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ARISTOTLE UNIVERSITY OF THESSALONIKI
SCHOOL OF ENGINEERING
DEPARTMENT OF CHEMICAL ENGINEERING

OPTIMIZATION OF ENERGY MARKETS WITH HIGH PENETRATION OF RENEWABLE ENERGY RESOURCES

by

EVANGELOS G. TSIMOPOULOS
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A Thesis
Submitted in Fulfillment of the Requirements
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Abstract

Over the last decades the electricity industry has experienced a remarkable reformation mainly for two reasons. The first reason is the market deregulation. This term describes the shift from vertically integrated monopolies to competitive markets. The latter give access to other players who can invest in generation and transmission facilities, thus increasing the competition. The second reason is the strong penetration of renewable energy resources (RES), whose the inherently intermittent generation has changed the operational framework and introduced new tools to handle both power production and demand response.

Considering RES, their financially subsidized generation and the prioritized dispatch (merit-order) have resulted in reduced conventional (thermal) production volumes and suppressed electricity prices. Following this, a question arises about the sustainability of the existing thermal units. In addition, a second question arises about the attainability of future investments not only for the conventional units but also for the RES generation facilities as the continuous growth of the latter leads to further suppressed electricity prices. Within the above framework, this thesis investigates the strategic reaction of a power producer to exercise market power by means of capacity withholding and transmission-related strategies to offset expected profit losses. Initially, considering a producer with conventional generation portfolio, we develop a stochastic bi-level complementarity model to derive optimal offer strategies for the aforementioned producer in a jointly cleared energy and reserve pool-based market settled through an hourly auction process. The upper level of the model represents the maximization of the strategic producer's expected profits while the lower level repre-

sents the market clearing mechanism optimizing the security-constrained expected cost of the system conducted by the independent system operator. The mechanism is modeled though a two-stage stochastic programming where the first stage clears the day-ahead DA) market, and the second stage presents the system operation in RT though a set of plausible wind power production realizations. Then, we extend the proposed bi-level model for an incumbent power producer who possesses a conventional and wind generation portfolio. Both bi-level models are recast into mathematical programming with equilibrium constraints (MPEC) models which are then reformulated into equivalent mixed integer linear programming (MILP) models solvable by commercial solvers like CPLEX/GAMS in global optimality. These transformations occur using the Karush-Kuhn-Tucker (KKT) first order optimality conditions, the strong duality theory and disjunctive constraints. The proposed algorithms:

- provide optimal offering (energy/price) strategies for a power producer participating in a jointly cleared energy and balancing pool market where other conventional and wind power producers are concerned as competitors.
- derive robust DA and balancing market prices which are created endogenously as dual variables of the energy balance constrains.
- identify producer's arbitrage opportunities between DA and RT markets.
- offer a novel framework that determines the impact of the strategic producer's behavior on the local marginal prices (LMPs) under stochastic production.
- provide a systematic analysis of behavior adjustments of the aforementioned producer depending on wind production uncertainty , network congestions, and different levels of wind power penetration.

Finally, we investigate the interaction between strategic power producers participating in the pool market. Thus, based on the extended bi-level model of each producer, we propose a new MPEC model with primal-dual formulation. The joint solution of all producers' MPEC models construct an equilibrium programming with equilibrium constraints (EPEC) model.

This is then, lying on different objective functions, linearized into an MILP model and solved using a single-iteration diagonalization process. The proposed algorithm addresses several network cases and provides a range of meaningful market equilibria in an ex-post analysis of the received MILP results taking into consideration wind production uncertainty and transmission lines congestions.

Περίληψη

Σήμερα η κλιματική αλλαγή είναι χωρίς αμφιβολία ένα από τα μεγαλύτερα περιβαλλοντικά προβλήματα. Αντιμέτωποι με τα καταστρεπτικά αποτελέσματα των ανθρώπινων δραστηριοτήτων στο κλίμα, τα κέντρα αποφάσεων καλούνται να υιοθετήσουν ενδελεχή μέτρα όσον αφορά στην αειφορία του περιβάλλοντος. Τα συστήματα παραγωγής ηλεκτρικής ενέργειας παίζουν σημαντικό ρόλο στην επίτευξη των περιβαλλοντικών στόχων καθώς είναι υπεύθυνα για το μεγαλύτερο ποσοστό εκπομπών αερίων του θερμοκηπίου. Με αυτό το σκεπτικό η Ευρωπαϊκή Ένωση έχει ευθυγραμμίσει τις ενεργειακές της πολιτικές έτσι ώστε το 2050 η παραγόμενη ηλεκτρική ενέργεια που σχετίζεται με εκπομπές άνθρακα να έχει μειωθεί κατά 80% σε σχέση με το 1990. Αυτές οι πολιτικές υποστηρίζονται σημαντικά από μέτρα που επιτρέπουν την ισχυρή διείσδυση ανανεώσιμων πηγών ενέργειας (ΑΠΕ) σε ποσοστό 75% της ακαθάριστης τελικής ενεργειακής κατανάλωσης.

Παραδοσιακά οι κανόνες της αγοράς ενέργειας λειτουργούσαν με σκοπό τον έλεγχο των εκπομπών άνθρακα. Επιπροσθέτως τα συστήματα παραγωγής ηλεκτρικής ενέργειας ακολουθούν τις διακυμάνσεις της ζήτησης. Παρόλα αυτά το λειτουργικό πλαίσιο αλλάζει σαν αποτέλεσμα των συμφυών μη ελεγχόμενων διακυμάνσεων της παραγωγής ηλεκτρικής ενέργειας από μονάδες ΑΠΕ. Η προαναφερθείσα φύση των ΑΠΕ σε συνδυασμό με την έλλειψη τεχνολογίας αποθήκευσης της ηλεκτρικής ενέργειας οδηγεί τις συμβατικές μονάδες παραγωγής να λειτουργούν διακοπτόμενα για να αντιμετωπίσουν τις συχνές ανισορροπίες στο δικτύου μεταφοράς. Έτσι αυξάνεται η ανάγκη για πιο ευέλικτες αλλά ακριβές εφεδρείες ενέργειας (reserves) ώστε να διασφαλισθεί η αξιοπιστία του συστήματος. Η ανωτέρω κατάσταση επηρεάζει την απο-

δοτικότητα και το λειτουργικό κόστος αρνητικά. Επιπλέον η μειούμενη ωριαία λειτουργία και συνεπώς ο όγκος παραγωγής σε συνδυασμό με τις συμπιεσμένες τιμές ηλεκτρικής ενέργειας εγείρουν ερωτήματα όχι μόνο για τη βιωσιμότητα των υπαρχόντων μονάδων αλλά και για το εφικτό των μελλοντικών επενδύσεων. Επιπροσθέτως το κατάλληλο μείγμα ευέλικτης χωρητικότητας που έχει σκοπό να εξομαλύνει την συνεχώς αυξανόμενη μεταβλητότητα της παροχής ηλεκτρικής ενέργειας εμποδίζεται από ανωμαλίες της αγοράς. Οι τελευταίες σχετίζονται με παραγωγούς που έχουν εξασφαλισμένη προτεραιότητα στη τροφοδοσία του δικτύου (priority feed-in) λαμβάνοντας επωφελής επιδοτήσεις και άλλους μη επιδοτούμενους παραγωγούς οι οποίοι είναι αποδέκτες τιμών εκκαθαρισμένης αγοράς για την κάλυψη πάγιων δαπανών.

Γενικά η απαιτούμενη ευελιξία έχει μακροχρόνιο αντίκτυπο σε όλο το φάσμα του ηλεκτρικού συστήματος από τη προ-ημερήσια και ημερήσια λειτουργία της αγοράς ηλεκτρικής ενέργειας μέχρι τη μελλοντική παραγωγική ικανότητα. Η υποχρέωση εξισορρόπησης της διαλείπουσας παροχής ηλεκτρικής ενέργειας έχει δημιουργήσει την ανάγκη για νέο σχεδιασμό που θα επιλύει τα προβλήματα ενσωμάτωσης μονάδων παραγωγής στο δίκτυο καθώς επίσης και την ανάγκη για ένα νέο πλαίσιο για την εξισορρόπηση του πολιτικού τριλήμματος μιας αποτελεσματικής και ανταγωνιστικής αγοράς ενέργειας σε ένα ασφαλές σύστημα μεταφοράς με χαμηλές εκπομπές άνθρακα.

Αναφορικά με την ισχυρή διείσδυση των ΑΠΕ η οποία υποστηρίζεται από ένα γενναιόδωρο μηχανισμό επιδοτούμενης παραγωγής και προτεραιότητας στον εφοδιασμό, ο ρόλος της συμβατικής παραγωγής ενέργειας φθίνει. Παρόλα αυτά λόγω της μεταβλητότητας της παραγωγής, της συμφόρησης του δικτύου καθώς και των διακυμάνσεων της ηλεκτρικής ισχύος που τροφοδοτείται στο σύστημα, οι λειτουργοί της αγοράς αναγκάζονται να συναλλάσσονται σε πραγματικό χρόνο ώστε να διορθώνονται οι ανισορροπίες του συστήματος. Οι συναλλαγές αυτές βασίζονται στην ικανότητα των θερμοηλεκτρικών μονάδων να παράγουν ενέργεια κατά απαίτηση. Παρά την αναγνώριση από τις αγορές του σημαντικού ρόλου των θερμοηλεκτρικών μονάδων οι τελευταίες αντιμετωπίζουν μια άνιση μεταχείριση και πρέπει να υιοθετήσουν συγκεκριμένη στρατηγική συμπεριφορά ώστε να διασφαλίσουν την ανταγωνιστικότητα τους.

