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Optimality Conditions and Cost Recovery in Electricity Markets with Variable Renewable Energy and Energy Storage

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Abstract

We formulate generation capacity portfolio planning in the power grid as a least-cost optimization problem and derive analytical expressions for the optimality conditions for dispatchable generation, variable renewable energy (VRE), and energy storage systems (EES) using a generalized net load duration curve approach. This is done for different operational strategies for EES with and without VRE in the system. For all studied combinations of technologies and operational strategies, we show that all units, including VRE and EES, recover their costs and maximize their profits in the system optimum, for an ideal short-term electricity market based on marginal cost and scarcity pricing. We verify the analytical findings through a numerical example, which shows that the general net load duration curve approach gives identical results to a standard capacity expansion model with sequential operation of the generation and ESS units, under the assumption of limited power capacity but infinite energy capacity of EES. The results highlight that the net load duration curve models presented in this paper can be a useful supplement to more detailed simulation studies of markets with high penetration of VRE and EES, to better understand the underlying factors that determines the optimal capacity mix and profitability of each technology in energy-only electricity markets.

Keywords: electricity markets, optimality conditions, market equilibrium, variable renewable energy, energy storage system, duration curve model

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Nomenclature

Indices

b	Baseload plant
d	Demand
e	Electric Energy Storage (EES)
$e+$	Discharging of EES
$e-$	Charging of EES
F	Firm
G	(Thermal) generator
nd	Net demand
P	Peaker plant
S	Load shedding
V	Variable renewable energy (VRE)
$vpot$	VRE potential (uncurtailed)

Symbols

α_i	Annuity factor of plant *i* [p.u.]
η_i	Efficiency of plant *i* [p.u.]
λ_d	Lagrange multiplier for power balance [$/MWh]
μ_i^{min}	Lagrange multiplier for minimum generation of plant *i*
μ_i^{max}	Lagrange multiplier for maximum generation of plant *i*
π_i	Profit function for plant *i* [$/yr]
$\mathcal{L}$	Lagrangian
d	Storage duration [h]
p	Price of electricity in the market [$/MWh]
p_{CO2}	Price for CO2 emissions [€/ton$_{CO2}$]
q	Power generation or consumption [MW]
$\overline{q}, \underline{q}$	Maximum/minimum generation or consumption [MW]
R	Discount rate [%]
t	Duration or time step [h]
v_i	Variable cost of plant *i* [$/MWh]
x_i	Power capacity of plant *i* [MW]
ACE	Average cost of electricity [$/MWh]
AC_i	Annual cost of plant *i* [$/yr]
AR_i	Annual revenue of plant *i* [$/yr]
AF_v	Availability factor of VRE plant [p.u.]
$AF_v^{[t_{i-1},t_i]}$	Availability factor of VRE plant during the time segment between t_{i-1} and t_i [p.u.]
C	Total annual system costs [$/yr]
CRF	Cost recovery factor [1/yr]
F_i	Annual fixed costs of plant *i* [$/MW/yr]
F_e^{pwr}	Annual fixed cost of EES power capacity [$/kW/yr]
F_e^{en}	Annual fixed cost of EES energy capacity [$/kWh/yr]
E	Energy [MWh]
EF_{fuel}	Emission factor of fuel [ton$_{CO2}$/MWh$_{fuel}$]
$\overline{E}_e$	Energy capacity of EES [MWh]
L	Lifetime [yr]
$LCOE$	Levelized cost of electricity [$/MWh]
$OM_{var,i}$	Variable operation and maintenance cost of plant *i* [$/MWh]
$OM_{fix,i}$	Fixed operation and maintenance cost of plant *i* [$/kW/yr]
SCC_i	Specific capital cost of plant *i* [$/kW/yr]
T	Hours of the year (T=8760 h)
$WAPE$	Weighted average price of electricity [$/MWh]

Sets

E	EES plants
G	(Thermal) generators
V	VRE plants

1 Introduction

Variable Renewable Energy (VRE) technologies are now deployed at an accelerated phase in electricity markets all over the world. Up to now, investments in these resources have to a large extent been driven by different subsidy schemes, either in the form of feed-in tariffs, green certificates, compulsory power purchasing agreements (PPAs), investment refunds, tax credits or other mechanisms. However, in the last few years, the cost for field-ready VRE installations has declined so fast that in more and more areas, onshore wind and utility-scale solar have reached a cost-level that is lower than conventional generation without any form of subsidy (Smith 2019).

In a future where VRE is the cheapest technology, calculated in terms of lifetime costs of kWh delivered, current electricity markets are challenged if no changes to their design takes place. First and foremost, this is due to the well-known merit-order effect (Sensfuß, Ragwitz, and Genoese 2008; Trötscher and Korpås 2008; Hirth 2013; Levin and Botterud 2015), which simply expresses that conventional generators with higher marginal costs are dispatched less and potentially pushed out of the market as more low or zero marginal cost VRE enters the system and reduce the average short-term price in the electricity market.

In principle, the merit-order effect will also impact the deployment of VRE as long as they receive no subsidies and must rely on electricity short-term prices in the electricity market to cover their expenses. Although often discussed as a challenge in the literature (Milligan et al. 2015; Pollitt and Anaya 2016; Botterud and Auer 2019), this limiting factor of VRE expansion in electricity markets has not been studied in much depth, with regards to the cost recovery conditions of the VRE plants or other generators in the system. Other relevant studies have taken a central planner approach for future scenarios (California Energy Commission 2018; European Commission 2016), or investigated present subsidy schemes for VRE (Hiroux and Saguan 2010; Kalkuhl, Edenhofer, and Lessmann 2013; Nicolini and Tavoni 2017) or capacity credits (Bothwell and Hobbs 2017). The literature has often described how externally funded VRE plants (i.e. built outside the pure market incentives) lowers the net load and thereby lowers the income of thermal generators, see (Traber and Kemfert 2011), and impact the resource adequacy in the system (Milligan et al. 2016). As recently described in (Joskow 2019), most theoretical work so far has treated VRE capacity as given exogenously. An important exception is (Helm and Mier 2016), which present a two-stage model for efficient investment in VRE and fossil generators for deceasing VRE capacity costs, assuming a uniform[1] availability function for VRE variability. In this paper, we will derive simple but generally valid cost recovery conditions for VRE and thermal generators in energy-only markets. Under a set of assumptions, we show that all generators (including VRE) recovers their costs by traditional marginal cost pricing, and that this results in an optimal generation capacity portfolio for the system. This implies that the merit-order effect of VRE may not be a problem for efficient development and operation of the power market as such, but it will obviously have an impact on the number of conventional generators that is needed in the system.

In this paper, we further investigate the market equilibrium implications of introducing energy storage systems (ESS) in energy-only markets based on marginal cost pricing. VRE, ESS, and especially batteries, have experienced a tremendous cost reduction in recent years, and there is a vast number of research articles on how EES can be used to facilitate VRE in future power systems, both from technical, economical, and environmental viewpoints, see e.g (Toledo, Oliveira Filho, and Diniz 2010; Díaz-González et al. 2012; Zhao et al. 2015; Denholm et al. 2010; Sioshansi et al. 2009). Most literature that studies the economic viability of EES either takes a system cost-minimization perspective (N. Li et al. 2016; Arbabzadeh et al. 2019; de Sisternes, Jenkins, and Botterud 2016) or a price-taker perspective (Bathurst and Strbac 2003; Korpås, Holen, and Hildrum 2003; Sioshansi et al. 2009). To our knowledge, there is not much published material on the equilibrium conditions for EES in ideal energy-only markets based on marginal cost pricing. Green and Staffell (2015) analyze the impact of ESS on wholesale markets with large amount of renewable energy using a cost-minimizing optimization model. They show that ESS reduces the price volatility and some of the very highest prices, but also leads to higher near-peak prices due to the influence on the equilibrium condition of the conventional generators. They

[1] Their model is not limited to uniform functions, but this representation is chosen for convenience in order to derive closed-form solutions.

also describe that ESS increases the market value of wind power by raising the prices in the low-price periods and reduces the number of zero-price hours. Steffen and Weber (2013) establish optimality conditions for ESS in a system with thermal generators and VRE plants using a similar duration curve as here, but do not analyze market aspects or optimality conditions for the VRE power plants. A recent contribution by Schmalensee (2019) takes a theoretical approach to analyze market aspects of both ESS and VRE plants. By introducing ESS and stochastic VRE into a two-stage model, the paper suggests that the long-run equilibrium value of storage capacity minimizes expected system cost in most cases. However, the paper also states that it cannot be ruled out that inefficient equilibria exist when ESS is introduced to the system. Schmalensee models the daily operation of EES within a two-stage model, and derives first-order and second-order optimality conditions for all units. In contrast, we derive system optimality and cost recovery conditions using a model that represents hourly operation of the system over a full year based on a load duration curve approach. Helm and Mier (2018) analyze optimal subsidies and capacities for VRE and EES in systems with imperfect carbon pricing. As in (Schmalensee 2019), they derive optimality conditions over a representative storage cycle for an assumed regular pattern of renewable energy input.

In this paper, we take an analytical approach to study market equilibrium in competitive low-carbon electricity markets. We first derive analytical expressions for the optimality conditions for thermal generators, VRE and EES where the objective is to minimize the total cost of a system with fixed demand. We then show how profit maximization of each generation and storage resource in a market based on marginal cost pricing and administrative scarcity pricing can give the same results as the optimal investment portfolio under system cost minimization. Our approach follows to a large extent traditional literature on system optimality and cost recovery with thermal generators based on a load duration curve for demand and constant marginal generator costs (Stoft 2002; Green 2000). However, we extend the analysis to incorporate VRE and EES, and investigate the long-term market equilibrium implications that follow from different operational strategies used for the EES. Finally, the theoretical findings are illustrated by a simple, yet representative numerical example based on data and scenarios for the European power system in 2050. Although the duration curve approach is simplified with respect to representation of energy storage constraints, it is proven to be useful for illustrating the impacts of VRE and EES on market equilibrium in an easy and transparent way.

The rest of the paper is organized as follows: Chapter 2 presents the general capacity expansion problem that is used to derive the system optimality conditions in Chapters 3-4. Chapter 3 recaptures the traditional system with only thermal generators meeting the load represented as a duration curve. Chapter 4 introduces a general representation of VRE technologies in the net load duration curve framework. Chapter 5 presents the EES, which is modelled for two system configurations: Only thermal power plants (Chapter 5.1) and VRE + thermal (Chapter 5.2). In the latter case, the optimality conditions of all types of plants are derived for three different operational strategies for EES. Throughout Chapters 3-5, we verify that the optimal least-cost system solution is also obtained in a perfect market with marginal cost pricing, by investigating cost recovery conditions under profit maximization of price-taking generation units. Chapter 6 presents the results of a numeric case study based on real data and scenarios for the European power system stadium 2050. Finally, Chapter 7 concludes the paper and provides directions for future research.

2 Scope and methodology

We consider an energy-only market with scarcity pricing, i.e. an administratively determined price during supply shortages, as the basis for analysis, without discussing additional capacity remuneration mechanisms. As shown in previous literature, e.g. by (Stoft 2002) and (Green 2000), an energy-only market with scarcity pricing provides the theoretically optimal incentives for investments in dispatchable generators. It is also known that the presence of VRE changes the amount of optimally installed thermal generation in a system (Levin and Botterud 2015), but less is known about how costs are recovered in equilibrium, including costs for VRE and ESS. In our model, we treat VRE and ESS capacity as endogenous variables using a simplified yet representative model of VRE output variations, and derive analytical expressions for the equilibrium conditions for all generators given marginal cost pricing.

Demand side flexibility is expected to play a vital role in enhancing VRE integration (Strbac 2008), and the system optimization problem must therefore in the general case be formulated as a welfare maximization problem. Since the scope of this paper is cost recovery of conventional generation, VRE and ESS devices, we reformulate the system optimization problem to a deterministic cost minimization problem, and leave the inclusion of demand side flexibility and uncertainty for future work as these are substantial topics on their own. Hence, the central planner's least-cost problem can in its basic form be formulated as:

$$\min C = \sum_{g=1}^{G}\left[F_g x_g + v_g \int_0^T q_g(t)\,dt\right] + \sum_{v=1}^{V} F_v x_v + \sum_{e=1}^{E}\left[F_e^{pwr}\cdot x_e + F_e^{en}\cdot \overline{E}_e\right] + v_s \int_0^T q_s(t)\,dt \quad (1)$$

$$\text{s.t.} \sum_{g=1}^{G} q_g(t) + \sum_{v=1}^{V} q_v(t) + \sum_{e=1}^{E}[q_e(t) - q_{e-}(t)] + q_s(t) = q_d(t) \quad (2)$$

$$0 \le q_g(t) \le x_g \quad \forall\, g \in G \quad (3)$$

$$0 \le q_v(t) \le AF_v(t)\cdot x_v \quad \forall\, v \in V \quad (4)$$

$$0 \le q_{e+}(t) \le x_e \quad \forall\, e \cdot\in E \quad (5)$$

$$0 \le q_{e-}(t) \le x_e \quad \forall\, e \cdot\in E \quad (6)$$

$$\frac{dE_e(t)}{dt} = \eta_{e-}\cdot q_{e-}(t) - \frac{q_{e+}(t)}{\eta_{e+}} \quad \forall\, e \cdot\in E \quad (7)$$

$$0 \le E_e(t) \le \overline{E}_e \quad \forall\, e \cdot\in E \quad (8)$$

The objective function (1) minimizes the sum of annualized fixed costs, annual variable generation costs and annual costs of load shedding. Variable costs of VRE are set to zero under the assumption that variable O&M costs are negligible. ESS investment costs are linear functions of both power capacity and energy capacity. The instantaneous power balance is given in (2), conventional generation limits in (3) while VRE output is limited by the instantaneous availability factor in (4). EES limits and storage balances, including roundtrip losses, are expressed in (5)-(8). Note that our formulation focuses on the market for energy and does not include ancillary services. Moreover, the impacts of the transmission network and generator unit commitment are also ignored.

The linear model described by (1)-(8) is applicable for any number and types of fossil generators, VRE generators and EES units. To ease the notation in the remainder of the paper, we limit the model to two types of thermal generators (i.e. peaker and baseload), one type of VRE technology and one type of EES. By "type" we here refer to a technology with a given cost and performance, i.e. two units of the same type are identical. Moreover, (8) explicitly models the limit on energy storage capacity, which is straightforward to implement in a time-sequential model, but only possible to account for indirectly in duration curve models as discussed in more detail in Chapter 5. By applying these assumptions, the cost-minimization problem can be simplified to:

$$\min_{x_i, q_k(t), q_{e-}(t)} C = \textstyle\sum_i F_i x_i + \sum_j v_j \int_0^T q_j(t)\,dt \quad (9)$$

$$\text{s.t.} \quad q_d(t) - \sum\nolimits_k q_k(t) + q_{e-}(t) = 0 \quad (10)$$

$$-q_k(t) \le 0\,, \qquad -q_{e-}(t) \le 0 \quad (11)$$

$$q_l(t) - x_l \le 0\,, \qquad q_{e-}(t) - x_e \le 0 \quad (12)$$

$$q_v(t) - AF_v(t)x_v \le 0 \quad (13)$$

$$\eta_e \int_0^T q_{e-}(t)dt - \int_0^T q_e(t)dt = 0 \tag{14}$$

Sets: $i \in \{p, b, v, e\}$, $j \in \{s, p, b\}$, $k \in \{s, p, b, v, e\}$, $l \in \{p, b, e\}$

where indices *s*, *p*, *b*, *v*, *e* refers to load shedding, peaker, baseload, VRE plant and EES respectively. The administrative price assumed to be set during load shedding has been expressed as a variable cost $v_s = p_s$ for ease of notation. Moreover, we simplify storage notation by defining $q_e \equiv q_{e+}$, so that q_e refers to discharging power, while charging is q_{e-} as before. Equation (14) is the energy storage balance over the whole analysis period, where we have introduced the round-trip efficiency $\eta_e = \eta_{e-} \cdot \eta_{e+}$.

3 Conventional generators

3.1 System optimality conditions

Optimality conditions for conventional generators in power markets have been extensively covered in the literature e.g. (Joskow 1976; Stoft 2002; Green 2000). For the sake of consistency with the later part of the paper, we show here how to derive the first-order optimality conditions for a system consisting of only conventional generators which serve a given demand with a temporal profile over the year. The system cost-minimization problem (9)-(14) becomes:

$$\min_{x_i, q_j(t)} C = \sum_i F_i x_i + \sum_j v_j \int_0^T q_j(t)\, dt \quad \forall\, i \in \{p, b\}, j \in \{s, p, b\} \tag{15}$$

$$\text{s.t.} \quad \sum_j q_j(t) - q_d(t) = 0 \qquad \forall\, j \in \{s, p, b\} \quad (\lambda_d) \tag{16}$$

$$-q_j(t) \leq 0 \qquad \forall\, j \in \{s, p, b\} \quad (\mu_j^{min}) \tag{17}$$

$$q_i(t) - x_i \leq 0 \qquad \forall\, i \in \{p, b\} \quad (\mu_i^{max}) \tag{18}$$

By sorting the time-varying demand over the year in descending order, we obtain the duration curve as illustrated in Figure 1. The time parameter $t \in [0, T]$ now refer to the sorted demand (i.e. the duration curve) and not the chronological time-series. The figure also displays how the demand is covered by the two generators for a solution where both generators are part of the optimal generation portfolio, i.e. x_p and x_b are both strictly positive.

