CHESTER

Compressed Heat Energy Storage for Energy from Renewable sources

D6.2 Business cases definition and baseline for business models

PROJECT	**CHESTER**
PROJECT NO.	**764042**
DELIVERABLE NO.	**D6.2**
DOCUMENT VERSION	**1**
DOCUMENT PREPARATION DATE	**12/09/2019**
RESPONSIBILE PARTNER	**PlanEnergi**
DISSEMINATION LEVEL	**Public**

Type of Deliverable		
R	Document, Report	**X**
DEM	Demonstrator, pilot, prototype	
DEC	Websites, patent fillings, videos, etc.	
OTHER		
ETHICS	Ethics requirements	
ORDP	Open Research Data Pilot	

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No. 764042.

EC Grant Agreement	No.764042
Project Acronym	CHESTER
Project Title	Compressed Heat Energy Storage for Energy from Renewable sources
Program	HORIZON 2020
Start Date of Project	01-04-2018
Duration	48 Months

Financial/Administrative Coordinator	
Project Coordinator Organization Name	TECNALIA
Address	Parque Tecnológico de Bizkaia C/Geldo, Edificio 700 (Spain)
Phone Numbers	+34 946 430 850
E-mail Address	nora.fernandez@tecnalia.com
Project web-site	www.chester-project.eu

Version Management			
Filename	CHESTER D6.2: Business cases definition and baseline for business models		
Author(s)	Caroline Nørregård Potter, Federico Bava, Magdalena Kowalska		
Reviewed by	Oscar Smulders (PNO)		
Approved by	Nora Fernandez Perez (Tecnalia)		
Revision No.	**Date**	**Author**	**Modification description**
RV 1	07-07-2019	F. Bava	Aalborg case study
RV 2.0	30-07-2019	C.N. Potter, F. Bava	Alpha Ventus case: boundary conditions
RV 2.1	15-08-2019	C.N. Potter	Alpha Ventus case: analysis
RV 3	17-08-2019	M. Kowalska	Ispaster case
RV 4	27-08-2019	M. Kowalska	Hydrogen case
RV 5.0	10-09-2019	M. Kowalska	Revision of the document: 1st complete version
RV 5.1	20-09-2019	O. Smulders	Revision by designed reviewer (PNO)
RV 5.2	22-09-2019	M. Kowalska, F. Bava,	Revision of the document: 2nd version
RV 5.3	24-09-2019	Nora Fernandez	Revision of the final version
RV 5.4	24-09-2019	F. Bava	Correction and clarifications
RV 6	26-09-2019	Nora Fernandez	Final revision to conclusions

Contents

List of Figures

List of Tables

Glossary, Abbreviations and Acronyms

EES	Electric energy storage
HP	Heat pump
HT	High temperature
HT-TES	High temperature thermal energy storage
LHV	Lover Heating Value
LT	Low temperature
ORC	Organic Rankine Cycle
P2P	Power-to-power
TSO	Transmission System Operator
WP	Work package

1. Introduction

1.1. Executive Summary

This report builds on top of previous CHESTER deliverables adding a business perspective to the technical solution. Business cases for three case studies are analyzed: Aalborg, Ispaster, Alpha Ventus. For the Aalborg case study, an alternative energy-conversion and storage solution in the form of hydrogen is also analyzed.

The case studies were analyzed through simulations having an hourly resolution in either TRNSYS or energyPRO software. The input data included local electricity and heat prices as well as the technical parameters, such as capacity requirements of the CHEST system, identified in WP2. A range of scenarios was investigated, including different sizes of the system, energy prices and purposes of the system.

The key finding of the study was that — given today's boundary conditions (i.e. electricity markets and investment costs) — the CHEST system does not provide a very promising business case in most of the investigated scenarios.

In the Aalborg case, for instance, several different boundary conditions were considered, such as electricity prices, participation in the regulating market, taxation schemes, frequency of cap and floor prices and heat prices. Only in the case of very frequent and very high electricity prices, the CHEST system proved to be economically viable. More specifically, this case assumed that the spot price reached its cap price of 3000 €/MWh for 500 hours in a year. The investment cost of the HP, HTES and ORC will need to be reduced significantly, so that the CHEST system is economically feasible also in other market conditions.

Regarding Ispaster, CHEST was compared to an existing battery solution, that is charged by local PV-production, hence reducing the later need of importing electricity from the grid. There is not a favorable regulation so far to export electricity to the grid in Spain, as there are no incomes, therefore it was not considered. So far as the Ispaster micro-grid configuration is nowadays, the supplied renewable energy is not enough to cover the demand, and thus it cannot be a standalone configuration. If properly sized and disconnected from the grid, a more positive business scenario could be possible for the Ispaster micro-grid. However, with the current configuration in none of the scenarios the savings from reducing the amount of imported electricity compensated for the investment costs.

In Alpha Ventus, the CHEST system was modelled to shift the feed-in of the locally produced wind electricity to hours with higher electricity prices. Hereby, the CHEST system improved the value of the wind power production by up to 6 %. This does not sufficiently compensate for the investment costs of the CHEST system, but if this initial investment is funded anyhow, the operation alone is profitable. The CHEST system could also increase the power sales (volumes and earnings) in case of limited transmission capacity to the grid compared to the reference case. If the investment costs are not considered, then this additional service yields a higher profit compared to the instantaneous sale of the non-curtailed electricity.

However, it is expected that the investment cost of the HP, HT-TES and ORC will be reduced significantly in the next future, and that the environmental compromises will boost more favorable electric markets conditions for prosumers (self-production and energy storage), to increase the potential scenarios and market conditions in which the CHEST system will be economically feasible. Indeed, in this sense, the new Renewable Energy Directive (Directive (EU)

2019/944) obliges the member states to open their power grids to energy from renewable sources and to even give them priority, and this will pose a more favorable framework.

Finally, the CHEST system showed a better techno-economic performance compared to the hydrogen technology, which consisted of a hydrogen production unit, a hydrogen storage and a hydrogen fuel cell. Despite the lower investment cost for the hydrogen system, the expected revenues were lower by 20 %-30 %, and the operating expenses were up to 3.5 times higher compared to the CHEST case. This finding indicates the potential of CHEST technology as a good business case for the future changing regulations and electricity markets.

1.2. Purpose and Scope

This deliverable covers WP 6.2 with the scope of giving an initial economic assessment of the integration of the CHEST system in the energy system. The assessment started with defining an economic baseline for the CHEST market implementation which should be further used during the development of detailed business models in T6.6. The potential business cases were then simulated and evaluated for different boundary conditions.

In the previous CHESTER deliverables D2.2 and D2.3, five case studies (Aalborg, Ispaster, Alpha Ventus, Torino and Barcelona) were investigated from an energy perspective. Two of them had to be selected to go on with further analyses, being Aalborg and Ispaster the chosen ones due to their higher interest and availability of monitored data. In the present work an additional case study has been also assessed, Alpha Ventus, due to its potential interest and promising higher suitability in terms of business models. The three analyzed cases studies were therefore: Aalborg, Ispaster and Alpha Ventus.

These case studies were also selected due to their use of the CHEST system. The different uses of the CHEST system included: CHEST as energy system involved in both the electricity market and the heating market; CHEST as a flexible electric storage to increase the self-consumption of locally-produced PV electricity; CHEST as a battery connected to a wind farm with the aim of increasing the economic value of the power production by deferring the feed-in into the grid in hours with higher demand (and hence higher electricity prices).

Hence, the business cases consider the possibilities and boundary conditions connected to the geographical location of the case studies. Other analyses such as a standalone micro-grid, without imports-exports of electricity to the grid, were not studied because there is no such a case among those available in the CHESTER project, but it could be another possible business model for the CHEST system, through the elimination of the electricity imports.

The case study of Barcelona presented similar characteristics to that of Aalborg in terms of business case. Due to the absence of locally produced and fluctuating RES electricity, the business model in the Barcelona case would have been that of arbitrage (i.e. selling and buying electricity to and from the grid, depending of the market price). An analysis of the electricity prices in Spain showed a less fluctuating behavior, both in terms of amplitude and frequency. Given the poor business case for the Aalborg case, the analysis of the Barcelona case was regarded as redundant and most likely leading to poorer results.

The case study of Turin presented a different business case, involving the use of the CHEST system to balance the electricity output from a CHP plant, in order to more closely meet the electricity feed-in profile that the plant is committed to supply. As can be seen from Figure 2 and

3 of the CHESTER deliverable D2.3, most of the energy unbalances occurs at high power (>10 MW), but a CHESTER system sized to compensate for these unbalances would have a very low number of full-load hours, which would not pay back the initial investment. Conversely, a CHEST system sized for small capacities would be cheaper, but it would handle much lower amounts of electricity, negligible compared to the overall unbalance of the plant.

Additionally, the CHEST-system is compared to hydrogen, as an alternative way to convert and store electricity.

The cases are simulated with the software energyPRO, which is a complete modelling program for combined techno-economic design, analysis and optimization of several types of complex energy projects. The performance outputs from the TRNSYS-model developed in WP2 were used in the scenario for Ispaster. The input data to the models are based on the findings of the CHESTER deliverables D2.1. and D2.2.

1.3. Structure of the document

The document is composed of three main sections.

The research methodologies and procedures behind the analysis are described in the beginning of the report (Section 2). This section provides a general description of the energyPRO model and of the TRNSYS model, which were developed to perform these analyses.

Section 3 describes the purpose and application of CHEST/hydrogen system in each of the case studies. This section presents all boundary conditions and assumptions regarding technical details and prices as well as the chosen investigated scenarios.

Section 4 presents the results and discussion for each case study.

Lastly, Section 5 provides the conclusions for key findings.

1.4. Relations with other deliverables

Key technical details derived from previous work packages have been utilized in this deliverable. These include the sizing parameters of the CHEST system in the Aalborg case and in the Alpha Ventus case, the TRNSYS model of the Ispaster case study developed in T2.2 and T2.3, as well as the economic assumptions collected in T6.1.

2. Research Methodology and Procedures

2.1. Models

The results presented in this study were obtained from simulations performed in TRNSYS in the case of Ispaster, and in energyPRO in the case of Aalborg and Alpha Ventus, as well as for the hydrogen storage scenario.

2.1.1. energyPRO

The model developed in energyPRO simulates a simplified CHESTER system using an hourly timestep and optimizes its operation in terms of economic revenue. Figure 1 shows the model of the CHEST system used to simulate the Aalborg case study. In the model the CHEST system consists of three components (*Heat pump*, *HT-TES* and *ORC*) and is integrated in the electricity system (*Elec.import* and *Elec.export*) from which it can import and export electricity. Because both the HP requires heat in input (that will in really be provided by the excess heat of an industry or from renewable sources) and the ORC produces low-temperature heat, a component for a *Heat source* and one for a *Heat sink* are also seen in the model.

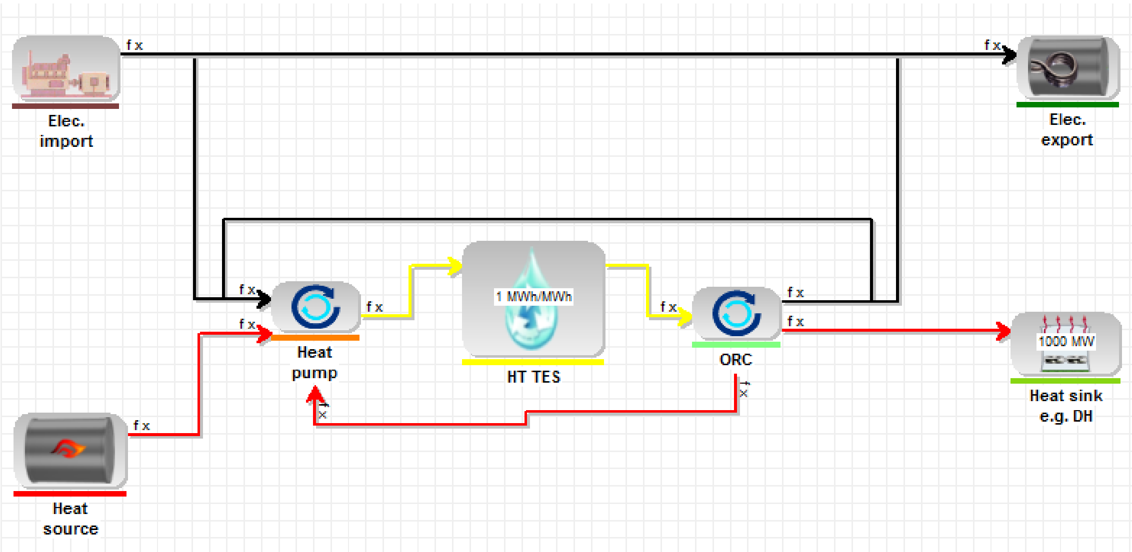

Figure 1: CHESTER model in energyPRO as assumed for the Aalborg case.

Briefly explained, the logic of operation of the CHEST system in the energyPRO model is the following. Based on the hourly electricity prices as well as the relevant taxes and fees on the bought/sold electricity, the model seeks to run the HP during the low-price hours and sell electricity during the high-price hours throughout a year. The energyPRO model exchanges energy between the different units solely in terms of MWh and does not consider aspects such as flows and temperatures. A detailed of the specific variants of energyPRO models used to carry out the analysis is given for each specific scenario of the Aalborg case study (Section 3.2), the Alpha Ventus case study (Section 3.4) and the hydrogen scenario (Section 3.5).

Unless otherwise specified, the electrical power which can be exchanged between the CHEST system and the electrical grid is only limited by the size of the CHEST components and not by the grid itself.

The CHEST system is a price-taker, which means that the CHEST system imports and exports electricity at market prices, which are unaffected by the operation of the CHEST system itself, given its small size compared to the rest of the market. No specific electricity demand or heat demand are defined to be covered, so the goal of the CHEST control strategy is purely to maximize its economic operational profit.

The thermal power made available by the heat source and the thermal power which can be discharged to the heat sink are assumed infinite, so that they never constrain the operation of the CHEST system.

As validation, the results from the energyPRO model have been compared against results from a Mixed-Integer-Linear-Programming model built in Excel. The Excel model has been built to reflect the energyPRO setup in Figure 1 and has been given the same constraints and inputs as applied in the energyPRO simulations. Both models aim at maximizing the profit of the operation of the CHEST system.

The two models performed very similar to each other. Figure 2 shows the energy content in the HT-TES for one month of operation for both models. The two curves overlap almost perfectly with only minor differences, proving that the two models charge and discharge the HT-TES at the same points in time. Consequently, the net profit from operation (i.e. the difference between operational revenues and operational expenditures) calculated with the models are almost identical, as they deviate by only 0.5 % as shown in Table 1.

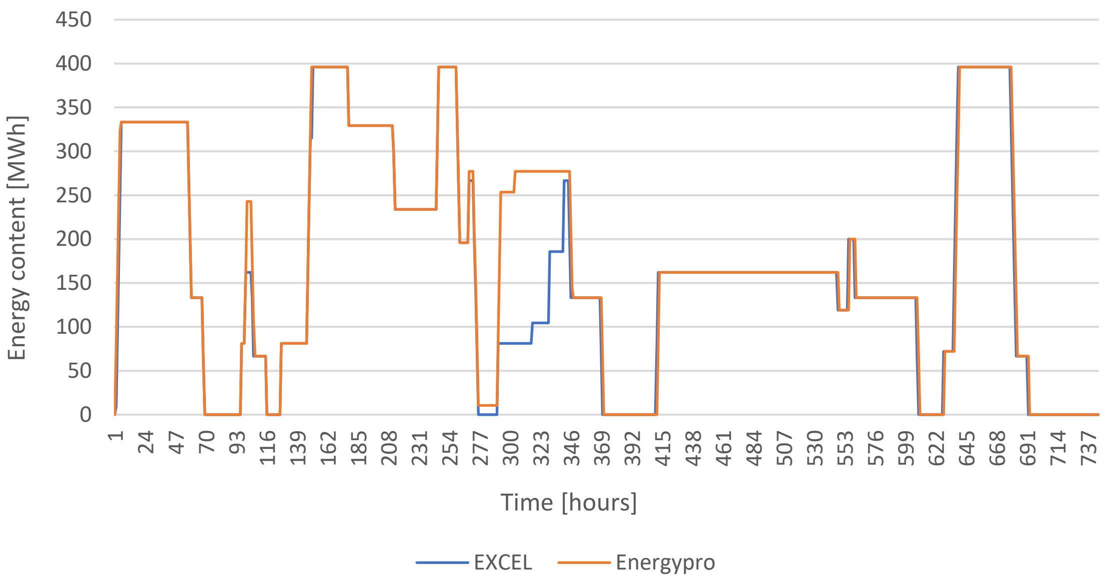

Figure 2: Energy content of the HT-TES according to the energyPRO model and Excel model.

Table 1: Results from the Excel and energyPRO-model runs.

Parameter	Unit	EXCEL	EnergyPRO
Total income	€	566,078	569,525
Deviation	*%*		0.5%
HP electricity consumption	*MWh*	376	393
ORC electricity production	*MWh*	304	318
Hours of operation (HP)	*hours*	27	28
Run time	*min*	7	<1

Unlike the Excel model, the energyPRO model was able to handle 1-year simulation. Additionally, the latter was considerably faster. Therefore, energyPRO was chosen to be used to carry out the simulations presented in this study.

2.1.1. TRNSYS

The TRNSYS model used to analyze the business case of the Ispaster case study is the one that has been developed in connection to T2.3. The reader should therefore refer to the deliverable D2.3 for a detailed description of the model.

3. Case studies

3.1. General assumptions

3.1.1. Energy prices

In all scenarios, local electricity prices from 2018 were applied. These consisted of the hourly market prices and the electricity buy or sell add-ons, which consist of grid fees, taxes, etc. Only in the Aalborg case it was relevant to take into account the price of heat.

3.1.2. Technical parameters

The technical parameters were varied in each case study and are described for each study in its relevant section (Sections 3.2, 3.3, 3.4, respectively).

3.1.1. Financial parameters

Table 2 shows the financial parameters applied in all scenarios, regardless of the size of components. The assumed investment costs, O&M costs and lifetimes of the components were provided by Tecnalia. Based on an assumed lifetime and an interest rate of 3.5 %, the annualized capital cost is obtained through the loan discount formula.

Table 2: Economic assumptions for the components of the CHEST system.

	Specific investment cost	Lifetime [years]	Annualized capital cost	Variable O&M cost
HP	500,000 €/MW_{th}	30	27,200 €/MW_{th}	10 €/MWh_e
ORC	800,000 €/MW_e	30	43,500 €/MW_e	15 €/MWh_e
HT-TES	90,000 €/MWh_{th}	30	4900 €/MWh_{th}	0

3.2. Case study #2: Aalborg

The business case for the Aalborg case study used the following assumptions.

The ORC had a constant size of 5 MW_{el} in all the investigated scenarios. This specific size was chosen based on the simulation results of CHESTER deliverable D2.2. Additionally, 5 MW is also the minimum capacity which can be bid in the tertiary regulation market (or manual frequency restoration reserve, mFRR) in Denmark (Energinet, 2017A).

Unless otherwise specified, the efficiency of the ORC is 15 %, assuming condensation to the environment. This value was derived from the CHESTER deliverable D2.1, based on the performance map of the ORC for Butene.

Regarding the HT-HP, its size was varied in the different simulations, to identify its optimal value in the different scenarios. Its COP was assumed constant and equal to 5.4, which corresponds to a temperature of the heat source of 80 °C, based on the performance map of the HT-HP for Butene (see CHESTER deliverable D2.1).

The size of the HT-TES was also varied depending on the simulated scenario.

The main assumptions used in the model of the Aalborg case study are summarized in Table 3, and were used in all the scenarios, unless otherwise specified.

Table 3: General assumptions in the energyPRO model for Aalborg case. See detailed cost breakdown for the electricity taxes and fees in 6.2 Appendix 2.

Parameter	Value
Capacity of the ORC	5 MW_e
Capacity of the HP	Variable
Storage capacity of the HT-TES	Variable
Efficiency of the ORC	15 %
COP of the HP	5.4
Overall tax and fees on purchased electricity ($Addon_{buy}$)	21.53 €/MWh_e
Fee paid when selling electricity ($Addon_{sell}$)	0.52 €/MWh_e
Price for the heat absorbed by the HP	0 €/MWh_{th}
Price for the heat produced by the ORC	0 €/MWh_{th}

A scheme of the energyPRO model used to treat the Aalborg case is shown in Figure 1.

3.2.1. Current and future spot electricity market

The first simulations for the Aalborg case were performed using the spot electricity prices for Denmark in 2018 (from now on, *Spot2018*) (Figure 3) to regulate the operation of the CHEST system.

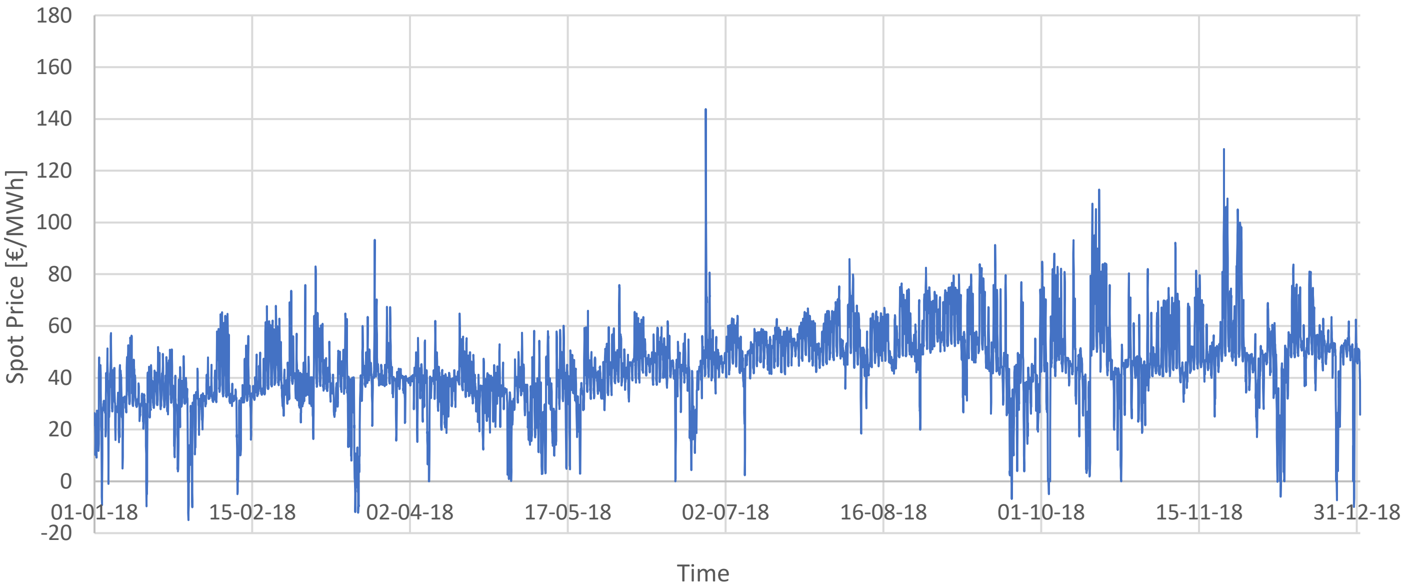

Figure 3: Spot prices in Western Denmark (DK1) in 2018 (Nordpool, 2019B).