Μέσα στο παραπάνω πλαίσιο η παρούσα εργασία μελετά τη στρατηγική συμπεριφορά και την αντίδραση μιας εταιρίας παραγωγής ηλεκτρικής ενέργειας με δεσπόζουσα θέση στην αγορά. Η εταιρία συμμετέχει μαζί με άλλους παραγωγούς συμβατικής και αιολικής ενέργειας σε χρηματιστήριο ενέργειας όπου ο ανεξάρτητος διαχειριστής του συστήματος ή ο διαχειριστής της αγοράς (σε πολλές χώρες η οντότητα είναι η ίδια) εκκαθαρίζει από κοινού τη προ ημερήσια (day-ahead) αγορά και την αγορά εξισορρόπησης (balancing or real-time). Η εταιρία εξασκεί την θέση ισχύος της μέσω στρατηγικών συγκράτησης παραγωγής (physical withholding) και αύξησης τιμών προσφορών (financial withholding) καθώς και με στρατηγικές που σχετίζονται με τη μεταφορά ενέργειας (transmission-related strategies) με σκοπό την αποφυγή απώλειας κέρδους. Έτσι με βάση τις υποθέσεις του οικονομικού μοντέλου του Stackelberg και λαμβάνοντας υπόψιν μια εταιρία συμβατικής (θερμικής) παραγωγής ηλεκτρικής ενέργειας, αναπτύσσουμε αρχικά ένα στοχαστικό διεπίπεδο μοντέλο συμπληρωματικότητας (stochastic bi-level complimentarity model) το οποίο ανταποκρίνεται στα κίνητρα του πρωτοπόρου (εταιρία παραγωγής) και του ουραγού (ανεξάρτητος διαχειριστής συστήματος) που συμμετέχουν στο παίγνιο βελτιστοποίησης των προσδοκιών τους.

Το άνω επίπεδο του μοντέλου μεγιστοποιεί τα προσδοκώμενα κέρδη της εταιρίας ενώ το κάτω επίπεδο του μοντέλου ελαχιστοποιεί το κόστος του συστήματος προσδιορίζοντας τις αποδεκτές ποσότητες έγχυσης και απορρόφησης ενέργειας καθώς και την ενιαίες τιμές εκκαθάρισης των αγορών. Η εκκαθάριση των αγορών γίνεται μέσω δύο σταδίων στοχαστικού προγραμματισμού. Το πρώτο στάδιο εκκαθαρίζει την προ ημερήσια αγορά καθορίζοντας την προγραμματισμένη παραγωγή θερμικών και ΑΠΕ καθώς και την τιμή της αγοράς η οποία λαμβάνεται ως δυική μεταβλητή σχετιζόμενη με τον περιορισμό ισοζυγίου ισχύος. Το δεύτερο στάδιο εκκαθαρίζει την αγορά εξισορρόπησης λαμβάνοντας υπόψιν την αβεβαιότητα της αιολικής παραγωγής μέσω πιθανών σεναρίων παραγωγής και καθορίζει εφεδρείες για την ισορροπία του συστήματος και προσδοκώμενες τιμές εκκαθάρισης της αγοράς που και αυτές λαμβάνονται ως δυικές μεταβλητές του περιορισμού ισοζυγίου ισχύος σε πραγματικό χρόνο. Κατόπιν, το διεπίπεδο μοντέλο επεκτείνεται για μια εταιρία με δεσπόζουσα θέση στην αγορά που διαχειρίζεται θερμικό και

αιολικό ενεργειακό χαρτοφυλάκιο. Και τα δύο μοντέλα μετασχηματίζονται σε μαθηματικού προγραμματισμού με περιορισμούς ισορροπίας (mathematical programming with equilibrium constraints, MPEC) μοντέλα αντικαθιστώντας το κάτω μέρος των διεπίπεδων μοντέλων με τη χρήση των Karush-Kuhn-Tucker (KKT) συνθηκών βελτιστοποίησης. Κατόπιν διατυπώνουμε τις KKT συνθήκες συμπληρωματικότητας (complementarity constraints) με τη χρήση διαζευκτικών περιορισμών (disjunctive constraints) ανασχεδιάζοντας τα MPEC μοντέλα σε μοντέλα μεικτού ακέραιου γραμμικού προγραμματισμού (Mixed Integer Linear Programme, MILP) τα οποία είναι ελέγξιμα από εμπορικούς λύτες όπως ο CPLEX/GAMS και επιλύσιμα σε παγκόσμιο βέλτιστο. Οι φυσικές ροές της ηλεκτρικής ενέργειας μοντελοποιούνται με τη βοήθεια συνεχούς ρεύματος υπό γραμμική προσέγγιση με σκοπό να συμπεριλάβουμε τον αντίκτυπο των επιδράσεων του δικτύου στις αποφάσεις του παίγνιου. Η επίλυση των μοντέλων μας δίνει τη δυνατότητα να:

- προσδιορίσουμε τις στρατηγικές προσφορών ενός παραγωγού ηλεκτρικής ενέργειας που συμμετέχει μαζί με άλλους συμβατικούς και αιολικής ενέργειας παραγωγούς σε ένα χρηματιστήριο ενέργειας.
- λάβουμε οριακές τιμές συστήματος για την προ ημερήσια αγορά και την αγορά εξισορρόπησης σαν δυικές μεταβλητές των περιορισμών ισοζυγίου ισχύος.
- εξετάσουμε τη δυνατότητα arbitrage μεταξύ προ-ημερήσιας και ημερήσιας αγοράς με βάση τον πιο κερδοφόρο συνδυασμό ζεύγους προσφορών ποσότητας και τιμής.
- καθορίσουμε την επίδραση των στρατηγικών προσφορών σε συνθήκες αβεβαιότητας οριακών τιμών ζώνης και να εκτιμήσουμε τις οικονομικές επιπτώσεις στους συμμετέχοντες.
- αναλύσουμε συστηματικά τις συμπεριφορικές προσαρμογές του συγκεκριμένου παραγωγού ως προς την αβεβαιότητα της αιολικής παραγωγής, των διαφορετικών επιπέδων διύσδησης της καθώς και ως προς τους τεχνικούς περιορισμούς μονάδων παραγωγής και συστήματος μεταφοράς.

Στη συνέχεια για να μελετήσουμε την αλληλεπίδραση μεταξύ παραγωγών με στρατηγική συμπεριφορά χρησιμοποιούμε το εκτεταμένο διεπίπεδο μοντέλο και το μετασχηματίζουμε σε

MPEC μοντέλο με τη μορφή κύριου-δυικού σχηματισμού για κάθε παραγωγό. Η κοινή επίλυση όλων των MPEC συνιστά ένα μοντέλο προγραμματισμού ισορροπίας με περιορισμούς ισορροπίας (equilibrium programming with equilibrium constraints, EPEC). Στη συνέχεια και εφαρμόζοντας διαφορετικές αντικειμενικές συναρτήσεις για να προσδιορίσουμε το εύρος των πιθανών ισορροπιών της αγοράς γραμμικοποιούμε το μοντέλο και επαληθεύουμε τις έγκυρες λύσεις του με τη χρήση μεθόδου σύγκλισης μιας επανάληψης. Το μοντέλο επιλύει διάφορα συστήματα εξετάζοντας:

- τις Nash ισορροπίες υπό έντονο, χαλαρό (σύμπραξη) και μονοπωλιακό ανταγωνισμό.
- τον καθορισμό τιμών εκκαθάρισης της αγοράς λαμβάνοντας υπόψιν την αβεβαιότητα της αιολικής παραγωγής.
- την επίδραση α) της αυξανόμενης διύσδησης της αιολικής ενέργειας, β) της μεταβλητότητα της καθώς και γ) της συμφόρηση των γραμμών μεταφοράς ενέργειας στα προσδοκώμενα κέρδη των παραγωγών.

