Equilibrium Assessment of Storage Technologies in a Power Market With Capacity Remuneration

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Abstract

A linear complementarity model is developed and presented for two different electricity market designs comprising an energy-only as well as a capacity market. In addition, storage units are implemented, assessing the impact of the market design on these units. Results of a case study for the Northern Europe show that the availability of storage units can have a significant impact on the optimal generation mix to reduce the need for mid-merit and peaking thermal generation capacity. Given a capacity market, the derating of storage technologies creates a bias towards conventional thermal units and has a significant negative impact on the profitability and hence incentive to invest in energy storage units. Furthermore, due to the vastly different cost characteristics and round-cycle efficiencies, it is found that batteries and pumped hydro energy storage complement each other in the power system instead of reducing each other's business opportunities.

Keywords: energy storage; capacity remuneration mechanism; complementarity problem; market design; generation mix

1. Introduction

The ongoing large-scale deployment of renewable energy sources (RES) in the European power system causes challenges to maintaining the continuous balance between supply and demand since renewable energy sources, e.g. wind or solar, will generate electricity according to the availability of the renewable

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source. There is also a challenge to achieve a long-term balance, i.e. sufficient investments so that the available firm generation capacity can cover the maximum demand [1]. These problems can be addressed by, among others, increased generation capacity or energy storage. In contrast to thermal generation capacity, energy storage can capture RES that would otherwise be curtailed when there is an overproduction in the system. However, energy storage have a limited amount of energy that can be discharged before it is depleted.

Energy storage technologies can rely on price arbitrage in the energy market or income from providing ancillary services to recover their investment cost [2]. In addition, capacity remuneration mechanisms (CRMs) are measures to ensure sufficient firm capacity and to attract additional generation capacity compared to an energy-only market. These measures are widely discussed throughout Europe and the rest of the world according to for example [3]. These CRMs can have different designs and the goal is to create incentives for additional capacity in the power system by providing an additional income stream based on capacity.

In this work we seek to assess the economic feasibility of Norwegian hydro power in the form of expansion in pumped-hydro capacity to provide bulk energy storage for the northern Europe. In order to assess the potential role of various energy storage technologies as an alternative or addition to thermal generation capacity, a complementarity model is developed to include energy storage. The model in this paper is based on an early version of the fundamental power market model presented in [4] which does not include a representation of energy storage. The model could also be cast as a regular linear problem. However, using the complementarity model formulation we are able to more easily trace cause and effect when coupling energy storage, thermal generation technologies and demand through energy- and capacity markets. One of the advantages using complementarity modeling is that the optimality conditions for each market participant are developed as separate problems which then are coupled through markets, which provides flexibility when studying various market settings in comparative studies.

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The main contribution in this paper is the comparative analysis of pumped-hydro and distributed batteries as bulk energy storage to assess which role these technologies may fill when the share of renewable energy in the power system increase. We also include an assessment of how a possible capacity market may influence the results. The analysis is performed by utilizing a complementarity model with energy storage [5]. A case study representing the Northern European power system with different storage technologies in an energy only and a possible capacity market (CM) is presented and the influence of various energy storage on the market equilibrium is discussed. Models incorporating both short-term operation and long-term decisions are increasingly important to address the issues facing the power sector as the share of renewable energy resources [6]. Therefore, we do a co-optimization of storage technologies with rather different properties to assess which fundamental characteristics make them cost-effective for short- or long-term storage.

The modeling tool that has been utilized is the General Algebraic Modeling System (GAMS) to solve the linear complementarity problem (LCP) formulated in this paper.

The remainder of this paper is structured as follows. First, we do a literature review with emphasis on economical aspects of energy storage technologies in the power system in section 2. Thereafter, the model we use is formulated in the form of separate Linear Problems (LPs) and reformulated as a LCP in section 3. A schematic of the model described in this paper can be found in Figure 1 with the decision variables and the most important parameters indicated. Section 4 presents the comparative case study of the northern Europe where we assess the business case of batteries and pumped hydro energy storage. Section 5 provides conclusions based on the case study.

2. Research Context

An increasing share of renewable energy is a part of the modern deregulated power system which mean that the continuous balance between supply and de-

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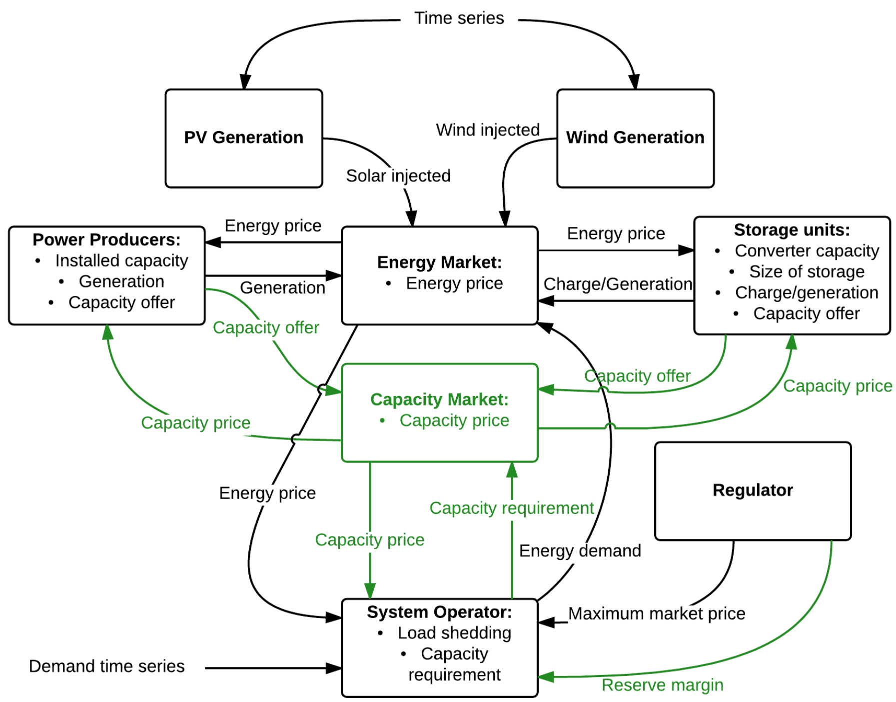

