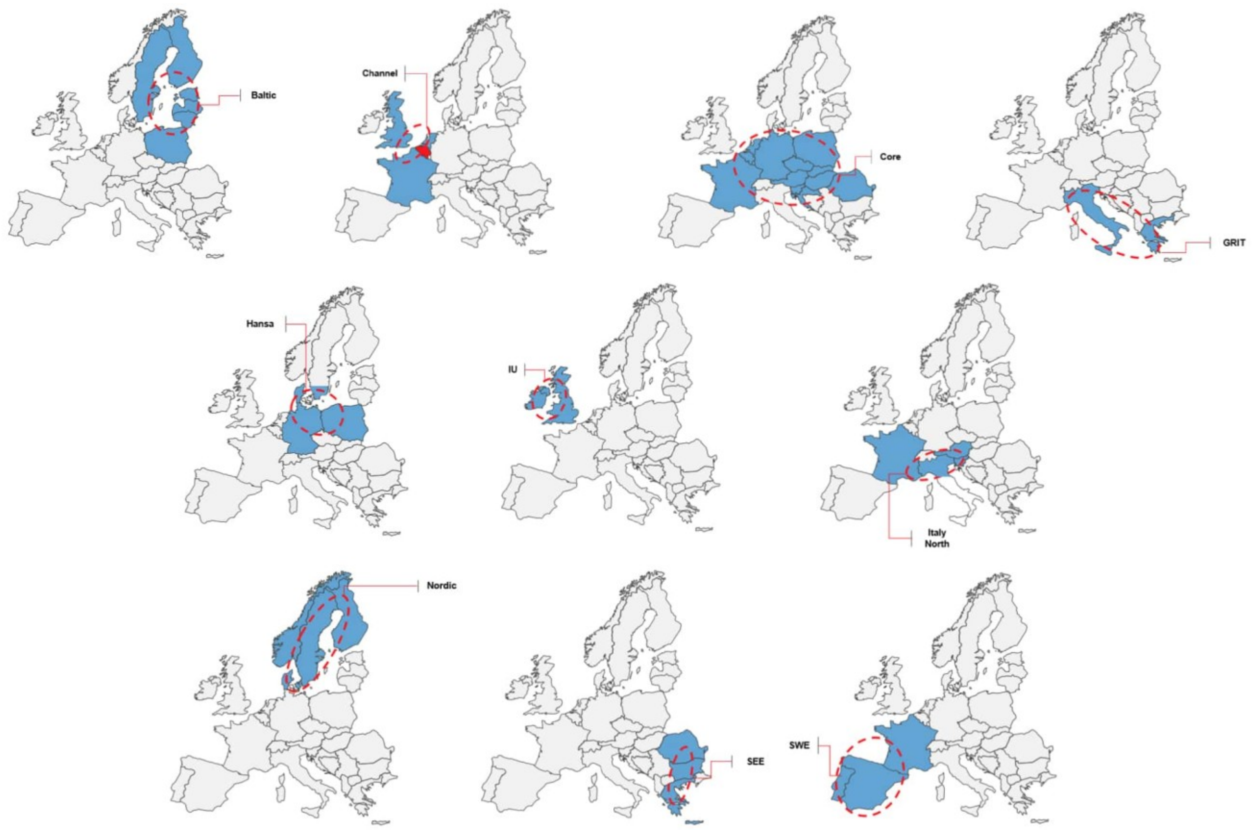

Figure 1 – Capacity Calculation Regions [3]

2 Two of the CCRs submitted their proposals to public consultation after the legal deadline, the South-East Europe CCR in December 2017 and the IT North CCR in Feb-March 2018.

2. Approach towards the integration of CCRs

TSOs within ENTSO-E have decided to implement and enforce a higher level of coordination among the TSOs for operating the European transmission system, as an answer to the challenge of the transformation of the European electricity system.
Regional Security Coordinators (RSCs) are established and operationally cover all countries and TSOs of Europe – not just the EU, as illustrated in Figure 2.
RSCs and TSOs are partners and collaborators on the same task of ensuring the highest security of electricity supply standards in Europe RSCs are key actors for enabling TSO coordination in Europe and should encourage mutual cooperation. [4]
RSCs must perform five tasks for the TSOs, including coordinated capacity calculation (specified in the CACM and FCA regulations), operational planning security analysis, outage planning coordination, short-term and very short-term adequacy forecasts, and a common grid model with hourly updates (all four services specified in the SOGL).