Consider first the operational problem for an arbitrary time instant t and given plant capacities x_i. The investment cost term in (15) becomes 0, and we can write the Lagrangian

$$\begin{aligned} \mathcal{L}_{op}\left(q_j, \lambda_d, \mu_j^{min}, \mu_i^{max}, t\right) &= \sum_j v_j q_j(t) + \lambda_d(t) \cdot \left(q_d(t) - \sum_j q_j(t)\right) \\ &+ \sum_j \mu_j^{min}(t) \cdot \left(-q_j(t)\right) + \sum_i \mu_i^{max}(t) \cdot (q_i(t) - x_i) \\ &\forall\, i \in \{p, b\}, j \in \{s, p, b\} \end{aligned} \tag{19}$$

where λ_d is the Lagrange multiplier associated with the demand balance (16), μ_j^{min} is the Lagrange multiplier for generator j in (17) and μ_i^{max} is the Lagrange multiplier for generator i in (18). Note that multiplier μ_j^{min} also applies for load shedding, i.e. for $j \in \{s, p, b\}$. λ_d is the system marginal cost, which defines the spot price for energy under marginal pricing (Hasan, Galiana, and Conejo 2008). The optimal dispatch is given by the Karush-Kuhn-Tucker (KKT) conditions which in addition to (16)-(18) comprises

$$v_i - \lambda_d(t) + \mu_i^{max}(t) - \mu_i^{min}(t) = 0\ \forall\, i \in \{p, b\} \tag{20}$$

$$v_s - \lambda_d(t) - \mu_s^{min}(t) = 0 \tag{21}$$

$$\mu_i^{max}(t) \cdot (q_i(t) - x_i) = 0\ \forall\, i \in \{p, b\} \tag{22}$$

$$\mu_j^{min}(t) \cdot \left(-q_j(t)\right) = 0\ \forall\, j \in \{s, p, b\} \tag{23}$$

where we have followed the sign convention from (Gabriel et al. 2013). It should be noted that the Lagrangian and corresponding KKT-conditions derived above apply to any number of generators in the set i, although we have used an example with only two generators here. The KKT conditions provide the optimal operation of each generator for all demand levels, as summarized for our two-generator problem in Table 1.

Table 1. System marginal cost and optimal operation for different demand levels.

$t \le t_s$: $x_b + x_p \le q_d(t)$	$t_s < t \le t_p$: $x_b \le q_d(t) < x_b + x_p$	$t > t_p$: $q_d(t) > x_b$
$\lambda_d(t) = v_s$	$\lambda_d(t) = v_p$	$\lambda_d(t) = v_b$
$q_b(t) = x_b$	$q_b(t) = x_b$	$q_b(t) = q_d(t)$
$q_p(t) = x_p$	$q_p(t) = q_d(t) - x_b$	$q_p(t) = 0$
$q_s(t) = q_d(t) - x_p - x_b$	$q_s(t) = 0$	$q_s(t) = 0$

From Table 1, we see that the output of each generator and load shedding are functions of the demand $q_d(t)$ and the installed capacities $x_i \forall\ i \in \{p, b\}$. For given installed capacities, we also know the output of each unit, since the units must be dispatched due to the merit order to minimize operating costs. We can therefore convert the problem (15)-(18) to an unconstrained cost minimization problem:

$$\min_{x_p,x_b} C = F_p x_p + F_b x_b + v_s \int_0^{t_s} [q_d(t) - x_p - x_b]\, dt + v_p \cdot \left(\int_0^{t_s} x_p\, dt + \int_{t_s}^{t_p} [q_d(t) - x_b]\, dt \right) + v_b \cdot \left(\int_0^{t_p} x_b\, dt + \int_{t_p}^{T} q_d(t)\, dt \right) = F_p x_p + F_b x_b + v_s \left(E_d^{[0,t_s]} - (x_p + x_b) t_s \right) + v_p \left(E_d^{[t_s,t_p]} + (x_p + x_b) t_s - x_b t_p \right) + v_b \left(E_d^{[t_p,T]} + x_b t_p \right) \tag{24}$$

where $E_d^{[t_1,t_2]}$ is the energy demand over the period t_1 to t_2, corresponding to the area in Figure 1 bounded by $[t_1, t_2]$ and $[q_d(t_1), q_d(t_2)]$. The relation between the durations and generation capacities is also illustrated in the figure and we can write $t_p = f(x_b)$ and $t_s = f(x_p, x_b)$. Derivation of C with respect to the unknowns x_p and x_b gives:

$$\frac{\partial C}{\partial x_p} = F_p - (v_s - v_p) t_s + v_s \left(\overbrace{\frac{\partial E_d^{[0,t_s]}}{\partial x_p} - (x_p + x_b) \frac{\partial t_s}{\partial x_p}}^{0} \right) + v_p \left(\overbrace{\frac{\partial E_d^{[t_s,t_p]}}{\partial x_p} + (x_p + x_b) \frac{\partial t_s}{\partial x_p}}^{0} \right) = F_p - (v_s - v_p) t_s \tag{25}$$

$$\frac{\partial C}{\partial x_b} = F_b - (v_s - v_p) t_s - (v_p - v_b) t_p + v_s \left(\overbrace{\frac{\partial E_d^{[0,t_s]}}{\partial x_b} - (x_p + x_b) \frac{\partial t_s}{\partial x_b}}^{0} \right) + v_p \left(\overbrace{\frac{\partial E_d^{[t_s,t_p]}}{\partial x_b} + (x_p + x_b) \frac{\partial t_s}{\partial x_b} - x_b \frac{\partial t_p}{\partial x_b}}^{0} \right) + v_b \left(\overbrace{\frac{\partial E_d^{[t_p,T]}}{\partial x_b} + x_b \frac{\partial t_p}{\partial x_b}}^{0} \right) = F_b - (v_s - v_p) t_s - (v_p - v_b) t_p \tag{26}$$

The first-order optimality conditions become:

$$\frac{\partial C}{\partial x_p} = 0 \Rightarrow t_s = \frac{F_p}{(v_s - v_p)} \tag{27}$$

$$\frac{\partial C}{\partial x_b} = 0 \Rightarrow t_p = \frac{F_b - F_p}{(v_p - v_b)} \tag{28}$$

When the durations are known, the optimal capacities are found from the demand curve $x_b = q_d(t_p)$ and $x_p = q_d(t_s) - x_b$. Problem (24) with solutions (27) and (28) are valid under the assumption that both x_p and x_b are strictly positive. To find the true optimal solution of (15) using the duration curve method, we must compare the result of (24) with the result for all other possible generator combinations. In this case, that means to remove the peaker and the baseplant, respectively, from the solution space and obtain optimal durations for these cases.

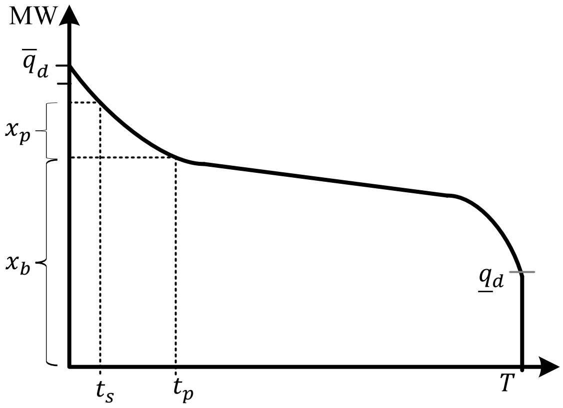

Figure 1. Load duration curve with durations and optimal capacities of peaker and base plants.

3.2 Profit maximization and cost recovery

The annual profit of generator i in the market is:

$$\pi_i = AR_i - AC_i = \int_0^{t_i} (p(t) - v_i) q_i(t) dt - F_i x_i \tag{29}$$

The price $p(t)$ is equal to the dual value λ_d of the load balance (16) in a system with marginal cost pricing. Using the values of λ_d and the optimal operation regimes derived in the previous section, the profit functions for the peaker and baseplant become:

$$\pi_p = (v_s - v_p) t_s x_p - F_p x_p = \left((v_s - v_p) t_s - F_p\right) x_p \tag{30}$$

$$\begin{aligned} \pi_b &= (v_s - v_b) t_s x_b + (v_p - v_b)(t_p - t_s) x_b - F_b x_b \\ &= \left((v_s - v_b) t_s + (v_s - v_b)(t_p - t_s) - F_b\right) x_b \end{aligned} \tag{31}$$

It follows that in the system optimum, the profits of the individual generators are 0, i.e. all generators recovers their cost: $\pi_p = 0$ for $t_s = F_p / (v_s - v_p)$ and $\pi_b = 0$ for $t_p = (F_b - F_p)/(v_p - v_b)$. This holds true independently of how many generator firms that are participating in the market. Costs are recovered in optimum whether x_i represents the aggregated capacity of generators owned by different firms, or it represents the capacity of one firm being the only owner of a given generator type i.

In a long-term market equilibrium, no individual firm has an incentive to change its capacity, given that the other firm's capacities (and all parameters) are kept constant. Under perfect market conditions with no barriers to exit and entry, no single firm f can influence the duration of the different generators (or load shedding) by changing its capacity. Profit maximization of firm f owning a peaker plant yields:

$$\max_{x_{f,p}} \pi_{f,p} = \int_0^{t_p} (p(t) - v_p) q_{f,p}(t) dt - F_p x_{f,p} = \left((v_s - v_p) t_s - F_p\right) x_{f,p} \tag{32}$$

Since t_s is not influenced by the investment $x_{f,p}$ of firm f, the first-order optimality condition becomes:

$$\frac{\partial \pi_{f,p}}{\partial x_{f,p}} = 0 \Rightarrow (v_s - v_p) t_s - F_p = 0 \Rightarrow t_s = \frac{F_p}{(v_s - v_p)} \tag{33}$$

which exemplifies the well-known general result that the profit of each single generator company maximizes its profit in system optimum in a perfect market. Similarly, the market solution for the baseplant technology becomes:

$$\max_{x_{f,b}} \pi_{f,b} = \int_0^T (p(t) - v_b) q_{f,b}(t) dt - F_b x_{f,b} \tag{34}$$

$$= \left((v_s - v_b)t_s + (v_p - v_b)(t_p - t_s) - F_b\right) x_{f,b}$$

$$\frac{\partial \pi_{f,b}}{\partial x_{f,b}} = 0 \Rightarrow t_p = \frac{F_b - F_p}{(v_p - v_b)} \tag{35}$$

4 Variable Renewable Energy (VRE) power plants

VRE plants are powered by weather-driven and variable primary energy sources with zero fuel costs. Dependent on the conversion technology and control systems, the output of VRE plants can be controlled in both downwards (by reducing its output) or upwards (by initially running at a set-point lower than maximum possible) directions (Milligan et al. 2015). In this paper, we simplify the representation of VRE plants by assuming zero variable costs and full downward dispatch capability. By assuming that the VRE output scales linearly with its installed capacity, the relative power output variations become independent of the capacity of the VRE generator, and we can write $q_v(t) = AF_v(t) \cdot x_v$ where $AF_v(t)$ is the availability factor at time instant t. The assumption of linear scaling of VRE output is a significant simplification since e.g. different wind power sites have different wind conditions which lead to smoothing of aggregated output as a function of capacity. Nevertheless it is a common approximation in more detailed modelling work than what is presented here (Sepulveda et al. 2018; De Vita, Kielichowska, and Mandatowa 2018; Cole et al. 2016; de Sisternes, Jenkins, and Botterud 2016).

With zero marginal costs, VRE plants will always be dispatched first, and the conventional generators must cover the net demand

$$q_{nd}(t) = q_d(t) - \overline{q}_v(t) = q_d(t) - AF_v(t)x_v \tag{36}$$

where $\overline{q}_v(t)$ refer to the uncurtailed available VRE generation. The time parameter t now refers to the duration of the net demand, sorted from highest to lowest value over the year, as illustrated in Figure 2.

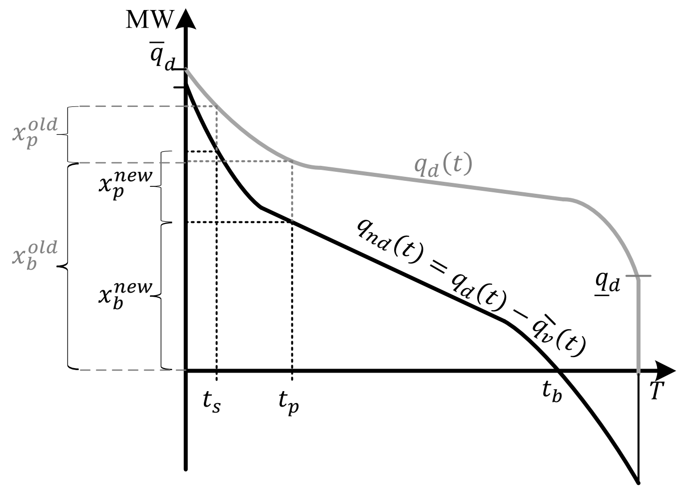

Figure 2. Load duration curve for demand (grey line) and net demand (black) line for a system with two conventional generators ("peak" and "base") and one VRE plant. The optimal capacities of peaker and baseplant with and without VRE are indicated in the figure as "new" and "old", respectively.

With a VRE plant added to the system in addition to the peaker and baseplant, the optimization problem becomes

$$\min_{x_i, q_k(t)} C = \sum_i F_i x_i + \sum_j v_j \int_0^T q_j(t)\, dt \tag{37}$$

$$\text{s.t.} \quad q_d(t) - \sum_k q_k(t) = 0 \tag{38}$$

$$-q_k(t) \leq 0 \tag{39}$$

$$q_l(t) - x_l \leq 0 \tag{40}$$

$$q_v(t) - AF_v(t)x_v \leq 0 \tag{41}$$

Sets: $i \in \{p, b, v\}\,, j \in \{s, p, b\}\,, k \in \{s, p, b, v\}\,, l \in \{p, b\}$

4.1 System optimality conditions

As for the case with only conventional generators, we first derive the conditions for optimal dispatch with given plant capacities. The Lagrangian of the operation problem for an arbitrary time instant t is:

$$\mathcal{L}_{op}(t) = \sum_j v_j q_j(t) + \lambda_d(t)\left(q_d(t) - \sum_k q_k(t)\right) + \sum_l \mu_l^{max}(q_l(t) - x_l) + \sum \mu_v^{max}(q_v(t) - AF_v(t)x_v) + \sum_k \mu_k^{min}\left(-q_k(t)\right) \tag{42}$$

$$\forall\ j \in \{s, p, b\}, k \in \{s, p, b, v\}, l \in \{p, b\}$$

The KKT-conditions for this problem consist of (38)-(41), in addition to the following equations:

$$v_l - \lambda_d(t) + \mu_l^{max} - \mu_l^{min} = 0\ \forall\ l \in \{p, b\} \tag{43}$$

$$-\lambda_d(t) + \mu_v^{max} - \mu_v^{min} = 0 \tag{44}$$

$$v_s - \lambda_d(t) - \mu_s^{min} = 0 \tag{45}$$

$$\mu_l^{max} \cdot (q_l(t) - x_l) = 0\ \forall\ l \in \{p, b\} \tag{46}$$

$$\mu_v^{max} \cdot (q_v(t) - AF_v(t)x_v) = 0$$

$$\mu_k^{min} \cdot \left(-q_k(t)\right) = 0\ \forall\ k \in \{s, p, b, v\} \tag{47}$$

From the KKT-conditions, we get the dispatch according to the merit-order similarly to Chapter 3, but now with the VRE plant added. The resulting optimal dispatch levels of each generator in each period are provided in Table 2, where the time parameter t is sorted after the net demand.

Table 2. System marginal cost and optimal operation for different net demand levels.