Figure 1: Model schematic

mand is challenged. Energy storage arise as an interesting solution in literature and practical applications to contribute to the balance between supply and demand in the power system. However, such solutions need to be cost-effective for large-scale implementation to be feasible. The literature regarding applications of energy storage in the power systems is vast and range from technical assessments to political issues. In the following we focus on literature concerning how energy storage technologies with different characterizations may be a resource for the power system from an socio-economic point of view.

Utilization of demand-side tools to facilitate the integration of RES is discussed in [7] and [8]. It is suggested to optimize the mix of RES with the goal of achieving fewer problems related to system balance compared to relying on a single RES technology. It is also suggested that flexible demand can mitigate some of the problems introduced by RES. These papers motivates further re-

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search of to which extent the same logic of mixing different technologies also applies to energy storage.

If we are to see investments in adequate capacity by market participants to cover the maximum demand, the investments must be remunerated in one way or another. In general, [9] suggests that the deregulation of the power market requires integration of capacity mechanisms in the market in order to achieve a robust deregulated power market. This view is supported by [10] where the optimal capacities are predetermined and an analysis of the ability of power plants to recover their investment costs was carried out using 2030 scenario data. It was argued that, if no capacity remuneration mechanism is included, recovering the investment cost is only possible in the case of extreme oligopoly, implying the long-term capacity adequacy problem facing the EU due to lack of investment signals from the energy market. Further, capacity remuneration through the allocation of transmission capacity rights is the topic of [11]. A concept called Flow-Based Forward Capacity Mechanism is proposed as a means to remunerate generators in a decentralized market. The capacity remuneration is done through rights in the transmission network and the approach is to design an allocation of rights to the generators that provide peaking power. Next, the allocated rights are used by the generator or traded in a marketplace to provide an income source in addition to the spot market for electricity.

Capacity remuneration mechanisms under different RES scenarios are the subject of [12]. Energy storage is included as a pooling of different technologies in the model, but not included in the CRMs. Further information is required on how the different storage technologies might fill various needs in the power system, and what the impact of inclusion or exclusion of energy storage in a capacity market would be.

Strategic behavior of energy storage in an equilibrium model is the topic of [13]. It is found that price arbitrage by storage units can be a benefit for the power system. However, it does not include fixed cost recovery or investment decisions to assess if the investments in such capacity would be cost-effective. Further, [14] address the operation of energy storage to maximize both the

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social welfare and income from price arbitrage. Peak prices are reduced while the lowest prices are increased resulting in a net social welfare gain even though some energy is wasted in the round-cycle losses of the energy storage. However, the investments in energy storage are given as a model input so an assessment of the economics regarding recovery of investment costs is not provided.

The choice of which energy storage technologies should be implemented is a complex topic. A comparison of short and long-term energy storage technologies is found in [15]. It is argued that coupled renewable and energy storage systems will be economical in the future due to a further drop in prices. A point is made that we will need more than a single storage technology to address both long- and short-term power issues. However, an assessment of such benefit from implementing several energy storage technologies is left for further work.

Adding to the argument that we need more than a single energy storage technology is [16], which argue that different technologies have a comparative advantage in only one or a few dimensions, such as storage size, cost per unit of power or efficiency. For example, it is argued that batteries should be deployed at the distribution system level to, among others, reduce the need for grid reinforcement. The case of building interconnectors to Norway is also made since these can provide access to site dependent hydro power. While the factors affecting the profitability of various energy storage are laid out, a suggestion of the optimal mix of energy storage technologies to be deployed is not provided.

A cost analysis based on available literature of energy storage technologies is provided in [17] in which energy storage technologies are divided into three types of application: Bulk energy storage, grid support and frequency regulation. It is argued that both pumped hydro energy storage and batteries fit into the first category. However, the analysis focus on short term applications up to 8 hours and do not consider the issue of seasonal vs. short term storage.

Based on the available literature we argue that there is a need for assessments regarding to which extent different energy storage technologies compete or complement each other when the objective is bulk energy storage in the short and long term. The research presented in the following is also motivated by the

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argued economic feasibility of Norwegian pumped hydro and batteries according to [18] and [19], respectively. To contribute to the base of available literature the analyses presented in the following sections will provide further insights to energy storage applications under various conditions by considering energy storage investments determined by profitability in an equilibrium model of the power system. Energy storage in the form of pumped hydro and batteries are compared to explore how size, storage horizon, costs and round-cycle efficiencies affect investment decisions and operation of the storage units as well as the market outcome for the rest of the stakeholders such as thermal generators.