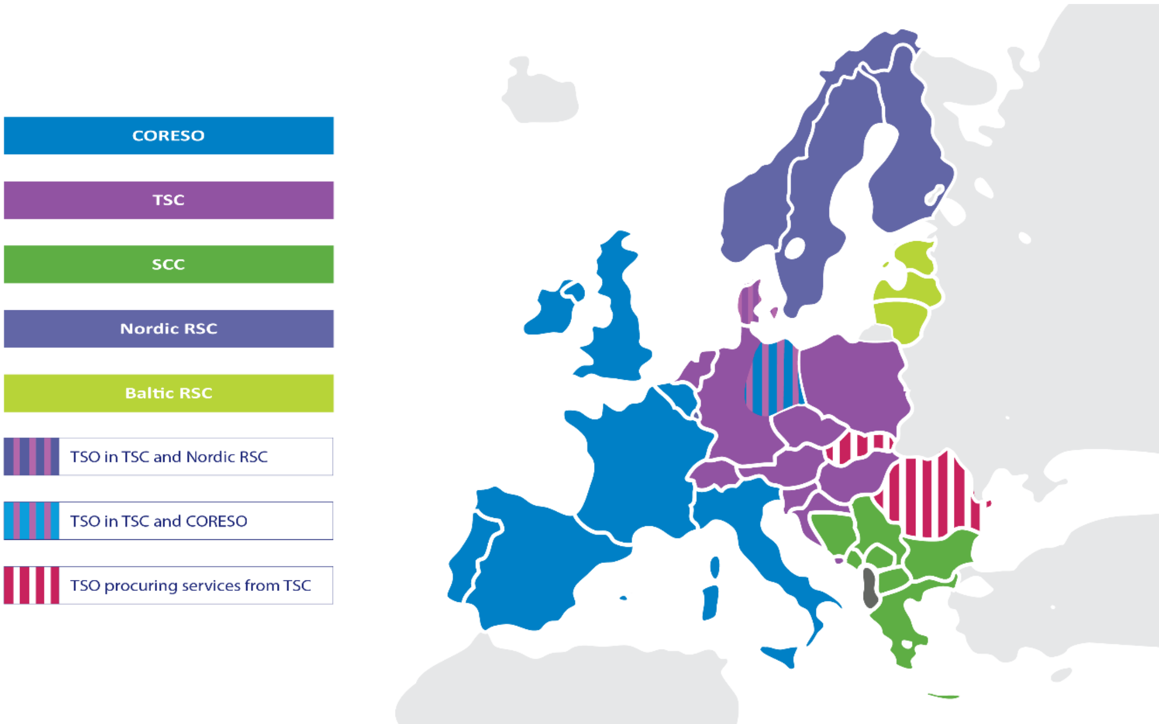

Figure 2 – Overview of the RSCs (simplified illustration) [3]

To achieve those targets set in the CACM Regulation to promote the completion and efficient functioning of the internal market and ensure optimal management, coordinated operation and sustainable technical development of the electricity transmission system in Europe, EC, ACER, regulatory authorities, TSOs and ENTSO-E acknowledge the importance of involving European non- EU TSO members of ENTSO-E, especially those responsible for electricity systems physically connected to EU Member States, in defining the CCRs. TSOs believe this is the best way forward to ensure the efficiency, relevance and accuracy of the capacity calculation processes.
The first step for developing of CCRs is an implementation of the new regional Flow-Based (FB) and Coordinated Net Transmission Capacity (CNTC) calculation methodologies. The second step should be to harmonize requirements within and between CCRs.

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Future goals

Annex 1 of the Proposal [5] describes Regions which in the future will also include non-EU bidding zone borders. This annex will be submitted to all affected non-EU regulatory authorities for their information or eventual approval.

In particular, the 11th Region (SEE) will include borders from: Greece, Bulgaria, Romania, Croatia, Hungary, Serbia, Bosnia-Herzegovina, Montenegro, FYR of Macedonia and Italy (when the submarine connection with Montenegro starts to be operational).

