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Impact of High Levels of Wind Penetration on the Exercise of Market Power in the Multi-Area Systems

Ekaterina Moiseeva



Impact of High Levels of Wind Penetration on the Exercise of Market Power in the Multi-Area Systems

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The doctoral research has been carried out in the context of an agreement on joint doctoral supervision between Comillas Pontifical University, Madrid, Spain, KTH Royal Institute of Technology, Stockholm, Sweden and Delft University of Technology, the Netherlands.

Keywords: wind integration, market power, game theory, mathematical programming

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SETS Joint Doctorate

The Erasmus Mundus Joint Doctorate in **Sustainable Energy Technologies and Strategies**, SETS Joint Doctorate, is an international programme run by six institutions in cooperation:

- Comillas Pontifical University, Madrid, Spain
- Delft University of Technology, Delft, the Netherlands
- Florence School of Regulation, Florence, Italy
- Johns Hopkins University, Baltimore, USA
- KTH Royal Institute of Technology, Stockholm, Sweden
- University Paris-Sud 11, Paris, France

The Doctoral Degrees issued upon completion of the programme are issued by Comillas Pontifical University, Delft University of Technology, and KTH Royal Institute of Technology.

The Degree Certificates are giving reference to the joint programme. The doctoral candidates are jointly supervised, and must pass a joint examination procedure set up by the three institutions issuing the degrees.

This Thesis is a part of the examination for the doctoral degree.

The invested degrees are official in Spain, the Netherlands and Sweden respectively.

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Abstract in English Language

Author: Ekaterina Moiseeva

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Title: Impact of high levels of wind penetration on the exercise of market power in the multi-area systems

Language: English

Keywords: wind integration, market power, game theory, mathematical programming

New European energy policies have set a goal of a high share of renewable energy in electricity markets. In the presence of high levels of renewable generation, and especially wind, there is more uncertainty in the supply. It is natural, that volatility in energy production induces the volatility in energy prices. This can create incentives for the generators to exercise market power by traditional means: withholding the output by conventional generators, bidding not the true marginal costs, or using locational market power. In addition, a new type of market power has been recently observed: exercise of market power on ramp rate.

This dissertation focuses on modeling the exercise of market power in power systems with high penetration of wind power. The models consider a single, or multiple profit-maximizing generators. Flexibility is identified as one of the major issues in wind-integrated power systems. Therefore, part of the research studies the behavior of strategic hydropower producers as main providers of flexibility in systems, where hydropower is available.

Developed models are formulated as mathematical and equilibrium problems with equilibrium constraints (MPECs and EPECs). The models are recast as mixed-integer linear programs (MILPs) using discretization. Resulting MILPs can be solved directly by commercially-available MILP solvers, or by applying decomposition. Proposed Modified Benders Decomposition Algorithm (MBDA) significantly improves the computational efficiency.

Abstract in Spanish Language

Autor: Ekaterina Moiseeva

Afiliación: KTH Royal Institute of Technology

Título: Impacto de los altos niveles de penetración del viento en el ejercicio del poder de mercado en los sistemas de múltiples zonas

Idioma: Ingles

Palabras claves: integración del viento, poder de mercado, teoría de juegos, programación matemática

Las nuevas políticas energéticas europeas han establecido como objetivo un alto nivel de intercambio de energías renovables, en el Mercado eléctrico. Con la presencia de altos niveles de generación de energías renovables, especialmente la producida por el viento, aumenta la incertidumbre en la transmisión de la energía procedente de esta fuente. Esto es un efecto natural donde la volatilidad de la producción de esta energía se refleja en la volatilidad de los precios de mercado eléctrico. Este hecho puede repercutir en incentivos económicos para los productores de energía a la hora de ejercer más poder de mercado por medios tradicionales: retener la producción convencional, atando los costes marginales o ejerciendo más poder en mercados localizados. Además, se ha observado un nuevo tipo de poder de mercado: el poder de mercado que refiere a *ramp rate*.

Esta tesis se centra en el modelado de las prácticas de poder de mercado en los sistemas de potencia donde existe alta generación de energía eólica. Los modelos consideran la maximización de beneficio con uno o múltiples productores de energía. La flexibilidad se identifica como uno de los mayores problemas en los sistemas de potencia con integración eólica. Por este motivo, parte de este trabajo de investigación estudia el comportamiento de estrategias de productores de energía hidroeléctrica como los principales proveedores de flexibilidad en los sistemas de potencia, allá donde la hidroeléctrica esté presente.

Los modelos desarrollados son formulados como problemas matemáticos y problemas de equilibrio con restricciones de equilibrio (MPECs y EPECs). Los modelos son reformulados como mixed-integer programas lineales enteros mixtos (MILP). Los MILPs resultantes pueden ser resueltos directamente por algoritmos MILP comerciales, o aplicando descomposición. Esta tesis propone un nuevo *Modified Benders Decomposition Algorithm* (MBDA), el cual mejora significativamente la eficiencia computacional.

Abstract in Swedish Language

Författare: Ekaterina Moiseeva

Anslutning: Kungliga Tekniska Högskolan

Titel: Inverkan av höga nivåer av vindkraft på utövande av marknadsinflytande i flerområdes kraftsystem

Språk: Engelska

Nyckelord: vind integration, marknadsinflytande, spelteori, matematisk programmering

Ny europeisk energipolitik har som mål att öka andelen förnybar elproduktion. Förnybar elproduktion från vindkraft har till skillnad från konventionell kraftproduktion, en större osäkerhet i utbudet. Det är naturligt, att den här volatila osäkerheten i energiproduktionen skapar volatilitet även i energipriserna. Detta kan skapa möjligheter för producenter att utöva marknadsinflytande genom att undanhålla produktionen av konventionella kraftkällor, genom att använda fabricerade marginalkostnader eller med hjälp av lokalt marknadsinflytande. Dessutom har en ny typ av marknadsinflytande nyligen observerats, vilket är att utöva marknadsinflytande med hjälp av ramphastigheter.

Denna avhandlings fokus är på modellering av utövandet av marknadsinflytande i kraftsystem med hög andel av vindkraft. Modellerna beaktar en enda eller flera vinstmaximerande generatorer. Flexibilitet har identifierats som en av de stora problemen vid integrering av hög andel vindkraft i ett kraftsystem. Storskalig vattenkraft är väldigt flexibel och därför fokuserar en del av forskningen på vattenkraftsproducenternas strategiska möjligheter att leverera flexibilitet i kraftsystem med hög andel elproduktion från vindkraft.

De utvecklade modellerna har formulerats som matematiska jämviktproblem med jämviktsbegränsningar (MPECs och EPECs). Modellerna är omarbetade till så kallade *mixed-integer linear programs* (MILPs) med hjälp av diskreta metoder. Resultande MILPs kan lösas direkt med hjälp av kommersiellt tillgängliga MILP-lösare, eller genom att applicera så kallad decomposition. Den föreslagna *Modified Benders Decomposition Algorithm* (MBDA) förbättrar effektiviteten i beräkningarna avsevärt.

Abstract in Dutch Language

Auteur: Ekaterina Moiseeva

Instituut: KTH Royal Institute of Technology

Titel: Impact van hoge niveaus van windpenetratie bij de uitoefening van marktmacht in de multizone systemen

Taal: Engels

Trefwoorden: windintegratie, marktmacht, speltheorie, wiskundige programmering

Het nieuwe Europese energiebeleid heeft als doel gesteld om een groot aandeel duurzame energie op de elektriciteitsmarkten te realiseren. In aanwezigheid van hoge niveaus van hernieuwbare elektriciteitsproductie, vooral op basis van wind, is er een grotere voorzieningsonzekerheid. Volatiliteit in de energieproductie veroorzaakt vanzelfsprekend volatiliteit in de energieprijzen. Dit kan prikkels voor producenten creëren om de marktmacht op traditionele wijze uit te oefenen: reductie van de conventionele productie-eenheden, inbieden op andere dan de marginale productiekosten, of plaatselijke marktmacht te gebruiken. Daarnaast is recentelijk een nieuw type marktmacht waargenomen: uitoefening van de machtspositie op de *ramp rate*.

Dit proefschrift richt zich op het modelleren van de uitoefening van de marktmacht in energiesystemen met een hoog aandeel windvermogen. De modellen beschouwen een enkele of meerdere winst-maximerende producenten. Flexibiliteit wordt geïdentificeerd als een van de belangrijkste problemen in zulke energiesystemen. Daarom richt een deel van dit onderzoek zich op het strategisch gedrag van waterkrachtproducenten als belangrijkste leveranciers van flexibiliteit, wanneer tenminste waterkracht beschikbaar is.

De ontwikkelde modellen worden geformuleerd als wiskundige en *equilibrium* problemen met *equilibrium constraints* (MPEC's en EPEC's). De modellen worden herschikt als *mixed-integer* lineair programmeren opgaven (MILP's) met discretisatie. De resulterende MILP's kunnen worden opgelost door commercieel verkrijgbare MILP-*solvers*, of door ontleding toe te passen. Het voorgestelde *Modified Benders Decomposition Algorithm* (MBDA) verbetert de berekeningsefficiëntie significant.

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List of symbols

Nomenclature for Chapter 4:

Exercise of market power in wind-integrated power systems

Indices

t	Time periods, $t \in (1..T)$,
c	Possible contingencies, $c \in (1..C)$,
i	Generating units, $i \in (1..I)$,
i_s	Strategic generating units, $i_s \in (1..I_s), I_s \subset I$,
s	Bidding strategies, $s \in (1..S)$,
l	Transmission lines, $l \in (1..L)$,
n	System nodes, $n \in (1..N)$.

Variables

π_i	Profit of generator i ,
g_{itc}	Dispatched output by generator i ,
\hat{R}_i^{up}	Ramp-up bid of generator i ,
\hat{R}_i^{dn}	Ramp-down bid of generator i .

Parameters

K_i	Maximum output by unit i ,
c_i	Marginal cost of unit i ,
p_c	Probability of contingency c ,
R_i^{up}	Ramp-up limits for unit i in Δt
R_i^{dn}	Ramp-down limits for unit i in Δt
H_{ln}	Power Transfer Distribution Factor (PTDF),
F_l	Flow limit on line l ,
d_n	Demand at node n .

Lagrange multipliers (LM)

μ_{itc}^{A1}	LM of unit i lower capacity limit,
μ_i^{A2}	LM of unit i initial state upper capacity limit,
μ_{itc}^{A3}	LM of unit i transient states upper capacity limit,
λ_{tc}^B	LM of energy balance,
μ_{itc}^C	LM of a flow constraint on line l ,
μ_{itc}^{D1}	LM of unit i ramp-up constraint,
μ_{itc}^{D2}	LM of unit i ramp-down constraint.

Nomenclature for Chapter 5:**Market power in power systems with high share of wind power and hydropower***Indices*

i	Generating units
t	Time periods
l	Transmission lines
n	System nodes
k	Bid alternatives
w	Stochastic scenarios
j	Benders iterations

Sets

I	Generating units
I^h	Strategic hydropower units, $I^h \subset I$
I^{up}, I^{dn}	Upstream and downstream units, $I^{up}, I^{dn} \subset I^h$

Parameters (upper-case letters)

M_i^0	Initial water level of unit $i \in I^h$, m^3
M_i	Maximum water level of unit $i \in I^h$, m^3
V_{itw}	Inflow to the reservoir of unit $i \in I^h$ in t , m^3
Γ_i	Production equivalent of unit $i \in I^h$, m^3/MWh
Q_i	Maximum generation of unit i , MW
R_i	Maximum ramp rate of unit i , MW/h
C_i	Maximum price bid of unit $i \in I^h$, $\$/MWh$
C_i^M	Marginal cost of unit i , $\$/MWh$

Λ_i^f	Future price for unit $i \in I^h$, \$/MWh
P_w	Probability of scenario w
H_{ln}	Power Transfer Distribution Factor
F_l	Power flow limit on line l , MW
D_{ntw}	Demand at node n in t , MWh

Variables (lower-case letters)

π	Profit of strategic hydropower producer, \$
q_{itw}	Dispatched generation of unit i in t , MWh
s_{itw}	Spillage of unit $i \in I^h$ in t , m ³
m_{itw}	Water level of unit $i \in I^h$ in t , m ³
x_{itk}^q	Binary variable of quantity bidding decision
x_{itk}^r	Binary variable of ramp-rate bidding decision
x_{itk}^c	Binary variable of price bidding decision
\hat{q}_{it}	Quantity bid of unit i in t , MW
\hat{r}_i	Ramp-rate bid of unit i , MW/h
\hat{c}_{it}	Price bid of unit i in t , \$/MWh

Lagrange multipliers (LM)

$\mu_{itw}^{A_1}, \nu_{itw}^{A_1}$	LM of unit i lower capacity limit constraint
$\mu_{itw}^{A_2}, \nu_{itw}^{A_2}$	LM of unit i upper capacity limit constraint
$\lambda_{tw}^B, \phi_{tw}^B$	LM of energy balance constraint
μ_{ltw}^C, ν_{ltw}^C	LM of the flow constraint of line l
$\mu_{itw}^{D_1}, \nu_{itw}^{D_1}$	LM of unit i ramp-up constraint
$\mu_{itw}^{D_2}, \nu_{itw}^{D_2}$	LM of unit i ramp-down constraint
μ_{itw}^E, ν_{itw}^E	LM of spillage nonnegativity constraint
$\mu_{itw}^{F_1}, \nu_{itw}^{F_1}$	LM of lower water-level-limit constraint
$\mu_{itw}^{F_2}, \nu_{itw}^{F_2}$	LM of upper water-level-limit constraint
$\lambda_{itw}^G, \phi_{itw}^G$	LM of water balance constraint

Operator

$\mathbf{I}(\text{condition})$	“If” operator
--------------------------------	---------------

List of abbreviations

BNE	Best Nash Equilibrium
DC	Dispatch Cost
EPEC	Equilibrium Problem with Equilibrium Constraints
KKT	Karush-Kuhn-Tucker conditions
LM	Lagrange multiplier
LMP	Locational Marginal Price
LP	Linear program
MBDA	Modified Benders Decomposition Algorithm
MILP	Mixed-Integer Linear Program
MPEC	Mathematical Problem with Equilibrium Constraints
OPcOP	Optimization Problem constrained by Optimization Problem
PTDF	Power Transfer Distribution Factor
SC	Social Cost
SRED	Short-Run Economic Dispatch
STD	Standard Deviation
WNE	Worst Nash Equilibrium

Chapter 1

Introduction

This chapter motivates the topic of the dissertation and defines the background for the studies in Sections 1.1 and 1.2. The list of publications in journals with Journal Citation Report (JCR) and peer-reviewed conference papers is provided in Section 1.3. Finally, the outline for the remaining chapters is given in Section 1.4.

1.1 Background

The deregulation of electric power industry has started in 1981 in Chile, followed by England and Wales (1990), Norway (1991), and Argentina (1992) [1]. The aim of liberalization was to bring economic benefits in the long term, delivering timely and well-located investments by private companies. Liberalization was also expected to improve efficiency in the operation of generation plants, networks, and distribution services. Competition was seen as a driving force behind these changes [2]. This required significant changes in the way the electricity industry is organized and operated.

Electricity industry reform has apparently improved the efficiency and productivity of the industry. In Australia there are evidences of greater efficiency and reliability amongst generating plants [3]. The liberalization in Europe has allowed increasing opportunities for electricity market integration and cross-border trade [4].

However, the liberalization of the electricity markets was not always a smooth process. The crisis and market breakdown that hit California in 2001, only a few years after the new market was launched [2], have raised

significant skepticism in the society. During the crisis, the electricity prices went to extreme levels, forcing the disconnection of some of the loads. The crisis had serious consequences for consumers, who were disconnected from the grid in rotating blackouts, and for electric utilities, which suffered major financial distress. Unilateral market power has been identified as one of the major causes of these events [5]. Another example is the liberalization of power industry in England and Wales. Even though the reform there has led to significant improvements in many dimensions, the decision to create only three generating companies out of the state-owned CEGB has led to significant market power, persisting for several years [6].

Market power is the ability of electricity generating firms to influence market prices through their unilateral actions [5, 7]. Electricity markets have many features, which make them prone to the exercise of market power: binding transmission constraints, largely inelastic demand, limited number of competing firms, repeated bidding [8]. There are no large scale technologies for storing electrical energy. These factors give rise to physical and economic withholding by dominant generating firms: the companies bid capacity or price, which differ from their true characteristics. The lessons learned from the beginning of the liberalization process have led to the development of market power indicators – measures, showing the presence of market power in electricity markets. Some indicators, e.g. HHI and four-firm concentration ratio, are based on calculating the share of the largest companies in the market [3, 9]. Other classic measures calculate the margin between the price bids and real marginal costs of producers [10].

While these measures had an important role in the beginning of the liberalization process, modern power industry has considerably evolved. In particular, the share of renewable resources has considerably increased in many countries around the world bringing new challenges. The European Union (EU) has set a target to reduce greenhouse gas emissions by 80-95% in 2050 as compared to 1990 levels [11]. The governmental and social support resulted in a significant increase in the installed capacity of renewable power sources, in particular wind power. Wind power was installed more than any other form of power generation in 2015. It accounted for 44.2% of total power capacity installations [12]. The amount of new wind power turbines installations continues to increase every year. One of the primary challenges in the integration of wind power is the problem of intermittency. Even a carefully predicted wind power output may suddenly depart from the forecast level. This calls for an increased amount of flexibility required in the system.

Flexibility expresses the capability of a power system to maintain continuous service, even when exposed to rapid and large swings in supply or demand [13]. There are many levels at which flexibility can be offered in power systems: flexibility of generation resources, flexibility of transmission and distribution systems [14], flexibility of the market to incentivize the power system to account for variability [15], and demand side flexibility [16]. Ramp rates largely define flexibility from the generation side.

There is some evidence of strategic behavior with respect to ramp rates occurring in practice. In the Australian National Electricity Market (NEM), when transmission constraints arise within a certain region, the generators are paid the regional price for their output rather than the correct local marginal price. Generators in this situation are said to be “constrained on” or “constrained off”. When the regional price is high, a generator, which is constrained off, will strategically manipulate its bid in a variety of ways in order to maintain a high output target from the dispatch engine. This typically involves offering the generator’s output at the price floor (-1,000 \$/MWh). Alternatively, some generators also routinely reduce their offered ramp rate in order to maintain their dispatch level. In an attempt to prevent this, in 2009 a new rule was introduced which requires generators to offer a minimum ramp rate of 3 MW per minute (or 3% of unit capacity). More recently the Australian Energy Regulator (AER) has proposed a rule, which requires generators to offer a ramp rate which matches their technical capability.

1.2 Research motivation

The theoretical foundation behind the exercise of market power in power systems with high penetration of wind power is still very weak. The incentives for the exercise of market power in such systems should be carefully studied. There is a need for new models, able to capture the increased need for flexibility in wind-integrated systems. In present dissertation this challenge is addressed. New models are proposed, capturing the exercise of market power in wind-integrated systems. Such models can be used for full-scale market modeling and analysis.

1.3 List of publications

The following articles were published (to be published) during the PhD studies:

Papers published in journals with Journal Citation Report (JCR):

- [J1] E. Moiseeva, M.R. Hesamzadeh, D.R. Biggar, “Exercise of Market Power on Ramp Rate in Wind-Integrated Power Systems,” *IEEE Transactions on Power Systems*, Vol. 30, No. 3, pp. 1614-1623, May 2015 (Invited paper to special section on Wind & Solar Energy: Uncovering and Accommodating Their Impacts on Electricity Markets).
- [J2] E. Moiseeva, S. Wogrin, M.R. Hesamzadeh, “Generation Flexibility in Ramp Rates: Strategic Behavior and Lessons for Electricity Market Design,” *European Journal of Operational Research*, accepted February 2017.
- [J3] E. Moiseeva, M.R. Hesamzadeh, “Strategic Bidding of a Hydropower Producer under Uncertainty: Modified Benders Approach,” *IEEE Transactions on Power Systems*, accepted April 2017.

Paper under review in journal with JCR:

- [J4] E. Moiseeva, M.R. Hesamzadeh, “Nash Equilibria in Hydro-Dominated Systems under Uncertainty: Modified Benders Approach,” *IEEE Transactions on Sustainable Energy*, submitted February 2017.

Working paper:

- [J5] E. Moiseeva, M.R. Hesamzadeh, D. Bunn, D.R. Biggar “Modeling the Hedging Decisions of a Generator with Market Power in Systems with High Penetration of Wind Power,” *European Journal of Operational Research*.

Peer-reviewed conference papers:

- [C1] E. Moiseeva, M.R. Hesamzadeh, “Modeling the Unilateral Multi-part Strategic Withholding in Electricity Markets,” Australasian Universities Power Engineering Conference, Wollongong, Australia, 27-30 September 2015.
- [C2] E. Moiseeva, M.R. Hesamzadeh, “Strategic Bidding by a Risk-Averse Firm with a Portfolio of Renewable Sources,” IEEE PowerTech Conference, Eindhoven, the Netherlands, 29 June-2 July 2015.
- [C3] E. Moiseeva, M.R. Hesamzadeh, I. Dimoukias, “Tacit Collusion with Imperfect Information: Ex-Ante Detection,” IEEE Power & Energy Society General Meeting, National Harbor, MD, USA, 27-31 July 2014.
- [C4] E. Moiseeva, M.R. Hesamzadeh, “Modeling the Hedging Decisions in Electricity Markets Using Two-stage Games,” IEEE ISGT Europe 2013 Conference, Copenhagen, Denmark, 6-9 October 2013.
- [C5] E. Moiseeva, M.R. Hesamzadeh, “Impact of Energy Storage Devices on Energy Price in Decentralized Wind-Diesel Utilities,” 10th International Conference on the European Energy Market, Stockholm, Sweden, 28-30 May 2013.

1.4 Thesis outline

The remaining chapters of this dissertation are organized as follows:

- Chapter 2 provides the mathematical foundations for the dissertation, including the relevant concepts from game theory, optimization, and stochastic programming.
- Chapter 3 gives a brief description of power system modeling conventions and assumptions.
- Chapter 4 reviews exercise of market power in wind-integrated systems and identifies flexibility as one of the drivers for strategic behavior. The chapter is based on the publication [J1].
- Chapter 5 focuses on the exercise of market power in hydro-dominated power systems with high share of wind power. Since hydropower producers are often the main providers for flexibility, their strategic behavior is carefully reviewed. The chapter is based on publications [J3] and [J4].

