# Strategic Offering of a Flexible Producer in Day-Ahead and Intraday Power Markets

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**Abstract**

The increase in intraday electricity market volumes due to intermittent renewable generation may give a strategic producer an opportunity to exert market power. We study offering strategies of a flexible producer in day-ahead and intraday markets using a bi-level model in which the upper level represents the profit-maximization problem of the producer and the lower-level problems clear the day-ahead and intraday markets sequentially. Using a three-node network, we first demonstrate that a flexible producer with perfect forecasts can increase its profit in both markets by coordinating its offer so as to cause transmission grid congestion or lack of competitive generation capacity. Moreover, we show that strategic behavior is possible even when the day-ahead and intraday markets are cleared simultaneously to lower balancing costs. We next assess these market designs in a Nordic test network and offer an explanation for high Nordic intraday prices. Finally, via an annual simulation using the Nordic market data, we verify that strategic offering in day-ahead and intraday markets under imperfect forecasts leads to increased profits vis-à-vis perfect competition but are mitigated through simultaneous market clearing.

*Keywords:* OR in energy, day-ahead market, intraday market, strategic offering, renewable energy, mathematical programming with equilibrium constraints

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## 1. Introduction

In the continental European and Nordic electricity markets, the initial generation, load, and transmission flow plans are revealed after the clearing of the day-ahead spot market. As a result of asset failures and updated forecasts, these day-ahead plans may be altered in the intraday market until one hour (Nordic countries) or 15 minutes (Germany) before delivery. Ultimately, transmission system operators (TSOs) balance real-time deviations from the final plans by activating balancing power (see Figure 1 and Mauritzen, 2015; Pape et al., 2016). While such a clearing mechanism may have been adequate for power systems based on conventional generation, it may not be effective in integrating intermittent renewable energy resources in line with EU policy (European Commission, 2014; Morales et al., 2014). Indeed, from 2010 to 2016, intraday volumes have surged up to 200% in northwestern Europe due to the increase in the generation of intermittent renewables such as wind power (EPEX Spot, 2017; Nord Pool, 2017). Flexible producers such as hydropower and gas-fired generators can profit from trading in the intraday market because a deficit leads to a higher intraday price than the day-ahead spot price given that less expensive offers have already been settled in the spot market. By contrast, a surplus causes the intraday price to be lower than the day-ahead spot price, which enables the flexible producer to replace its expensive generation with cheaper output from the intraday market (Boomsma et al., 2014).

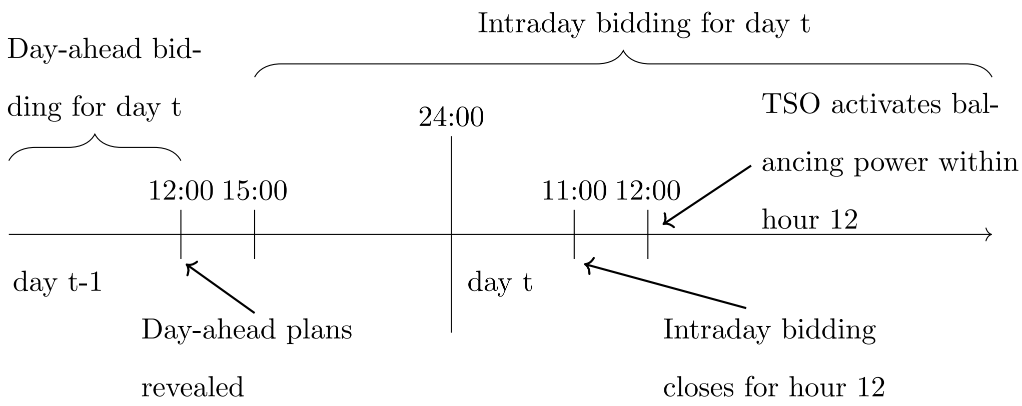


**Figure 1:** Timeline of day-ahead and intraday markets in the Nordic countries

In this paper, we study how a flexible strategic producer can use day-ahead and intraday offers to exploit market designs in the presence of high intraday volumes. Because the day-ahead and intraday markets typically face inflexible demand and share the same generation and transmission constraints, such a strategic producer may affect the market-clearing transmission flows and the generation plans of its rivals in both markets. By correctly anticipating a deficit or surplus in the intraday market via time-series forecasting, for example (Klæboe et al., 2015), a flexible producer can increase its profit by decreasing or increasing its offering to the day-ahead spot market, respectively. However, if the deviations do not realize as forecasted, then the producer can make a loss as it may not deploy its generation assets optimally.

We build a stochastic bi-level model in which the strategic producer maximizes its profit in the upper level and the day-ahead and intraday markets are cleared in the lower level. Our main contribution is an assessment of coordinated strategic offering in both markets by allowing for endogenous determination of prices in the day-ahead and intraday markets in the presence of ramp restrictions and possible transmission grid congestion. Earlier work assumes exogenous intraday prices (e.g., Boomsma et al., 2014; Baringo and Conejo, 2016; Wozabal and Rameseder, 2019), Cournot competition without a transmission network model (Ito and Reguant, 2016; Knaut and Obermüller, 2016), or a producer with limited opportunities for strategic behavior (Dai and Qiao, 2015, 2017). To this end, we address three objectives:

1) We employ a representative test network to illustrate how a range of coordinated offering strategies in the day-ahead and intraday markets may be formed when the strategic producer has perfect forecasts for all market data.
2) Building on these strategies, we conduct a case study using real market data to provide evidence for the very high intraday prices observed in Nord Pool in early 2016.
3) By employing the real market data in a simulation of day-ahead and intraday markets over a year, we estimate the expected impact of strategic offering on both day-ahead and intraday profits and generation costs when the offer curves are built with imperfect forecasts.

In addition, we show that an alternative market design that simultaneously minimizes day-ahead and expected intraday costs (Morales et al., 2014) can be manipulated by a strategic producer. However, via an annual simulation to assess the mean performance of the market designs, we find that this alternative market design mitigates the impact of strategic behavior vis-à-vis the conventional dispatch model in expectation. Methodologically, we provide computationally tractable model reformulations using duality theory (Ruiz and Conejo, 2009) and by extending binary expansion (Barroso et al., 2006) for signed quantities.

This paper is organized as follows. In Section 2, we discuss models for day-ahead and intraday electricity markets as well as strategic offering. Section 3 presents our bi-level model, and Section 4 gives numerical results for objectives 1) – 3). Section 5 concludes and provides directions for future work.

## 2. Literature review

Offering into day-ahead electricity markets is well-studied in the literature. Fleten and Kristoffersen (2007) develop a stochastic programming model for building detailed offer curves of a flexible hydropower producer when market prices are modeled by an exogenous stochastic process. Using a bi-level model, Ruiz and Conejo (2009) build offer curves of a strategic producer for a single transmission-constrained electricity market under uncertainty about demand bids and offer curves of rival firms. To maximize its profits, the strategic producer can withhold generation and utilize transmission grid congestion as well as limited ramping speed of its rivals (Clements et al., 2016). Moiseeva et al. (2015) consider a market design in which producers bid their ramp rates and show that flexible strategic generators seek to lift prices by bidding ramp rates below their technical capability. By contrast, Kazempour et al. (2015) consider a strategic consumer with elastic demand who seeks to increase its utility by decreasing its bid prices. Kwon and Frances (2012) review such mathematical programming models for a power producer's offers with both strategic and perfectly competitive assumptions.

The day-ahead offering models can readily consider additional markets such as intraday markets by introducing exogenous prices. For example, Baringo and Conejo (2013) build wind power offer curves while taking exogenous balancing market price scenarios into account. Kardakos et al. (2016) model a virtual power plant with load, generation, and storage that maximizes expected profit resulting from endogenous day-ahead sales revenue and exogenous balancing costs. On the other hand, Rahimiyan and Baringo (2015) use robust optimization to determine offers into uncertain but perfectly competitive day-ahead and regulation markets.

Ito and Reguant (2016) consider a Cournot competition model in which a monopolist decides its commitment into two sequential markets such as the electricity day-ahead and real-time markets. The demand that the monopolist faces in the day-ahead and intraday market is assumed to be linearly dependent on the day-ahead price and the price difference between the two markets, respectively. As a result, their theoretical framework predicts that the monopolist withholds quantity in the day-ahead market and increases its commitment in the intraday market. Meanwhile, price-taking competitive producers have an incentive to arbitrage the price difference between the two markets by selling more in the day-ahead market. The authors analyze market and plant-level data from the Iberian electricity market to confirm the predictions for the monopolist and competitive producers.

Knaut and Obermüller (2016) model Cournot competition between strategic renewable energy and competitive conventional producers in a day-ahead market with uncertainty about renewable generation, which is resolved in a sequentially cleared intraday market. They find that it is optimal for renewable energy producers to sell less than their expected generation in the day-ahead market. However, the sales volume approaches expected production if either the number of symmetric renewable energy producers increases or the flexibility of conventional producers in the intraday market decreases.

Dai and Qiao (2015) consider a strategic wind power producer that builds offer curves for sequentially cleared day-ahead and real-time markets. They find that the producer can increase its profits in both markets with strategic offering. However, the strategic producer has limited offering possibilities into the real-time market as it needs to correct its deviations from the day-ahead dispatch caused by wind power forecast errors. Dai and Qiao (2017) find that day-ahead and real-time profits and prices increase further in the presence of multiple strategic wind power and conventional producers. However, due to computational challenges, they use an approximation algorithm to determine the strategies of wind power producers and a discrete set of strategies for the conventional generators, which are likely to ignore possibilities for strategic behavior. Bjørndal et al. (2013) search iteratively for strategic spot price offers that lead to transmission grid congestion, higher prices in the intraday market, and lower social welfare.

Morales et al. (2014) find that the market design that minimizes the sum of day-ahead and expected intraday costs is more economical than the sequential dispatch. Even though their market design can anticipate the cost-increasing impact of strategic offers in the intraday market, we show that a strategic player can still coordinate its offer to increase prices in the day-ahead market. Our result is in line with that of Lei et al. (2016) who show that the strategic behavior of a wind power producer reduces social welfare when the day-ahead and intraday markets are cleared simultaneously.

Indeed, there is recent empirical support for strategic behavior in different power markets:

Tangerås and Mauritzen (2018) find evidence for day-ahead market power by flexible producers in certain Swedish price areas in Nord Pool, Just and Weber (2016) for the German balancing market, Amountzias et al. (2017) for the U.K. wholesale and retail markets, and CAISO (2018) for the 5-minute market in California. To this end, our objectives are to illustrate coordinated offering strategies into day-ahead and intraday markets, provide evidence for very high observed prices in Nord Pool using these strategies, and estimate the expected impact of strategic offering on both day-ahead and intraday generation costs.

## 3. Mathematical model for strategic offering in day-ahead and intraday markets

### 3.1. Overview of day-ahead and intraday bidding

To enter the possibly more profitable intraday market, a flexible producer may choose to alter its day-ahead offer curves based on anticipated intraday deviations. As an example, the producer can offer lower volume in the day-ahead market if it anticipates a deficit and higher prices in the intraday market. Consequently, the two markets need to be considered jointly already when bidding to the day-ahead market. When the day-ahead plans are revealed around noon as shown in Figure 1, the producer can start submitting offer curves into intraday and balancing markets. The producer can update these initial intraday offer curves as new information such as updated wind power forecasts or outage schedules becomes available. This process, which repeats every trading day, is done by all producers and consumers in the market.

We focus on modeling the building of day-ahead and intraday offer curves from the perspective of a flexible and strategic producer. In addition to adjusting the day-ahead and intraday offer curves based on external factors such as anticipated intraday deviations due to wind power forecast errors, the producer can pursue higher profits by manipulating prices in both markets by setting strategic price and volume offers. More specifically, strategic producer (SP) $x \in \mathscr{X}$ coordinates the building of day-ahead and intraday offer curves by selecting price ($p^{da}, p^{up}$, and $p^{down}$) and quantity offers ($q^{da}$) to maximize its expected profit in the day-ahead and intraday markets. To this end, the SP solves a bi-level problem in which the upper level represents the profit maximization of the SP and sets exchange-specific constraints on the permitted price and quantity offers. In turn, the profit of the

SP is affected by the day-ahead and intraday prices ($\lambda_s^{da}$ and $\lambda_s^{intra}$) and generation ($g_s^{da}$, $g_s^{up}$, and $g_s^{down}$), which are determined as the solution to a collection of lower-level problems that minimize the costs of generation in each scenario $s$ given the price and quantity offers of the SP. Other producers are assumed to be perfectly competitive in that the price and quantity offers of these competitive producers (CPs) equal their marginal generation costs ($C^{da}$, $C^{up}$, and $C^{down}$) and available generation capacities ($G^{max}$), respectively. These parameters can be estimated using market data.

Similarly, we assume that all consumers are competitive and the total consumption in the day-ahead and intraday markets is represented using parameters $D_s^{da}$ and $D_s^{intra}$, respectively. We make this simplification because i) demand is very inelastic (Cialani and Mortazavi, 2018), ii) demand-side flexibility is limited in availability (Müller and Möst, 2018), and iii) a part of $D_s^{intra}$ is not controlled by consumers due to unexpected weather changes, for example. We do not model an explicit linkage between $D_s^{da}$ and $D_s^{intra}$, but practitioners may use existing market data and predictive models for estimating $D_s^{da}$ and $D_s^{intra}$ so that possible correlations or consumer behavior are implicitly reflected in the parameter values for each scenario $s$ when the SP builds its offer curves.

In this conventional dispatch model (ConvD), the day-ahead and intraday markets clear sequentially so that the intraday market is dependent on the generation and transmission flows in the day-ahead market ($g^{da}$ and $f^{da}$). An illustration of strategic offer curve building in day-ahead and intraday markets with ConvD is shown in Figure 2.