Other simulations were performed using forecast electricity spot prices for Denmark in 2030 and 2040 (**¡Error! No se encuentra el origen de la referencia.** and **¡Error! No se encuentra el origen de la referencia.** in Appendix, respectively). These forecast prices were provided by the Danish TSO Energinet. As stated by Energinet, the prices are the result of model simulations which are based on specific assumptions about the future, including developments in fuel prices, production capacity, electricity consumption, etc. They are therefore very uncertain and must be used with all due reservation. In the rest of the report, the two above-mentioned time series of electricity prices are referred to as *Spot2030* and *Spot2040*, respectively.

The control of the CHEST system for the Aalborg case works as follows. The CHEST system converts electricity into HT heat when the spot electricity prices are low, and it converts HT heat into electricity, when the spot electricity prices are high. The exact value of “low” and “high” electricity prices is determined by a balance between the electricity sale price and electricity consumption price. This means that the ORC converts HT heat into electricity when the net revenue from the sale of this electricity is equal to or higher than the cost that the plant has incurred when purchasing and converting electricity into that amount of HT heat.

The net revenue from the sale of electricity comprehends the spot market price reduced by the charges related to the sale of electricity and the maintenance cost of running the ORC. The cost that the plant incurs when purchasing and converting electricity includes the spot market price, electricity charges (transmission fee, system tariff, distribution fee and electricity tax) and the maintenance cost of running the HP. Refer to Appendix 2 for the detailed price breakdown.

If also the amounts of heat which are consumed by the HP and produced by the ORC have an economic value, the control strategy takes into account the heat sale price and heat purchase price.

The above-mentioned explanation corresponds to the following equations:

$$HP\ el.\ price \leq\ ORC\ el.price \cdot \eta_{ORC} \cdot COP_{HP} + ORC\ heat\ price \cdot COP_{HP} \cdot (1-\eta_{ORC}) - (COP_{HP}-1) \cdot HP\ heat\ price$$

where $HP\ el.\ price$ [€/MWh$_e$] is the total cost paid on the electricity consumed by the HP, which is defined as

$$HP\ el.\ price = Spot\ el.price + Addon_{buy} + O\&M_{var,HP}$$

$ORC\ el.price$ [€/MWh$_e$] is the net income from the sale of the electricity produced by the ORC, which is defined as:

$$ORC\ el.\ price = Spot\ el.price - Addon_{sell} - O\&M_{var,ORC}$$

The terms of the equation are described in Table 4:

Table 4: Applied terms in the control strategy including heat sale/purchase

Term	Unit	Description
$\boldsymbol{Spot\ el.price}$	[€/MWh$_e$]	Spot electricity price
$\boldsymbol{Addon_{buy}}$	[€/MWh$_e$]	Add-on which includes taxes and grid fees paid on the purchased electricity; Refer to Appendix 2 for the detailed price breakdown
$\boldsymbol{O\&M_{var,HP}}$	[€/MWh$_e$]	Variable O&M cost of the HP per unit of absorbed electricity
$\boldsymbol{Addon_{sell}}$	[€/MWh$_e$]	Addon which includes fees paid on the sold electricity; Refer to Appendix 2 for the detailed price breakdown
$\boldsymbol{O\&M_{var,ORC}}$	[€/MWh$_e$]	Variable O&M cost of the ORC per unit of absorbed electricity
$\boldsymbol{\eta_{ORC}}$	[-]	Electric efficiency of the ORC
$\boldsymbol{COP_{HP}}$	[-]	COP of the HP

3.2.2. Participation in the regulating market

The possibility to operate in the tertiary regulation market (mFRR) was investigated too. As the up-regulation price at a specific hour is higher than or equal to the spot market price at the same hour, and the down-regulation price is lower than or equal to the spot market price, the participation in the mFRR market allows a facility with flexible production/consumption capacity to plan its operation so to improve its economy.

In Denmark, the participation in the mFRR market gives access to more favorable energy prices compared to the spot market (a plant receives a payment based on the amount of regulating energy supplied) and possibly to capacity payments (a plant can be paid for the available capacity to balance the grid). To be able to participate in the mFRR, a plant should be able to go online within 15 minutes and offer at least 5 MW of regulating capacity. Energinet does not usually purchase reserve capacity for mFRR down-regulation (Energinet, 2018).

There are two opportunities for participation in the mFRR market. The first opportunity is that the operator has received an availability payment (in €/MW) to make a specific capacity available as manual reserve. Thus, the operator is obliged to submit bids for regulation for a defined period of time. Alternatively, the operator can make a voluntary bid on the mFRR market, whenever the operator finds it attractive. In this case, however, no availability is due. In both cases the operator receives a payment based on the amount of electricity which the operator has actually regulated.

For simulating the participation of the CHEST system in the mFRR market, a new time series of electricity prices was created. This is based on the historical electricity prices valid for DK1 (Western Denmark) in 2018. In the new price time series, each hour of the year was assigned an electricity price, determined as follows:

$$\text{Price} = \begin{cases} \text{spot price} & \text{if regulation volume}=0 \\ \text{up-regulation price} & \text{if regulation volume}>0 \text{ (up regulation)} \\ \text{down-regulation price} & \text{if regulation volume}<0 \text{ (down regulation)} \end{cases} \qquad \text{(Eq. 1)}$$

The time series of electricity prices defined by Eq. 1 is referred to as *Spot+Reg2018* and is shown in Figure 39 in Appendix.

In case of hours with both up- and down-regulations volumes, the following conditions are added:

1. the HP can operate, only if the net regulating volume at each hour (i.e. the difference between the absolute value of up-regulation volume and the absolute value of the down-regulation volume) is lower than or equal to 0 MWh.
2. the ORC can operate, only if the net regulating volume at each hour is higher than or equal to 0 MWh.

The availability payment to which the CHEST system is entitled as reserve capacity is calculated in post-processing after the energyPRO model calculation, so without affecting the control strategy of the energyPRO model. More specifically, it is assumed that the CHEST system receives an availability payment for each hour during which the following conditions are simultaneously satisfied:

1. the HT-TES has energy content to allow for the operation of the ORC at full load for at least 1 hour;

2. the CHEST system does not operate on the spot market. Therefore, if either the ORC or the HP operates in an hour with regulation volume equal to 0 MWh, then the CHEST system does not receive availability payment for that hour.

The specific availability payment for up regulation DK1 in 2018 (in €/MW per hour) was retrieved from the Energinet website as monthly values, listed in Table 5. On the other hand, no down regulation capacity was purchased by Energinet in 2018, therefore no availability payment was assumed.

Table 5: Availability payment per unit capacity in DK1 in 2018 (Energinet, 2019).

Month	€/MW/h
January	0.34
February	0.61
March	0.57
April	0.50
May	0.86
June	0.63
July	0.66
August	0.65
September	0.62
October	3.24
November	1.01
December	0.88

The particularly high value in October 2018 (which was the highest registered monthly rate since 2010) was caused by an increased purchase of reserves in the period 8-13 October 2018, when the transmission line between the two separate synchronous areas East (DK2) and West (DK1) Denmark was out of order for inspection. This resulted in an additional demand for reserves by 300 MW.

3.2.3. Taxation scheme

Under the current legislation, electric energy storage (EES) is treated as a consumer, so it pays taxes and fees on the absorbed electricity, although this is not technically “consumed”. When the EES releases the previously absorbed electricity, the final consumer of that electricity also pays taxes and fees on its consumption. Therefore, the same electricity is taxed twice.

Additional simulations are performed assuming a more convenient taxation on EES. More specifically, it is assumed that the CHEST system does not pay the taxes on the absorbed/sold electricity, i.e. the charges “Overall tax and fees on purchased electricity” and “Fee paid when selling electricity” in Table 3 were set to 0 €/MWh. However, because the P2P ratio of the CHEST system is lower than 100 % (in fact, $COP_{HP} \cdot \eta_{ORC}$ = 81 %), not all the electricity absorbed by the HP is discharged by the ORC. Therefore, it is fair to consider the CHEST system as a consumer of the 19 % of the consumed electricity. On this energy share, the “Overall tax and fees on purchased electricity” (Table 3) is paid.

3.2.4. Spot prices reaching cap price

Preliminary results showed that the economic feasibility of the CHEST system was poor, when the system operates on the current spot market, buying electricity when its price is low and selling it when the price is high (arbitrage). Therefore, the original time series of electricity spot prices were altered by replacing a number of spot price hours with the market's upper cap price, which in Denmark is 3000 €/MWh (Nordpool, 2019). Two time series were created, by replacing the 100 and 500 hours demonstrating the highest spot prices, with the upper cap price. In the rest of the report, the two above-mentioned time series of electricity prices are referred to as *Spot2018_100h_max* and *Spot2018_500h_max*, respectively. Analogously, other two times series were created by replacing the 100 and 500 hours of the lowest spot prices, with the lower cap price, which in Denmark is -500 €/MWh (Nordpool, 2019). These two time series of electricity prices are referred to as *Spot2018_100h_min* and *Spot2018_500h_min*, respectively.

The above-described time series of electricity prices neither mean to represent realistic scenarios now nor in the future. Their setup and the resulting simulations were performed to identify how much the spot electricity prices should deviate from the current level to make the CHEST system economically feasible, if its business model is based on the participation in the spot market only (arbitrage).

3.3. Case study #3: Ispaster

In Ispaster the possible economic benefit of introducing CHEST is compared to their current energy storage solution, i.e. lead-acid batteries. The batteries installed in Ispaster are GNB - OPzS Solar 190, with an overall gross capacity of 197 kWh. These are used to store the electricity generated by the installed PV system. If the PV+battery system cannot fulfill the electricity demand, electricity is imported from the grid. The imported electricity is assumed to be purchased at the spot market hourly price. Currently, there is no electricity export in place, as it is considered unprofitable (due to the Spanish regulation), and hence, this alternative income source is not investigated in the analysis.

This analysis carried out for Ispaster aims at answering to the following questions:

- How much imported electricity can be avoided through the introduction of CHEST compared to the current batteries?
- What is the value of the reduced import electricity?
- What is the optimal combination of HP, ORC and HT-TES capacities?
- Do the savings from avoided imported electricity compensate the investments in the CHEST system?

The technical input data (see Table 6) are retrieved from the CHESTER deliverable D2.3. Based on the results in D2.3, HP capacities in the range of 1-9 kW yielded average COPs between 4.4 and 3.7, hence a COP of 4 was applied in all scenarios. As no significant change in effect was shown for HT-TES sizes >12 hours, this analysis initially studied HT-TES sizes between 2-12 hours. Scenarios were run with HP capacities ranging between 3-13 kW.

The ORC is assumed to condense to the LT-TES, as this mode demonstrated the highest overall system efficiency (ratio between the ORC electricity output and the additional heat production from the DH plant required to make up for the heat consumption in the CHEST system) for HP-capacities larger than 3 kW in deliverable 2.1.

Table 6: General assumptions in the energyPRO model for the Ispaster case

Parameter	Value
CHEST	
Relative ORC/HP capacity	25 %
Capacity of the HP	3-13 kW_e
Storage capacity of the HT-TES	8-48 hours
COP of the HP	4
Battery	
Storage capacity	197 kWh_e
Power	49.9 kW
Maximum discharge	60%
Lifetime	10-20 years
Investment costs	180 €/kWh (Battery price)
O&M	8.9 €/kW-yr
Both scenarios	
Spot price, avg.	57.3 €/MWh
Overall tax and fees on purchased electricity, avg. ($Addon_{buy}$)	66.1 €/MWh_e
Price for the heat absorbed by the HP	0 €/MWh_{th}
Price for the heat produced by the ORC	0 €/MWh_{th}

Data regarding consumption, solar PV-production and solar heat is applied in modelling of the system. As opposed to the Aalborg case, dimensioning the CHEST system in Ispaster is affected by existing local boundaries for production units and local demand. Figure 4 shows the electricity production, consumption and the resulting balance of the first week of 2017 in Ispaster. On an annual basis (based on 2017 data) the electricity surplus (yellow curve above zero) occurs 1889 hours with total of 12.89 MWh and electricity deficit (yellow curve below zero) occurs 6872 hours with a total of 38.72 MWh.

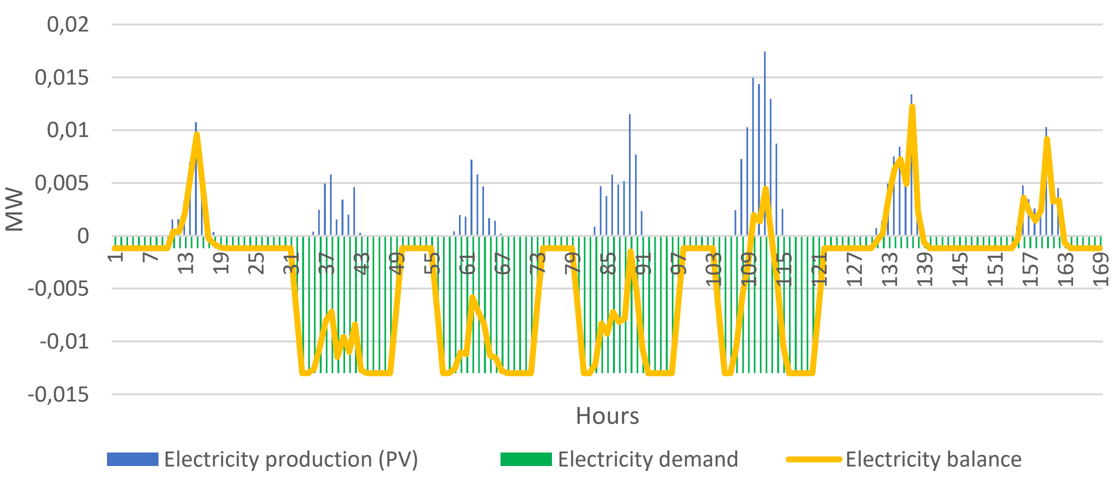

Figure 4: Hourly electricity balance the first week of 2017 in Ispaster

To compare the economic feasibility of the CHEST system with the lead batteries, the investment and operational costs of the latter must be considered. The investment cost assumed for the batteries is 180 €/MWh (excl. VAT) (AutoSolar, 2019). O&M costs are assumed to be 8.9 €/kW-year (Bakos, 2016).

The battery lifetime depends on the discharge depth and the temperature at which the battery is kept. At 40 °C, 30 °C and 20 °C the lifetime is 5, 10 and 20 years, respectively (victron energy).

The economic inputs regarding CHEST are the same as in the other cases (see Table 2).

Spanish spot prices from 2018 including addons, as shown in Figure 5, were applied in the analysis. The mean spot price of 2018 was 57.3 €/MWh. The addons on top of the Spot prices varied hour by hour between 59.5-76.6 €/MWh. The total electricity price sums to an average of 129.6 €/MWh including energy taxes (IE).

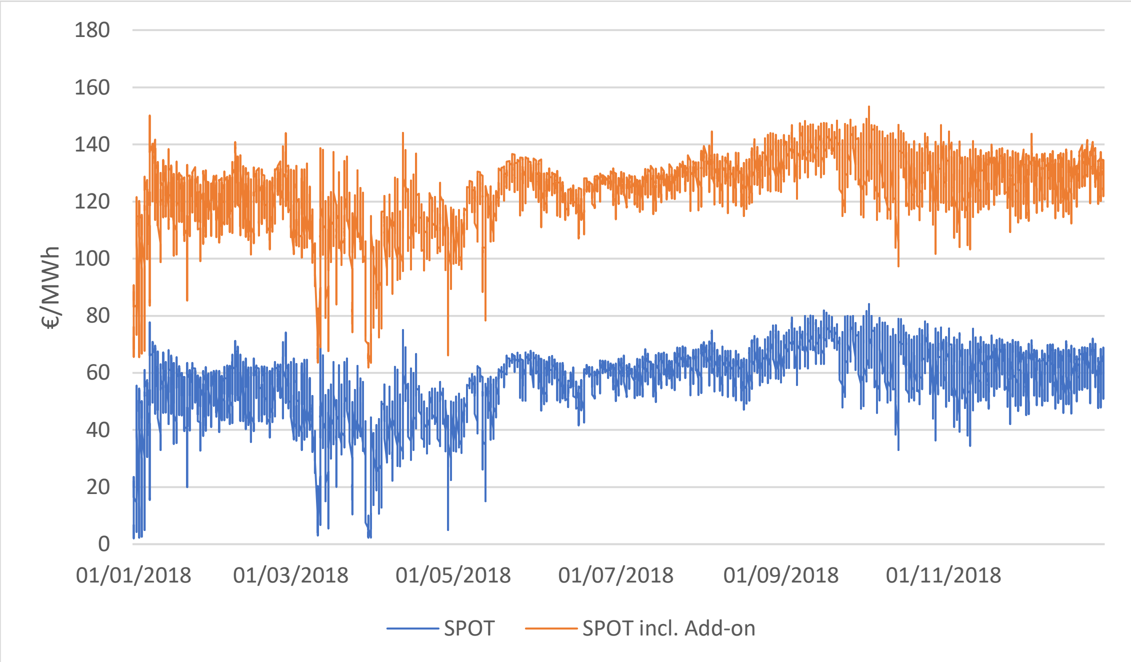

Figure 5: Spanish 2018 spot prices and the applied electricity prices (spot prices including the electricity add-ons) in the Ispaster economic analysis.

The Spanish power contracts consist of energy payments (Spot price + addon per MWh) consumed and an annual power payment for the expected maximum power offtake (MW) during the year. The power payments were initially reduced when introducing the micro-grid with local PV-production. The addition of the battery did not reduce it further, and hence this part of the electricity price was the same as in the case without the battery.

3.4. Case study #5: Alpha Ventus

The analysis for the Alpha Ventus case study was conducted using the following assumptions.

The CHEST system would be installed in connection with the Alpha Ventus wind farm, as a behind-the-meter measure. In this way the following goals can be achieved:

- Increase the profitability of the wind farm shifting the supply of electricity produced by the wind turbines from hours characterized by low electricity prices to hours with higher electricity prices.
- Avoid or reduce curtailment of the wind electricity in periods when there is overproduction from the wind farms in North Germany compared to the consumption.

Additionally, the CHEST system could also operate on the electricity market in arbitrage, i.e. purchasing electricity when the market prices are low and selling it back when the prices are higher, similarly to what has been assumed in the Aalborg case study.

The wind farm Alpha Ventus consists of 12 wind turbines with a nominal power of 5 MW each, i.e. with a total power of 60 MW. In the energyPRO model of Alpha Ventus case study, the wind turbines were modelled through the wind power curve shown in Figure 6. The curve was created based on the turn-on wind speed, turn-off wind speed and nominal wind speed of the turbines as described in the CHESTER deliverable D2.1, and assuming a typical profile of a wind turbine power curve.

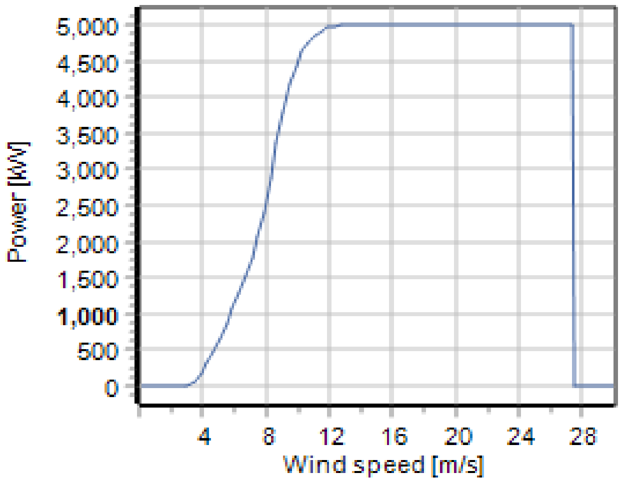

Figure 6: Power curve of a wind turbine as used in the energyPRO model of Alpha Ventus case study.

The time series of wind speed used as input for the simulations was taken from the online database energyPRO makes available. The time series comes from the ERA5 database, whose data originates from EU funded project Copernicus Climate Change Service (C3S) and delivered by ECMWF (https://www.ecmwf.int/). The data are obtained in a form of an hourly-averaged time series of wind speed at the height of 10 m. Data referring to the year 2018 and to the closest location (54.1° N; 6.3° E) to Alpha Ventus (54.0° N; 6.6° E) were used. To transpose the wind speed measured at 10 m to the turbine hub height of 91 m, the wind profile power law was used:

$$w(z) = w_{10} \cdot \left(\frac{z}{z_{10}}\right)^{\alpha}$$

where $w(z)$ [m/s] is the velocity of the wind at hub height z (which is 91 m in this specific case);

w_{10} [m/s] is the measured wind speed at height z_{10} = 10 m;

α [-] is the so-called Hellmann exponent, which was assumed equal to 0.06 given the off-shore location.

3.4.1. Investigated scenarios

The ORC had a constant size of 20 MW_{el} in all the investigated scenarios. The efficiency of the ORC was 15 %, assuming condensation to the environment. This value was assumed based on the performance map of the ORC for Butene, as presented in the CHESTER deliverable D2.1.