- Chapter 6 reviews market power from the market design perspective. Two market design possibilities are compared and the impact of each of the design on the propensity of strategic generators to exercise market power in wind-integrated systems is discussed. The chapter is based on publication [J2].
- Chapter 7 concludes the dissertation and provides the possible directions for future research.

Chapter 2

Mathematical foundation

This chapter reviews the main mathematical principles, forming the theoretical foundation of this dissertation. The necessary chapters of game theory are reviewed in Section 2.1, optimization concepts are discussed in Section 2.2. Section 2.3 describes the uncertainty modeling, utilized in this dissertation. Section 2.4 describes Benders decomposition technique, which is used to solve large optimization problems' instances.

2.1 Game theory

In this dissertation game theory is used to model the interaction of strategic players. The players are assumed to be rational and possess perfect information regarding the set of competitors' strategies. The section focuses on simultaneous-move and sequential games.

2.1.1 Simultaneous-move games

Simultaneous-move games are often used to model the interaction of strategic players in the markets. The situation with multiple profit-maximizing firms and no collusion can be modeled as Cournot [17–19] or Bertrand [20] games. Alternatively, conjectured-price response parameter is sometimes used to express a variety of competition intensities [21].

In Bertrand games each firm chooses a single price for each generator, or each area served, and believes that other firms will change prices in response [20, 22, 23]. The limitation of the Bertrand models is that even with

a large number of companies in presence of capacity limit and transmission system the prices in the market can rise above marginal costs and even fluctuate without convergence [22, 24].

Cournot is another form of competition, where firms choose quantities, as best response to the anticipated competitors' strategies. Its simplicity and valuable qualities have made Cournot a popular concept in power market models [17, 25–29]. It has been shown that even in the markets with relatively large number of competing firms Cournot models yield prices well above the competitive levels [30].

Conjectured-price response captures various degrees of strategic behavior in the spot market. Conjectural variations reflect the firm's conjecture about other firms' reaction to a change in its production [21, 31]. This representation allows us to express the special cases of oligopolistic behavior ranging from perfect competition to a Cournot oligopoly [32]. Since this method can be seen as a "shortcut" for more complicated behaviors in implicit dynamic games, it has been a subject of theoretical controversies [33]. However, the conjectural variations appear versatile, when used in industrial applications. They can capture the competition structure, which is neither perfectly competitive, nor Cournot [34].

Nash equilibrium

Nash equilibrium is a solution concept for a non-cooperative game, in which each player is assumed to know the equilibrium strategies of the other players, and no player has an incentive to deviate from its equilibrium strategy [35]. This solution concept was introduced by John Nash [36, 37] and has been widely used in economics and industrial organization. Nash equilibrium concept is used in game-theoretic models of simultaneous-move games in electricity markets [38–41].

The definition of Nash equilibrium can be expressed mathematically as following:

$$\pi_i(s_i^*, s_{-i}^*) \geq \pi_i(s_i, s_{-i}^*), \quad \forall i. \quad (2.1)$$

This condition guarantees that for each strategic actor i the profit in the candidate strategy combination s_i^* must be greater or equal than the profit under alternative choice of strategy s_i , while the strategies of the competitors s_{-i}^* are held fixed.

Multiple Nash equilibria

Depending on a case study, one problem may have several Nash equilibria [42]. In this dissertation two methods are utilized to deal with this multiplicity of solutions: finding all Nash equilibria or focusing on the extremal Nash equilibrium.

- **Finding all Nash equilibria** can be done by formulating an optimization problem, aiming to find one Nash equilibrium and extending it with an integer cut [43]. An integer cut removes each newly obtained equilibrium from the feasible set. The problem is solved multiple times, until there are no more Nash equilibria. This technique is demonstrated in [J4].
- **Extremal Nash equilibrium** was introduced in [44], where it was defined as Nash equilibrium that maximizes or minimizes a certain objective function, in the context of a selfish routing game. In [45] Worst and Best extremal Nash equilibria (WNE and BNE) are applied to the social cost. If S^* is the set of all Nash equilibria strategies and $SC(s_i^*)$ is the social cost of each Nash equilibrium, $s_i^{*\text{worst}}$ is the worst Nash equilibrium of the game if and only if

$$s_i^{*\text{worst}} \in \arg \max_{s_i^* \in S^*} SC(s_i^*). \quad (2.2)$$

In a similar way Best Nash equilibrium is a Nash equilibrium at which social costs are minimized. The concept of extremal Nash equilibria allows to differentiate between multiple Nash equilibria, according to the defined criterion (in this case – social cost).

Nash equilibrium under uncertainty

In this dissertation proposed models often include uncertainty. Bayesian and robust Nash equilibria are two ways of finding Nash equilibrium under uncertainty:

- For **Bayesian Nash equilibrium** each player is assumed to have a subjective uncertainty probability distribution function [46]. This assumption is applicable to the most of the uncertainties observed in the power system, such as wind, reservoir inflows, demand uncertainty.

When introducing scenarios w describing the uncertainty, the Nash equilibrium (2.1) becomes:

$$E_w[\pi_{iw}(s_i^*, s_{-i}^*)] \geq E_w[\pi_{iw}(s_i, s_{-i}^*)], \quad \forall i. \quad (2.3)$$

- Finding **robust Nash equilibrium** does not require the prior knowledge of probability distribution function for the incomplete information [47]. This is very useful, when certain scenarios have no historic data or when probabilities of the scenarios are difficult to compute. Robust Nash equilibrium uses the worst-case approach, where (2.1) is reformulated as follows:

$$\min_w[\pi_{iw}(s_i^*, s_{-i}^*)] \geq \min_w[\pi_{iw}(s_i, s_{-i}^*)], \quad \forall i. \quad (2.4)$$

2.1.2 Sequential-move game

Another type of model used in this dissertation is Stackelberg game. In Stackelberg game one player is the leader of the game – it acts first. Other players are observing the action of the leader and reacting using their available actions [48]. This structure is often used to represent a dominant firm, deciding on its strategic bids. The bids are received by the system operator, who dispatches the firm and the competitive fringe [49, 50]. More information on the electricity market organization can be found in Section 3.2. Stackelberg game can be formulated as a bilevel optimization problem. This type of problems will be reviewed in Section 2.2.3.

2.2 Optimization

An optimization problem or mathematical programming problem is a mathematical entity that allows maximizing or minimizing a certain objective (i.e. objective function) subject to restrictions, typically in the form of equality or inequality constraints [51]. An optimization problem has general form:

$$\underset{x}{\text{minimize}} \quad f(x) \quad (2.5a)$$

$$\text{subject to: } h(x) = 0 \quad (2.5b)$$

$$g(x) \leq 0, \quad (2.5c)$$

where $x \in \mathbb{R}^n$ is the optimization variable vector, $f(x) : \mathbb{R}^n \rightarrow \mathbb{R}$ is the objective function to be minimized, $h(x) : \mathbb{R}^n \rightarrow \mathbb{R}^{m_E}$ are the functions for the equality constraints and $g(x) : \mathbb{R}^n \rightarrow \mathbb{R}^{m_I}$ for the inequality constraints.

2.2.1 Linear optimization problems

Linear programming problems (LP) is a particular class of optimization problems. An LP is generally formulated as:

$$\underset{x}{\text{minimize}} \quad c^T x \quad (2.6a)$$

$$\text{subject to: } Ax \geq b \quad (2.6b)$$

$$x \geq 0. \quad (2.6c)$$

The dual problem of a linear problem is formulated as:

$$\underset{\lambda}{\text{maximize}} \quad \lambda^T b \quad (2.7a)$$

$$\text{subject to: } \lambda^T A \leq c^T \quad (2.7b)$$

$$\lambda \geq 0. \quad (2.7c)$$

According to the Strong Duality Theorem [52] if x is an optimal solution of the primal problem (2.6) and λ is an optimal solution of the dual problem (2.7), then

$$c^T x = \lambda^T b. \quad (2.8)$$

Additionally, it can be shown that at an optimal solution

$$\lambda_j = \frac{\Delta(c^T x)}{\Delta b_j} \quad \forall j. \quad (2.9)$$

It means that λ_j is the sensitivity of the objective function of the primal problem with respect to the right-hand-side parameter b_j of that primal problem. This result will be important for the Benders decomposition technique.

The Karush-Kuhn-Tucker (KKT) conditions are conditions that the optimal solutions of a broad range of optimization problems should satisfy. For linear problems the KKT conditions are both sufficient and necessary for the optimality [51]. The KKT conditions of problem (2.6) are:

$$c^T - \lambda^T A = 0 \quad (2.10a)$$

$$Ax \geq b \quad (2.10b)$$

$$x \geq 0 \quad (2.10c)$$

$$\lambda^T (b - Ax) = 0 \quad (2.10d)$$

$$\lambda \geq 0 \quad (2.10e)$$

The KKT conditions include stationary conditions (2.10a), primal feasibility conditions (2.10b)-(2.10c), complementary slackness conditions (2.10d), and dual feasibility conditions (2.10e). For linear problems only complementary slackness conditions are non-linear. KKT conditions can be written as linear or mixed-integer system of equations using one of the three following techniques to avoid nonlinear complementary slackness conditions (CSCs).

Disjunctive Constraints

The disjunctive constraints, or BigM technique, is a commonly used technique, first introduced in [53], to linearize the expressions of the form: $y^T g(x, y) = 0$, where both y and $g(x, y)$ are positive continuous variables. Introducing a binary variable b , the expression can be rewritten as $yb + g(x, y)(1 - b)$, which in turn can be expressed with a set of constraints:

$$\begin{aligned} 0 &\geq y \geq \bar{K}(1 - b) \\ 0 &\geq g(x, y) \geq \bar{K}b \end{aligned}$$

The value of \bar{K} is a pre-determined parameter and should be chosen in such a way that the value of $y^T g(x, y)$ is bounded above by it. However, the value should not be chosen too high, as it makes the optimization task, where such technique is implemented, ill-conditioned, and, therefore, computationally difficult [54]. It also should not be chosen too low to impose extra bounds on involved variables. The advantage of the method is that it is straight-forward in implementation [55].

SOS1-based Approach

The SOS1-based approach for solving mathematical problems with equilibrium constraints is explicitly discussed in [56]. The method is applied to the problem with equilibrium constraints in the form: $y^T g(x, y) = 0$, where $y \geq 0$, $g(x, y) \geq 0$, and x, y are optimization variables. After the introduction of SOS1 variables v^+ and v^- the equivalent constraint set is:

$$\begin{aligned} y &\geq 0 \\ g(x, y) &\geq 0 \\ v^+ + v^- &= (y + g(x, y))/2 \\ v^+ - v^- &= (y - g(x, y))/2 \end{aligned}$$

Strong duality

Another way of reformulating a lower-level optimization problem is by using the strong duality property similar to (2.8) in the KKT conditions. To do this, the problem should satisfy Slater's sufficient condition for strong duality, namely the primal problem should be convex and strictly feasible. This technique is commonly used for the solution of MPECs [57], as it allows avoiding the complementary slackness conditions and, therefore, nonlinearities in the lower level.

Comparison

The common problem with using the disjunctive constraints is that, while seemingly easy to implement, parameters \bar{K} need to be chosen carefully, as described in detail in [54]. Additionally, using this method of linearization requires adding a number of binary variables, which increases the computational time for the large-scale mixed-integer problems [58].

In contrast, using Schur decomposition and SOS type 1 technique does not require preliminary design. Authors in [56] show that under certain conditions, the nonlinear terms, arising in KKT conditions, can be linearized using the SOS1 technique. This, in turn, requires the introduction of new variables, but the method is shown to outperform the disjunctive constraints technique in terms of computational efficiency.

The drawback of the additional variables is canceled out in the strong duality formulation used to avoid the nonlinear terms in the formulation [59]. The conditions for applying this technique typically hold in the problems arising from modeling the electricity markets. The strong duality holds if the weak Slater's condition holds.

2.2.2 Mixed-integer linear optimization problems

In mixed-integer linear optimization problems (MILP) some of the variables are integer. An example of MILP can be formulated as follows:

$$\underset{x,y}{\text{minimize}} \quad c^T x + d^T y \quad (2.11a)$$

$$\text{subject to: } A_1 x \geq b_1 \quad (2.11b)$$

$$A_2 y \geq b_2 \quad (2.11c)$$

$$x \geq 0, \quad y \in \{0, 1\}. \quad (2.11d)$$

MILP can be solved to the global optimum by commercial solvers. MILP solvers are usually based on modern modifications of grid search algorithm [60], simplex-like method [61], or branch and bound [62]. However, due to the solution procedure, even small mixed-integer problems can be very computationally intensive and require significant amounts of physical memory.

2.2.3 Equilibrium problems

Equilibrium problems are commonly used to model the game-theoretic situations. Two models discussed in this dissertation are Mathematical Problems with Equilibrium Constraints (MPEC) and Equilibrium Problems with Equilibrium Constraints (EPEC).

MPEC problems

The leader-follower structure of the Stackelberg game can be expressed using optimization problem constrained by optimization problem (OPcOP). The mathematical representation can be as following:

$$\underset{x,y}{\text{minimize}} \quad f(x, y, z) \quad (2.12a)$$

$$\text{subject to: } h(x, y, z) = 0 \quad (2.12b)$$

$$g(x, y, z) \leq 0 \quad (2.12c)$$

$$z \in \underset{z}{\text{arg minimize}} \quad f_1(x, y, z) \quad (2.12d)$$

$$\text{subject to: } h_1(x, y, z) = 0 \quad (2.12e)$$

$$g_1(x, y, z) \leq 0 \quad (2.12f)$$

If the lower level problem satisfies the constraint qualification, OPcOP can be directly reformulated to MPEC, by taking the KKT conditions of the lower-level optimization problem [51]. The structure of two problems is compared in Figure 2.1. Complementary slackness conditions can be further reformulated by one of the techniques presented in Section 2.2.1.

EPEC problems

The previous section describes MPEC models as representing leader-follower structure, when a single leader anticipates the equilibrium reaction of the followers, who in turn naively believe that the leader's decisions are exogenous

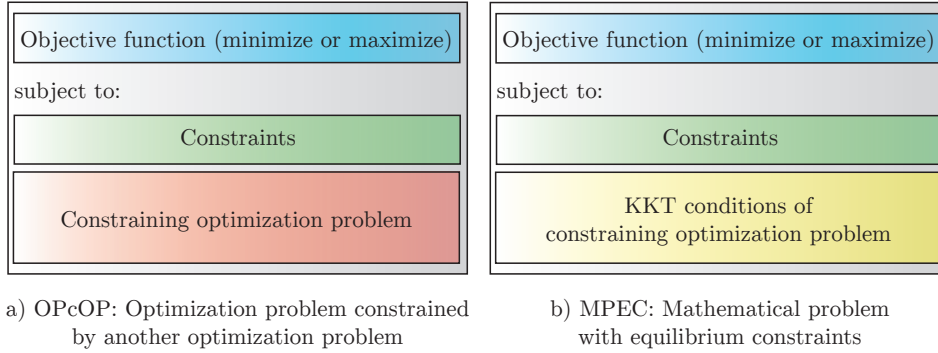


Figure 2.1: Structure of optimization problem constrained by optimization problem (OPcOP) as compared to mathematical problem with equilibrium constraints (MPEC)

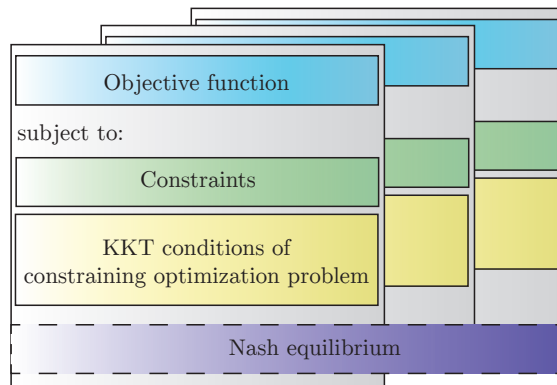


Figure 2.2: Structure of equilibrium problem with equilibrium constraints (EPEC)

and fixed. EPEC models are used to model games when there is more than one leader. The aim is to find an equilibrium between multiple leaders – in the context of electricity markets, Nash equilibrium between strategic players. An illustration to EPEC structure is presented in Figure 2.2.

EPEC can be thought as a collection of MPEC problems. Accordingly, a common way to solve such problem is diagonalization [63–65]. Using this method MPEC problems corresponding to different producers can be solved

iteratively, by fixing the decision variables for all but one strategic agents and looking for a stable point, when neither of the players wants to change its strategy unilaterally. This method is used in [J2]. However, the method is only applicable to smaller case studies, due to a computationally intensive convergence procedure. Additionally, a post-check is required to guarantee that obtained stable point is a Nash equilibrium.

Other possible methods can include solving the whole EPEC formulation, and checking the second-order sufficient condition for each player's MPEC, as in [42]. The scalability of the problem can be limited. One way to avoid the scalability difficulties is to combine Bertrand and Cournot models of competition, or to disregard some of the constraints [66].

In this dissertation EPEC instances are solved by discretization of the solution space [45, 67–69]. The method is demonstrated in [J1] and [J4]. Using this method Nash equilibrium constraint and constraints for all strategic generators, including the formulation for the alternative strategies are specified as in (2.1). EPEC problem for finding a Nash equilibrium can be formulated as a MILP optimization problem:

$$\underset{\Omega^{\text{MILP}}}{\text{minimize}} \Delta\pi = \sum_{i \in I^h} \epsilon_i \quad (2.13a)$$

$$\text{subject to: } \pi_i(s_i^*, s_{-i}^*) + \epsilon_i \geq \pi_i(s_i, s_{-i}^*), \quad \forall i \in I^{\text{strategic}}, \quad (2.13b)$$

$$\epsilon_i \geq 0, \quad \forall i \in I^{\text{strategic}}, \quad (2.13c)$$

$$\Omega^{\text{MILP}} \in \mathbf{X}. \quad (2.13d)$$

Here Ω^{MILP} is a set of variables including upper-level and lower-level variables. Set \mathbf{X} describes the feasible set of the whole problem including the upper level constraints and KKT conditions of the lower level. Variable ϵ_i is a deviation of current strategy from the profit-maximizing strategy, expressed in profit difference. At Nash equilibrium $\epsilon_i = 0, \forall i$.

2.3 Uncertainty modeling

Uncertainty is a crucial element of the models used in this dissertation. The relevant sources of uncertainty, including wind power generation uncertainty, can be represented using scenarios. Sources of uncertainty, identified in this dissertation, and utilized scenario generation techniques are described in the following sections.

2.3.1 Sources of uncertainty

The following sources of uncertainty are identified as relevant for the models under consideration:

- Uncertainty in wind power production – can be modeled using sampling from a probability distribution function, or using a moment-matching technique. These scenario-generation techniques are described in the following section. This source of uncertainty is considered in all models [J1], [J2], [J3], and [J4].
- Uncertainty in demand – demand is an important source of uncertainty in the short term. While deviations are usually mild, they may affect the strategy of generating company.
- Inflow uncertainty – is identified as the most important source of uncertainty in the models including hydropower producers [70–72]. This source of uncertainty is considered in the models of hydro-dominated systems in [J3] and [J4].
- Uncertainty in competitors’ offers – is used to represent possible deviations in the bids of the fringe generators. This source of uncertainty is relevant for MPEC models of a single dominant firm [73–75].

2.3.2 Scenario generation techniques

A single-period stochastic programming model can be formulated [76] as:

$$\underset{x}{\text{minimize}} \quad g_0(x, \bar{\epsilon}) \quad (2.14a)$$

$$\text{subject to: } g_i(x, \bar{\epsilon}) \leq 0 \quad \forall i \quad (2.14b)$$

$$x \in \mathbf{X} \subset \mathbb{R}^n, \quad (2.14c)$$

where $\bar{\epsilon}$ is a random vector. Except for some trivial cases (2.14) can not be solved with continuous distributions. Hence, continuous distribution of the stochastic parameters have to be approximated by discrete distributions with a limited number of outcomes. Such discretization is often called a scenario tree [77]. In this dissertation two scenario-generation methods are used, described below.

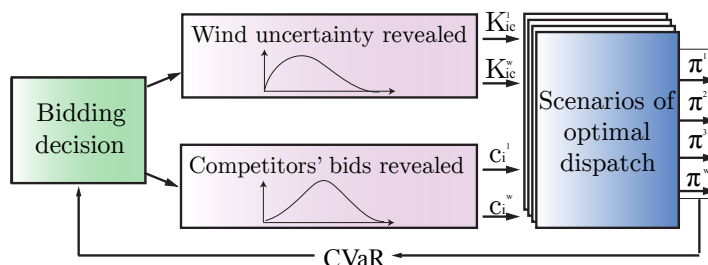


Figure 2.3: Scenario creation for a problem of risk-concerned profit-maximizing producer.

Conditional sampling

Conditional sampling is the most common method for generating scenarios [77]. At each stage of the scenario tree several values are sampled from the stochastic process $\{\bar{\epsilon}\}$, sampling each marginal (the univariate component) separately. The samples are then combined all-against-all, resulting in a vector of independent random variables. An example of this approach, utilized for the publication [C4] is presented in Figure 2.3.

Resulting scenario tree grows exponentially with the dimension of the random vector. Sampling w scenarios for k marginals, the obtained number of scenarios is w^k . To mitigate this problem a scenario reduction technique can be applied [78, 79]. Many of the scenario reduction techniques are readily implemented in optimization software (GAMS), and therefore the number of scenarios can be scaled according to computational requirements [80].

Moment matching

Conditional sampling has two important limitations: it can only be applied if the exact probability distribution functions of random parameters are provided, and it does not take into account the correlation between multiple uncertain parameters. These drawbacks are mitigated by the moment-matching technique [81]. Marginals can be described by the moments (mean, variance, skewness, kurtosis, etc.), obtained from the real data.

In [J3] and [J4] Nord Pool data is used to generate scenarios reflecting the correlations and statistical properties of the real data. Other examples of moment-matching technique usage can be found in [82–85].