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Abbreviations

BE	Binary Expansion
CPU	Central Processing Unit
CSF	Conjectured Supply Function
CVAR	Conditional Value at Risk
DA	Day-ahead
DC	Direct Current
EPEC	Equilibrium Programming with Equilibrium Constraints
GWh	Gigawatt hour
ISO	Independent System Operator
KKT	Karush-Kuhn-Tacker
LMP	Local Marginal Price
MWh	Megawatt hour
MILP	Mixed Integer Linear Programming
MO	Market operator
MPEC	Mathematical Programming with Equilibrium constraints
NLP	Non Linear Programming
PJM	Pennsylvania-New Jersey-Maryland
RES	Renewable Energy Resources
RT	Real-time
RTS	Reliability Test System
SFE	Supply Function Equilibrium

Chapter 1

Introduction

1.1 Motivation and objectives

Nowadays, climate change is beyond any doubt one of the biggest environmental problems. Confronting the detrimental results of human activities on the climate, policy makers are prompted to adopt thoroughgoing measures concerning environmental sustainability. Electric generation systems are playing a significant role in encountering environmental objectives as they account for the bulk of the greenhouse emissions. Under this canopy, the EU has aligned its energy policies so that by 2050 the energy related to carbon emissions will have been reduced by 80% compared to 1990. These policies are highly supported by measures allowing for a strong penetration of high renewable energy sources (RES) reaching a level of 75% in gross final energy consumption (European Commission's communication for Energy, 2011).

Traditional energy market rules operated on the basis of facilitating carbon-intensive controllable capacity. Additionally, power system operations followed demand variations. However, as a result of the inherent uncontrollable fluctuations of the RES generation the operational frame is changing (Eurelectric, 2011). The aforementioned nature of RES, together with the lack of storage technology, increases the need for more responsive and expensive reserves to secure the network reliability, thus causing the conventional (thermal)

electric power generators to operate intermittently to deal with the frequent imbalances. This affects their efficiency and operational cost in a negative way. Furthermore, the decreased hourly operations and the resulting production volumes combined with the depressed electricity prices raise the question not only of the viability of the existing units but also of the feasibility of future investments. In addition, the appropriate mix of flexible capacity to accommodate the soaring amounts of variable supplies is prevented by anomalies in the energy market. The latter concern non-dispatchable generators being guaranteed priority feed-in (merit-order) while receiving profitable subsidies for producing electricity and other non-subsidized generators being price takers for fix cost recovery (Baker et al., 2010).

In general, the demanded flexibility has a long-term impact on the whole spectrum of the electric system from the day-ahead (DA) and real-time (RT) market operation to the future capacity (MIT, 2011). The obligation to offset the emerged intermittency has created the need for a new design which must resolve the integration challenges as well as the need for a new agenda in order to balance the policy trilemma of an efficient competitive energy market with a secure transmission system under an effecting low-carbon electricity supply.

Concerning the strong penetration of RES supported by a generous mechanism of subsidized production and priority dispatch, the role of conventional energy production is diminishing. Nevertheless, due to the variability of the generation, the congestions of the network, and the fluctuations of the electric power fed in the system the market operators are enforced to trade in RT to correct the imbalances which depend on the ability of thermal plants to supply energy under demand. Despite the market acknowledgement of the important role of the thermal plants as capacity providers, the latter are faced with unequal treatment and have to adopt specific strategic behaviour to ensure competitiveness.

Within the above context and considering the conventional energy production, we study the strategic behaviour and reaction of an incumbent conventional power producer and examine its incentives to exert market power and ensure its dominant position in order to avoid energy profit losses. For the sake of this thesis, RES refer to wind power producers.

Thus, based on the assumptions of the sequential Stackelberg single-leader single-follower game (Stackelberg, 1934), we initially develop a stochastic bi-level complementarity model. The upper-level problem maximizes conventional producer's (leader) expected profits, and the lower-level problem facilitates the economic dispatch conducted by independent system operator (ISO) (follower) considering wind production uncertainty. Assuming the continuity and differentiability of the lower-level problem, the latter is substituted by its first order Karush-Kuhn-Tucker (KKT) reforming the bi-level model into a single-level mathematical programming with equilibrium constraints (MPEC). Then we formulate the KKT complementarity conditions as disjunctive constraints (Fortuny-Amat and McCarl 1981) recasting the MPEC into a mixed integer linear programming (MILP), which is tractable by commercial solvers and can be solved to global optimality (Floudas, 1995). In order to include the impact of network effects on the game decisions, the energy physical flows will be modeled by means of direct current (DC) linear approximation (Kirschen and Strbac, 2004; Zavala et al., 2017).

The primary objective of this thesis is to:

- Encourage research on the market implications of strategic behaviour in low-carbon electricity systems.
- Examine the implications of market power in coordinated auctions for energy and reserves (Birge and Louveaux, 2011).
- Investigate dynamics of arbitrage between the DA and RT stage based on the most profitable combination of quantity and price offers.
- Determine the impact of strategic offering under uncertainty on locational marginal prices and assess the economic consequences on industry-wide participants (Pritchard et al., 2010).

Moreover, considering the paradox faced by RES as their continuous growing penetration in generation industry suppresses further the market prices, the same questions also arise for

the WPPs. Therefore, concerning the incentives of a WPP to mitigate its expected profit losses, we extend the previous model for an incumbent producer who possesses a thermal and wind generation portfolio. Using a similar process, the new bi-level model is reformed first into an MPEC and then into an equivalent MILP. In addition, the objective of the new model is to:

- Investigate the effect of WWPs' strategic behaviour on network constrained market prices.
- Identify further arbitrage opportunities given that now the producer exercising market power by means of capacity withholding can change the mixture of both thermal and wind productions to its benefit.

Finally, this research analyzes the market under the assumption that more than one producer exercises market power. To do so, the bi-level model of each producer is recast into an MPEC with primal-dual formulation. The joint solution of all MPECs constitutes a multi-leader single-follower equilibrium programming with equilibrium constraints model (EPEC). The objective of this work is to:

- Study the interaction between producers with conventional and wind generation portfolios in a two-settlement electricity market.
- Derive meaningful market equilibria in an ex-post analysis using a single-iteration diagonalization method.
- Define the range of market equilibria by applying different objective functions considering competitive, less competitive, and monopoly markets.
- Investigate the impact of wind power increment and wind power volatility on market equilibria.

This thesis also proposes a new approach to linearize the nonlinear objective functions of MPEC models avoiding the use of any binary expansion method, thereby, reducing the computational burden and rendering solvable more sophisticated networks.

1.2 Thesis overview

This thesis is organized as follows:

Chapter 1 introduces motivation, objectives and solution approaches to cope with the problems raised in this thesis. It also provides an overview of power system and electricity markets. It analyzes the concepts of merit-order effect and market power, and it offers a literature review of the state-of-the-art research in energy market equilibria considering the strategic offering problem. Finally, it provides the mathematical background of bi-level models deriving the optimality conditions of the MPEC and EPEC models proposed in this thesis.

Chapter 2 describes a network constrained electricity pool which co-optimizes the DA and RT markets. It provides the mathematical model of the market clearing process considering wind production uncertainty through a two-stage stochastic programming, the main assumptions, and the pricing scheme. At the beginning, the Chapter also includes a section with the nomenclature associated to the market clearing algorithm as well as the MPEC and EPEC models proposed in Chapters 3, 4, and 5.

Chapter 3 addresses the strategic offering problem of a conventional producer in a pool market with large scale wind power production. Based on the single-leader single-follower Stackelberg game, a stochastic bi-level model is introduced to derive optimal offers (price/quantity) for this producer (leader). The upper level maximizes the expected profit of the strategic producer, and the lower level clears the market under economic dispatch conducted by the ISO (follower). The bi-level model is recast into an MPEC and then into an MILP with the use of the KKT conditions, the strong duality theory, and disjunctive constraints. Two different networks (6-bus and RTS systems) are used to show the applicability of the proposed model.

Chapter 4 provides an extension of the previous model. In this case, the generation portfolio of the strategic producer also includes wind power. Following a similar process

the bi-level model is initially reformed into an MPEC and then it is reduced into an equivalent MILP. The proposed algorithm is applied to the same networks analyzing further arbitrage opportunities for the strategic producer.

Chapter 5 examines market equilibria when more than one producer act strategically. Based on the multi-leader single follower game, an MPEC with primal-dual formation is introduced to model the strategic behavior of each producer. The joint solution of all producers' MPECs forms an EPEC model. The EPEC is recast into an MILP considering different degrees of competition. The applicability of the proposed model is illustrated by two case studies with 2-bus and 6-bus systems.

Chapter 6 provides a synopsis including the relevant conclusions drawn from the research throughout this thesis, the main contributions of the research, and considerations for future work.

Appendix A offers the linearization processes of the objective functions of the MPEC and EPEC models. It also presents the substitution of the EPEC's KKT complementarity constraints with the equivalent linear disjunctive constraints.

Appendix B depicts the correlation between demand energy blocks and bidding prices for a 24-hour period (Chapters 3 and 4).

Appendix C provides data for the one-area (24-bus) RTS system of IEEE and the conventional power generating units, as well as for the location and distribution of the demand.

1.3 Electricity power system

The previous two decades have seen a gradual reformation of the electricity sector in various countries. There has been market liberalization of the electricity markets because of the privatization of the big state-owned companies, or more frequently, due to the deregulation of privately owned controlled utilities by developing organizations that encourage

rules to ensure that these electricity markets function appropriately. In many cases organizations have been developed, for example Regulatory Commissions, and these may or may not have anti-trust jurisdiction. However, there is extended jurisdiction of organizations that are nearly always extant such as the the Federal Energy Regulatory Commission (FERC, 2020). The restructuring process is being carried out by several countries, who take significant lessons from other countries that have already carried out liberalization of their own markets (Joskow, 2008). Consequently, new and normally sophisticated economic theories are used to develop complex regulatory models.