3. Model Formulation

In this section, the optimization problems for each of the power market stakeholders are formulated as LP problems and reformulated as LCP conditions. Each market stakeholder represent one technology and is the aggregation of all firms employing it. The Lagrangian of the problem incorporates restrictions into the objective function as penalty functions by the use of Lagrangian multipliers [20, p.455]. Kuhn-Tucker conditions are applied to the Lagrangian formulation in order to obtain the optimality conditions [20, p. 145] [21, p.34]. The final model formulation comprises the Kuhn-Tucker conditions formulated as LCP optimality conditions [22]. For further details, see also [5].

The market participants are coupled through the energy and capacity markets according to Figure 1 by combining all LCP conditions. The CM in this model is a volume-based mechanism that provide a new revenue stream to the suppliers of capacity. The aim is to trigger capacity investments, avoiding under-investments leading to lack of generation capacity[23]. Reserve markets are not included in the formulation.

3.1. Nomenclature

In the mathematical description of the model, the following symbols are used:

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3.1.1. Sets

- f $\in$ F: Set of thermal power producers
- h $\in$ H: Set of time steps
- s $\in$ S: Set of storage units

3.1.2. Variables

- cap_f^{inst} [MW]: Producer capacity
- cap_s^{inst} [MW]: Storage capacity
- cap_f^{cm} [MW]: Offered producer capacity to CM
- cap_s^{cm} [MW]: Offered storage capacity to CM
- $\mathrm{charge}_{s,h}$ [MWh/h]: Charging of storage
- cap^{req} [MW]: Capacity required from CM
- en_s^{inst} [MWh]: Storage size
- $\mathrm{en}_{s,h}^{stored}$ [MWh]: Stored energy at the end of time step
- $\mathrm{gen}_{f,h}$ [MWh/h]: Thermal output
- $\mathrm{gen}_{s,h}$ [MWh/h]: Storage output
- ls_h [MWh/h]: Load shedding
- π_f [EUR]: Thermal profit
- π_s [EUR]: Storage profit
- β [EUR/MW]: Capacity reserve margin marginal cost
- γ [EUR/MW]: Capacity price in volume-based CRM
- $\iota_{s,h}$ [EUR/MWh]: Scarcity rent for storage size
- λ_h [EUR/MWh]: Energy price in the energy market

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- $\mu_{f,h}$ [EUR/MWh]: Scarcity rent of producer capacity
- $\mu_{s,h}$ [EUR/MWh]: Scarcity rent of storage capacity
- θ_f [EUR/MW]: CM scarcity rent for producer capacity
- θ_s [EUR/MW]: CM scarcity rent for capacity for storage
- $\zeta_{s,h}$ [EUR/MWh]: Value of stored energy

3.1.3. Parameters

- CF_s [%]: Rating of storage units in CRM
- DEM_h, DEM^{MAX} [MWh/h]: Demand data
- FC_f [EUR/MW]: Annual fixed cost, power producers
- FC_s^{cap} [EUR/MW]: Annual fixed cost, storage capacity
- FC_s^{en} [EUR/MWh]: Annual fixed cost, storage size
- INJ_h^{wind} [MWh/h]: Wind energy injected
- INJ_h^{solar} [MWh/h]: Solar energy injected
- L_s [%/h]: Self discharge
- P^{MAX} [EUR/MWh]: Maximum market price
- RS^{cap} [%]: Reliability standard: Capacity margin
- SL_s [%]: Storage converter efficiency
- T [h]: Length of time step
- VC_f [EUR/MWh]: Power producer variable costs

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3.2. Power Producers

The optimization problem for power producers is presented in equations (1) and (2). In case of a CM, the capacity remuneration term, $\gamma * cap_f^{cm}$ enters the objective function as a new revenue stream to the power producers. Equation (3) limits the producer from offering more capacity than the installed amount. Capacity offered to the capacity market do not incur any limitations to the power producer regarding plant operation. Hence, if the capacity price is above zero, the producers will offer all the installed capacity to the capacity market.

$\forall f$: Maximize:

$$\pi_f = \sum_{h=1}^{H} (\lambda_h - VC_f) * T * gen_{f,h} - FC_f * cap_f^{inst} + \gamma * cap_f^{cm} \quad (1)$$

$$\forall f, \forall h : cap_f^{inst} \geq gen_{f,h} \quad (2)$$

$$\forall f : cap_f^{inst} \geq cap_f^{cm} \quad (3)$$

The LCP conditions from the producer problem are formulated in equations (4) to (8).

$$\forall f, \forall h : -\lambda_h * T + VC_f * T + \mu_{f,h} \geq 0 \perp gen_{f,h} \geq 0 \quad (4)$$

$$\forall f : FC_f - \sum_{h=1}^{H} \mu_{f,h} - \theta_f \geq 0 \perp cap_f^{inst} \geq 0 \quad (5)$$

$$\forall f, \forall h : cap_f^{inst} - gen_{f,h} \geq 0 \perp \mu_{f,h} \geq 0 \quad (6)$$

$$\forall f : -\gamma + \theta_f \geq 0 \perp cap_f^{cm} \geq 0 \quad (7)$$

$$\forall f : cap_f^{inst} - cap_f^{cm} \geq 0 \perp \theta_f \geq 0 \quad (8)$$

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Due to a perfect market assumption so far[1], power producers are assumed to be price takers. Hence, the power price, λ, as well as the capacity price, γ, are treated as parameters in the derivation of the optimality conditions. The same applies to other market participants as the market prices is determined by the market clearing in the energy and capacity markets.