$t \leq t_s$: $x_b + x_p \leq q_{nd}(t)$	$t_s < t \leq t_p$: $x_b \leq q_{nd}(t) < x_b + x_p$	$t_p < t \leq t_b$: $0 \leq q_{nd}(t) < x_b$	$t > t_b$: $q_{nd}(t) < 0$
$\lambda_d(t) = v_s$	$\lambda_d(t) = v_p$	$\lambda_d(t) = v_b$	$\lambda_d(t) = 0$
$q_v(t) = AF_v(t)x_v$	$q_v(t) = AF_v(t)x_v$	$q_v(t) = AF_v(t)x_v$	$q_v(t) = q_d(t)$
$q_b(t) = x_b$	$q_b(t) = x_b$	$q_b(t) = q_{nd}(t)$	$q_b(t) = 0$
$q_p(t) = x_p$	$q_p(t) = q_{nd}(t) - x_b$	$q_p(t) = 0$	$q_p(t) = 0$
$q_s(t) = q_{nd}(t) - x_p - x_b$	$q_s(t) = 0$	$q_s(t) = 0$	$q_s(t) = 0$

Following the method from Chapter 3, we can use the result in Table 2 to express the capacity investment problem as:

$$\min_{x_p,x_b,x_v} C = F_p x_p + F_b x_b + F_v x_v + v_s \int_0^{t_s} [q_d(t) - AF_v(t)x_v - x_p - x_b]\, dt + v_p \cdot \left(\int_0^{t_s} x_p\, dt + \int_{t_s}^{t_p} [q_d(t) - CF_v(t)x_v - x_b]\, dt\right) + v_b \cdot \left(\int_0^{t_p} x_b\, dt + \int_{t_p}^{t_b} (q_d(t) - AF_v(t)x_v)\, dt\right) \tag{48}$$

which is equivalent to problem (37)-(41) under the condition that all generators are present in the system. From the resource model of the VRE plant, we can calculate the average availability factor $AF_v^{[t_1,t_2]}$ between two time steps t_1 and t_2, and use this to solve the integral

$$\int_{t_1}^{t_2} AF_v(t)\, dt = (t_2 - t_1) \cdot AF_v^{[t_1,t_2]} \tag{49}$$

Inserting into (49):

$$\min_{x_p,x_b,x_v} C = F_p x_p + F_b x_b + F_v x_v + v_s \left(E_d^{[0,t_s]} - \left(x_p + x_b + AF_v^{[0,t_s]} x_v\right) t_s\right) + v_p \left(E_{nd}^{[t_s,t_p]} + \left(x_p + x_b + AF_v^{[t_s,t_p]}\right) t_s - \left(x_b + AF_v^{[t_s,t_p]} x_v\right) t_p\right) + v_b \left(E_{nd}^{[t_p,t_b]} + \left(x_b + AF_v^{[t_p,t_b]} x_v\right) t_p - AF_v^{[t_p,t_b]} x_v t_b\right) \tag{50}$$

where we also have inserted the total energy demand $E_d^{[t_1,t_2]}$ over the period $[t_1, t_2]$. The first-order optimality conditions of (50) with respect to x_p and x_b becomes identical to the case without VRE given by (27) and (28). The optimal capacities are now found from the net demand curve, which is a function of the VRE capacity. Derivation of the cost function (50) with respect to x_v yields:

$$\frac{\partial C}{\partial x_v} = F_v - v_s AF_v^{[0,t_s]} t_s - v_p AF_v^{[t_s,t_p]} (t_p - t_s) - v_b AF_v^{[t_p,t_b]} (t_b - t_p) \tag{51}$$

$$\frac{\partial C}{\partial x_v} = 0 \Rightarrow F_v = v_s AF_v^{[0,t_s]} t_s + v_p AF_v^{[t_s,t_p]} (t_p - t_s) + v_b AF_v^{[t_p,t_b]} (t_b - t_p) \tag{52}$$

During all periods when the net demand is higher than zero, each additional kWh from the VRE plant will reduce the output of the marginal generator with the same amount, while all other generator outputs are unchanged. In optimum, the marginal value of this replacement of thermal generators and load shedding will equal the marginal cost of installing the corresponding capacity. Since t_s and t_p are known, we can solve (52) with respect to t_b:

$$t_b = t_p + \left(v_b AF_v^{[t_p,t_b]}\right)^{-1} \cdot \left(F_v - v_s t_s AF_v^{[0,t_s]} - v_p (t_p - t_s) AF_v^{[t_s,t_p]}\right) \tag{53}$$

A special case occurs when the optimal x_v is non-zero, but still not high enough to cause surplus generation, i.e. the optimal t_b is equal to T. The optimality condition (52) then indirectly determines x_v through the availability factor AF_v. Consider a situation where $x_v = 0$, and the right-hand side of (52) is larger than the left-hand side, i.e. it is profitable marginally increase the VRE capacity. A marginal increase in VRE capacity pushes the net demand curve downwards, and thus also changes the average availability factor in the different price segments. As more VRE capacity is installed, more of the generation is pushed towards the periods of the year with less net demand and lower prices. At a certain value of x_v, the marginal benefit for the system equals the marginal investment cost F_v. This can occur at $t_b = T$ or $t_b < T$, depending on the VRE investment cost. Figure 15 in Appendix A exemplifies this result for a case using European offshore wind data.

Thus, under the assumption of one type of VRE plant which scales linearly, it is the duration of the thermal generator with lowest marginal cost (in our case t_b) and the VRE output variations, that determines its optimal capacity x_v. The duration t_b expresses the duration of the year when the net demand is non-negative. The optimal VRE capacity x_v is the capacity that leads to net demand of zero at exactly t_b, and can easily be found from the load and VRE resource data. When x_v is known, the peaker and baseplant capacities can be found directly from the net demand curve.

In Figure 2, the base generator capacity is reduced significantly while the peak generator capacity is marginally increased when VRE is included, which is a result of the illustrated VRE variability; higher availability factor during low loads than high loads. Maximum load shedding is therefore higher with

VRE, to ensure optimal duration of the peaker with the changed net demand. However, note that the duration of load shedding t_s remain unchanged with the introduction of VRE. If the energy cost of the VRE plant is sufficiently low, it might push one of the thermal generators out of the solution space. To find the true optimum of the capacity investment problem (37)-(41), we must therefore compare the result of sub-problem (48) with the remaining options, i.e. VRE+peaker and VRE+baseplant. With only one thermal generator, here denoted i, the problem becomes a simpler variant of (48):

$$\begin{aligned}\min_{x_i,x_v} C = F_i x_i + F_v x_v + v_s \left(E_d^{[0,t_s]} - \left(x_i + AF_v^{[0,t_s]} x_v\right) t_s\right) \\ + v_i \left(E_{nd}^{[t_s,t_i]} + \left(x_i + AF_v^{[t_s,t_i]} x_v\right) t_s - AF_v^{[t_s,t_i]} x_v t_i\right)\end{aligned} \tag{54}$$

with the VRE optimality condition:

$$t_i = t_s + \frac{\left(F_v - v_s t_s AF_v^{[0,t_s]}\right)}{v_i AF_v^{[t_s,t_i]}} \tag{55}$$

Again, the optimal VRE capacity is found from the net demand curve that fulfils $q_{nd}(t_i) = 0$.

4.2 Profit maximization and cost recovery

Given a market where any number of VRE plants of the same type v is fully exposed to the electricity market prices, their aggregated profit function is:

$$\pi_v = AR_v - AC_v = \int_0^T p(t) q_v(t) dt - F_v \cdot x_v = x_v \int_0^T p(t) AF_v(t) dt - F_v \cdot x_v \tag{56}$$

In a market based on marginal cost pricing, we have from Table 2:

$$\begin{aligned}\pi_v &= x_v \left(v_s \int_0^{t_s} AF_v(t) dt + v_p \int_{t_s}^{t_p} AF_v(t) dt + v_b \int_{t_p}^{t_b} AF_v(t) dt \right) - F_v \cdot x_v \\ \pi_v &= \left(v_s AF_v^{[0,t_s]} t_s + v_p AF_v^{[t_s,t_p]} (t_p - t_s) + v_b AF_v^{[t_p,t_b]} (t_b - t_p) - F_v\right) \cdot x_v\end{aligned} \tag{57}$$

We see from (57) that the VRE power plants exactly recover their cost in a market based on marginal cost pricing if plant capacities are according to system optimum: $\pi_v = 0$ leads to (52) and the corresponding optimal duration of the baseplant in (53).

Maximization of the profit function (56) for a firm f owning some VRE capacity $x_{v,f}$ gives the same result:

$$\frac{\delta \pi_{v,f}}{\delta x_{v,f}} = 0 \Rightarrow F_v = \int_0^T p(t) AF_v(t) dt \tag{58}$$

where we have required that each owner of the VRE plant is too small to change the generator durations alone. Thus, market based VRE investments reaches an equilibrium at system optimum where it is not profitable for any single owner to change its capacity given that all external parameters remain constant.

5 Electric Energy storage (EES)

EES are applied for numerous services in the power system, such as load shifting, energy arbitrage, operating reserves, backup capacity, transmission and distribution deferral, among others (Dell and Rand 2001; Denholm et al. 2010; Akhil et al. 2015). Conventional storage technologies like pumped hydro has been used for shifting energy from base load to peak load periods for decades (Mcdaniel and Gabrielle 1966; Botterud, Levin, and Koritarov 2014; Harby et al. 2013). Newer storage technologies like Li-Ion batteries and flow batteries has received a lot of attention the last two decades, both with respect to renewable energy integration, price arbitrage and grid services (Aneke and Wang 2016; Denholm et al. 2010; Akhil et al. 2015). In this paper we will keep EES modelling at a simple and general level, in order to derive analytical expressions for all optimality conditions when EES is present in the system. A similar load duration method for analysis of storage systems is reported in (Steffen and Weber 2013), which derives optimality conditions for EES, but is limited to cases where the VRE plant capacity is an external input and not part of the system optimum.

Inclusion of EES in a modelling framework based on duration curves cannot be achieved without major simplifications, due to the chronological nature of the EES dispatch. EES is limited by the power capacity, energy capacity and round-trip efficiency of the storage devices. Capacity degradation mechanisms and other aging effects are also important to consider for certain EES types such as most electrochemical batteries (Xu et al. 2018). The aim of the modelling framework presented here is to supplement, not replace detailed optimization studies. To get a principal understanding of the potential for EES under ideal conditions, we therefore choose a representation of storage which takes explicitly into account the power capacity and round-trip efficiency, but only indirectly accounts for the energy capacity. This is obviously a simplistic representation, but, as will be shown, is still useful to indicate what potential role ESS have in power market equilibrium.

5.1 EES with conventional generators

5.1.1 System optimality conditions

We will first investigate how the optimality conditions for thermal generators are influenced by the presence of ESS. The output of the ESS will depend on the installed capacity of conventional generators when we use ESS for load shifting. Hence, it follows that the optimal duration of conventional generators also will change in the presence of storage, as earlier derived in (Steffen and Weber 2013). We simplify the analysis by first assuming that we can shift energy from any instance of time to any other, i.e. that the storage only has a power (kW) constraint, as also assumed in (Steffen and Weber 2013). The optimal operational strategy of an EES unit will then be to shift as much energy as possible to the hours with load shedding. If EES charged by baseload is cheaper than the peaking generator, the ESS will also be discharged when the peaker is the marginal unit, as illustrated in Figure 3.

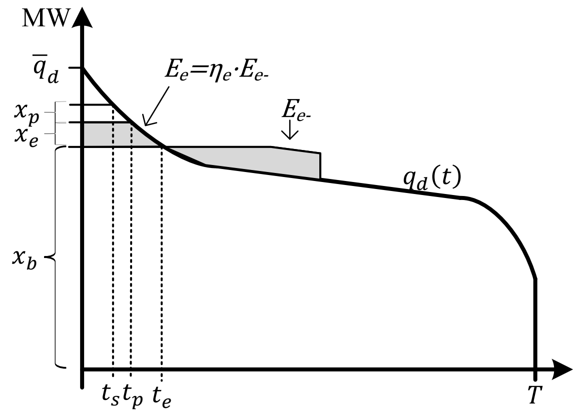

Figure 3. Load duration curve including energy storage, which is charged by the base plant. The storage device sets the price between t_p and t_e. The grey areas are the charging and discharging energy.

Referring to Figure 3, we can split the whole year into four main periods:

$[0, t_s]$: EES is discharging at full power during load shedding. A marginal increase in x_e causes a marginal decrease of load shedding over the whole period. From energy storage preservation it follows that this generation must be compensated by charging of the same amount divided by the round-trip efficiency η_e. We have assumed that the energy storage capacity is sufficiently large to be charged only by the cheapest generator.

$\langle t_s, t_p]$: EES is discharging at full power when the peaker is the marginal generator. A marginal increase in x_e causes a marginal decrease in generation from the peaker. As above, this is compensated by marginally more charging energy. Again, this operating strategy assumes that the EES energy capacity is sufficiently large and that $v_p > \eta_e v_b$.

$\langle t_p, t_e]$: EES is the marginal generator. A marginal increase in demand increases marginally the discharge by the same amount. This leads to a marginal increase in charging sometime during $\langle t_e, T]$ of the same amount, divided by the round-trip efficiency η_e.

$\langle t_e, T]$: The baseplant is the marginal generator, while the EES is either charging or stand-by.

The system cost minimization problem is identical to the general problem described in Chapter 2 without the VRE plant:

$$\min_{x_i} C = \sum_i F_i x_i + \sum_j v_j \int_0^T q_j(t)\, dt \tag{59}$$

$$\text{s.t.} \quad q_d(t) - \sum\nolimits_k q_k(t) + q_{e-}(t) = 0 \tag{60}$$

$$-q_k(t) \leq 0 \;, \qquad -q_{e-}(t) \leq 0 \tag{61}$$

$$q_i(t) - x_i \leq 0 \,, \qquad q_{e-}(t) - x_e \leq 0 \tag{62}$$

$$\eta_e \int_0^T q_{e-}(t)dt - \int_0^T q_e(t)dt = 0 \tag{63}$$

$$\text{Sets: } i \in \{p, b, e\}\,, j \in \{s, p, b\}\,, k \in \{s, p, b, e\}$$

We first consider the optimal operation during the whole discharging period $[0, t_e]$. According to the assumptions stated above, all generated power from the EES comes from the baseplant with variable cost v_b. With a storage round-trip efficiency of η_e, the variable cost of generation from EES is $v_e = v_b/\eta_e$. Under the assumption that there is enough energy available for charging the EES, it can be treated as a conventional generator with variable cost v_b/η_e during the discharge period. Based on the operation problem formulation (15)-(18) with corresponding Lagrangian (19) and KKT-conditions (20)-(23), which applies for any number of conventional generators, we derive the optimal operating policy during discharging as shown in Table 3. In the charging period $\langle t_e, T]$, the baseplant supplies the consumer demand and the charging power. Since the marginal cost of generation is constant equal to v_b over the whole period $\langle t_e, T]$, the charging can take place any time in this interval as long as the storage conservation (63) is fulfilled. The cost of charging is thus equal to v_b.

Table 3. System marginal cost and optimal operation for different demand levels with EES charged by the baseplant, under the assumption that $v_p > \eta_e v_b$.

$t \leq t_s$: $x_b + x_e + x_p \leq q_d(t)$	$t_s < t \leq t_p$: $0 \leq q_d(t) - x_b - x_e < x_p$	$t_p < t \leq t_e$: $0 \leq q_d(t) - x_b < x_e$	$t > t_e$: $q_d(t) + q_{e-}(t) > x_b$
$\lambda_d(t) = v_s$	$\lambda_d(t) = v_p$	$\lambda_d(t) = v_b/\eta_e$	$\lambda_d(t) = v_b$
$q_b(t) = x_b$	$q_b(t) = x_b$	$q_b(t) = x_b$	$q_b(t) = q_d(t) + q_{e-}(t)$
$q_e(t) = x_e$	$q_e(t) = x_e$	$q_e(t) = q_d(t) - x_b$	$q_e(t) = 0$
$q_p(t) = x_p$	$q_p(t) = q_d(t) - x_b - x_e$	$q_p(t) = 0$	$q_p(t) = 0$
$q_s(t) = q_d(t) - x_p - x_e - x_b$	$q_s(t) = 0$	$q_s(t) = 0$	$q_s(t) = 0$

Table 3 contains the the operational constraints (60)-(62) for problem (59) solved for optimal operation over the whole duration $[0, T]$. We can use these operational conditions to express the total cost minimization problem as:

$$\min_{x_p, x_b, x_e} C = F_p x_p + F_b x_b + F_e x_e + v_s \int_0^{t_s} [q_d(t) - x_p - x_e - x_b]\, dt + v_p \cdot \left(\int_0^{t_s} x_p\, dt + \int_{t_s}^{t_p} [q_d(t) - x_b - x_e]\, dt\right) + v_b \cdot \left(\int_0^{t_e} x_b\, dt + \int_{t_e}^{T} [q_d(t) + q_{e-}(t)]\, dt\right) \tag{64}$$

$$\text{s.t. } \eta_e \int_{t_e}^{T} q_{e-}(t)dt - \int_0^{t_e} q_e(t)dt = 0 \tag{65}$$

By the use of the storage constraint (65) and the optimal operation strategy from Table 3, the last term of the objective function can be substituted by:

$$\int_{t_e}^{T} q_{e-}(t)dt = \eta_e^{-1} \int_0^{t_e} q_e(t)dt = \eta_e^{-1} \left(\int_0^{t_p} x_e\, dt + \int_{t_p}^{t_e} [q_d(t) - x_b]\, dt\right) \tag{66}$$

The optimization problem can now be written as

$$\min_{x_p,x_b,x_e} C = F_p x_p + F_b x_b + F_e x_e + v_s \int_0^{t_s} [q_d(t) - x_p - x_e - x_b]\,dt + v_p \cdot \left(\int_0^{t_s} x_p\,dt + \int_{t_s}^{t_p} [q_d(t) - x_b - x_e]\,dt\right) + \eta_e^{-1} v_b \cdot \left(\int_0^{t_p} x_e\,dt + \int_{t_p}^{t_e} [q_d(t) - x_b]\,dt\right) + v_b \cdot \left(\int_0^{t_e} x_b\,dt + \int_{t_e}^{T} q_d(t)\,dt\right) \tag{67}$$

which is identical to a three-generator problem where the mid-merit generator has marginal cost $\eta_e^{-1} v_b$. The optimality condition for the peaker is unchanged from (27), while the EES and baseplant conditions becomes:

$$\frac{\partial C}{\partial x_e} = 0 \Rightarrow F_e - (v_s - \eta_e^{-1} v_b) t_s - (v_p - \eta_e^{-1} v_b)(t_p - t_s) = 0 \tag{68}$$

$$\Rightarrow t_p = \frac{F_e - F_p}{v_p - \eta_e^{-1} v_b} \tag{69}$$

$$\frac{\partial C}{\partial x_b} = 0 \Rightarrow F_b - (v_s - v_b) t_s - (v_p - v_b)(t_p - t_s) - (\eta_e^{-1} v_b - v_b)(t_e - t_p) \tag{70}$$

$$\Rightarrow t_e = \frac{F_b - F_e}{v_b(\eta_e^{-1} - 1)} \tag{71}$$

These conditions apply for an ideal storage device which can move energy from any instant of time to another, only limited by its power capacity and round-trip efficiency, i.e. with unbounded energy capacity. For real-world applications, the last assumption is of course too optimistic, so the results should be regarded as an upper limit to how much storage can contribute with in system optimum. Furthermore, the durations above only apply for storage efficiencies less than 1, which is always the case in real systems. The conversion losses make discharge more expensive in operation than direct supply from the generator used for charging. From (71) we see that the optimality condition leads to an infeasible solution for round-trip efficiency of 1. The discharge duration according to (74) goes to infinity; you will replace as much thermal energy as you can with ESS as long as the fixed costs of ESS are lower than for the baseload plant. However, the discharge duration is strictly limited by the storage preservation (65) which always applies, since it is not possible to discharge more energy than available from the charging period.