2.4 Benders decomposition

EPEC and MPEC problems, introduced in Section 2.2.3 can be reformulated to MILP using strong duality condition as in Section 2.2.1 and discretization. MILP problems can be solved in a centralized manner using the powerful solvers nowadays available [86]. Alternatively, MILP problems can be decomposed to separate integer and continuous variables. For stochastic MPEC problems the resulting continuous problems can be further decomposed by blocks per scenarios. In further section several modifications of Benders decomposition are presented, which exploit the special structure of MILP problems.

2.4.1 Primal Benders decomposition

Primal Benders decomposition is a short name for the “Benders decomposition based on primal problem”, adopted in this dissertation. Assume a MILP problem of a form

$$\underset{x,y}{\text{minimize}} \quad \sum_i c_i x_i + \sum_j d_j y_j \quad (2.15a)$$

$$\text{subject to:} \quad \sum_i a_{li} x_i + \sum_j e_{lj} y_j = b_l \quad \forall l \quad (2.15b)$$

$$x_i \in \{0, 1\} \quad \forall i, \quad y_j \in \mathbb{R} \quad \forall j. \quad (2.15c)$$

Primal master problem ($\mathbf{MP}^{\text{primal}}$) is formulated as:

$$\underset{x,\alpha}{\text{minimize}} \quad \sum_i c_i x_i + \alpha \quad (2.16a)$$

$$\text{subject to:} \quad \alpha \geq \sum_j d_j y_j^{(k)} + \sum_i \lambda_i^{(k)} (x_i - x_i^{(k)}), \quad k = 1, \dots, v - 1 \quad (2.16b)$$

$$x_i \in \{0, 1\} \quad \forall i \quad (2.16c)$$

$$\alpha \geq \alpha^{\text{down}}. \quad (2.16d)$$

Here $x_i^{(k)}$ is the value of x_i in the previous iteration (expression (2.16b) does not exist for the first iteration), α^{down} is a value for the lower bound of the problem. It can be chosen arbitrarily low: $\alpha^{\text{down}} \rightarrow -\infty$.

Corresponding primal linear Benders subproblem ($\mathbf{SP}^{\text{primal}}$) can be formulated as follows:

$$\underset{x,y}{\text{minimize}} \quad \sum_j d_j y_j \quad (2.17a)$$

$$\text{subject to:} \quad \sum_j e_{lj} y_j = b_l - \sum_i a_{li} x_i \quad \forall l \quad (2.17b)$$

$$x_i = x_i^{(v)} : \lambda_i \quad \forall i \quad (2.17c)$$

$$x_i \in \mathbb{R}, \quad y_j \in \mathbb{R}. \quad (2.17d)$$

Here (2.17c) is used to fix the value of x_i to the parametric value $x_i^{(v)}$ obtained in iteration (v) . The solution of this problem is y_j and λ_i .

The procedure for solving the problem using this implementation of Benders decomposition, requires solving $\mathbf{MP}^{\text{primal}}$ and $\mathbf{SP}^{\text{primal}}$ iteratively, until the lower bound ($z_{\text{down}}^{(v)} = \sum_{i=1}^n c_i x_i^{(v)} + \alpha^{(v)}$) and upper bound ($z_{\text{up}}^{(v)} = \sum_{i=1}^n c_i x_i^{(v)} + \sum_{j=1}^m d_j y_j^{(v)}$) would match. This type of decomposition is easy in implementation, as it requires just minimal reformulation of the initial MILP problem. However, very often the models formulated in this dissertation contain disjunctive constraints. This method has a very limited performance on such problems. Obtained Benders cuts are loose and sometimes contain irrelevant information, which causes numerical difficulties limiting the use of the method [87].

2.4.2 Dual Benders decomposition

Dual Benders decomposition is short for ‘‘Benders decomposition based on dual problem’’. It is the initial Benders procedure, described in [88]. This type of decomposition is especially useful for MILP with disjunctive constraints. With this formulation the disjunctive parameter is only included in the objective function.

Assume an initial MILP problem with disjunctive constraints:

$$\underset{x,y}{\text{minimize}} \quad \sum_j d_j y_j \quad (2.18a)$$

$$\text{subject to:} \quad \sum_j e_{lj} y_j \geq b_l \quad \forall l \quad (2.18b)$$

$$\sum_j \bar{e}_{ij} y_j \geq \bar{b}_i - H(1 - x_i) \quad \forall i \quad (2.18c)$$

$$y_j \in \mathbb{R}, \quad x_i \in \{0, 1\}. \quad (2.18d)$$

Here H is a disjunctive parameter – a large constant which relaxes or enforces constraint (2.18c) depending on the value of variable x_i . Fixing binary variables to a candidate vector x_i , a general linear subproblem (similar to $\mathbf{SP}^{\text{primal}}$) is:

$$\begin{aligned} & \underset{y}{\text{minimize}} && \sum_j d_j y_j \\ & \text{subject to:} && \sum_j e_{lj} y_j \geq b_l \quad : u_l \quad \forall l \\ & && \sum_j \bar{e}_{ij} y_j \geq \bar{b}_i - H(1 - x_i) \quad : \bar{u}_i \quad \forall i \\ & && y_j \in \mathbb{R}. \end{aligned}$$

Here u_l are Lagrange multipliers of general (non-disjunctive) constraints, \bar{u}_i are the Lagrange multipliers for the disjunctive constraints. The dual of this problem ($\mathbf{SP}^{\text{dual}}$) is:

$$\underset{u, \bar{u}}{\text{maximize}} \quad \sum_l u_l b_l + \sum_i \bar{u}_i (\bar{b}_i - H(1 - x_i)) \quad (2.19)$$

$$\text{subject to:} \quad \sum_l u_l e_{lj} + \sum_i \bar{u}_i \bar{e}_{ij} \leq d_j \quad \forall j \quad (2.20)$$

$$u_l, \bar{u}_i \geq 0. \quad (2.21)$$

Notice that the feasible region of problem $\mathbf{SP}^{\text{dual}}$ is free from the disjunctive parameter H . The extreme points of the feasible region can be denoted as $\{u^p, \bar{u}^p\}_p$, the initial MILP (2.15) can be restated as $\mathbf{MP}^{\text{dual}}$:

$$\begin{aligned} & \underset{x, \alpha}{\text{minimize}} && \alpha \\ & \text{subject to:} && \alpha \geq \sum_l u_l^p b_l + \sum_i \bar{u}_i^p (\bar{b}_i - H(1 - x_i)), \quad \forall p \\ & && x_i \in \{0, 1\} \quad \forall i \\ & && \alpha \geq \alpha^{\text{down}}. \end{aligned}$$

Similarly to the previous formulation, master and subproblems are solved iteratively, until the convergence is attained [88].

2.4.3 Modified Benders decomposition (MBDA)

Modified Benders decomposition is based on the reformulation of Benders procedure, proposed in [89] and additionally modified in this dissertation to improve the computational properties. Subproblem can be reformulated as follows ($\mathbf{SP}^{\text{MBDA}}$):

$$\begin{aligned} & \underset{u, \bar{u}}{\text{maximize}} && \sum_l u_l b_l + \sum_i \bar{u}_i \bar{b}_i \\ & \text{subject to:} && \sum_l u e_{lj} + \sum_i \bar{u} \bar{e}_{ij} \leq d_j \quad \forall j \\ & && \sum_i \bar{u}_i (1 - x_i) = 0 \\ & && u_l, \bar{u}_i \geq 0. \end{aligned}$$

Notice that subproblem becomes completely independent from the disjunctive parameter H . The lemma that allows removing the disjunctive parameter from the objective function is stated in [J3]. The corresponding master problem $\mathbf{MP}^{\text{MBDA}}$ is based on set-partitioning reformulation of problem $\mathbf{MP}^{\text{dual}}$.

$$\begin{aligned} & \underset{x, \omega_p}{\text{minimize}} && \sum_p K^p \omega_p \\ & \text{subject to:} && \sum_{i \in \Omega^p} x_i \leq |\Omega^p| - 1 + \sum_{p' \geq p} \omega_{p'}, \quad \forall p, \\ & && \sum_p \omega_p = 1, \\ & && \omega_p, x_i \in \{0, 1\}. \end{aligned}$$

Here Ω^p is the index set corresponding to the strictly positive \bar{u} , K^p is the calculated value of the objective function at different extreme points. The author in [89], also shows that the properties of Benders decomposition (existence and uniqueness of the solution) hold for MBDA using tree search algorithm. Applications of MBDA are explored in [J3] and [J4]. They are further discussed in Chapter 5.

Chapter 3

Power System Modeling

This chapter reviews the models utilized for representing the elements of power system. Section 3.1 describes the DC power flow assumption, Section 3.2 focuses on the electricity market organization and mathematical formulation of the optimal dispatch. Section 3.3 presents the models for generating technologies, operating in the market. Section 3.4 describes the assumptions regarding the consumers in electricity markets.

3.1 DC power flow

According to [90], the exact expression for the real power flow from node i to node j (measured at node i , in the direction of node j) is:

$$F_{ij} = G_{ij}[V_i^2 - V_i V_j \cos(\delta_i - \delta_j)] + \Omega_{ij} V_i V_j \sin(\delta_i - \delta_j),$$

where $G_{ij} = R_{ij}/(R_{ij}^2 + X_{ij}^2)$, $\Omega_{ij} = X_{ij}/(R_{ij}^2 + X_{ij}^2)$, R_{ij} and X_{ij} are correspondingly resistance and reactance of the line from i to j . V_i and V_j are voltages at nodes, δ_i and δ_j are the phase angles relative to the reference node. For the models used in this paper the following can be assumed:

1. Line resistances are negligible compared to line reactances ($R_{ij} \ll X_{ij}$ for all lines).
2. The voltage amplitude is equal for all nodes in per unit values: $|V_N| \approx 1$ p.u.
3. Voltage angle differences between neighboring nodes are small: $\sin(\delta_i - \delta_j) \approx (\delta_i - \delta_j)$ and $\cos(\delta_i - \delta_j) \approx 1$.

These assumptions allow us to use a linear formulation for the power flow: $F = HZ$, where H is a Power Transfer Distribution Factors (PTDF) matrix, and Z is a matrix of injections. It is empirically and theoretically shown in the literature that DC power flow equations can be used for all operating points of the grid as long as the grid topology is retained [91, 92]. In the following formulations the DC power flow assumption is used in order to represent the network flows in a convenient linear manner.

3.2 Electricity market organization

Liberalized electricity markets are run by the system operator. In general, market participants, producers and consumers, submit their bids on price and production/consumption to the system operator. The system operator collects the bids and orders them to maximize the productive and allocative efficiency: the producers offering their production at the lowest price are dispatched first, also the consumers, who value their consumption the most, are supplied first. The dispatch, which minimizes the costs, subject to the system constraints is also called optimal dispatch.

3.2.1 Optimal dispatch

Assume \hat{C}_{it} and \hat{Q}_{it} are given values for the price and production bids of generators. Optimal dispatch for scenarios w and time steps t can be formulated as a linear optimization problem:

$$\text{minimize}_{q_{itw}} \sum_{i,t,w} P_w \hat{C}_{it} q_{itw} \quad (3.1a)$$

$$\text{subject to: } 0 \leq q_{itw} \leq \hat{Q}_{it} \quad \forall itw, \quad (3.1b)$$

$$\sum_i q_{itw} = \sum_n D_{ntw} \quad \forall tw, \quad (3.1c)$$

$$\sum_n H_{ln} \left(\sum_{i:n} q_{itw} - D_{ntw} \right) \leq F_l \quad \forall tw. \quad (3.1d)$$

Here (3.1a) is the objective of the system operator, minimizing the total cost of dispatch, (3.1b) is the capacity constraint, setting limit on the dispatched production, (3.1c) represent the system balance, and (3.1d) is an expression setting the limit on flows. This set of constraint can be further expanded, in

order to reflect the presence of special generating technologies, or additional system constraints.

3.2.2 Security-constrained economic dispatch

The increasing uncertainty and variability in power system conditions call for a revised market design, where a market operator forecasts contingencies and carries out an efficient security-constrained dispatch. The authors in [93] proposed a short-run economic dispatch approach to the security-constrained economic dispatch problem. The proposed short-run economic dispatch approach models (1) the probabilities of contingencies, and (2) the trade-off between the preventive and corrective actions, in (3) a convex optimization structure. The system is dispatched in a way that fast-ramping generators can react to the contingencies in the most economic way. The advantages of the proposed model are discussed in details in [94]. Short-run economic dispatch can be formulated as follows:

$$\underset{q_i, q_{itc}}{\text{minimize}} \quad (1 - \sum_c P_c) \sum_i \hat{C}_i q_i + \sum_{c,i,t} P_c \hat{C}_i q_{itc} \quad (3.2a)$$

$$\text{subject to: } 0 \leq q_i \leq \hat{Q}_i \quad \forall i, \quad (3.2b)$$

$$0 \leq q_{itc} \leq \hat{Q}_{ic} \quad \forall itc, \quad (3.2c)$$

$$\sum_i q_{itc} = \sum_n D_{ntw} \quad \forall itc, \quad (3.2d)$$

$$\sum_n H_{ln} (\sum_{i:n} q_{itc} - D_{nt}) \leq F_l \quad \forall lt, \quad (3.2e)$$

$$q_{itc} - q_{i(t-1)c} \leq \hat{R}_i^{up} \quad \forall itc, \quad (3.2f)$$

$$-q_{itc} + q_{i(t-1)c} \leq \hat{R}_i^{dn} \quad \forall itc. \quad (3.2g)$$

Here t is the number of time periods needed for the system to recover fully from the contingency. Time step 1 is considered a non-contingency stage, therefore: $q_{i(t=1)c} = q_i$. Generation in the following time steps in case of a contingency c is denoted as q_{itc} . There are new constraints, compared to (3.1): (3.2c) defines the capacity limits of units in case of contingency, (3.2f)-(3.2g) set the ramp limits of units.

This formulation expresses the need of flexibility in ramps in case the contingency, or wind power fluctuation occurs. Strategic behavior in such setup is studied in [J1].

3.3 Generating technologies

The formulations (3.1) and (3.2) above can be used to model conventional generating technologies, assuming not taking into account start-up and shut-down costs. These formulations can be extended to include additional constraints, representing certain generation technologies [75].

3.3.1 Wind power

Wind power is a rapidly growing renewable source usually characterized by considerable investment costs and relatively low maintenance and operation costs. Spilling the energy produced by a wind power unit is usually cost-inefficient, but could be reasonable in order to manage the network congestions or as a part of profit-maximizing strategy [95]. To model this undesirable, but possible power spillage wind turbines are modeled as power producers with close to zero marginal costs. The intermittency of a wind turbine output is modeled by introducing the scenarios of available capacity as in (3.1b).

3.3.2 Hydropower

Hydropower producers are the main providers of flexibility in the systems, where they are present. Hydropower producers can be modeled using the following expressions:

$$0 \leq s_{itw} \quad \forall (i \in I^h)tw, \quad (3.3a)$$

$$0 \leq m_{itw} \leq M_i \quad \forall (i \in I^h)tw, \quad (3.3b)$$

$$m_{itw} - m_{i(t-1)w} = M_i^0 \mathbf{I}(t=1) + V_{itw} - \Gamma_i q_{itw} - s_{itw} \\ + \sum_{i \in I^{up}} (\Gamma_i q_{i(t-T_i)w} + s_{i(t-T_i)w}) \quad \forall (i \in I^h)tw. \quad (3.3c)$$

Here in time step t , scenario w : s_{itw} is spillage of hydropower producer, m_{itw} is the water level, V_{itw} is an inflow. M_i is the maximum water level, and M_i^0 is the initial water level taken into account if the constraint is formulated for the first time step ($\mathbf{I}(t=1)$). In hydropower plants with a large storage capacity, head variation has negligible influence on operating efficiency in the short-term, therefore a constant production equivalent Γ_i can be assumed [96]. Constraint (3.3a) limits spillage, (3.3b) sets the limits on water level, (3.3c) describes the hydrological balance.

A system of connected reservoirs is considered. Therefore the hydrological balance for unit i , includes the water used for production or spilled by an upstream unit $i \in I^{up}$. Additionally, depending on the waterways' structure, there might be time lag in water relocation T_i .

In certain applications it may be also needed to model a problem of hydropower producer. Since hydropower producers have limited volume of the reservoir, it might be profitable to save some water for the future. The future water value is included in the profit formulation of the producer:

$$\pi = \sum_{(i \in I^h), w} P_w \left(\sum_t (\lambda_{ntw} - C_i^M) q_{itw} + m_{iTw} \Lambda_i^f \frac{1}{\Gamma_i} \right) \quad (3.4)$$

Here the first term in paranthesis describes the market profit of the hydropower producer: λ_{ntw} is the locational marginal price, and C_i^M is the marginal costs of the generator. The second term describes the value of the water kept in the reservoir by the end of the modeling horizon: Λ_i^f is a parameter, forecast by the hydropower producer and defining the value of water in the future.

3.3.3 Energy storage

Energy storage can act as a load within its capacity $L_i \leq 0$, consuming electricity during the periods of a lower price, or like a generator, smoothing out the demand spikes [97]. For energy storage constraint (3.2c) becomes:

$$\text{for } i \in I^{\text{storage}} : L_{ic} \leq q_{itc} \leq K_{ic}. \quad (3.5)$$

The conversion cannot be regarded as completely free, as there are certain losses. Power flowing in the battery, $P_{itc}^{in} \geq 0$, amounts to $\frac{P_{itc}^{in}}{\eta^{in}}$ energy stored, where η^{in} is an efficiency factor. Analogically, $P_{itc}^{out} \geq 0$ flowing out of a battery becomes $P_{itc}^{out} \eta^{out}$ after conversion. Therefore, the output of energy storage unit can be written as:

$$\text{for } i \in I^{\text{storage}} : q_{itc} = -\frac{P_{itc}^{in}}{\eta^{in}} + P_{itc}^{out} \eta^{out} \quad (3.6)$$

Other constraints for the battery are the minimum E^{min} and maximum E^{max} states of charge. Considering the initial state of charge E^0 they can be

written as:

$$E^0 + \sum_t \left(\frac{P_{itc}^{in}}{\eta_{in}} - P_{itc}^{out} \eta^{out} \right) \leq E^{max} \quad (3.7a)$$

$$E^0 + \sum_t \left(\frac{P_{itc}^{in}}{\eta_{in}} - P_{itc}^{out} \eta^{out} \right) \geq E^{min} \quad (3.7b)$$

To avoid the simultaneous charging and discharging of the battery the objective function is updated with penalizing terms. For example, the objective function (3.2a) can be rewritten as:

$$\begin{aligned} \text{minimize}_{q_i, q_{itc}} \quad & (1 - \sum_c P_c) \left(\sum_i \hat{C}_i q_i + P_{i(t=1)c}^{in} c^{in} + P_{i(t=1)c}^{out} c^{out} \right) + \\ & \sum_{c,i,t} P_c (\hat{C}_i q_{itc} + P_{i(t>1)c}^{in} c^{in} + P_{i(t>1)c}^{out} c^{out}) \end{aligned} \quad (3.8)$$

Here c^{in} and c^{out} are small penalizing costs. These costs are ensuring the correct operation of the storage device.

3.4 Demand

In the formulations (3.1) and (3.2) it is assumed that demand is inelastic, expressed with a parameter D_{ntw} . This assumption is common in power systems, where consumers often do not receive price signals and therefore do not respond by reducing their consumption [98]. However, demand response can be modeled in this framework as a “virtual” generator with high costs C_{itw}^{DR} and capacity equivalent to the capacity of demand-responsive consumers. This generator can be dispatched, when the price reaches high-enough levels, imitating the disconnection of flexible consumption. The symmetry between total surplus maximization and generation cost minimization is proved in [3].

Chapter 4

Exercise of market power in wind-integrated systems

This chapter focuses on modeling strategic behavior on ramps in wind-integrated power system. The findings are based on the publication [J1]. We propose a model for describing the strategic behavior on ramp rates and demonstrate illustrative and numerical results.

4.1 Introduction

With an increasing penetration of wind power, there is likely to be an increasing need for fast-ramping generating units. These generators ensure that no load is lost if supply drops due to the uncertainties in wind power generation. However, it is observed in practice that, in a presence of network constraints, fast-ramping generating units are prone to act strategically and exercise market power by withholding their ramp rates. In the Australian National Electricity Market (NEM), when the prices increase to very high levels, some generators were observed to decrease their declared ramp-rate capabilities, in order to maintain high output for a longer period of time.

Another evidence of strategic behavior was observed in South Australia, an area with very high penetration of wind power. A sudden reduction in wind output there must be matched by a rapid increase in the output of thermal generators. On several occasion the price in the area spiked up to \$12000/MWh. These occasions tended to coincide with times when the offered ramp rate from thermal units was less than their technical capability.

It appears that at times generators may have a commercial incentive to limit the rate at which they ramp up in response to a fall in wind power output.

In this chapter we propose a model, capable to model ramp-rate game in wind integrated power systems. The model covers an important gap in the literature. The authors of [99, 100] consider ramp rates as a part of the bidding information of profit-maximizing generating companies, but they do not assume any strategic behavior relating to ramp rates. The authors of [101] provide an analysis of strategic ramp-rate bidding, but significantly simplify the market clearing problem and do not take into account possible contingencies or network constraints.

The model in this chapter is set up using the concept of the multiple leaders-follower game as discussed in Section 2.2.3. The follower is a market operator who runs the short-run economic dispatch problem, discussed earlier in Section 3.2.2. SRED allows to model a trade-off between preventive and corrective measures for possible contingencies, e.g. wind power outages, in convex structure. The leaders are the profit-maximizing generators, strategic on both ramp rate and generation capacity. The whole setup is modeled as an Equilibrium Problem with Equilibrium Constraints (EPEC). The result of the EPEC model is a set of Nash equilibria of the ramp-rate game. To tackle the multiple Nash equilibria problem, we use the concept of the extremal-Nash equilibria, introduced in Section 2.1.1. We use different techniques for the linearization of the problem and motivate the best one [59]. The final formulation of the proposed game-theoretic model is a single-stage Mixed-Integer Linear Program (MILP). To show the distinctive features of the proposed game model, the whole formulation is applied to the illustrative two-node example system and to the IEEE 24-node system.

4.2 Modeling

This section gives the detailed formulation of the model used in the simulations and the assumptions made. We model a ramp-rate Stackelberg game with multiple leaders and a single follower. The leaders are strategic generators, seeking to maximize their profits by offering strategic bids to the market. The follower is a market operator performing a security-constrained short-run economic dispatch. We assume that all forward contracts [102] have been released before the dispatch takes place.