3.3. Storage Units

The storage units are characterized by installed converter (charge/generation) capacity (in MW), storage size (in MWh), and losses. Equations (9) to (14) represent the LP for energy storage. The storage units determine operation each time step in addition to the installed capacity, limiting the amount of power that can be charged or generated, and storage size, which limits the amount of energy that can be stored. Storage units can participate in the capacity market by including equation (14) and the term $\gamma * cap_s^{cm} * CF_s$ in the objective function. CF_s can take any value between 1 and 0, which describes a possible derating of the technology, due to the limited energy content compared to thermal generation units. The amount of stored energy is characterized by a round coupling and has no fixed starting value.

$$\begin{aligned}\forall s : \text{Maximize: } \pi_s = &\sum_{h=1}^{H} (gen_{s,h} - charge_{s,h}) * T * \lambda_h \\ &- FC_s^{cap} * cap_s^{inst} - FC_s^{en} * en_s^{inst} + \gamma * cap_s^{cm} * CF_s \end{aligned} \quad (9)$$

$$\forall s, h = 1 : en_{s,H}^{stored} * L_s + charge_{s,1} * SL_s * T - gen_{s,1} * T - en_{s,1}^{stored} \geq 0 \quad (10)$$

$$\forall s, \forall h > 1 : en_{s,h-1}^{stored} * L_s + charge_{s,h} * SL_s * T - gen_{s,h} * T - en_{s,h}^{stored} \geq 0 \quad (11)$$

[1] An additional reason to develop a LCP is the possibility to represent market power or strategic behavior at a later stage.

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$$\forall s, \forall h : en_s^{inst} \geq en_{s,h}^{stored} \tag{12}$$

$$\forall s, \forall h : cap_s^{inst} \geq gen_{s,h} + charge_{s,h} \tag{13}$$

$$\forall s : cap_s^{inst} \geq cap_s^{cm} \tag{14}$$

The derived LCP optimality conditions for the storage units are formulated in equations (15) to (26).

$$\forall s, \forall h : -\lambda_h * T + \zeta_{s,h} * T + \mu_{s,h} \geq 0 \perp gen_{s,h} \geq 0 \tag{15}$$

$$\forall s, \forall h : \lambda_h * T - \zeta_{s,h} * SL_s * T + \mu_{s,h} \geq 0 \perp charge_{s,h} \geq 0 \tag{16}$$

$$\forall s : FC_s^{cap} - \sum_{h=1}^{H} \mu_{s,h} - \theta_s \geq 0 \perp cap_s^{inst} \geq 0 \tag{17}$$

$$\forall s : FC_s^{en} - \sum_{h=1}^{H} \iota_{s,h} \geq 0 \perp en_s^{inst} \geq 0 \tag{18}$$

$$\forall s, \forall h < H : -\zeta_{s,h+1} * L_s + \zeta_{s,h} + \iota_{s,h} \geq 0 \perp en_{s,h}^{stored} \geq 0 \tag{19}$$

$$\forall s, h = H : -\zeta_{s,1} * L_s + \zeta_{s,H} + \iota_{s,H} \geq 0 \perp en_{s,H}^{stored} \geq 0 \tag{20}$$

$$\begin{aligned}\forall s, h = 1 : en_{s,H}^{stored} * L_s + charge_{s,1} * SL_s * T \\ - gen_{s,1} * T - en_{s,1}^{stored} \geq 0 \perp \zeta_{s,1} \geq 0\end{aligned} \tag{21}$$

$$\begin{aligned}\forall s, \forall h > 1 : en_{s,h-1}^{stored} * L_s + charge_{s,h} * SL_s * T \\ - gen_{s,h} * T - en_{s,h}^{stored} \geq 0 \perp \zeta_{s,h} \geq 0\end{aligned} \tag{22}$$

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$$\forall s, \forall h > 1 : en_s^{inst} - en_{s,h}^{stored} \geq 0 \perp \iota_{s,h} \geq 0 \tag{23}$$

$$\forall s, \forall h : cap_s^{inst} - gen_{s,h} - charge_{s,h} \geq 0 \perp \mu_{s,h} \geq 0 \tag{24}$$

$$\forall s : -\gamma * CF_s + \theta_s \geq 0 \perp cap_s^{cm} \geq 0 \tag{25}$$

$$\forall s : cap_s^{inst} - cap_s^{cm} \geq 0 \perp \theta_s \geq 0 \tag{26}$$

The dual value $\zeta_{s,h}$ represents the marginal value of the stored energy during time step h. In case of the pumped hydro energy storage this is analogous to the so-called water value[24].

3.4. System Operator and Demand Side

Within the developed model, a system operator (SO) operating on behalf of the consumers represents the demand side. Consumers are characterized by a given demand, whereas the system operator requires a certain generation capacity in case of a CM. This requirement is imposed as a restriction from the regulator, but paid by the demand side. The energy demand is defined by a time-series and the possibility of involuntary load shedding at a defined market price cap, P^{MAX}.