The optimality conditions state that the optimal duration of the peaker is proportional to the EES fixed cost F_e, while the baseplant duration is negatively proportional to F_e. The durations are equal when

$$F_e' = (F_b - F_p)\frac{(v_p - \eta_e^{-1} v_b)}{(v_p - v_b)} \tag{72}$$

$F_e > F_e'$ implies that $t_p > t_e$, which is not feasible if $v_p > \eta_e v_b$, i.e. EES investment is zero in that case. If $v_p < \eta_e v_b$, on the other hand, the EES and the peaker will shift places in the merit-order, and we can directly set up the optimality conditions in a similar manner as above::

$$\frac{\partial C}{\partial x_e} = 0 \Rightarrow t_s = \frac{F_e}{v_s - \eta_e^{-1} v_b} \tag{73}$$

$$\frac{\partial C}{\partial x_p} = 0 \Rightarrow t_e = \frac{F_p - F_e}{v_p(\eta_e^{-1} - 1)} \tag{74}$$

where it is still assumed that all stored energy is generated from the baseplant. For a less optimistic case where EES is charged only by the peaker, it is necessary to replace v_b in the denominator of (73) with v_p. The optimality condition for the baseplant is given by (28), since the peaker again is adjacent to the baseplant in the merit-order.

5.1.2 Cost recovery

The profit function of EES is

$$\pi_e = AR_e - AC_e = \int_0^T p(t)\left(q_e(t) - q_{e-}(t)\right)dt - F_e \cdot x_e \tag{75}$$

where the instantaneous charging and discharging power is given by the storage operation strategy and is generally a function of the storage capacity (power and energy) and the market price. In our modelling framework, we take explicitly into account the power constraint by (61) and (62), while energy storage conservation is fulfilled on an annual basis by (63). In the previous section, it was shown that the marginal cost of energy generated from the EES is equal to the variable cost of the marginal thermal generator that is used for charging, divided by the round-trip efficiency.

By using the segments from the KKT-conditions in Table 3 and marginal cost pricing, the profit function can be expressed as

$$\pi_e = v_s x_e t_s + v_p x_e (t_p - t_s) + p_e \int_{t_p}^{t_e} q_e(t)dt - v_b \int_{t_e}^{T} q_{e-}(t)dt - F_e \cdot x_e \quad (76)$$

where p_e is the short-term electricity price during period $[t_p, t_e]$, when the storage is the marginal generator. From the KKT-conditions, we know that this price should be equal to $\eta_e^{-1} v_b$ to ensure optimal operation, since this is the marginal cost of charging the EES. In other words, we assume perfect knowledge of the future to determine the value of stored energy, by applying a deterministic model of the system on an annual basis. In a real market setting, on the other hand, the future prices, demand, weather conditions etc. are not known, and the marginal value of the stored energy, i.e. the opportunity cost (Førsund 2015) will consequently change over time. In hydropower planning this is referred to as the "water value" (Stage and Larsson 1961; Fosso et al. 1999; Førsund 2015), which is typically calculated as an expectation value based on stochastic representation of future unknown parameters. For detailed treatment of uncertainty in EES operation strategies, see (Xu, Botterud, and Korpås 2019). The use of stochastic parameters for storage valuation in the duration curve framework is an area for future research.

By applying $p_e = \eta_e^{-1} v_b$, and the storage conservation $\eta_e \int_{t_e}^{T} q_{e-}(t)dt = x_e t_p + \int_{t_p}^{t_e} q_e(t)dt$, the profit function becomes:

$$\pi_e = v_s x_e t_s + v_p x_e (t_p - t_s) + \eta_e^{-1} v_b x_e t_p - F_e \cdot x_e \quad (77)$$

By setting $\pi_e = 0$ we obtain the optimality condition for EES given by (69). In perfect competition where no EES owner is large enough to change the durations t_s or t_p, profit maximization yields

$$\frac{\partial \pi_e}{\partial x_e} = 0 \Rightarrow v_s t_s + v_p (t_p - t_s) + \eta_e^{-1} v_b t_p - F_e = 0 \quad (78)$$

which also gives the optimality condition (69). As shown above, the optimal price for discharging energy is equal to the marginal cost of charging, under the assumption of perfect foresight and annual storage balance.

5.2 Energy storage in systems with VRE

Building on the storage model for conventional generators from Section 5.1, we explore two main ESS operating strategies when introducing VRE. The first principle is to use storage exclusively for utilizing surplus VRE, which is discussed further in Section 5.2.1 and 5.2.2. The second operating principle is general price arbitrage regardless of the source of energy, which is covered in Section 5.2.3.

In the storage model introduced in the previous section, it was assumed that it was possible to move energy from any instant of time to another over the course of the year. Although very optimistic, the assumption can at least partly be justified for systems with only conventional generators, which alternate in setting the price on a daily or weekly basis. With VRE, this assumption is more questionable, as the time of surplus VRE generation and the time of peak load might be in different seasons of the year and would require very large amounts of storage capacity. Therefore, we also present a restrictive operational strategy in Section 5.2.2, where we assume that the stored VRE energy is only able to replace base plant generation due to storage limitations.

5.2.1 VRE storage with unlimited energy capacity

In the ideal case with no storage limits, it is possible to discharge the stored energy in the periods with highest price first. This is illustrated in Figure 4 for a system with one peaker p, one base plant b, one VRE plant p and one energy storage device e. In the illustrated case, there is enough surplus VRE energy to discharge during all periods where load shedding and conventional generators sets the price for electricity. A new variable t_v is introduced in the figure, which is defined as the time instant when the negative net load equals the charging capacity: $q_{nd}(t_v) = -x_e$.

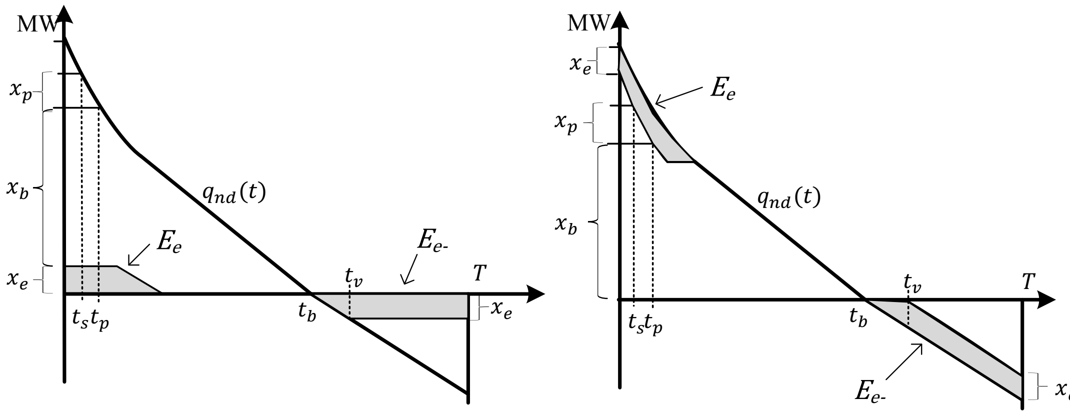

Figure 4. Net load duration curve including energy storage charged by surplus VRE energy. Left: Storage as individual generator and consumer. Right: Storage as part of the net demand. These are equivalent representations.

Consider the illustrated case in Figure 4 where the available amount of discharged energy is limited by the power capacity of storage, the duration of VRE surplus and the storage efficiency. Since we assume unbounded energy storage, it is most beneficial to discharge at full power during load shedding $[0, t_s]$ and the peaker period $[t_s, t_p]$ and discharge the rest of the stored energy in the base plant period $[t_p, t_b]$. The available discharge energy during $[t_p, t_b]$ is limited by:

$$E_e^{[t_p,t_b]} = \int_{t_p}^{t_b} q_e(t)dt = \eta_e \int_{t_b}^{T} q_{e-}(t)dt - x_e t_p = \eta_e E_{e-}(x_v, x_e) - x_e t_p \tag{79}$$

where it is indicated that the annual charging energy is a function of both the VRE capacity and the storage capacity, as visualized in Figure 4. Equation (79) holds true if there is enough charging energy available to discharge at full power during the whole period $[0, t_p]$.

It is indifferent at which time during $[t_p, t_b]$ that the storage is discharged, since the base plant is the marginal generator over the whole period. Note that it is not possible to cover a marginal load increase in $[t_p, t_b]$ by stored energy, as all the surplus energy from $[t_b, T]$ is already utilized. Thus, the marginal generator in $[t_p, t_b]$ is the base plant, even with storage present, and the short-term marginal cost in this time segment is v_b. However, in the long-term, there exists two additional options to cover a marginal demand increase during $[t_p, t_b]$:

- Increasing the power capacity of the storage x_e while the VRE capacity is constant. Referring to Figure 4, this option increases the amount of charged energy during $[t_b, T]$.
- Increasing the VRE capacity x_v while x_e is constant. This option moves the net demand curve to the left, and thus increases the length of $[t_b, T]$ which leads to more available stored energy.

As will be shown in the next section, the optimal response to a marginal increase in demand is a combination of these two options, i.e. increasing both x_e and x_v, according to their optimality conditions.

5.2.1.1 Minimization of system costs

The system cost minimization problem is identical to the main problem (9)-(14), except that we add the charging constraint:

$$q_{e-}(t) - q_{nd}(\mathrm{t}) \leq 0 \tag{80}$$

which ensures that only surplus VRE energy is stored (general price arbitrage is treated in Section 5.2.3). We first find the optimal operation in each of the periods indicated in Figure 4, under the assumption that there is sufficient stored energy available to discharge at full power during the whole period $[0, t_p]$:

$[0, t_s]$: All dispatchable generators are operated at full power, so the marginal cost is given by load shedding. Hence $\lambda_d = v_s$ as before.

$\langle t_s, t_p]$: The baseplant and EES are operated at full power, and the marginal plant is the peaker. Hence $\lambda_d = v_p$ as before.

$\langle t_p, t_b]$: The demand is covered by the baseplant, VRE and EES. The baseplant is the marginal generator in the whole period, hence $\lambda_d = v_b$. Consider that the EES covers a marginal demand increase over a small time interval Δt during $[t_p, t_b]$: $\Delta P_d \cdot \Delta t = \Delta P_e \cdot \Delta t$ The marginal increase in EES generation will reduce the storage level according to the instantaneous storage balance $\Delta E_{stored} = \eta_e^{-1} \Delta P_e \cdot \Delta t = \eta_e^{-1} \Delta P_d \cdot \Delta t$. However, the annual storage balance (14) must be fulfilled. Since all available VRE energy is already utilized, the EES is forced to charge energy from the baseplant to cover the storage deficit caused by the marginal demand increase: $\Delta P_b \cdot \Delta t = \eta_{e,ch}^{-1} \Delta E_{stored} \Rightarrow \Delta P_b = \eta_e^{-1} \Delta P_d$. Hence, without new investments, a marginal increase in EES generation during $[t_p, t_b]$ must be covered by the baseplant. Due to the storage efficiency, $\eta_e < 1$, it will always be cheaper to cover a marginal demand increase during this period directly by the baseplant, i.e. the baseplant is the marginal generator and $\lambda_d = v_b$ over the whole period.

$\langle t_b, t_v]$: In this period, there is surplus of VRE energy, and the EES is charged below its full capacity, $0 \leq q_{nd}(t) < x_e$. Hence, during this period, the EES is the marginal load, and the marginal cost of electricity is set by the marginal value of stored energy, $\lambda_d = \eta_e v_b$. This corresponds to the increase in required baseplant generation in period $\langle t_p, t_b]$ if EES charging is reduced in period $\langle t_b, t_v]$, accounting for the EES efficiency. During $[t_b, t_v]$, there are two competing options for supplying a marginal increase in demand: 1) Starting up the baseplant with marginal cost v_b. 2) Reducing the charging of EES with the same amount $\Delta P_{e-} \cdot \Delta t = -\Delta P_d \cdot \Delta t$. This gives less stored energy $\Delta E_{stored} = -\eta_{e,ch} \Delta P_d \cdot \Delta t$, which reduces the available energy for discharging: $\Delta E_e^{[t_p, t_b]} = \eta_{e,dch} \Delta E_{stored} = -\eta_e \Delta P_d \cdot \Delta t$. The reduced energy from discharging must be substituted by the marginal generator in the least expensive discharging period, i.e. the baseplant: $\Delta P_b = -\frac{\Delta E_e^{[t_p, t_b]}}{\Delta t} = \eta_e \Delta P_d$, with marginal cost v_b. Hence, the cost of a marginal increase in demand ΔP_d is $\lambda_d = \eta_e v_b$, which is always cheaper than the baseplant since $\eta_e < 1$.

$\langle t_v, T]$: There is surplus of VRE energy, and the EES is charged at full power. Hence, VRE is the marginal plant and $\lambda_d = 0$.

With the optimal operating strategies for each period described above, we can formulate the total cost minimization problem:

$$\min_i C = \sum_i F_i x_i + v_s \int_0^{t_s} \left[q_d(t) - AF_v(t) x_v - \sum_j x_j\right] dt + v_p \cdot \left(\int_0^{t_s} x_p \, dt + \int_{t_s}^{t_p} \left[q_d(t) - AF_v(t) x_v - \sum_k x_k\right] dt\right) + v_b \cdot \left(\int_0^{t_p} x_b \, dt + \int_{t_p}^{t_b} \left[q_d(t) - AF_v(t) x_v - q_e(t)\right] dt\right) \ \forall i \in \{p, b, e, v\}, j \in \{p, b, e\}, k \in \{e, b\} \tag{81}$$

$$\text{s.t. } \eta_e \int_{t_e}^{T} q_{e-}(t) dt - \int_0^{t_e} q_e(t) dt = 0 \tag{82}$$

For this problem, the storage constraint (82) is equivalent to

$$E_e^{[t_p,t_b]} = \eta_e E_{e-}^{[t_b,t_v]} + \eta_e x_e (T - t_v) - x_e t_p \tag{83}$$

where we have used the result that the EES is charging at maximum capacity during $\langle t_v, T]$ and discharging at maximum capacity during $[0, t_p]$. Substituting (83) into (81):

$$\begin{aligned}\min_i C &= \sum_i F_i x_i + v_s E_d^{[0,t_s]} + v_p E_d^{[t_s,t_p]} + v_b E_d^{[t_p,t_b]} - (x_p + x_b + x_e)(v_s - v_p)t_s - \\ &(x_b + x_e)(v_p - v_b)t_p - x_e \eta_e v_b (T - t_v) - \eta_e v_b E_{e-}^{[t_b,t_v]} - x_v \Big(v_s CF_v^{[0,t_s]} t_s + \\ &v_p CF_v^{[t_s,t_p]} (t_p - t_s) + v_b CF_v^{[t_p,t_b]} (t_b - t_p) \Big) \forall i \in \{p, b, e, v\}\end{aligned} \tag{84}$$

Problem (84) without additional constraints minimizes the system cost under the following assumptions:

- EES is only bounded by power capacity and yearly energy balance. EES operation is treated deterministic, i.e. with full foresight.
- EES is only used for storing surplus VRE energy that otherwise would have been curtailed.
- All power plants (peaker, baseload, EES and VRE) forms part of the solution. Other combinations form a simpler subset, and must be treated separately.
- It is enough stored energy available for the EES to generate at full power during the whole period $[0, t_p]$. Cases with less available charging are simpler variants of the problem and must be treated separately.