The SEE Region will include borders between EU and non-EU countries, as well as borders between two non-EU countries and will be completed only when CACM Regulation becomes an effective law in the legal framework of each non-EU countries.

Thus, to facilitate the implementation by the non-EU TSOs and the cooperation of the EU and non-EU regulatory authorities at an early stage, within the legal boundaries set by EU or national laws, these involved TSOs (the EU and non-EU) will start working informally together based on the future CCRs composition presented in Annex 1 to achieve the targets set in the CACM Regulation to promote the completion and efficient functioning of internal markets and in order to ensure the optimal management, coordinated operation and sustainable technical development of the electricity transmission system in Europe.

Article 20(4) of the CACM Regulation sets timelines for application of flow based capacity calculation methodology to SEE region as well. [6]

CCR 10 is the official SEE capacity calculation region, consisted of EU's TSOs: ADMIE, TRANSELECTRICA and ESO EAD. In order to include Non-EU's TSOs from SEE region in coordinated capacity calculation process, Shadow CCR 10 region is proposed. Shadow CCR 10 is based on: ACER's decision on CCRs and the Explanatory document sent to all TSOs' proposal for CCR.

Shadow CCR 10 includes the WB6 TSOs (CGES, EMS, KOSTT, MEPSO, NOS BiH and OST) and CCR 10 TSOs, as well as borders to neighboring TSOs – MAVIR, HOPS and TERNA.

Figure 3 – Shadow CCR 10 (recreated)

Shadow CCR 10 (recreated), Figure 3 [7] consists of:

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6 EU parties

- RO, BG, GR (3 in CCR 10)
- HR, HU, IT (IT after commissioning of the DC cable IT-ME)

6 WB parties

One of the issues is who will be the capacity calculator for the particular borders between TSOs belonging to different RSCs. Also, while there are borders where TSOs from both sides have already been designated Regional Security Coordinator (RSC) / Coordinated Capacity Calculator (CCC) and there is no issue on the selection of the expected CCC, there are borders between TSOs belonging to different RSCs/CCCs, and the question of calculation and harmonization of NTC values remains pending.
TSOs underscore that Article 29(9) of the CACM Regulation obliges each CCC to cooperate with the neighboring CCCs by exchanging and confirming information on interdependency with the relevant CCCs.
Security Coordination Centre (SCC) Ltd. Belgrade performs a Dry run of day-ahead NTC calculations for all service users borders (18 borders). NTC calculations are performed and they are based on D2CF models delivered by TSOs. Finally, results are being delivered to service users.

Efficiency – facts and solutions

The CACM Regulation (Article 34) organises the regular reporting by ENTSO-E on the efficiency of the existing bidding zone configuration.
In December 2016, ACER issued a request for a review of the bidding zone configuration as specified in CACM Article 32(4). This review covered Austria, Belgium, Czech Republic, Denmark, France, Germany, Hungary, Italy, Luxembourg, the Netherlands, Poland, Slovakia and Slovenia, with a legal deadline of 21 March 2018. During 2017, the participating TSOs have re-defined the scope of the project so as to be able to deliver it by the legal deadline, run the computations and formally submit the methodologies and assumptions to NRAs. ENTSO-E's role was that of a facilitator, supporting the participating TSOs in the process.
This first attempt at analysing bidding zone configurations in Europe demonstrated the significant technical complexity of the task. The participating TSOs considered that the evaluation presented in the first edition of the Bidding Zone Review did not provide sufficient evidence for a modification of it or for maintaining of the current bidding zone configuration. Therefore they recommended that, given the lack of a clear evidence, the current bidding zone delimitation should be maintained. Further work is ongoing on the TSOs side to assess and learn from the current review, so that more concrete recommendations will be available in future.

For developing and possible merging of CCRs, the idea is to find the optimal future CCR configuration based on clear and transparent criteria following socioeconomic efficiency. With that purpose, it is important to ensure smooth cooperation within described regions. For those regions who are more efficient, benefits will invite them to become even larger region over time, as needed. Development with ambition to deliver maximum benefits to end-consumers in the shortest possible timeframe usually results with faster integration process.