The objective of the SO is to maximize consumer surplus (CS) [25, p. 314] as described by the objective function in equation (27).

$$\text{Maximize: CS} = \sum_{h=1}^{H} ((P^{MAX} - \lambda_h) * (DEM_h - ls_h)) * T - \gamma * cap^{req} \tag{27}$$

$$cap^{req} - RS^{cap} * DEM^{MAX} \geq 0 \tag{28}$$

The restriction in equation (28) and the term $\gamma * cap^{req}$ in the objective function are related to the capacity market. The restriction implies how much

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capacity should be required from the market whereas the cost of maintaining the capacity margin is subtracted from the objective function.

The LCP conditions based on equations (27) and (28) are formulated in equations (29) to (31).

$$\forall h : -\lambda_h * T + P^{MAX} * T \geq 0 \perp ls_h \geq 0 \tag{29}$$

$$\gamma - \beta \geq 0 \perp cap^{req} \geq 0 \tag{30}$$

$$cap^{req} - RS^{cap} * DEM^{MAX} \geq 0 \perp \beta \geq 0 \tag{31}$$

3.5. Energy Market

The LCP conditions for power producers, storage providers and the SO is coupled through markets, including energy and capacity. The energy only market (EO) balances the energy in the system for each time step of the operating period as shown in equation (32). The generation from power plants and storage added to the injected solar and wind production must at least be equal to the demand subtracted load curtailment. The energy balance is formulated as a >= restriction to account for situations with excess production due to the RES injection. If production is higher than the demand, RES curtailment will occur in reality.

$$\forall h : \sum_{f=1}^{F} gen_{f,h} + \sum_{s=1}^{S} (gen_{s,h} - charge_{s,h}) + INJ_h^{solar} + INJ_h^{wind} \geq DEM_h - ls_h \tag{32}$$

The energy price is calculated by applying the complementarity slackness theorem [20, p. 145] on equation (32) with λ as the dual variable as stated in equation (33).

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$$\forall h : \sum_{f=1}^{F} gen_{f,h} + \sum_{s=1}^{S}(gen_{s,h} - charge_{s,h})$$
$$+ INJ_h^{solar} + INJ_h^{wind} - DEM_h + ls_h \geq 0 \perp \lambda_h \geq 0 \quad (33)$$

3.6. Capacity Market

The modeled capacity mechanism is a volume-based capacity market similar to a simplified version of the auction in the Great Britain [26], [27]. The CM clearing condition can be found in equation (34) which states that the amount of generation capacity provided by conventional producers and storage units should be at least the capacity required by the system operator. The CM clearing will determine the lowest possible capacity price that will fulfill the balance. The capacity offered from storage units can be derated by applying a CF lower than one due to their energy limitations. RES capacity is not included in the CM.

$$\sum_{f=1}^{F} cap_f^{cm} + \sum_{s=1}^{S} cap_s^{cm} * CF_s - cap^{req} \geq 0 \quad (34)$$

Again, according to the complementarity slackness theorem [20, p. 145] the optimality condition of equation (34) is formulated in equation (35) with the capacity price, γ, as the dual variable.

$$\sum_{f=1}^{F} cap_f^{cm} + \sum_{s=1}^{S} cap_s^{cm} * CF_s - cap^{req} \geq 0 \perp \gamma \geq 0 \quad (35)$$

3.7. RES Generation

Generation from RES is represented by a time series of input data. The energy that is generated by wind and solar each period is a parameter and will not be affected by the rest of the model. The properties of different RES technologies and level of RES is not the scope of this paper.

If the RES production in the system exceed demand, there will be an over-production. The assumption is that excess production is automatically curtailed as described in the energy balance in section 3.5.

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3.8. Regulator

The regulator controls the requirements for the SO. In the case of a capacity market the regulator requires a minimum percentage of the maximum demand, RS^{cap}, from the capacity market.

4. Case Study

The presented model is applied in a case study. The following underlying assumptions are made:

- The case study covers Belgium, France, Germany, and the Netherlands without any transmission constraints.
- Potential PHES is provided from Norway through a limited HVDC connection.
- Perfect market with no strategic players.
- The demand is firm and only affected by involuntary load curtailment.
- The scenario is deterministic.
- Power producers have a cost structure characterized by fixed and variable costs.
- Storage units have a cost structure characterized by fixed costs and losses.
- No ramping rate restrictions.
- RES production is characterized by a time series of injected power.

A case study on the given model is performed to assess the role of energy storage in the power system. Two different market designs are analyzed: EO and CM with a 100% capacity requirement. For each of the two market configurations, four different storage possibilities are analyzed, resulting into eight cases:

1. EO with no energy storage

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2. CM with no energy storage
3. EO with Norwegian PHES
4. CM with Norwegian PHES
5. EO with lead-acid batteries
6. CM with lead-acid batteries
7. EO with both storage technologies
8. CM with both storage technologies

Data for a full year were used to obtain robust results when comparing the short-term properties of batteries with seasonal operation of Norwegian pumped hydro energy storage (PHES). This poses a challenge concerning problem size. The operation pattern of batteries require a detailed resolution to capture short-term variations in prices whereas PHES requires a long time horizon to capture the seasonal variations. The analyses were performed with a 2-hour resolution. Computing time ranged from 5 minutes for the cases with no energy storage to approximately 4 hours for the cases with both storage technologies.

4.1. Input Data

4.1.1. Producers and storage

Input data for storage units and conventional power producers are presented in Tables 1 and 2. The calculations of annual fixed costs are based on a interest rate of 5% for all technologies. PHES is based on existing reservoir capacity in Norwegian hydropower and fixed cost for pumping and generation expansion including the HVDC interconnections to continental Europe. For the battery, cost parameters for lead-acid were chosen after performing initial analyses with lithium-ion battery data [28] which resulted in zero installed capacity due to high costs. In order to compare energy storage technologies with season-shifting properties (PHES) to a technology relying on short-term arbitrage, the lead-acid batteries provide a reference for assessing how the characteristics influence how the technologies operate in the market.