The commodity of electricity typically involves four key activities, which are generation, transmission, distribution and commercialization (Bhattacharya, 2001; Zhang, 2010; Sheblé, 2012; Ilic, 2013). In traditional power systems, these activities are typically controlled by a single vertically integrated company that is generally state-owned. This means that a centralized body makes decisions that decreases overall operating expenses, adheres to the technical limitations and makes certain that there is adequate reliability. This is how mathematical programming approaches and instruments have been instrumental in carrying out these rules.

The deregulation process of the electricity market is being carried out since the early part of the 1980s, where there is an evident inclination towards dissolution and separation of the various activities to encourage competition. This development has been based on the search for (Bhattacharya, 2001) :

- Low electricity prices based on real generation cost rather than tariff set.
- Efficient capacity expansion.
- Operation and planning cost minimization.
- High quality services based on reliable power systems.
- Increasing competition by allowing new entries in the market.
- Supporting transparency in all market transactions.

A decentralized approach should be used when considering the planning and functioning of power systems in this new setting for energy trading. For instance, each power generating firm determines the amount of energy to be generated on its own and how to maintain its production units. There is a lack of centralization of the investment on capacity extension; therefore, firm takes the decisions in accordance with its aim of maximizing profits from the investments since it usually does not have specified duties pertinent to suitability of the system. Therefore, the decisions being taken in the planning and operation of power systems are driven by economic objectives. The fundamental theories on microeconomic evaluation need to be considered to comprehend the behaviour exhibited by the participants. In this field, a vital part has been played by the game theory market equilibrium models in influencing the market for power systems.

1.3.1 Power system participants

There are different agents that take part in the electricity market, including consumers, producers, market operator, retailers and the system operator. A brief description follows:

- Producers: The role of producers is to generate electricity to cover the demand and also to look after the investment, functionality and maintenance of their generation capacities.
- Consumers: Consumers refer to those who buy energy, typically from the retailers. Large-scale consumers are permitted by a few regulatory frameworks to directly purchase energy from the market or the producers.
- Retailers: The trading of energy between producers and consumers is carried out by the retailers. They do not have ownership of generating units; hence, they buy energy from the electricity market and then sell it to consumers.
- Market Operator: It is the responsibility of the market operator to perform economic regulation of the power system as part of the supply generation offers and the demand

offers obtained. It ensures that the market laws are implemented and that the market clearing process depends on increasing social welfare and decreasing generation expenses.

- Independent System Operator: It looks after the technical management of the system. The key aim of the independent system operator (ISO) is to ensure that a dependable RT energy supply is provided. This can be attained when the ISO synchronizes the generation, consumption and transmission of electricity. In many power systems, like PJM and ISO-New England, ISO embodies market operator, therefore, it is the responsibility of the ISO to perform the economic as well as the technical management of the market.

There are a few more significant parties involved in the power system; however, they do not have a direct involvement in the wholesale energy market. These include:

- Transmission companies: these companies carry out the development, maintenance and operation of the transmission lines under their ownership. In most power systems A single transmission company has ownership of majority of the transmission grid.
- Distribution companies: Most of the energy is obtained by the distribution companies from the transmission grid and then is provided to consumers situated in distinct geographical areas.
- Market regulator: This is an independent body that supervises the electricity market and makes sure that the market is operating properly, i.e. it ensures that the market is efficient, transparent and competitive.

1.3.2 Electricity markets

The market systems that are used most commonly across the world for energy trading are presented below. They typically back distinct time trading floors that are appropriate for maintaining the balance between demand and supply.

- Forward market: In this market, energy trading involves delivery being made in the future, which may in a week, a month or even one year in advance. Transactions in this market may be carried out with a physical supply of energy, a financial agreement or just by price differentials against the DA market.
- Bilateral contracts: Purchase contracts (known as physical bilateral contracts) can be established between agents instead of establishing contracts in organized markets. The ISO should be informed about the energy related to this kind of contracts so that it considers they while distributing electricity.
- Day-ahead market: This market is of a short-term nature, in which energy trading is carried out for each of the 24 hours of the following day on an hourly or a 30-minute basis. The ideal reference price of electricity is the price of this market, and it is used to perform settlement of the futures market and other aspects pertaining to the sector's regulation. One day before energy is delivered, the production of energy is determined in this market with economic criteria based on the viability of the established energy program to cover the demand.
- Ancillary services: It is imperative for power systems to ensure that the production levels of the generating units are according to the demand at any given point in time. This can be accomplished by means of ancillary services that are classified into primary, secondary and tertiary control, in addition to imbalance management. It needs to be considered that with the exception of primary control, the others are offered at market rates by means of auctions, where just the producers that are capable of meeting the load variation are permitted.

1.3.3 Energy transmission

The electricity system can become more reliable with the transmission of electricity, while encouraging the use of technologies to produce electricity at lower costs.

In majority of the power systems, electricity distribution is a natural monopoly that is usually regulated by a monopolist in every political jurisdiction (though this is not always true, such as in the United States). This means that the network functions as a single unit. This aspect is particularly significant in the prevailing context of majority of the electricity markets which have seen the unbundling of production activities and sale of electricity. Here, the meeting point for buying and selling of energy is the transmission of electrical energy, which is very critical to make sure that these power systems are in a good condition. In addition, since it is an essential facility, it is vital to control access. The characteristics of the transmission network can be categorized into four points when viewed from an economic perspective:

i) There are very little operational expenses of the network (nearly 3% every year) in comparison to investment expenses.
ii) Transmission cost shows economy of scale.
iii) The comparative economy of the transmission network varies according to the geographic expansion of the country and the distribution of generation and consumption.
iv) The operation of the power system should be carried out as a whole also engaging the transmission network.

1.4 Market price and merit-order effect

In electricity exchanges, which have the form of an auction, the market clearing price is defined at the point where demand and supply curves intersect. Thus, considering demand, it is the lowest accepted bid to buy energy, and considering power generating units supply, it is the most expensive marginal cost accepted in the auction which actually define the price in the market for all generating units involved.

The term merit-order defines the sequence in which generating units are scheduled to produce power by seeking the economic optimization of energy supply. Separating the fix

cost associated to power generating technology, the merit-order prioritizes power units, which continuously produce electricity at the lowest marginal cost, and subsequently adds units in an ascending marginal cost order. This price clearing mechanism is called uniform pricing since all the units are compensated at the same price for their feed-in production, in contrast to the pay-as-bid mechanism where the units are paid at different prices in a continuous trading.

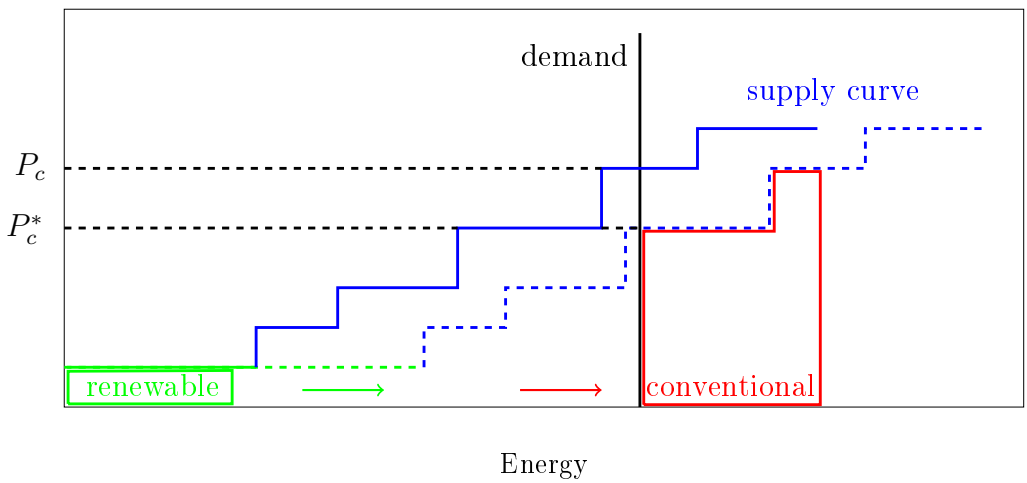

Figure 1.1: Merit-order effect

However, the uninterrupted increasing share of RES in energy markets has influenced the electricity market prices, since the feed-in of production with low or even zero cost causes a rightward shift of the supply curve. As shown in Figure 1.1 the shift removes the intersection point between supply and demand curve at lower level, reducing the market clearing price ($P_c - P_c^*$) and cutting out higher cost conventional generation. This phenomenon is called merit-order effect (Sensfuß et al., 2008).