It is possible to derive the first-order optimality conditions for all plants directly from (79). For the peaker and the baseload, we obtain the same result as in Chapter 3 since these generators have not changed position in the merit order, see (27) and (28). For the EES plant, we get:

$$\frac{\partial C}{\partial x_e} = F_e - (v_s - v_p)t_s - (v_p - v_b)t_p - \eta_e v_b (T - t_v) - \eta_e v_b \frac{\partial E_{e-}^{[t_b,t_v]}}{\partial x_e} \tag{85}$$

where the last term is zero, since the EES is the marginal load during $\langle t_b, t_b]$ and therefore operates lower than its capacity. Setting $\frac{\partial C}{\partial x_e} = 0$, the optimality condition for the EES becomes:

$$\eta_e (T - t_v) = \frac{F_e - F_b}{v_b} \tag{86}$$

$$\Rightarrow t_v = T + \frac{F_b - F_e}{\eta_e v_b} \tag{87}$$

Equation (86) is equivalent to the optimality condition of a generator with zero variable cost, with a duration $t^* = \eta_e (T - t_v)$. The duration $\eta_e (T - t_v)$ expresses how long time it is necessary to charge the EES at full power, accounting for the storage losses η_e. Rearranging to (87), we get directly the unknown duration t_v, which is the time instant when the available surplus power is equal to the charging capacity x_e. An equivalent definition of t_v is the duration of full VRE energy utilization, i.e. the number of hours of the year without VRE curtailment. From (87) we see that t_v is proportional to $-F_e$, i.e. if the fixed cost of EES is decreased, less hours with zero price is needed to make the EES beneficial for the system. The threshold for EES to be economically viable is when $t_v = t_b$. If the calculated t_v is lower than t_b, this implies a negative charging capacity x_e which is infeasible (See Figure 4).

The baseplant duration t_b is found from the optimality condition for the VRE plant. From (84):

$$\begin{aligned}\frac{\partial C}{\partial x_v} = F_v - v_s AF_v^{[0,t_s]} t_s - v_p AF_v^{[t_s,t_p]} (t_p - t_s) - v_b AF_v^{[t_p,t_b]} (t_b - t_p) \\ - \eta_e v_b \frac{\partial}{\partial x_v} E_{e-}^{[t_b,t_v]}\end{aligned} \tag{88}$$

Previously in this section, we showed that a marginal increase in demand during $\langle t_b, t_v]$ caused a marginal decrease in charging of the same amount since the EES is the marginal load unit in this period. If instead the VRE capacity increases marginally, the net load during the period will decrease by $AF_v^{[t_s,t_p]} (t_v - t_b)$. Since the EES does not operate at its maximum charging capacity during $\langle t_b, t_v]$, it can absorb the whole amount of additional VRE energy. Thus, the marginal increase in charging energy is $\frac{\partial}{\partial x_v} E_{e-}^{[t_b,t_v]} = AF_v^{[t_b,t_v]}(t_v - t_b)$. The optimality condition for VRE becomes:

$$\frac{dC}{dx_v} = 0 \Rightarrow F_v = v_s t_s \cdot AF_v^{[0,t_s]} + v_p(t_p - t_s) \cdot AF_v^{[t_s,t_p]} + v_b(t_b - t_p) \cdot AF_v^{[t_p,t_b]} + \eta_e v_b(t_v - t_b) \cdot AF_v^{[t_b,t_v]} \quad (89)$$

$$t_b = \frac{F_v - v_s t_s \cdot AF_v^{[0,t_s]} - v_p(t_p - t_s) \cdot AF_v^{[t_s,t_p]} - v_b\left(\eta_e t_v AF_v^{[t_b,t_v]} - AF_v^{[t_p,t_b]} t_p\right)}{v_b\left(AF_v^{[t_p,t_b]} - \eta_e AF_v^{[t_b,t_v]}\right)} \quad (90)$$

We see that the duration of the baseload plant, which determines the optimality condition for VRE, is dependent of the characteristic of the EES. If we set $t_v = t_b$ (corresponding to zero EES investment) in (90), the duration t_b becomes equal to the result for the case without EES given in (53). We find from (90) that $\frac{\partial t_b}{\partial t_v} < 0$. This shows that an investment in EES (corresponding to $t_v > t_b$) leads to a higher investment of VRE in optimum, since a reduction in t_b only can be caused by increasing x_v as long as the demand is not changing.

When t_b and t_v has been calculated, it is straightforward to find the optimal VRE capacity and EES capacity from the net demand curve: $q_{nd}(t_b) = 0$ and $q_{nd}(t_v) = -x_e$.

5.2.1.2 Cost recovery of EES

As already mentioned, we present results for the case where no generator types are entirely pushed out of the market. Both the peaker and base plant will be present in the system. VRE and EES will cause a change in the capacity and generation of the base and peaker, but the duration of load shedding (optimality condition for the peaker) and duration of the peaker (optimality condition for the base plant) are both unchanged.

The profit function of the EES is set up similarly to Section 5.1.2:

$$\pi_e = \int_0^T p(t)\big(q_e(t) - q_{e-}(t)\big)\,dt - F_e \cdot x_e \quad (91)$$

Using the optimal EES operation from Section 5.2.1.1 and the corresponding Lagrange multipliers λ_d as price we can write:

$$\pi_e = v_s \int_0^{t_s} x_e\,dt + v_p \int_{t_s}^{t_p} x_e\,dt + v_b \int_{t_p}^{t_b} q_e(t)\,dt - \eta_e v_b \int_{t_b}^{t_v} q_{e-}(t)\,dt - F_e \cdot x_e = x_e \cdot \big(v_s t_s + v_p(t_p - t_s) - F_e\big) + v_b\left(E_e^{[t_p,t_b]} - \eta_e E_{e-}^{[t_b,t_v]}\right) \quad (92)$$

Substituting the rightmost parenthesis with $\eta_e x_e(T - t_v) - x_e t_p$ from the annual storage balance (83) gives:

$$\pi_e = x_e \cdot \big(v_s t_s + v_p(t_p - t_s) + v_b(\eta_e(T - t_v) - t_p) - F_e\big) \quad (93)$$

Cost recovery $\pi_e = 0$ gives

$$v_s t_s + v_p(t_p - t_s) + v_b(\eta_e(T - t_v) - t_p) - F_e = 0$$
$$\Rightarrow t_v = T - \frac{1}{\eta_e v_b}\big(F_e + v_b t_p - v_s t_s - v_p(t_p - t_s)\big) = T - \frac{F_b - F_e}{\eta_e v_b} \quad (94)$$

which is equal to the system optimal condition found in (82) in the previous section.

Profit maximization of an individual EES owner who is sufficiently small to not change the duration t_v on its own gives the same result:

$$\frac{\partial \pi_e}{\partial x_e} = 0 \Rightarrow v_s t_s + v_p(t_p - t_s) + v_b(\eta_e(T - t_v) - t_p) - F_e = 0 \quad (95)$$

5.2.1.3 Cost recovery of VRE
The general profit function for VRE is given in (56). Inserting the prices (Lagrange multipliers) derived from the optimal operation in Section 5.2.1.1, we get:

$$\begin{aligned}\pi_v = v_s AF_v^{[0,t_s]} x_v t_s + v_p AF_v^{[t_s,t_p]} x_v(t_p - t_s) + v_b AF_v^{[t_p,t_b]} x_v(t_b - t_p) \\ + \eta_e v_b AF_v^{[t_b,t_v]} x_v(t_v - t_b) - F_v x_v\end{aligned} \tag{96}$$

Cost recovery, $\pi_v = 0$, gives the same result as system optimum (90):

$$\begin{aligned}F_v = p_s AF_v^{[0,t_s]} t_s + v_p AF_v^{[t_s,t_p]}(t_p - t_s) + v_b AF_v^{[t_p,t_b]}(t_b - t_p) \\ + \eta_e v_b AF_v^{[t_v,t_e]}(t_v - t_b)\end{aligned} \tag{97}$$

We see directly from (96) that this result is also obtained by maximizing the profit of an individual VRE owner in a perfect market: $\frac{d\pi_v}{dx_v} = 0$ gives the same result since π_v is a linear function of x_v.

5.2.2 VRE storage with limited energy capacity
As discussed in the introduction to this chapter, EES storage is only represented by its power capacity and efficiency since the duration curve model cannot handle energy capacity limitations of the storage explicitly. So far, we have assumed that it is possible to shift the stored energy between any time instants over the year, which obviously is a very optimistic assumption for both present and emerging storage technologies such as batteries, flow batteries, CAES and pumped hydro. These technologies are often reported with durations in the range of hours, both in real-world installations and future scenario studies (Pinnangudi, Kuykendal, and Bhadra 2017; Argyrou, Christodoulides, and Kalogirou 2018; Cole et al. 2016; McPherson, Johnson, and Strubegger 2018; Sepulveda et al. 2018; de Sisternes, Jenkins, and Botterud 2016). Although there are several promising alternatives for long-duration storage, these are so far limited by different factors, e.g. 1) Being at the R&D stage, such as Aqueous sulfur/sodium/air systems (Z. Li et al. 2017). 2) High round-trip losses such as hydrogen storage (Pellow et al. 2015; Korpås 2004). 3) Specific geographical locations such as seasonal-storage from reservoir hydro with pumping capability (Graabak et al. 2019).

In this section, we introduce an EES model that is limited to only discharge in the baseload period. The motivation behind this model is to represent short-term storage of e.g. PV energy from day to night, so-called "valley filling" strategy. The model is also used as a building-block of the general price arbitrage model (Section 5.2.3).

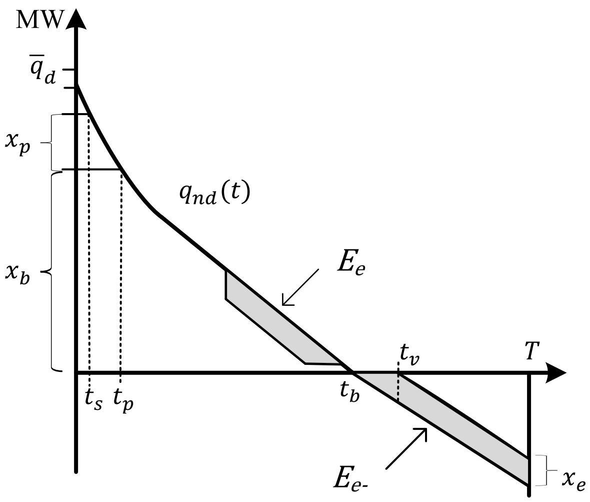

Figure 5. Net load duration curve for a system where stored VRE energy replaces baseload power only.

5.2.2.1 System optimality conditions
Based on the conservative assumption explained above, we can directly derive a simplified variant of the model presented in Section 5.2.1 where the storage only shifts energy between the surplus period

$[t_b, T]$ to the base plant period $[t_p, t_b]$. In this case, neither the optimal duration nor the sizing of the peaker and base plant is affected by the inclusion of the storage. The optimality condition for the VRE plant is also unchanged. For EES, on the other hand, the periods when load shedding and peaker sets the marginal cost are no longer available for discharge, so the optimality condition similar to (85)-(87) becomes:

$$\eta_e v_b (T - t_v) = F_e \tag{98}$$

$$\Rightarrow t_v = T - \frac{F_e}{\eta_e v_b} \tag{99}$$

since the EES now discharges all its energy from surplus VRE to replace energy from the baseload plant in the period $[t_p, t_b]$.

5.2.2.2 Cost recovery

Cost recovery and profit maximization follows directly from the derivations in Section 5.2.1, by simply setting the EES profits to zero in the period $[0, t_p]$. The equivalents of (94) and (95) for this case both gives:

$$F_e = \eta_e v_b (T - t_v) \tag{100}$$

which is equal to the system optimum (98).

For the VRE-plant, the conditions for cost recovery and profit maximization is unchanged from Section 5.2.1, thus (97) applies also here.

5.2.3 Storage for general price arbitrage

In this section, we combine the limited VRE storage model from Section 5.2.2 with the storage model for conventional generators from Section 5.1. The rationale behind this combined model is to utilize ESS whenever it is profitable, whether that means storing thermal energy or renewable energy. In principle, a time-sequential optimization model based on the general formulation presented in Chapter 1 will seek cost-minimum without restricting the use of storage charging to any type of power plant. However, it is not possible to fully represent time-sequential storage optimization in a duration model approach due to the lack of chronology of the sorted net load. Based on the storage operations strategies presented previously, we propose in this section a combined storage model with the following operating strategy:

> $\langle t_b, T]$: The EES stores surplus VRE energy and discharges it sometime during $[t_p, t_b]$. In Figure 6, this period is illustrated to be immediately before t_b, but it is not a necessary assumption as long as the storage is discharged sometime during the baseplant period. The operation strategy follows Section 5.2.2.
>
> $\langle t_e, t_b]$: During this period, the baseload is the marginal generator. During a part of this period, the EES discharges surplus VRE energy, indicated by $E_{e,2}$ in Figure 6. In the rest of the period, the EES is available for charging baseload power to replace peaker and load shedding during $[0, t_p]$.
>
> $[0, t_e]$: The EES energy which was charged by the baseload is discharged in this period. Surplus energy from VRE is assumed not to be available for discharge in this period. This is a simplistic representation of the limited energy capacity (kWh capacity) of the storage, which also was used in Section 5.2.2.

For this EES representation to be practically applicable, the baseload period $[t_p, t_b]$ must be sufficiently long to have room for both discharging VRE energy from $[t_b, T]$ and to shift energy to the load shedding peaker periods. As an example, consider a system with peaker duration equal to 500 hours and with 2000 hours of surplus VRE energy. The period $[t_p, t_b]$ will then be 6260 hours, which is more than enough for the proposed storage operation. Nevertheless, the result should always be checked for this limitation.

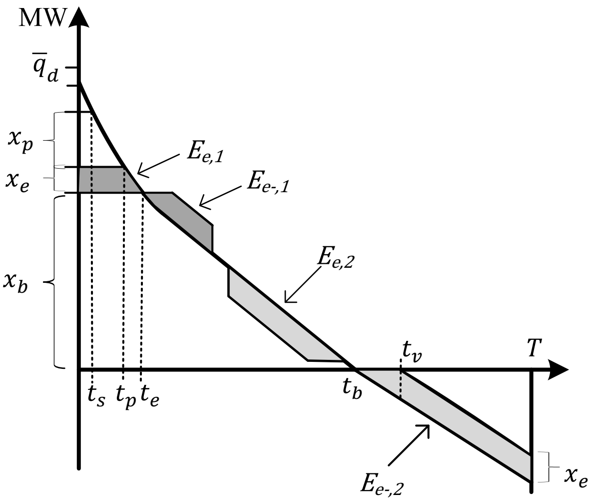

Figure 6. Net Load duration curve including energy storage, which is charged by baseload ($E_{e-,1}$) and VRE ($E_{e-,2}$). The stored energy from the baseplant is discharged during load shedding and peaker operation ($E_{e,1}$). The stored energy from VRE replaces only baseload ($E_{e,2}$) due to the model assumption of limited storage capacity.

5.2.3.1 System optimality conditions

The EES operational model is a combination of two modes: 1) Store baseload energy ($E_{e-,1}$) to supply during load shedding and peaker operation ($E_{e,1}$). 2) Store surplus VRE energy ($E_{e-,2}$) to supply during baseload period ($E_{e,2}$). These operating and storage regimes do not interfere, and occurs at different periods, so we can treat them separately when deriving the optimal system operation.

> $[0, t_s]$, $\langle t_s, t_p]$, $\langle t_p, t_e]$: The optimal operation in the these intervals is identical to what is stated in Table 3, except that the thermal generators and EES must meet the net demand instead of demand since VRE is present.
>
> $\langle t_e, t_b]$: The baseload is the marginal generator, both when EES is charging from the baseload (See Table 3) and when it is discharging previously stored VRE energy (as explained in Section 5.2.1.1).
>
> $\langle t_b, t_v]$, $\langle t_v, T]$: The optimal operation is the same as in Section 5.2.1.1 for these intervals.