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Table 1: Technology characteristics for storage units [5] [18] [28]

	PHES	Battery
Fixed costs [EUR/MW]	114 098	25 901
Fixed costs [EUR/MWh]	0	6 475
Converter efficiency [%]	80	92
Self discharge [%/MWh]	0	0
Maximum Capacity [TWh]	15	-
Technology life [years]	30	10

Table 2: Technology characteristics for power producers [5] [29]

	Nuclear	Hard coal	CCGT	OCGT
Fixed costs [EUR/MW]	280 000	72 000	41 000	16 000
Variable costs [EUR/MWh]	3	35	48	150
Technology life [years]	40	40	40	40

4.1.2. Injected wind and solar power

The renewable energy injected into the system is a time series of hourly production injected into the system. Fixed costs for RES is problematic to predict. Hence, fixed levels of RES is chosen in the case study. The base data from the COSMO weather model gathered from [29] is scaled according to the ten-year network development plan by ENTSO-E [30]. Ignoring network restrictions, Belgium, France, Germany, and the Netherlands are modeled as one area. Based on Vision 4 the total RES share is 41.5% of total energy demand (30.5% wind and 11.0% solar) [30].

4.1.3. Demand

The source for demand data is the time-series data from ENTSO-E Vision 4 [30]. The data for Belgium, France, Germany, and the Netherlands are aggregated to represent the total demand for this area.

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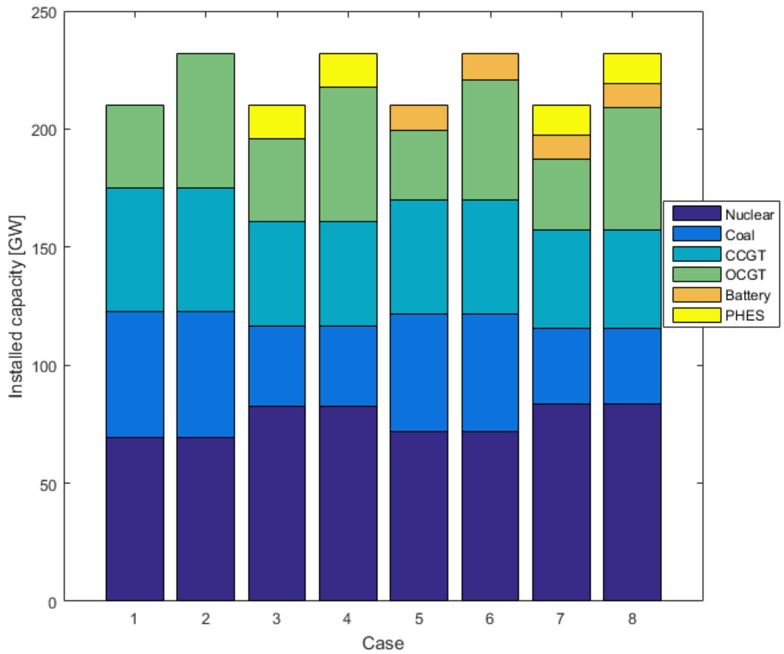

Figure 2: Installed Capacity

4.1.4. Regulatory restrictions

The regulator impose restrictions on the system operator. In the cases with a CRM the capacity margin, represented by RS^{cap}, is equal to 100% of the peak demand. The market price cap is set to 3000 EUR/MWh.

4.2. Results

4.2.1. Capacity

The equilibrium generation portfolio of all power producers and the energy storage units are shown in Fig 2. The according numbers are reported in Tables 3 and 4. Assessing the results, it is important to keep in mind that investments are purely determined by profitability. Derating of energy storage is not done in these initial results and is assessed further in section 4.2.2.

The studies show an increase in total capacity if a capacity market is im-

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plemented. The increase occurs as the capacity margin is set to ensure enough capacity for covering the peak demand and the capacity remuneration is determined by the capacity market to achieve the required capacity, satisfying a higher reliability standard than an energy only market with a price cap. The additional technology that is invested in, in order to fulfill the capacity requirement, is OCGT in the case of no storage available, as well as when only PHES is available. This is due to OCGT having the lowest fixed cost, whereas PHES is not competitive in the CM under these assumptions because it is not economical to invest in additional PHES to be used as stand-by capacity due to the high fixed costs. PHES serve as a long-term storage that require a high utilization rate because of the relatively high fixed costs compared to batteries and OCGT. However, when the battery is included in the market, a small increase in battery investments can be observed when comparing cases 5 and 7 (CM) to cases 6 and 8 (EO). This suggests that low-cost energy storage can be an economical alternative to peaking power plants. Further, in a real market setting, a capacity mechanism would lead to a more certain cash flow for the investments in such assets. The additional income stream from a possible capacity market is more reliable than relying on only arbitraging the energy market. Thus, the presence of a capacity market may be necessary to decrease the uncertainty of cost recovery for energy storage.