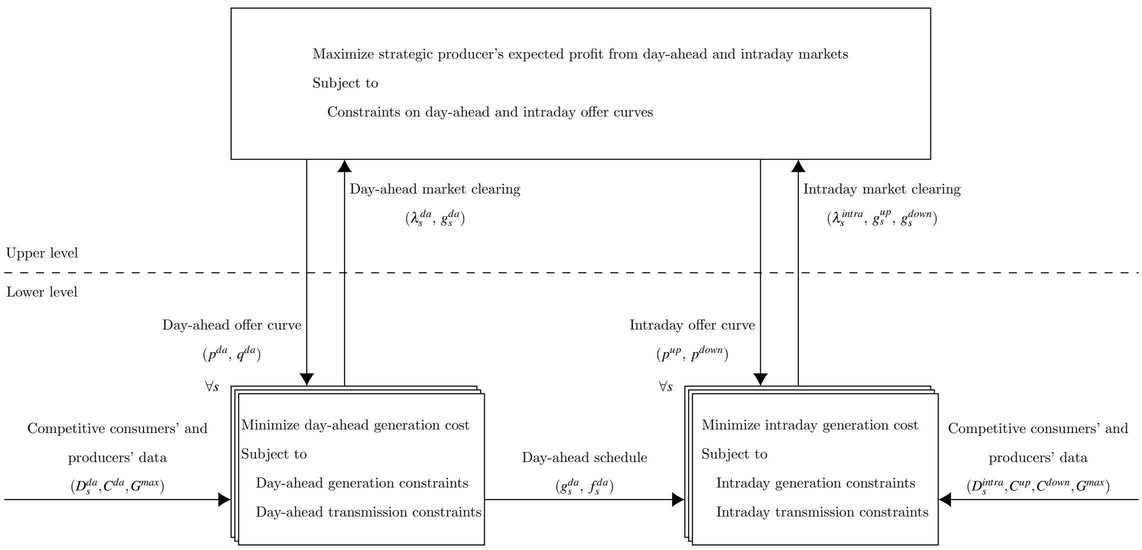


**Figure 2:** Illustration of strategic offer curve building in day-ahead and intraday markets with ConvD (all variable indices except scenarios $s$ have been omitted)

We compare the aforementioned ConvD model, which clears the day-ahead and intraday markets sequentially, to a market design that clears the day-ahead and intraday markets simultaneously by representing the two markets with a single lower-level problem for each scenario. This design is similar to the StochD model of Morales et al. (2014) and may cause a generator to be dispatched out of merit order in the day-ahead market if that generator lowers the expected intraday cost. An illustration of building strategic day-ahead and intraday offer curves with StochD is shown in Figure 3.

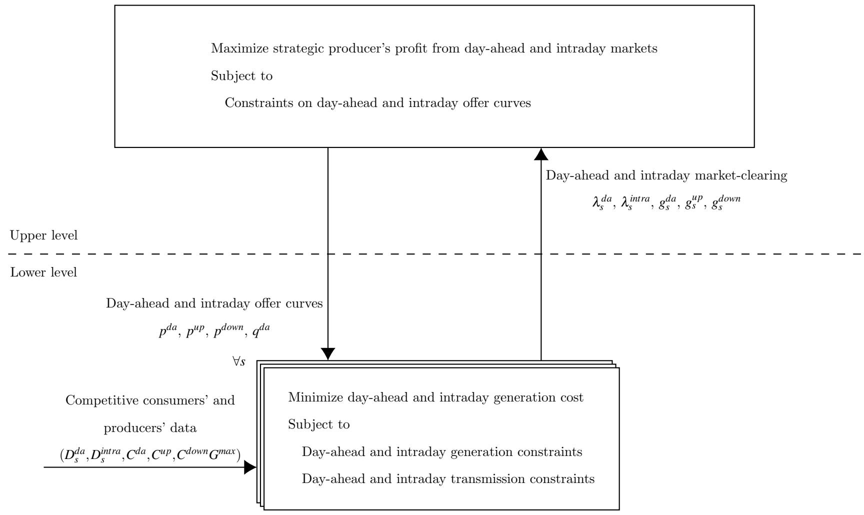


**Figure 3:** Illustration of strategic offer curve building in day-ahead and intraday markets with StochD (all variable indices except scenarios $s$ have been omitted)

Moreover, we compare strategic offering with ConvD and StochD to a perfectly competitive (PC) model in which the price and quantity offers of the SP equal its marginal generation costs and available generation capacities, respectively. Consequently, the SP becomes one of the CPs and can no longer manipulate prices in the day-ahead and intraday markets. An illustration of the PC model is shown in Figure 4.

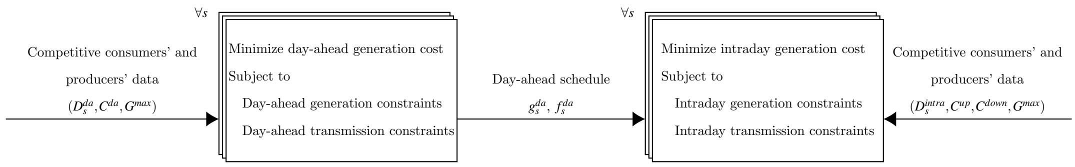


**Figure 4:** Illustration of PC in which the SP is no longer strategic but is one of the CPs (all variable indices except scenarios $s$ have been omitted)

In what follows, we present the mathematical formulation for building strategic offer curves with the ConvD model. The formulation for PC and StochD models is presented in Appendices A and C, respectively.

### 3.2. Mathematical formulation

#### 3.2.1. Notation

**Sets and indices**

| | |
|---|---|
| $n \in \mathscr{N}$ | nodes |
| $u \in \mathscr{U}$ | generation units |
| $b \in \mathscr{B}$ | generation blocks |
| $\ell \in \mathscr{L}$ | transmission lines |
| $s \in \mathscr{S}$ | scenarios |
| $f \in \mathscr{F}$ | generation firms |
| $x \in \mathscr{X} \subset \mathscr{F}$ | strategic firms |
| $y \in \mathscr{Y} \subset \mathscr{F}$ | competitive firms |

$\left.\begin{array}{l}\text{strategic firms}\\ \text{competitive firms}\end{array}\right\} \mathscr{X} \cap \mathscr{Y} = \emptyset$ and $\mathscr{X} \cup \mathscr{Y} = \mathscr{F}$

**Parameters**

| | |
|---|---|
| $W_s$ | the probability of scenario $s$ |
| $D^{da}_{s,n}$ | demand at node $n$ in scenario $s$ in the day-ahead market (MW) |
| $D^{intra}_{s,n}$ | demand at node $n$ in scenario $s$ in the intraday market (MW) |
| $C^{da}_{f,n,u,b}$ | day-ahead marginal cost of generation of the $b$:th block of firm $f$'s unit $u$ at node $n$ (€/MW) |
| $C^{up/down}_{f,n,u,b}$ | up/down-regulation cost of the $b$:th block of firm $f$'s unit $u$ at node $n$ (€/MW) |
| $G^{max}_{f,n,u,b}$ | maximum generation capacity of the $b$:th block of firm $f$'s unit $u$ at node $n$ (MW) |
| $G^{up/down,ramp}_{f,n,u,b}$ | maximum up/down-regulation ramp of the $b$:th block of firm $f$'s unit $u$ at node $n$ (MW) |
| $NTC^{max/min}_{\ell}$ | maximum/minimum transmission flow on the line $\ell$ (MW) |
| $Y_{\ell,n}$ | transmission line and node incidence matrix $\ell \times n$ |
| $\Lambda^{da,max/min}$ | maximum/minimum day-ahead price in the power exchange (€/MW) |
| $\Lambda^{intra,max/min}$ | maximum/minimum intraday price in the power exchange (€/MW) |

**Free variables**

| | |
|---|---|
| $\lambda^{da}_{s,n}$ | day-ahead price in scenario $s$ at node $n$ (€/MW) |
| $\lambda^{intra}_{s,n}$ | intraday price in scenario $s$ at node $n$ (€/MW) |
| $p^{da}_{x,n,u,b}$ | price offer of the $b$:th block of strategic firm $x$'s unit $u$ at node $n$ for the day-ahead market (€/MW) |
| $p^{up/down}_{x,n,u,b}$ | price offer of the $b$:th block of strategic firm $x$'s unit $u$ at node $n$ for up/down-regulation (€/MW) |
| $f^{da}_{s,\ell}$ | transmission flow on line $\ell$ in scenario $s$ in the day-ahead market (MW) |
| $f^{intra}_{s,\ell}$ | transmission flow on line $\ell$ in scenario $s$ in the intraday market (MW) |

**Positive variables**

| | |
|---|---|
| $q^{da}_{x,n,u,b}$ | quantity offer of the $b$:th block of strategic firm $x$'s unit $u$ at node $n$ for the day-ahead market (MW) |
| $g^{da}_{s,f,n,u,b}$ | day-ahead generation of the $b$:th block of firm $f$'s unit $u$ at node $n$ in scenario $s$ (MW) |
| $g^{up/down}_{s,f,n,u,b}$ | up/down-regulation of the $b$:th block of firm $f$'s unit $u$ at node $n$ in scenario $s$ (MW) |
| $\beta^{da}_{s,f,n,u,b}$ | dual for maximum day-ahead generation of the $b$:th block of firm $f$'s unit $u$ at node $n$ in scenario $s$ (€/MW) |
| $\beta^{up/down}_{s,f,n,u,b}$ | dual for maximum up/down-regulation of the $b$:th block of firm $f$'s unit $u$ at node $n$ in scenario $s$ (€/MW) |
| $\beta^{up/down,ramp}_{s,f,n,u,b}$ | dual for maximum up/down-regulation ramp of the $b$:th block of firm $f$'s unit $u$ at node $n$ in scenario $s$ (€/MW) |

| | |
|---|---|
| $\mu_{s,\ell}^{da,max/min}$ | dual for maximum/minimum flow on line $\ell$ in scenario $s$ in the day-ahead market (€/MW) |
| $\mu_{s,\ell}^{intra,max/min}$ | dual for maximum/minimum flow on line $\ell$ in scenario $s$ in the intraday market (€/MW) |
| **Binary variables** | |
| $up_{s,x,n}$ | indicator variables equal 1 if strategic firm $x$ up-regulates at node $n$ in scenario $s$ |

### 3.2.2. Upper-level problem

The bi-level problem is solved with respect to $\Omega^{UL} = \{q_{x,n,u,b}^{da}, p_{x,n,u,b}^{da}, p_{x,n,u,b}^{up}, p_{x,n,u,b}^{down}, up_{s,x,n}\}$, $\Omega^{LL^{da}} = \{g_{s,f,n,u,b}^{da}, f_{s,\ell}^{da}\}$, and $\Omega^{LL^{intra}} = \{g_{s,f,n,u,b}^{up}, g_{s,f,n,u,b}^{down}, f_{s,\ell}^{intra}\}$. The upper level of the bi-level problem is:

$$\text{Minimize}_{\Omega^{UL}\cup\Omega^{LL^{da}}\cup\Omega^{LL^{intra}}}$$

$$\sum_s W_s \left[\sum_n\sum_u\sum_b \left(g_{s,x,n,u,b}^{da}\left(C_{x,n,u,b}^{da} - \lambda_{s,n}^{da}\right) + g_{s,x,n,u,b}^{up}\left(C_{x,n,u,b}^{up} - \lambda_{s,n}^{intra}\right) - g_{s,x,n,u,b}^{down}\left(C_{x,n,u,b}^{down} - \lambda_{s,n}^{intra}\right)\right)\right] \quad (1)$$

s.t.

$$\Lambda^{da,min} \leq p_{x,n,u,b}^{da} \leq \Lambda^{da,max} \qquad \forall n,u,b \quad (2)$$

$$\Lambda^{intra,min} \leq p_{x,n,u,b}^{up} \leq \Lambda^{intra,max} \qquad \forall n,u,b \quad (3)$$

$$\Lambda^{intra,min} \leq p_{x,n,u,b}^{down} \leq \Lambda^{intra,max} \qquad \forall n,u,b \quad (4)$$

$$p_{x,n,u,b}^{da} \geq p_{x,n,u,b-1}^{da} \qquad \forall n,u, \text{ and } \forall b>1 \quad (5)$$

$$p_{x,n,u,b}^{up} \geq p_{x,n,u,b-1}^{up} \qquad \forall n,u, \text{ and } \forall b>1 \quad (6)$$

$$p_{x,n,u,b}^{down} \leq p_{x,n,u,b-1}^{down} \qquad \forall n,u, \text{ and } \forall b>1 \quad (7)$$

$$q_{x,n,u,b}^{da} \leq G_{x,n,u,b}^{max} \qquad \forall n,u,b \quad (8)$$

$$g_{s,x,n,u,b}^{up} \leq M \cdot up_{s,x,n} \qquad \forall s,n,u,b \quad (9)$$

$$g_{s,x,n,u,b}^{down} \leq M \cdot (1 - up_{s,x,n}) \qquad \forall s,n,u,b, \quad (10)$$

Day-ahead market dispatch in Eqs. (11)-(15)

Intraday market dispatch in Eqs. (16)-(22)

The objective function (1) represents the maximization of the expected profit of the SP over a set of a scenarios $s$ by adding the expected day-ahead profit to the expected profit from increasing and decreasing generation in the intraday market. We assume that every generation unit is divided into blocks that have a constant cost for day-ahead generation ($C_{f,n,u,b}^{da}$) as well as up- and down-regulation ($C_{f,n,u,b}^{up}$ and $C_{f,n,u,b}^{down}$, respectively), i.e., increasing or decreasing generation in the intraday market, respectively. Note that in case of day-ahead generation and up-regulation, the generators lose $C_{f,n,u,b}^{da}$ or $C_{f,n,u,b}^{up}$ and receive $\lambda_{s,n}^{da}$ or $\lambda_{s,n}^{intra}$ from a buyer, respectively, and in case of down-regulation, the generators save $C_{f,n,u,b}^{down}$ and pay $\lambda_{s,n}^{intra}$ to a seller. The SP can specify a price offer for each of its generation blocks for both the day-ahead and intraday market, while a quantity offer is set only for the day-ahead market. This is because we assume that the volumes that are not dispatched in the day-ahead market are available in the intraday market.