4.2.1 Lower level

The short-run economic dispatch (SRED) represents the lower level of the ramp-rate game. The setup of this dispatch, the motivation behind it, and the adopted assumptions are discussed in Section 3.2.2. The linear problem representing the optimal short-run economic dispatch in this chapter is as follows:

$$\underset{g_i, g_{itc}}{\text{minimize}} \quad (1 - \sum_c p_c) \sum_i (c_i g_i) + \sum_{c,i,t} p_c (c_i g_{itc}) \quad (4.1a)$$

$$\text{subject to: } g_i, g_{itc} \geq 0 \quad \leftrightarrow \mu_{itc}^{A1} \quad (4.1b)$$

$$g_i \leq K_i \quad \leftrightarrow \mu_i^{A2} \quad (4.1c)$$

$$g_{itc} \leq K_{ic} \quad \leftrightarrow \mu_{itc}^{A3} \quad (4.1d)$$

$$\sum_{n,i \in n} g_{itc} = \sum_n d_n \quad \leftrightarrow \lambda_{itc}^B \quad (4.1e)$$

$$\sum_n H_{li} \sum_{n,i \in n} (g_{itc} - d_n) \leq F_l \quad \leftrightarrow \mu_{litc}^C \quad (4.1f)$$

$$g_{itc} - g_{i(t-1)c} \leq \hat{R}_i^{up} \quad \leftrightarrow \mu_{itc}^{D1} \quad (4.1g)$$

$$-g_{itc} + g_{i(t-1)c} \leq \hat{R}_i^{dn} \quad \leftrightarrow \mu_{itc}^{D2} \quad (4.1h)$$

The short-run economic dispatch problem in (4.1a)-(4.1h) is convex and satisfies the weak Slater's condition. Accordingly, the Karush-Kuhn-Tucker (KKT) optimality conditions can be written as linear or mixed-integer system of equations using one of the three techniques to avoid nonlinear complementary slackness conditions described in Section 2.2.1: strong duality, SOS type 1 technique, or BigM technique.

We will denote the total number of primal feasibility equations (4.1b)-(4.1h) as a star (*). Three discussed techniques for linearizing the KKT system are compared in Table 4.1 in terms of constraints, variables and constant parameters. Simulating these techniques shows that computational time depends strongly on these values. As shown in Table 4.1, the strong duality technique is the most computationally efficient technique for linearizing our KKT system. Therefore, to ensure the scalability and computational efficiency of the problem formulation, we adopt the strong duality technique in our further simulations.

Table 4.1: Linearization techniques for KKT system. $(*) = (4TIC - 3IC + I + TC + LTC)$ – number of primal feasibility constraints. Capital letters – number of elements in sets, see Nomenclature.

	Strong duality	SOS type 1	BigM technique
Constraints	$2(*) + 1 - TC$	$4(*) - 3TC$	$4(*) - 3TC$
Binary variables	0	0	$(*) - TC$
SOS1 variables	0	$2(*) - 2TC$	0
BigM constants	0	0	$(*) - TC$

4.2.2 Upper level

The upper level of the ramp-rate game is the profit-maximization task solved by the strategic generators. The profit formulation for the generator i can be written as:

$$\pi_i = (p_n - c_i)g_i, \quad (4.2)$$

where p_n is the price at the connection node n of generator i . The nodal price p_n can be expressed as a summation of a system price, λ_{tc}^B , and transmission congestion price, $\sum_l \mu_{ltc}^C H_{li}$, ($p_n = \lambda_{tc}^B - \sum_l \mu_{ltc}^C H_{li}$). The expression (4.2) for the initial state and for each time step t is then:

$$\pi_{itc} = (\lambda_{tc}^B - \sum_l \mu_{ltc}^C H_{li} - c_i)g_{itc}. \quad (4.3)$$

Expressing the λ_{tc}^B from stationary conditions, following the logic in [45], we recast the profit expression as:

$$\pi_{itc} = \mu_i^{A2} g_i + (\mu_{itc}^{A3} + \mu_{itc}^{D1} + \mu_{itc}^{D2})g_{itc}. \quad (4.4)$$

This expression contains nonlinear terms in primal and dual variables. However, using the complementary slackness conditions, we can equivalently write:

$$\begin{aligned} \mu_i^{A2} g_i &= \mu_i^{A2} K_i, & \mu_{itc}^{A3} g_{itc} &= \mu_{itc}^{A2} K_{ic} \\ \sum_t \mu_{itc}^{D1} g_{itc} &= \sum_t \mu_{itc}^{D1} \hat{R}_i^{up} \\ \sum_t \mu_{itc}^{D2} g_{itc} &= \sum_t \mu_{itc}^{D2} \hat{R}_i^{dn} \end{aligned} \quad (4.5)$$

For the nonstrategic generators the bidding levels of ramp rates are true ramping capabilities, ($\hat{R}_i^{up} = R_i^{up}$ and $\hat{R}_i^{dn} = R_i^{dn}$). For the strategic generators, we assume a strategic choice on ramping level. We can model this strategic choice, by introducing a vector of binary variables x_{ik}^{up} and x_{ik}^{dn} :

$$\hat{R}_i^{up} = (b_0 + \sum_k b_k x_{ik}^{up}) R_i^{up}, \quad (4.6a)$$

$$\hat{R}_i^{dn} = (b_0 + \sum_k b_k x_{ik}^{dn}) R_i^{dn}. \quad (4.6b)$$

Here b_0 and b_k are vectors of constants, such that $b_0 + \sum_k b_k = 1$. This way, $x_{ik}^{up,dn} = \mathbf{1}$ means that the generator bids the full ramp-rate capability to the market. If $x_{ik} = \mathbf{0}$, then $\hat{R}_i^{up} = b_0 R_i^{up}$ and $\hat{R}_i^{dn} = b_0 R_i^{dn}$, which means the generator bids the minimum possible ramp rate level. This way a strategy set $S_i = \{s_1, s_2, \dots, s\}$ for the strategic unit i is obtained as a set of all k possible combinations for the vector $x_{ik}^{up,dn}$.

We substitute the expressions (4.5)-(4.6) in the profit formulation (4.4) and use the disjunctive constraints [53] to linearize the product of binary variables $x_{ik}^{up,dn}$ and continuous variables $\mu_{itc}^{D1,D2}$, by introducing a new variable $z_{ik}^{D1,D2} = x_{ik}^{up,dn} \mu_{itc}^{D1,D2}$. Assuming for conciseness that $R_i^{up} = R_i^{dn} = R_i$, we obtain the following expression for the profit:

$$\begin{aligned} \pi_i = & \mu_i^{A2} K_i + \sum_{tc} \left(\mu_{itc}^{A3} K_{ic} + b_0 (\mu_{itc}^{D1} + \mu_{itc}^{D2}) \right) \\ & + \sum_k (z_{itck}^{D1} + z_{itck}^{D2}) b_k R_i. \end{aligned} \quad (4.7)$$

The $z_{ik}^{D1,D2}$ terms are linearized with a following set of constraints:

$$\begin{aligned} z_{ik}^{D1,D2} & \leq \bar{K}_{1,2} x_{ik}^{up,dn}, \\ z_{ik}^{D1,D2} & \leq \mu_{itc}^{D1,D2}, \\ z_{ik}^{D1,D2} & \geq \mu_{itc}^{D1,D2} - \bar{K}_{1,2} (1 - x_{ik}^{up,dn}). \end{aligned} \quad (4.8)$$

Here \bar{K}_1 and \bar{K}_2 are big-enough disjunctive constants, designed according to the recommendations in [54].

The Nash equilibrium between the strategic generators on ramp rate is reached, when given the ramp-rate strategy of other generators, no player

wants to deviate from the chosen strategy. Or, expressed mathematically:

$$\sum_{itc} \pi_{itc}(s_i^*, s_{-i}^*) \geq \sum_{itc} \pi_{itc}(s_i, s_{-i}^*). \quad (4.9)$$

To avoid the problem of multiple Nash equilibria, we use the concept of extremal Nash equilibria, as in 2.1.1. The whole ramp-rate game model consists of the optimality conditions derived in Section 4.2.1, the profit formulation (4.7), disjunctive constraints (4.8), an expression ensuring the Nash equilibrium outcome (4.9), and an extremal-Nash equilibrium expression. As an example, the mixed-integer linear programming problem for finding the best-Nash equilibrium is set out in below:

$$\text{Minimize}_{x_{ik}^{up,dn}} \left(1 - \sum_c p_c\right) \sum_u (c_i g_i) + \sum_{c,i,t} p_c (c_i g_{itc}) \quad (4.10)$$

$$\text{subject to: } g_i, g_{itc} \geq 0, \quad g_i \leq K_i, \quad g_{itc} \leq K_{ic} \quad (4.11)$$

$$\sum_{n,i \in n} g_{itc} = \sum_n d_n \quad (4.12)$$

$$\sum_n H_{li} \sum_{n,i \in n} (g_{itc} - d_n) \leq F_l \quad (4.13)$$

$$g_{itc} - g_{i(t-1)c} \leq \hat{R}_i^{up} \quad (4.14)$$

$$-g_{itc} + g_{i(t-1)c} \leq \hat{R}_i^{dn} \quad (4.15)$$

$$\mu_{itc}^{A1}, \mu_i^{A2}, \mu_{itc}^{A3}, \mu_{itc}^C, \mu_{itc}^{D1}, \mu_{itc}^{D2} \geq 0 \quad (4.16)$$

Profit formulation and linearization (4.7)-(4.8)

Nash equilibrium condition (4.9)

Stationary conditions

Strong duality implication

4.3 Illustrative case study

We consider a network with two distinctive areas. The areas are represented by 2 nodes: G1, G2, G3 are placed in node 1, G4, G5, G6 and demand are placed in node 2. We consider a capacity-constrained line, connecting these 2 nodes. Node 1 represents a generation surplus area, while the demand is mostly concentrated in node 2. An example of this setup is the Swedish power system, where generation is mainly concentrated in North and the

load centers are situated in South. The northern and southern parts are only connected by several constrained links. The unit data is presented in Table 4.2.

While units G1 to G3, G5 and G6 have low probabilities of failure, unit G4, representing the aggregation of wind power units, has a 1% probability of going off the network, due to the extreme wind conditions. The demand is predicted to be 1500 MW during the short dispatch period under consideration. The dispatch is shown in Figure 4.1.

We consider 2 cases: case (a) represents a base-case, when generators are bidding their true ramping capabilities. In case (b) the generators G5 and G6 have 4 bidding strategies on their ramping capabilities. They can offer 4 levels of ramp rate, from 25% to 100% of their true ramping capability.

In case (b) the bidding decisions of strategic generators G5 and G6 differ. Table 4.2 presents that in case of the best-Nash equilibrium (BNE) generator G6 withholds 25% of its ramping capability. The optimal dispatch of the system is shown in Figure 4.1-(b). We see that the lower ramp rate of G6 forces the market operator to dispatch G5 even in a no-contingency state (time step 1). In the case of the worst-Nash equilibrium (WNE) both generators withhold. The corrective actions are taking more time and dispatch costs increase. As shown in Table 4.3, the costs of market power in cases of BNE and WNE are €6862 and €13365, respectively. This means 21.6% and 42% increase in dispatch costs as compared to the dispatch cost of the competitive case. The average market clearing prices (MCPs), calculated through 7 periods, increase as well.

We see that the concept of extremal-Nash equilibria, introduced in Section

Table 4.2: Unit data for the 2-nodes system. $R_i^{up}=R_i^{dn}=R_i$ In bold – identified cases of withholding.

Unit, i	Capacity, K_i (MW)	Costs, c_i (€/MW)	Ramp rates, (MW/hr)		
			R_i	BNE \hat{R}_i	WNE \hat{R}_i
G1	500	10	1000	1000	1000
G2	500	100	100	100	100
G3	800	50	100	100	100
G4	800	0.1	100	100	100
G5	500	200	100	100	75
G6	500	1000	500	375	375

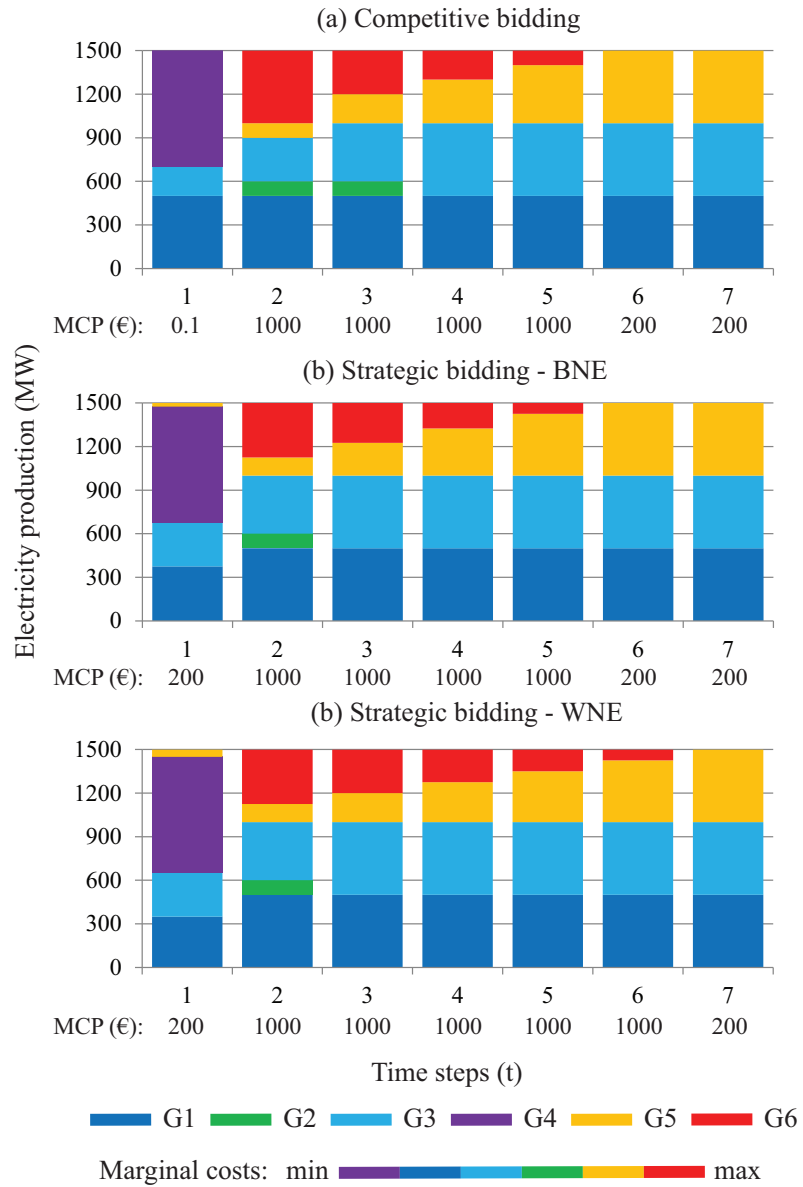


Figure 4.1: Short-run economic dispatch and market clearing prices (MCPs) for the cases of (a) competitive and (b) strategic bidding. BNE: best-Nash equilibrium case, WNE: worst-Nash equilibrium case.

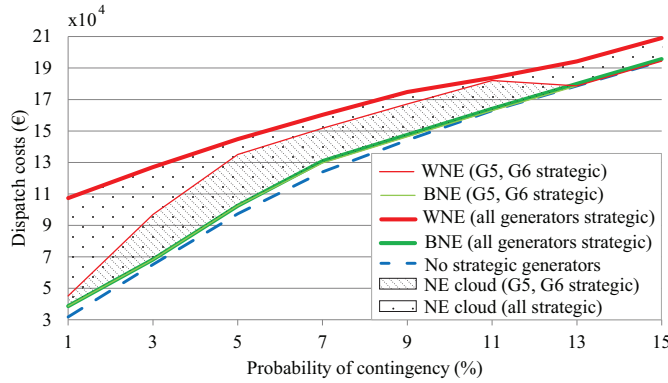


Figure 4.2: The concept of Nash-equilibria band with BNE and WNE as the lower and upper bounds. Clouds of Nash equilibria solutions for the cases, when generators G5 and G6 are strategic, and when all generators are strategic.

Table 4.3: Cost of market power on ramp rate for the illustrative case study (loss of G4 with probability of 1%, G5 and G6 strategic)

	No gaming	Best NE	Worst NE
Dispatch costs (€)	31,779	38641	45144
Cost of market power (€)		6862	13365
Relative increase in costs		21.6%	42%
Average electricity price (€)	629	657	771

2.1.1 sets the bounds for the solution space (Nash-equilibria cloud) in the case of strategic generators. The solutions in the cloud are equiprobable.

Figure 4.2 presents the evolution of dispatch costs over different contingency probabilities. The cloud of solutions, when all generators are strategic, is a super set for the cloud of solutions, when only generators G5 and G6 are strategic. Both bounds are important for the market power assessment; however, depending on the application we could be interested in a lower or upper bound. Another observation from the figure is that the cloud becomes thinner and tends to the non-strategic costs, when the probability of contingency is higher. This can be explained by the trade-off between preventive and corrective actions. As a severe contingency is more probable, system operator takes more preventive actions to minimize the costs and often the

most expensive generators are dispatched in the preventive action.

4.4 Numerical results

Here we present only the main findings of the ramp-game modeling on a larger network, for more results we refer the reader to [J1]. EPEC problems are known to be computationally intensive [103], the purpose of this section is to demonstrate that the developed formulation is scalable to larger system, in this case 24-node IEEE system [104]. We assume that G13 is an aggregation of several wind power units. The output of G13 is predicted to be 300 MW, however there is a certain probability that the real output will be different.

In this section we consider a joint game for ramp and quantity. To do so, we introduce a variable \hat{K}_{ic} , which describes the production bid of the strategic generator:

$$\hat{K}_{ic} = (b_0 + \sum_k b_k x_{ik}^{cap}) K_i. \quad (4.17)$$

Here x_{ik}^{cap} is a vector of binary variables. Constraints (4.11) are then changed to the following expressions:

$$g_i, g_{itc} \geq 0, \quad g_i \leq \hat{K}_{ic}, \quad g_{itc} \leq \hat{K}_{ic}. \quad (4.18)$$

Following the same logic as in ramp-game, we change the expression for the profit:

$$\begin{aligned} \pi_i = & b_0 \mu_i^{A2} + \sum_k b_k z_{ik}^{A2} + \sum_{tc} \left(\sum_k b_k z_{itck}^{A3} K_{ic} + b_0 (\mu_{itc}^{A3} + \mu_{itc}^{D1} \right. \\ & \left. + \mu_{itc}^{D2}) + \sum_k (z_{itck}^{D1} + z_{itck}^{D2}) b_k R_i \right). \end{aligned} \quad (4.19)$$

Here $z_{ik}^{A2} = \mu_i^{A2} x_{ik}^{cap}$ and $z_{itck}^{A3} = \mu_{itc}^{A3} x_{ik}^{cap}$ are linearized the same way as described in (4.8). It should be noted that the formulation can be extended further to include other strategic parts of the bid, as for example in [105].

The wind-integrated power systems are characterized by variability of wind power output. Therefore, we investigate different probabilities and sizes for wind power contingencies. Figure 4.3 shows the dispatch costs in the case of two-step demand response with 7 strategic generators (G1, G2, G3, G5, G6, G11 and G12). Both BNE and WNE costs are plotted. In the BNE case, when the actual output of the wind generating unit is more or

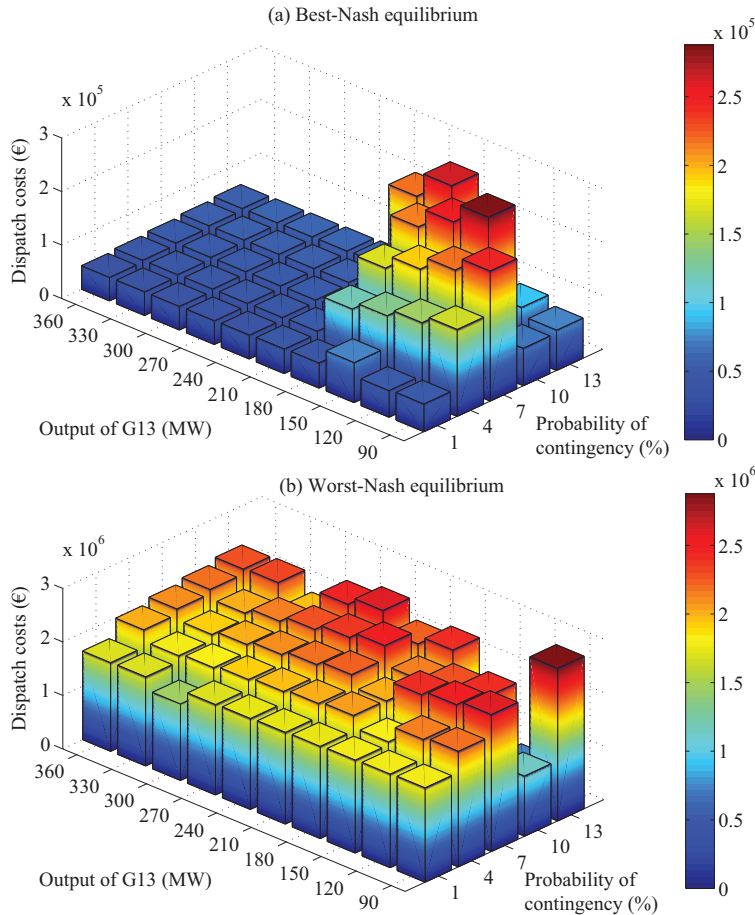


Figure 4.3: Dispatch costs for the cases with different output deviation predicted with different probabilities. (a) Best-Nash equilibrium case, (b) Worst-Nash equilibrium case.

around the predicted value we observe a linear increase in the dispatch costs with the increased probability of congestion. However, when the severity of contingency is high – the actual wind output is less than predicted value by 25% or more – we observe rapid increases in the dispatch costs caused by the gaming behavior of strategic generators. In the WNE case, the dispatch costs are high in all studied cases.