The capacity margin is designed to avoid any shortage of capacity in the system. However, situations with shortage of generation capacity are still possible with energy storage in the system due to the limited energy content. Hence, load curtailment would be the case in a situation with depleted storage and insufficient thermal generation capacity to cover the demand. In the analyses performed in this paper, no load shedding occurred with a CM. This may be explained by the deterministic approach since storage units will keep energy available for situations with generation capacity shortage since these are associated with very high energy prices.

The amount of OCGT capacity is decreased when a battery is included in the system. This suggests that the battery provides a cost effective alternative

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to OCGT for providing peaking power in the power system. Further, when both storage technologies are modeled simultaneously the results show that both are needed in the system, as the installed capacities of the energy storages are only slightly reduced compared to the single-storage cases. The storage technologies complements each other and further reduce the amount of thermal capacity instead of reducing each other's business opportunities. This will be elaborated further in section 4.2.2 and 4.2.3.

Table 3: EO Comparison of Results

	Case 1 No Storage	Case 3 PHES	Case 5 Battery	Case 7 Both
Nuclear [MW]	69 342	85 528	72 117	83 605
Utilization [%]	89.7	91.3	90.3	91.7
Coal [MW]	53 527	34 052	49 355	32 229
Utilization [%]	52.1	50.7	51.7	50.6
CCGT [MW]	52 291	44 405	48 707	41 566
Utilization [%]	11.6	9.50	11.4	9.36
OCGT [MW]	35 031	35 031	29 081	29 798
Utilization [%]	1.08	1.08	1.18	1.19
PHES [MW]	0	14 175	0	12 742
PHES [MWh]	0	15 000 000	0	15 000 000
Battery [MW]	0	0	10 930	10 251
Battery [MWh]	0	0	47 862	43 797
Load curt. [MWh]	26 533	26 533	26 533	26 533
RES curt. [MWh]	4 491 146	2 296 571	3 049 513	1 499 946

A large increase of 23.3% in nuclear generation capacity is observed in the cases with PHES (3 and 4) compared to the no storage cases (1 and 2). The nuclear power generation technology represent the base load unit requiring 6500 full load hours (FLH) to be cost competitive compared to coal. Energy storage, and especially PHES, is able to somewhat even out the residual demand in

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Table 4: CM Comparison of Results

	Case 2 No Storage	Case 4 PHES	Case 6 Battery	Case 8 Both
Nuclear [MW]	69 342	85 528	72 117	83 616
Utilization [%]	89.7	91.3	90.3	91.7
Coal [MW]	53 527	34 052	49 355	32 176
Utilization [%]	52.1	50.7	51.7	50.6
CCGT [MW]	52 291	44 405	48 707	41 610
Utilization [%]	11.6	9.50	11.4	9.36
OCGT [MW]	56 857	56 857	50 818	51 565
Utilization [%]	0.67	0.67	0.68	0.69
PHES [MW]	0	14 175	0	12 752
PHES [MWh]	0	15 000 000	0	15 000 000
Battery [MW]	0	0	11 018	10 297
Battery [MWh]	0	0	48 029	43 883
Load curt. [MWh]	0	0	0	0
RES curt. [MWh]	4 491 146	2 296 571	3 043 409	1 497 420

the system by storing excess energy when the prices are low and discharging when it is needed. Energy storage helps the base load capacity by storing excess low cost energy and dispatching it when the prices are higher. Hence, the base load capacity that can be run for the minimum FLH increases. The improved conditions for nuclear power give a substantial decrease of coal and CCGT generation capacity because some of the capacity can be replaced by a more cost effective mix of energy storage and base load nuclear power. OCGT capacity is not affected by including PHES in the system, but is decreased when batteries are introduced as previously explained.

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4.2.2. Sensitivity Analysis: Derating

Case 8, representing no derating (100% rating), is the base case for these analyses. Storage units have limited energy content. Hence, it is uncertain if these units can effectively generate when needed. Due to the disadvantages of storage units regarding fulfillment of the objectives of a capacity mechanism, derating of storage units may be warranted. The storage derating can be adjusted by changing the parameter CF_s which has been varied between zero (full derating) and one (no derating) in order to study different levels of derating of batteries in the capacity market. A storage unit with high risk of emptying the energy buffer would have a CF close to 0 whereas a unit with low risk of emptying would have a CF close to one. Compared to PHES, the battery has a relatively high capacity in relation to storage size, which means that it can easily deplete all the stored energy in a short amount of time whereas this is less likely for the PHES due to the large reservoir size.

The difference in capacity for a battery participating in a CM is shown in Fig. 3. It can be observed, that the installed generation capacity of energy storage in the case of CM is only similar to the case of EO if there is no derating, i.e. a CF_s close to one. This happens as the competitiveness of energy storage is drastically reduced when it does not receive the same remuneration from the CM as thermal generation units and PHES.

The relation between derating and installed capacity follows a linear pattern for the battery technology. There is no derating of PHES and the profitability of PHES is only slightly affected by derating of the battery, which means that PHES is not suited to fill the gap when battery capacity is reduced.

4.2.3. Sensitivity Analysis: Cost

Case 7, representing 0% cost change of batteries, is the base case for these analyses. Operational patterns of the battery such as increased cycling may give different cost profiles than the base case. The cost analysis is performed on the battery using the EO model by changing the fixed costs parameters. Both the storage size and capacity costs were changed by the same percentage value.