The upper-level problem is constrained by Eqs. (2)-(4), which define maximum and minimum price offers of the SP for the day-ahead and intraday markets. Moreover, Eqs. (5)-(7) ensure that offer curves are increasing. The day-ahead quantity offers are limited by the generation capacity of each block (8). Eqs. (9) and (10) forbid simultaneous up- and down-regulation at each node through the binary variable $up_{s,x,n}$ so that the SP is not able to increase its up-regulation profit by adversely down-regulating while it is also up-regulating.

### 3.2.3. Day-ahead market dispatch

The day-ahead market is given by a collection of lower-level problems in Eqs. (11)-(15).

$$
\forall s \left\{
\begin{array}{llll}
\text{Minimize}_{\Omega^{LL^{da}}} & & & \\
\sum_n \sum_u \sum_b p^{da}_{x,n,u,b} g^{da}_{s,x,n,u,b} + \sum_y \sum_n \sum_u \sum_b C^{da}_{y,n,u,b} g^{da}_{s,y,n,u,b} & & & (11) \\
\text{s.t.} & & & \\
\quad D^{da}_{s,n} = \sum_f \sum_u \sum_b g^{da}_{s,f,n,u,b} + \sum_\ell Y_{\ell,n} f^{da}_{\ell,n} & \lambda^{da}_{s,n} \text{ free} & \forall n & (12) \\
\quad g^{da}_{s,x,n,u,b} \le q^{da}_{x,n,u,b} & \beta^{da}_{s,x,n,u,b} \ge 0 & \forall n,u,b & (13) \\
\quad g^{da}_{s,y,n,u,b} \le G^{max}_{y,n,u,b} & \beta^{da}_{s,y,n,u,b} \ge 0 & \forall y,n,u,b & (14) \\
\quad NTC^{min}_\ell \le f^{da}_{s,\ell} \le NTC^{max}_\ell & \mu^{da,min/max}_{s,\ell} \ge 0 & \forall \ell & (15)
\end{array}
\right.
$$

The objective function (11) minimizes the day-ahead cost of generation in each scenario $s$, which consists of the price offers of the SP and the marginal costs of the CPs. Eqs. (12) ensure that, in each scenario and node, supply matches demand, which is given by the parameters $D^{da}_{s,n}$. These constraints consider the effect of flows $f^{da}_{s,\ell}$ using an incidence matrix $Y$ whose element $(\ell,n)$ equals to 1 if node $n$ is the starting point of the line $\ell$, -1 if $n$ is the end point, and 0 otherwise. Such a flow model is used in the Nordic market, for example (Nord Pool, 2009). Also, the dual variables on the right-hand side of Eqs. (12) correspond to nodal day-ahead prices. Eqs. (13) and (14) limit the generation of the SP blocks by the quantity offers and the CP blocks by the block capacities, respectively. Eqs. (15) bound day-ahead transmission flows so that congestion occurs in the transmission network in the day-ahead market if any of these constraints becomes binding.

### 3.2.4. Intraday market dispatch

The intraday market is given by a collection of lower-level problems in Eqs. (16)-(22).

$$
\forall s \begin{cases}
\text{Minimize}_{\Omega^{LL^{intra}}} \\
\sum_n \sum_u \sum_b \left( p^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - p^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} \right) + \sum_y \sum_n \sum_u \sum_b \left( C^{up}_{y,n,u,b} g^{up}_{s,y,n,u,b} - C^{down}_{y,n,u,b} g^{down}_{s,y,n,u,b} \right) & & & (16) \\
\text{s.t.} \\
\quad D^{intra}_{s,n} = \sum_f \sum_u \sum_b \left( g^{up}_{s,f,n,u,b} - g^{down}_{s,f,n,u,b} \right) + \sum_\ell Y_{\ell,n} f^{intra}_{\ell,n} & \lambda^{intra}_{s,n} \text{ free} & \forall n & (17) \\
\quad g^{down}_{s,f,n,u,b} \leq g^{da}_{s,f,n,u,b} & \beta^{down}_{s,f,n,u,b} \geq 0 & \forall f,n,u,b & (18) \\
\quad g^{da}_{s,f,n,u,b} + g^{up}_{s,f,n,u,b} \leq G^{max}_{f,n,u,b} & \beta^{up}_{s,f,n,u,b} \geq 0 & \forall f,n,u,b & (19) \\
\quad g^{down}_{s,f,n,u,b} \leq G^{down,ramp}_{f,n,u,b} & \beta^{down,ramp}_{s,f,n,u,b} \geq 0 & \forall f,n,u,b & (20) \\
\quad g^{up}_{s,f,n,u,b} \leq G^{up,ramp}_{f,n,u,b} & \beta^{up,ramp}_{s,f,n,u,b} \geq 0 & \forall f,n,u,b & (21) \\
\quad NTC^{min}_\ell \leq f^{da}_{s,\ell} + f^{intra}_{s,\ell} \leq NTC^{max}_\ell & \mu^{intra,min/max}_{s,\ell} \geq 0 & \forall \ell & (22)
\end{cases}
$$

Similar to the day-ahead market, the objective function (16) minimizes the cost of intraday generation in each scenario $s$ given the intraday price offers of the SP and the marginal costs of the CPs. In intraday balance Eqs. (17), scenario- and node-wise intraday demand $D^{intra}_{s,n}$ is a parameter that can take on either positive or negative values because real-time demand can be higher or lower than anticipated in the day-ahead market, respectively. Note that $D^{intra}_{s,n}$ can be estimated by an exogenous model that correlates it with day-ahead demand $D^{da}_{s,n}$. Also, the dual variables on the right-hand side of Eqs. (17) correspond to nodal intraday prices. The intraday dispatch takes the day-ahead generation and transmission plans as an input so that Eqs. (18) and (19) ensure that the final generation of each block is between zero and the block capacity if ramping constraints (20) and (21) are not already met. Finally, Eqs. (22) constrain the final transmission flows between the minimum and maximum transmission capacity ($NTC^{min}_\ell$ and $NTC^{max}_\ell$, respectively).

We compare the results of the above conventional dispatch (ConvD) model with a perfectly competitive (PC) model in which just the two lower-level problems (11)-(15) and (16)-(22) are run sequentially. Similar to the CPs, the price and quantity offers of the SP are set to its blockwise generation costs ($p^{da/up/down}_{x,n,u,b} = C^{da/up/down}_{x,n,u,b}$) and capacities ($q^{da}_{x,n,u,b} = G^{max}_{x,n,u,b}$), respectively. Moreover, we compare our results to the StochD model of Morales et al. (2014) that combines the two lower-level problems by adding the intraday objective function (16) to that of the day-ahead market clearing (11) and by augmenting the constraints of the day-ahead problem (12)-(15) with the intraday constraints (17)-(22).

Morales et al. (2014) consider only perfect competition, and we show that their market design can be manipulated by a strategic producer even if it leads to lower total generation cost than ConvD in expectation.

Following the solution procedure of Gabriel and Leuthold (2010), the bi-level ConvD problem is reformulated as a single-level mathematical program with equilibrium constraints (MPEC) in Appendix A, which is further reformulated and solved as a mixed-integer linear programming (MILP) problem in Appendix B. For ConvD, the bilinear terms $g^{up}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ and $g^{down}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ in Eq. (1) are discretized using a reformulation of binary expansion of Barroso et al. (2006) so that the terms can become negative. The discretization may lead to suboptimal results, but the suboptimality can be reduced by making the related discretization intervals $\bar{G}^{up/down}_{x,n,u,b} > 0$ smaller. For StochD, we are able to provide an exact MILP reformulation without discretization using strong duality (Ruiz and Conejo, 2009) in Appendix C. The PC model can be solved exactly as a series of linear systems as detailed in Appendix A.

## 4. Numerical results

In Section 4.1, we address our first objective to demonstrate the logic of coordinated offering strategies in detail using a representative test network. Consequently, we take only the perspective of a strategic producer by building the day-ahead and intraday offer curves and by analyzing what would happen in the day-ahead and intraday markets if both would realize exactly as the SP anticipates. In Section 4.2, we use the strategies and insights from Section 4.1 to address our second objective to explain high prices observed in Nord Pool in 2016. Finally, in Section 4.3, we address our third objective to estimate the expected impact of strategic offering on day-ahead and intraday costs by considering a more realistic setting in which a market operator clears the day-ahead and intraday markets sequentially given real market data and the coordinated day-ahead and intraday offer curves that the SP builds using estimated market data. This process simulates the real timeline of day-ahead and intraday markets as shown in Figure 1.

### 4.1. Three-node network

To address our objective 1) to demonstrate coordinated offering strategies in day-ahead and intraday markets, we first consider an illustrative three-node network in which there is demand at each node and each transmission line has a capacity of 10 MW in both directions (Figure 5). The SP operates a flexible generation unit at node 1 (unit 0), while the remaining less flexible, but low marginal cost units at nodes 1, 2, and 3 (units 1, 2, 3, respectively) are owned by a CP (see Table 1 for generation-related parameters). We illustrate three distinct cases in which strategic behavior can lead to higher profits through three scenarios: 1) the scenario "Congestion" demonstrates how the SP can cause and profit from transmission network congestion, 2) the scenario "Ramp limit" demonstrates how the SP can profit from limited flexibility of other producers, 3) the scenario "Surplus" illustrates how the SP can profit from not only deficit but also a large surplus in the intraday market.

The demand in the day-ahead and intraday markets for each equally weighted scenario is in Table 2. Each generation unit is divided into two blocks, and, with ConvD, the discretization interval of the binary expansion for up- and down-regulation of the SP ($\bar{G}^{up}_{x,n,u,b,j}$ and $\bar{G}^{down}_{x,n,u,b,k}$) is 1 MW, which causes no error in the results with the selected parameter values.[1] Maximum and minimum day-ahead and intraday prices are set to 3000 and -500 €/MW, respectively, to match those of Nord Pool (Nord Pool, 2019). Note that in this illustrative example, we assume that the SP has perfect knowledge of all model parameters including the intraday demand, the real value of which would be revealed only after the intraday market is cleared. In what follows, we study scenariowise generation and transmission flows in the day-ahead and intraday markets resulting from the offer curves of the SP. These values are obtained by solving Eqs. (1)-(22) (ConvD), or (C-1)-(C-5) (StochD), or (11)-(15) as well as (16)-(22) (PC) with the above input data.

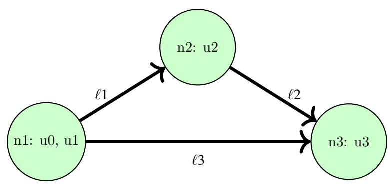


**Figure 5:** Three-node network indicating conventional direction of flow and each node's units

[1] All parameters are integral and the discretization interval is 1 MW. Also, since all cost parameters are distinct, there do not exist multiple solutions in which one producer would produce $0 \leq x \leq D$ and another one $D-x$ for some constant demand $D$. Thus, the discretization does not lead to errors.

Table 3 shows the offer curve with PC. Table 4 shows that, in each scenario, most of the demand in day-ahead and intraday markets is met by the CP units 1, 2, and 3 as the SP unit 0 has higher marginal costs. Both day-ahead and intraday prices are at the marginal costs of the different units.

| Parameter \ Unit | SP u0 | CP u1 | CP u2 | CP u3 |
|---|---|---|---|---|
| $C^{da}_{f,n,u,b}$ (€/MW) | 8 | 5 | 6 | 7 |
| $C^{up}_{f,n,u,b}$ (€/MW) | 25 | 10 | 15 | 20 |
| $C^{down}_{f,n,u,b}$ (€/MW) | 1 | 4 | 3 | 2 |
| $G^{max}_{f,n,u,b}$ (MW) | 25 | 2 | 25 | 25 |
| $G^{up,ramp}_{f,n,u,b}$ (MW) | 5 | 2 | 2 | 2 |
| $G^{down,ramp}_{f,n,u,b}$ (MW) | 5 | 2 | 2 | 2 |

**Table 1:** Blockwise generation parameters in the three-node example

| Parameter | $D^{da}_{s,n}$ | | | $D^{intra}_{s,n}$ | | |
|---|---|---|---|---|---|---|
| Scenario \ Node | n1 | n2 | n3 | n1 | n2 | n3 |
| Congestion | 22 | 22 | 22 | 10 | 0 | 0 |
| Ramp limit | 4 | 2 | 2 | 10 | 0 | 0 |
| Surplus | 14 | 22 | 30 | -9 | 0 | 0 |

**Table 2:** Demand parameters in the three-node example (in the intraday market, positive figures indicate a deficit and negative figures a surplus)

| Variable | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | |
|---|---|---|---|---|
| Offer \ Block | $b1$ | $b2$ | $b1$ | $b2$ |
| Day-ahead | 8 | 8 | 25 | 25 |
| Up-regulation | 25 | 25 | – | – |
| Down-regulation | 1 | 1 | – | – |

**Table 3:** Offer curve of the SP in the three-node example with PC

| Variable | $\sum_b g^{da}_{s,f,n,u,b}$ (MW) | | | | $f^{da}_{s,\ell}$ (MW) | | | $\lambda^{da}_{s,n}$ (€/MW) | | | $\sum_b g^{up/down}_{s,f,n,u,b}$ (MW) | | | | $f^{intra}_{s,\ell}$ (MW) | | | $\lambda^{intra}_{s,n}$ (€/MW) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario \ Index | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 |
| Congestion | | 4 | 42 | 20 | -10 | 10 | -8 | 7 | 6 | 7 | 8 | | | 2 | | | -2 | 25 | 3 | 20 |
| Ramp limit | | 4 | 4 | | | 2 | | 6 | 6 | 6 | 2 | | 4 | 4 | -4 | | -4 | 25 | 15 | 20 |
| Surplus | | 4 | 42 | 20 | -10 | 10 | | 7 | 6 | 7 | | -4 | -4 | -1 | 4 | | 1 | 1 | 3 | 2 |

**Table 4:** Day-ahead and intraday generation, flows, and prices in the three-node example with PC, where positive (negative) intraday generation corresponds to up-regulation (down-regulation)

Tables 5 and 7 show the offer curves, and Tables 6 and 8 indicate the resulting generation, flows, and prices with ConvD and StochD, respectively. With ConvD, the SP's day-ahead price offer $p^{da}_{x,n,u,b1/b2} = 7$ €/MW is not competitive enough for the SP unit to be dispatched in the day-ahead market in the scenario "Congestion." As a result, the CP unit 1 at node 1 is fully dispatched in the day-ahead market and the transmission lines to node 1 are nearly congested to meet the high day-ahead demand at node 1. The SP recognizes that, in the intraday market, there is no more CP capacity available at node 1 and only a part of the intraday demand at node 1 can be met by the CP before the transmission lines to node 1 become fully congested. Thus, the SP is able to cover the remaining intraday demand at a high profit by setting its up-regulation price offer $p^{up}_{x,n,u,b1/b2}$ to maximum price of 3000 €/MW. In Section 4.2, we show how a similar offering strategy can explain very high intraday prices in Nord Pool.