1.5 Market power in electricity markets

The prime target of electricity market liberalization is to give incentives for power producers to minimize their cost, to encourage innovation, and to keep the market prices down

through competition, thereby, providing final consumers with high quality services and low-price electricity. However, the hypothesis that liberalization will naturally derive competitive conditions and results is not always guaranteed. The price orientation, the specific features of the industry, and the physical characteristics of the electric energy make the market vulnerable to market power exertion. First, as the large-scale energy storage is not available, and RT production is needed to cover demand, a shortage of supply can be caused due to technical limitations faced by generating units to provide short-run reserve deployments (Borenstein, 2000). Second, the physical laws, which govern the power flow, render the scheduled operation complicated and set any network stability failure financially problematic (Green, 2008). Third, the frequently concentrated structure of power generating firms, the inelastic to price demand, and the scarce nature of electricity as product which stems from the objective limitation of supply give the incentives to incumbent firms to raise their profits by suppressing competition and increasing market prices.

In the literature of economic theory, the term market power is defined as "the ability to profitably alter prices from competitive levels" (Stoft, 2002; Twomey et al. 2006; Krugman and Wells; 2009; Mankiw, 2016). A similar definition is also given by the United States Department of Justice according to which market power is "the ability of a supplier to profitably raise prices above competitive levels and maintain those prices for a significant time period". Each word of these definitions is important and wisely chosen. The word "ability" makes it possible for the regulator to distinguish the difference between "exercising" and "having" market power as the latter is not automatically unlawful. However, Stoft (2002) claims that the only rational reaction of a firm having market power is to exercise it. This distinction has meaning when we examine the market power under an ex-post (exercising) or ex-ante (having) analysis. The word "profitably" defines that market power exertion should be profitable; therefore, an action of production curtailment or unit shutdown can be characterized as market power exertion only under profitability requirements. The expression "maintain prices above" excludes the case where an incumbent firm set the

prices lower than competitive prices to prevent new entrances in the market (predatory pricing). Even if McGee (1980) and Easterbrook (1981) show that a predator's threat is not credible considering long time period as the incurred losses are higher compared to those of coexisting with a rival, a successful predatory pricing policy would set the prices higher in the post-predation period to offset the incurred losses in predatory period. In addition, Hansen and Percebois (2012) identify that a dominant firm has certain incentives to make room for new entrants taking benefits from short-term increased prices and attracting less attention from regulatory authorities. This is why the definition of market power indirectly refers to market prices increase. Finally, the phrase "above competitive levels" is the most important for the definition of market power even if it can be controversial as there are cases which could result in higher market prices. This can happen, for example, when demand exceeds supply and the will for consumption is offered higher than that of supply or in a case where high demand permits costlier units to operate covering their fixed costs. In these cases, market power is not exercised as the market balance is based on system marginal cost even if the prices are high. This is why, a firm is said to exercise market power when it only increases market price above system marginal cost.

1.6 Capacity withholding strategies

Considering electricity markets , the literature recognizes two types of market power: vertical and horizontal. Vertical market power refers to firms which are involved in more than one activity in downstream line e.g. generation and transmission. In this case the firm, using its dominant position in one activity, takes the comparative advantage and increases its overall revenues. Horizontal market power refers to firms which exercise market power at one stage of the production process and influence outcomes and prices at another stage. In our case, as we only study generation and energy-only markets, we concentrate on horizontal market power. The instruments used by a power producer to exercise market power concern mainly capacity withholdings. The term withholding is used to describe strategies and has

two components physical or quantity withholding and financial or economic withholding. The former considers the case where the producer exercises market power by withholding production. As shown in Figure 1.2, production curtailment (in red) shifts the competitive

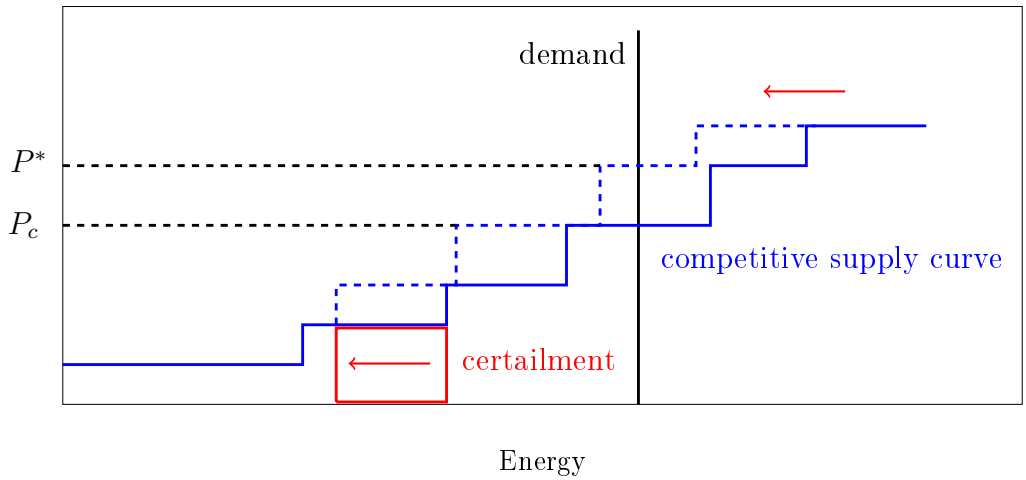

Figure 1.2: Physical withholding strategy

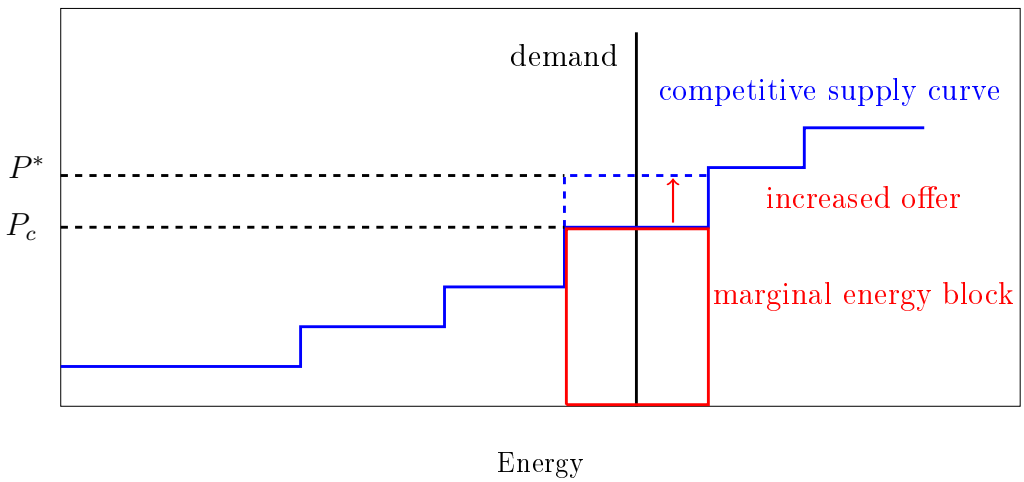

Figure 1.3: Financial withholding strategy

supply curve to the left setting the market price at higher level. In case of financial withholding, the strategic producer leads to the same result using increased offers. As presented in Figure 1.3 the marginal energy block (in red), which defines the market price, is bid

higher shifting the competitive supply curve upwards. Analyzing the markets, we can see the capacity withholding results, but it is difficult to distinguish which strategy the producer follows. Finally, in a network-constrained market, a third instrument for a producer with a well-diversified generation portfolio is to exercise market power through the manipulation of the production mixture. Thus, based on line transmission related limits the producer can create monopoly pockets raising the LMPs and increasing its profits.

There are two main social consequences of market power exertion. First, the transfer of wealth from consumers to producers which equals to price distortion ($P^* - P$) multiplied by the total energy production. Second, the increased profits do not concern only the producer who exercises market power but all the producers as everyone is paid at the same price. In fact, in many cases market power exertion is less profitable for the one exerting it considering the exercise cost.

1.7 Literature review

This Chapter provides literature review under the canopy of energy economics with a particular consideration on strategic behavior of market participants. Game theory offers the appropriate mathematical framework to model the interaction between economically involved entities each of which anticipates the maximization of its own pay-off.

1.7.1 Oligopoly competition and market equilibria

The mathematical model for determining the equilibrium in an n-person game was presented by John F. Nash in 1950, which was known as the Nash equilibrium (Nash, 1950). Several publications have been put forward for forming new theories of equilibrium, new algorithms to solve them and new applications in nearly all knowledge domains. A new field of knowledge has been established by the Game Theory. The strategic behaviour of the individual players is expressed by the Game theory, in which the decision of each players is

based on the decision made by other players (Fudenberg and Tirole, 1991). The new questions that have emerged following the deregulation process in power systems are answered by applying the game theory. A required goal for both the participants and regulators of the market is looking for potential market equilibrium. It is required by participants because it demonstrates the strategies of the competitors to the participants, while it is required by market regulators as it allows market power supervision and corrective measures. Knowledge about equilibrium serves as a significant tool that power producers can use to execute their strategies. Since power systems are of an oligopolistic nature, perfect competition is not exhibited and equilibrium models are needed to evaluate the market outcomes and the behaviour of participants. Oligopolistic competition suggests that the outcomes of the market can be influenced by the market participants. When decisions are made at the same time by participants (one-shot game), it is possible to classify the market equilibrium as follows:

- **Cournot equilibrium**. This is one of the main methods used by researchers to analyze the market and the behaviour of the participants (Cabral, 2006). In this form of equilibrium, the output quantities are simultaneously selected by the participants and the market price is defined at the point that total produced quantity equals to demand. Two Cournot models are developed by Hobbs (2001) as mixed complementary problems, consisting of a DC network representation. The first one is put forward for bilateral agreements, while the other one pertains to a pool-based market. Another model identical to previous one is put forward by Contreras at al. (2004). However, the equilibrium is sought using a relaxation algorithm on the basis of the Nikaido-Isoda function, rather than the KKT conditions employed by Hobbs.
- **Bertrand equilibrium**. This equilibrium is based on the interdependency of price decisions between competitors where prices are used as strategic variables, rather than quantities. In the absence of any capacity or transmission limitations and the presence of a unique good, the model leads to perfect competition (David and Wen, 2001). This model cannot be extensively applied to electricity markets and does not have many

uses. For instance, a linear model was formulated by Hobbs (1986) for identifying the equilibrium of the electricity market on the basis of price competition. In another study conducted by Lee and Baldick (2003), the findings of the Bertrand equilibrium are contrasted with other equilibria. Here, the Nash equilibrium is developed for a three-player game in mixed strategies for Cournot and Bertrand games.