As there are no district heating companies near Alpha Ventus, the LT-heat absorbed by the HP was assumed to be excess heat from industry and assumed free of charge. Also, with the ORC condensation to the environment, no heat sale was included in the scenarios.

Regarding the HP, its size was varied in the different simulations, to identify its optimal value in the different scenarios. Its COP was assumed constant and equal to 5.4, which corresponds to a temperature of the heat source of 80 °C, based on the performance map of the HP for Butene (see CHESTER deliverable D2.1). The size of the HT-TES was also varied (4, 6 and 12 hours) depending on the simulated scenario.

The following assumptions were used in the model of the Alpha Ventus case study, unless otherwise specified:

Table 7: General assumptions in the energyPRO model for Alpha Ventus case.

Parameter	Value
Capacity of the ORC	20 MW_{el}
Capacity of the HP	1-20 MW_{el}
Storage capacity of the HT-TES	4-12 hours
Efficiency of the ORC	15 %
COP of the HP	5.4
Overall taxes and fees on purchased electricity	12.8 €/MWh_{el}[1]
Taxes and fees paid on electricity deriving from the wind farm	3.9 €/MWh_e
Fee paid when selling electricity	0 €/MWh_{el}[2]
Price for the heat absorbed by the HP	0 €/MWh_{th}
Price for the heat produced by the ORC	0 €/MWh_{th}

The assumptions on the investment costs and O&M costs for the different CHEST components were the same as those used in the Aalborg case (see Table 2).

A scheme of the energyPRO model used to treat Alpha Ventus case is shown in Figure 7. As depicted, the HP can charge electricity either from the wind farm production or import the electricity from the grid or a combination of the two in case the wind farm production is smaller than the HP capacity.

[1] This includes a transmission fee, electricity taxes, a concession fee and a metering service fee.
[2] The fee is zero, as all addons are forwarded to the final consumer of the electricity.

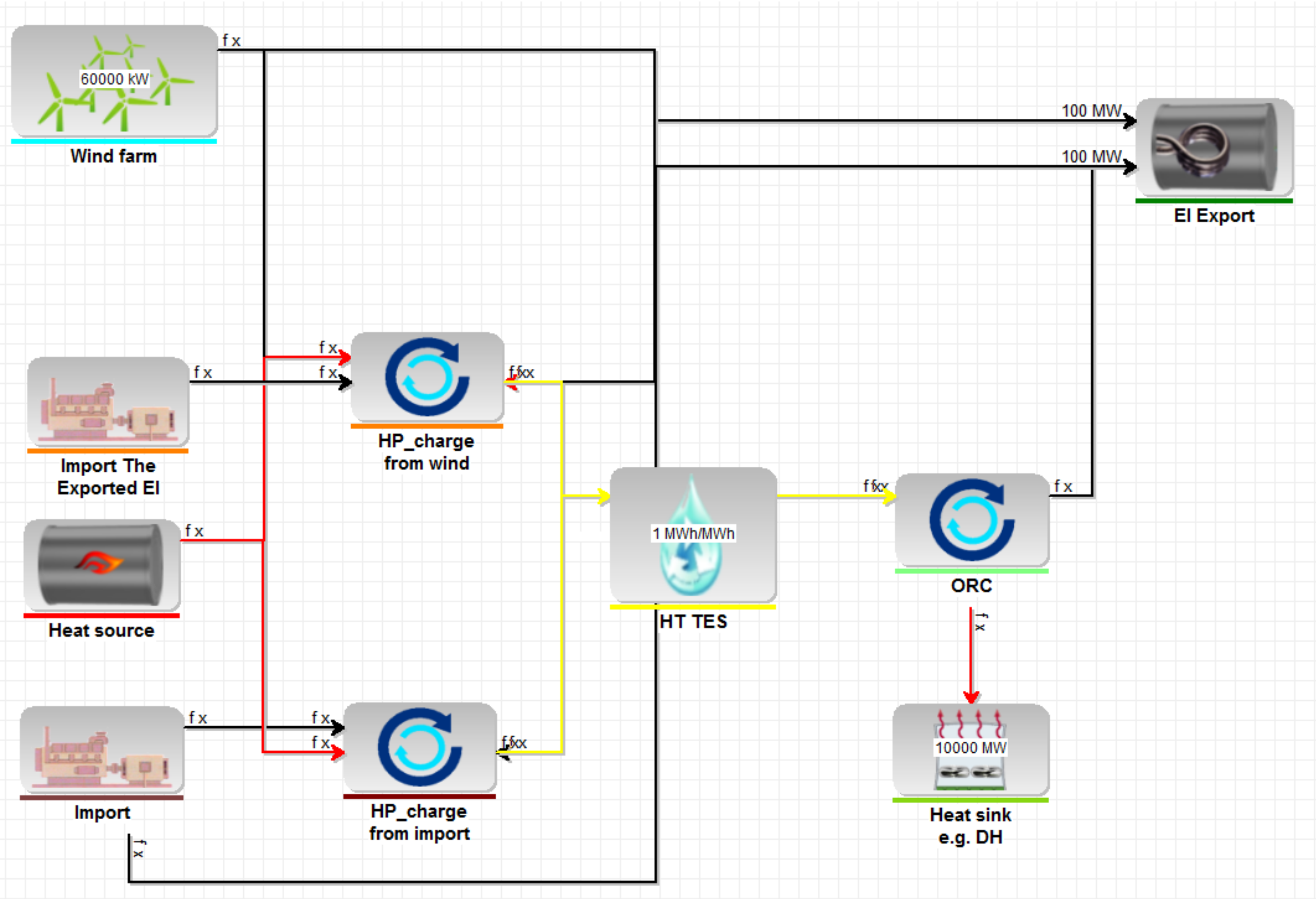

Figure 7: CHESTER model in energyPRO as assumed for the Alpha Ventus case.

3.4.2. Electricity market

The wind electricity production cannot be estimated as accurately as the production from a conventional power plant due to the uncertainty of the wind forecast, which is higher the more in advance the forecast is made. Acting on the intraday market instead of on the spot market is one way to reduce the uncertainty, as the deadline is much closer to the hour of delivery than in the spot market. Therefore, in the Alpha Ventus case the electricity prices on the intraday market in Germany were used as input to the model. The prices (see Figure 8) were retrieved as hourly averages of the intraday market prices on the EPEX market in Germany for the year 2018 (source: www.energy-charts.de/price.htm)

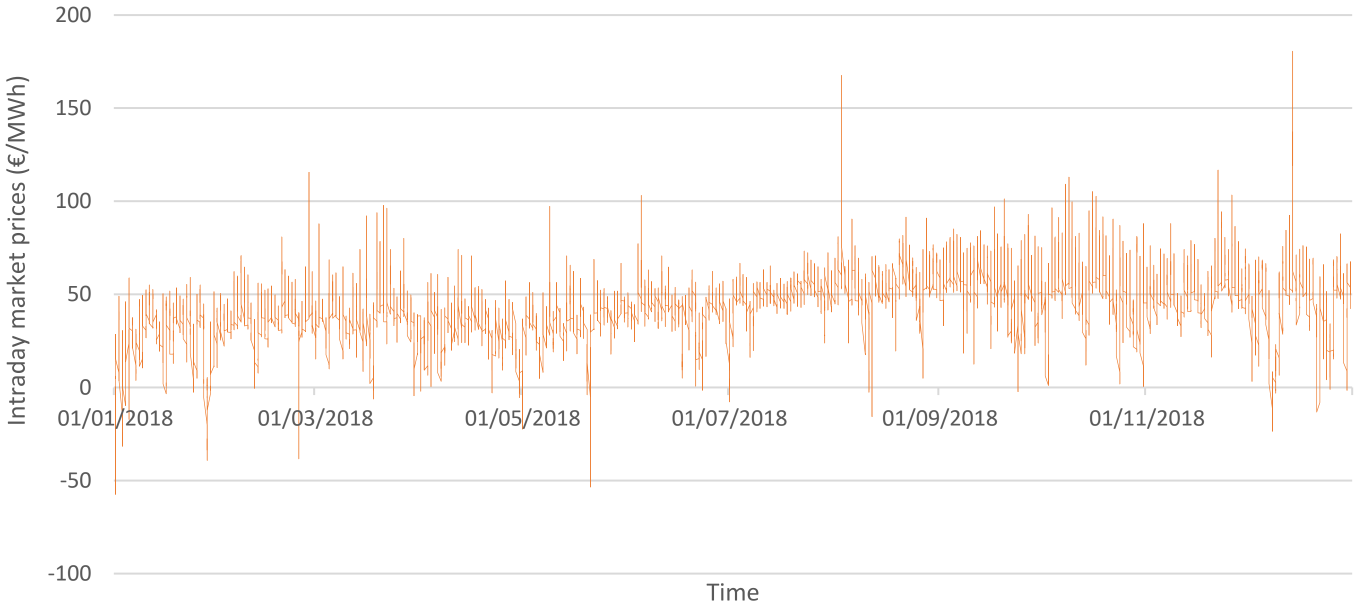

Figure 8: Hourly-averaged intraday market price in Germany in 2018.

Figure 9 shows the intraday market prices consistent with wind speeds sorted from low speed to high speed. One could expect to see a great correlation between the two i.e. high amounts of electricity from wind in a system should result in low electricity prices. This does not seem to be the case for Alpha Ventus, most likely because Germany has a one-price system for the entire country and therefore the market prices is affected by many other factors besides the wind speed in specific part of the country.

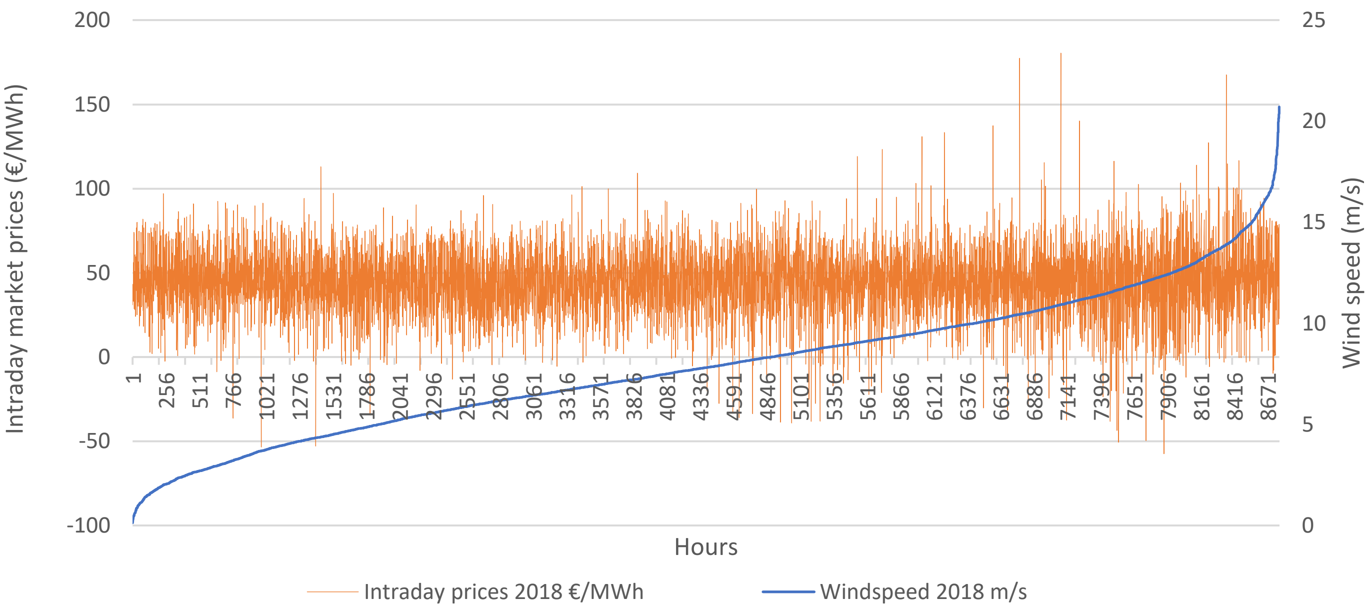

Figure 9: Correlation between Intraday market prices and wind speeds in 2018.

The main source of income of the CHEST system in the Alpha Ventus case can be expected to be the additional income from shifting the supply of electricity from hours with low electricity market prices to hours with higher prices, instead of selling the wind electricity when it is generated. This type of operation was therefore set as a priority to run the system.

Moreover, the CHEST system was also enabled to operate directly on the electricity market (with a second priority), where would purchase electricity in periods of low prices and sell it in periods of high prices. Also, in this operation mode, the same intraday electricity prices as presented above were used.

It should be noted that whenever the electricity price was negative, the electricity production possibly sold to the grid was considered as sold at null price (i.e. given for free to the network), and not at the market price, which otherwise would have entailed an expense for the wind farm production instead of an income. This assumption is equivalent to the wind turbines being shut down.

Taxes and tariffs as shown in Table 7 were added to the electricity prices. They cover some of the elements from Table 8, as provided by DLR.

Table 8: Taxes and tariffs in Germany according to DLR

Taxes and tariffs, Germany	EUR/MWh
Transmission fees	25
Electricity taxes	20.5
EEG surcharge	64
CHP surcharge	10
Concession fee	1.1
Metering service	3.1

The add-on on electricity imported from the grid covers the transmission fee and electricity tax on the part that is not returned to the grid. Also, the CHEST system is charged a concession fee and a tariff for the metering service.

In the case of consumption from the wind farm, it is assumed that CHEST has a 'direct local connection' with the wind farm. This entails that the CHEST system and the wind farm are operated by the same operator and are in the geographical proximity of each other. Applying this assumption, the only addon to be paid on the electricity deriving from the wind farm and consumed by the CHEST system is the electricity tax.

The tariffs and taxes on exported electricity are passed onto the final consumer, and hence no addon was applied to the exported electricity.

3.5. Alternative scenario – Hydrogen

The economic performance of the CHEST system proved to be unprofitable under the assumed boundary conditions. On the other hand, the assumptions made towards the behavior of future market and regulatory mechanisms for such an innovative energy solution would entail an error of misinterpreting the outcomes. A wise method for validating the economic analysis of the CHEST plant is comparing the case with a similar — though more mature — EES solution. This was identified in a power-to-hydrogen-to-power system.

In such a system hydrogen is produced via electrolysis of water at the time of low electricity prices. The electrolysis process is assumed to occur in a Low Temperature Proton Exchange Membrane Electrolyzer Cell (LTPEMEC), referred as *electrolyzer*.

The so-produced hydrogen is stored under pressure in a hydrogen storage tank and it is later converted back to electricity in a low-temperature proton exchange membrane (PEM) fuel cell at the time of high electricity prices.

Electrolyzer

The schematic of the LTPEMEC electrolyzer is shown in Figure 10. The polymer electrolyte membrane is built of a solid plastic material which along with the anode and cathode are immersed in water. This reacts at the anode to form oxygen and positively charged hydrogen ions. Owing to the electrons flow, these hydrogen ions then travel through the membrane to the negative cathode. At the cathode, hydrogen ions combine with electrons and create hydrogen gas (Energy.gov, Electrolyzer).

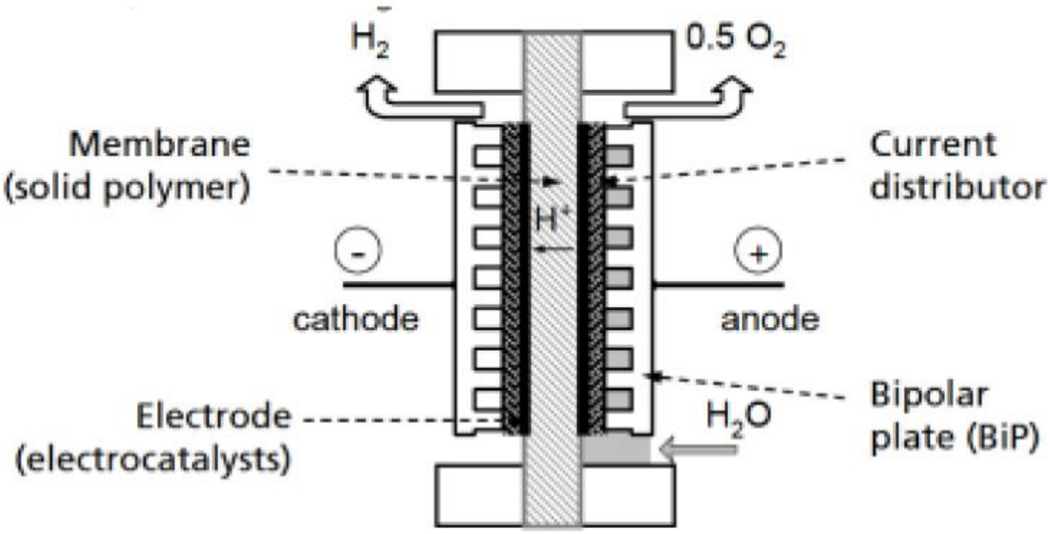

Figure 10 Principle of the Electrolyzer (Energinet, 2017).

In the energyPRO model for the hydrogen case, the only input assumed for the electrolyzer is electricity. In principle, demineralized water is also needed, but this was not considered in the calculations given its negligible economic value compared to that of the consumed electricity. The hydrogen fuel is produced with a conversion efficiency as indicated in Table 9, which refers to the expected performance of such a system for the year 2020.

Table 9: Electrolyzer specification.

Parameter	Value	Reference
Electrolyzer efficiency	1/58 kgH_2/kWh_{el}	LTPEMEC, Datasheet, 2020 (Energinet, 2017).
Electrolyzer operating temperature	80 °C	LTPEMEC, Datasheet, 2020 (Energinet, 2017).
Capacity range	5 MW, 7.5 MW	the same as HP rate in Aalborg case

Hydrogen storage

The hydrogen storage consists in a pressurized tank. No electricity consumption for compression work is assumed at this stage. The key parameters of the storage are provided in the table below.

Table 10: Hydrogen storage specification.

Parameter	Value	Reference
Storage time range	6 h, 9 h, 12 h, 15 h	the same as HT-TES rate in Aalborg case
Storage capacity range	30 MWh, 45 MWh, 60 MWh, 75 MWh	corresponds to the HP capacity and storage time; the same as in Aalborg case

Fuel cell

The schematic of the PEM fuel cells is presented in Figure 11. In a fuel cell, hydrogen is fed to the anode and air is supplied to the cathode. A catalyst at the anode separates hydrogen molecules into protons (that migrates through the membrane to the cathode) and electrons (which flow through an external circuit as electricity). The side product of the chemical process is heat that can utilized for DH or heating purposes. This was included in the technical model of the fuel cell, however, no income was accounted for the heat product. (Energy.gov, Fuel cells)

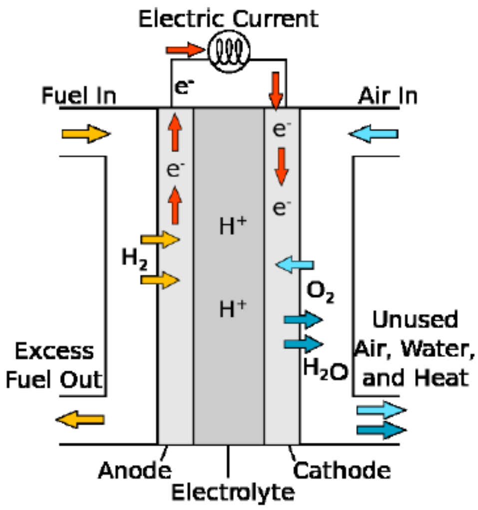

Figure 11 Principle of the PEM fuel cells (Energinet, 2016).

The key parameters of PEM fuel cells are provided in the table below.

Table 11: Specification of PEM fuel cells.

Parameter	Value	Reference
Electrical efficiency	50 %	LTPEMFC CHP, Datasheet, 2020 (Energinet, 2016).
Thermal efficiency	35 %	Aiguasol
PEM cooling circuit temperatures	80 °C/75 °C	Aiguasol
Capacity	5 MW	the same as ORC rate in Aalborg case

Because the energyPRO models needs a conversion factor between energy output and amount of storage medium, the efficiency of the fuel cell (expressed as percentage) had to be appropriately converted.

Given the definition of electrical efficiency, $\eta_{Fuel\ cells}$:

$$\eta_{Fuel\ cells} = \frac{E_{out}}{m_{H2} * LHVM}$$

where E_{out} [kJ] is the electricicty output of the PEM fuel cell,

m_{H2} [kg] is the mass of hydrogen,

$LHVM$ [kJ/kg] is the lower calorific value of hydrogen, which is equal to 120,210 kJ/kg (Biomass Energy Data Book, 2011).

the resulting electrical conversion factor is 16.7 kWh_{el}/kgH_2, while the thermal conversion factor is 11.7 kWh_{th}/kgH_2.

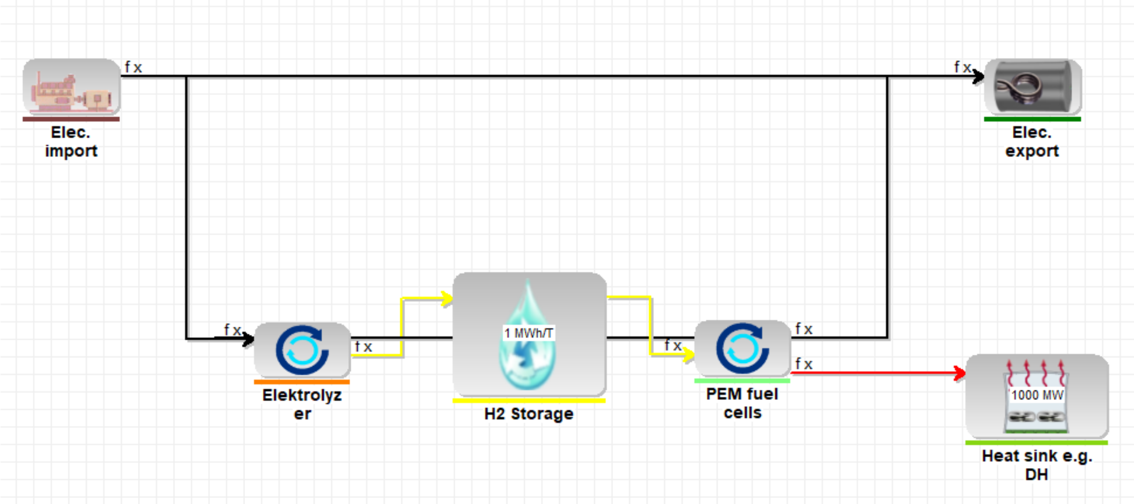

Figure 12: energyPRO model of the hydrogen-based energy conversion and storage system.