Based on the optimal operation in the different duration segments according to Figure 6, we can set up the system cost minimization problem in the same manner as previously:

$$\min_i C = \sum_i F_i x_i + v_s \int_0^{t_s} \left[q_d(t) - AF_v(t)x_v - \sum_j x_j\right] dt + v_p \cdot \left(\int_0^{t_s} x_p \, dt + \int_{t_s}^{t_p} \left[q_d(t) - AF_v(t)x_v - \sum_k x_k\right] dt \right) + v_b \cdot \left(\int_0^{t_e} x_b \, dt + \int_{t_e}^{t_b} \left[q_d(t) - AF_v(t)x_v + q_{e-}(t) - q_e(t)\right] dt \right) \; \forall i \in \{p, b, v, e\}, j \in \{p, b, e\}, k \in \{e, b\} \tag{101}$$

$$\text{s.t.} \int_{t_e}^{t_b} q_{e-}(t) dt = \eta_e^{-1} x_e t_p + \eta_e^{-1} \int_{t_p}^{t_e} q_e(t) dt \tag{102}$$

$$\int_{t_e}^{t_b} q_e(t) dt = \eta_e \int_{t_b}^{t_v} q_e(t) dt + \eta_e x_e (\mathrm{T} - t_v) \tag{103}$$

By setting $\int_{t_e}^{t_b} q_{e-}(t) dt = E_{e-}^{[t_e,t_b]}$, and applying storage conservation of the charged baseload energy, we can formulate (102):

$$\begin{aligned} E_{e-}^{[t_e,t_b]} &= \eta_e^{-1} x_e t_p + \eta_e^{-1} E_e^{[t_p,t_e]} \\ &= \eta_e^{-1} x_e t_p + \eta_e^{-1} E_d^{[t_p,t_e]} - \eta_e^{-1} (x_b + AF_v^{[t_p,t_e]} x_v) \cdot (t_e - t_p) \end{aligned} \tag{104}$$

Similarly, for the VRE storage constraint (103):

$$E_e^{[t_e,t_b]} = \eta_e AF_v^{[t_b,t_v]} x_v - \eta_e E_d^{[t_b,t_v]} + \eta_e x_e (\mathrm{T} - t_v) \tag{105}$$

As previously, we write for convenience $E_d^{[0,t_s]} = \int_0^{t_s} q_d(t)dt$ and $AF_v^{[0,t_s]} = \int_0^{t_s} AF_v(t)dt$ etc. We insert the reformulated storage constraints (104) and (105) into the objective function (102) and rearrange with respect to the generator capacities x_i. The cost minimization problem can then be written:

$$\min_i C = \sum_i a_i x_i + b \; \forall i \in \{p,b,e,v\} \tag{106}$$

where

$$b = v_s E_d^{[0,t_s]} + v_p E_d^{[t_s,t_p]} + \eta_e^{-1} v_b E_d^{[t_p,t_e]} + v_b E_d^{[t_e,t_b]} + \eta_e v_b E_d^{[t_b,t_v]} \tag{107}$$

$$a_p = F_p - (v_s - v_p) t_s \tag{108}$$

$$a_b = F_b - v_s t_s - v_p(t_p - t_s) - v_b \eta_e^{-1}(t_e - t_p) + v_b t_e \tag{109}$$

$$a_v = F_v - v_s AF_v^{[0,t_s]} t_s - v_p AF_v^{[t_s,t_p]}(t_p - t_s) - \eta_e^{-1} v_b AF_v^{[t_p,t_e]}(t_e - t_p) - v_b AF_v^{[t_e,t_b]}(t_b - t_e) - \eta_e v_b AF_v^{[t_b,t_v]}(t_v - t_b) \tag{110}$$

$$a_e = F_e - v_s t_s - v_p(t_p - t_s) + v_b \eta_e^{-1} t_p - v_b \eta_e (T - t_v) \tag{111}$$

Since a_i is the partial derivate of C with respect to x_i, the optimality condition for the investment in each technology $i \in \{p,b,v,e\}$ is found by setting $a_i = 0$ in (108)-(111). t_s is solved directly from (108) as before. We then have three equations left with four unknowns (t_p, t_b, t_e, t_v). However, the durations are also constrained by the net demand curve $q_{nd}(t) = q_d(t) - AF_v(t) \cdot x_v$. The net demand is zero at $t = t_b$:

$$q_{nd}(t_b) = q_d(t_b) - AF_v(t_b) \cdot x_v = 0 \Rightarrow x_v = \frac{q_d(t_b)}{AF_v(t_b)} \tag{112}$$

Equation (112) expresses x_v as a function of t_b. Furthermore, the net demand is equal to $-x_e$ at $t = t_v$:

$$x_e = -q_{nd}(t_v) = -q_d(t_v) + AF_v(t_v) \cdot x_v \tag{113}$$

From the left part of Figure 6, we see that x_e is also bounded by:

$$x_e = q_{nd}(t_p) - q_{nd}(t_e) = q_d(t_p) - AF_v(t_p) \cdot x_v - q_d(t_e) + AF_v(t_e) \cdot x_v \tag{114}$$

By combining (112), (113) and (114) we get a non-linear equation $f(t_p, t_b, t_e, t_v) = 0$ which bounds the solutions to the net demand curve, Thus, there are in total four equations with four unknowns which determines the optimality conditions for EES, VRE and the baseplant:

$$0 = F_b - v_s t_s - v_p(t_p - t_s) - v_b \eta_e^{-1}(t_e - t_p) + v_b t_e \tag{115}$$

$$0 = F_v - v_s AF_v^{[0,t_s]} t_s - v_p AF_v^{[t_s,t_p]}(t_p - t_s) - \eta_e^{-1} v_b AF_v^{[t_p,t_e]}(t_e - t_p) - v_b AF_v^{[t_e,t_b]}(t_b - t_e) - \eta_e v_b AF_v^{[t_b,t_v]}(t_v - t_b) = 0 \tag{116}$$

$$0 = F_e - v_s t_s - v_p(t_p - t_s) + v_b \eta_e^{-1} t_p - v_b \eta_e (T - t_v) = 0 \tag{117}$$

$$0 = q_d(t_v) + q_d(t_p) - q_d(t_e) - \frac{q_d(t_b)}{AF_v(t_b)} \cdot \left(AF_v(t_v) + AF_v(t_p) - AF_v(t_e)\right) \tag{118}$$

This set of equations can be solved with respect to the unknowns $t_i \; \forall \; i \in \{p,b,e,v\}$ by a suitable iterative procedure or non-linear equation solver. i.e. the bisection method. When the durations are found, it is straightforward to calculate the optimal capacities $x_i \; \forall \; i \in \{p,b,e,v\}$ from the net demand duration curve.

5.2.3.2 Cost recovery and profit maximization

According to the optimal operating strategy derived in the previous section, there are now six periods with different prices obtained from the Lagrange multiplier λ_d, displayed in Table 4.

Table 4. Price (λ_d) periods for the EES model with general price arbitrage.

Period	$[0, t_s]$	$\langle t_s, t_p]$	$\langle t_p, t_e]$	$\langle t_e, t_b]$	$\langle t_b, t_v]$	$\langle t_v, T]$
λ_d	v_s	v_p	$\eta_e^{-1} v_b$	v_b	$\eta_e v_b$	0

The cost recovery and profit maximization results for the all technologies can be summarized as follows:

Peaker: Operation is similar to the previous sections, so results from Section 3.2 also applies here.

Baseload: Operation is similar to the case with EES but no VRE (Section 5.1.2), except that there are some discharge of stored energy from VRE during $\langle t_e, t_b]$. However, this does not change the profit of the baseload, because it is the marginal generator during $\langle t_e, t_b]$. Therefore, the profit function is equal to the one found in Section 5.1.2, and the results applies here as well.

VRE: Profits are similar to Section 5.2.1.3, expect that there is an additional price segment $\langle t_p, t_e]$ to account for:

$$\pi_v = \Big(v_s AF_v^{[0,t_s]} t_s + v_p AF_v^{[t_s,t_p]}\big(t_p - t_s\big) + \eta_e^{-1} v_b AF_v^{[t_e,t_b]}(t_b - t_e) + v_b AF_v^{[t_e,t_b]}(t_b - t_e) + \eta_e v_b AF_v^{[t_b,t_v]}(t_v - t_b) - F_v\Big) \cdot x_v \tag{119}$$

Cost recovery and profit maximization both yields:

$$v_s AF_v^{[0,t_s]} t_s + v_p AF_v^{[t_s,t_p]}\big(t_p - t_s\big) + \eta_e^{-1} v_b AF_v^{[t_p,t_e]}\big(t_e - t_p\big) + v_b AF_v^{[t_e,t_b]}(t_b - t_e) + \eta_e v_b AF_v^{[t_b,t_v]}(t_v - t_b) - F_v = 0 \tag{120}$$

which is the equal to the optimality condition for the VRE found in Section 5.2.3.1.

EES: The market operation is now a combination of the optimal strategies from Section 5.1.2 and Section 5.2.2.2 with profit function:

$$\pi_e = v_s \int_0^{t_s} x_e \, dt + v_p \int_{t_s}^{t_p} x_e \, dt - v_b \int_{t_e}^{t_b} q_{e-}(t) \, dt + v_b \int_{t_e}^{t_b} q_e(t) \, dt - \eta_e v_b \int_{t_b}^{t_v} q_{e-}(t) \, dt - F_e \cdot x_e \tag{121}$$

Substituting $\int_{t_b}^{t_v} q_{e-}(t) \, dt$ and $\int_{t_b}^{t_v} q_e(t) \, dt$ with the storage conservation equations (104) and (105) yields:

$$\pi_e = \big(v_s t_s + v_p\big(t_p - t_s\big) - v_b \eta_e^{-1} t_p + v_b \eta_e (T - t_v) - F_e\big) \cdot x_v \tag{122}$$

We see that both cost recovery ($\pi_v = 0$) and profit maximization ($\frac{d\pi_v}{dx_v} = 0$) lead to the system optimal condition from Section 5.2.3.1.

6 Numerical example

6.1 Case study description

To illustrate potential use of the proposed model we constructed a numerical example based on European energy and cost data from the EU 2050 Reference Scenario (European Commission 2016) and an associated technology data set from the EU-project ASSET (De Vita, Kielichowska, and Mandatowa 2018). The analyzed cases are listed in Table 5, where the case numbering follows the order of appearance in Chapters 3-5.

Table 5. Case study description.

Case	Peaker	Base	VRE	EES	EES model	Chapter
1	x	x			-	3
2	x	x	x		-	4
3	x	x		x	EES for thermal plants	5.1
4	x	x	x	x	Unlimited VRE storage	5.2.1
5	x	x	x	x	Limited VRE storage	5.2.2
6	x	x	x	x	General price arbitrage	5.2.3

The peaker and baseload technologies are chosen to be OCGT and CCGT, respectively. Simple OCGT plant data are not included in the EU Reference data, so we set the capital cost was set to 50 % of the CCGT capital cost, based on data from the U.K. Dept. of Energy and Climate Change, 2013 (Parsons Brinckerhoff 2013). Offshore wind is implemented as the VRE technology, while stationary Li-Ion Battery Energy Storage System (BESS) and Pumped Hydro Energy Storage (PHES) are used as examples of EES. Costs of Li-ion BESS are based on the low cost assumptions from (Cole et al. 2016).

We use the Norwegian reservoir hydropower system as basis for setting up the PHES model parameters. Several papers have described the possibilities for extending parts of the Norwegian hydro system by installing new reversible pump systems between large existing reservoirs (Harby et al. 2013; Korpås, Wolfgang, and Aam 2015; Askeland, Jaehnert, and Korpås 2019; Graabak et al. 2019). Previous studies have revealed that there is a large potential for utilizing the existing hydro reservoirs with additional pumping capability and increase the capacity of offshore HVDC connections to balance North Sea offshore wind and to connect to the continental European power system. In our case study, we analyze the investment of pumping capacity to the existing seasonal hydro storage system in Norway based on cost and technology data from (Korpås, Wolfgang, and Aam 2015). This means that this EES option has all its costs associated with power capacity, assuming seasonal storage by existing reservoirs.

We use load time series from the ENTSO-E 2040 GCA dataset for the following European countries: AT, BE, BG, CH, CZ, DE, DK, EE, ES, FI, FR, EL, HR, HU, IE, IT, LT, LU, LV, NL, NO, PL, PT, RO, SI, SK, SE, UK. Offshore Wind production data is provided by the JRC EMHIRES data set (European Commission 2019) for the countries above with shoreline. We use generation capacities from the ENTSO-E 2040 Global Climate Action Scenario (ENTSO-E 2018) for the same countries. Aggregated offshore wind time-series are given in p.u. of the total installed capacities. All time-series represent historical weather and load conditions for year 2007. We set the scarcity price in the market to 3000 €/MWh, which is equal to the current maximum price in the EPEX spot market (http://www.epexspot.com).

The cost and technology data are summarized in Table 6. Variable cost of thermal generation is calculated from

$$v_i = \eta_i^{-1}\left(p_{fuel,i} + p_{CO2}EF_{fuel,i}\right) + OM_{var,i} \tag{123}$$

The resulting variable costs are 155.0 €/MWh and 103.2 €/MWh for the peaker and the baseplant, respectively. Annual fixed costs are calculated from $F_i = SCC_i \cdot \alpha_i + OM_{fix,i}$ where α_i is the annuity factor, $\alpha_i = r \cdot (1-(1+r)^{-L_i})^{-1}$. Since energy capacity restrictions of the EES are not handled explicitly in the duration curve model, it is necessary to assume a certain energy capacity to calculate the total fixed cost of EES per kW. This is done by specifying the storage duration d in the BEES cost function provided in Table 6. For the PHES model, this is not necessary since the energy storage capacity is assumed to be the existing one, and all investment costs are associated with expanding the existing hydro plant with reversible pumps and necessary extensions of grid infrastructure.

Table 6. Cost data and power system data for the numerical example. *e1* is BESS, *e2* is PHES. The total cost of *e1* depends on its assumed duration *d*.

Parameter	Value	Unit	Parameter	Value	Unit
$p_{fuel,i}$, $i \in [p,b]$	[48.5 48.5]	€/MWh$_{fuel}$	v_s	3000	€/MWh
$OM_{var,i}$, $i \in [p,b,v,e]$	[1.73 1.73 0 0]	€/MWh	p_{CO2}	63	€/ton$_{CO2}$
$OM_{fix,i}$, $i \in [p,b,v,e]$	[15 15 40.7 0]	€/MW/yr	$\overline{P}_d$	100	MW
$EF_{fuel,i}$, $i \in [p,b]$	[0.18 0.18]	ton$_{CO2}$/MWh$_{fuel}$	r	8.5	%
L_i , $i \in [p,b,v,e]$	[30 30 25 15]	yr			
η_i , $i \in [p,b,e]$	[39 59 81]	%			
SCC_i , $i \in [p,b,v]$	[320 640 1891]	€/kW			
SCC_{e1}	265+d·65	€/kW			
SCC_{e2}	2500	€/kW			

The analytical solutions derived in chapters 3-5 showed that the market solution gives the optimal solution for all the cases listed in Table 5. Thus, the Weighted Average Price of Electricity (WAPE) for the costumers in the market will be equal to the Annual Cost of Electricity (ACE):

$$ACE_{op} = \frac{v_s \int_0^{t_s} q_s(t)dt + v_p \int_0^{t_p} q_p(t)dt + v_b \int_0^{t_b} q_b(t)dt}{\int_0^T q_d(t)dt} = \frac{v_s E_s + v_p E_p + v_b E_b}{E_d} \tag{124}$$

$$ACE_{fix} = \frac{\sum_{i \in \{p,b,v,e\}} F_i \cdot x_i}{E_d} \tag{125}$$

$$ACE = ACE_{op} + ACE_{fix} \tag{126}$$

The general equation for WAPE used here is

$$WAPE = \frac{\int_0^T p(t) q_d(t)dt}{E_d} \tag{127}$$

where the price $p(t)$ is given by the marginal generator/consumer of electricity at time instant (t). For the most general case with EES, Case 6, WAPE becomes:

$$WAPE = \frac{v_s \int_0^{t_s} q_d(t)dt + v_p \int_{t_s}^{t_p} q_d(t)dt + \frac{v_b}{\eta_e} \int_{t_p}^{t_e} q_d(t)dt + v_b \int_{t_e}^{t_b} q_d(t)dt + \eta_e v_b \int_{t_b}^{t_v} q_d(t)dt}{E_d} \tag{128}$$

In all cases $WAPE = ACE$ so we only report ACE in the results for convenience.

Finally, we use the Levelized Cost of Electricity (LCOE) for VRE to analyze the economic impact of curtailment:

$$LCOE_{vpot} = \frac{(F_v + OM_{fix,v})x_v}{\int_0^T q_{vpot}(t)dt} = \frac{F_v + OM_{fix,v}}{\int_0^T AF_v(t)dt} \tag{129}$$

$$LCOE_v = \frac{(F_v + OM_{fix,v})x_v}{\int_0^{t_b} q_v(t)dt} = \frac{F_v + OM_{fix,v}}{\int_0^{t_b} AF_v(t)dt} \tag{130}$$

where $q_{vpot}(t)$ is the potential VRE output in time instant t in the absence of curtailment.

6.2 Results without EES (Case 1 and 2)

The main results for the two cases without EES are given in Table 7. From Case 2 we see that VRE is competitive in the market, with an optimal capacity of 94.4 % of the peak demand, resulting in a VRE share of 62.1 %. There is surplus VRE generation, and the price becomes zero in 31 % of the year. VRE pushes some baseplant capacity out of the market and gives room for some more peaker capacity. This shift in capacities is visualized in Figure 7 where the duration curves for Case 1 and Case 2 are plotted together. With the assumed cost estimates for 2050, unsubsidized VRE reduces the average cost of energy for the customers by almost 30 %. Note that the number of hours with load shedding t_s is the same in two cases due to the optimality condition for the peaking plant, which does not change with the introduction of VRE. However, there is an increase in the energy not supplied (ENS) and maximum load shedding in Case 2. This effect of VRE is unavoidable given that 1) there are no entry of new technologies, 2) demand is inelastic, 3) all generators must recover their costs in the energy-only market. Changes in reserve requirements and/or capacity payments due to VRE integration may lead to a different ENS result, but such analyses are left for future works using models with more detailed representation of system operation.

Table 7. Results for Case 1 (Only thermal) and Case 2 (Thermal+VRE). In Case 2, the energy share of wind is 62.1 % of the annual demand. Wind curtailment is 9.5 % of the annual available wind energy.