- **Supply function equilibrium (SFE)**. In this equilibrium model the participants put forward their offers in price as well as in quantity. Every participant needs to determine their entire supply curve for various prices and quantities. The proposed model derives particularly good results; however, it is difficult to employ in extensive power systems. The results of SFE are identical to the Cournot equilibrium when the system is at peak demand where production nearly achieves the maximum generation capacity of the system and close to the Bertrand equilibrium at off-peak demands and when the generation capacity is considerably larger than the demand (Smeers, 1997). There has been extensive use of linear (Weber and Overbye, 1999; Baldick et al., 2004; Liu et al., 2004), piece-wise (Baldick and Hogan, 2001) and step-wise supply function (Barroso et al., 2006a; Pozo and Contreras, 2011) models for determining equilibria in electricity markets.

It should be noted that the participants increase their profits individually by making the assumption that the competitors do not modify their outputs in response to the rivals' decisions. If this is not the case, then every participant makes speculations about the reactions of the other competitors by using their views or anticipations regarding the response of their rivals to modification in their output. The equilibrium approaches given above are often combined with the term conjectural variation (CV) equilibrium (Garcia et al., 2002). In work of Song et al. (2003), CV in Cournot decisions is used for the optimal offering problem of power producers in the DA market. Conjectured SFE is used by Day et al. (2002), where supply functions are selected by the producers to determine the way competitors will modify their sales following price variations. When decisions are made by the participants at various

stages (sequential game), the market equilibrium may be categorized as follows:

- **Stackelberg equilibrium**. The prime Stackelberg equilibrium refers to a single-leader single-follower game, in which a participant, referred to as the leader, makes the decision before other market participants, who are referred to as the followers. The leader is able to maximize their profits, anticipating the response of follower, who act optimally to the decision of leader. Thus, in this hierarchical game, the leader's decisions are influenced by those of the follower, and vice versa. Therefore, the leader benefits from being the first one to take a decision. Considering power systems, the Stackelberg game is employed to model: the strategic offering problem, the generation capacity investment problem, and the assessment of the vulnerability of power systems following calculated attacks (Arroyo, 2010).
- **Multi-leader multi-follower game**. In this game of multiple players there is an hierarchy between two groups of players. One group acts as leader deciding first and the other group acts as follower responding to leaders' decision similarly to Stackelberg model. However, each player at the same hierarchical group maximizes their payoff in a non-cooperative game considering the optimal strategies of the rest players of the group. These games are known as Stackelberg-Nash games (De Wolf and Smeers, 1997; Xu, 2005) since they involve a Nash equilibrium problem within each group and a Stackelberg equilibrium problem between the hierarchical groups.

In general, Stackelberg equilibrium and Nash-Stackelberg equilibrium problems can be modeled as bi-level optimization problems. When there is a single leader the problem can be stated as a mathematical programming with equilibrium constraints optimization problem (Dempe, 2003; Facchinei and Pang, 2007). In case there are multiple leaders the problem can be stated as an equilibrium problem with equilibrium constraints optimization problem (Ralph and Smeers, 2006; Hu and Ralph, 2007; Zhang, 2010).

1.7.2 MPEC modeling in energy markets

Mathematical problems with equilibrium constraints (MPEC) are hierarchically related optimization problems essential to the formulation of today's energy markets as they can treat both prime (generation) and dual (price) variables and incorporate diverse technical and economic market characteristics such as transmission capacity limits or power market exertion (Gabriel et al. 2012). Particularities in electricity markets such as transmission constraints, generation capacity, and demand allocation as well as transmission pricing and bilateral contracts may lead to imperfect competition allowing production firms to exert their dominant position to influence the market prices above their marginal cost. Hobbs et al. (2000) developed an MPEC to examine the behaviour of several incumbent energy producers in an oligopolistic market on a general linearized DC network where power flows, and participant's offers are constrained by the system operator (SO). The model calculates market price equilibria using the supply function conjectural variation regarding the offering strategies for each producer. Consequently, a two-level optimization problem is formed in which the upper-level problem derives the strategic behaviour of the leader producer calculating the optimal supply curve, and the lower level simulates the algorithm performed by the SO to optimize the energy dispatch and clear the market price. Despite the fact that no algorithm can guarantee optimal solutions to a problem which is inherently non-convex, the advanced interior point algorithm used to solve the problem ensures efficient results.

Day et al. (2002) introduced conjectured supply function (CSF) models. In these models based on Stackelberg hypothesis, a generation firm participates in a competition through an affine supply function anticipating its rivals' adjusted sales in response to market price changes. Subsequently, a mixed complementarity problem to derive Nash equilibria is adopted using first order Karush-Kuhn-Tucker (KKT) optimality conditions under the assumption of convexity. The CSF approach is more flexible than the Cournot, and it can be applied successfully to large networks while SFE cannot. The CSF can also be extended to ancillary service markets where the demand is characterized by zero elasticity. The proposed

model by Bautista et al. (2006) is an extension of the work done by Day et al. (2002), and it concerns a joint energy and reserve market. Additionally, with the CSF competition the model introduces the conjectured reserve price responses to find equilibrium within a spectrum of strategies allowing the identification of the parameters of the opportunity cost between generation and reserves as well as the identification of the manipulation effect on the reserve prices. The complementarity model is applied in a multi-period market for a six-node system using a linearized DC approximation, but it does not consider commitment decisions such as start-up and shut-down to avoid non-convexities.

Haghighat et al. (2007) are ambivalent about the CSF method considering the difficulties in construction of CSF due to the lack of marginal cost data. Therefore, to model the strategic behaviour of power producers which participate in a joint energy end reserve oligopolistic market, they introduced a parameterized SFE model. In their research, the developed method employs a two-degree of freedom parameterization which involves the manipulation of both the slope and the intercept of the supply functions as shown in Baldick (2002). The engaged bi-level optimization problem results in Nash equilibrium strategies under the pay-as-bid pricing and marginal pricing mechanisms.

Pereira et al. (2005) proposed a binary expansion (BE) approach to solve the strategic offering problem in short-term electricity markets. The BE scheme eliminates the nonlinearities approximating the continuous decision variables by a set of discrete values, and the nonlinear problem is recast into a mixed integer linear programming (MILP) problem solvable by commercial solvers. Additionally, the BE approach can be applied to joint price/quantity offers, network constraints, financial instruments, uncertainties under a diversity of price and quantity scenarios, and unit commitment.

Based on the BE approach mentioned above Bakirtzis et al. (2007) suggested a bi-level optimization problem to attain the optimal offering strategies of electricity producers in a spot market with a stepwise offers format. The MPEC is transformed into an MILP. Furthermore, the results of a ten-unit system produced by MILP are compared with those

derived by nonlinear programming (NLP) solvers. The comparison shows the supremacy of the MILP even if it is a time-consuming formation as the NLP fails to deliver the optimal global solution in several cases. However, the model is restricted to energy-only markets and small networks avoiding multi-period decisions and network constraints.

Ruiz and Conejo (2009) proposed a 24-hourly transmission constrained MPEC to derive the optimal offering strategies of a power producer with a dominant position in a pool-based electricity market. The uncertainty of the generating offers and of the demand side bids is considered, and the local marginal prices (LMPs) are generated endogenously. The MPEC is reformed to an MILP obliterating the nonlinearities using the KKT optimality conditions and the strong duality theory. The mathematical formulation is applied in networks of diverse intricacy, and the network congestions are used as one more strategic mechanism for further growth of the strategic producer's profit.

Barroso et al. (2006a) formulated a Nash Equilibria (NE) in strategic offering algorithm for short-term electricity markets using a BE approach. In contrast, Gabriel and Leuthold (2010) transformed the strategic player MPEC to an MILP including network transmission constraints. They replaced the KKT optimality conditions with disjunctive constraints and linearized the bilinear terms price-generation with the use of a discrete set of valid generation levels in connection with indicator binary variables that equal to one, when the generation level is true, and to zero in all other cases. The method is applied in both a three-node network and a fifteen-node system representative of the Western European grid under several scenarios. The results show that even if the computational time increases with the increase of the number of the discrete variables as the available production of the strategic producer expands, the prospects of using the suggested mathematical approach for large-scale models is promising.