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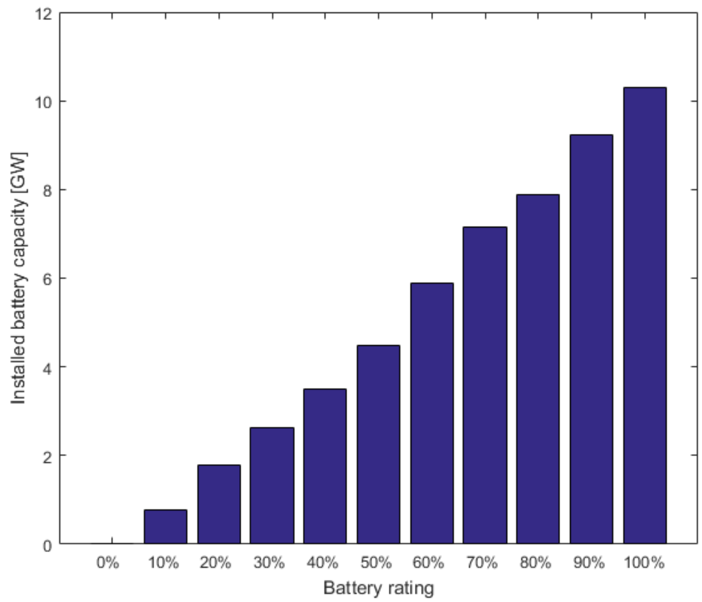

Figure 3: Battery sensitivity to derating in case 8

The costs were varied from -50% and increased in 10% intervals until the result was zero installed capacity. Cycling costs have not been modeled, but increased cycling would mean increased battery cost. Hence, this section provides some insight to how this would affect the outcome.

Fig. 4 show the results for a battery in the EO model. Similarly to the previous section, the installed capacity relation to costs follow a linear pattern. A 30% cost increase resulted in zero installed capacity. These results indicate that although the battery investment decision is sensitive to costs, the result will not be very different for relatively small changes. Further, the profitability of lead-acid batteries show that if the cost of lithium-ion batteries can be reduced to a level approaching the level of lead-acid batteries it should be possible to profitably operate these without subsidies.

PHES costs were kept constant throughout these analyses and the change in battery costs did not have a significant on the installed PHES capacity. PHES

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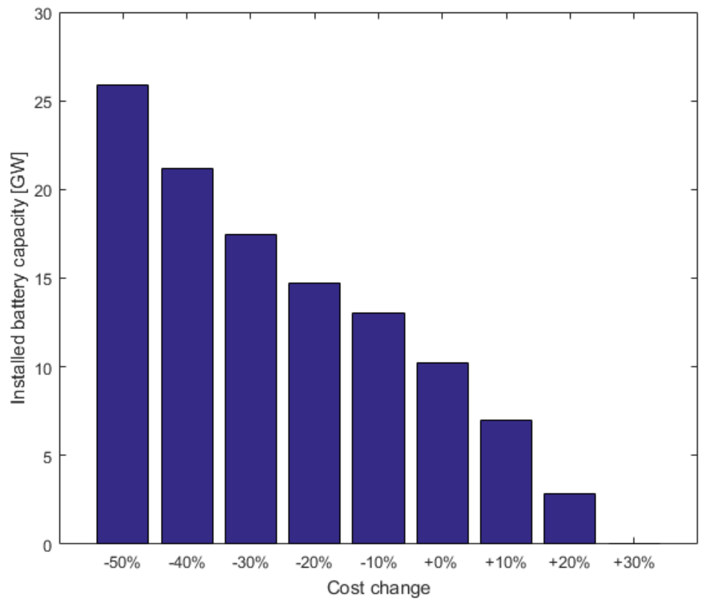

Figure 4: Battery sensitivity to costs in case 7

capacity ranged from 10 426 MW when the battery cost were half of the base case costs to 14 175 MW with battery costs at +30% relative to the base case. Similar to previous results, these findings indicate that PHES and batteries complements each other rather than compete.

5. Conclusion

A complementarity model of a power system is developed to assess the potential of energy storage under energy only and volume-based capacity market conditions in a scenario with a renewable energy source share of 41.5% of total demand. Norwegian pumped hydro energy storage and lead-acid batteries have been analyzed in order to compare results for technologies with different characteristics.

It is found that batteries can be a cost effective alternative to peaking power thermal generation (OCGT) for covering some of the peak load and contribute

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to a capacity reserve requirement if a capacity market is implemented. The competitiveness is a result of the cost structure of the battery and the high efficiency, resulting in a relatively high capacity in relation to storage size.

The introduction of Norwegian pumped hydro energy storage in the system resulted in an increase of 23.3% of nuclear power, the base load unit. This is because the pumped hydro storage is able to shift load so that the residual demand becomes more even, giving increased competitiveness for nuclear power compared to coal.

Derating of the batteries were discussed and a sensitivity analysis show that if a capacity market is implemented, possible storage derating is important for the competitiveness of batteries since it creates a bias against batteries. Batteries were able to provide a cost effective alternative to OCGT for providing some of the peaking power.

The two storage technologies considered in this paper have different roles in the system and complements each other rather than reduce each other's business opportunities. The findings suggests that there is no universal energy storage technology. Several options need to be implemented in the same system to reap all the benefits that are possible from introducing storage units as a tool to balance the power system.

The presented model provides a starting point for further research. For example, reserve markets are not included in this paper and is one of several future development possibilities. Additional topics of further work are increased detail for the battery model, additional markets, increased detail for thermal units, and investments in renewable energy sources.

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