The resulting energyPRO model for the hydrogen-based system is shown in Figure 12. This is equiavalent to the CHEST system in Figure 1, but the electrolyzer now replaces the HP, the hydrogen storage replaces the HT-TES and the PEM fuel cell replaces the ORC.

The hydrogen case was considered as an alternative EES in the Aalborg case study only, and hereby the similarity between the two energyPRO models (Figure 1 and Figure 12). As for the Aalborg case with CHEST system, the business model was that of operating in arbitrage with respect to the electricity market. This means that the PEM fuel cell converts the stored hydrogen into electricity, when the net revenue from the sale of electricity is equal to or higher than the cost that the plant has incurred when purchasing and converting electricity into that amount of hydrogen fuel. This is indicated by the equation:

$$Electrolyzer\ el.\ price \leq\ PEM\ el.price \cdot \eta_{PEM_{el}} \cdot \eta_{Electrolyzer}$$

$$+PEM\ heat\ price \cdot \eta_{Electrolyzer}\ \cdot \eta_{PEM\_th}$$

where $Electrolyzer\ el.\ price$ [€/MWh_e] is the total cost paid on the electricity consumed by the Electrolyzer, which is defined as

$$Electrolyzer\ el.\ price = Spot\ el.price + Addon_{buy}$$

$PEM\ el.price$ [€/MWh$_e$] is the net income from the sale of the electricity produced by the ORC, which is defined as:

$$PEM\ el.\ price = Spot\ el.price - Addon_{sell}$$

The charges related to the mainatance of hydrogen units which are fixed annual payments do not affect the plant operation strategy, hence were included in the energyPRO model, but considered in the economic calculations in post-processing, together with the investment costs.

The terms of the equation are described in chapter for the Aalborg case while:

$\eta_{PEM_{el}}$ [%] is the electrical efficiency of PEM fuel cell

η_{PEM_th} [%] is thermal efficiency of PEM fuel cell

$\eta_{Electrolyzer}$ [%] is the efficiency of electrolyzer

The cost assumptions for the economic analysis are listed in Table 12.

Table 12: Cost assumptions for the hydrogen system.

CAPEX		
Parameter	Value	Reference
Electrolyzer	1.1 M€/MW$_{el}$	LTPEMEC, Datasheet, 2020 (Energinet, 2017)
Hydrogen storage	10 €/kg	Aiguasol
PEM fuel cells	1.3 M€/MW$_{el}$	LTPEMFC CHP, Datasheet, 2020 (Energinet, 2016)
OPEX		
Parameter	Value	Reference
Electrolyzer	55,000 €/MW$_{el}$/year	LTPEMEC, Datasheet, 2020 (Energinet, 2017)
Hydrogen storage	Negligible	Aiguasol
PEM fuel cells	65,000 €/MW$_{el}$/year	LTPEMFC CHP, Datasheet, 2020 (Energinet, 2016)
Technology lifespan		
Parameter	Value	Reference
Electrolyzer	15 years	LTPEMEC, Datasheet, 2020 (Energinet, 2017)
Hydrogen storage	50 years	Aiguasol
PEM fuel cells	10 years	LTPEMFC CHP, Datasheet, 2020 (Energinet, 2016)
Tariffs and taxes		
Overall tax and fees on purchased electricity (Addon$_{buy}$)	21.53 €/MWh$_{el}$	Aalborg case study
Fee paid when selling electricity (Addon$_{sell}$)	0.52 €/MWh$_{el}$	Aalborg case study
Price for the heat absorbed by the HP	0 €/MWh$_{th}$	Aalborg case study
Price for the heat produced by the ORC	0 €/MWh$_{th}$	Aalborg case study

4. Results and discussion

4.1. Case study #2: Aalborg

4.1.1. Current and future spot electricity market

Figure 13 shows the amount of electricity absorbed by the HP and that produced by the ORC under the boundary conditions listed below:

- As electricity price the price series *Spot2018* was used;
- Storage capacity of the HT-TES: 400 MWh, corresponding to 6 hours of full-load operation of the ORC
- Capacity of the HP varying between 1 MW_{el} and 20 MW_{el}
- Capacity of the ORC constant and equal to 5 MW_{el}

For the remaining assumptions, the reader should refer to Table 3.

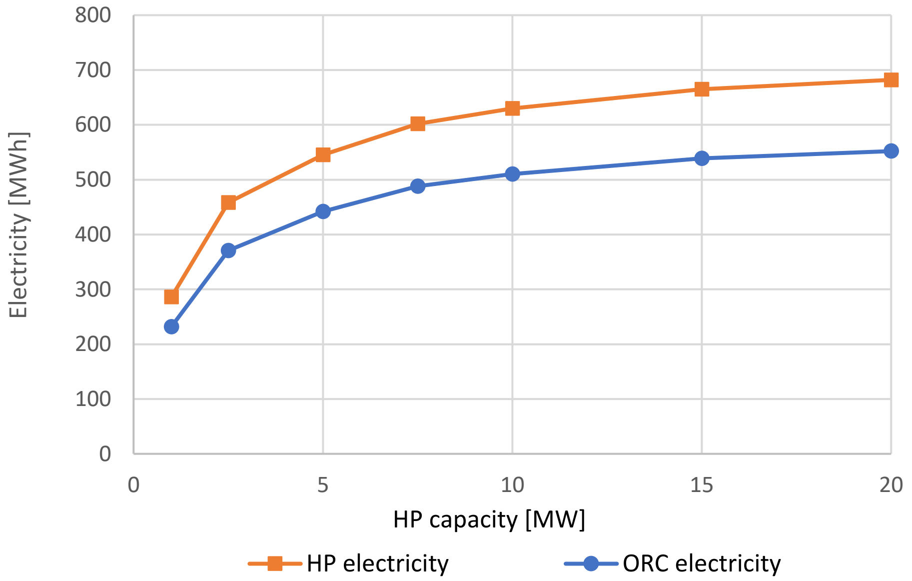

Figure 13: Electricity absorbed by the HP and electricity produced by the ORC as function of the HP capacity for the case with 6 hours of HT-TES storage capacity and Spot2018 electricity prices.

The difference between the two curves illustrates that the P2P ratio is less than 100%, and equal to 81%).

For the same case Figure 14 shows the yearly revenues, expenditures and profit (i.e. the difference between revenues and expenditures) resulting from the operation of the CHEST system, as well as the profit of the system after taking into account the investment cost of the CHEST components.

Figure 15 shows the breakdown of cash flows referring to the specific case of 1 MW HP and 6 hours HT-TES storage capacity.

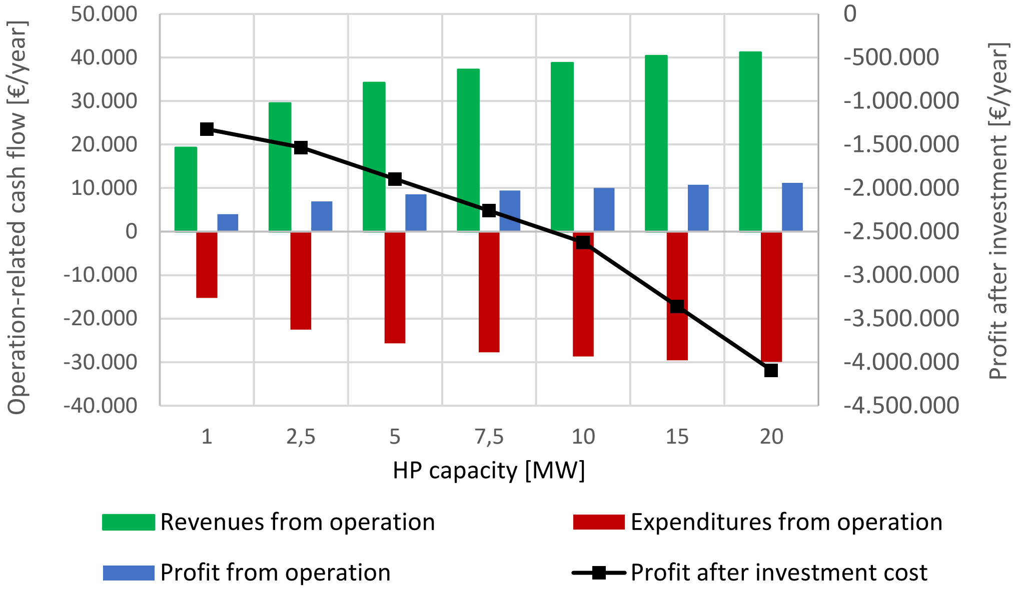

Figure 14: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity and Spot2018 electricity prices.

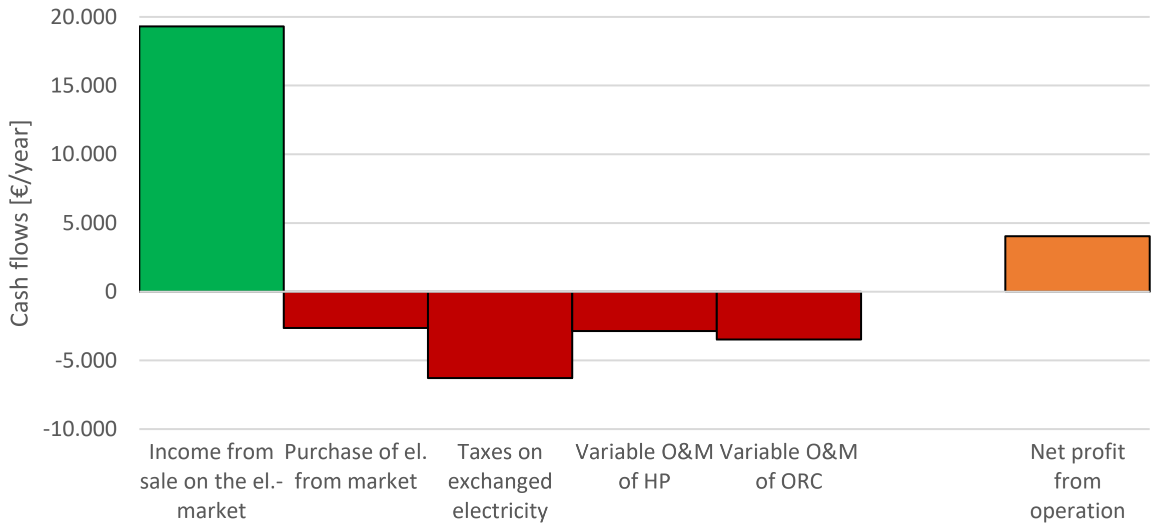

Figure 15: Breakdown of cash flows referring to the case with 1 MW HP, 6 hours of HT-TES storage capacity and Spot2018 electricity prices.

The yearly net profit coming from the operation of the CHEST system when operated under the above-mentioned boundary conditions was relatively low, ranging from 4000 € to 11,000 € depending on the capacity of the HP. The limited profit was caused by:

- a relatively small amplitude of the fluctuations in the spot electricity market (Figure 3),
- a relatively low number of very strong fluctuations (Figure 3),
- a high taxation level compared on the consumed electricity compared to the amplitude of the price fluctuations in the spot market (Table 3 and Figure 3).

Therefore, the net profit originated by the operation of the CHEST system did not compensate for the high investment costs of the different components in their expected lifetime. In fact, the annualized capital cost of the investment in the components of the CHEST systems was in the range 1-4 M€, depending on the capacity of the HP, so 3-4 orders of magnitudes larger than the net profit coming from the operation.

Simulations were carried out increasing the storage capacity of the HT-TES up to 12 hours, but larger HT-TES made the business case even worse. In fact, although the net profit from the operation of the CHEST system increased, up to +50 % in case of a 20 MW HP, the additional cost for the HT-TES more than counterbalanced for it.

Better results — but still very negative when considering the necessary investment cost — were obtained when simulating smaller CHEST systems, with a HP capacity of 1 MW, ORC capacities of 1 and 2 MW, and storage capacities of 2 and 4 hours. Therefore, it is concluded that the implementation of the CHEST system cannot be profitable under the assumed boundary conditions, given the high investment costs and the relatively low net profit originated by its operation on the spot market.

The net profit of the CHEST system increased in the scenarios applying the electricity price forecast for 2030 and 2040, as shown in Figure 16 and in Figure 17, respectively. Compared to the scenario using the spot prices from 2018, the 2030 scenario saw the net profit increasing from about 4000 € to about 20,000 € for the smallest HP (1 MW), and from about 11,000 € to about 41,000 € for the largest HP (20 MW). In the 2040 scenario, the net profit further increased to about 32,000 € for the 1 MW HP, and to about 69,000 € for the largest 20 MW HP.

This was caused by the higher and more frequent price volatility, which increased not only the number of hours of operation of the CHEST system, but it also entailed a higher specific profit on the MWh of stored electricity. This derives from the higher volume weighted electricity prices that the system sells at, as shown for the different HP capacities in Table 13. On the other hand, the average price at which the CHEST system bought electricity was roughly constant in all three scenarios, ranging between 0 and 27 €/MWh.

Table 13: Average electricity prices that the CHEST system sells at in the various price scenarios. The range of values refers to the different HP capacities investigated.

	Spot2018	Spot2030	Spot2040
Average electricity price (SELL)	74-84 €/MWh	92-114 €/MWh	109-140 €/MWh

However, when the investment costs were considered (black lines in graphs), the overall business case was again negative.

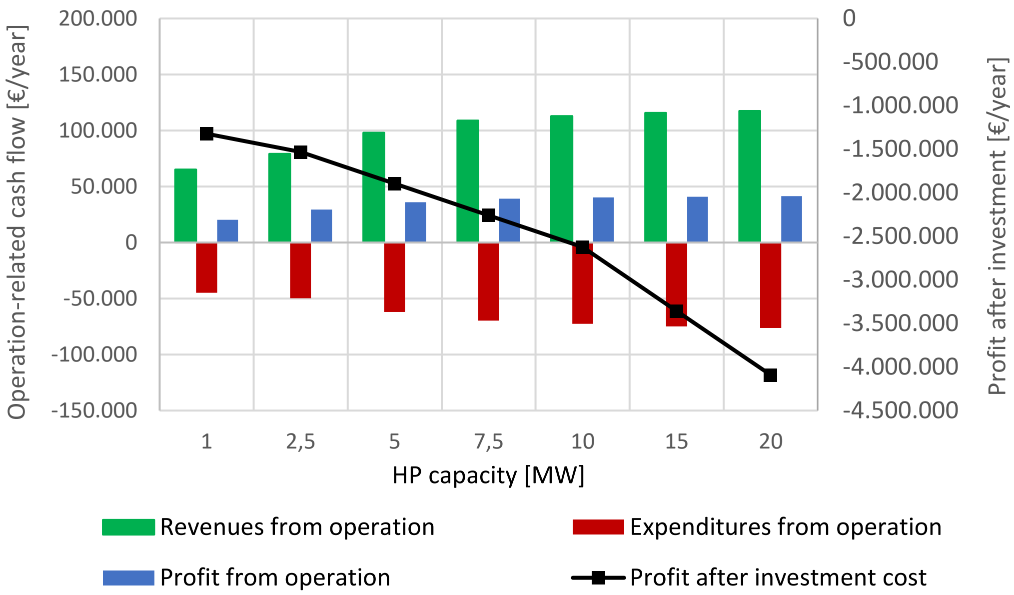

Figure 16: With Spot2030 electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

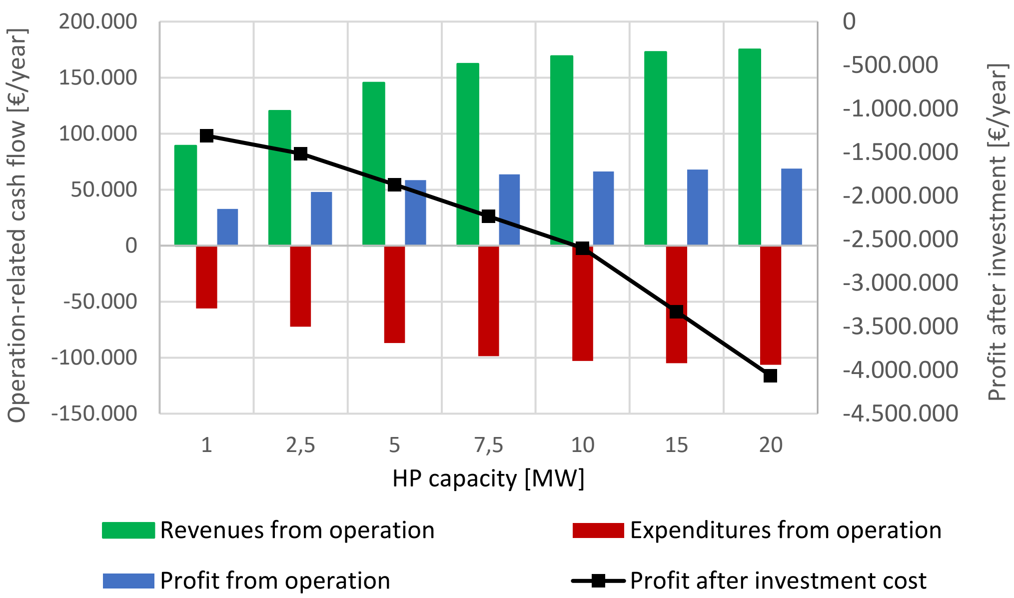

Figure 17: With Spot2040 electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

4.1.2. Participation in the regulating market

Given the limited revenue achieved by the CHEST system when operating on the spot market, the possibility to operate in the mFRR market was investigated. Because previous simulation results showed that the CHEST system should be sized to be as small as possible to reduce investment costs, only the three lowest HP capacities (1, 2.5 and 5 MW) were considered, and the storage capacity of the HT-TES was assumed to be 6 hours.

Under the current regulation, an operator cannot participate in the mFRR market, if the offered regulation capacity is lower than 5 MW. However, it was decided to ignore this limitation, when running the simulations, as more relaxed requirements for participating in the regulation markets might be introduced in the future, to facilitate the deployment of EES.

For the above-mentioned boundary conditions, Figure 18 shows the yearly revenues, expenditures and profit coming from the operation of the CHEST system, as well as the profit of the system after including the investment cost of the CHEST components. The revenues consist of the "Revenues from sale of electricity" (i.e. energy payments related to amount of energy actually produced and sold either on the spot market or on the regulating market) and the "Availability payment" (i.e. capacity payments). For comparison, the cash flows referring to an identical CHEST system operating only on the spot market (*Spot2018*) are shown too, extracted from the results in Section 4.1.1.

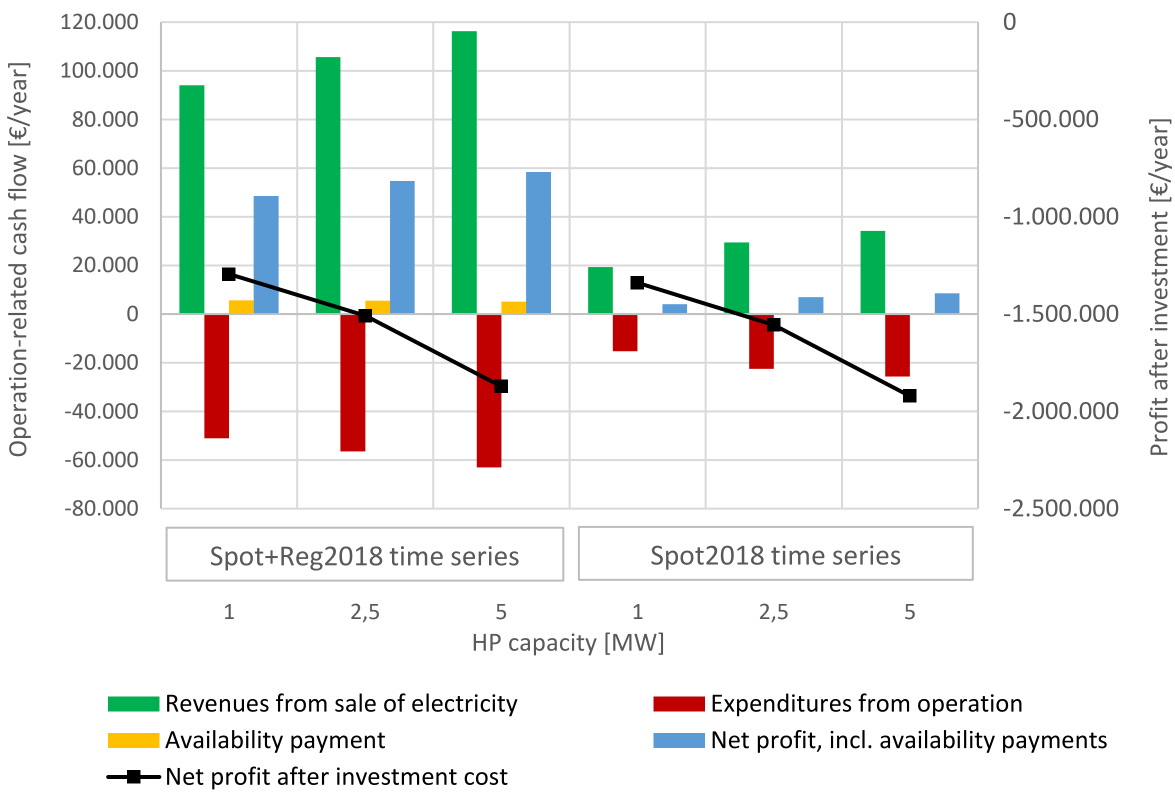

Figure 18: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity and assuming participation to both spot market and mFRR market.

Although the availability payments represented a minor contribution to the balance sheets of the CHEST operation (around 5000 €/year), the participation in the regulating market gave access to much more volatile electricity prices, which significantly increased both the hours of operation and the specific revenue of the CHEST system compared to the reference scenario, (operated only on the spot market). In fact, the net profit from the purchase and sale of electricity (excluding the availability payments) increased from 4000-8500 €/year in the *Spot2018* scenario up to 43,000-53,000 €/year, depending on the HP capacity.