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3. Conclusion

Along with increasing interdependencies between different transmission systems and shorter market time intervals, new challenges arise for the TSO community and require much deeper coordination between operators close to the real time.
Enhancing TSO's coordination will benefit consumers through improved security of supply (by minimising the risk of wide area fault events), and lowering costs through increased efficiency in system operation and maximised availability of transmission capacity to market participants.

All TSOs are invited to duly and proactively consider merging future amendment proposals to the determination of the capacity calculation regions, as a way of ensuring an efficient process.
This dynamic period is supported by RSCs/RCCs with the following:

- common data exchange infrastructure and standards (harmonized data exchange format and process)
- alignment of regional methodologies and tools (for capacity, remedial actions, outage planning and adequacy assessment)

Therefore, no matter which final configuration of CCRs is going to happen, regional strength will be established for sure and efficiency will be achieved safely, Figure 4.

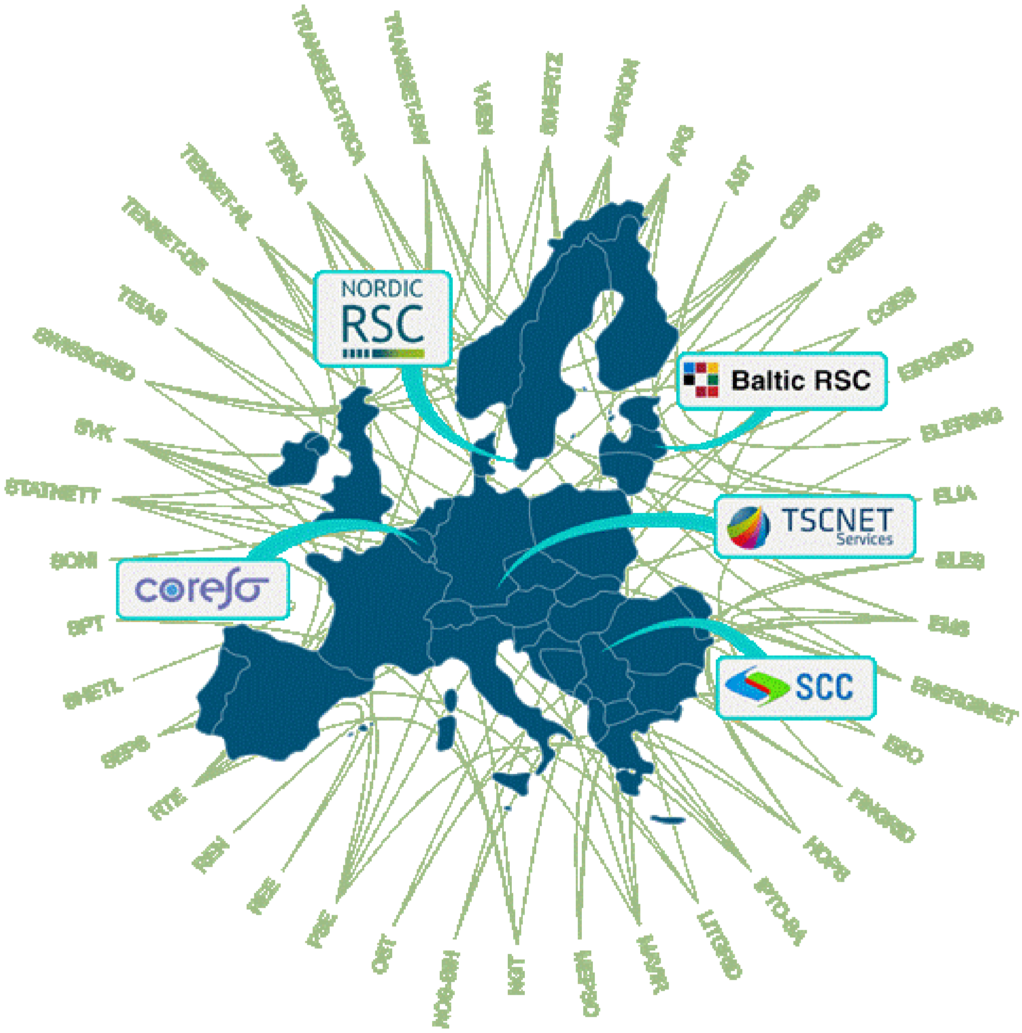

Figure 4 – European Regional Developments
(European coverage by services of the existing RSCs)

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