According to the obtained results we can observe that when the severity of

contingency is high, which may depend on the system flexibility, the generators are prone to exercise market power by bidding strategically on their capacity and ramp rate levels. This strategic behavior affects considerably the dispatch costs and prices in the system, especially when the demand response is limited. This result supports the necessity of ramp-game modeling in the systems with intermittent supply.

The model is implemented on GAMS platform and solved by CPLEX solver. The GAMS code runs on 2.8 GHz Intel Processor with 2 cores and 8 GB RAM. As an example, the computation time for the BNE case of two-steps demand response and the wind generators output predicted to be 120 MW with probability of 1% is 38 minutes.

4.5 Conclusion

In this chapter we model the strategic behavior in wind-integrated systems, where the intermittency is high, so that the security-constrained short run economic dispatch is a welfare-maximizing way of operating the system. We assume a market operator who collects the bid information, including marginal costs, available capacity and ramp rates. Strategic generators, willing to maximize their profit, can bid lower than their true ramp rates and capacities. The outcome of the market is a Nash equilibrium.

Illustrative case study demonstrates that in presence of network constraints and a major contingency, the generators are prone to exercise market power and bid a lower ramp rate to the market. Further, using a 24-node case study we show that if the severity of contingency is high, strategic generators are prone to maximize their profits by bidding strategically to the market.

This study shows that contingencies, introduced by a strong intermittency, have a significant effect on the proneness of generators to bid strategically, which in turn affects the dispatch costs and, therefore, the system social welfare. Here, the ramping capabilities of the units are particularly important, as they define the speed, with which the system reacts to the contingencies.

Chapter 5

Market power in power systems with high share of wind power and hydropower

In this chapter we study the strategic behavior of hydropower producers as main providers of generation flexibility in wind-integrated systems. The chapter is based on publications [J3] and [J4]. In this chapter we will study the cases of a single dominant hydropower producer and of Nash equilibrium of multiple hydropower producers.

5.1 Introduction

As we have seen in Chapter 4, flexibility plays a crucial role in the systems with high penetration of wind power. Fast-ramping producers compensate the fluctuations of wind power and may have incentives to withhold this flexibility in order to obtain higher profits. Hydropower producers are often regarded as flexibility providers in the systems, where this type of power is available.

The annual hydropower share in electricity generation in Norway is 95-99%. It is also high in Brazil (80%), Iceland (88%), New Zealand (65%), Austria (70%), Canada (62%) and Sweden (42%) [106]. Even though hydropower producers have such an important market share, they have been traditionally regarded as price-takers, optimizing their production schedule based on the price expectation. However, the price-taking assumption for a hydropower

producer does not always hold [3]. Reference [107] shows that in hydrothermal systems the strategic behavior can lead to significantly higher prices. In winter 2002-2003, extraordinary high prices were observed in Nordic market. A number of observers voiced the concern that the high prices were a result of strategic behavior by hydropower producers. The hydropower producers may have used an opportunity to spend more stored water in summer in order to create scarcity and, therefore, high prices, in winter [70].

Hydropower producers can use their unique characteristics (such as a capability to store energy, hydrological coupling between units and near-zero marginal cost) to behave strategically in the market [106], [108]. With an increasing penetration of wind and solar generation, hydropower producers can ramp fast to cover the generation fluctuations. Withholding such ramping capability adds another dimension to the strategic behavior of hydropower producers.

Modeling the hydro-dominated systems requires accounting for hydro-specific constraints. The few studies that have looked at market power assessment involving the hydropower producers, have significantly simplified the modeling. Usually only a single profit-maximizing hydropower producer is considered, and the optimal dispatch conditions are simplified as a residual demand curve [109], [110]. In reference [107] the authors consider the market power assessment in a hydrothermal power system, but employ a simplifying residual demand approach, expressing price as a function of price-makers' production, rather than as a result of the optimal dispatch. The authors in [28] include the equilibrium constraints, but their model neglects the uncertainty in reservoir inflows and contains nonlinearities.

In this chapter we model the cases of single dominant hydropower producer and multiple hydropower producers in power systems with high share of wind power. The respective MPEC and EPEC models are recast as MILP and solved using a Modified Benders Decomposition Algorithm (MBDA), discussed earlier in Section 2.4.3. We compare the numerical results with other types of Benders decomposition and monolith solution by CPLEX solver.

5.2 Modeling

In this section we discuss the models of a single profit-maximizing hydropower producer, formulated as an MPEC, and multiple producers, formulated as an EPEC.

5.2.1 Single profit-maximizing hydropower producer

The price-making hydropower producer is modeled in (5.1).

$$\underset{\hat{q}_{it}, \hat{r}_i, \hat{c}_{it}}{\text{maximize}} \pi = \sum_{(i \in I^h), w} P_w \left(\sum_t (\lambda_{ntw} - C_i^M) q_{itw} + m_{iT_w} \Lambda_i^f \frac{1}{\Gamma_i} \right) \quad (5.1a)$$

$$\text{subject to: } 0 \leq \hat{q}_{it} \leq Q_i, \quad 0 \leq \hat{r}_i \leq R_i, \quad 0 \leq \hat{c}_{it} \leq C_i, \quad \forall (i \in I^h)t, \quad (5.1b)$$

where $\lambda_{ntw}, q_{itw}, s_{itw}, m_{itw} \in$

$$\arg \left\{ \underset{q_{itw}, s_{itw}, m_{itw}}{\text{minimize}} \sum_{i,t,w} P_w \hat{c}_{it} q_{itw} \right. \quad (5.1c)$$

$$\text{subject to: } 0 \leq q_{itw} \leq \hat{q}_{it} \quad : \mu_{itw}^{A_1}, \mu_{itw}^{A_2}, \quad \forall i, \quad (5.1d)$$

$$\sum_i q_{itw} = \sum_n D_{ntw} \quad : \lambda_{tw}^B, \quad \forall tw, \quad (5.1e)$$

$$\sum_n H_{ln} \left(\sum_{i:n} q_{itw} - D_{ntw} \right) \leq F_l \quad : \mu_{ltw}^C, \quad \forall ltw, \quad (5.1f)$$

$$-\hat{r}_i \leq q_{i(t-1)w} - q_{itw} \leq \hat{r}_i \quad : \mu_{itw}^{D_1}, \mu_{itw}^{D_2}, \quad \forall itw, \quad (5.1g)$$

$$0 \leq s_{itw} \quad : \mu_{itw}^E, \quad \forall (i \in I^h)tw, \quad (5.1h)$$

$$0 \leq m_{itw} \leq M_i \quad : \mu_{itw}^{F_1}, \mu_{itw}^{F_2}, \quad \forall (i \in I^h)tw, \quad (5.1i)$$

$$m_{itw} - m_{i(t-1)w} = M_i^0 \mathbf{I}(t=1) + V_{itw} - \Gamma_i q_{itw} - s_{itw} \\ + \sum_{i \in I^{up}} (\Gamma_i q_{itw} + s_{itw}) \quad : \lambda_{itw}^G, \quad \forall (i \in I^h)tw \left. \right\}. \quad (5.1j)$$

Here (5.1a) is the profit formulation, where λ_{ntw} is a locational marginal price (LMP) and it can be expressed as $\lambda_{ntw} = \lambda_{tw}^B - \sum_{l,n} \mu_{ltw}^C H_{ln}$. We model hydropower producer using the assumptions made in Section 3.3.2. The term $m_{iT_w} \Lambda_i^f \frac{1}{\Gamma_i}$ describes the future value of water left in the reservoir by the end of the modeling horizon (at time step T). Strategic hourly bids ($\hat{q}_{it}, \hat{c}_{it}$), and ramp-rate bid \hat{r}_i of the hydropower producer are modeled by the constraints (5.1b). The LMPs and the dispatch variables are the output of the lower-level economic dispatch problem (5.1c)-(5.1j). Expressions (5.1d) are the generation constraints. Expression (5.1e) represents the energy balance constraint, (5.1f) accounts for the network constraints and (5.1g) is setting the constraints on ramp rate. A system of connected reservoirs is considered for the hydropower producer. We model the constraints on spillage (5.1h), water level (5.1i) and hydrological balance condition (5.1j).

Since the lower-level problem (5.1c)-(5.1j) is linear, we can equivalently rewrite it as Karush-Kuhn-Tucker (KKT) conditions. We avoid the complementary slackness conditions by substituting them with the strong duality condition, as it was shown to be more convenient for linearization in Chapter 4. Accordingly, primal feasibility constraints (5.1d)-(5.1j), dual feasibility constraints, stationarity constraints and strong duality constraint form the optimality conditions of the lower-level problem. Now, we can reformulate the profit by deriving the LMP from the stationary conditions:

$$\begin{aligned} \pi = & \sum_{(i \in I^h), w} P_w \left(\sum_t (\lambda_{tw}^B - \sum_{l, n} \mu_{ltw}^C H_{ln} - C_i^M) q_{itw} + m_{iTw} \Lambda_i^f \frac{1}{\Gamma_i} \right) = \\ & \sum_{(i \in I^h), w} P_w \left(\sum_t (\hat{c}_{it} - \mu_{itw}^{A_1} + \mu_{itw}^{A_2} + \mu_{itw}^{D_1} - \mu_{itw}^{D_2} - \mu_{i(t+1)w}^{D_1} + \mu_{i(t+1)w}^{D_2} \right. \\ & \left. - \Gamma_i \lambda_{itw}^G + \Gamma_i \sum_{i \in I^{dn}} \lambda_{itw}^G - C_i^M) q_{itw} + m_{iTw} \Lambda_i^f \frac{1}{\Gamma_i} \right). \end{aligned} \quad (5.2)$$

We simplify expression (5.2) using the complementary slackness (CS) conditions. The term $(*) = (-\Gamma_i \lambda_{itw}^G + \Gamma_i \sum_{i \in I^{dn}} \lambda_{itw}^G) q_{itw}$ appeared from the hydrological balance constraint (5.1j) and it exists only for hydropower units. The final profit expression becomes:

$$\begin{aligned} \pi = & \sum_{(i \in I^h), w} P_w \left(\sum_t \left(\mu_{itw}^{A_2} \hat{q}_{it} + (\mu_{itw}^{D_1} + \mu_{itw}^{D_2}) \hat{r}_i + \hat{c}_{it} q_{itw} - C_i^M q_{itw} \right. \right. \\ & \left. \left. + \mu_{it}^{F_2} M_i - \lambda_{itw}^G (M_i^0 \mathbf{I}(t=1) + V_{it}) \right) + m_{iTw} \Lambda_i^f \frac{1}{\Gamma_i} \right). \end{aligned} \quad (5.3)$$

The equivalent one-level program can be formulated by combining the upper-level constraints and the lower-level optimality conditions. The variables of one-level optimization include primal variables and dual variables of the lower-level problem, and variables of the upper-level problem: $\Omega^{\text{NLP}} = \{q_{itw}, s_{itw}, m_{itw}, \mu_{itw}^{A_1}, \mu_{itw}^{A_2}, \mu_{itw}^{D_1}, \mu_{itw}^{D_2}, \mu_{itw}^E, \mu_{itw}^{F_1}, \mu_{itw}^{F_2}, \mu_{itw}^C, \lambda_{tw}^B, \lambda_{itw}^G, \hat{q}_{it}, \hat{r}_i, \hat{c}_{it}\}$. The final profit expression (5.3) and strong duality condition contain bilinear terms $\mu_{itw}^{A_2} \hat{q}_{it}$, $\mu_{itw}^{D_1} \hat{r}_i$, $\mu_{itw}^{D_2} \hat{r}_i$ and $\hat{c}_{it} q_{itw}$. For the non-strategic units we assume: $\hat{q}_{it} = Q_i$, $\hat{r}_i = R_i$, $\hat{c}_{it} = C_i^M$, $\forall i \in (I \setminus I^h)$. For the strategic units these terms need to be linearized.

We approximate the generation capacity Q_i by a pre-defined number of discrete capacities \hat{Q}_{ik} . Therefore: $\mu_{itw}^{A_2} \hat{q}_{it} = \mu_{itw}^{A_2} \sum_k x_{itk}^q \hat{Q}_{ik} = \sum_k z_{itwk}^{A_2}$,

where $\sum_k x_{itk}^q = 1$. Variable $z_{itwk}^{A_2}$ can be linearized as follows [53]:

$$-\bar{K}^q(1 - x_{itk}^q) \leq z_{itwk}^{A_2} - \hat{Q}_{ik}\mu_{itw}^{A_2} \leq \bar{K}^q(1 - x_{itk}^q) : (\bar{\alpha}_{itwk}^{A_2}, \underline{\alpha}_{itwk}^{A_2}), \forall (i \in I^h)twk, \quad (5.4a)$$

$$-\bar{K}^q x_{itk}^q \leq z_{itwk}^{A_2} \leq \bar{K}^q x_{itk}^q : (\bar{\beta}_{itwk}^{A_2}, \underline{\beta}_{itwk}^{A_2}), \forall (i \in I^h)twk. \quad (5.4b)$$

In the constraints above \bar{K}^q is a suitably large constant, not too high to create computational instabilities, and not too low to put extra bounds on the variables [111]. Introducing \bar{K}^r , we rewrite (5.1d) and (5.1g) as follows.

$$q_{itw} \leq \hat{Q}_{ik} + \bar{K}^q(1 - x_{itk}^q) : (\nu_{itwk}^{A_2}), \forall (i \in I^h)twk, \quad (5.5a)$$

$$q_{i(t-1)w} - q_{itw} \leq \hat{R}_{ik} + \bar{K}^r(1 - x_{ik}^r) : (\nu_{itwk}^{D_1}), \forall (i \in I^h)twk, \quad (5.5b)$$

$$q_{itw} - q_{i(t-1)w} \leq \hat{R}_{ik} + \bar{K}^r(1 - x_{ik}^r) : (\nu_{itwk}^{D_2}), \forall (i \in I^h)twk. \quad (5.5c)$$

We repeat the linearization steps for other bilinear terms, introducing $z_{itwk}^{D_1} = \mu_{itw}^{D_1} \sum_k x_{ik}^r \hat{R}_{ik}$, $z_{itwk}^{D_2} = \mu_{itw}^{D_2} \sum_k x_{ik}^r \hat{R}_{ik}$, $z_{itwk}^{obj} = q_{itw} \sum_k x_{itk}^c \hat{C}_{ik}$. We form a new set of variables Ω^{MILP} by adding x_{itk}^q , x_{ik}^r , x_{itk}^c , $z_{itwk}^{A_2}$, $z_{itwk}^{D_1}$, $z_{itwk}^{D_2}$, z_{itwk}^{obj} to Ω^{NLP} . The proposed stochastic MILP model is set out in (5.6).

$$\begin{aligned} \text{maximize } \pi = & \sum_{(i \in I^h), w} P_w \left(\sum_t (z_{itwk}^{A_2} + z_{itwk}^{D_1} + z_{itwk}^{D_2} + z_{itwk}^{obj} - C_i^M q_{itw} \right. \\ & \left. + \mu_{itw}^{F_2} M_i - \lambda_{itw}^G (M_i^0 \mathbf{I}(t=1) + V_{it})) + m_{iT_w} \Lambda_i^f \frac{1}{\Gamma_i} \right) \end{aligned} \quad (5.6a)$$

subject to: (5.1e), (5.1f), (5.1h)-(5.1j), (5.4), (5.5),

$$(5.1d), (5.1g), \text{ stationary conditions } \forall i \in I \setminus I^h, \quad (5.6b)$$

$$\mu_{itw}^{A_1}, \mu_{itw}^{A_2}, \mu_{itw}^{D_1}, \mu_{itw}^{D_2}, \mu_{itw}^E, \mu_{itw}^{F_1}, \mu_{itw}^{F_2}, \mu_{itw}^C \geq 0, \quad (5.6c)$$

Linearization of $z_{itwk}^{D_1}$, $z_{itwk}^{D_2}$, z_{itwk}^{obj} as in (5.4), $\forall i \in I^h$,

Linearization of strong duality implication as in (5.4).

5.2.2 Multiple profit-maximizing hydropower producers

Section 5.2.1 described the formulation of a stochastic MILP model for a single profit-maximizing hydropower producer. In this section we discuss, how we can formulate the game of multiple strategic hydropower producers.

In Section 2.2.3 we discussed that Nash equilibrium can be formulated as an optimization problem:

$$\underset{\Omega^{\text{MILP}}}{\text{minimize}} \Delta\pi = \sum_{i \in I^h} \epsilon_i \quad (5.7a)$$

$$\text{subject to: } \pi_i(s_i^*, s_{-i}^*) + \epsilon_i \geq \pi_i(s_i, s_{-i}^*), \quad \forall i \in I^h, \quad (5.7b)$$

$$\epsilon_i \geq 0, \quad \forall i \in I^h \quad (5.7c)$$

At a Nash equilibrium point the deviation ϵ_i is zero for all players. Under uncertainty the profit π_i can be different in different scenarios. There are several ways of how to extend the definition of Nash equilibrium in the case of uncertainty.

Bayesian Nash equilibrium

Each player is assumed to have a subjective uncertainty probability distribution function [46]. This assumption is applicable to the most of the uncertainties observed in the power system, such as wind, reservoir inflows, demand uncertainty. When introducing scenarios w describing the uncertainty, the Nash equilibrium (5.7b) becomes:

$$E_w[\pi_{iw}(s_i^*, s_{-i}^*)] + \epsilon_i \geq E_w[\pi_{iw}(s_i, s_{-i}^*)], \quad \forall i \in I^h. \quad (5.8)$$

Robust Nash equilibrium

Finding robust Nash equilibrium does not require the prior knowledge of probability distribution function for the incomplete information [47]. This is very useful, when certain scenarios have no historic data or when probabilities of the scenarios are difficult to compute. Robust Nash equilibrium uses the worst-case approach, where (5.7b) is reformulated as follows:

$$\min_w[\pi_{iw}(s_i^*, s_{-i}^*)] + \epsilon_i \geq \min_w[\pi_{iw}(s_i, s_{-i}^*)], \quad \forall i \in I^h. \quad (5.9)$$

We introduce π_w^{min} to formulate a mixed-integer reformulation of (5.9):

$$\pi_i^{\text{min}}(s_i^*, s_{-i}^*) + \epsilon_i \geq \pi_i^{\text{min}}(s_i, s_{-i}^*), \quad \forall i \in I^h \quad (5.10)$$

Introducing binary variables x_{iw}^{rob} we ensure that π_i^{min} takes the smallest value in scenarios $\min_w[\pi_{iw}]$:

$$\pi_i^{min} \leq \pi_{iw}, \forall (i \in I^h)ws \quad (5.11a)$$

$$\pi_i^{min} \geq \pi_{iw} - \bar{K}(1 - x_{iw}^{rob}), \forall (i \in I^h)ws, \quad (5.11b)$$

$$\sum_w x_{iw}^{rob} = 1. \quad (5.11c)$$

The profit for the hydropower producer can be derived in a similar way as in (5.2). Extending the formulation by considering the profit in alternative strategies $\pi_{iw}(s_i, s_{-i}^*)$ we can write the whole optimization problem as a stochastic MILP problem (5.12).

$$\underset{\Omega^{MILP}}{\text{minimize}} \quad \Delta\pi = \sum_{i \in I^h} \epsilon_i \quad (5.12a)$$

subject to: NE definition (5.8), or (5.10)-(5.11), $\epsilon_i \geq 0$,

For s_i^* and (s_i, s_{-i}^*) , $\forall i \in I^h$:

$$\{\pi_{iw} = \sum_t (\sum_k (z_{itwk}^{A_2} + z_{itwk}^{D_1} + z_{itwk}^{D_2} + P_w z_{itwk}^{obj}) - C_i^M q_{itw} + \mu_{itw}^{F_2} M_i - \lambda_{itw}^G (M_i^0 \mathbf{I}(t=1) + V_{it})) + m_{iT_w} \Lambda_i^f \frac{1}{\Gamma_i}, \forall (i \in I^h)w, \quad (5.12b)$$

(5.1e), (5.1f), (5.1h)-(5.1j), (5.4), (5.5),

(5.1d), (5.1g), stationary conditions $\forall i \in I \setminus I^h$,

$$\mu_{itw}^{A_1}, \mu_{itw}^{A_2}, \mu_{itw}^C, \mu_{itw}^{D_1}, \mu_{itw}^{D_2}, \mu_{itw}^E, \mu_{itw}^{F_1}, \mu_{itw}^{F_2} \geq 0,$$

Linearization of $z_{itwk}^{D_1}$, $z_{itwk}^{D_2}$, z_{itwk}^{obj} as in (5.4), $\forall i \in I^h$,

Linearization of strong duality as in (5.4)}.

5.3 Solution Approach

In optimization problem (5.6), if we fix binary variables x_{itk}^q , x_{ik}^r and x_{itk}^c , the problem separates in a series of linear programs which can be solved in parallel. For the stochastic MILP problem in (5.12) fixing the binary variables results in a linear program, partly decomposable by blocks in case of the robust Nash equilibrium.

Benders decomposition is commonly used for mixed-integer program, as it allows dealing with complicating variables. In this section we propose

Modified Benders Decomposition Algorithm (MBDA). In Section 5.5 we compare it numerically with alternative Benders approaches (as described in Section 2.4) and with solution by CPLEX solver. In this section we discuss subproblem and master problem based on the model of a single profit-maximizing generator. The corresponding derivations for the case of multiple strategic hydropower producers are provided in [J4].