Although the net profit from the operation was about 10 times higher in the *Spot+Reg2018* scenario compared to the *Spot2018* scenario, the overall business case was still heavily negative when considering the investment cost (see the curve "Net profit after investment cost" in Figure 18).

4.1.3. Taxation scheme

To improve the economic feasibility of the CHEST system when operating on the spot and regulating market, a more convenient taxation on EES electricity was assumed. Under this scheme the taxes which are usually charged on the absorbed electricity were charged only on the amount of electricity, which was consumed by the CHEST system. The consumed electricity is the difference between the yearly HP-absorbed electricity and the yearly ORC-produced electricity, as the P2P ratio is less than 1.

The corresponding results are shown in Figure 19 and compared to the case using the same CHEST system but under the normal taxation scheme. All the 6 cases shown used the *Spot+Reg2018* time series as electricity price and assumed a HT-TES storage capacity of 6 hours.

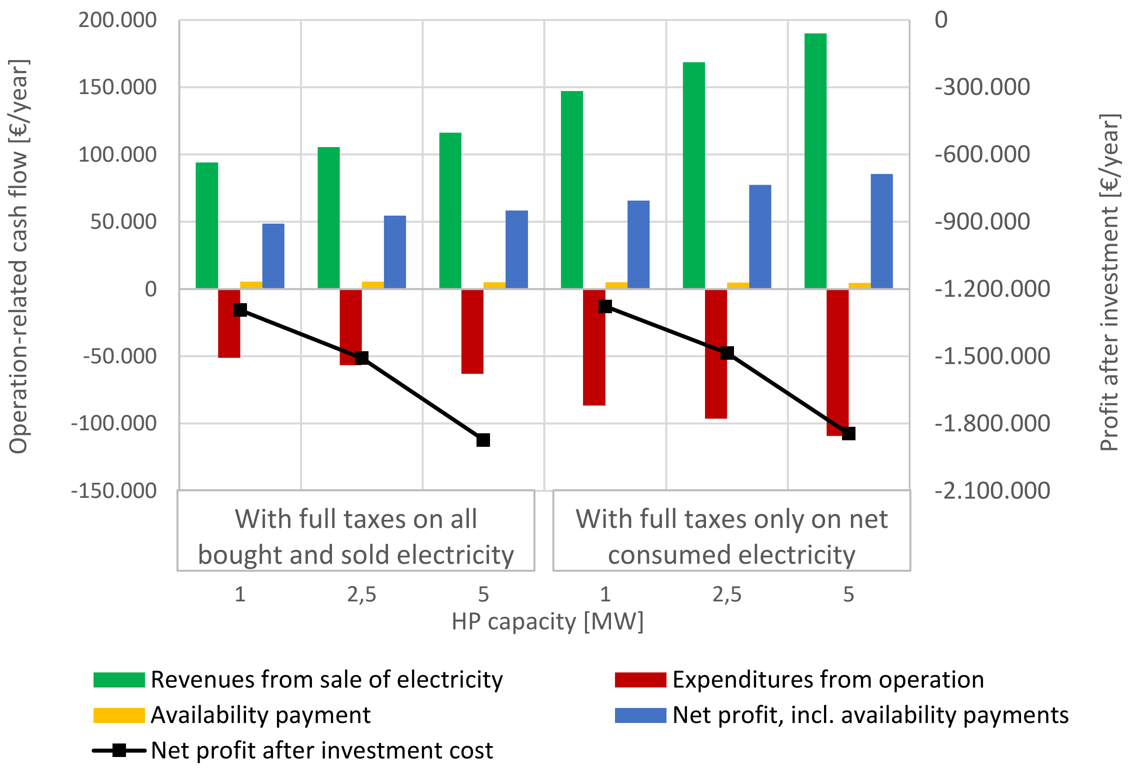

Figure 19: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity, assuming participation to both spot market and mFRR market under different taxation scheme.

Although the more convenient taxation scheme considerably increased the net profit from operation (between +35 % and +46 %, depending on the HP capacity), it was still not enough to pay back the high investment costs.

4.1.4. Spot prices reaching cap price

Figure 20, Figure 21, Figure 22 and Figure 23 show the revenues, expenditures and profit coming from the operation of the CHEST system, as well as the profit of the system after taking into account the investment cost of the CHEST components, assuming as electricity prices the time series reaching cap price levels described in Section 3.2.4. Figure 20, Figure 21, Figure 22 and Figure 23 refer to the time series *Spot2018_100h_max*, *Spot2018_500h_max*, *Spot2018_100h_min* and *Spot2018_100h_min*, respectively.

In the four different price scenarios, the storage capacity of the HT-TES was assumed to be 6 hours and the capacity of the HP was varied between 1 MW and 20 MW. For the remaining assumptions, the reader should refer to Table 2 and Table 3.

Figure 20 and Figure 21 refer to the time series with 100 and 500 hours of upper cap price (3000 €/MWh), respectively. The new price time series entailed much higher revenues from the sale of electricity compared to the *Spot2018* scenario. Because the number of hours of the ORC operation increased, also the HP had to operate more hours. The increased electricity prices affected both the annual income and expenditures for running the heat pump. The latter ones were however lower than the revenues, resulting in high profit from operation.

When considering the profit after the investment, only the scenario with 500 hours at upper cap price (*Spot2018_500h_max* in Figure 21) presented a positive business case. Within this scenario, the size of the HP which maximized the net profit (after investment cost) was 5 MW. For the scenario with 100 hours at upper cap price (*Spot2018_100h_max* in Figure 20), the overall business case was negative, regardless of the size of the HP. Therefore, the simulation results suggested to size the CHEST system as small as possible, so to reduce the net loss.

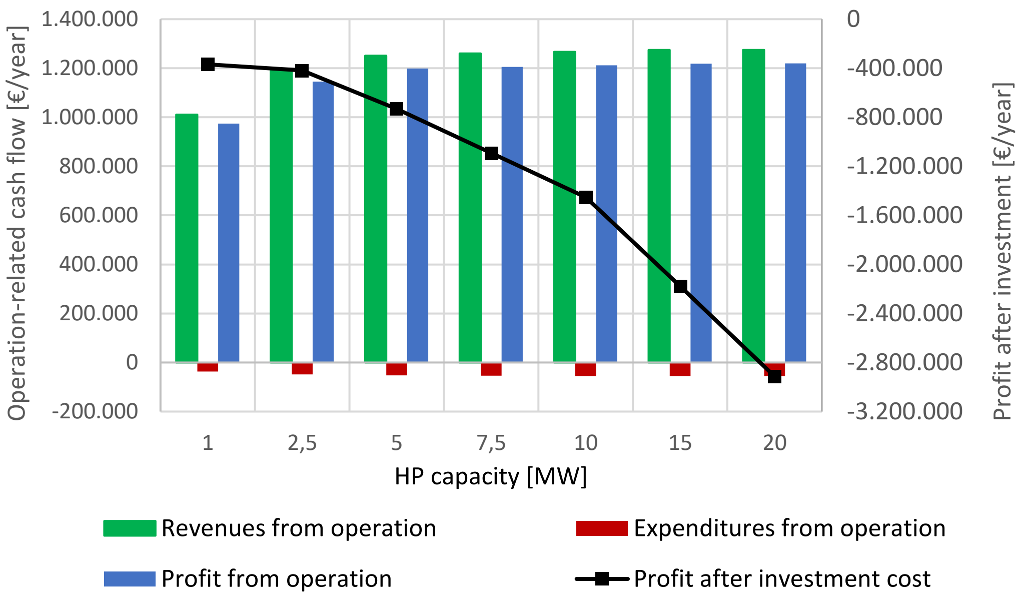

Figure 20: With Spot2018_100h_max electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

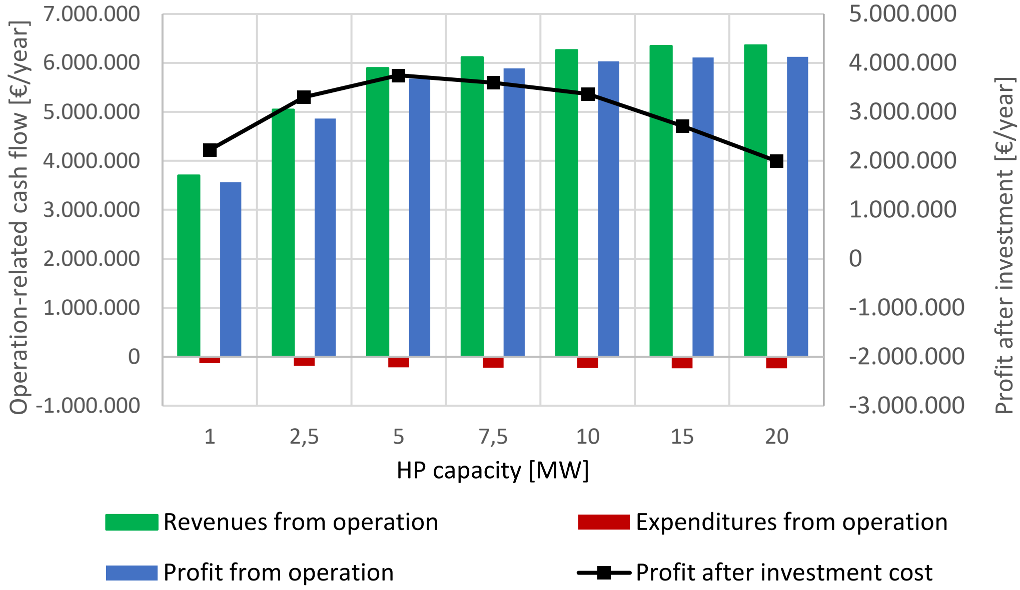

Figure 21: With Spot2018_500h_max electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

Figure 22 and Figure 23 refer to the time series with 100 and 500 hours of lower cap price (-500 €/MWh) respectively. It should be noted that the bars corresponding to "Expenditure from operation" lay on the positive side of the vertical axis, meaning that in these scenarios the CHEST system had a net income rather than an expense, when purchasing electricity from the grid. Therefore, the purchase of electricity was the main source of income of the CHEST system in these scenarios.

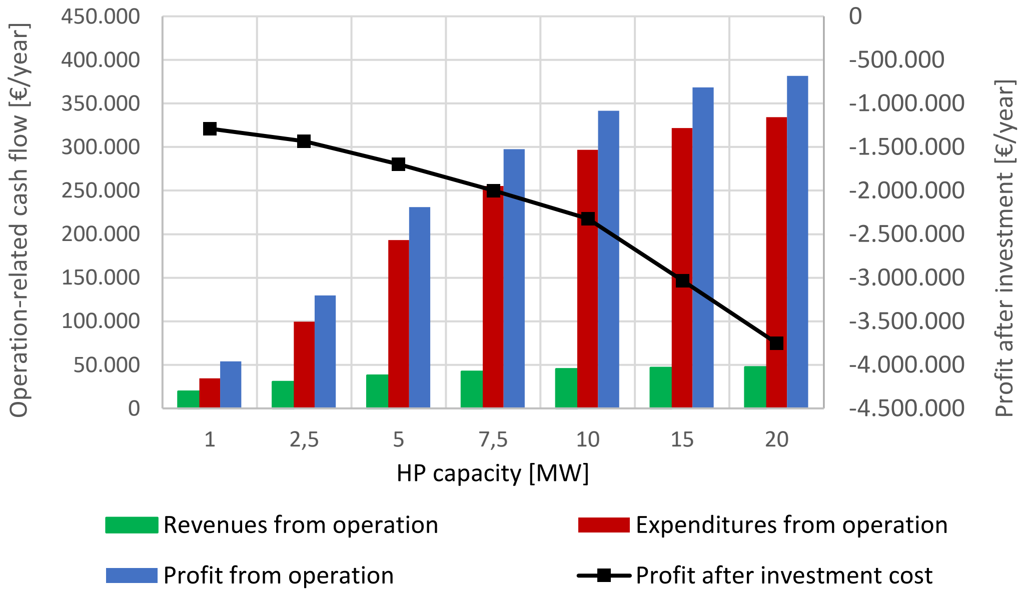

Figure 22: With Spot2018_100h_min electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

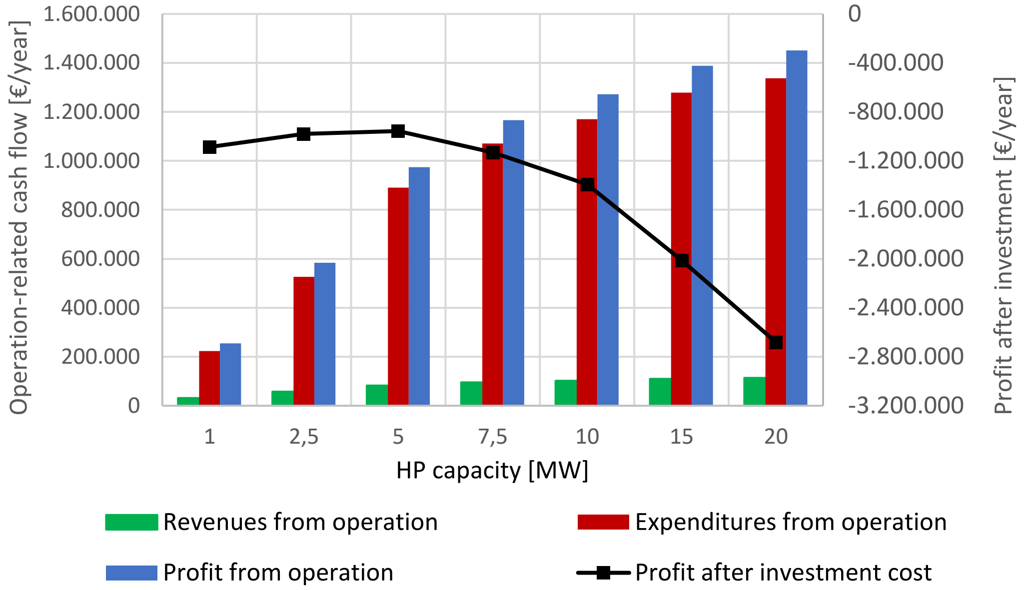

Figure 23: With Spot2018_500h_min electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 6 hours of HT-TES storage capacity.

Despite the many hours with negative electricity prices, the investment cost of the system's components still had a major impact on the overall economy of the system, which was negative in both price scenarios and for all the considered HP capacities.

Based on the results shown above, the only scenario which had a positive business case was the one using *Spot2018_500h_max* as time series for the electricity prices. Within this scenario, the optimal size of HP was found to be in the range 5-7.5 MW. This was used as starting point to run a parametric analysis where the size of the HT-TES was varied between 6 and 15 hours for both a 5 MW HP and a 7.5 MW HP, to identify the optimal configuration. The corresponding results are shown in Figure 24.

It is seen that the first identified configuration (i.e. 6 hours of HT-TES storage capacity) is not the optimal one, when the HP capacity is 5 MW or 7.5 MW. A HT-TES storage capacity of 9 hours was found to maximize the profit after the investment cost. Larger HT-TES storage capacities would entail a higher investment cost for the HT-TES without significantly increasing the profit from the CHEST operation. Conversely, a smaller HT-TES would lower not only the investment cost, but also the number of hours of operation, so reducing the profit of the system.

From the trend of the "Profit after investment cost" curve, it is seen that the decrease in the HT-TES storage capacity for values lower than 9 hours had a worse effect on the overall economy in case of the 7.5 MW HP compared to the case with 5 MW HP. In fact, in the 7.5 MW HP and 6 hours HT-TES configuration, the HP resulted to be oversized with respect to the HT-TES capacity.

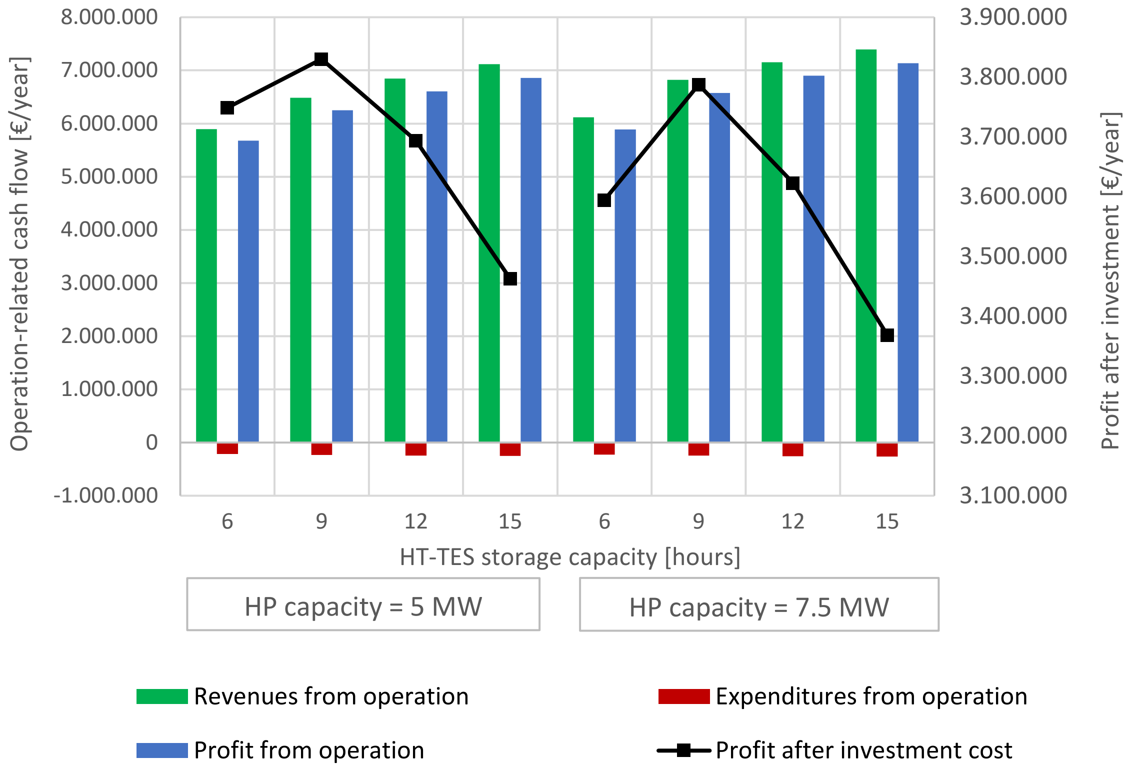

Figure 24: With Spot2018_500h_max electricity prices: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HT-TES storage capacity for the case with 5 MW and 7.5 MW HP.

4.1.5. Heat price

All the previous results were obtained assuming that the heat absorbed and released by the CHEST system had no economic value. This corresponded to the assumptions that the heat absorbed by the HP was freely available (e.g. excess heat from a factory that would otherwise be wasted), and that the condenser of the ORC dissipated the residual heat to the environment.

In this section the effect of introducing an economic value on the absorbed/released heat is considered. The heat price was assumed to be 46 €/MWh, which corresponds to the price (taxes excluded) of the heat delivered by the DH network in Aalborg (Forsyningstilsynet, 2019). As the heat absorbed by the HP is at a higher temperature than the heat released by the ORC, it could be argued that a different heat price should be applied. However, assuming that the thermal efficiency of the DH plants supplying the Aalborg DH network do not depend on the temperature of the delivered heat, this simplification is acceptable.

The following cases were investigated:

- Case *HP-heat*: the heat price of 46 €/MWh was assigned to the heat absorbed by the HP only (purchased heat). The ORC efficiency was 15 % and the HT-TES storage capacity was 9 hours, corresponding to a heat capacity of 300 MWh.
- Case *HP&ORC-heat*: the heat price of 46 €/MWh was assigned to both the heat absorbed by the HP (purchased heat) and that released by the ORC (sold heat). For the heat from the ORC to have an economic value, it should be available at temperature

sufficiently high so that it can be usefully recovered by the DH network. Therefore, the ORC efficiency was reduced from 15 % to 11 %, which corresponds to an inlet temperature on the cold side at the ORC condenser of 40 °C (see the performance map of the ORC when using Butene in the CHESTER deliverable D2.2). In fact, 40 °C is the lowest return temperature which can be expected from the Aalborg DH network. The maximum heat capacity of the HT-TES was 300 MWh, so identical to the *HP-heat* case. Given the lower ORC efficiency, the HT-TES heat capacity corresponded to 6.6 hours of ORC full-load operation.

- Case *HP&ORC-heat+*: this case was identical to the case *HP&ORC-heat*, with the only difference being that the HT-TES was sized so to ensure 9 hours of uninterrupted operation of the ORC, which corresponded to heat capacity of the HT-TES of 409 MWh.

The three above-mentioned scenarios were compared to a reference case characterized by a null heat price, 5 MW HP, ORC efficiency of 15 % and HT-TES capacity of 300 MWh (i.e. 9 hours of ORC full-load operation). This is the case which was found as the most feasible based on the results presented in Section 4.1.4, and is referred to it in this section as *0 heat price* case.

Figure 25 shows the revenues, expenditures and profit from the operation of the CHEST system, as well as from the profit of the system after accounting for the investment cost of the CHEST components. The three described "heat price" cases are compared with the reference case *0 heat price.*

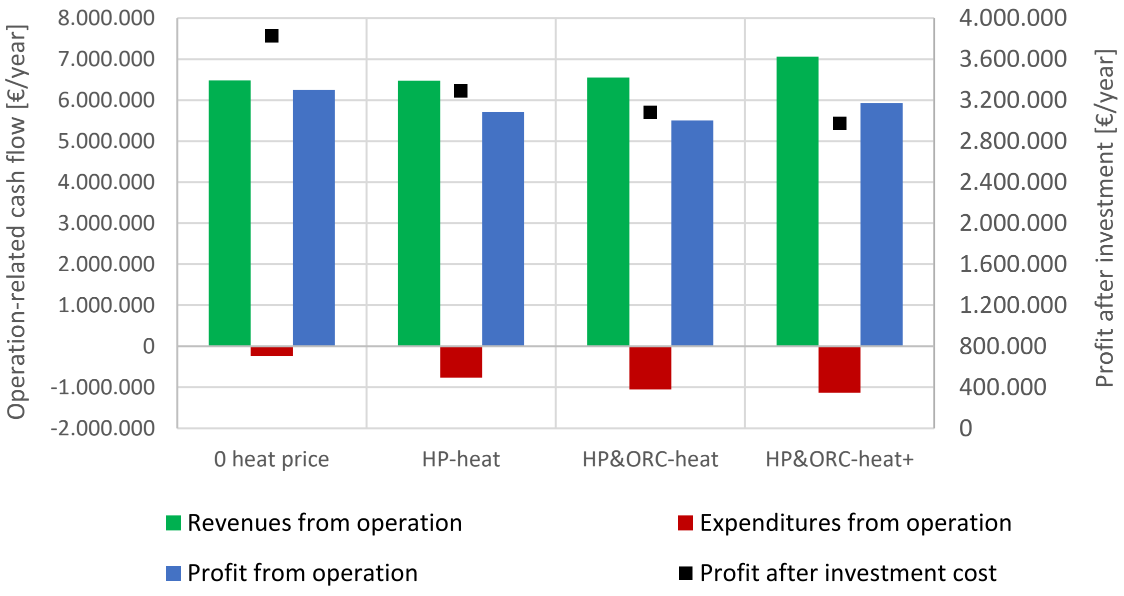

Figure 25: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) in the different "heat price" cases and in the reference case with no heat price.