Likewise, in scenario "Congestion" with StochD, the SP sets the same high up-regulation price offer

$p^{up}_{x,n,u,b1/b2} = 3000$ €/MW. With StochD, the market operator is able to anticipate the high intraday cost caused by the combination of the SP's high up-regulation offer, congestion, and the lack of CP capacity at node 1 in the intraday market. To counter this, the market operator can dispatch the SP already in the day-ahead market. However, the SP is able to anticipate this action and sets a strategic day-ahead offer $p^{da}_{x,n,u,b2} = 2991$ €/MW with a positive capacity. As a result, the market operator chooses to dispatch the SP unit both in the day-ahead and intraday markets in quantities that minimize its objective function. Indeed, we check numerically that 1) perturbing the SP's price offer $p^{da}_{x,n,u,b2} = 2991$ €/MW even by a small constant $\varepsilon$ leads to a lower profit for the SP, and 2) having higher dispatch for the SP in the day-ahead or intraday market does not lead to an improvement in the market operator's objective. Consequently, this scenario shows that the SP is able to game also the alternative dispatch method StochD.

In scenario "Ramp limit" with ConvD, the low day-ahead demand is covered without any congestion on the transmission lines to node 1 by having the cheapest CP unit 1 fully dispatched and the second cheapest CP unit 2 partially dispatched. Regardless of the abundant transmission capacity left for the intraday market, the high intraday demand at node 1 cannot be met by the CP units 2 and 3 because they are limited by ramping constraints. As a consequence, the SP is able to lift the intraday price to the maximum level even though none of the transmission lines is congested. By contrast, StochD is able to anticipate the limited ramping of the CP units 2 and 3 and decides to deviate from the lowest cost day-ahead dispatch by not dispatching the CP unit 1. Consequently, the CP unit 1 is available in the intraday market and displaces the SP unit with the high up-regulation offer. Thus, this shows how StochD can mitigate the impact of strategic offering in some scenarios.

| Variable | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | |
|---|---|---|---|---|
| Offer \ Block | $b1$ | $b2$ | $b1$ | $b2$ |
| Day-ahead | 7 | 7 | 0 | 25 |
| Up-regulation | 3000 | 3000 | – | – |
| Down-regulation | -500 | -500 | – | – |

**Table 5:** Offer curve of the SP with ConvD

| Variable | $\sum_b g^{da}_{s,f,n,u,b}$ (MW) | | | | $f^{da}_{s,\ell}$ (MW) | | | $\lambda^{da}_{s,n}$ (€/MW) | | | $\sum_b g^{up/down}_{s,f,n,u,b}$ (MW) | | | | $f^{intra}_{s,\ell}$ (MW) | | | $\lambda^{intra}_{s,n}$ (€/MW) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario \ Index | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 |
| Congestion | | 4 | 42 | 20 | -10 | 10 | -8 | 7 | 6 | 7 | 8 | | | 2 | | | -2 | 3000 | 3 | 20 |
| Ramp limit | | 4 | 4 | | | 2 | | 6 | 6 | 6 | 2 | | 4 | 4 | -8 | -4 | | 3000 | 3000 | 3000 |
| Surplus | 10 | 4 | 42 | 10 | -10 | 10 | 10 | 7 | 6 | 7 | -1 | -4 | -4 | | 4 | | | -500 | -500 | 20 |

**Table 6:** Day-ahead and intraday generation, flows, and prices in the three-node example with ConvD

| Variable | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | |
|---|---|---|---|---|
| Offer \ Block | $b1$ | $b2$ | $b1$ | $b2$ |
| Day-ahead | -500 | 2991 | 0 | 6 |
| Up-regulation | 3000 | 3000 | – | – |
| Down-regulation | -500 | -500 | – | – |

**Table 7:** Offer curve of the SP with StochD

| Variable | $\sum_b g^{da}_{s,f,n,u,b}$ (MW) | | | | $f^{da}_{s,\ell}$ (MW) | | | $\lambda^{da}_{s,n}$ (€/MW) | | | $\sum_b g^{up/down}_{s,f,n,u,b}$ (MW) | | | | $f^{intra}_{s,\ell}$ (MW) | | | $\lambda^{intra}_{s,n}$ (€/MW) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario \ Index | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 | u0 | u1 | u2 | u3 | $\ell_1$ | $\ell_2$ | $\ell_3$ | n1 | n2 | n3 |
| Congestion | 6 | | 38 | 22 | -10 | 6 | -6 | 2991 | 6 | 7 | 2 | 4 | 4 | | | 4 | -4 | 3000 | 15 | 16 |
| Ramp limit | | | 8 | | -4 | 2 | | 6 | 6 | 6 | | 4 | 4 | 2 | -4 | | -2 | 20 | 20 | 20 |
| Surplus | | 4 | 42 | 20 | -10 | 10 | | 7 | 6 | 7 | | -4 | -4 | -1 | 4 | | 1 | 2 | 2 | 2 |

**Table 8:** Day-ahead and intraday generation, flows, and prices in the three-node example with StochD

In scenario "Surplus," there is high demand in the day-ahead market and a large surplus at node 1 in the intraday market. With ConvD, the CP units are not able to down-regulate all of the surplus due to 1) limited capacity of the CP unit 1, 2) limited ramping of the CP unit 2, and 3) transmission network congestion that leaves the CP unit 3 unutilized. Again, the SP anticipates this situation and set its down-regulation price $p^{down}_{x,n,u,b1/b2}$ to the minimum intraday price of -500 €/MW to gain a high profit. Indeed, negative intraday prices are caused by insufficient downward flexibility (Brijs et al., 2015). However, with StochD, the market operator is able to anticipate and avoid the SP's expensive down-regulation offer. By increasing the CP unit 3's day-ahead generation, transmission congestion is alleviated in the intraday market and the CP unit 3 is able to replace the SP unit's down-regulation. Therefore, intraday costs are greatly reduced with StochD in this scenario.

If the day-ahead and intraday markets would realize as in these three scenarios, then, with ConvD, the SP would achieve an expected profit of €9979.53, whereas with StochD, its expected profit would be €7869.84 (Table 9). Compared to ConvD, StochD leads to 69% lower intraday costs because in scenario "Congestion," StochD reduces the SP's expensive up-regulation and in scenarios "Ramp limit" and "Surplus" the SP's expensive intraday price offers are avoided entirely by dispatching CP units out of merit order in the day-ahead market. As a consequence, the total day-ahead generation costs increase by approximately 20 times. Such a large increase can occur because the objective function of StochD (C-3) does not model the changes to the day-ahead price and, thus, day-ahead generation costs caused by out-of-merit-order dispatch. Nevertheless, the total generation costs are still 38% lower with StochD, and, as we show later in Section 4.3, StochD outperforms ConvD in expectation in real market conditions, too. With PC, the SP has no profit, and the total generation costs are only a fraction of those of ConvD and StochD. All problem instances are solved in one second with Gurobi 8.1.1 with an Intel i7 4.2 GHz processor with 8 GB RAM.

| Metric \ Design | Conventional dispatch | Stochastic dispatch | Perfect competition |
|---|---|---|---|
| SP day-ahead profit (€) | -3.3 | 5906.34 | 0.0 |
| SP intraday profit (€) | 9982.83 | 1963.5 | 0.0 |
| SP total profit (€) | 9979.53 | 7869.84 | 0.0 |
| CP day-ahead profit (€) | 6.6 | 2.64 | 6.6 |
| CP intraday profit (€) | 9203.04 | 3970.56 | 3.96 |
| CP total profit (€) | 9209.64 | 3973.2 | 10.56 |
| Day-ahead generation cost (€) | 293.04 | 6202.68 | 293.04 |
| Intraday generation cost (€) | 19318.2 | 6019.86 | 135.96 |
| Total generation cost (€) | 19611.24 | 12222.54 | 429.0 |

**Table 9:** Expected profits and costs in the three-node example

### *4.2. Case study: strategic behavior in Nord Pool in 2016*

In 2016, extremely high intraday prices were observed in Nord Pool. For example, on 22 January 2016, the Finnish up-regulation price peaked at €3000/MWh. In accordance with our objective 2), we seek to examine reasons for these high prices using the offering strategies from Section 4.1.

We model the electricity markets in the Nordic countries with a simplified five-node network in Figure 6, which is adequate for capturing congestion and the resulting area price differences. We obtain transmission capacities for the lines shown in Figure 6 from Nord Pool (Nord Pool, 2016) and show them in Table 13 of Appendix D. In this network, each node contains demand as well as generators of different types. The day-ahead demand and generation capacities of wind, nuclear, and thermal in Tables 14 and 15, respectively, are set by averaging realized peak-hour data in January 2016 from Nord Pool, ENTSO-E, and the Finnish and Swedish TSOs (Nord Pool, 2016; ENTSO-E, 2016; Fingrid, 2016; Svenska Kraftnät, 2016). Due to the flexibility of hydropower, we take the maximum generation as its capacity. Also, we adjust the day-ahead demand with the average peak-hour exchange with neighboring countries such as Germany and Estonia. The piecewise constant generation cost parameters in Table 16 are fitted to match to the observed day-ahead and regulation price range approximately. We round generation and transmission capacity as well as demand data to the nearest 50 MW and, with ConvD, set the discretization interval of the binary expansion for up- and down-regulation of the SP ($\bar{G}^{up}_{x,n,u,b,j}$ and $\bar{G}^{down}_{x,n,u,b,k}$) to match the 50 MW precision, which leads to optimal results.[2] Using a higher precision keeps our conclusions unchanged because the 50 MW

[2]Since cost parameters are not distinct now, there are likely to be solutions with different generation and transmission flows but with the same objective value.

precision introduces only small discrepancies to the computed values as it is small compared to the market-clearing transmission flows and generation.

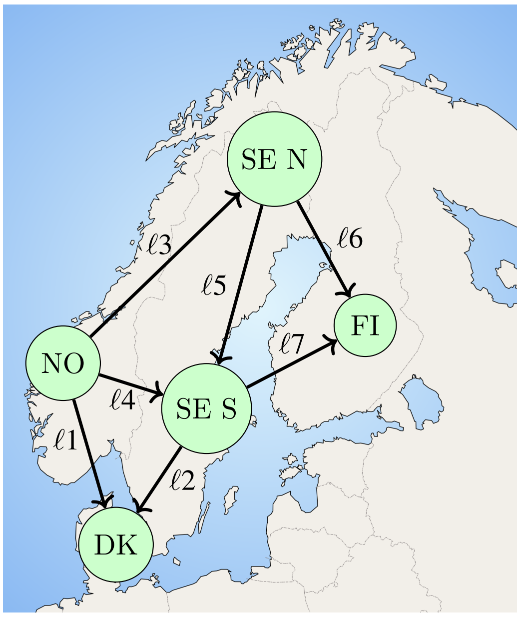


**Figure 6:** Nordic network indicating conventional direction of flow (SE N and SE S refer to Sweden north and south, respectively)

Corresponding to maximum regulation volumes observed in January 2016, we study two scenarios: one with 400 MW up-regulation ("Maximum deficit") and one with 300 MW down-regulation in Finland ("Maximum surplus"). We place a hypothetical SP with 500 MW capacity in Finland because the extremely high Finnish intraday price was set by a producer in Finland as the transmission lines from Sweden to Finland were congested. The SP with 500 MW capacity may correspond to a single large conventional plant or a few hydropower plants. All other generation capacities in Table 15 are assigned to CPs. The day-ahead generation as well as up- and down-regulation marginal costs of the SP are the same as those of hydropower (Table 16). In the following, the SP builds offer curves with the above input data, and we analyze the resulting generation and transmission flows in the day-ahead and intraday markets in the scenarios "Maximum deficit" and "Maximum surplus."

The optimal price and quantity offers are in Table 10. The generation, transmission flow, and price results in the day-ahead and intraday markets for each scenario are in Tables 17 through 22 of Appendix D, respectively. In both PC scenarios, the SP is fully dispatched in the day-ahead market as its marginal cost equals that of hydropower. All up- and down-regulation is done by the CPs.

By contrast, with ConvD, the SP sets its day-ahead price offer at the same level as the most expensive thermal generation so that in scenario "Maximum deficit," the SP does not produce in the day-ahead market but, rather, lets the transmission lines between Sweden and Finland become congested. Also, the SP's withdrawal from the day-ahead market results in high CP day-ahead generation and, thus, lack of CP capacity in the intraday market. Consequently, the SP can increase its up-regulation price to the maximum and gain a high profit as in the scenario "Congestion" of the three-node example. This leads to the very high intraday price of 3000 €/MW with ConvD in Finland as observed in the market data.

As in scenario "Congestion" in the three-node example with StochD, the strategic offer $p^{da}_{x,n,u,b} = 2990$ €/MW $< p^{up}_{x,n,u,b} = 3000$ €/MW causes the market operator in scenario "Maximum deficit" to i) dispatch the SP in the day-ahead market and ii) reserve CP capacity from the day-ahead market to the intraday market to avoid a high intraday cost. Thus, StochD effectively introduces an opportunity for the SP to affect the day-ahead market with intraday offers unlike with ConvD. However, this offering strategy leads to very high total day-ahead generation costs as the day-ahead price of Finland becomes high. This was not considered in Morales et al. (2014) as they assume perfect competition. Indeed, if we disable strategic offering in the intraday market, then the SP does not withhold generation in the day-ahead market but seeks to increase it both with ConvD and StochD because the SP anticipates that the intraday price remains at its marginal cost. This supports the interpretation that the high prices in Nord Pool were caused by strategic offering and shows that the possibility for high intraday profits impacts the SP's day-ahead generation decisions.