1.7.3 Modeling wind power integration

Considering the significant penetration of wind power production in energy systems, Hatziargyriou and Zervos (2001) indicated the need for assessing the effect of market liberalization process on distributed energy resources. Under the full scope of unit commitment schedule in operational planning, Bouffard et al. (2005) proposed a stochastic security constrained, multi-period electricity market clearing algorithm with unit commitment taking into account inter-temporal decisions, network capacity limits, involuntary load shedding, and likely contingencies. Pinson et al. (2007) propose a generic methodology to derive optimal strategies for a wind energy producer in pool markets. The model takes into consideration a probabilistic forecast production assuming that the wind power producer does not exercise any production control strategy. To facilitate the wind energy production Morales et al. (2009) extended the two-stage stochastic program proposed by Bouffard et al. to derive the required reserve levels considering both the wind spillage and load shedding costs. Dent et al. (2011) propose a model to optimize strategies for an averse volume risk wind power producer in forward markets. The model is based on the RT wind power capacity availability and the expected RT prices which correlate with forward prices and wind power units out-turns. Papavasiliou et al. (2011) presented a two-stage stochastic unit commitment model quantifying reserve requirement and operational cost under uncertain production in a non-sequential market clearing and system operation approach. On the contrary, Morales et al. (2012) provided a marginal pricing scheme of both DA and balancing market through a two-stage stochastic programming model where scheduled generation and reserve deployment are represented sequentially.

In previous work, wind power producers (WPs) are considered as price takers. Baringo and Conejo (2013) introduced a stochastic MPEC formulation to derive the optimal bidding strategy of a WP who exerts its dominant position participating as price maker in the DA market and as price taker in the balancing market. On the other hand, Zugno et al. (2013) developed an MPEC approach to optimize the expected revenues of a WP who participates

as price taker in the DA market and as price maker in the RT market.

1.7.4 EPEC modeling in energy markets

EPEC models are extension to MPEC models wher more than one player act as leader in the upper-level problem. In previous years, several works examined market equilibria under uncertainty. Klemperer and Meyer (1989) study oligopoly competition with demand uncertainty where each firm selects its own supply function relating optimal quantities to best offers. De Wolf and Smeers (1997) propose a two-stage single-leader Stackelberg-Nash-Cournot model. In the first stage the leader chooses its production taking into consideration the follower's reaction, and in the second stage the follower reacts according to Cournot assumption. Pang and Fukushima (2005) present a multi-leader follower game formulated as a quasi-variational inequality model solved by an iterative penalty method. Hu and Ralph (2007) develop a bi-level non-cooperative recast into an EPEC for restructured short-term electricity markets with nodal marginal prices. The model introduces Nash stationary points based on the stationary theory of MPECs to establish sufficient conditions for pure strategy Nash equilibria. Sauma end Oren (2007) propose a three period model. In third period an energy market is modeled for transmission and generation. In second period the competitors optimize the expected value of new investments in generation capacity. In first period a network planner is called to decide which transmission line to build or upgrade anticipating the reaction of the lower problems the joint solution of which constitutes an EPEC model. Daxhelet and Smeers (2007) illustrate an EPEC model where power generators from different countries act as leaders (Stackelberg leaders) seeking to maximize their countries net profits. The regulator of each country is represented by equilibrium constraints in response to electricity market operation (the market acts as Stackelberg follower). In the meantime, each regulator assumes that the others do not alter their decision (Nash equilibrium between regulators)

Anderson and Hu (2008) extend the model of Klemperer and Meyer using an asymmetric

supply function with capacity constraints. They show that not only do equilibrium solutions appear in order, but that in many cases there is only one solution. Yao et al. (2008) propose a two-period Nash-Cournot equilibrium model in two-settlement (forward and spot) electricity markets considering flow constraints and demand uncertainty and market power. In this case the Nash equilibrium is formulated as an EPEC in which each firm solves its own MPEC. The EPEC equilibrium solution is based on a reiterative application of all firms' MPECs. DeMiguel and Hu (2009) extend the previous model to a multi-leader Stackelberg model where then the finding of equilibrium is based on the sample average approximation method. Leyffer and Munson (2010) propose a multi-leader common-follower game where they examine a synthesis of non-linear optimizations and complementarity formulation of EPECs.

Ruiz et al (2012) based on an hierarchical structure propose an EPEC using a primal-dual formulation of the MPEC's strong stationary conditions. However, the stationary points of the EPEC solution could be equilibrium points, saddle points, or local optimizers; therefore, an ex-post analysis is needed for the selection of meaningful equilibria. Regarding wind power penetration in energy markets, the literature until recently considers wind power producers as price takers. Furthermore, in oligopoly conditions Kazempour and Zareipour (2014) develop an EPEC model to examine the impact of high wind power penetration on DA and RT market equilibria considering equilibria in a single bus and only under producers' expected profit maximization. In addition, Dai and Qiao (2017) advance an EPEC model to derive equilibria in short-term markets with strategic and non-strategic wind and conventional power producers. The model takes into account wind power production and demand uncertainty, and its solution is approached by a diagonalization algorithm.

1.8 Mathematical framework of bi-level problems

Bi-level optimization problems are problems with an hierarchical structure where an upper-level (leader's) problem with the general form (1.1) - (1.3) is constrained by a lower-

level (follower's) problem (1.4) - (1.6). On account of this, an optimal solution of the upper-level problem should satisfy the upper-level constraints and belong to the feasible region of the lower-level problem.The general form of a bi-level optimization problem is given below:

Upper-level problem

$$\underset{\Xi^U}{minimize} \quad f^U(x^U, x^L, \lambda, \mu) \tag{1.1}$$

$$subjected\ to \quad h^U(x^U, x^L, \lambda, \mu) = 0 \tag{1.2}$$

$$g^U(x^U, x^L, \lambda, \mu) \leq 0 \tag{1.3}$$

Lower-level problem

$$\underset{x^L}{minimize} \quad f^L(x^U, x^L) \tag{1.4}$$

$$subjected\ to \quad h^L(x^U, x^L) = 0 \qquad : \lambda \tag{1.5}$$

$$g^L(x^U, x^L) \leq 0 \qquad : \mu \tag{1.6}$$

The two optimization problems have their own objective functions and constraints which are characterized by the superscripts U and L respectively. Correspondingly, there are also two classes of decision variable vectors x^U and x^L and since the lower-level problem constrains the upper-level problem, the prime variable vector x^L and the dual variable vectors λ and μ of the former are included in the variable vector set of the latter as well. Thus, the prime variable set of the upper-level problem (1.1) - (1.3) is $\Xi^U = \{x^U, x^L, \lambda, \mu\}$.

The lower-level optimization problems proposed in this thesis are parametric optimization problems solved with respect to lower-level decision variable vectors since the upper-level decision vectors are received as parameters; therefore, they can be characterized as linear, continuous and thus convex. Based on that, the lower-level problem can be replaced by its own first order optimality conditions. The latter can be formulated through two substitute approaches.

1) **Karush-Kuhn-Tucker (KKT) conditions.** In this case, the lower-level problem is replaced by a set of equality constraints derived from the partial derivatives of the corresponding Lagrangian function with respect to each prime variable and a set of complementarity conditions, which express the orthogonality relationship between the inequality constraints of the lower-level problem and the associated dual variables.
2) **Primal-dual formulation.** In this approach the lower-level problem is substituted with a set of prime and dual constraints which are equivalent to KKT equality constraints, and with the strong duality equality which is equivalent with the KKT complementarity constraints.

The following sections provide the reformulation of the bi-level model into an equivalent MPEC based on both approaches.

1.8.1 MPEC formulation with KKT conditions

Replacing the lower-level problem (1.4) - (1.6) with its KKT conditions the bi-level model (1.1) - (1.6) is recast into a single-level MPEC model as follows:

$$\underset{\Xi^U}{minimize} \quad f^U(x^U, x^L, \lambda, \mu) \tag{1.7}$$

$$subjected\ to \quad h^U(x^U, x^L, \lambda, \mu) = 0 \tag{1.8}$$

$$g^U(x^U, x^L, \lambda, \mu) \leq 0 \tag{1.9}$$

$$\bigtriangledown_{x^L} f^U(x^U, x^L) + \lambda^T \bigtriangledown_{x^L} h^L(x^U, x^L) + \mu^T \bigtriangledown_{x^L} h^L(x^U, x^L) = 0 \tag{1.10}$$

$$h^L(x^U, x^L) = 0 \tag{1.11}$$

$$0 \leq -g^L(x^U, x^L) \perp \mu \geq 0 \tag{1.12}$$

$$\lambda : \text{free} \tag{1.13}$$

Where the equality (1.10) is derived by differentiating the corresponding Lagrangian function of lower-level problem with respect to prime variable x^L. Equality (1.11) is iden-

tical to equality (1.5). Constraint (1.12) expresses the complementarity slackness, and it is equivalent to the following constraints

$$g^L(x^U, x^L) \leq 0, \quad \mu \geq 0, \quad g^L(x^U, x^L)\mu^T = 0 \tag{1.14}$$

Finally, the condition (1.13) states that the dual variable associated with the equality (1.5) is free.