Case	t_s [h]	t_p [h]	t_b [h]	x_p [MW]	x_b [MW]	x_v [MW]	ACE [€/MWh]	$\max(q_s)$ [MW]	ENS [%]
1	15.7	572.5	8760	8.2	89.1	-	115.0	2.4	0.003
2	15.7	572.5	6029	15.0	66.7	94.3	81.6	11.4	0.008

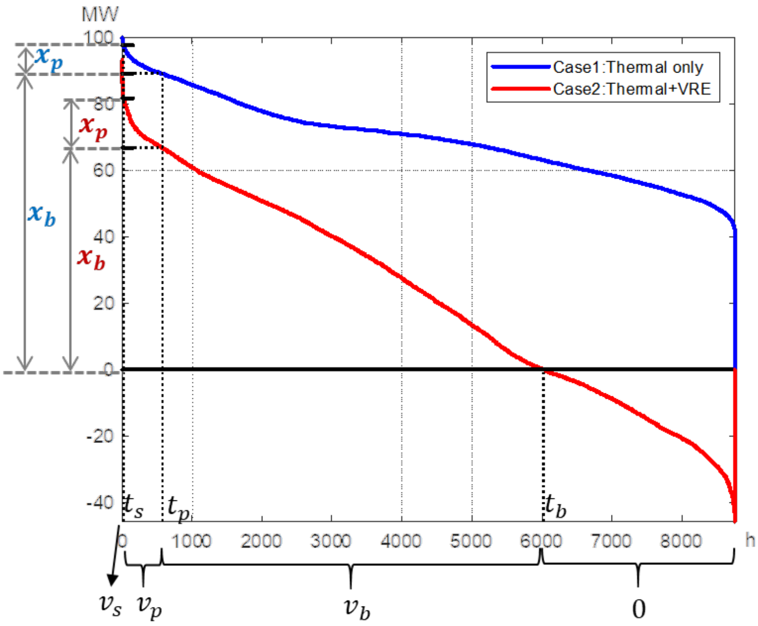

Figure 7. Duration curves for Case 1 and Case 2. The duration of load shedding is too short to be clearly visible. Price segments are placed beneath the x-axis.

The results presented above are obtained for a specific 2050 scenario for offshore wind in Europe, where future investment costs are obviously very uncertain. It is therefore important to study how the optimal capacities and durations is influenced by changes in VRE investment cost. In Figure 8, we have plotted the optimal installed VRE capacity as a function of its investment cost. The shape of the curve is interesting; an almost exponential increase as the cost decreases from 5000 to 4500 €/kW, followed by a long segment with linear increase. Finally, at very low investment costs, the VRE capacity increases at a higher pace again. Detailed analysis of this effect is provided in Appendix A.

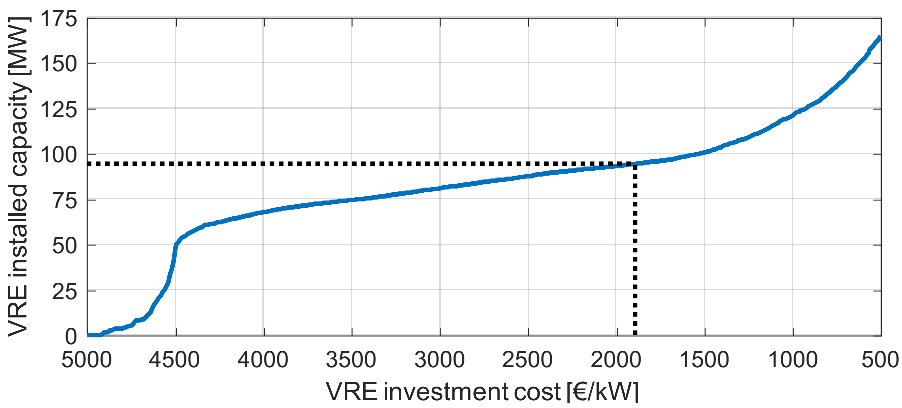

Figure 8. Optimal installed capacity of VRE as a function of its specific investment cost. The result of the selected EU cost scenario for 2050 is shown with dotted lines.

From Figure 9 (upper), we see that the VRE energy share follows in general the same pattern as its capacity when the investment cost comes down. However, at very low investment costs, the energy share increases more moderately due to the unavoidable curtailment of excess wind generation. In the same figure (lower), we have also plotted the energy share as function of installed capacity, where we recognize the expected saturation of utilized VRE energy as the capacity increases beyond the minimum demand of 42 MW.

Figure 10 shows ACE and LCOE as functions of VRE investment costs. The LCOE of the baseload plant first start to increase noticeably when its duration becomes less than 8760 hours, which occurs for VRE costs lower than 4500 €/kW. At very low VRE investment cost, the ACE starts to tip downwards.

This might seem as a surprising result, as since the VRE curtailment increases at the same time. However, this effect can be explained by recalling the non-linear increase in optimal VRE capacity in the same cost region (see rightmost part of Figure 8 and detailed discussion in Appendix A). If we instead plot the ACE as a function of optimal VRE capacity, we see that the ACE reduction slows down at the higher capacities due to the curtailment of surplus VRE generation (Figure 11).

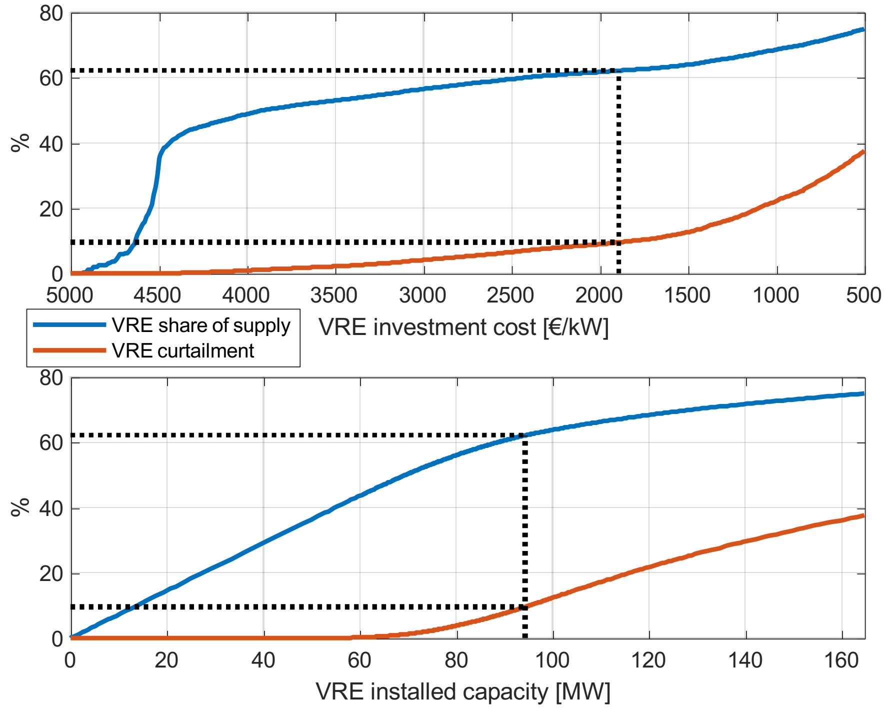

Figure 9. VRE share of supply (blue) and VRE curtailment (red) as a function of VRE investment cost (upper) and installed capacity (lower). The optimal result of the selected EU 2050 cost scenario is shown with dotted lines.

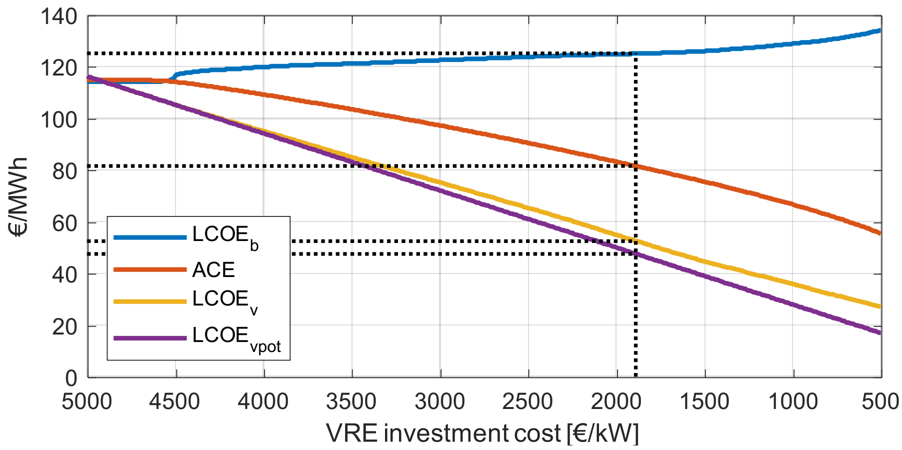

Figure 10. Average Cost of Electricity (ACE) and Levelized Cost of Electricity (LCOE) as a function of VRE investment cost. The result of the selected EU 2050 cost scenario is shown with dotted lines.

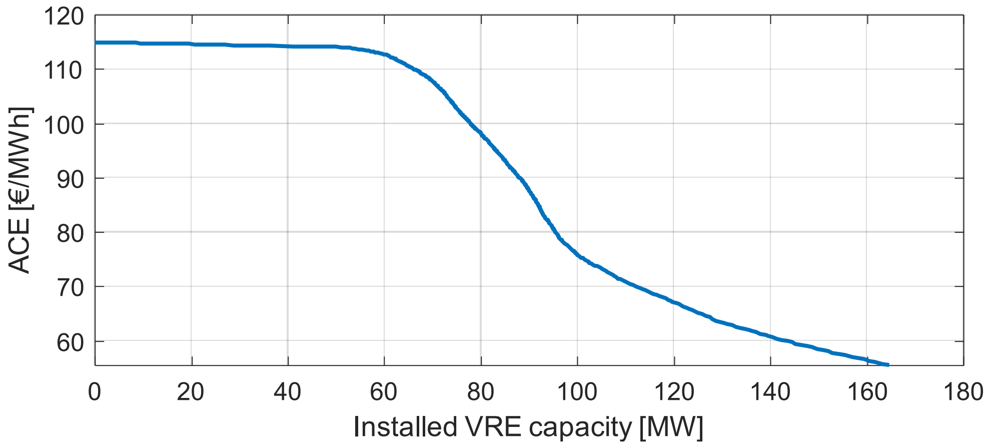

Figure 11. Average Cost of Electricity as a function of optimal VRE capacity.

6.3 Results with EES

6.3.1 Case 3: Peaker+Baseload+EES

Here, EES is only used for shifting energy from the base plant period to the peaker and load shedding periods. The highest possible fixed cost F_e' for EES to be feasible can be found from (72). With the parameters in Table 6, $F_e' = 60.7$ €/kW/yr, corresponding to $SCC_e' = 504$ €/kW. Using the BESS cost formula from Table 6 ($SCC_e = 265 + d \cdot 64$) the maximum economically feasible storage duration becomes $d = 3.74$ h.

We found in the previous section that $ACE = 115$ €/MWh with only peaker and baseplant in the system. If we add BESS with very optimistic cost estimate $SCC_e = 100$ €/kW, the ACE is only reduced by 1 %. This is because the EES does not contribute to more than a modest amount of load shifting between thermal generators which highly limits the cost reduction potential for the system. Therefore, the cases with VRE is more interesting, since EES can facilitate a higher VRE share and thus a significant change in system characteristics.

6.3.2 Case 4: Peaker+Baseload+VRE+EES "Unlimited VRE storage"

In this case, the EES is only charged by surplus VRE, and it can be discharged at any other period of the year. The optimality condition for the EES (87) determines the duration of the year t_v when the available VRE is fully utilized. Equation (87) states that that t_v is negatively correlated with the EES investment cost. The criterion for EES to be profitable is when t_v is equal to the baseload duration for the case without EES: $F_e' = F_b + \eta_e v_b (T - t_v)$. From this relation, we can find the maximum acceptable investment cost $SCC_e' = F_e' / \alpha_e$. Inserting the case study parameters from Table 6, we get $SCC_e' = 2514$ €/kW. This is very close to the cost estimate of PHES of 2500 €/kW, indicating that a PHES investment would only have been marginally profitable in this case. If we use the BESS cost formula from Table 6 instead, the maximum economically feasible storage duration becomes $d = 35$, which may be realistic for flow batteries in the future. For comparison, the generation expansion studies performed in (Cole et al. 2016; de Sisternes, Jenkins, and Botterud 2016; Cebulla, Naegler, and Pohl 2017) reports Li-Ion BESS storage durations in the range of 2-8 hours.

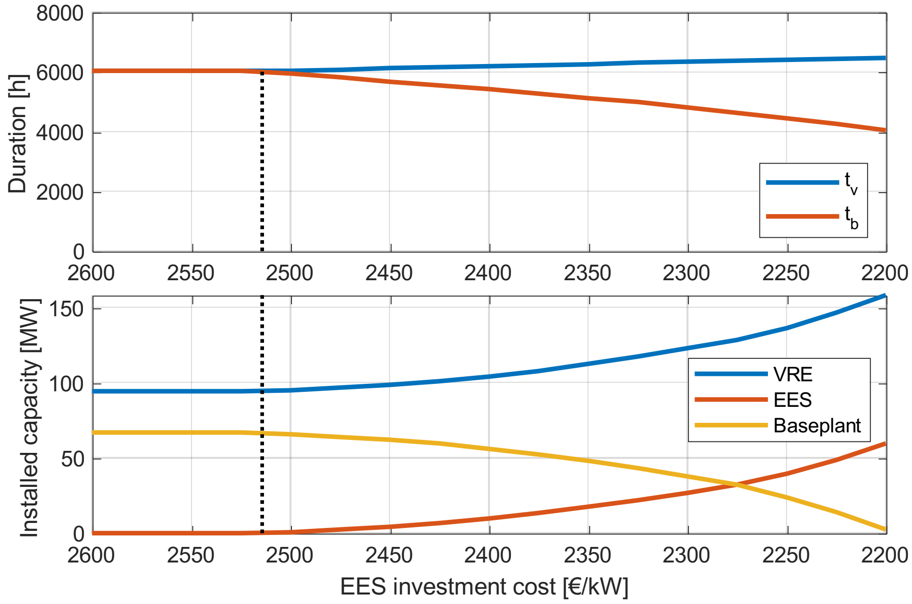

Figure 12. Upper figure: Durations t_v and t_b as functions of EES investment cost SCC_e. Lower figure: Capacities x_v, x_e and x_b as functions of SCC_e. The dotted line is the threshold cost of EES for being profitable.

In the upper part Figure 12, we plot t_v and t_b as functions of EES investment cost, where the threshold cost SCC_e' also is marked. This is the point where t_v and t_b diverge, and we observe that the baseload duration t_b is much more sensitive to the EES cost than t_v. The resulting installed capacities are shown in the lower part of Figure 12. It is evident that EES triggers significant amounts of additional VRE capacity. This creates a double negative effect on the baseload capacity as the EES costs declines: Both the EES itself and the additional VRE capacity replace the baseload plant. The peaker capacity (not shown in the figure) is not noticeably affected (i.e. x_p is around 15 MW for all EES costs, as in the VRE-only case). This is because it is still needed together with the EES in the peak hours, being less capital intensive than the baseplant.

An interesting observation from Figure 13 (upper) is that the impact of EES investment cost on the ACE is almost negligible, as opposed to the impact of VRE cost, which has causes a much larger reduction, as shown in Figure 10. Hence, our results indicate that cost reductions in clean generation technologies are more important than cost reductions in balancing technologies. On the other hand, EES expansion makes a significant impact on the VRE share, and indirectly on emissions, since it both replaces thermal generation for balancing and causes an increase in system optimal VRE investment. This is illustrated in the lower part of Figure 13. From this figure, we also see that EES lead to less relative curtailments of VRE. Moreover, the total amounts of curtailed VRE (in MWh/year) also decreases, although the EES triggers more VRE capacity in the system.

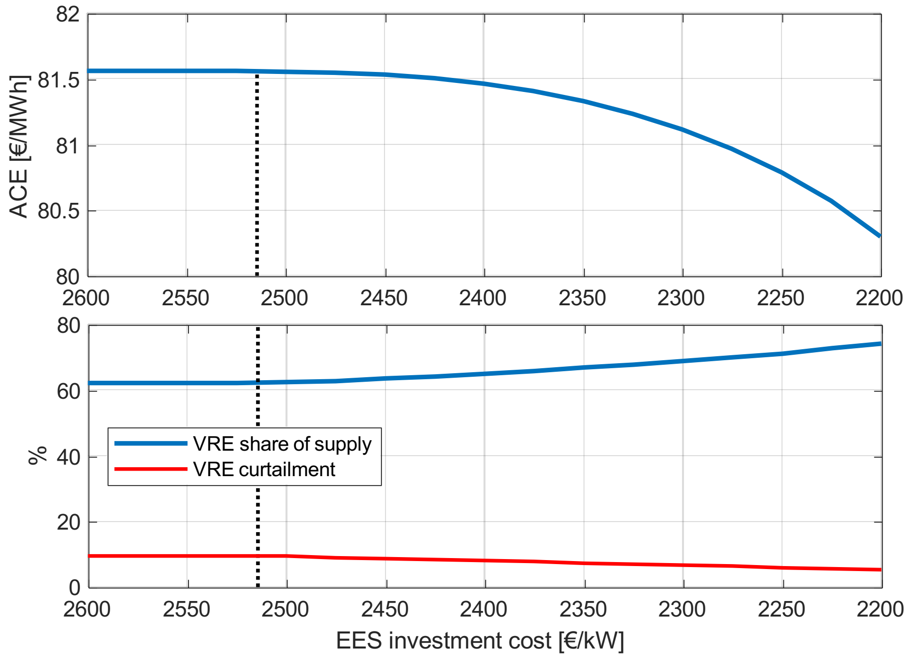

Figure 13. Upper: Average Cost of Electricity. Lower: VRE share and VRE curtailment as a function of EES investment cost SCC_e.