In scenario "Maximum surplus" with ConvD, the SP competes against the thermal generators and becomes fully dispatched in the day-ahead market. As a consequence, it can participate in balancing the down-regulation need. However, the SP observes that there is abundant down-regulation capacity in Finland and in the adjacent nodes, and, thus, it sets its down-regulation price offer at the same level as the cost of down-regulation for hydropower. Indeed, in 2016, the lowest down-regulation price in Finland was 0 €/MW, which is close to the marginal cost of hydropower and other renewables. With StochD, the SP is dispatched out of merit order in the day-ahead market as it offers down-regulation at a price higher than any of the CPs. This leads to higher total profits because the day-ahead profit of the SP is higher than its intraday loss as the SP buys back the capacity it offered in the day-ahead market.

If the day-ahead and intraday markets would realize as in these two scenarios, then the SP would make an expected profit of 154.75 k€ with ConvD and 152.625 k€ with StochD. Thus, StochD is not able to reduce the profit of the SP significantly. Moreover, the total generation costs of StochD are significantly higher because of the extremely high day-ahead prices in Finland in scenario "Maximum deficit." However, as we show in Section 4.3, possibilities for adverse offering similar to scenario "Maximum deficit" are rare, and, therefore, StochD can outperform ConvD in expectation. In the perfectly competitive case, the SP makes a profit of 12.5 k€ as the SP is dispatched together with hydropower. In summary, the extremely high peak prices observed in Finland can be attributed to the combination of low up-regulation capacity, transmission congestion, and strategic behavior. All problem instances are solved to optimality in approximately one second.

| | Conventional dispatch | | | | Stochastic dispatch | | | | Perfect competition | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | | $p_{x,n,u,b}$ (€/MW) | | $q_{x,n,u,b}$ (MW) | |
| Offer \ Block | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ |
| Day-ahead | 50 | 50 | 250 | 250 | 2990 | 2990 | 250 | 50 | 20 | 30 | 250 | 250 |
| Up-regulation | 3000 | 3000 | – | – | 3000 | 3000 | – | – | 30 | 40 | – | – |
| Down-regulation | 20 | 20 | – | – | 3000 | 2960 | – | – | 20 | 15 | – | – |

**Table 10:** Price and quantity offers of the strategic producer in the Nordic example

| Metric \ Policy | Conventional dispatch | Stochastic dispatch | Perfect competition |
|---|---|---|---|
| SP day-ahead profit (k€) | 6.25 | 152.75 | 12.5 |
| SP intraday profit (k€) | 148.5 | -0.125 | 0.0 |
| SP total profit (k€) | 154.75 | 152.625 | 12.5 |
| CP day-ahead profit (k€) | 732.0 | 15136.0 | 732.0 |
| CP intraday profit (k€) | 438.0 | 2.0 | 0.0 |
| CP total profit (k€) | 1170.0 | 15138.0 | 732.0 |
| Day-ahead generation cost (k€) | 2005.0 | 16562.0 | 2005.0 |
| Intraday generation cost (k€) | 597.0 | 5.0 | 13.0 |
| Total generation cost (k€) | 2602.0 | 16567.0 | 2018.0 |

**Table 11:** Expected profits and costs in the Nordic example

## *4.3. Mean performance of the market designs in Nord Pool*

Finally, in order to address our objective 3) to estimate the expected impact of the offering strategies on day-ahead and intraday costs, we conduct a simulation that resembles the real timeline of day-ahead and intraday markets as shown in Figure 1 and the procedure in Baringo and Conejo (2016). The decision sequence is as follows:

1) The SP generates a set of initial day-ahead and intraday demand scenarios $(D^{da}_{s,n}, D^{intra}_{s,n})$ by applying k-means clustering to historical data.

2) The SP builds coordinated offer curves ($p^{da/up/down}_{x,n,u,b}$ and $q^{da}_{x,n,u,b}$) for the day-ahead and intraday markets by solving Eqs. (B-2)-(B-42) (ConvD) or (C-12)-(C-15) (StochD) given the initial day-ahead and intraday scenarios from 1). With PC, the SP sets $p^{da/up/down}_{x,n,u,b} = C^{da/up/down}_{x,n,u,b}$ and $q^{da}_{x,n,u,b} = G^{max}_{x,n,u,b}$.

3) The market operator receives the offer curves of the participants. It clears the day-ahead market by solving Eqs. (11)-(15) (ConvD and PC) or (C-3)-(C-5) (StochD) using real market data and communicates the resulting generation, transmission flows, and prices to the participants.

4) The SP generates an updated set of intraday scenarios by applying k-means clustering to historical data selected based on the day-ahead realization.

5) The SP updates its intraday offer curves ($p^{up/down}_{x,n,u,b}$) by solving Eqs. (E-6)-(E-9) (ConvD and StochD) using the updated intraday scenarios and the day-ahead results. With PC, no update is required.

6) The market operator receives the intraday offer curves of the participants and clears the intraday market by solving Eqs. (16)-(22) using real market data.

The steps 2)-6) are repeated for 1000 randomly sampled time steps $t$ to obtain good estimates of expected profits and costs. We use the Nord Pool network from Section 4.2, and each time step $t \in [1, 8760]$ is defined by realized hourly day-ahead demand, generation, flows to neighboring countries, and regulation volumes in 2016. Similar to Section 4.2, input data are rounded to 50 MW precision to match the discretization intervals $\bar{G}^{up}_{x,n,u,b,j}$ and $\bar{G}^{down}_{x,n,u,b,k}$ of ConvD. The mean rounding error for the input data is less than 1 MW, which may cause small discrepancies in the estimated values but do not affect our conclusions. The transmission and generation capacity data used in the market clearings are assumed to be known exactly when building the offer curves.

The day-ahead and intraday scenarios at step 1) are given by

$$(D^{da}_{s,n}, D^{intra}_{s,n}) = (\hat{D}^{da}_{t,n} + \tilde{e}^{da}_{s,n}, \tilde{e}^{intra}_{s,n}), \tag{23}$$

where $\hat{D}^{da}_{t,n}$ is the predicted day-ahead demand in node $n$ at time step $t$ and $(\tilde{e}^{da}_{s,n}, \tilde{e}^{intra}_{s,n})$ are estimated day-ahead forecast error and regulation volume in scenario $s$ at node $n$, respectively. Following

Baringo and Conejo (2013), we compute $(\tilde{e}^{da}_{s,n}, \tilde{e}^{intra}_{s,n})$ by applying k-means clustering from scikit-learn (Pedregosa et al., 2011) to nodewise, hourly total of forecast errors for demand and wind power in 2015 and to the nodewise, hourly regulation volumes in 2015 obtained from Nord Pool data, respectively. Consequently, each data point $(\tilde{e}^{da}_{n1}, \ldots, \tilde{e}^{da}_{n5}, \tilde{e}^{intra}_{n1}, \ldots, \tilde{e}^{intra}_{n5})$ is a vector of length 10. This representation of the data allows us to capture spatial correlations between the nodes as well as possible correlations between the day-ahead and intraday markets. We randomize the order of the data points and use 80% of the data for fitting the clusters and the remaining 20% as a validation set. We select seven clusters ($k = 7$), because additional clusters increase solution times while not improving the k-means objective function value in the validation set significantly as shown by Figure 7. By assigning each of the seven cluster centers to one scenario, we obtain seven 10-vectors $\left[(\tilde{e}^{da}_{s1,n1}, \ldots, \tilde{e}^{da}_{s1,n5}, \tilde{e}^{intra}_{s1,n1}, \ldots, \tilde{e}^{intra}_{s1,n5}), \ldots, (\tilde{e}^{da}_{s7,n1}, \ldots, \tilde{e}^{da}_{s7,n5}, \tilde{e}^{intra}_{s7,n1}, \ldots, \tilde{e}^{intra}_{s7,n5})\right]$, which, using Eq. (23), allow us to compute seven day-ahead and intraday scenarios $(D^{da}_{s,n}, D^{intra}_{s,n}), \forall s \in (s1, \ldots, s7), \forall n \in (n1, \ldots, n5)$. The weight of a scenario is the weight of the corresponding cluster defined as the ratio of the number of data points belonging to the cluster to the total number of data points. Figure 8 indicates that there is a positive correlation between the day-ahead and intraday deviations. Finally, near-zero and negative deviations have the highest probability, which is consistent with the fact that down-regulation is more frequent than up-regulation in the Nord Pool market as shown by Nord Pool regulation data.

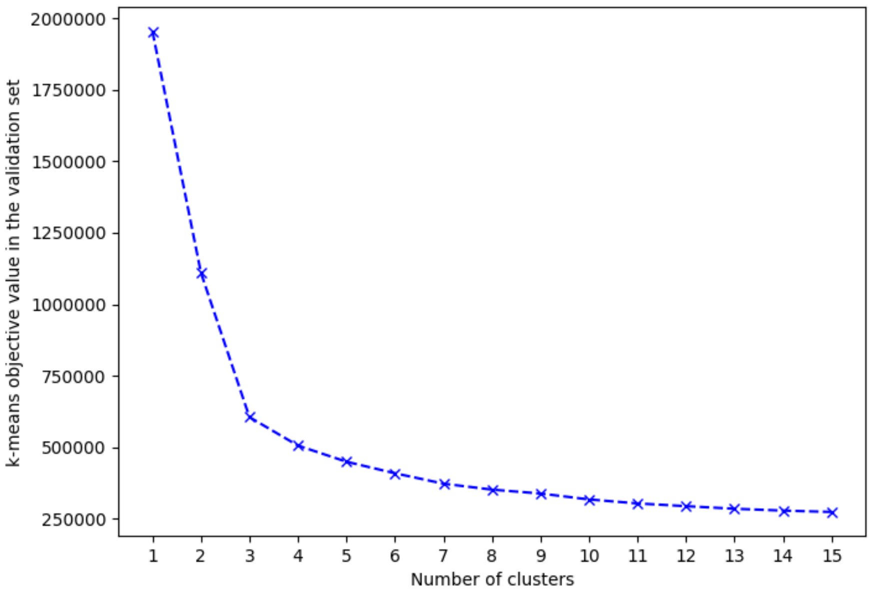


**Figure 7:** Impact of the number of clusters on the k-means objective function value in the validation set

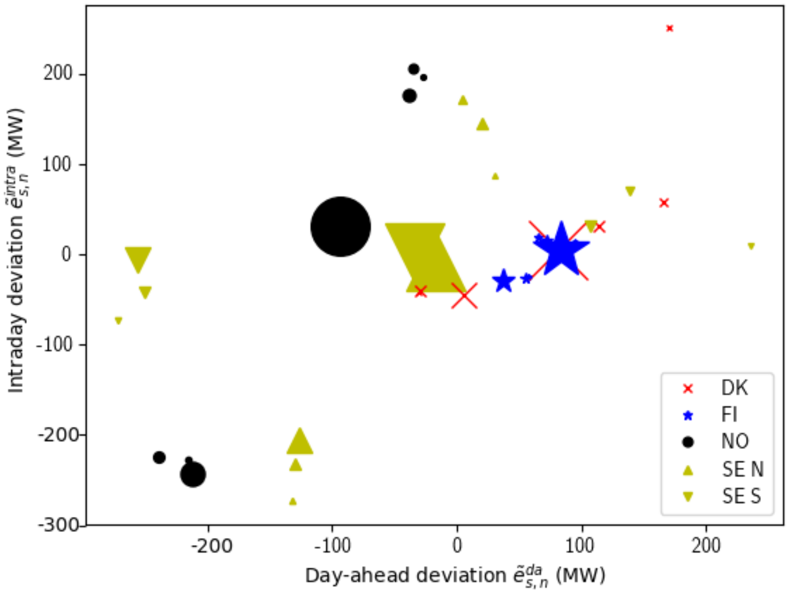


**Figure 8:** Nodewise day-ahead and intraday clusters, where the diameter of the marker indicates the weight of a cluster

Using these seven day-ahead and intraday scenarios including negative, near-zero, and positive deviations as an input to Eqs. (B-2)-(B-42) (ConvD) or (C-12)-(C-15) (StochD), the SP builds coordinated day-ahead and intraday offer curves ($p^{da/up/down}_{x,n,u,b}$ and $q^{da}_{x,n,u,b}$) at step 2). As an additional uncertainty, we sample uniform noise from U($-5$ €/MW, $5$ €/MW) to the day-ahead and intraday generation cost parameters of the CP ($C^{da}_{y,n,u,b}$, $C^{up}_{y,n,u,b}$, $C^{down}_{y,n,u,b}$). Note that, as shown in Sections 4.1 and 4.2, coordinated offering requires considering the intraday market when building the day-ahead offer curve. However, with PC, the offer curve building reduces to setting $p^{da}_{x,n,u,b} = C^{da}_{x,n,u,b}$, $p^{up}_{x,n,u,b} = C^{up}_{x,n,u,b}$, $p^{down}_{x,n,u,b} = C^{down}_{x,n,u,b}$, and $q^{da}_{x,n,u,b} = G^{max}_{x,n,u,b}$. Given the offer curves and realized hourly day-ahead demand ($D^{da}_{t,n}$), the market operator clears the day-ahead market at step 3) by solving Eqs. (11)-(15) (ConvD and PC) or (C-3)-(C-5) (StochD). The market operator communicates the day-ahead market-clearing generation, transmission flows, and prices to the participants.

Then, given the day-ahead results from step 3), the SP updates its intraday scenarios at step 4). We update the values of $D^{intra}_{s,n}$ by running k-means clustering on the set of regulation volumes corresponding to the 1000 closest (in terms of mean $L^2$ distance) day-ahead demand and wind power realizations in historical data. The weights of the scenarios are defined as above. At step 5), the

SP updates its intraday offer curves by solving Eqs. (E-6)-(E-9) (ConvD and StochD) by using the updated intraday scenarios and the realized day-ahead generation and transmission flows. With PC, the intraday offer curves from step 2) remain unchanged. Finally, the market operator clears the intraday market at step 6) by solving Eqs. (16)-(22) given the updated intraday offer curves, realized day-ahead generation, transmissions flows, and intraday demand ($D_{t,n}^{intra}$).