Modified subproblem corresponding to initial MILP (5.6) can be formulated as follows:

$$\begin{aligned} \text{maximize } \pi^{dual} = & \sum_w P_w \sum_t \left(\phi_{tw}^B \sum_n D_{ntw} - \sum_l \nu_{ltw}^C (F_l + \sum_n H_{ln} D_{ntw}) - \right. \\ & \sum_{i \in I \setminus I^h} \phi_{itw}^{stq} C_i - \sum_{i \in I^h} \phi_{itw}^{stq} \sum_k \hat{C}_{ik} \check{x}_{ik}^c - \sum_{i \in I \setminus I^h} \phi_{itw}^{A_2} Q_i - \sum_{i \in I^h} \phi_{itw}^{A_2} \sum_k \hat{Q}_{ik} \\ & - \sum_{i \in I \setminus I^h} (\phi_{itw}^{D_1} + \phi_{itw}^{D_2}) R_i - \sum_{i \in I^h} (\phi_{itw}^{D_1} + \phi_{itw}^{D_2}) \sum_k \hat{R}_{ik} - \sum_{i \in I^h} \phi_{itw}^{F_2} M_i + \\ & \left. \sum_{i \in I^h} \phi_{itw}^G (M_i^0 \mathbf{I}(t=1) + V_{itw}) \right), \end{aligned} \quad (5.13a)$$

$$\begin{aligned} \text{subject to: } \sum_{(i \in I^h), t, w, k} & \left(((1 - \check{x}_{itk}^q) (\nu_{itwk}^{A_2} + \bar{\alpha}_{itwk}^{A_2} + \underline{\alpha}_{itwk}^{A_2}) + \check{x}_{itk}^q (\bar{\beta}_{itwk}^{A_2} + \underline{\beta}_{itwk}^{A_2})) \right. \\ & + ((1 - \check{x}_{ik}^r) (\nu_{itwk}^{D_1} + \bar{\alpha}_{itwk}^{D_1} + \underline{\alpha}_{itwk}^{D_1}) + \check{x}_{ik}^r (\bar{\beta}_{itwk}^{D_1} + \underline{\beta}_{itwk}^{D_1})) \\ & + ((1 - \check{x}_{ik}^r) (\nu_{itwk}^{D_2} + \bar{\alpha}_{itwk}^{D_2} + \underline{\alpha}_{itwk}^{D_2}) + \check{x}_{ik}^r (\bar{\beta}_{itwk}^{D_2} + \underline{\beta}_{itwk}^{D_2})) \\ & \left. + ((1 - \check{x}_{itk}^c) (\bar{\alpha}_{itwk}^{obj} + \underline{\alpha}_{itwk}^{obj}) + \check{x}_{itk}^c (\bar{\beta}_{itwk}^{obj} + \underline{\beta}_{itwk}^{obj})) \right) = 0, \end{aligned} \quad (5.13b)$$

$$\Omega^{SP} \in X. \quad (5.13c)$$

The feasible region X includes stationary conditions for all variables of (5.6) with fixed binary variables and dual feasibility constraints. We observe that both feasible region and the objective function of the subproblem are free from the disjunctive parameters.

Using the special form of the disjunctive constraints, we can formulate the modified master problem. We use an observation that disjunctive constraints require that solutions to a mathematical program satisfy a subset of given constraints. Therefore, all constraints can be distributed in two sets: relaxed and enforced constraints, depending on the value of the binary variables x_{itk}^q , x_{ik}^r , x_{itk}^c . We propose the following formulation, where disjunctive parameters

are removed.

$$\underset{x_{itk}^q, x_{ik}^r, x_{itk}^c, \theta_j}{\text{minimize}} \quad K_0\theta_0 + \sum_j K_j\theta_j \quad (5.14a)$$

$$\begin{aligned} \text{subject to: } \quad & \sum_{i,k \in \Omega_j^p} \left(\sum_t ((1-x_{itk}^q) + (1-x_{itk}^c)) + (1-x_{ik}^r) \right) \\ & \leq |\Omega_j^p| - 1 + \sum_{j' \in J'} \theta_{j'} \mathbf{I}(K_j \leq K_{j'}), \forall j, \end{aligned} \quad (5.14b)$$

$$\sum_k x_{itk}^q = 1, \sum_k x_{ik}^r = 1, \sum_k x_{itk}^c = 1, \forall (i \in I^h)t, \quad (5.14c)$$

$$\theta_0 + \sum_j \theta_j = 1, \quad \{x_{itk}^q, x_{ik}^r, x_{itk}^c, \theta_j\} \in \{0, 1\}. \quad (5.14d)$$

In optimization problem (5.14), parameter $K_j = \sum_w P_w \tilde{\pi}_{wj}^{dual}$ where $\tilde{\pi}_{wj}^{dual}$ is a calculated objective function of (5.13). Also parameter $K_0 = -\infty$ is the lower bound of (5.14). θ_j is an auxiliary binary variable, created at every iteration. J' is the index set of previous iterations and j is the index of current iteration. If we define $\Omega = \{\bar{\alpha}_{itwk}^{A_2}, \underline{\alpha}_{itwk}^{A_2}, \bar{\beta}_{itwk}^{A_2}, \underline{\beta}_{itwk}^{A_2}, \bar{\alpha}_{itwk}^{D_1}, \underline{\alpha}_{itwk}^{D_1}, \bar{\beta}_{itwk}^{D_1}, \underline{\beta}_{itwk}^{D_1}, \bar{\alpha}_{itwk}^{D_2}, \underline{\alpha}_{itwk}^{D_2}, \bar{\beta}_{itwk}^{D_2}, \underline{\beta}_{itwk}^{D_2}, \bar{\alpha}_{itwk}^{obj}, \underline{\alpha}_{itwk}^{obj}, \bar{\beta}_{itwk}^{obj}, \underline{\beta}_{itwk}^{obj}, \nu_{itwk}^{A_2}, \nu_{itwk}^{D_1}, \nu_{itwk}^{D_2}\}$, then Ω_j^p is the index set of strictly positive variables of Ω in iteration j . $|\Omega_j^p|$ is the cardinality of this set.

5.4 Illustrative case studies

The models formulated in Section 5.2 allow us to model the strategic behavior of hydropower producers in the systems with high levels of wind power uncertainty. Publication [J3] presents several illustrative case studies, highlighting the possibilities for the exercise of market power by hydropower producer. In [J4] we explore possible Nash equilibria, which may occur under uncertainty. Below we present some of our findings.

5.4.1 The impact of forecast future water price on price bidding of hydropower producer

The opportunity cost of the hydropower producer depends on the future expected prices. For hydropower producer the cost today is the benefit

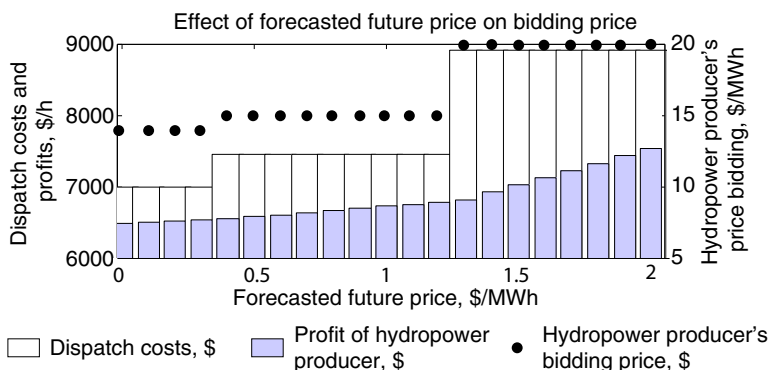


Figure 5.1: Study of future price effect on dispatch cost and profits.

obtained by using the water tomorrow [106]. This benefit is calculated using the best available optimization techniques and historic data, and determines how much water should be saved today in order to be used tomorrow. The price-quantity bids of a hydropower producer are based on the result of these calculations.

The stochastic MILP model (5.6) is used to study the impact of forecast future price on the price bidding of a hydropower producer. We should note that forecast is very much dependent on the availability of data on wind power. In wind-integrated power systems this forecast may be very rough. In Figure 5.1, the forecast future price Λ_i^f in (5.6) is varied between \$0/MWh and \$2/MWh. We observe that the price bid of the strategic hydropower producer depends on the forecast future price.

The price bid of the strategic hydropower producer changes between three values of \$14, \$15 and \$20/MWh. This means that in proximity of these steps the sensitivity of price bid to the forecast future price is very high. The same holds for the dispatch cost. For example, the strategic hydropower producer bids \$15 and \$20/MWh for forecast future prices \$1.2/MWh and \$1.3/MWh, respectively. This results in \$1450 (+19.5%) increase in the dispatch cost for just \$0.1/MWh (+7.7%) increase in the forecast future price. This shows the sensitivity of dispatch cost with respect to the forecast future price. Accordingly, the accuracy of forecast future price can have a severe impact on price bidding of a strategic hydropower producer.

5.4.2 Strategic behavior in price, quantity and ramp-rate bids

The optimization model (5.6) can be used to derive the price, quantity and ramp-rate bids of the hydropower producer (Figure 5.2-(a)). The strategic bids increase the profit of hydropower producer above its competitive level. In Figure 5.2-(b), 5.2-(c), and 5.2-(d) the profit increase with respect to wind generation level and its standard deviation is shown.

We observe that all three types of bid have an important effect on the dispatch cost. Strategic behavior in quantity and price (Figure 5.2-(b) and 5.2-(c)) produce similar results. This is because both of them can be used by the strategic hydropower producer to drive the price to the highest possible value. We also see that strategic behavior in ramp-rate bidding has an important

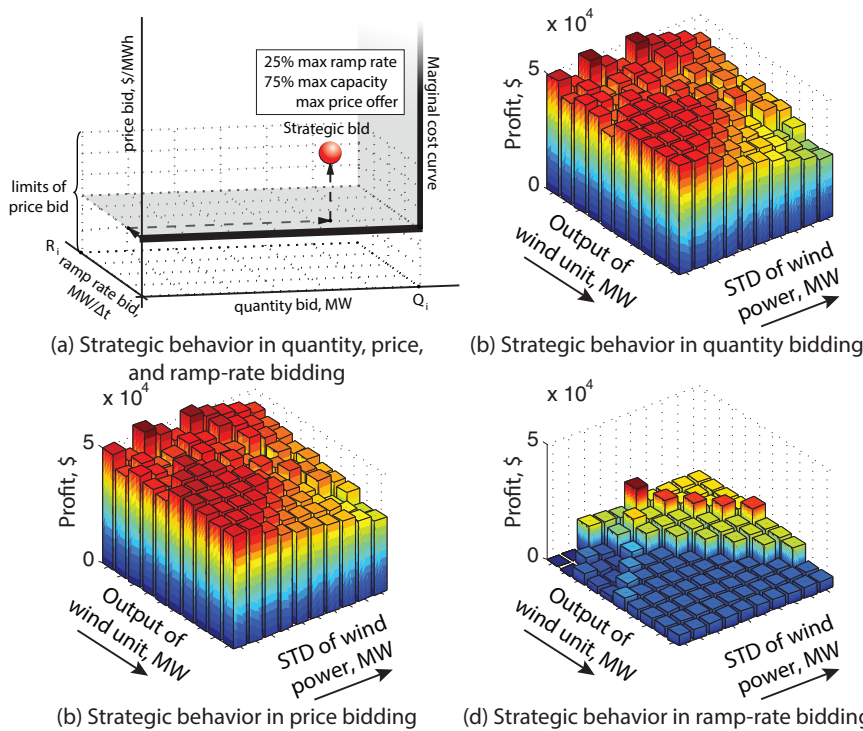


Figure 5.2: Increase in hydropower producer’s profit, resulting from strategic bidding on quantity, price and ramp rate. STD: standard deviation.

effect even when the other two types of strategic bids are not employed (Figure 5.2-(d)). This happens in the systems with limited flexibility, where there are not many fast-ramping generators. In our simulations, the strategic hydropower producer is the main provider of system flexibility. Therefore its strategic behavior in ramp-rate bidding leads to the increase in its profit and market prices.

5.4.3 Comparison of Nash equilibria

Since a multitude of solutions is difficult in interpretation, the policy makers and market participants would often prefer to have a single Nash equilibrium reference that can characterize the market situation. This is sometimes implemented with a concept of the best/worst Nash equilibrium [45]. We implement this by extending the objective function (5.12a) by minimization/maximization of the total social costs in the system correspondingly. In this section we analyze the strategic behavior, as different concepts of Nash equilibrium introduced in Section 5.2 are applied.

We compare the results from the best and worst Nash equilibria in Table 5.1: we provide the bids offered by the strategic hydropower producers to the market operator (bold values show withholding), profits, and dispatch cost corresponding to the different Nash equilibria. The following observations can be made:

- **Bids:** Withholding occurs in both types of Nash equilibria. There is more withholding if we consider the worst Nash equilibria, resulting in higher profits for the strategic generators. Worst Nash equilibria (high social costs) – is usually the result from high market prices.
- **Profits of strategic generators:** The profits in Bayesian Nash equilibrium are higher, than in the robust Nash equilibrium. In robust Nash equilibrium strategic bid is optimal for the worst-case scenario, while for Bayesian Nash equilibrium all scenarios are taken into account.
- **Social costs span:** The difference between the worst and the best Nash equilibria is the largest for the robust Nash equilibria. For robust Nash equilibrium we only consider the worst-case scenario, therefore we do not consider if the chosen strategy holds as a Nash equilibrium for another scenario. This provides more flexibility for the strategic generator when choosing its strategy.

Table 5.1: Comparison of Bayesian and robust best and worst Nash equilibria. DC: dispatch cost.

		Bayesian		Robust	
		best	worst	best	worst
Capacity bid, \hat{q} , MW	G3	100	100	100	75
	G4	25	50	75	100
Ramp-rate bid, \hat{r} , $\frac{MW}{\Delta t}$	G3	10	10	10	2.5
	G4	10	7.5	10	5
Price bid, \hat{c} , $\frac{\$}{MWh}$	G3	20	20	15	20
	G4	20	35	20	35
Profit, $\sum_w \pi_{iw}$, $\$$	G3	4637.5	5400	2845	4500
	G4	287.5	287.5	100	250
DC, $\$$		4950	5250	3890	5700

Different types of Nash equilibrium can be used depending on the modeling goals. We can interpret from the results that Bayesian Nash equilibrium is more consistent with realistic behavior, assuming that the probability distributions of the uncertain parameters are known. Robust Nash equilibrium can be applied, when the probability distribution functions of the uncertain parameters are impossible to obtain (e.g., if the event does not have a historical data).

5.5 Numerical results

The performance is evaluated in [J3] and [J4] using the 4-, 24-, 118- and 300-node case studies, obtained from MATPOWER [112]. Simulations for [J3] are performed on a computer with two 2.80 GHz CPU and 8 GB of RAM, while for [J4] we use a computer with 18 cores with hyper-threading Intel Xeon E5-2699 CPU and 128 GB of RAM. In order to improve the performance, the parallelized MBDA is implemented in GAMS using the grid solve and Gather-Update-Scatter-Solve (GUSS) facilities. A detailed explanation of these facilities is provided in [113].

We assume 4 time periods and strategic hydropower producer has 3 actions for each type of the bid (19683 possible combinations for bidding). Additionally, uncertainty in each time period is represented by 20 stochastic scenarios. The scenarios for our simulations have been generated from the real data using the moment-matching technique [81], obtained from Nord

Pool [114] and processed to fit the case studies. The numerical results in [J3] and [J4] prove the computational efficiency of the proposed MBDA approach. We conclude that disjunctive parameter, which is present in primal and dual Benders approaches has an important numerical effect. Primal and dual Benders do not converge after 10 hours of simulation.

We also compare MBDA to the state-of-the-art MILP solver – CPLEX. While CPLEX is better for smaller case studies it considerably underperforms on larger case studies, e.g. 118-node IEEE case study. The reason is in the solution procedure, having large memory requirements. Full evaluation of the numerical results and time quotes are provided in [J3] and [J4].

5.6 Conclusion

One of the reasons, why exercise of market power can be present in wind-integrated power systems, is due to strong fluctuations in supply. Such fluctuations need to be balanced by fast-ramping generators. The role of such flexible generators (especially in the Nordic region) is on hydropower producers, able to ramp up and down quickly to cover the wind power intermittency. It is commonly assumed that hydropower producers are price-takers, deciding their price bids based on price forecasts and future value of water in the reservoirs. However, in this chapter we find out that the crucial role of hydropower producers implies an advantageous position, which can be exploited in order to exercise market power.

In this chapter we derive two stochastic bilevel programs for strategic bidding of hydropower producers. The upper level is one or multiple strategic hydropower producers, bidding their price, quantity and ramp rate to the lower-level system operator. Using a disjunction-based linearization technique the stochastic bilevel program is reformulated as a stochastic MILP with disjunctive constraints. To solve the reformulated stochastic MILP model, the modified Benders decomposition algorithm is proposed. The proposed solution algorithm does not require the optimal tuning of disjunctive parameters and it can be parallelized. The computational efficiency of the parallelized MBDA is demonstrated using the 118-node and 300-node case studies. We have also compared our parallelized MBDA with the state-of-the-art CPLEX solver.

Through an illustrative example system and the developed stochastic MILP model, we identify possible strategies specific to hydropower producers for maximizing the profit. We also study the outcome of Nash equilibrium under uncertainty by applying Bayesian and robust Nash equilibria approaches.

Chapter 6

Lessons for market design in wind-integrated power systems

In previous chapters we have seen that exercise of market power on ramp rate is an important issue in wind-integrated power systems. In this chapter we study how market design can create incentives for generators to behave strategically or competitively. This chapter is based on publication [J2].

6.1 Introduction

With a high wind power share, when generation suddenly departs from the dispatched level it is very important that there are enough of fast-ramping generators, able to sustain the energy balance [115]. We have seen in the previous chapters that a lack of such generators, or their strategic behavior may result in price spikes. The higher the ramping gradient that a power plant can cover, the fewer plants are needed to meet a given net load ramp, thus leading to less minimum generation per ramping [116]. There is a variety of market designs created in the deregulated framework taking into account the limitations of the units: markets in PJM Interconnection, New York Independent System Operator (NYISO) and New England electricity markets involve multi-dimensional auctions, so that participants specify technical constraints during the dispatch.

There is a thorough analysis in [117], showing that preventing gaming on ramp rates is a difficult task and there are no commonly adopted instruments that guarantee to prevent gaming behavior. One of the techniques to avoid

the manipulation is to allow ramp-rate constraints to change only once a month, or some other suitable time interval, as adopted, for example, in California [118]. The “NYISO Market Participants User’s Guide” states that regulation movement (MW/6 sec) response rate can be updated in three business days [119]. While this has a very little theoretical foundation, the purpose is to prevent generators from responding to the market conditions with false ramp rates. The expected effect would be that, exposed to the uncertainty and high competition, generators would bid the true ramp rate constraints. However, such a mitigating strategy allows a company to specify a deceptive constraint for the whole period in which the ramp constraint can be changed: a regulatory agency often cannot certify the constraint as generators are usually allowed to bid to several markets and may divide their ramping capability between the markets [117]. A different strategy is adopted for example in Nordic electricity market, where generators are free choosing the ramp rate between their flexible orders. To the best of our knowledge there is no research evaluating the efficiency of separating the market stages of production and ramp bids with respect to market power considerations.

In this paper we study the practical implications of separating the stages of a strategic decision as a technique to mitigate the exercise of market power. We model a day-ahead market and allow generators to specify the ramp-rate level as a part of their offers. We use two types of models: a single-stage equilibrium model, corresponding to taking the strategic decision regarding a ramp-rate level and produced quantity simultaneously; and a two-stage model, in which generators choose their ramp rates in the first stage and compete in quantities in the second stage. A single-level setup can be reflected by a complementarity problem formulation (linear – LCP, or mixed – MCP) [120, 121], while a bilevel setup takes a form of an equilibrium problem with equilibrium constraints (EPEC) [103].

6.2 Methodology

Equilibrium models are often employed to represent the nature of market interactions and competition between the strategic generators [122]. In this section we explore the impact of flexibility of power generation on market outcomes. In particular, we compare two different market setups represented by two models: a model that considers the case when ramp-rate and production decisions are taken simultaneously; and a model in

which ramp rate is decided first, and then production decisions are taken. We employ a conjectured-price response parameter, which is immediately obtained from the conjectural variations model, capturing various degrees of strategic behavior in the spot market. Conjectural variations [21, 31] reflect the firm's conjecture about other firms' reaction to a change in its production. This representation allows us to express the special cases of oligopolistic behavior ranging from perfect competition to a Cournot oligopoly [32].

6.2.1 Simultaneous ramp and quantity bidding: the one-stage model

In the single-stage model, every generating unit i faces a profit-maximization problem: in time period t it chooses the level of production q_{it} . The ramp-rate level r_i is chosen simultaneously with the production level in the first time period and stays constant throughout the modeling horizon. The objective of the generator is to maximize the revenues in the production stage minus the costs. Parameter c represents the symmetric marginal production cost.

In order to derive the analytic results in this section, let us assume that there are two consecutive time periods: t_1 and t_2 . The optimization problem of a company i can be formulated as follows:

$$\forall i : \begin{cases} \underset{q_i, r_i}{\text{maximize}} (p_{t_1}(q_{it_1}, q_{-it_1}) - c)q_{it_1} + (p_{t_2}(q_{it_2}, q_{-it_2}) - c)q_{it_2} & (6.1a) \\ \text{subject to: } \hat{Q} \geq q_{it} \geq 0 & : \bar{\mu}_{it}, \underline{\mu}_{it} \quad \forall t & (6.1b) \\ \hat{R} \geq r_i \geq 0 & : \bar{\lambda}_i, \underline{\lambda}_i & (6.1c) \\ r_i \geq q_{it_2} - q_{it_1} & : \bar{\gamma}_i & (6.1d) \\ q_{it_1} - q_{it_2} \geq r_i & : \underline{\gamma}_i & (6.1e) \end{cases}$$

In the optimization problem above \hat{Q} is the symmetric installed capacity of the generating unit i and \hat{R} is the maximum technically possible ramp rate. Constraints (6.1d)-(6.1e) show that the change of production between two time periods is limited by the ramp rate. These constraints are specified for the time steps following the first one ($|t| > 1$). The variables on the right are the dual variables associated with constraints (6.1b)-(6.1e).

Prices $p_t(q_i, q_{-i})$ come from the market equilibrium (ME) conditions that link optimization problems of all producers: energy balances for both load periods and the affine definition of the elastic demand d_t , where α is the

elasticity parameter.

$$\text{ME : } d_t = \sum_i q_{it}, \quad d_t = D_t^0 - \alpha p_t(q_{it}, q_{-it}) \quad \forall t. \quad (6.2)$$

The ME conditions mimic the economic dispatch problem of the system operator. These conditions define the price $p_t(q_{it}, q_{-it})$, dependent on the production q_{it} of the generating companies. The demand elasticity α reflects the price responsiveness of the consumers in the market. This formulation aims at reflecting the market setups used in most of the countries with liberalized electricity markets [51]. Choosing arbitrary the case of increasing demand allows us to remove the constraint (6.1e) from our model as it will be inactive. Since only two time periods are considered, the declared up-rate will be equal to the increased production without loss of generality. The production in the second time period can therefore be expressed as:

$$q_{it_2} = q_{it_1} + r_i. \quad (6.3)$$

Since electricity is a perfectly substitutable good, we can capture a range of behavioral outcomes by conjectural variations in the short-run market formulation, as first introduced in [123]. Conjectural variation is the belief that one firm has about the way its competitors may react if it varies its output or price. This approach attempts to reproduce the dynamic pricing in a “reduced-form” static competition, therefore we are specifying exogenously the reaction of the firms to their rivals. This approach is criticized for the the exogenous nature of the conjectural variations [33], but it allows us to capture a range of behavioral outcomes – from competitive to cooperative and has one parameter which has a simple economic interpretation. We define a conjectured price response parameter θ_i as a company i ’s belief concerning its influence on price $p_t(q_{it}, q_{-it})$ in a short-term spot market. We express the conjectured price response as:

$$\theta_i = - \frac{dp_t(q_{it}, q_{-it})}{dq_{it}}.$$

This parameter only captures the effect of change in q_{it} and not r_i . By considering only conjectured price response on production we express the type of competition in either of the ramping and the energy markets.