6.3.3 Case 5: Peaker+Baseload+VRE+EES "Limited VRE storage"

We only briefly report results from this special case, where the EES is assumed to be limited to discharge during the baseplant period. The rationale behind this assumption is that it is a "worst-case", contrasting the much more optimistic assumption behind Case 4 above. The threshold EES investment cost is obtained by setting $t_v = t_b$ in the optimality condition (99). Using the input data from Table 6, we get:

$$F_e' = \eta_e v_b (T - t_b) = 0.81 \cdot 103.2 \cdot (8760 - 6029) = 22\,821 \, \frac{€}{\text{MW yr}}$$

$$SCC_e' = \frac{F_e'}{\alpha_e} = 1000 \cdot \frac{22\,821}{0.1204} = 1\,895 \, \frac{€}{\text{kW}}$$

$$d' = \frac{(SCC_e' - 265)}{65} = 25.5 \text{ h}$$

Not surprisingly, the threshold cost SCC_e' is lower than in Case 4, and considerably lower than the PHES investment cost (2500 €/kW), since the EES creates less value for the system here by only replacing baseload capacity. Equivalently, the maximum affordable energy capacity of BESS, measured in storage duration, is 25.5 h, compared to 33 h in Case 4.

6.3.4 Case 6: Peaker+Baseload+VRE+EES "General price arbitrage"

The last EES model that has been developed here combines the "limited VRE storage" of Case 5 with Case 3, where some baseplant energy is charged by the battery to reduce load shedding and peaker generation. It is therefore a model that places in between Case 4 and Case 5 when it comes to how EES contributes to the system. The threshold EES cost cannot be calculated directly from the optimality conditions, since they form a non-linear set of equations with four unknowns $f(t_p, t_b, t_e, t_v) = 0$. Setting $t_v = t_b = 6029$ at the threshold of the EES investment, we get from (111):

$$\frac{\partial C}{\partial x_e} = a_e = 0 \Rightarrow F_e' = v_s t_s + v_p (t_p - t_s) - v_b \eta_e^{-1} t_p + v_b \eta_e (T - t_b) = 26\,312 \, \frac{€}{\text{MW yr}}$$

$$SCC_e' = 2\,185 \, \frac{€}{\text{kW}} \, , \quad d' = 30 \text{ h}$$

As expected, the threshold cost is between the corresponding values from Case 4 (most optimistic case) and Case 5 (most pessimistic case).

6.4 Comparison with Linear Programming formulation

To assess the proposed Duration Curve (DUR) model, we have also modelled the system as a time-sequential Linear Programming (LP) problem based on the basic formulation (1)–(8) for comparison. Note that the LP model handles energy storage constraints explicitly by equation (8). We ran the model without activating this constraint, in order to represent the same system as in the DUR model for Cases 1-3. Moreover, to model the case of storing only surplus VRE (Case 4 from Section 5.2.1) in the LP model, we added the following charging constraint to the LP model:

$$q_{e-}(t) \leq q_v(t) - q_d(t) \quad \forall\, t \in [1, T] \tag{131}$$

This constraint forces the charging power to be equal to or less than the surplus VRE power. The LP optimization model is implemented in Julia v. 0.64, using the JuMP and Clp libraries (https://julialang.org/). We compared the results of the DUR model with the LP model for Cases 1-4. Cases 5 and 6 are not directly comparable with the LP model due to the modelling of storage constrains, and therefore needs more extensive analyses which is a topic for future works.

For the EES cases, the DUR model gives a threshold investment cost of 504 €/kW in Case 2 and 2514 €/kW in Case 4. We have therefore chosen different EES costs for Case 2 (425 €/kW) and Case 4 (2377 $/kW) to trigger some investments in EES in the respective cases. The EES cost of Case 2 is equivalent to a BESS with 2.5 h storage duration, while Case 4 is equivalent to a PHES plant with 5 % lower investment cost than the original data from Section 6.1. Table 8 presents the main results for both models. As expected, the results from LP and the duration curve model are identical in all four cases since they basically solve the same optimization problem for Cases 1 to 4. There are some negligible numerical discrepancies due LP discretization of the year into 8760 discrete time steps.

Table 8. Results from the duration curve model and LP model for Cases 1-4.

Case	1		2		3		4	
Model	DUR	LP	DUR	LP	DUR	LP	DUR	LP
Obj. func. (C) [k€/yr]	69.9	69.9	69.8	69.8	49.6	49.6	49.5	49.5
t_s [h]	15.7	16.0	15.7	16.0	15.7	16.0	15.7	16.0
t_p [h]	572.5	573.0	572.5	573.0	230.2	231.0	572.5	573.0
t_e [h]	-	-	-	-	966	966	-	-
t_b [h]	8760	8760	6029	6028	8760	8760	5288	5289
t_v [h]	-	-	-	-	-	-	6226	6226
x_p [MW]	8.5	8.5	15.0	15.0	5.4	5. 4	15.2	15.2
x_b [MW]	89.1	89.1	66.7	66.7	85.9	85.9	52.5	52.5
x_v [MW]	-	-	94.3	94.3	-	-	107.9	107.9
x_e [MW]	-	-	-	-	6.2	6.2	13.2	13.2
ACE [€/MWh]	115.0	115.0	81.6	81.6	114.9	114.9	81.4	81.4
$\max(q_s)$ [MW]	2.4	2.4	11.4	11.4	2.4	2.4	11.9	11.9
ENS [%]	0.003	0.003	0.008	0.008	0.003	0.003	0.009	0.009
VRE share [%]	-	-	62.1	62.1	-	-	72.5	72.5
VRE curtail. [%]	-	-	9.5	9.5	-	-	7.7	7.7

Figure 14 shows the duration curves which have been extracted from the LP optimization results of Case 4. It corresponds to the generic duration curve in Figure 4. From this figure, it is possible to extract the optimal durations that are derived directly from the analytic model and corresponding capacities, as summarized in Table 8 for both models.

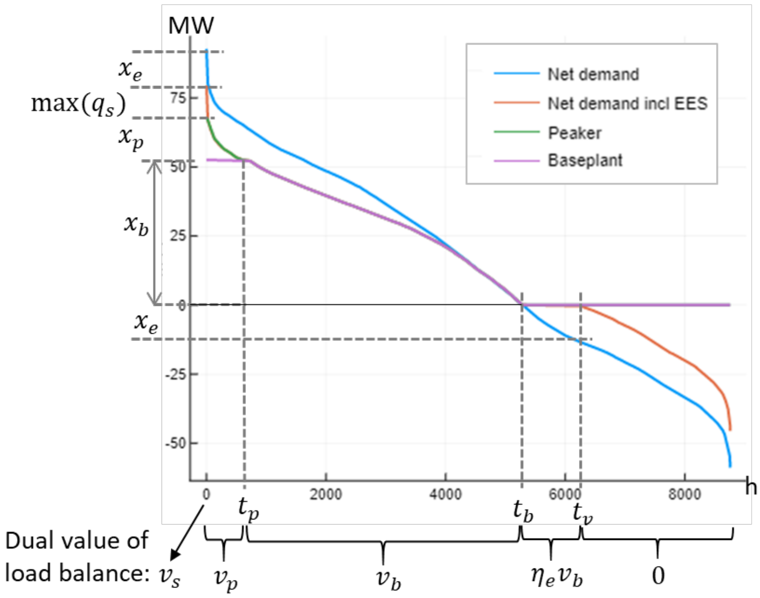

Figure 14. Duration curves extracted from the LP model for Case 4. Optimal capacities, prices, and durations are displayed in the figure. The VRE capacity is not visible in the figure, since it is indirectly given through the net load. Moreover, the duration of load shedding is too short (16 hours) to be visible.

7 Conclusions and further work

We presented an analytical approach to analyze system optimality conditions and cost recovery in systems with VRE and EES. We proposed a duration curve methodology based on existing theoretical models for systems with only thermal generation. We used the methodology to show that in all the modelled cases, all power plants recover their costs in system optimum. This result also applies for cases where surplus VRE gives periods with zero prices, and cases where EES sets the price either based on the marginal cost of charging or the marginal value of discharging, depending on the instantaneous power balance. Our analytical results show how VRE changes the capacity of thermal generation in equilibrium, causing less baseload capacity but more peaker capacity. The impacts of EES on optimal thermal and VRE capacity depends on how EES is operated and what limitations that are assumed on the energy storage capacity.

When EES is used for charging excess VRE that otherwise would have been curtailed, it triggers more VRE capacity in equilibrium, since the EES creates a new price segment based on the marginal value of storage, where the VRE gains additional profits. This result has several implications for the market equilibrium: 1) EES pushes more thermal capacity out of the market, both because of its balancing ability and because it triggers more investments in VRE, 2) EES leads to lower total amounts of curtailed VRE in equilibrium, although it triggers more VRE investments, 3) Numerical analyses indicates that the main benefit of EES is to increase the VRE share in the system and consequently further reduce emissions caused by thermal generation. The emission benefit is much more evident from the results than the impacts on electricity cost, even with high carbon prices in line with low-carbon scenarios for Europe stadium 2050. How a marginal economic benefit will impact the willingness to invest in merchant EES in electricity markets is a topic for further analyses.

Since the approach is based on the duration curve of the net demand, the model represents the energy limit of ESS is in an approximate way. We presented different EES representations which are suited for duration curve modelling, and the models were tested against LP optimization which gave identical results. The analytical models are well suited for expansion in several ways. First and foremost, more research is needed to explore improved ways of modelling the energy constraints of EES and how they impact market prices and optimal generation capacities. Another important simplification is the assumption of deterministic input data for demand and VRE, and optimal EES operation assuming perfect foresight of the whole year. Hence, adding uncertainty to the formulation is another direction for future work. The models could also be enhanced to include operating reserve requirements.

Finally, we believe that customer participation in the market will be increasingly important as more of the generation is based on VRE technologies with zero marginal costs. Hence, crucial work lies ahead to include demand-side flexibility in analytical modelling frameworks as the one presented here, to gain further insights in how prices and optimal generation mix will evolve in markets based on marginal cost pricing in the future.

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Appendix A: Optimal VRE capacity as a function of investment cost

This appendix provides a detailed analysis of the shape of the VRE capacity curve in Figure 8. Recall from Figure 7 that the net demand curve determines the different price segments. The profitability of VRE depends on how much production that takes place in the different price segments. Lower investment cost leads to higher VRE capacity which again alters the net demand curve.

In Figure 15 we have plotted the duration curve for net demand together with the corresponding VRE output for different VRE investment cost scenarios. With an investment cost of 4800 €/kW (blue curve), VRE is only marginally profitable, and the installed capacity is so low that the net demand is almost identical to the demand curve without VRE. We see that the VRE output variations sorted by the net demand follows a rather favorable pattern, with slightly higher production during high demand. This result is due to the weather variations of European offshore wind with highest average wind speeds during winter when the demand also is high. With a slight decrease in investment cost (red curve), the optimal installed VRE capacity increases, and pushes the net demand curve downwards. Consequently, more VRE production takes place during lower net demand. The VRE capacity is still so low that there are no hours with zero prices. When the investment cost is reduced to 4500 €/kW (yellow curve), the installed VRE capacity has reached a level where situations with price equal to zero are about to occur. A further decrease in investment cost from this point is expected to lead to marginally less added VRE capacity due to two reasons: 1) Higher VRE capacity leads to more and more hours with zero prices, 2) Higher VRE capacity alters the net demand slightly and thereby pushes even more of the VRE production to the low-price hours.

When the investment cost is reduced below 2000 €/kW, the installed VRE capacity is already at such a high level that a continued increase in capacity does not noticeably change the VRE output variations in the different price segments (the green and purple VRE output curves are almost identical). This "saturation" of VRE variations gives rise to an interesting effect on the installed VRE capacity, which from this point on increases non-linearly again, as shown in Figure 7. This result can be explained from the cost recovery condition of the VRE plant from Chapter 4.1:

$$\pi_v = 0 \Rightarrow F_v = v_s \int_0^{t_s} AF_v(t)dt + v_p \int_{t_s}^{t_p} AF_v(t)dt + v_b \int_{t_p}^{t_b} AF_v(t)dt$$

where AF_v refers to the Availability Factor of the VRE plant before curtailment. From Figure 15, we see that AF_v can be approximated by a step-wise linear function of t for VRE investment cost of 1000 €/kW (green) and 2000 €/kW (purple):

$$\begin{aligned} F_v \approx v_s \int_0^{t_s} (a_1 t + b_1)dt + v_p \int_{t_s}^{t_p} (a_2 t + b_2)dt + v_b \int_{t_p}^{t_b} (a_3 t + b_3)dt \\ = \frac{1}{2} v_s a_1 t_s^2 + \frac{1}{2} v_p a_2 (t_p - t_s)^2 + \frac{1}{2} v_b a_3 (t_b - t_p)^2 + v_s t_s b_1 + v_p b_2 (t_p - t_s) \\ + v_b b_3 (t_b - t_p) \Rightarrow F_v = c_1 t_b^2 - c_2 t_b + c_3 \end{aligned}$$

where a_i, b_i, c_i refers to constants. As explained in the main part of the paper, the optimal values of t_s and t_p remains constant as long as the peaker and baseplant are not entirely pushed out of the system. The cost recovery condition gives thus a quadratic relation between cost-optimal duration of the baseload plant t_b and VRE investment cost if the availability factor of VRE, AF_v, is a linear function of the net demand duration t. The relation between t_b and VRE capacity, x_v, is given by the net demand curve. With an approximated linear relation between net demand duration and VRE output, we can also express the net demand as a linear function of VRE capacity x_v: $q_{nd}(t) \approx a_6 - a_7 \cdot t \cdot x_v$. The base duration t_b is given by $q_{nd}(t_b) = 0 \Rightarrow t_b = a_8/x_v$. Inserting into the cost-optimality condition above, we obtain the following non-linear relation between VRE investment cost and VRE capacity:

$$F_v = A x_v^{-2} - B x_v^{-1} + C$$

where A, B and C are constants. This function approximates the right part of Figure 8, with the axes inverted. For very high x_v, the investment cost goes asymptotically towards the constant C, which we also can observe from Figure 8. As F_v goes towards zero, the VRE capacity will go towards the amount that is required to supply the load by VRE only. This is theoretically possible if the VRE output is always higher than zero, which e.g. can be the case for aggregation of VRE over a large region or country.

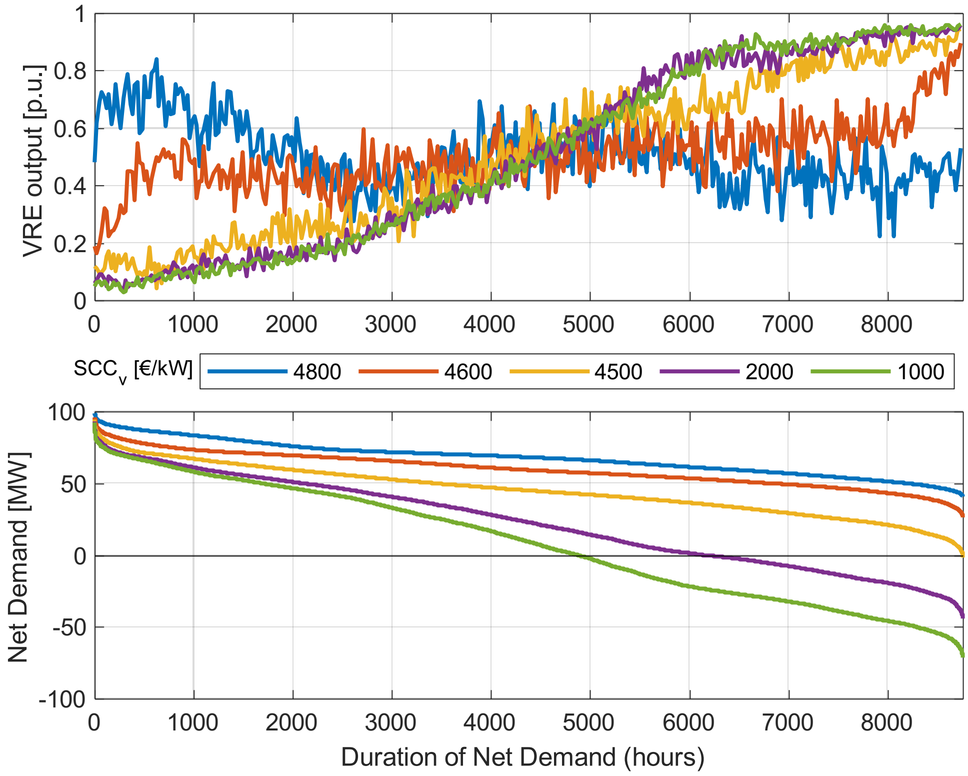

Figure 15. Duration curves of net demand (lower) and corresponding VRE output sorted by net demand (daily averages, upper) for different VRE investment cost scenarios. The corresponding VRE installed capacities and relative VRE curtailments are 3.6 MW / 0 % (blue), 19.4 MW / 0 %(red), 48.2 MW / 0.001 % (yellow), 93.0 MW / 8.9 % (purple), 121.1 MW / 22 % (green).

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