Table 12 shows the results of this simulation. The total generation costs and the profits of the SP are approximately 123% and 466% higher with ConvD than with PC, respectively. StochD leads to lower costs and SP profits at approximately 100% and 404% higher than PC, respectively. Consequently, the StochD model is able to mitigate strategic behavior to some extent, but it cannot eliminate it in all cases as our examples illustrate. The PC, ConvD, and StochD simulations are executed in approximately 20 seconds, 18 hours and 15 minutes, and 7 hours and 5 minutes, respectively.

| Metric \ Policy | Conventional dispatch | Stochastic dispatch | Perfect competition |
|---|---|---|---|
| SP day-ahead profit (k€) | 42.61 | 37.61 | 8.15 |
| SP intraday profit (k€) | 3.53 | 3.43 | 0.0 |
| SP total profit (k€) | 46.14 | 41.04 | 8.15 |
| CP day-ahead profit (k€) | 2305.23 | 1992.36 | 619.96 |
| CP intraday profit (k€) | 0.20 | 1.11 | 0.23 |
| CP total profit (k€) | 2305.43 | 1993.47 | 620.18 |
| Day-ahead generation cost (k€) | 3123.95 | 2807.10 | 1420.11 |
| Intraday generation cost (k€) | 6.04 | 5.02 | 2.81 |
| Total generation cost (k€) | 3129.99 | 2812.12 | 1404.92 |
| Regulation volume (MW) | 450 | 446 | 450 |

**Table 12:** Expected profits and costs in the mean performance analysis

## 5. Conclusion

Due to high barriers to entry, many day-ahead electricity markets have major players that can exert market power. Often, intraday markets have even less competition because flexible capacity is required. In fact, Knaut and Paschmann (2017) find restricted participation to be one reason for the high price volatility of the 15-minute German intraday products. Moreover, there may be less competition in areas that have low transmission capacity to neighboring areas. Consequently, as day-ahead prices decrease due to the increasing penetration of renewable energy with zero marginal costs, it is plausible to expect that higher profits are being pursued in the intraday market. Motivated by this possibility, we have developed a model that captures strategic offering not only in the day-ahead but also in the intraday market. Indeed, in Section 4.1 (objective 1), we show using a three-node network that transmission grid congestion and the lack of flexible capacity allow an SP to increase its profit in the day-ahead and intraday markets. On the one hand, withholding generation from the day-ahead market forces the CPs to generate more, which can lead to higher prices in the intraday market as the non-dispatched competitive capacity decreases. On the other hand, the SP can put forward generation in the day-ahead market and buy it back at a lower price from the intraday market if there is a surplus. Also, in Section 4.2 (objective 2), we have provided evidence that such strategic offering can explain high intraday prices observed in Nord Pool in 2016. Finally, Section 4.3 (objective 3) shows that strategic offering based on forecasts leads to higher expected profits and total generation costs vis-à-vis perfect competition (PC). However, the stochastic dispatch model of Morales et al. (2014) (StochD) can reduce the expected impact of strategic offering on total generation costs compared to the the conventional dispatch model (ConvD).

Our model simplifies the building of day-ahead and intraday offer curves by ignoring more complex bid types spanning multiple time periods, for example. In addition, our model has only one intraday market, whereas, in reality, one-hour and 15-minute intraday trades can be made several hours before delivery and closer to real-time at different response times. Due to these structures and a low degree of competition, there are likely additional strategies for exerting market power. However, the impact of strategic offering will be mitigated if other players change their behavior in response to the strategic offers. Exploring the impact of multiple supply- and demand-side strategic players is left as a future research direction as it would result in an equilibrium problem with equilibrium constraints (EPEC) problem that generally requires custom heuristics to obtain a Nash equilibrium possibly out of many.

Additionally, the model could be made more realistic by introducing multiple time steps, elastic demand, and piecewise linear offer curves for hydropower, in particular. Regardless of the simplifications, the ConvD model is still computationally intensive due to the discretization procedure applied to non-convexities. Consequently, alternative solution methods - such as reformulating the discretization procedure through Benders decomposition of the products of binary and continuous variables - could be explored to tackle larger problem instances. Also, it is often possible to build smaller problem instances by reducing the size of the network by aggregating nearby areas into larger areas like in our Nordic network in Section 4.2 and by using clustering methods such as k-means (Section 4.3) for scenario reduction. Moreover, the endogenously computed day-ahead ($\lambda_{s,n}^{da}$) and intraday prices ($\lambda_{s,n}^{intra}$) can be replaced with exogenous values before solving only the upper-level problem in Eqs. (1)-(10) to quickly construct competitive coordinated offering into day-ahead and intraday markets.

Our results indicate that more transmission and flexible-generation capacity as well as development of more robust dispatch mechanisms may mitigate the impact of market power in intraday markets with a high penetration of variable renewable generation. As strategic behavior could be detected from plant-level data (Clements et al., 2016), data-transparency policies are also warranted.

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## Appendix A MPEC formulation

The lower-level problems (11)-(15) and (16)-(22) are linear, and, therefore, convex. To solve the bi-level program as if it were a single optimization problem, we reformulate it as a single-level mathematical program with equilibrium constraints (MPEC) by replacing the lower-level problems by their Karush-Kuhn-Tucker (KKT) conditions (A-2)-(A-9) and (A-10)-(A-21), respectively (Gabriel and Leuthold, 2010). Correspondingly, the set of dual variables is denoted by $\Omega^{DV} = \{\lambda^{da}_{s,n}, \lambda^{intra}_{s,n}, \beta^{da}_{s,f,n,u,b}, \beta^{up}_{s,f,n,u,b}, \beta^{down}_{s,f,n,u,b}, \beta^{up,ramp}_{s,f,n,u,b}, \beta^{down,ramp}_{s,f,n,u,b}, \mu^{da,max}_{s,\ell}, \mu^{da,min}_{s,\ell}, \mu^{intra,max}_{s,\ell}, \mu^{intra,min}_{s,\ell}\}$. The MPEC is non-convex due to the bilinear terms $g^{da}_{s,x,n,u,b}\lambda^{da}_{s,n}$, $g^{up}_{s,x,n,u,b}\lambda^{intra}_{s,n}$, and $g^{down}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ in Eq. (A-1) and the complementarity conditions (A-4)-(A-9) and (A-12)-(A-21). These non-convexities are resolved in Appendix B.

$$\text{Minimize}_{\Omega^{UL}\cup\Omega^{LL^{da}}\cup\Omega^{LL^{intra}}\cup\Omega^{DV}}$$

$$\sum_s W_s\left[\sum_n\sum_u\sum_b\left(g^{da}_{s,x,n,u,b}\left(C^{da}_{x,n,u,b}-\lambda^{da}_{s,n}\right)+g^{up}_{s,x,n,u,b}\left(C^{up}_{x,n,u,b}-\lambda^{intra}_{s,n}\right)-g^{down}_{s,x,n,u,b}\left(C^{down}_{x,n,u,b}-\lambda^{intra}_{s,n}\right)\right)\right] \quad \text{(A-1)}$$

s.t.

Eqs. (2)-(10) (upper-level conditions)

$$f^{da}_{s,\ell} \text{ free, } -\sum_n Y_{l,n}\lambda^{da}_{s,n}+\mu^{da,max}_{s,\ell}-\mu^{da,min}_{s,\ell}=0 \qquad \forall s,\ell \quad \text{(A-2)}$$

$$\lambda^{da}_{s,n} \text{ free, } D^{da}_{s,n}-\sum_f\sum_u\sum_b g^{da}_{s,f,n,u,b}-\sum_\ell Y_{\ell,n}f^{da}_{\ell,n}=0 \qquad \forall s,n \quad \text{(A-3)}$$

$$g^{da}_{s,x,n,u,b}\geq 0\perp p^{da}_{x,n,u,b}-\lambda^{da}_{s,n}+\beta^{da}_{s,x,n,u,b}\geq 0 \qquad \forall s,x,n,u,b \quad \text{(A-4)}$$

$$g^{da}_{s,y,n,u,b}\geq 0\perp C^{da}_{y,n,u,b}-\lambda^{da}_{s,n}+\beta^{da}_{s,y,n,u,b}\geq 0 \qquad \forall s,y,n,u,b \quad \text{(A-5)}$$

$$\beta^{da}_{s,x,n,u,b}\geq 0\perp q^{da}_{x,n,u,b}-g^{da}_{s,x,n,u,b}\geq 0 \qquad \forall s,x,n,u,b \quad \text{(A-6)}$$

$$\beta^{da}_{s,y,n,u,b}\geq 0\perp G^{max}_{y,n,u,b}-g^{da}_{s,y,n,u,b}\geq 0 \qquad \forall s,y,n,u,b \quad \text{(A-7)}$$

$$\mu^{da,max}_{s,\ell}\geq 0\perp NTC^{max}_\ell-f^{da}_{s,\ell}\geq 0 \qquad \forall s,\ell \quad \text{(A-8)}$$

$$\mu^{da,min}_{s,\ell}\geq 0\perp f^{da}_{s,\ell}-NTC^{min}_\ell\geq 0 \qquad \forall s,\ell \quad \text{(A-9)}$$

$$f^{intra}_{s,\ell} \text{ free, } -\sum_n Y_{l,n}\lambda^{intra}_{s,n}+\mu^{intra,max}_{s,\ell}-\mu^{intra,min}_{s,\ell}=0 \qquad \forall s,\ell \quad \text{(A-10)}$$

$$\lambda^{intra}_{s,n} \text{ free, } D^{intra}_{s,n}-\sum_f\sum_u\sum_b\left(g^{up}_{s,f,n,u,b}-g^{down}_{s,f,n,u,b}\right)-\sum_\ell Y_{\ell,n}f^{intra}_{\ell,n}=0 \qquad \forall s,n \quad \text{(A-11)}$$

$$g^{up}_{s,x,n,u,b}\geq 0\perp p^{up}_{x,n,u,b}-\lambda^{intra}_{s,n}+\beta^{up}_{s,x,n,u,b}+\beta^{up,ramp}_{s,x,n,u,b}\geq 0 \qquad \forall s,x,n,u,b \quad \text{(A-12)}$$

$$g^{up}_{s,y,n,u,b}\geq 0\perp C^{up}_{y,n,u,b}-\lambda^{intra}_{s,n}+\beta^{up}_{s,y,n,u,b}+\beta^{up,ramp}_{s,y,n,u,b}\geq 0 \qquad \forall s,y,n,u,b \quad \text{(A-13)}$$

$$g^{down}_{s,x,n,u,b}\geq 0\perp -p^{down}_{x,n,u,b}+\lambda^{intra}_{s,n}+\beta^{down}_{s,x,n,u,b}+\beta^{down,ramp}_{s,x,n,u,b}\geq 0 \qquad \forall s,x,n,u,b \quad \text{(A-14)}$$

$$g^{down}_{s,y,n,u,b}\geq 0\perp -C^{down}_{y,n,u,b}+\lambda^{intra}_{s,n}+\beta^{down}_{s,y,n,u,b}+\beta^{down,ramp}_{s,y,n,u,b}\geq 0 \qquad \forall s,y,n,u,b \quad \text{(A-15)}$$

$$\beta^{up}_{s,f,n,u,b}\geq 0\perp G^{max}_{f,n,u,b}-g^{da}_{s,f,n,u,b}-g^{up}_{s,f,n,u,b}\geq 0 \qquad \forall s,f,n,u,b \quad \text{(A-16)}$$

$$\beta^{down}_{s,f,n,u,b} \geq 0 \perp g^{da}_{s,f,n,u,b} - g^{down}_{s,f,n,u,b} \geq 0 \qquad \forall s,f,n,u,b \tag{A-17}$$

$$\beta^{up,ramp}_{s,f,n,u,b} \geq 0 \perp G^{up,ramp}_{f,n,u,b} - g^{up}_{s,f,n,u,b} \geq 0 \qquad \forall s,f,n,u,b \tag{A-18}$$

$$\beta^{down,ramp}_{s,f,n,u,b} \geq 0 \perp G^{down,ramp}_{f,n,u,b} - g^{down}_{s,f,n,u,b} \geq 0 \qquad \forall s,f,n,u,b \tag{A-19}$$

$$\mu^{intra,max}_{s,\ell} \geq 0 \perp NTC^{max}_{\ell} - f^{da}_{s,\ell} - f^{intra}_{s,\ell} \geq 0 \qquad \forall s,\ell \tag{A-20}$$

$$\mu^{intra,min}_{s,\ell} \geq 0 \perp f^{da}_{s,\ell} + f^{intra}_{s,\ell} - NTC^{min}_{\ell} \geq 0 \qquad \forall s,\ell \tag{A-21}$$

In the PC model, the systems (A-2)-(A-9) and (A-10)-(A-21) are solved to optimality sequentially by setting $p^{da}_{x,n,u,b} = C^{da}_{x,n,u,b}$, $p^{up}_{x,n,u,b} = C^{up}_{x,n,u,b}$, $p^{down}_{x,n,u,b} = C^{down}_{x,n,u,b}$, and $q^{da}_{x,n,u,b} = G^{max}_{x,n,u,b}$.