Different levels of the conjectured price response parameter correspond to different market structures. We assume θ_i varying from 0, which corresponds

to perfect competition in the market to $(1/\alpha)$, which represents the Cournot oligopoly [124]. By choosing the conjectured price response parameter to vary in this range we study the behavioral outcomes most common in electricity markets. Further, in this section we assume symmetric conjectured price responses $\theta = \theta_1 = \theta_2$.

The Lagrangian function of problem (6.1) for producer i is:

$$\mathcal{L}_i = (p_{t_1}(q_{it_1}, q_{-it_1}) - c)q_{it_1} + (p_{t_2}(q_{it_2}, q_{-it_2}) - c)q_{it_2} + \sum_t (\bar{\mu}_{it}(\hat{Q} - q_{it}) + \underline{\mu}_{it}q_{it}) + \bar{\lambda}_i(\hat{R} - r_i) + \underline{\lambda}_i r_i + \bar{\gamma}_i(r_i - q_{it_2} + q_{it_1}).$$

Although parameter θ is implicit in formulation (6.1) it becomes explicit when we solve the problem by taking the KKT conditions, which are equivalent to the original optimization problem.

We substitute the first derivative of price by θ and use the dual multipliers introduced previously. Note that \perp denotes the complementarity between the constraint and its respective dual variable. The KKT conditions of the problem (6.1) are as follows:

$$\forall i : \left\{ \begin{array}{l} \frac{\partial \mathcal{L}_i}{\partial q_{it_1}} = p_{t_1} - \theta q_{it_1} - c + \underline{\mu}_{it_1} - \bar{\mu}_{it_1} + \bar{\gamma}_i = 0 \quad (6.4a) \\ \frac{\partial \mathcal{L}_i}{\partial q_{it_2}} = p_{t_2} - \theta q_{it_2} - c + \underline{\mu}_{it_2} - \bar{\mu}_{it_2} - \bar{\gamma}_i = 0 \quad (6.4b) \\ \frac{\partial \mathcal{L}_i}{\partial r_i} = \underline{\lambda}_i - \bar{\lambda}_i + \bar{\gamma}_i = 0 \quad (6.4c) \\ 0 \leq \underline{\mu}_{it} \perp q_{it} \geq 0 \quad \forall t \quad (6.4d) \\ 0 \leq \bar{\mu}_{it} \perp \hat{Q} - q_{it} \geq 0 \quad \forall t \quad (6.4e) \\ 0 \leq \underline{\lambda}_i \perp r_i \geq 0 \quad (6.4f) \\ 0 \leq \bar{\lambda}_i \perp \hat{R} - r_i \geq 0 \quad (6.4g) \\ 0 \leq \bar{\gamma}_i \perp r_i - q_{it_2} + q_{it_1} \geq 0 \quad (6.4h) \end{array} \right.$$

$$d_t = \sum_i q_i, \quad d_t = D_t^0 - \alpha p_t \quad \forall t. \quad (6.5)$$

For the case, when $\hat{Q} > q_{it} > 0$ and $\hat{R} > r_i > 0$, the dual multipliers $\underline{\mu}_{it}$, $\bar{\mu}_{it}$ and $\underline{\lambda}_i$, $\bar{\lambda}_i$ are equal to zero and we can solve a system of equations:

$$\forall i : \left\{ \begin{array}{l} \frac{D_{t_1}^0 - \sum_i q_{it_1}}{\alpha} - \theta q_{it_1} - c + \bar{\gamma}_i = 0, \\ \frac{D_{t_2}^0 - \sum_i (q_{it_1} + r_i)}{\alpha} - \theta (q_{it_1} + r_i) - c - \bar{\gamma}_i = 0, \\ \bar{\gamma}_i = 0. \end{array} \right.$$

This set of equations can be simplified to the following:

$$\forall i : \begin{cases} D_{t_1}^0 - \sum_i q_{it_1} \alpha - \alpha \theta q_{it_1} - \alpha c = 0, \\ D_{t_2}^0 - \sum_i (q_{it_1} + r_i) - \alpha \theta (q_{it_1} + r_i) - \alpha c = 0 \end{cases}$$

We can derive a closed-form solution for the optimal production level and the ramp rate, as presented below. Note that *SL* indicates “single level”, since the solution corresponds to the single-stage equilibrium model where ramp and production decisions were taken simultaneously:

$$r_i^{SL} = \frac{D_{t_2}^0 - D_{t_1}^0}{\alpha \theta + 2}, \quad (6.6a)$$

$$q_{it_1}^{SL} = \frac{D_{t_1}^0 - \alpha c}{\alpha \theta + 2}, \quad q_{it_2}^{SL} = q_{it_1}^{SL} + r_i^{SL}. \quad (6.6b)$$

6.2.2 Separated stages of ramp and quantity bidding: the two-stage model

The market setup, where the generators choose their ramp rate in the first stage and compete in quantities in the second stage, can be modeled using a bilevel equilibrium formulation – EPEC. The bilevel structure aims to represent the market situation when ramp bidding occurs before the actual quantity game. The EPEC problems, known for their complexity, are hard to solve in a closed form. Similar to the previous single-level model, we study the case of two load periods with increasing demand and two symmetric power producers.

In the first stage of the game, the generating units take their decisions regarding the ramp-rate levels that will maximize their profits taking into account the optimal production decisions from the second stage. The upper level of a bilevel model representing the ramp game can be formulated as follows:

$$\forall i : \begin{cases} \underset{r_i}{\text{maximize}} (p_{t_1}(q_{it_1}, q_{-it_1}) - c)q_{it_1} + (p_{t_2}(q_{it_2}, q_{-it_2}) - c)q_{it_2} & (6.7a) \\ \text{subject to:} & \hat{R} \geq r_i \geq 0 \quad : \bar{\lambda}_i, \underline{\lambda}_i & (6.7b) \\ & q_{it} \in \Omega^{LL}. & (6.7c) \end{cases}$$

Quantity q_{it} is an outcome of the lower-level Ω^{LL} market equilibrium game:

$$\forall i : \begin{cases} \text{maximize}_{q_i} (p_{t_1}(q_{it_1}, q_{-it_1}) - c)q_{it_1} + (p_{t_2}(q_{it_2}, q_{-it_2}) - c)q_{it_2} & (6.8a) \\ \text{subject to:} & \hat{Q} \geq q_{it} \geq 0 \quad : \bar{\mu}_{it}, \underline{\mu}_{it} \quad \forall t & (6.8b) \\ & r_i \geq q_{it_2} - q_{it_1} \quad : \bar{\gamma}_i. & (6.8c) \end{cases}$$

The market equilibrium conditions link together the optimization problems of the generators:

$$\text{ME} : d_t = \sum_i q_i, \quad d_t = D_t^0 - \alpha p_t \quad \forall t. \quad (6.9)$$

Let us first focus on the lower-level problem (6.8). Following the same logic as in the single-level model we can show that the second derivative of the objective function is negative and the constraint qualification holds. Hence, the problem (6.8) can equivalently be written and solved as a set of KKT conditions. The KKT conditions take a form:

$$\forall i : \begin{cases} \frac{\partial \mathcal{L}_i}{\partial q_{it_1}} = p_{t_1}(q_{it_1}, q_{-it_1}) - \theta q_{it_1} - c + \underline{\mu}_{it_1} - \bar{\mu}_{it_1} + \bar{\gamma}_i = 0 & (6.10a) \\ \frac{\partial \mathcal{L}_i}{\partial q_{it_2}} = p_{t_2}(q_{it_2}, q_{-it_2}) - \theta q_{it_2} - c + \underline{\mu}_{it_2} - \bar{\mu}_{it_2} - \bar{\gamma}_i = 0 & (6.10b) \\ 0 \leq \underline{\mu}_{it} \perp q_{it} \geq 0 \quad \forall t & (6.10c) \\ 0 \leq \bar{\mu}_{it} \perp \hat{Q} - q_{it} \geq 0 \quad \forall t & (6.10d) \\ 0 \leq \bar{\gamma}_i \perp r_i - q_{it_2} + q_{it_1} \geq 0 & (6.10e) \end{cases}$$

In order to obtain a closed-form solution we follow a backward induction. We first find the optimal solution of the lower level parameterized by the upper-level variable. Then, we plug this expression in the upper-level and deduce a subgame-perfect Nash equilibrium (SPNE) – an equilibrium, which is optimal for both stages and for the game as a whole, [125]. This concept is often used for describing the sequence of decisions in the electricity market, as for example in the case of forward price caps in [126]. We express the prices in time periods t_1 and t_2 from the market equilibrium conditions (6.9) and use them to complement the equations (6.10).

Simplifying and solving the system (6.10) for the optimal level of quantity parameterized by the r_i variable, we get:

$$\forall i : \begin{cases} \frac{\partial \mathcal{L}_i}{\partial q_{it_1}} = \frac{D_{t_1}^0 - \sum_i q_{it_1}}{\alpha} - \theta q_{it_1} - c + \bar{\gamma}_i = 0 \\ \frac{\partial \mathcal{L}_i}{\partial q_{it_2}} = \frac{D_{t_2}^0 - \sum_i (q_{it_1} + r_i)}{\alpha} - \theta (q_{it_1} + r_i) - c - \bar{\gamma}_i = 0 \end{cases}$$

Summing up the expressions for two time periods, and solving the resulting system of equations for two producers we get the following:

$$q_{it_1}^{BL} = \frac{D_{t_1}^0 + D_{t_2}^0 - 2\alpha c - r_i(2 + \alpha\theta)}{2\alpha\theta + 4}, \quad q_{it_2}^{BL} = q_{it_1}^{BL} + r_i \quad \forall i. \quad (6.11)$$

Note that *BL* indicates “bilevel”, since this solution for quantities corresponds to the bilevel equilibrium model, and helps distinguish it from q^{SL} .

We can substitute q_{it_1} in (6.7) by the derived lower-level optimal expression for the production level (6.11). The expression for the bilevel-optimal ramp-rate level becomes:

$$\begin{cases} -D_{t_1}^0 + D_{t_2}^0 - 2r_{i_1} - r_{i_2} = 0 \\ -D_{t_1}^0 + D_{t_2}^0 - r_{i_1} - 2r_{i_2} = 0 \end{cases} \rightarrow r_i^{BL} = \frac{D_{t_2}^0 - D_{t_1}^0}{3}. \quad (6.12)$$

We observe that the expression for the optimal level of ramp rate in two-stage model is independent from the conjectured price response parameter θ . In the next section we discuss this result and compare the single-stage and two-stage models.

6.2.3 Discussing the results

The solutions derived in Sections 6.2.1 and 6.2.2 provide us with important insights on strategic decisions regarding the ramp-rate flexibility. In the following propositions we sum up our observations.

Proposition 1.1. *For two time periods, two symmetric generators with affine cost functions and perfectly substitutable products we find that the optimal level of ramp rate for the two-stage model is independent from the conjectured price response parameter θ , representing any market structure from perfect competition to the Cournot oligopoly. In particular, this can be observed for the ramp-rate level as given in (6.12).*

Proof. Section 6.2.2 proves the above proposition by deriving the closed-form solution to the two-stage model. The expression is derived assuming the nontrivial solution $\hat{Q}_i > q_{it} > 0$ and $\hat{R}_i > r_i > 0$. \square

Proposition 1.2. *Using the same assumptions as for the Proposition 1, we observe that in the one-stage model the level of ramp rate offered to the market varies with the level of competition, represented by the conjectured price response: (a) the levels of ramp-rate of single- and two-stage setups coincide when the market structure approaches Cournot ($\theta = 1/\alpha$); (b) in the case of perfect competition the ramp-rate level in a single-stage model is higher than in a two-stage model.*

Proof. (a) The optimal two-stage model ramp rate is given by expression (6.12) and is independent of the conjectured price response θ . The expression (6.6a) for an optimal ramp-rate level in a one-stage model depends on θ . However, if in the second expression we substitute $\theta = 1/\alpha$, which is the conjectured price response corresponding to the Cournot oligopoly, expressions (6.6a) and (6.12) coincide. (b) We can show that for any other choice of $\theta < 1/\alpha$ the optimal level of ramp rate in a single-stage model is higher, as the denominator of the expression (6.6a) is smaller than the denominator of the expression (6.12). Expressed mathematically, $\alpha\theta + 2 \leq 3$. \square

According to Proposition 1.1, if ramp-rate and quantity levels are decided sequentially and the producers hold conjectures on production, strategic producers are going to withhold the ramp rate regardless of their beliefs on the competition level in the spot market, since doing this improves total profits for the generators. This contradicts the logic of regulatory approaches that separate the two decision stages in order to incentivize producers to allow more ramp-rate flexibility in the second stage. Comparing expressions (6.6a) and (6.12) we see that the maximum value for $\alpha\theta$ in the denominator of (6.6a) is 1, and therefore if the generators are deciding their ramp rates before the spot market, the formulation for the optimal ramp rate takes the form of (6.12). We show theoretically that if the generators are able to behave strategically they do so in the first stage, withholding their ramp rate, therefore limiting the amount of production in the second stage for any degrees of market competition. We investigate this further using a case study in Section 6.4.

Proposition 1.2 shows that the optimal ramp-rate levels in two-stage and single-stage setups coincide in the case of Cournot oligopoly. However, for any other belief regarding the competition level in the market we can show that allowing offering the production and ramp simultaneously yields higher ramp-rate flexibility offered by the generators. The result, shown for the case

of two load periods and symmetric generators may hold for a bigger case study as it will be shown in Section 6.4.

In contrast, in the two-stage model ramping creates an additional layer of strategic behavior. Production variables are connected with ramp-rate variable through an inequality constraint. The intuition can be that in the two-stage model strategic firm tries to recover in the upper level the market power lost with more competitive energy markets expressed in the conjectural variations in the lower level. A conclusion of this intuition would be that there is nothing to recover in the Cournot model and hence the results of the single and two stage model coincide for that assumption. Ramping is the only way to recover the lost market power in perfect competition, this is possibly why the two results diverge the most.

6.3 Extension of the models

We can extend the models presented in Section 6.2 to consider a more realistic market situation with an arbitrary number of load periods and asymmetric firms.

6.3.1 Extended formulation of the single-level equilibrium problem

We introduce a parameter c_i^R , a cost of pre-committing the ramp rate. There are two reasons for including this cost. Including such a cost in the objective function reflects the wear-and-tear of the fast-ramping generating units if considered by the generating company. The single-level formulation, introduced in Section 6.2.1 can then be written as:

$$\forall i : \left\{ \begin{array}{ll} \text{maximize}_{q_{it}, r_{it}} & \sum_t \left((p_t(q_{it}, q_{-it}) - c_i)q_{it} - c_i^R r_{it} \right) \quad (6.13a) \\ \text{subject to:} & \hat{Q}_i \geq q_{it} \geq 0 : \bar{\mu}_{it}, \underline{\mu}_{it} \quad \forall t \quad (6.13b) \\ & \hat{R}_i \geq r_{it} \geq 0 : \bar{\lambda}_{it}, \underline{\lambda}_{it} \quad (6.13c) \\ & r_{it} \geq q_{it} - q_{i(t-1)} : \bar{\gamma}_{it} \quad (6.13d) \\ & r_{it} \geq q_{i(t-1)} - q_{it} : \underline{\gamma}_{it} \quad (6.13e) \\ & d_t = D_t^0 - \alpha p_t(q_{it}, q_{-it}) \quad \forall t \quad (6.14a) \\ & d_t = \sum_i q_{it} \quad \forall t. \quad (6.14b) \end{array} \right.$$

Here (6.13b) defines the production bid limits, (6.13c) limits the bid on ramp rate. Equations (6.13d) and (6.13e) define ramping constraints for every two sequential time periods. We consider a general load profile, where demand can increase or decrease, and therefore both upward and downward ramping constraints are necessary. The variables, following after the colon are the Lagrange multipliers associated with the respective constraints.

The KKT conditions of problem (6.13a)-(6.13a) are also the optimality conditions. The resulting equilibrium problem is as follows:

$$\forall i : \left\{ \begin{array}{l} \frac{\partial \mathcal{L}_i}{\partial q_{it}} = p_t(q_{it}, q_{-it}) - \theta_i q_{it} - c_i + \underline{\mu}_{it} - \bar{\mu}_{it} - \underline{\gamma}_{it} + \bar{\gamma}_{it} \\ \quad + \underline{\gamma}_{i(t+1)} - \bar{\gamma}_{i(t+1)} = 0 \quad \forall t \quad (6.15a) \\ \frac{\partial \mathcal{L}_i}{\partial r_{it}} = -c_i^R + \underline{\lambda}_{it} - \bar{\lambda}_{it} + \underline{\gamma}_{it} + \bar{\gamma}_{it} = 0 \quad \forall t \quad (6.15b) \\ 0 \leq \bar{\mu}_{it} \perp \hat{Q}_i - q_{it} \geq 0 \quad \forall t \quad (6.15c) \\ 0 \leq \underline{\mu}_{it} \perp q_{it} \geq 0 \quad \forall t \quad (6.15d) \\ 0 \leq \underline{\gamma}_{it} \perp r_{it} - q_{it} + q_{i(t-1)} \geq 0 \quad \forall t \quad (6.15e) \\ 0 \leq \bar{\gamma}_{it} \perp r_{it} + q_{it} - q_{i(t-1)} \geq 0 \quad \forall t \quad (6.15f) \\ 0 \leq \bar{\lambda}_{it} \perp \hat{R}_i - r_{it} \geq 0 \quad \forall t \quad (6.15g) \\ 0 \leq \underline{\lambda}_{it} \perp r_{it} \geq 0 \quad \forall t \quad (6.15h) \end{array} \right.$$

$$D_t^0 - \alpha p_t(q_{it}, q_{-it}) - d_t = 0 \quad \forall t \quad (6.16a)$$

$$\sum_i q_{it} - d_t = 0 \quad \forall t. \quad (6.16b)$$

The introduced setup can be directly programmed as a mixed complementarity problem (MCP) in GAMS and solved until optimality with PATH solver [127].

6.3.2 Extended formulation of the bilevel equilibrium problem

The ramp-bidding problem for a single generating company can be formulated as an MPEC. The corresponding bilevel program for generating company i^* optimizing over a set of variables $\Omega_{i^*} = \{r_{i^*t}, q_{it}, p_t(q_{it}, q_{-it}), d_t, \underline{\mu}_{it}, \bar{\mu}_{it}, \underline{\gamma}_{it}, \bar{\gamma}_{it}\}$

is as follows:

$$\text{maximize}_{\Omega_{i^*}} \sum_t \left((p_t(q_{it}, q_{-it}) - c_{i^*})q_{i^*t} - c_{i^*}^R r_{i^*t} \right) \quad (6.17a)$$

$$\text{subject to: } \hat{R}_{i^*} \geq r_{i^*t} \geq 0 \quad \forall t \quad (6.17b)$$

$$\hat{Q}_i \geq q_{it} \geq 0 \quad \forall(it) \quad (6.17c)$$

$$r_{it} - q_{it} + q_{i(t-1)} \geq 0 \quad \forall(it) \quad (6.17d)$$

$$r_{it} - q_{i(t-1)} + q_{it} \geq 0 \quad \forall(it) \quad (6.17e)$$

$$\underline{\mu}_{it} \geq 0, \bar{\mu}_{it} \geq 0, \underline{\gamma}_{it} \geq 0, \bar{\gamma}_{it} \geq 0 \quad \forall(it) \quad (6.17f)$$

$$p_t(q_{it}, q_{-it}) - \theta_i q_{it} - c_i + \underline{\mu}_{it} - \bar{\mu}_{it} - \underline{\gamma}_{it} + \bar{\gamma}_{it} \\ + \underline{\gamma}_{i(t+1)} - \bar{\gamma}_{i(t+1)} = 0 \quad (6.17g)$$

$$\underline{\mu}_{it} q_{it} = 0 \quad \forall(it) \quad (6.17h)$$

$$\bar{\mu}_{it} (\hat{Q}_i - q_{it}) = 0 \quad \forall(it) \quad (6.17i)$$

$$\underline{\gamma}_{it} (-q_{it} + q_{i(t-1)} + r_{it}) = 0 \quad \forall(it) \quad (6.17j)$$

$$\bar{\gamma}_{it} (q_{it} - q_{i(t-1)} + r_{it}) = 0 \quad \forall(it) \quad (6.17k)$$

$$D_t^0 - \alpha p_t(q_{it}, q_{-it}) - d_t = 0 \quad \forall t \quad (6.17l)$$

$$\sum_i q_{it} - d_t = 0 \quad \forall t. \quad (6.17m)$$

Here constraints (6.17b) correspond to the upper-level constraints, constraints (6.17c)-(6.17e) are the lower-level primal constraints. The corresponding Lagrange multipliers are nonnegative as outlined in the constraints (6.17f). Constraint (6.17g) is the stationarity condition. Conditions (6.17h) to (6.17k) are the complementary slackness conditions. Constraints (6.17l) and (6.17m) correspond to the equalities shared by all generators in the lower level.

With the state-of-the-art solvers (e.g., COUENNE), the problem can be attempted directly as a nonlinear problem, as in this paper. We can obtain a solution to the whole EPEC problem by solving the MPECs iteratively: we sequentially fix the strategic variables of all generators except of one, which is free to choose any level in response to the levels fixed for all other units. This procedure is repeated for all generators in loop until convergence to an equilibrium point, at which no producer wants to change the strategic decision unilaterally [111].