The *HP-heat* case was almost identical to the *0 heat price* in terms of electricity and heat balances, with the main difference being the higher expenditures connected to the operation of the HP, since in the *HP-heat* case the heat absorbed at the evaporator of the HP had a cost. This decreased the net profit from the operation and therefore also the profit after investment cost.

In the *HP&ORC-heat* case, the lower ORC efficiency decreased the amount of produced electricity compared to the first two cases, and therefore also the income from the sale of electricity diminished by about 750,000 € per year. However, this was more than compensated for by the sale of heat from the ORC condenser (+830,000 €/year). Therefore, the revenues from the operation were slightly higher than in the previous two cases.

On the other hand, the expenditures increased, as HP which was incentivized by the additional source of income for the residual heat, operated longer hours and hence consumed more electricity. Overall, the profit from operation was slightly lower in this case compared to the *HP-heat* case. Since the size of the system's components was the same, the profit after the investment cost was slightly lower too.

The *HP&ORC-heat+* case differed from the *HP&ORC-heat* case only with a larger HT-TES storage capacity. On one hand, this increased the amount of electricity which could be exchanged with the market (therefore increasing the profit from operation). On the other, it entailed higher investment costs for the HT-TES. The corresponding cash flows balanced each other so that the profit after the investment cost was comparable in the two cases.

In summary, in the *HP&ORC-heat* case and in the *HP&ORC-heat+* case, the COP of 5.4 for the HP and the ORC efficiency of 11 % for the ORC resulted in a P2P-ratio of about 59 %. Because no losses are assumed and the entire amount of condensing heat from the ORC is sold to the DH network, for each MWh of purchased heat for the HP, about 1.09 MWh of heat is made available at the ORC condenser and can, therefore, be sold. As the same heat price was applied to both the heat absorbed by the HP and the heat released by the ORC, the CHEST system had an additional income with respect to the cases where the exchanged heat had no economic value (*0 heat price* case). The reason why the profit from operation was lower in the *HP&ORC-heat* case and in the *HP&ORC-heat+* case was that the lower ORC efficiency (11 % against 15 %) reduced the amount of electricity which was produced during peak price hours. As the peak price was as high as 3000 €/MWh, the reduction in revenue from the sale of electricity was more important than the increased revenue from the sale of heat, and therefore the overall profit from operation decreased.

4.2. Case study #3: Ispaster

4.2.1. Reduced imported electricity

Figure 26 shows the performance of the lead acid-battery in the Ispaster case as obtained from the TRNSYS model. This represents the reference case which the CHESTER system is compared to.

In order not to compromise the lifetime of the battery, its level of charge was maintained above the recommended depth of discharge of 60 % (see Table 6). If the batteries are fully charged and there is still some surplus PV production which cannot be consumed immediately, this surplus is curtailed. During the year, the curtailed energy amounted to 3.3 MWh out of the available 13.0 MWh surplus which indicates that 9.7 MWh were stored. Given the battery round-trip efficiency of 70 %, the batteries discharge 6.6 MWh, so reducing by the amount the electricity which must be imported from the grid.

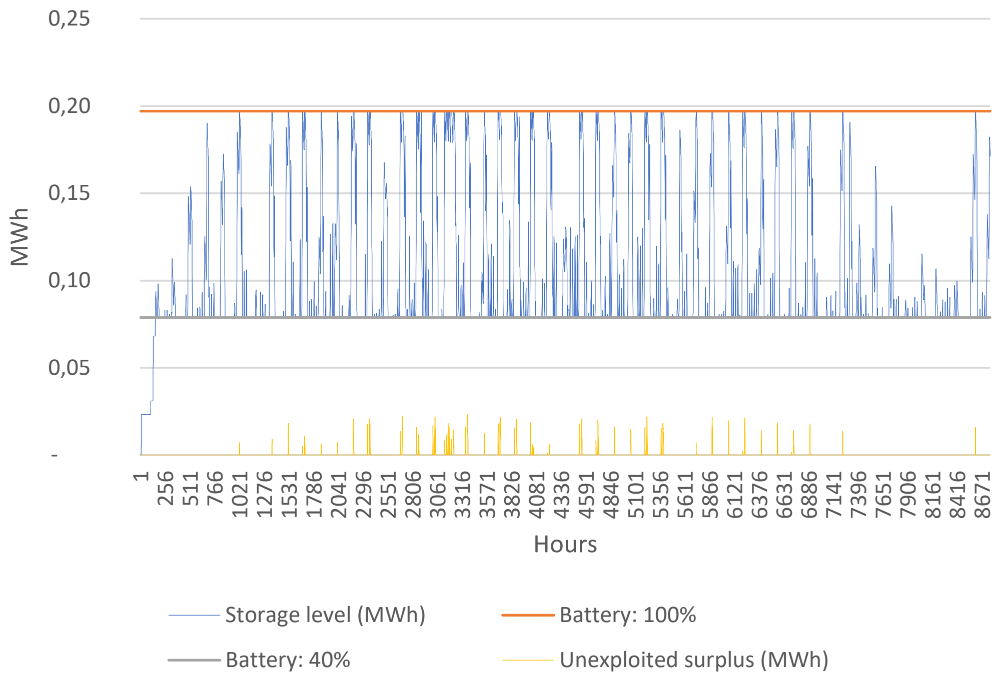

Figure 26: Reference case - Battery storage minimum and maximum capacity, storage level throughout the year and the unexploited surplus electricity

The alternative solution with the CHEST system was tested for different storage capacities. Figure 27 shows the import electricity savings reaching up to 5.1 MWh, given the storage capacities of 8 h-48 h and HP capacities of 3-13 kW_{el} with an ORC/HP-ratio of 25 %. The P2P ratio of the system varied between 46 %-53 %.

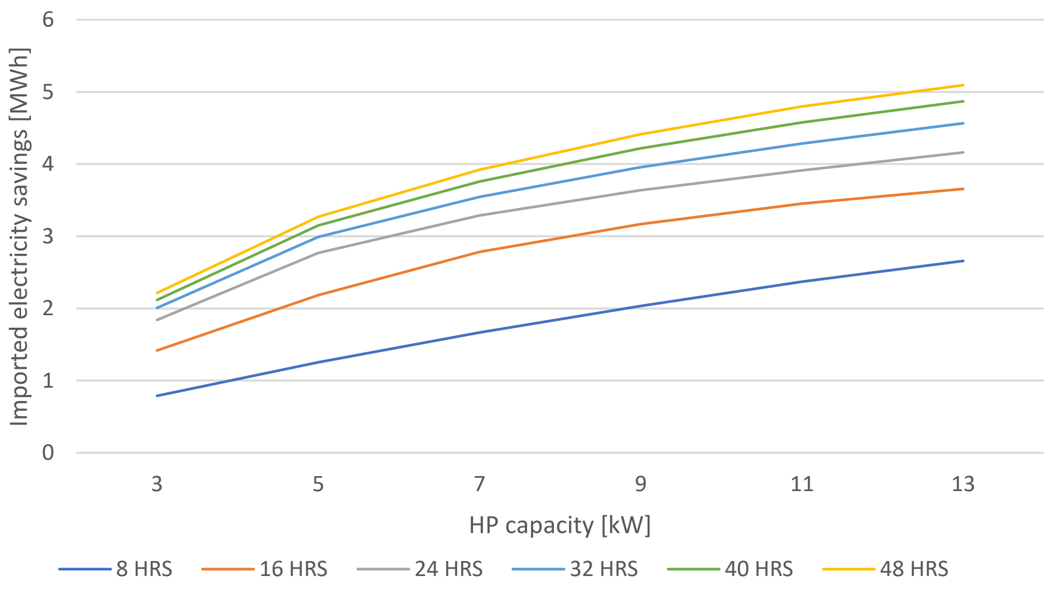

Figure 27: Reduction of the imported electricity as a function of HP capacity and storage capacity

The system was upscaled to maximize the electricity import savings. Due to low P2P ratio of the CHEST system compared with the lead-acid battery, the CHEST system would not be able to compete with the battery storage, because — irrespective of the CHEST size — less electricity will be retrieved. Even larger systems were investigated, in order to maximize the electricity utilization ratio from the Ispaster RES plant. For this purpose, the maximum sizes of HP and the ORC were selected based on the surplus power load in the Ispaster system (23.2 kW) and the maximum hourly electricity deficit (13 kW), respectively. The performance of the CHEST system was simulated with an infinite HT-TES which allowed to store nearly all excess electricity (only ~0.2 MWh unexploited electricity surplus). The upscaled system yielded a P2P ratio of 45 % of the 13 MWh resulting in a reduced import of 5.8 MWh.

Despite a smaller amount of unexploited surplus electricity with the upscaled CHEST system, the reference case with its electric efficiency could reduce more imported electricity than CHEST.

The value of the reduced import electricity was calculated using the 2018 hourly Spanish spot prices including add-ons, see Table 14.

Table 14: Results of the reference case and the upscaled CHEST system

		Reference case	CHEST upscaled
Reduced imported electricity	MWh	6.6	5.8
Imported electricty savings	€/year	881	760
Unexploited electricity	MWh	3.3	0.2
P2P ratio	%	70%	45%

4.2.2. Economy

With no additional revenue (streams from heat, electricity arbitrage or participation in secondary or tertiary markets), the economic case is determined by 1) how much import electricity can be offset and what economic saving this entails and 2) what are the investment costs of the CHEST system compared to the batteries.

1) The simulations demonstrated that the P2P ratio of the CHEST system is lower than the round-trip efficiency of the battery (70 %) both for smaller CHEST systems (~46-53%) and larger CHEST systems (~45%), as shown in Table 14. Therefore, regardless of its size, a CHEST system cannot reduce the electricity import more than a well-dimensioned battery. Applying the Spanish electricity prices including tariffs and taxes from 2018, the value of the reduced import of electricity is 881 €/year and 760 €/year for the batteries and CHEST respectively.

2) Table 15 shows the investment costs for the batteries and for the CHEST system. An estimate of the investment costs for the specific lead-acid batteries is 180 €/kWh, but as presented in deliverable D6.1 a source presents a span of 100-400 €/kWh. The lifetime stated by the producer varies between 5 and 20 years. This yields a large investment span; with annual capital costs between 7.0-88.6 €/kWh. Table 15 summarizes the economic assumptions used for the lead batteries, as well as those used for the CHEST system components.

In the calculation of the battery, the column graph on the far left-hand side in Figure 28 shows the results for an 'average' cost of the investment (10 years lifetime; 180 €/kWh).

Table 15: Investment costs for the reference case and for CHEST

Investment costs	Unit	Value	Source
Interest rate, real	%	3.5	
Battery			
Lifetime	years	5-20	(Victron energy)
Investment costs	€/kWh$_e$	100-400	Deliverable D6.1
Annual capital costs	€/kWh$_e$-year	7.0-88.6	Calculated based on technology lifespan and loan interest rate
CHEST			
Lifetime	years	30	The same lifespan assumed for all CHEST components due to sensitivity of price estimates at this early stage of design.
HP Investment	€/kW$_{th}$	500	Tecnalia
ORC investment	€/kW$_e$	800	Tecnalia
HT-TES investment	€/kWh$_{th}$	90	Tecnalia
Annual capital cost, HP	€/kW$_{th}$-year	27.2	Calculated based on technology lifespan and loan interest rate
Annual capital cost, ORC	€/kW$_e$-year	43.5	As above
Annual capital cost, HT-TES	€/kWh$_{th}$-year	4.9	As above

The economic performance of the CHEST system coupled with the smallest and the largest analyzed HT-TES is presented in Figure 28. As indicated for the 8 hours storage scenario, the small-scale CHEST demonstrated poor operational results in comparison with the reference case (the same trend was proved for the HT-TES rated between 2 and 12 hours).

Comparing the 'profit after investment cost' to the 'total annual investments', it is clear that the investments in both the battery and in the CHEST system play a major role in the overall economy of the system. Given the higher investment costs of the battery, the small-scale CHEST system proved less negative. With negative results in both scenarios, no investments in storage capacity seem to be a viable solution.

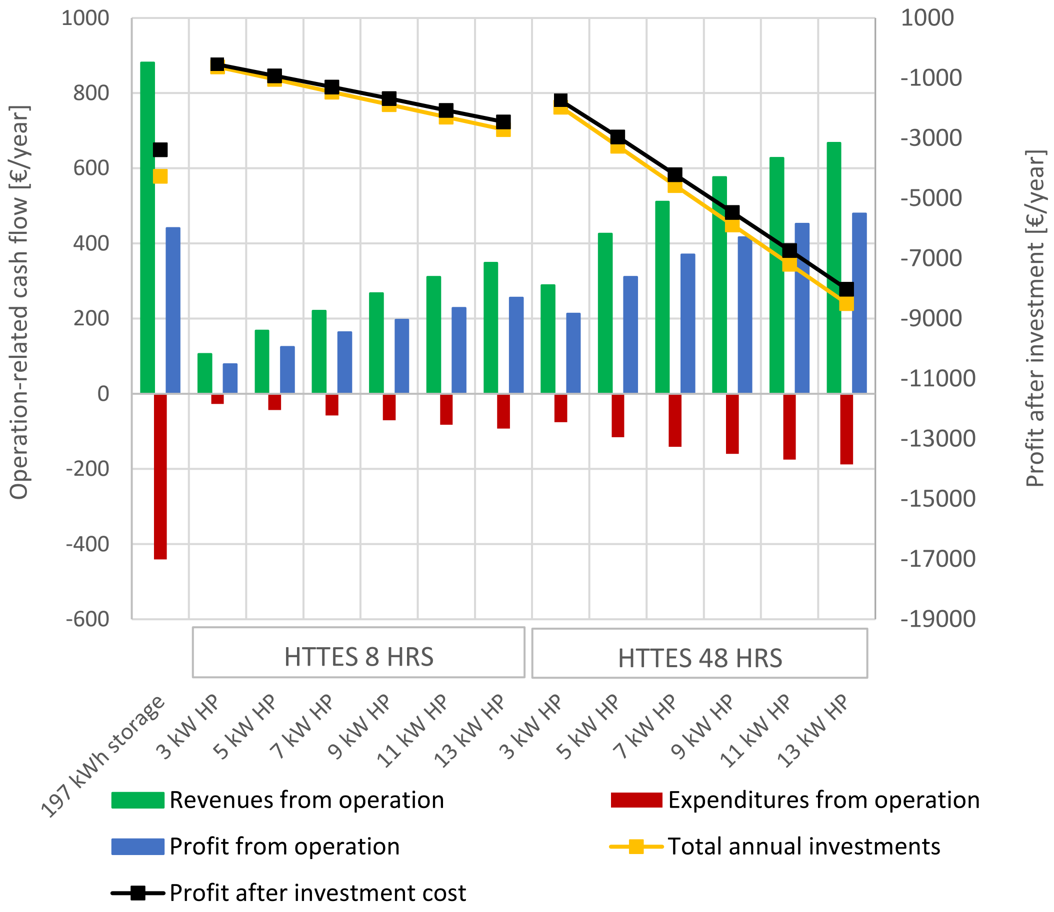

Figure 28: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and the investment cost and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with 2 and 12 hours of HT-TES storage capacity. The battery of 197 kWh$_e$ shown as the 1st from the left.

The CHEST system was also simulated with the capacity of its thermal storage matching the battery's electrical load. The equivalent thermal capacity of the battery can be calculated

$$HT\text{-}TES\ (0.752\ MWh) =$$

$$\frac{Battery\ capacity\ (0.197\ MWh) \cdot Battery\ \text{discharge ratio}\ (60\%) \cdot Battery\ efficiency (70\%)}{ORC\ effieciency\ (11\%)}$$

The corresponding storage time for HT-TES related to the ORC electrical capacity is then:

$$t(h) = \frac{HT\text{-}TES\ (MWh)}{HP\ capacity\ (MWe * COP) \cdot \frac{ORC}{HP} ratio\ (25\%)}$$

As seen in Figure 29 the 'profit from operation' of CHEST reached a similar level with the battery case, but the maximum 760 €/year, consistent with the profit achieved in the upscaled CHEST scenario (refer to Table 14).

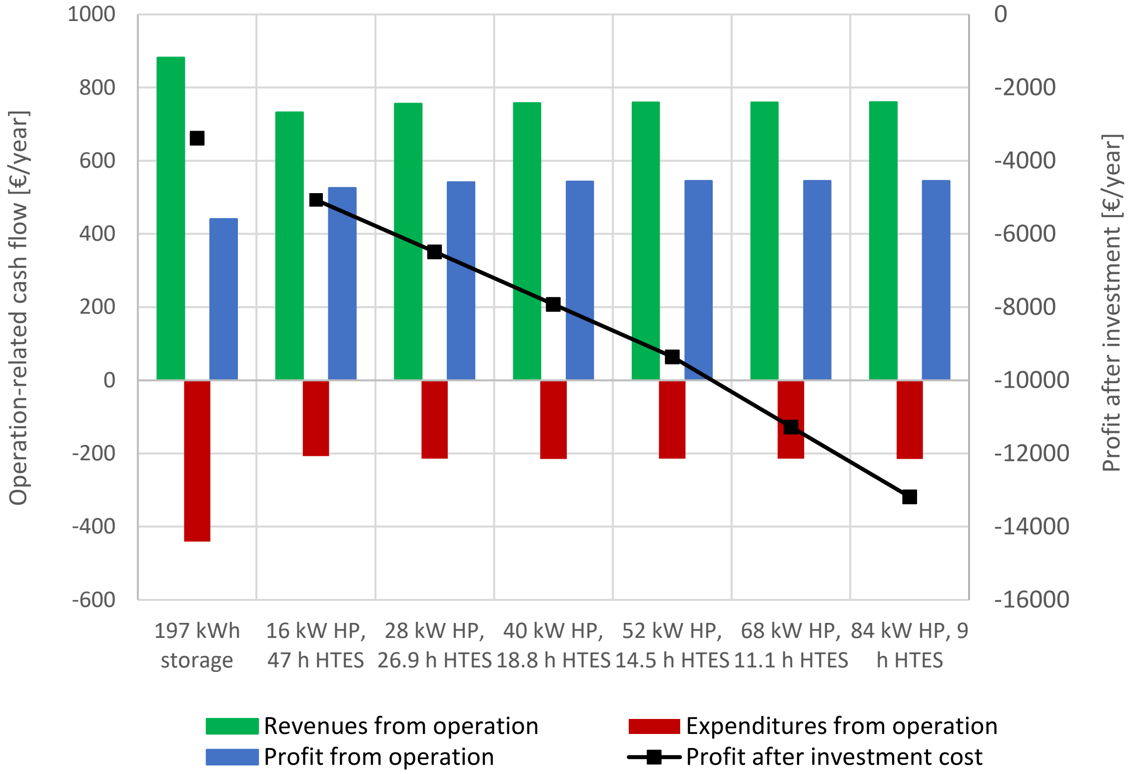

Figure 29: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and the investment cost and profit of the system after the investment cost (right axis) as function of the HP capacity for the case with HT-TES storage capacity of 752.2kWh$_{th}$ corresponding to the electric capacity of the battery of 197 kWh$_{el}$ (shown on the far left).

In both the reference case and the CHEST system, irrespective of the size, the savings from reduced electricity import are negligible compared to the investment costs, hence none of the solutions is perceived as economically feasible.

4.2.3. Sensitivities

As mentioned, the annualized investment cost in lead-acid batteries varies widely depending on the assumed investment cost and lifetime. Therefore, a sensitivity analysis of these parameters on the 'profit after investment costs' was carried out. In Figure 30 the 'profit after investment cost' is shown for lifetimes of 5-20 years of the battery with a constant investment cost of 180 €/kWh. Regardless of the lifetime, the battery never proved to be a positive business case. For a battery lifetime shorter than ~7 years, the CHEST system was more economically viable. However, none of the investigated storage solutions was a viable option.

The effect of a variable investment cost for a constant lifetime of 10 years is shown in Figure 31. In the investigated span, investing in the battery never proved to be a good business case. At a battery cost of ~250 €/kWh, CHEST yielded a higher 'profit after investment cost', despite still being negative.

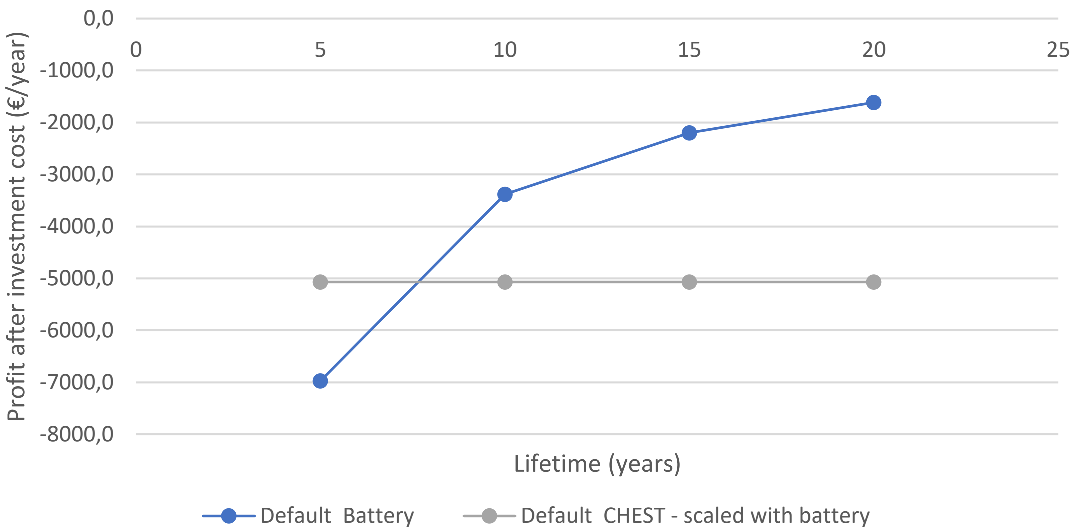

Figure 30: 'Profit after investment cost' for the battery given various lifetimes and CHEST (HP: 16 kW, ORC: 4 kW, HT-TES: 188 hours).