## Appendix B MILP formulation

First, the day-ahead lower-level problem in Eqs. (11)-(15) is linear, and, thus, strong duality holds. Consequently, we can follow the procedure in Ruiz and Conejo (2009) and linearize the non-convex term $g^{da}_{s,x,n,u,b}\lambda^{da}_{s,n}$ exactly by using Eqs. (A-2)-(A-9):

$$v^{da}_{s,x} = \sum_n \sum_u \sum_b g^{da}_{s,x,n,u,b}\lambda^{da}_{s,n} = \sum_y \sum_n \sum_u \sum_b \left(-C^{da}_{y,n,u,b} g^{da}_{s,y,n,u,b} - \beta^{da}_{s,y,n,u,b} G^{max}_{y,n,u,b}\right) + \sum_{\ell} \left(-\mu^{da,max}_{s,\ell} NTC^{max}_{\ell} + \mu^{da,min}_{s,\ell} NTC^{min}_{\ell}\right) + \sum_n D^{da}_{s,n}\lambda^{da}_{s,n} \tag{B-1}$$

Second, the bilinear term $g^{up}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ is replaced by the term $v^{up}_{s,x,n,u,b}$ using our reformulation of binary expansion (Barroso et al., 2006) that allows the term to become negative, which can happen if $\lambda^{intra}_{s,n}$ is negative. We do this because applying the procedure of Ruiz and Conejo (2009) to $g^{up}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ would require a more expensive reformulation of a larger number of bilinear terms $g^{up}_{s,y,n,u,b}\beta^{up}_{s,y,n,u,b}$. To this end, Eq. (B-3) represents $g^{up}_{s,x,n,u,b}$ as a binary number scaled by the discretization interval $\bar{G}^{up}_{x,n,u,b} > 0$ by selecting binary variables $h^{up}_{s,x,n,u,b,j}$. If $h^{up}_{s,x,n,u,b,j}$ equals to one, then (B-4) enforces $\hat{h}^{up}_{s,x,n,u,b,j}$ to equal $\lambda^{intra}_{s,n}$ but (B-5) limits its value between $\Lambda^{intra,min}$ and $\Lambda^{intra,max}$. However, if $h^{up}_{s,x,n,u,b,j}$ equals to zero, then (B-4) is not binding but (B-5) sets $\hat{h}^{up}_{s,x,n,u,b,j}$ to zero. As a result, (B-6) sets $v^{up}_{s,x,n,u,b}$ to the sum of selected generation levels multiplied by the intraday price. The term $g^{down}_{s,x,n,u,b}\lambda^{intra}_{s,n}$ is linearized similarly in Eqs. (B-7)-(B-10) using the binary variable $h^{down}_{s,x,n,u,b,k}$ and free variable $\hat{h}^{down}_{s,x,n,u,b,k}$. This reformulation may lead to suboptimal results, but the suboptimality can be reduced by making the discretization intervals $\bar{G}^{up/down}_{x,n,u,b} > 0$ smaller.

Third, the complementarity conditions (A-4)-(A-9) and (A-12)-(A-21) are modeled by disjunctive constraints in Eqs. (B-11)-(B-42) as in Gabriel and Leuthold (2010). In the following formulation, we have set $\Omega^{MILP} = \{v^{da}_{s,x}, v^{up}_{s,x,n,u,b,j}, v^{down}_{s,x,n,u,b,k}, h^{up}_{s,x,n,u,b,j}, h^{down}_{s,x,n,u,b,k}, \hat{h}^{up}_{s,x,n,u,b,j}, \hat{h}^{down}_{s,x,n,u,b,k}, r1, \ldots, r16\}$ and we use $M = 2\Lambda^{da,max}$ in all numerical results in Section 4.

$$\text{Minimize}_{\Omega^{UL}\cup\Omega^{LL^{da}}\cup\Omega^{LL^{intra}}\cup\Omega^{DV}\cup\Omega^{MILP}}$$

$$\sum_s W_s \left[ \sum_{n,u,b} \left( C^{da}_{x,n,u,b} g^{da}_{s,x,n,u,b} + C^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - C^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} - v^{up}_{s,x,n,u,b} + v^{down}_{s,x,n,u,b} \right) - v^{da}_{s,x} \right] \tag{B-2}$$

s.t.

$$g^{up}_{s,x,n,u,b} = \bar{G}^{up}_{x,n,u,b} \sum_j 2^{j-1} h^{up}_{s,x,n,u,b,j} \qquad \forall s,x,n,u,b \tag{B-3}$$

$$-M(1-h^{up}_{s,x,n,u,b,j}) \le \lambda^{intra}_{s,n} - \hat{h}^{up}_{s,x,n,u,b,j} \le M(1-h^{up}_{s,x,n,u,b,j}) \qquad \forall s,x,n,u,b,j \tag{B-4}$$

$$\Lambda^{intra,min} h^{up}_{s,x,n,u,b,j} \le \hat{h}^{up}_{s,x,n,u,b,j} \le \Lambda^{intra,max} h^{up}_{s,x,n,u,b,j} \qquad \forall s,x,n,u,b,j \tag{B-5}$$

$$v^{up}_{s,x,n,u,b} = \bar{G}^{up}_{x,n,u,b} \sum_j 2^{j-1} \hat{h}^{up}_{s,x,n,u,b,j} \qquad \forall s,x,n,u,b \tag{B-6}$$

$$g^{down}_{s,x,n,u,b} = \bar{G}^{down}_{x,n,u,b} \sum_k 2^{k-1} h^{down}_{s,x,n,u,b,k} \qquad \forall s,x,n,u,b \tag{B-7}$$

$$-M(1-h^{down}_{s,x,n,u,b,k}) \le \lambda^{intra}_{s,n} - \hat{h}^{down}_{s,x,n,u,b,k} \le M(1-h^{down}_{s,x,n,u,b,k}) \qquad \forall s,x,n,u,b,k \tag{B-8}$$

$$\Lambda^{intra,min} h^{down}_{s,x,n,u,b,k} \le \hat{h}^{down}_{s,x,n,u,b,k} \le \Lambda^{intra,max} h^{down}_{s,x,n,u,b,k} \qquad \forall s,x,n,u,b,k \tag{B-9}$$

$$v^{down}_{s,x,n,u,b} = \bar{G}^{down}_{x,n,u,b} \sum_k 2^{k-1} \hat{h}^{down}_{s,x,n,u,b,k} \qquad \forall s,x,n,u,b \tag{B-10}$$

Eqs. (2)-(10) (upper-level conditions)

Eqs. (A-2), (A-3), (A-10), (A-11) (lower-level equality conditions)

$$Mr1_{s,x,n,u,b} \ge p^{da}_{x,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,x,n,u,b} \ge 0 \qquad \forall s,x,n,u,b \tag{B-11}$$

$$M(1-r1_{s,x,n,u,b}) \ge g^{da}_{s,x,n,u,b} \ge 0 \qquad \forall s,x,n,u,b \tag{B-12}$$

$$Mr2_{s,y,n,u,b} \ge C^{da}_{y,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,y,n,u,b} \ge 0 \qquad \forall s,y,n,u,b \tag{B-13}$$

$$M(1-r2_{s,y,n,u,b}) \ge g^{da}_{s,y,n,u,b} \ge 0 \qquad \forall s,y,n,u,b \tag{B-14}$$

$$Mr3_{s,x,n,u,b} \ge q^{da}_{x,n,u,b} - g^{da}_{s,x,n,u,b} \ge 0 \qquad \forall s,x,n,u,b \tag{B-15}$$

$$M(1-r3_{s,x,n,u,b}) \ge \beta^{da}_{s,x,n,u,b} \ge 0 \qquad \forall s,x,n,u,b \tag{B-16}$$

$$Mr4_{s,y,n,u,b} \ge G^{max}_{y,n,u,b} - g^{da}_{s,y,n,u,b} \ge 0 \qquad \forall s,y,n,u,b \tag{B-17}$$

$$M(1-r4_{s,y,n,u,b}) \ge \beta^{da}_{s,y,n,u,b} \ge 0 \qquad \forall s,y,n,u,b \tag{B-18}$$

$$Mr5_{s,\ell} \ge NTC^{max}_{\ell} - f^{da}_{s,\ell} \ge 0 \qquad \forall s,\ell \tag{B-19}$$

$$M(1-r5_{s,\ell}) \ge \mu^{da,max}_{s,\ell} \ge 0 \qquad \forall s,\ell \tag{B-20}$$

$$Mr6_{s,\ell} \ge f^{da}_{s,\ell} - NTC^{min}_{\ell} \ge 0 \qquad \forall s,\ell \tag{B-21}$$

$$M(1-r6_{s,\ell}) \geq \mu_{s,\ell}^{da,min} \geq 0 \qquad \forall s,\ell \qquad \text{(B-22)}$$

$$Mr7_{s,x,n,u,b} \geq p_{x,n,u,b}^{up} - \lambda_{s,n}^{intra} + \beta_{s,x,n,u,b}^{up} + \beta_{s,x,n,u,b}^{up,ramp} \geq 0 \qquad \forall s,x,n,u,b \qquad \text{(B-23)}$$

$$M(1-r7_{s,x,n,u,b}) \geq g_{s,x,n,u,b}^{up} \geq 0 \qquad \forall s,x,n,u,b \qquad \text{(B-24)}$$

$$Mr8_{s,y,n,u,b} \geq C_{y,n,u,b}^{up} - \lambda_{s,n}^{intra} + \beta_{s,y,n,u,b}^{up} + \beta_{s,y,n,u,b}^{up,ramp} \geq 0 \qquad \forall s,y,n,u,b \qquad \text{(B-25)}$$

$$M(1-r8_{s,y,n,u,b}) \geq g_{s,y,n,u,b}^{up} \geq 0 \qquad \forall s,y,n,u,b \qquad \text{(B-26)}$$

$$Mr9_{s,x,n,u,b} \geq -p_{x,n,u,b}^{down} + \lambda_{s,n}^{intra} + \beta_{s,x,n,u,b}^{down} + \beta_{s,x,n,u,b}^{down,ramp} \geq 0 \qquad \forall s,x,n,u,b \qquad \text{(B-27)}$$

$$M(1-r9_{s,x,n,u,b}) \geq g_{s,x,n,u,b}^{down} \geq 0 \qquad \forall s,x,n,u,b \qquad \text{(B-28)}$$

$$Mr10_{s,y,n,u,b} \geq -C_{y,n,u,b}^{down} + \lambda_{s,n}^{intra} + \beta_{s,y,n,u,b}^{down} + \beta_{s,y,n,u,b}^{down,ramp} \geq 0 \qquad \forall s,y,n,u,b \qquad \text{(B-29)}$$

$$M(1-r10_{s,y,n,u,b}) \geq g_{s,y,n,u,b}^{down} \geq 0 \qquad \forall s,y,n,u,b \qquad \text{(B-30)}$$

$$Mr11_{s,f,n,u,b} \geq G_{f,n,u,b}^{max} - g_{s,f,n,u,b}^{da} - g_{s,f,n,u,b}^{up} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-31)}$$

$$M(1-r11_{s,f,n,u,b}) \geq \beta_{s,f,n,u,b}^{up} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-32)}$$

$$Mr12_{s,f,n,u,b} \geq g_{s,f,n,u,b}^{da} - g_{s,f,n,u,b}^{down} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-33)}$$

$$M(1-r12_{s,f,n,u,b}) \geq \beta_{s,f,n,u,b}^{down} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-34)}$$

$$Mr13_{s,f,n,u,b} \geq G_{f,n,u,b}^{up,ramp} - g_{s,f,n,u,b}^{up} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-35)}$$

$$M(1-r13_{s,f,n,u,b}) \geq \beta_{s,f,n,u,b}^{up,ramp} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-36)}$$

$$Mr14_{s,f,n,u,b} \geq G_{f,n,u,b}^{down,ramp} - g_{s,f,n,u,b}^{down} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-37)}$$

$$M(1-r14_{s,f,n,u,b}) \geq \beta_{s,f,n,u,b}^{down,ramp} \geq 0 \qquad \forall s,f,n,u,b \qquad \text{(B-38)}$$

$$Mr15_{s,\ell} \geq NTC_{\ell}^{max} - f_{s,\ell}^{da} - f_{s,\ell}^{intra} \geq 0 \qquad \forall s,\ell \qquad \text{(B-39)}$$

$$M(1-r15_{s,\ell}) \geq \mu_{s,\ell}^{intra,max} \geq 0 \qquad \forall s,\ell \qquad \text{(B-40)}$$

$$Mr16_{s,\ell} \geq f_{s,\ell}^{da} + f_{s,\ell}^{intra} - NTC_{\ell}^{min} \geq 0 \qquad \forall s,\ell \qquad \text{(B-41)}$$

$$M(1-r16_{s,\ell}) \geq \mu_{s,\ell}^{intra,min} \geq 0 \qquad \forall s,\ell \qquad \text{(B-42)}$$

## Appendix C Stochastic dispatch (StochD) formulation

In the following StochD bi-level formulation, Eqs. (C-1) and (C-2) are the upper-level objective function and constraints, respectively, which are constrained by the lower-level objective functions and constraints in Eqs. (C-3) and (C-4)-(C-5), respectively:

$$\text{Minimize}_{\Omega^{UL} \cup \Omega^{LL^{da}} \cup \Omega^{LL^{intra}}}$$

$$\sum_s W_s \left[ \sum_n \sum_u \sum_b \left( g^{da}_{s,x,n,u,b} \left( C^{da}_{x,n,u,b} - \lambda^{da}_{s,n} \right) + g^{up}_{s,x,n,u,b} \left( C^{up}_{x,n,u,b} - \lambda^{intra}_{s,n} \right) - g^{down}_{s,x,n,u,b} \left( C^{down}_{x,n,u,b} - \lambda^{intra}_{s,n} \right) \right) \right] \tag{C-1}$$

s.t.