6.3.3 Additional extensions

Additionally, we consider two main extensions:

- We reflect highly concentrated markets we consider a firm ownership of the generating units: a generating company may own several generating units with possibly different production costs. The objective functions in (6.13a) and (6.17a) become:

$$\pi_f = \sum_{i^* \in f,t} \left((p_t(q_{it}, q_{-it}) - c_{i^*})q_{i^*t} - c_{i^*}^R r_{i^*t} \right). \quad (6.18)$$

Here, unit i^* belongs to the firm f and the profit is maximized for the whole firm.

- We consider an important extension of the model to the decision-making under uncertainty. The uncertainty in wind-integrated power systems can be modeled with a set of scenarios W , where each scenario $w \in W$ has a certain probability $prob_w$. The profit formulation (6.18) introduced in the previous subsection is then extended as follows:

$$\pi_f = \sum_{i^* \in f,t,w} prob_w \left((p_{tw}(q_{itw}, q_{-itw}) - c_{i^*})q_{i^*tw} - c_{i^*}^R r_{i^*t} \right). \quad (6.19)$$

We also add a nonanticipativity constraint to ensure that ramp rate cannot be changed for every realization of the scenario in the two-stage model.

6.4 Case studies

The developed model can be a tool for analyzing how a market setup affects the flexibility bidding in the system. In this section we check, whether Propositions 1.1 and 1.2, introduced in Section 6.2.3, are still valid for the extended version of the models by performing the simulations. We also model the stochastic case study with firms owning several units. More case studies can be found in [J2].

6.4.1 Comparison of the duopoly models

The duopoly case study lets us analyze the importance of information revealed in the ramp and quantity game. As derived in Section 6.2, the closed-form

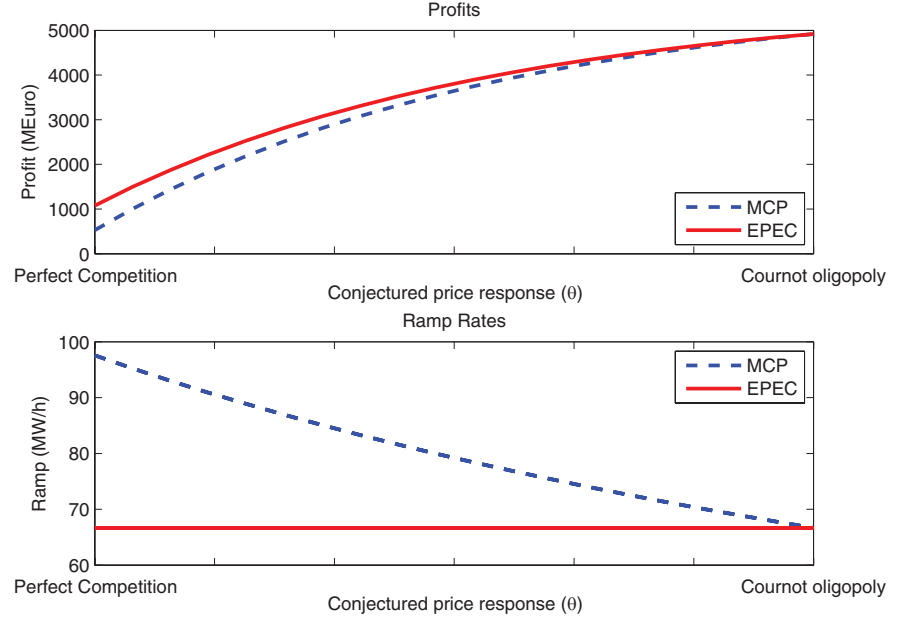


Figure 6.1: Single-stage and two-stage equilibrium solutions for a system with two symmetric generating companies.

expression for the ramp-rate bids in the case of a single-level (SL) and bilevel (BL) optimization problem formulations are:

$$r_i^{SL} = \frac{D_{02} - D_{01}}{\alpha\theta + 2}, \quad (6.20a)$$

$$r_i^{BL} = \frac{D_{02} - D_{01}}{3}. \quad (6.20b)$$

To check this result we formulate the models explicitly as optimization problems and perform the simulations. In this simple case study the capacity and ramp limits are considered nonbinding. The production costs are symmetric and equal to 10 €/MW. We assume two load periods with the demand intercepts $D_t^0 = [200, 400]$ MW. The elasticity of demand $\alpha = 7.2$ MW²h/€.

Figure 6.1 shows the simulation results for the different values of conjectured price parameter. We observe that the ramp-rate level in the single-stage model steadily decreases with a growing conjectured price response parameter until it reaches the value of a two-stage model bid in the point, which

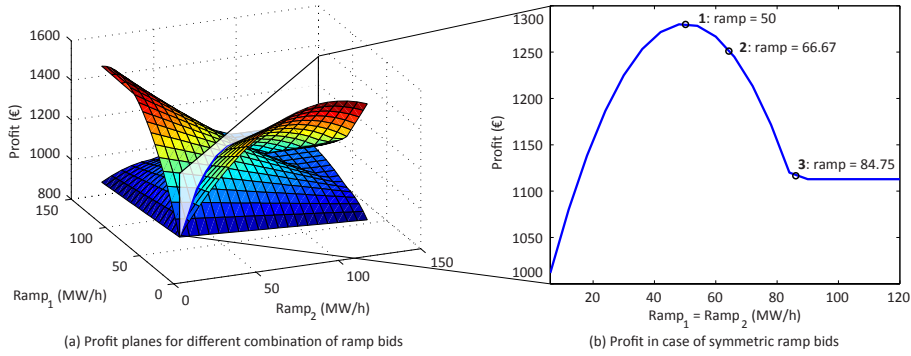


Figure 6.2: Symmetric duopoly case study results.

corresponds to the Cournot competition. The optimal level of ramp rate does not depend on how the unit perceives the competitiveness in the market. The producers prefer to withhold the flexibility and choose a relatively low level of ramp.

Figure 6.2-(a) is obtained by running the one-stage model for a fixed combination of ramp-rate levels of two players for an arbitrary level of the conjectured price response parameter $\theta = 0.05 \text{ €/MW}^2\text{h}$. Since the companies are symmetric, we can expect the equilibrium to lie on the middle line, where the bids of the both players are equal. This line is shown in Figure 6.2-(b). We observe that the highest profits for the both units are reached when $r_1 = r_2 = 50 \text{ MW/h}$ (point 1 in Figure 6.2-(b)). This solution would be a stable point if the producers were cooperating, as it maximizes the sum of their profits. However, as we can see in Figure 6.3, in which a profit curve of a single producer is shown for the ramp-rate level of other player fixed, a generator can obtain a higher profit by unilaterally changing its level of the ramp rate (which can be visualized by moving along the x axis of the plane following the arrow). A response to such strategy will be an increase of a ramp-rate level by the second producer. An equilibrium point is finally reached when no unit wants to change its bid unilaterally. In Figure 6.3 we can see that point 2 coincides with the point of the highest profit for a given combination of the ramp rates. This logic illustrates reaching a Nash equilibrium between strategic producers.

We can obtain the same point by fixing the decision of one of the players and observing the response, or reaction, of the other player. By repeating

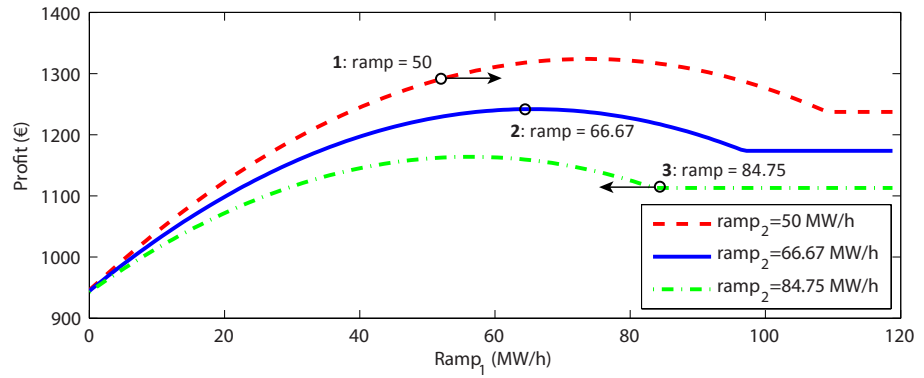


Figure 6.3: Stability of point 2 as an equilibrium point

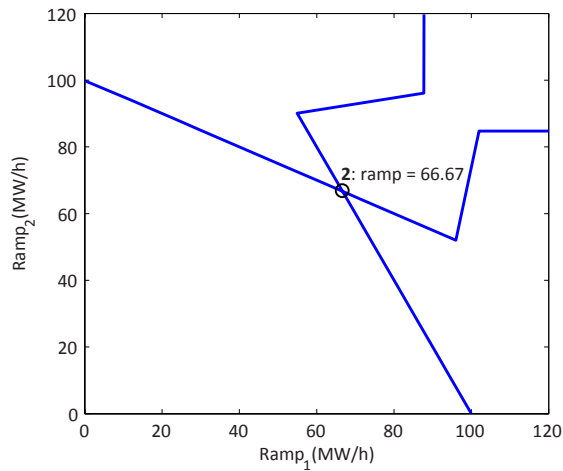


Figure 6.4: Reaction functions of both of the players. The intersection of the reaction function – Nash equilibrium.

this for a range of values and for both players we obtain reaction functions, shown in Figure 6.4. The reaction functions intersect in the only point, which is a Nash equilibrium (point 2 in Figures 6.2-(b), 6.3, and 6.4). In this simple case of smooth profit functions we can prove numerically that this point is the only Nash equilibrium.

Point 3 corresponds to the solution of the single-stage model for the given choice of parameter θ . We can see from Figure 6.2 that this point offers the

highest flexibility in ramp. Since the producers are competing in quantities and ramps at the same time, they choose to leave the ramp-rate level flexible, so they can react to the competitors' strategies by withholding or providing more production to the market.

The equivalence of the single-stage and two-stage models for the choice of the conjectured price response representing Cournot competition can be found in some other games. In [128] the authors study the capacity-investment problem and show that for the case of a one load-period game and 2 symmetric producers the investments are generally higher for the single-stage problem, converging to the same value when competition structure is approaching Cournot.

The above study confirms an intuition that market design impacts the generators' behavior and the social welfare. A two-stage setup, which may seem fair intuitively, can lead to higher withholding and therefore social welfare losses.

6.4.2 Stochastic case study

Authors in [117] find that by letting generators restate their ramp rates only once in a longer time period, policy makers can prevent them from responding to market conditions with false ramp rates. In this case study we show that uncertainty, and in particular, wind uncertainty may actually lead to the opposite results in certain circumstances. This means that there are numerical examples, where uncertainty leads to lower levels of flexibility than the deterministic case. In Table 6.1 we present the demand data used for this case study. Note that the deterministic data corresponds to the average of all stochastic scenarios. Figure 6.5 shows the comparison of ramp-rate levels obtained in the deterministic and stochastic cases (for single-stage MCP model we plot the maximum value of ramp rate in scenarios). We observe that while the expected value of the demand intercept in the stochastic scenarios is equal to the one in the deterministic case, the bids follow a very different pattern. Several observations can be made:

- Counter-intuitively, we can observe that stochasticity yields smaller total ramping levels than the deterministic scenario in both two- and single-stage models – this can be explained by the fact that there is a chance of getting higher profit from the expensive unit, if the high-demand scenario occurs. In this case study, the generating companies

facing the uncertainty choose to withhold their ramp rates to ensure a certain level of profits in every scenario. However, we should note that it is not the general case, and the results may be different depending on the parameters of the model;

- The initial gap for the low values of the conjectured price response corresponds to the situations close to perfect competition, when the less expensive generator provides the whole capacity to the market, so the second generator is not expected to ramp;
- The kinks in the simulations of the bilevel model can be explained by the solution procedure, as the EPEC is solved via diagonalization. While in a single-level model the result is unique, the two-level model can often have several Nash equilibria as solutions (several points at which no company wants to deviate unilaterally). This is a reason for the jumps in the optimal ramping level. In such case, when there are multiple equilibria, they can be evaluated based on criterion (e.g., social welfare - best/worst Nash equilibrium as discussed in [45]) to choose the equilibrium that yields the best result with respect to this criterion.
- Apart from these particularities that happen close to perfect competition, the ramping flexibility levels follow the same trend as in the duopoly case. The two-stage model levels, for the most part, do not seem to be affected by competitive market behavior. Moreover, the ramping levels obtained in the single-level model under Cournot competition, and the bilevel ramping levels for arbitrary market competition seem to converge to similar values.

These observations allow us to conclude that the outcome similarity of the single- and two-stage models at Cournot holds even for the case, when we consider the portfolio bidding and uncertainty. We also observe that in

Table 6.1: Optimization scenarios

Model	Scenario probability, p.u.	$D_{t_1}^0$, MW				$D_{t_2}^0$, MW			
Deterministic	1	700				1000			
Stochastic	s1: s2: s3: s4:	s1:	s2:	s3:	s4:	s1:	s2:	s3:	s4:
	0.25 0.25 0.25 0.25	700	900	500	700	1000	1000	800	1200

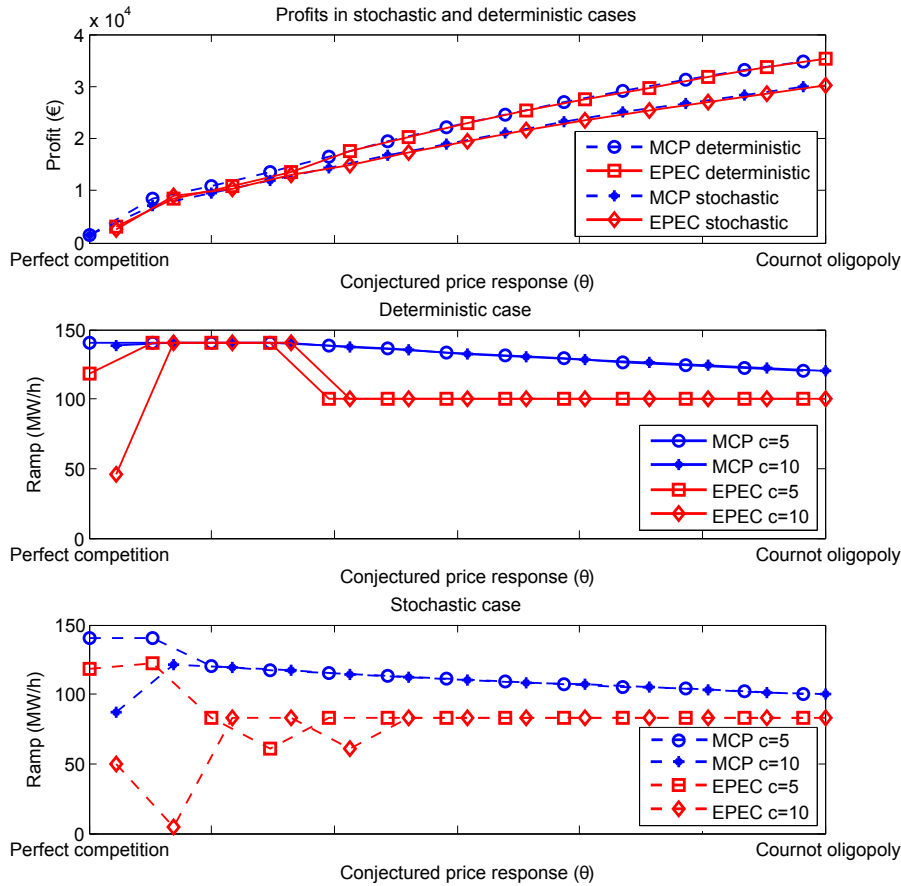


Figure 6.5: Comparison of the stochastic and deterministic cases

this particular case the ramp-rate levels in case of simultaneous bidding are steadily higher than in the case of the separated bidding stages.

It is worth noting that in the stochastic case the results do not show the same stability as in two previous case studies. For example, we can find cases, when the social welfare is higher in two-stage models, because it is more profitable for companies to produce more, so the prices decrease. The intuition for these observations is possibly in the structure of the stochastic model. In the stochastic two-stage model ramp rate is declared before the uncertainty is realized and production takes place. Therefore, the ramp rate constraint does not hold as an equality between ramp rate and the difference in the

production, and ramp rate cannot be always used by strategic generators to affect the production levels. However, the existence of the cases that the generators choose to limit their ramp rates even when facing the uncertainty questions considerably the logic of separating the stages of deciding the production and flexibility levels.

6.5 Conclusion

Generation-side flexibility becomes increasingly important as the share of wind generation becomes larger and there are frequent swings in generation supply. In this chapter we present how generating companies decide ramp-rate flexibility and production in a one-stage and a two-stage processes, and we analyze the impact of these different market setups on the results.

We present two models – a single- and a bilevel model – to represent two different types of market setups: bidding the ramp and quantity levels simultaneously; or doing it in two stages, where the generators choose their ramp rates in the first stage, and compete in quantities in the second stage. A market structure, where the bids on ramp rate are submitted before the actual market clearing happens is a common regulatory practice, aiming to minimize the manipulation on the ramping constraints. In this chapter we show that such a regulatory intuition can actually lead to a higher level of withholding. We provide a comparison for a range of different conjectured price responses, capturing company’s beliefs regarding its influence on market prices. The proposed model shows that for a market, the structure of which is more competitive than Cournot oligopoly, it may be advantageous to allow simultaneous bidding of ramp rates and quantities. We observe that otherwise, the producers are likely to exercise their market power in the pre-commitment stage as such strategy locks higher profits in the second stage.

Chapter 7

Conclusion

In the final chapter the key conclusions are drawn and the directions for the future research are outlined.

7.1 Concluding remarks

This dissertation studies the exercise of market power in power systems with high penetration of wind power. In this dissertation the problem of increased generation flexibility requirements in wind-integrated systems is tackled. The background for the studies and mathematical modeling, required to represent the problem, are presented in Chapters 1-3.

Starting from Chapter 4 a model of profit-maximizing generators in a system with high penetration of wind power is presented. The model captures the need for flexibility in such systems, due to fluctuations of wind power. This study is motivated by real examples of the strategic behavior, and demonstrates how strategic generators may choose to withhold the ramp rate in order to maximize their profit. The developed model represents the Nash equilibrium between multiple strategic generators and is therefore formulated as an EPEC. EPEC model is then recast as a single-stage MILP, which can be solved by commercial solvers. The case studies presented in the chapter emphasize the importance of modeling the ramp-rate withholding, as it turns out to be crucial in the wind-integrated systems.

Chapter 5 extends the findings of the previous chapter to power systems, where hydropower is present. Hydropower producers possess unique characteristics and are usually used to balance the fluctuations in supply. These unique

characteristics can create additional advantages for hydropower producers if they have incentives to exercise market power. Several case studies of single profit-maximizing hydropower producer and several hydropower producers are described in this chapter. Also, the definition of Nash equilibrium under uncertainty is discussed. The models of single and multiple producers can be formulated as MPEC and EPEC respectively. The equilibrium problems can then be reformulated as MILP and solved using modified Benders decomposition approach. This approach allows solving larger case studies by decomposing the formulation in smaller instances, avoiding the disjunctive parameter.

Finally, Chapter 6 opens the topic of regulatory strategies to limit the exercise of market power on ramp rate. In this chapter two market designs are compared: a design where ramp-rate bid is decided at the same time with production-bid (single-stage model), and a design, where generators first declare their ramp rate and then in the second stage decide their production bids. While the intention of the first design is exactly to limit the strategic behavior on ramp rates, a simple case study with two symmetric generators provides a close-form solution, which actually confirms the opposite. The results of the two-generators case study show that generator may choose to “lock in” higher profits by declaring lower ramp rate in the first stage. It may be more advantageous from the system perspective to allow producers declare their ramp rate at the same time with production bidding.

7.2 Future work

One of the major directions for future research is studying the techniques for mitigating market power in wind-integrated power systems. The study, described in Chapter 6, shows that the currently used techniques may not have a strong theoretical foundation and need reconsideration. One of the common mitigation approach is introduction of the forward contracts. This approach needs to be studied further in the context of wind-integrated power systems. Working paper [J5] will discuss the theoretical implications of forward contracts in wind-integrated power systems.

Another possible direction is studying the effect of new promising technologies for demand response. With advances in IT systems, cheaper storage technologies and price-observing consumers, there are more possibilities for demand side to mitigate the strategic behavior of producers and smooth out

the price peaks.

Presented models are also very computationally demanding. As case studies are getting larger, the computation time increases. In order to use the developed models for larger case studies, e.g. on European level, proposed decomposition technique can be further improved, or new techniques can be proposed.

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Complete List of Publications

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Curriculum Vitæ

Ekaterina Moiseeva was born on June 13th, 1989 in Tomsk, Russian Federation. She started her B.Sc. studies in the Energy Institute of Tomsk Polytechnic University in 2006. She has completed a double-degree M.Sc. program between Tomsk Polytechnic University (TPU) and Czech Technical University (CTU) in Prague in 2012. Ekaterina has graduated with a degree of M.Sc. in Power Engineering and M.Sc. in Management and Economics of Power Engineering, both with honors.

During the B.Sc. and M.Sc. studies Ekaterina had research and study visits to Czech Technical University (Prague, Czech Republic), Technical University of Vienna (Vienna, Austria), Catholic University of Louvain (Louvain-la-Neuve, Belgium). She has been twice selected the best student of TPU, and obtained a dean's prize from CTU.

In 2012, Ekaterina was selected as a PhD candidate of the Erasmus Mundus Joint Doctorate in Sustainable Energy Technologies and Strategies (SETS) and awarded an Erasmus Mundus Fellowship. She joined Electricity Market Research Group (EMReG) in KTH under the supervision of Associate Professor Mohammad Reza Hesamzadeh. The research topic covered the exercise of market power in the multi-area systems with high penetration of wind power. Research method included modeling of market power exercise in power system using equilibrium models. Also, the solution techniques using decomposition techniques and advanced optimization were developed.

In 2014-2015 Ekaterina has visited Institute for Research in Technology in Comillas Pontifical University. She worked with Assistant Professor Sonja Wogrin on close-form solutions to bilevel equilibrium models of market power exercise and on market design aspects.

The research interests of Ekaterina include large-scale optimization, wind power integration, power market modeling, and decomposition techniques.