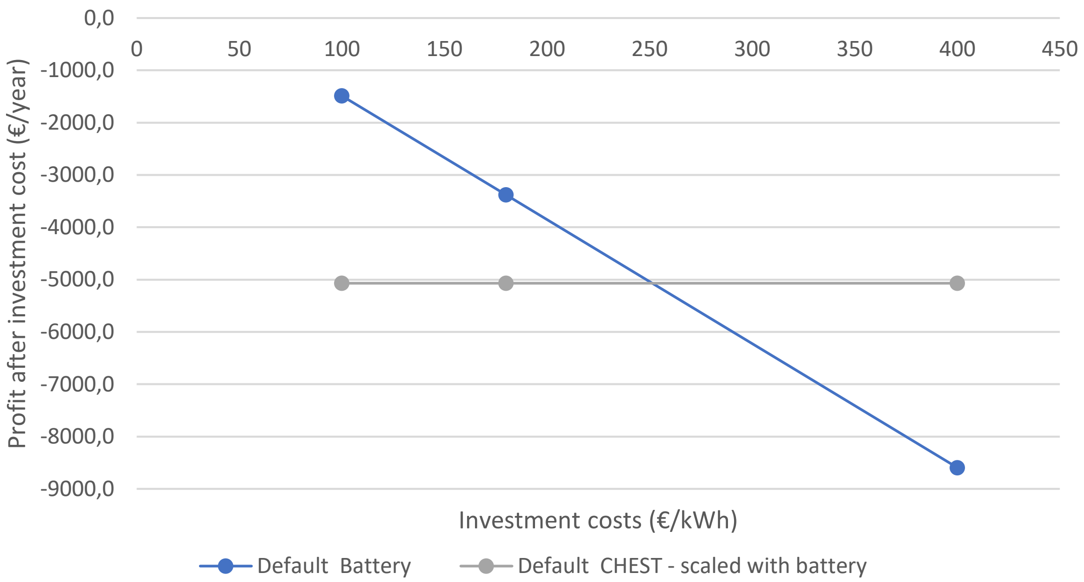

Figure 31: 'Profit after investment cost' for the battery given various investment costs and CHEST (HP: 16 kW, ORC: 4 kW, HT-TES: 188 hours).

4.3. Case study #5: Alpha Ventus

The following paragraphs present the results of the reference case of wind farm in Alpha Ventus system and the case in which the wind production is coupled with a CHEST system. The possibility of buying electricity from the grid is also considered.

In the reference case it is assumed that all possible power produced by the wind farm is sold on the intraday market, without any limitation, such as e.g. grid bottlenecks or curtailment. Hence, the power output delivered from the wind farm to the grid depends only on the wind speed and the power curve of the wind farm.

4.3.1. Unconstrained grid capacity

The simulation of the CHEST system in connection to the Alpha Ventus wind farm was run for different combinations of HP and storage capacity. The implementation of the CHEST system shifts the feed-in of wind electricity into the grid from hours with low electricity price to hours with higher prices.

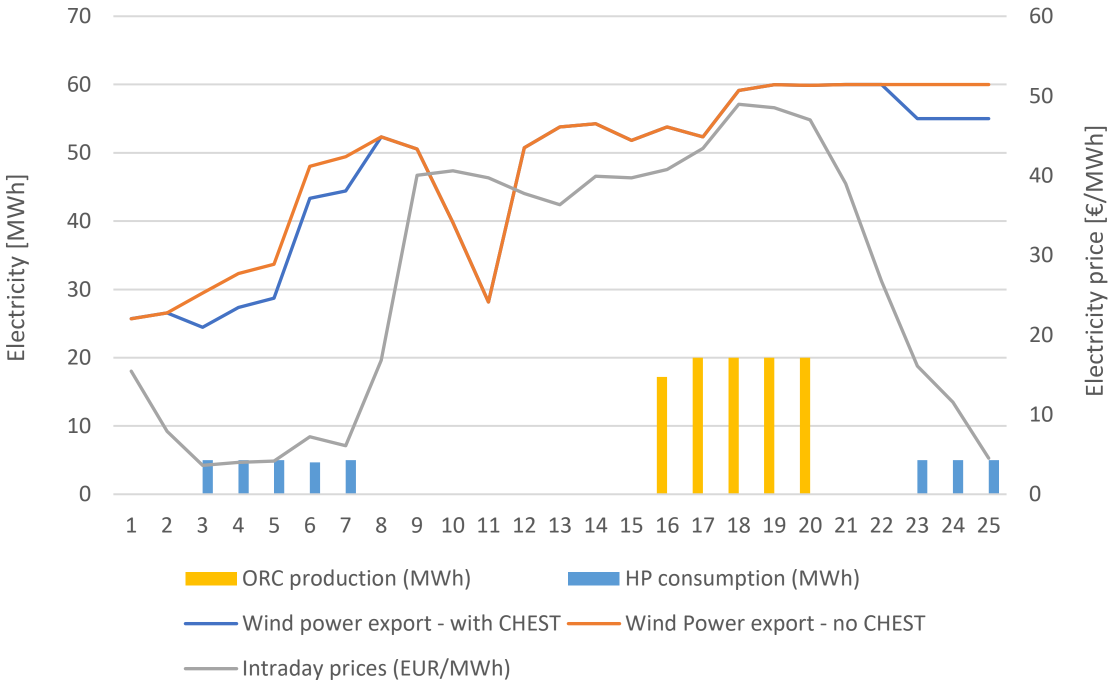

Figure 32: Wind power production with/without CHEST, HP el. consumption, ORC el. production and the corresponding intraday prices for 24 hours

Figure 32 shows the amount of electricity fed into the grid during a period 24 hours, both in the reference case and assuming the presence of a CHEST system having a 5 MW_{el} HP and a 12 hours HT-TES. When the electricity price is low, i.e. in hours 3-7 and 23-25, the HP consumes part of the electricity produced by the wind farm instead of the system directly exporting it. This energy is converted and stored in the HT-TES, and later discharged by the ORC to the grid in hours (16-20) when the electricity prices are higher.

The annual amounts of exported wind power are shown in Table 16 for the reference case and for two CHEST cases (HP: 1 MW_{el} and 20 MW_{el}. HT-TES: 12 hours) with the import option. The wind power direct export and the corresponding earnings are reduced due to the power consumption of the HP. The possibility of optimizing the wind power export according to the intraday prices does increase the volume weighted power sales price from 42.5 €/MWh to 43.9-45.3 €/MWh. The total earnings from electricity sold is increased by ~127,000-718,000 €.

Table 16: Annual sums of power production and sale in the reference case and in CHEST with import

Annual sums		**Reference case**	**1 MW HP - 12 hrs of storage**	**20 MW HP – 12 hrs of storage**
Wind power directly exported	MWh	310,100	306,700	290,600
Wind power sales	M€	13.2	13.1	13.0

ORC power production	MWh	-	2,800	15,900
ORC electricity sales	M€	-	0.2	0.9
Total electricity sales	M€	13.2	13.3	13.9
Volume-weighted wind power price	€/MWh	42.5	42.6	44.8
Volume-weighted ORC power price	€/MWh	-	85.3	54.3
Volume-weighted export power price	€/MWh	42.5	43.0	45.3
Increase in volume weighted wind power price	%	-	0.3 %	6 %
Increase in volume weighted export power price	%	-	1 %	7 %
Increase in total earnings from electricity sales	€	0	127,000	718,000

The reference case with the instantaneous sale of the wind electricity gave a yearly revenue of 13.2 M€ with an optimistic 5,170 full load hours for the 60 MW wind farm with 2018-data for wind speeds and intraday market prices.

The CHEST system was simulated with a HT-TES storage capacity of 12 hours (Figure 33) and with HP-capacities between 1 MW and 20 MW. Within this range, both the profit from the operation and the profit after the investment cost were higher, the smaller the system was. The highest profit after investment costs was 4.4 M€/year for a 1 MW HP. Even though the CHEST system had the possibility of importing electricity from the grid at the market price plus the buy-addon, this possibility was never exploited in the simulations, as it was not competitive compared to using the much less taxed electricity from the wind farm.

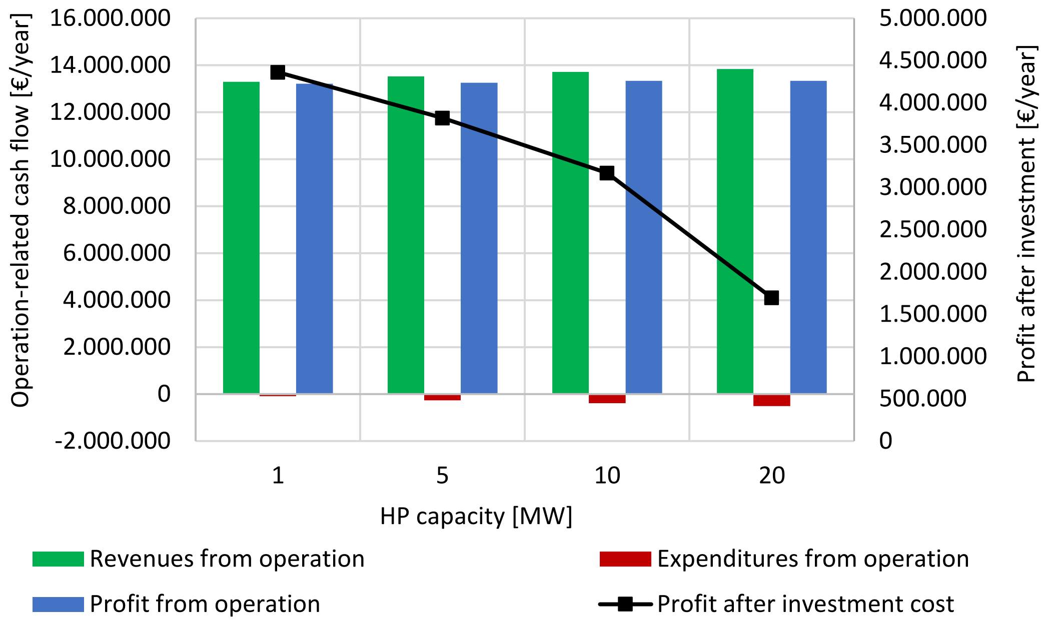

Figure 33: With HT-TES storage capacity of 12 hours: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as a function of the HP capacity with the option of importing electricity.

The applied HT-TES size of 12 hours is related to the ORC capacity, which was 20 MW in all four HP-scenarios. With various sizes of the HP, the HT-TES was exploited to various degrees, as seen in Figure 34. The HTTES was only fully exploited (discharged 100%) for 5 hours with the HP of 1 MW, whereas for 1280 hours with the HP of 20 MW. This indicated, that the HT-TES was oversized for the smaller HPs.

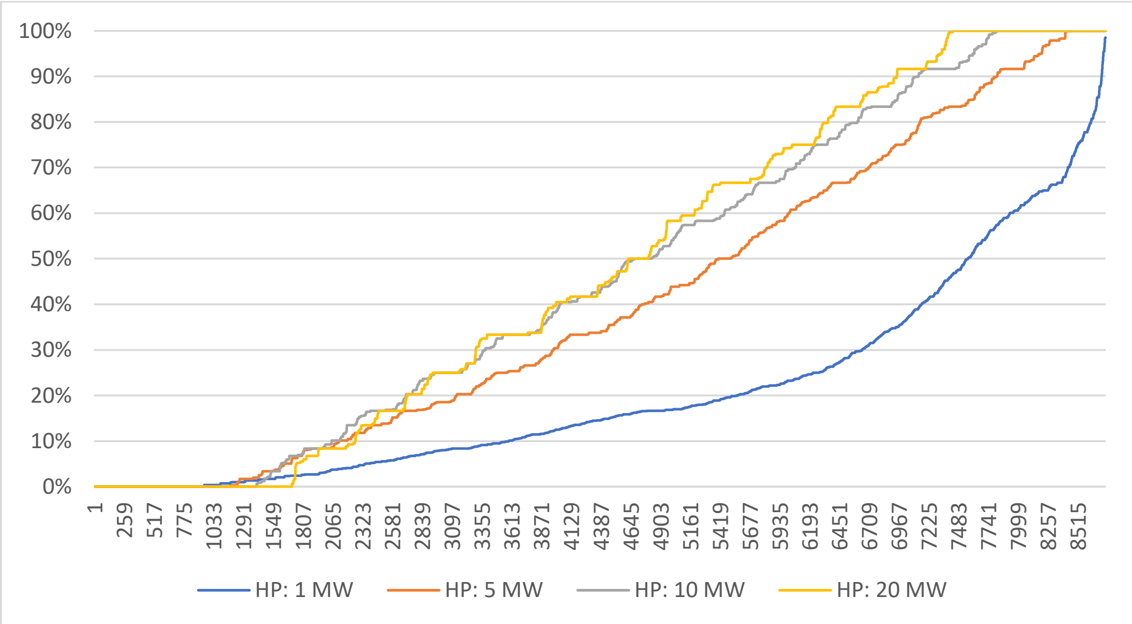

Figure 34: Exploitation of the HTTES capacity for the four HP scenarios (1 MW- 20MW).

Running the simulations with smaller HT-TES (see Figure 35) demonstrated that the revenues from operation were only marginally reduced by the reduced storage capacity. On the other hand, the profit after investment cost was significantly improved by circa 5.1 M€- 5.2 M€ for both HP-sizes, yielding a maximum profit after investment cost of 9.6 M€ for a 1 MW HP.

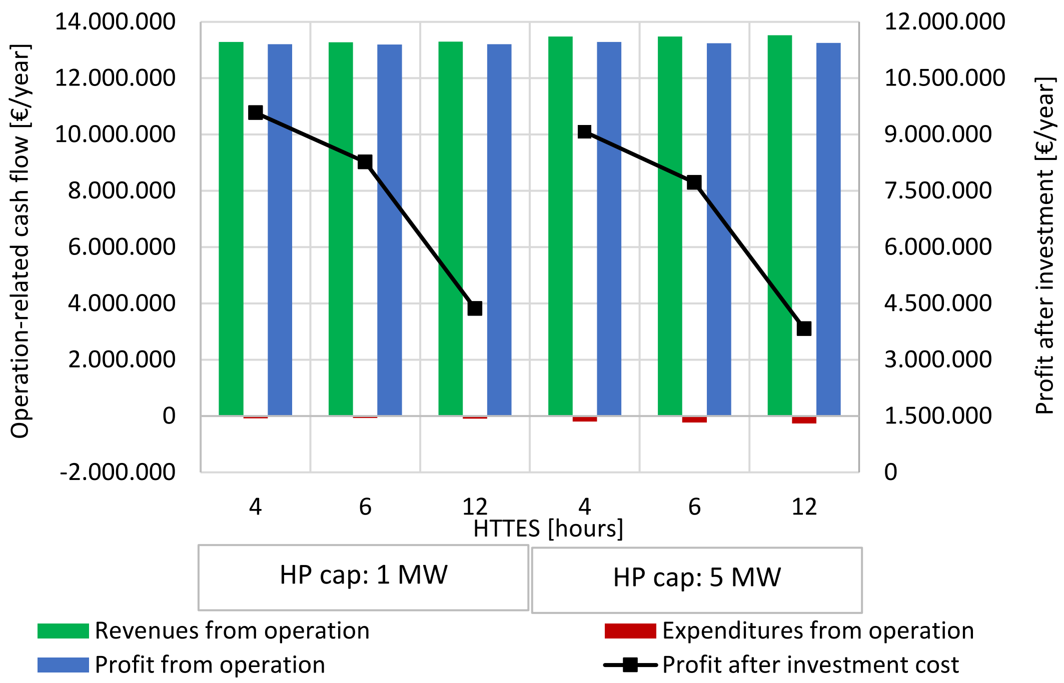

Figure 35: Revenues, expenditures and profit (left axis) coming from the CHEST operation, and profit of the system after the investment cost (right axis) as function of the HP capacity (1 MW or 5 MW) and HT-TES storage capacity (4, 6 and 12 hours).

Data from 2017 were also applied in the simulations. Electricity prices and wind speeds from 2017 only yield lower revenues and hence the results are not shown in the report and the simulations for the constrained grid capacity (Section 4.3.2) were performed with the data for 2018 only.

4.3.2. Constrained grid capacity

This section presents the results of the energyPRO model applied to the Alpha Ventus case study, when a limited transmission capacity of the power grid is assumed.

This scenario was motivated by a situation which has more frequently occurred in Germany in the last years. As explained in more detail in the CHESTER deliverable D6.1, a large share of the electrical demand in Germany occurs in the southern part of the country, while most of the wind power is installed in the northern part. With the increase of the wind power capacity and an unchanged transmission grid, the amount of curtailed wind power has increased in the last years (4.36 %-4.95 % in 2015-16) and the overall costs for congestion management has soared in the last decade peaking at over 1.1 G€ in 2015. At the same time, power loop flows — which occur when, due to insufficient internal transmission capacity, power produced in Germany is diverted through neighboring countries and back into Germany — have become more frequent.

In presence of a constrained grid capacity, a CHEST system could represent a temporary solution for or an alternative to the upgrade of the grid, avoiding at the same time the curtailment of wind power.

Being the maximum power output of the Alpha Ventus wind farm equal to 60 MW, two scenarios of a slightly constrained grid capacity (55 MW and 50 MW, respectively) were simulated for the cases with and without the CHEST system.

In order to match the nominal power output of the 60 MW wind farm, the HP of the CHEST system had a capacity of 5 MW_{el} for the case with a 55 MW grid capacity, and of 10 MW_{el} for the case with a 50 MW grid capacity.

The results are shown in Figure 37. In the reference case, implementing the limitations on grid capacities (55 MW and 50 MW) led to reductions in power production of 4% and 9% respectively, corresponding to an economic loss of 0.5 M€/year and 1.1 M€/year, respectively.

Compared to the three cases without the CHEST system (no grid limitation, 55 MW and 50 MW grid capacity, respectively), the scenarios implementing the CHEST system increased the electricity export by 2%-6% resulting in increased power sales by 0.3-0.9 M€/year, depending on the level of grid limitation. Looking at the amounts of exported electricity, it is seen that, although the CHEST system reduced the amount of curtailed electricity, it was not able to completely avoid it. In fact, despite the sum of the HP capacity and the grid capacity was equal to the maximum power output of the wind farm (60 MW), the HP operation was still constrained by the level of the charge of the HT-TES. When the HT-TES is completely, the HP cannot operate and, if the grid does not have a capacity at least equal to the wind farm power production, the excess power is curtailed.

As seen previously, when considering the investment costs too ('profit after investment cost'), it was seen that the CHEST system was less economically viable than the corresponding systems without CHEST in all three grid capacity scenarios.

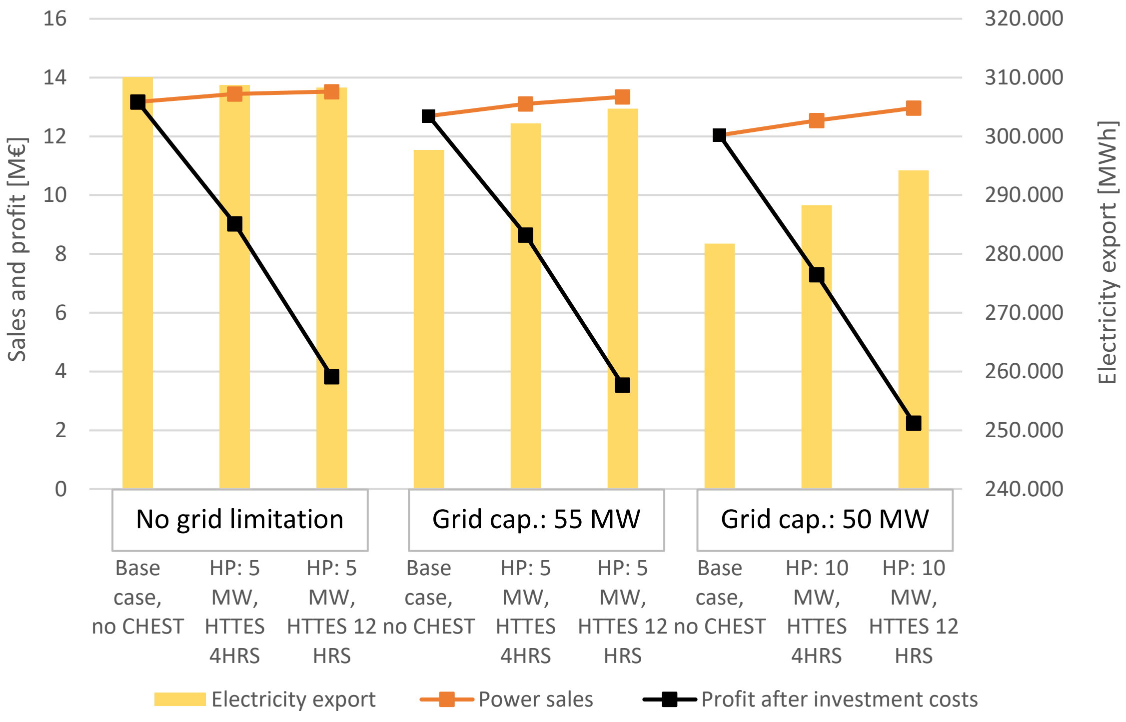

Figure 36: Electricity export (left axis), power sales and profit after investment costs (right axis) in the three scenarios: no grid limitations, grid capacity of 55 MW and 50 MW and for various HP capacities and HTTES capacities.