Eqs. (2)-(10) (upper-level conditions) (C-2)

$$\forall s \begin{cases} \text{Minimize}_{\Omega^{LL^{da}} \cup \Omega^{LL^{intra}}} \\ \sum_n \sum_u \sum_b p^{da}_{x,n,u,b} g^{da}_{s,x,n,u,b} + \sum_y \sum_n \sum_u \sum_b C^{da}_{y,n,u,b} g^{da}_{s,y,n,u,b} + \\ \sum_n \sum_u \sum_b \left( p^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - p^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} \right) + \sum_y \sum_n \sum_u \sum_b \left( C^{up}_{y,n,u,b} g^{up}_{s,y,n,u,b} - C^{down}_{y,n,u,b} g^{down}_{s,y,n,u,b} \right) & \text{(C-3)} \\ \text{s.t.} \\ \quad \text{Eqs. (12)-(15) (day-ahead constraints)} & \text{(C-4)} \\ \quad \text{Eqs. (17)-(22) (intraday constraints)} & \text{(C-5)} \end{cases}$$

Compared to ConvD, there is only one lower-level problem with the objective functions (C-3). Consequently, the KKT conditions (A-2) and (A-4)-(A-5) are replaced by:

$$f^{da}_{s,\ell} \text{ free, } -\sum_n Y_{l,n} \lambda^{da}_{s,n} + \mu^{da,max}_{s,\ell} - \mu^{da,min}_{s,\ell} + \mu^{intra,max}_{s,\ell} - \mu^{intra,min}_{s,\ell} = 0 \qquad \forall s, \ell \tag{C-6}$$

$$g^{da}_{s,x,n,u,b} \geq 0 \perp p^{da}_{x,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,x,n,u,b} - \beta^{down}_{s,x,n,u,b} + \beta^{up}_{s,x,n,u,b} \geq 0 \qquad \forall s,x,n,u,b \tag{C-7}$$

$$g^{da}_{s,y,n,u,b} \geq 0 \perp C^{da}_{y,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,y,n,u,b} - \beta^{down}_{s,y,n,u,b} + \beta^{up}_{s,y,n,u,b} \geq 0 \qquad \forall s,y,n,u,b \tag{C-8}$$

As a result, the disjunctive constraints (B-11) and (B-13) become:

$$Mr1_{s,x,n,u,b} \geq p^{da}_{x,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,x,n,u,b} - \beta^{down}_{s,x,n,u,b} + \beta^{up}_{s,x,n,u,b} \geq 0 \qquad \forall s,x,n,u,b \tag{C-9}$$

$$Mr2_{s,y,n,u,b} \geq C^{da}_{y,n,u,b} - \lambda^{da}_{s,n} + \beta^{da}_{s,y,n,u,b} - \beta^{down}_{s,y,n,u,b} + \beta^{up}_{s,y,n,u,b} \geq 0 \qquad \forall s,y,n,u,b \tag{C-10}$$

Using strong duality and Eqs. (C-7)-(C-8) and (A-12)-(A-19), we can linearize the bilinear terms in the upper level objective function in Eq. (C-1) exactly:

$$\begin{aligned} & \sum_n \sum_u \sum_b \left( g^{da}_{s,x,n,u,b} \lambda^{da}_{s,n} + g^{up}_{s,x,n,u,b} \lambda^{intra}_{s,n} - g^{down}_{s,x,n,u,b} \lambda^{intra}_{s,n} \right) \\ & = v^{da}_{s,x} + \sum_y \sum_n \sum_u \sum_b \Big( -C^{up}_{y,n,u,b} g^{up}_{s,y,n,u,b} + C^{down}_{y,n,u,b} g^{down}_{s,y,n,u,b} - \beta^{up}_{s,y,n,u,b} G^{max}_{y,n,u,b} - \beta^{up,ramp}_{s,y,n,u,b} G^{up,ramp}_{y,n,u,b} - \\ & \beta^{down,ramp}_{s,y,n,u,b} G^{down,ramp}_{y,n,u,b} \Big) - \sum_l \left( \mu^{intra,max}_{s,\ell} NTC^{max}_{\ell} - \mu^{intra,min}_{s,\ell} NTC^{min}_{\ell} \right) + \sum_n D^{intra}_{s,n} \lambda^{intra}_{s,n} = v^{da}_{s,x} + v^{StochD}_{s,x} \end{aligned} \tag{C-11}$$

Therefore, the discretization scheme in Eqs. (B-3)-(B-10) can be omitted from the following StochD MILP formulation in which we have set $\Omega^{MILP,StochD} = \{v^{da}_{s,x}, v^{StochD}_{s,x}, r1, \ldots, r16\}$:

$$\text{Minimize}_{\Omega^{UL} \cup \Omega^{LL^{da}} \cup \Omega^{LL^{intra}} \cup \Omega^{DV} \cup \Omega^{MILP,StochD}}$$

$$\sum_s W_s \left[ \sum_{n,u,b} \left( C^{da}_{x,n,u,b} g^{da}_{s,x,n,u,b} + C^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - C^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} \right) - v^{da}_{s,x} - v^{StochD}_{s,x} \right] \tag{C-12}$$

s.t.

Eqs. (2)-(10) (upper-level conditions) (C-13)

Eqs. (C-6), (A-3), (A-10), (A-11) (lower-level equality conditions) (C-14)

Eqs. (C-9), (B-12), (C-10), (B-14), (B-15)-(B-42) (disjunctive constraints) (C-15)

# Appendix D Calibration and results for the Nordic example

| Parameter \ Line | $\ell 1$ | $\ell 2$ | $\ell 3$ | $\ell 4$ | $\ell 5$ | $\ell 6$ | $\ell 7$ |
|---|---|---|---|---|---|---|---|
| $NTC_{\ell}^{max}$ (MW) | 1600 | 2000 | 1600 | 2100 | 7300 | 1500 | 1200 |
| $NTC_{\ell}^{min}$ (MW) | -1600 | -2400 | -1900 | -2100 | -7300 | -1100 | -1200 |

**Table 13:** Network parameters of the Nordic example

| Parameter \ Node | DK | FI | NO | SE N | SE S |
|---|---|---|---|---|---|
| $D_{s,n}^{da}$ (MW) | 4900 | 12900 | 21600 | 3700 | 17600 |

**Table 14:** Demand parameters in the Nordic example

| Node \ Type | wind | nuclear | hydro | thermal | SP |
|---|---|---|---|---|---|
| DK | 1800 | | | 2900 | |
| FI | 200 | 2800 | 2400 | 4400 | 500 |
| NO | 300 | | 26100 | 400 | |
| SE N | 600 | | 11200 | 200 | |
| SE S | 1100 | 8100 | 2200 | 1500 | |

**Table 15:** Total generation capacities (in MW) in the Nordic example

| Parameter \ Type, block | wind | | nuclear | | hydro | | thermal | | SP | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ | $b1$ | $b2$ |
| $C_{f,n,u,b}^{da}$ (€/MW) | 0 | 0 | 5 | 5 | 20 | 30 | 40 | 50 | 20 | 30 |
| $C_{f,n,u,b}^{up}$ (€/MW) | | | | | 30 | 40 | 60 | 80 | 30 | 40 |
| $C_{f,n,u,b}^{down}$ (€/MW) | | | | | 20 | 15 | 10 | 5 | 20 | 15 |
| $G_{f,n,u,b}^{up,ramp}$ (MW) | | | | | 1000 | 1000 | 1000 | 1000 | 250 | 250 |
| $G_{f,n,u,b}^{down,ramp}$ (MW) | | | | | 1000 | 1000 | 1000 | 1000 | 250 | 250 |

**Table 16:** Generation parameters in the Nordic example

| $\sum_b g_{s,f,n,u,b}^{da}$ (MW) | ConvD | | | StochD | | | PC | | |
|---|---|---|---|---|---|---|---|---|---|
| Scenario \ Type | hydro | thermal | SP | hydro | thermal | SP | hydro | thermal | SP |
| Maximum deficit | 2400 | 4100 | | 2400 | 4400 | 100 | 2400 | 3600 | 500 |
| Maximum surplus | 2400 | 3600 | 500 | 2400 | 3800 | 300 | 2400 | 3600 | 500 |

**Table 17:** Total day-ahead generation of marginal units in FI in the Nordic example

| $f_{s,\ell}^{da}$ (MW) | ConvD | | StochD | | PC | |
|---|---|---|---|---|---|---|
| Scenario \ Line | $\ell 6$ | $\ell 7$ | $\ell 6$ | $\ell 7$ | $\ell 6$ | $\ell 7$ |
| Maximum deficit | 1500 | 1200 | 1500 | 800 | 1500 | 1200 |
| Maximum surplus | 1500 | 1200 | 1500 | 1200 | 1500 | 1200 |

**Table 18:** Day-ahead exchange between FI and SE in the Nordic example

| $\sum_b g_{s,f,n,u,b}^{up/down}$ (MW) | ConvD | | | StochD | | PC | |
|---|---|---|---|---|---|---|---|
| Scenario \ Type | hydro (NO) | thermal | SP | hydro (NO) | SP | thermal | hydro |
| Maximum deficit | | 300 | 100 | 400 | | 400 | |
| Maximum surplus | -300 | | | | -300 | | -300 |

**Table 19:** Total intraday generation of marginal units in the Nordic example, where positive (negative) figures correspond to up-regulation (down-regulation)

| $f_{s,\ell}^{da}$ (MW) | ConvD | | StochD | | PC | |
|---|---|---|---|---|---|---|
| Scenario \ Line | $\ell 6$ | $\ell 7$ | $\ell 6$ | $\ell 7$ | $\ell 6$ | $\ell 7$ |
| Maximum deficit | | | | 400 | | |
| Maximum surplus | -300 | | | | | |

**Table 20:** Intraday exchange between FI and SE in the Nordic example

| $\lambda^{da}_{s,n}$ (€/MW) | ConvD | | | | | StochD | | | | | PC | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario \ Node | DK | FI | NO | SE N | SE S | DK | FI | NO | SE N | SE S | DK | FI | NO | SE N | SE S |
| Maximum deficit | 30 | 50 | 30 | 30 | 30 | 30 | 2990 | 30 | 30 | 30 | 30 | 50 | 30 | 30 | 30 |
| Maximum surplus | 30 | 50 | 30 | 30 | 30 | 30 | 50 | 30 | 30 | 30 | 30 | 50 | 30 | 30 | 30 |

**Table 21:** Day-ahead price results in the Nordic example

| $\lambda^{intra}_{s,n}$ (€/MW) | ConvD | StochD | PC |
|---|---|---|---|
| Scenario \ Node | FI | FI | FI |
| Maximum deficit | 3000 | 3000 | 80 |
| Maximum surplus | 20 | 20 | 20 |

**Table 22:** Intraday price results in the Nordic example

## Appendix E Model for updating intraday offer curves

The intraday offer curves ($\Omega^{UL,intra} = \{p^{up}_{x,n,u,b}, p^{down}_{x,n,u,b}, up_{s,x,n}\}$) can be updated by solving the following problem with $g^{da}_{s,f,n,u,b}$ and $f^{da}_{s,\ell}$ fixed to the values $G^{da}_{f,n,u,b}$ and $F^{da}_{\ell}$ from the day-ahead market clearing, respectively:

$$\text{Minimize}_{\Omega^{UL,intra} \cup \Omega^{LL^{intra}}}$$

$$\sum_s W_s \left[ \sum_n \sum_u \sum_b \left( g^{up}_{s,x,n,u,b} \left( C^{up}_{x,n,u,b} - \lambda^{intra}_{s,n} \right) - g^{down}_{s,x,n,u,b} \left( C^{down}_{x,n,u,b} - \lambda^{intra}_{s,n} \right) \right) \right] \tag{E-1}$$

s.t.

Eqs. (3), (4), (6), (7), (9), (10) (intraday upper-level conditions) (E-2)

$$\forall s \begin{cases} \text{Minimize}_{\Omega^{LL^{intra}}} \\ \sum_n \sum_u \sum_b \left( p^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - p^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} \right) + \sum_y \sum_n \sum_u \sum_b \left( C^{up}_{y,n,u,b} g^{up}_{s,y,n,u,b} - C^{down}_{y,n,u,b} g^{down}_{s,y,n,u,b} \right) & \text{(E-3)} \\ \text{s.t.} \\ \quad \text{Eqs. (17)-(22) (intraday constraints)} & \text{(E-4)} \end{cases}$$

Using strong duality, the bilinear terms in the objective function (E-1) can be linearized exactly:

$$\sum_n \sum_u \sum_b \left( g^{up}_{s,x,n,u,b} \lambda^{intra}_{s,n} - g^{down}_{s,x,n,u,b} \lambda^{intra}_{s,n} \right)$$
$$= \sum_y \sum_n \sum_u \sum_b \Big( - C^{up}_{y,n,u,b} g^{up}_{s,y,n,u,b} + C^{down}_{y,n,u,b} g^{down}_{s,y,n,u,b} - \beta^{up}_{s,y,n,u,b} (G^{max}_{y,n,u,b} - G^{da}_{y,n,u,b}) - \beta^{down}_{s,y,n,u,b} G^{da}_{y,n,u,b} - \beta^{up,ramp}_{s,y,n,u,b} G^{up,ramp}_{y,n,u,b} -$$
$$\beta^{down,ramp}_{s,y,n,u,b} G^{down,ramp}_{y,n,u,b} \Big) - \sum_l \left( \mu^{intra,max}_{s,\ell} (NTC^{max}_{\ell} - F^{da}_{\ell}) - \mu^{intra,min}_{s,\ell} (NTC^{min}_{\ell} - F^{da}_{\ell}) \right) + \sum_n D^{intra}_{s,n} \lambda^{intra}_{s,n} = v^{intra}_{s,x} \tag{E-5}$$

Therefore, discretization is not required for the following MILP formulation for updating the intraday offer curves in which we have set $\Omega^{MILP,intra} = \{v^{intra}_{s,x}, r7, \ldots, r16\}$ and $\Omega^{DV,intra} = \{\lambda^{intra}_{s,n}, \beta^{up}_{s,f,n,u,b}, \beta^{down}_{s,f,n,u,b}, \beta^{up,ramp}_{s,f,n,u,b}, \beta^{down,ramp}_{s,f,n,u,b}, \mu^{intra,max}_{s,\ell}, \mu^{intra,min}_{s,\ell}\}$:

$$\text{Minimize}_{\Omega^{UL,intra} \cup \Omega^{LL^{intra}} \cup \Omega^{DV,intra} \cup \Omega^{MILP,intra}}$$

$$\sum_{s} W_s \left[ \sum_{n,u,b} \left( C^{up}_{x,n,u,b} g^{up}_{s,x,n,u,b} - C^{down}_{x,n,u,b} g^{down}_{s,x,n,u,b} \right) - v^{intra}_{s,x} \right] \tag{E-6}$$

s.t.

Eqs. (3), (4), (6), (7), (9), (10) (intraday upper-level conditions) (E-7)

Eqs. (A-10), (A-11) (intraday lower-level equality conditions) (E-8)

Eqs. (B-23)-(B-42) (intraday disjunctive constraints) (E-9)