4.1. Alternative scenario – Hydrogen

The hydrogen solution was compared with the CHEST system based on the best economic business case in the Aalborg case study. This refers to the only profitable scenario which was identified, i.e. that with spot prices reaching the cap price level (3000 €/MWh) 500 hours per year (time series *Spot2018_500h_max*, see Section 3.2.4).

Figure 37 shows the revenues, expenditures and profit from the operation of the hydrogen system, as well as the profit of the system after the investment cost and the fixed operation cost of the hydrogen components.

The technical boundary conditions were the same as those of the comparative CHEST scenario in Aalborg case. Therefore, the capacity of PEM fuel cells was 5 MW, two sizes of electrolyzer were considered (5 MW and 7.5 MW) and the hydrogen storage capacity was varied between 6 hours and 15 hours (corresponding to 30 MWh and 75 MWh). Besides the same electricity market prices, also the same electricity taxes and fees as well as the same heat price were used. For the remaining assumptions, please refer to Section 3.5.

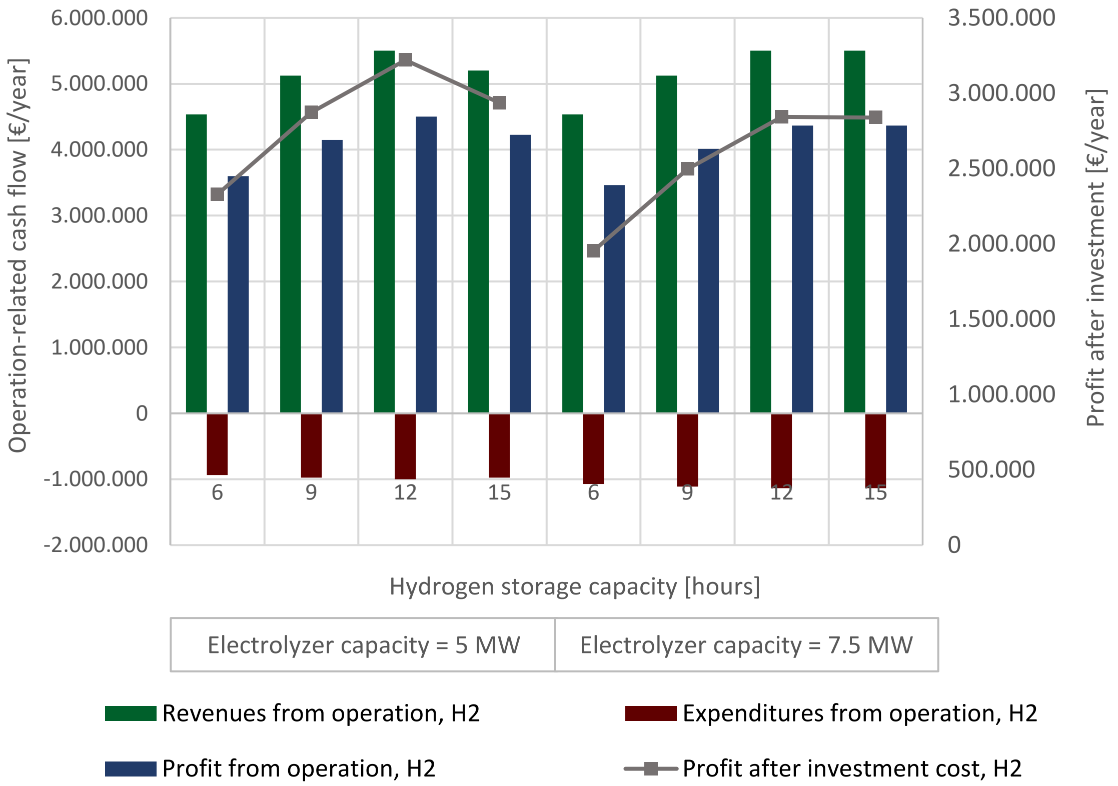

Figure 37: Revenues, expenditures and profit (left axis) from the Hydrogen plant operation, and profit of the system after the investment cost (right axis) as function of the H_2 storage capacity for the case of 5 MW and 7.5 MW Electrolyzer (based on Spot2018_500h_max electricity prices).

In the investigated scenarios, the net profit was positive, as already found in the Aalborg case study implementing the CHEST system. Despite the lower investment cost for hydrogen system, the anticipated revenues are lower by about 20 %-30 %, and the operating expenses up to 3.5 times higher compared to the CHEST scenario.

Therefore, the hydrogen system proved to be less economically viable than the CHEST system by between 15 % and 50 %. The higher cost of the electrolyzer, hydrogen storage and the fuel cells along with the capacity makes the 12 h storage variant the most cost effective, (for the CHEST solution this was achieved for 9 h HT-TES storage). (See Figure 38 for comparison).

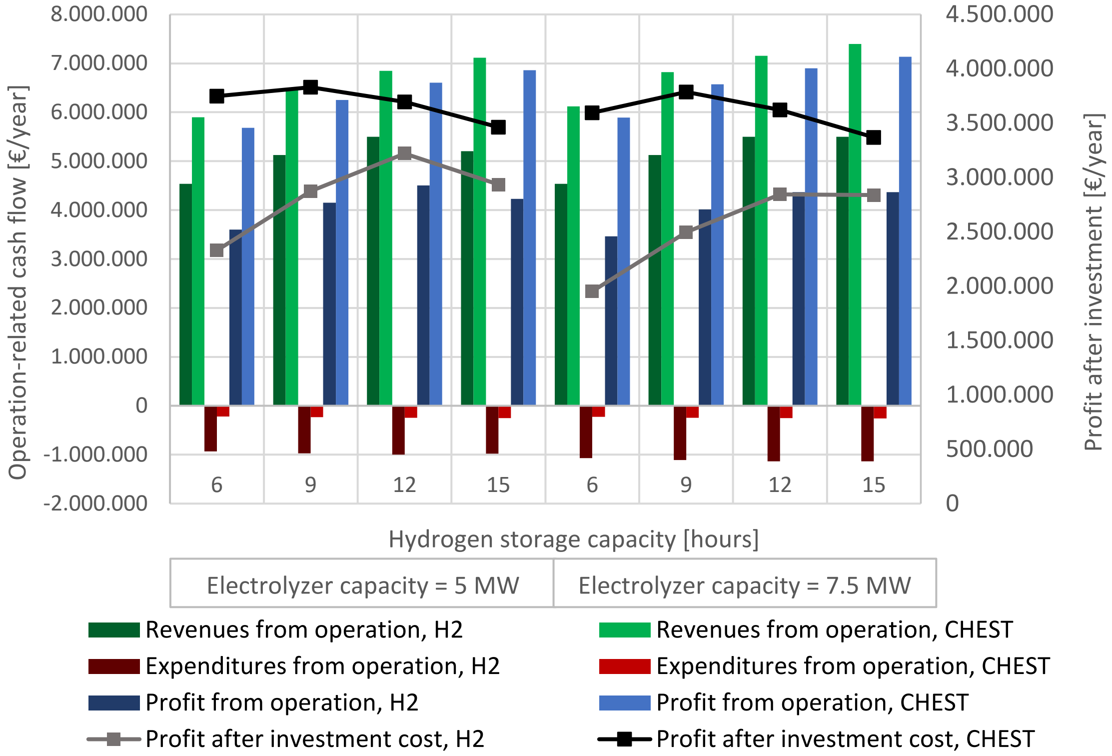

Figure 38: Comparison of the Hydrogen option (darker columns) with the CHEST option (lighter columns). Revenues, expenditures and profit (left axis) from the Hydrogen plant operation, and profit of the system after the investment cost (right axis) as function of the H_2 storage capacity for the case of 5 MW and 7.5 MW Electrolyzer (based on Spot2018_500h_max electricity prices).

5. Conclusions

An analysis about the business perspective of the CHEST system in the energy market has been carried out. Business cases for three selected case studies were analyzed: Aalborg, Ispaster, Alpha Ventus. Finally, for the Aalborg case study, an alternative energy-conversion and storage solution in the form of hydrogen is also analyzed.

The case studies were analyzed in either TRNSYS or energyPRO software. The input data included local electricity and heat prices as well as the capacity requirements of the CHEST technologies (from WP2). A range of scenarios was investigated, including different sizes of the system, energy prices and purposes of the system.

The conclusions of the analyses are given here.

5.1. Case study #2: Aalborg

Different simulations for different sizes of the CHEST system and different boundary conditions were performed. Based on the obtained results, the following conclusions can be drawn:

- In the current spot electricity market in Denmark, the CHEST system is not economically viable when operated in arbitrage. This is due to the relatively low volatility of the electricity prices, the high investment cost of the CHEST system, and the taxes and fees which are paid on the electricity purchased from the grid. For the investigated CHEST sizes, the profit from operation was of the order of 10^4 €/year, while the equivalent annualized capital cost was of the order of 10^6 €/year.
  Similar conclusions are valid for forecast spot electricity prices for 2030 and 2040, despite the higher price volatility.
- When the CHEST system operated on the regulating market as well as on the spot market, the net profit from operation increased by about 10 times, compared to the case where the same system operates only in arbitrage. Despite this increase, the investment cost was still not covered by the yearly operational profit.
- If taxes on consumed electricity were applied only on the actually consumed electricity and not on the absorbed electricity, the net profit from operation increased by about 35 %-46 % compared to the case with regular taxation.
- The scenario, where the spot electricity price reached the upper cap price (3000 €/MWh) for 500 hours during the year, makes the entire CHEST system profitable, after considering the investment costs.
- If the heat absorbed by the evaporator of the HP and that rejected by the condenser of the ORC had the same economic value, the CHEST system would gain a new source of profit because the amount of sold heat was larger than what was bought. However, for the condensing heat from the ORC to be useful, this required a sufficiently high temperature. This entailed a lower electric efficiency of the ORC, which in fact reduced the income from the electricity sale. If the main source of profit of the CHEST system is the electricity market, it is more convenient to prioritize the electricity production, with the ORC condensing to the environment, rather than increasing the condensing temperature to recover useful heat.

5.2. Case study #3: Ispaster

The CHEST system in the Ispaster case was compared to a reference case making use of 197 kWh of lead-acid batteries. The CHEST system was simulated both for small-scale systems (3-13 kW_{el} HP, ORC/HP-ratio 25%, HT-TES of 2-12 h) and large-scale systems (16-84 kW_{el} HP, ORC/HP-ratio 25%, and the HT-TES of 188.1 h-35.8 h, corresponding to ORC capacity). Based on the obtained results, the following conclusions can be drawn:

- Given an electric efficiency of 70 % the battery could reduce the imported electricity by 6.6 MWh. The CHEST system could at the most reduce it by 5.8 MWh, given its lower P2P ratio of around 45 %.
- The annual value of the reduced imported electricity amounted to 881 €/year and 760 €/year for the reference case and the CHEST case, respectively, based on Spanish electricity prices for 2018.
- If considering investment costs, the overall business case resulted in a net loss in investigated scenarios: the reference case had a net loss of 3400 €/year, the small-scale CHEST systems had net losses ranging between 550 and 2450 €/year, and the large-scale CHEST systems had net losses ranging between 5070 and 13200 €/year. In this case it must be considered that no income from exporting electricity to the grid is considered, due to the unfavorable regulations that currently regulate the export of RES electricity produced by small prosumers to the grid in Spain.
- In both the reference case and in the CHEST scenarios, the earnings from reducing the imported electricity were negligible compared to the investments in the storage options.
- The assumptions on the battery investment costs and lifetime had a relevant impact on the overall economic feasibility of the system and determined whether the lead-battery system was more or less expensive than the CHEST system. The CHEST system proved to be a better case with the following combinations of investment cost and lifetime for the batteries: 250 €/kWh and 10 years; or 180 €/kWh and 7 years. Still none of the storage solutions was found to be a positive business case.

5.3. Case study #5: Alpha Ventus

Different simulations for different sizes of the CHEST system were performed and compared to the reference case without any storage option in the Alpha Ventus case study. In this case it is assumed that all the electricity produced by the wind turbines is fed into the grid. The reality may be slightly different, and thus be in favor of CHEST (i.e. in Germany about 4-5 % of the wind electricity was curtailed in 2015-2016. Based on the obtained results, the following conclusions can be drawn:

- Given the electricity prices (intraday market) and wind speeds from 2018, the CHEST system increased the value of the produced wind power by up to 5.6 % in the investigated scenarios.
- The possibility of importing electricity from the grid by CHEST system was never exploited, as it was not economically competitive with respect to using the wind-produced electricity.
- Under the investigated HP capacities (1 MW-20 MW) and storage capacities (4-12 hours), the smaller the CHEST system was, the higher the 'profit after investment', so

suggesting that the most economically viable solution would be to sell the wind-produced electricity directly when produced, if this is technically feasible.

- The Alpha Ventus wind farm yielded an annual profit of about 13 M€ without a CHEST system. Implementing a CHEST system decreased the 'profit after investment cost' – in the best case – to 9.6 M€.
- In case of limitations on the transmission grid, implementing a CHEST system increased the amount of exported electricity by 2 %-6 % and the power sales by 0.3-0.9 M€/year. Considering the profit after investment costs, the implementation of the CHEST system was still not economically viable compared to the case without CHEST.
- It can, hence, be concluded that under the investigated boundary conditions the investments into a CHEST system is not repaid by the increased profit from the operation.

5.4. Alternative scenario – Hydrogen

The economic performance of the CHEST system was compared with the most alike and simultaneously more mature solution, a hydrogen plant. Based on the obtained results, the following conclusions can be drawn:

- Despite the lower investment cost for hydrogen system, the anticipated revenues are 20 %-30 % lower, and the operating expenses up to 3.5 times higher compared to the CHEST case.
- Overall, the business case with the hydrogen plant demonstrates to be economically worse than that utilizing a CHEST system by between 15 % and 50 %.
- The high cost of electrolyzer, hydrogen storage and the fuel cells along with the capacity makes the 12 h storage variant the most cost effective, (for the CHEST solution this was achieved for 9 h HT-TES storage).
- The larger profits due to operation of the CHEST system compared with the hydrogen solution, indicate the potential of CHEST technology as a good business case for the future, changing regulations and electricity markets.

As a general conclusion, it is observed that the current electric market conditions are not very favorable for this type of market actors, i.e. electric energy storage actors. The current regulation is still based on an old way of seeing the electric grid, i.e. with few and dispatchable producers of electricity and many consumers. However, given the increasingly larger share of RES (in good part non-dispatchable) in the electricity production mix, the fluctuation in the electricity production and electricity prices will increase. Currently, most of the regulation of the electricity grid is provided by fossil fuel-fired plants. However, if these are to be phased out, either for stricter environmental regulations or for increased taxation on fossil fuels and/or CO2 emissions, electric storage technology will become essential to still guarantee the cover of the demand, and a more economically favorable framework will need to be posed. Indeed, the new Renewable Energy Directive (Directive (EU) 2019/944) obliges Member States to open their power grids to energy from renewable sources and to even give them priority, and this will definitely contribute to the change.

Additionally, the regulation on electricity storage is likely to change. Electric energy storage is now the in the agenda of policy makers in different countries (see CHESTER deliverable D6.1).

It should also be considered that the presented analysis was carried out assuming preliminary estimates for the investment and operation costs of the CHEST components (HP, HT-TES and ORC). These can be expected to be reduced significantly in the next future, expecting that the technology will become more mature and produced on a large scale. As the economic feasibility of the CHEST system was found to be strongly affected by the investment costs, better business cases are most likely to be found, when these costs have been decreased.

References

AutoSolar (2019). Batería Estacionaria BAE 48V 4090Ah. Retrieved from https://autosolar.es/baterias-estacionarias-opzs-48v/bateria-estacionaria-bae-48v-4090ah.

Bakos, Panagiotis (2016). Life Cycle Cost Analysis (LCCA) for utility-scale Energy Storage systems.

Energinet.dk, (2017A). SYSTEMYDELSER TIL LEVERING I DANMARK UDBUDSBETINGELSER.

Energinet (2018). *Introduktion til systemydelser*. Retrieved from https://energinet.dk/-/media/Energinet/El-RGD/El-CSI/Dokumenter/SY/Introduktion-til-Systemydelser.pdf.

Energinet (2019). Pris på reserver. Retrieved June 24, 2019, from https://energinet.dk/El/Systemydelser/indkob-og-udbud/Pris-paa-reserver.

Forsyningstilsynet (2019). Fjernvarmepriser. Retrieved June 25, 2019, from http://forsyningstilsynet.dk/varme/statistik/prisstatistik/pr-1-januar-2019/.

Energinet, (2017, updated 2019), Danish Energy Agency, Technology Data for Renewable Fuels, chapter 87.

Energinet, (2016, updated 2019) Technology Data for Energy Plants for Electricity and District heating generation, Chapter 12.

Hydrogen Analysis Resource Center: Hydrogen Density (kg/m^3) at Different Temperatures (oC) and Pressures (MPa). Retrieved from https://h2tools.org .

Biomass Energy Data Book, 2011, Lower and Higher Heating Values of Gas, Liquid and Solid Fuels, Section: Appendix A. Retrieved from http://cta.ornl.gov/bedb .

Energy.gov, Electrolyzer, Hydrogen Production: Electrolysis. Retrieved from https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis .

Energy.gov, Fuel cells. Retrieved from https://www.energy.gov/eere/fuelcells/fuel-cells .

Nordling. A., Englund, R., Hembjer, A. & Mannberg, A., (2016). Energy Storage – Electricity storage technologies. Retrieved from https://www.iva.se/globalassets/rapporter/vagval-el/201604-iva-vagvalel-ellagring-rapport-english-e-ny.pdf.

Nordpool (2019). Single hourly order. Retrieved from https://www.nordpoolgroup.com/trading/Day-ahead-trading/Order-types/Hourly-bid/.

Nordpool (2019B). Historical Market Data. Retrieved from https://www.nordpoolgroup.com/historical-market-data/.

Victron energy. OPzS Solar Batteries. Retrieved from https://www.victronenergy.com/upload/documents/Datasheet-OPzS-batteries-EN.pdf.

Battery price. Retrieved from https://autosolar.es/baterias-estacionarias-opzs-48v/bateria-estacionaria-bae-48v-4090ah).

Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

6. Appendices

6.1. Appendix 1

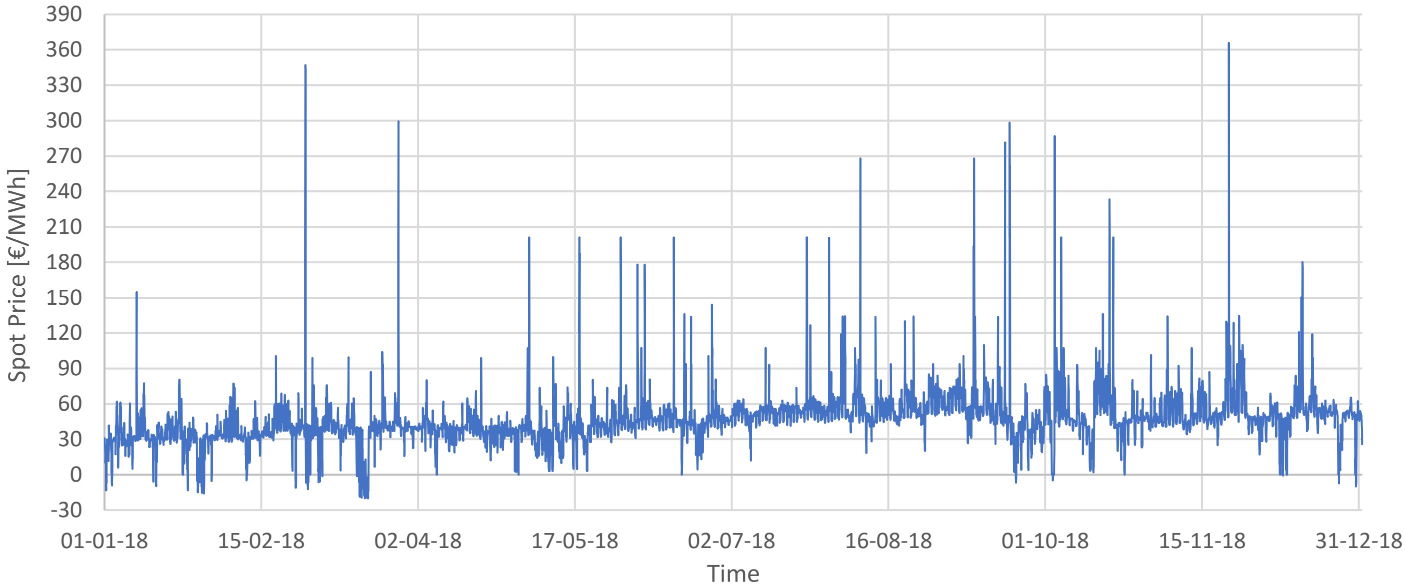

Figure 39: Time series of electricity prices resulting from merging the Spot2018 time series and the up-regulation and down-regulation prices for DK1 in 2018 (see Eq.1 in Section 0).

6.2. Appendix 2

€ to DKK conversion factor =7.46

		øre/kWh	€/MWh	
Buy margin sum	**Source/Tariff type**	**16.1**	**21.53**	**Reference**
Transmission tarif	TSO: Energinet	4.4	5.9	https://energinet.dk/El/Elmarkedet/Tariffer
System tarif	TSO: Energinet	3.6	4.8	https://energinet.dk/El/Elmarkedet/Tariffer
Balancing tarif	TSO: Energinet	0.2	0.2	https://energinet.dk/El/Elmarkedet/Tariffer
Distribution tarif	DSO: Nord Energi A/S /B2-customer >200000 kWh/year	7.5	10.1	http://www.nordenerginet.dk/Priser-og-gebyearer.964.aspx
Electricity tax	Taxation office: SKAT/ Electricity for process	0.4	0.5	https://skat.dk/skat.aspx?oid=2234584
Sell margin sum		**0.4**	**0.52**	
Feed-in tarif ('Indfødningstarif')	TSO: Energinet	0.3	0.4	https://energinet.dk/El/Elmarkedet/Tariffer
Balancing tarif for production	TSO: Energinet	0.1	0.1	https://energinet.dk/El/Elmarkedet/Tariffer