1.8.2 MPEC with primal-dual formulation

Since the lower-level problem (1.4) - (1.6) is considered linear, it can be rewritten with a linear form as follows, while the dual variable vectors are indicated in a colon alongside with the relevant constraints:

Primal lower-level problem

$$\underset{x^L}{minimize} \quad c(x^U)^T x^L \tag{1.15}$$

$$\text{subjected to} \quad A(x^U)x^L = b(x^U) \quad : \lambda \tag{1.16}$$

$$B(x^U)x^L \leq d(x^U) \quad : \mu \tag{1.17}$$

$$x^L \geq 0 \quad : \zeta \tag{1.18}$$

Where the $c(x^U)$ is the cost vector, $A(x^U)$ and $B(x^U)$ are the constraint matrices and $b(x^U)$ and $d(x^U)$ are the right hand-side vectors. Additionally, λ and μ are the dual variable vectors of the constraints (1.16) and (1.17) similar to those of the bi-level models constraints (1.5) and (1.6). Finally, the dual variable vector ζ corresponds to the non-negativity of the lower-level prime variable vector x^L.

The Lagrangian dual problem of the prime problem (1.15) - (1.18) is presented below:

Dual lower-level problem

$$\underset{\lambda,\mu,\zeta}{maximize} \quad b(x^U)^T\lambda + d(x^U)^T\mu \tag{1.19}$$

$$\textit{subjected to} \quad A(x^U)^T\lambda + B(x^U)^T\mu + \zeta = c(x^U) \tag{1.20}$$

$$\mu \geq 0,\ \zeta \geq 0 \tag{1.21}$$

$$\lambda : \text{free} \tag{1.22}$$

The optimality conditions which are associated with the lower level problem (1.15) - (1.18) and derive from the primal-dual formulation, are given below:

$$A(x^U)x^L = b(x^U) \tag{1.23}$$

$$B(x^U)x^L \leq d(x^U) \tag{1.24}$$

$$A(x^U)^T\lambda + B(x^U)^T\mu + \zeta = c(x^U) \tag{1.25}$$

$$c(x^U)^T x^L = b(x^U)^T\lambda + d(x^U)^T\mu \tag{1.26}$$

$$x^L \geq 0,\ \mu \geq 0,\ \zeta \geq 0 \tag{1.27}$$

$$\lambda : \text{free} \tag{1.28}$$

Where the constraints $A(x^U)x^L = b(x^U)$, $B(x^U)x^L \leq d(x^U)$ and $x^L \geq 0$ are included in the primal problem (1.15) - (1.18). The constraints $A(x^U)^T\lambda + B(x^U)^T\mu + \zeta = c(x^U)$, λ : free, $\mu \geq 0$ and $\zeta \geq 0$ are included in the dual problem (1.19) - (1.22). Finally, the strong duality constraint $c(x^U)^T x^L = b(x^U)^T\lambda + d(x^U)^T\mu$ enforces equality between primal optimal objective function (1.15) and dual optimal objective function (1.19).

The resulted MPEC model with primal-dual formulation equivalent to bi-level model (1.1) - (1.6) is presented as follows:

$$\underset{\Xi^U}{\textit{minimize}} \quad f^U(x^U, x^L, \lambda, \mu) \tag{1.29}$$

$$\textit{subjected to} \quad h^U(x^U, x^L, \lambda, \mu) = 0 \qquad : \alpha^U \tag{1.30}$$

$$g^U(x^U, x^L, \lambda, \mu) \leq 0 \qquad : \beta^U \tag{1.31}$$

$$A(x^U)x^L = b(x^U) \qquad : \gamma^{PC} \tag{1.32}$$

$$B(x^U)x^L \leq d(x^U) \qquad : \delta^{PC} \tag{1.33}$$

$$A(x^U)^T\lambda + B(x^U)^T\mu + \zeta = c(x^U) \qquad : \epsilon^{DC} \tag{1.34}$$

$$c(x^U)^T x^L = b(x^U)^T\lambda + d(x^U)^T\mu \qquad : \phi^{SD} \tag{1.35}$$

$$x^L \geq 0 \qquad : \xi^x \tag{1.36}$$

$$\mu \geq 0 \qquad : \xi^\mu \tag{1.37}$$

$$\zeta \geq 0 \qquad : \xi^\zeta \tag{1.38}$$

It should be noted that variable vector λ is free and the MPEC's dual variable vectors are shown in a column by the side of the constraints since they are used for the characterization of EPEC.

1.8.3 EPEC formulation

The joint solution of a set of interrelated MPECs constitutes an EPEC. To define the EPEC solution, the optimality conditions of all MPECs are jointly considered. It is essential to observe that the prime-dual formulation of the MPECs gives the mathematical advantage of avoiding the use of non-convex complementarity conditions, which are difficult to manage. However, since the MPECs are generally non-linear, in order to derive their optimality conditions associated with the EPEC it is better to use their KKT optimality conditions rather than a new primal-dual formulation.

Constructing the Lagrangian function $\mathcal{L}$ of the MPEC (1.29) - (1.38) KKT optimality conditions are derived as follows:

$$\begin{aligned}
\partial\mathcal{L}/\partial x^U = \quad & \nabla_{x^U} f^U(x^U, x^L, \lambda, \mu) \\
& + \alpha^{U^T} \nabla_{x^U} h^U(x^U, x^L, \lambda, \mu) \\
& + \beta^{U^T} \nabla_{x^U} g^U(x^U, x^L, \lambda, \mu) \\
& + \gamma^{PC^T} \nabla_{x^U} [A(x^U)x^L - b(x^U)] \\
& - \delta^{PC^T} \nabla_{x^U} [B(x^U)x^L - d(x^U)]
\end{aligned}$$

$$
\begin{aligned}
& + \epsilon^{DC^T} \nabla_{x^U} \left[A(x^U)^T\lambda + B(x^U)^T\mu - c(x^U)\right] \\
& + \phi^{SD^T} \nabla_{x^U} \left[c(x^U)^T x^L - b(x^U)^T\lambda - d(x^U)^T\mu\right] = 0 && (1.39)
\end{aligned}
$$

$$
\begin{aligned}
\partial\mathcal{L}/\partial x^L = \quad & \nabla_{x^L} f^U(x^U, x^L, \lambda, \mu) \\
& + \alpha^{U^T} \nabla_{x^L} h^U(x^U, x^L, \lambda, \mu) \\
& + \beta^{U^T} \nabla_{x^L} g^U(x^U, x^L, \lambda, \mu) \\
& + \gamma^{PC^T} A(x^U) - \delta^{PC^T} B(x^U) + \phi^{SD^T} c(x^U)^T - \gamma^x && (1.40)
\end{aligned}
$$

$$
\begin{aligned}
\partial\mathcal{L}/\partial \lambda = \quad & \nabla_{\lambda} f^U(x^U, x^L, \lambda, \mu) \\
& + \alpha^{U^T} \nabla_{\lambda} h^U(x^U, x^L, \lambda, \mu) \\
& + \beta^{U^T} \nabla_{\lambda} g^U(x^U, x^L, \lambda, \mu) \\
& + \epsilon^{DC^T} A(x^U)^T - \phi^{SD^T} b(x^U)^T = 0 && (1.41)
\end{aligned}
$$

$$
\begin{aligned}
\partial\mathcal{L}/\partial \mu = \quad & \nabla_{\mu} f^U(x^U, x^L, \lambda, \mu) \\
& + \alpha^{U^T} \nabla_{\mu} h^U(x^U, x^L, \lambda, \mu) \\
& + \beta^{U^T} \nabla_{\mu} g^U(x^U, x^L, \lambda, \mu) \\
& + \epsilon^{DC^T} B(x^U)^T - \phi^{SD^T} d(x^U)^T - \xi^{\mu} = 0 && (1.42)
\end{aligned}
$$

$$
\partial\mathcal{L}/\partial \zeta = \quad \epsilon^{DC^T} - \xi^{\zeta} = 0 \qquad (1.43)
$$

KKT equality constraints (1.39) - (1.43) are derived by differentiating the Lagrangian function with respect to the variable vectors x^U, x^L, λ, μ and ζ.

$$
h^U(x^U, x^L, \lambda, \mu) = 0 \qquad (1.44)
$$

$$
A(x^U)x^L = b(x^U) \qquad (1.45)
$$

$$
A(x^U)^T\lambda + B(x^U)^T\mu + \zeta = c(x^U) \qquad (1.46)
$$

$$
c(x^U)^T x^L = b(x^U)^T\lambda + d(x^U)^T\mu \qquad (1.47)
$$

Primal KKT equality constraints (1.44) - (1.47) are also included in the MPEC.

$$
0 \leq -g^U(x^U, x^L, \lambda, \mu) \perp \beta^U \geq 0 \qquad (1.48)
$$

$$0 \leq -[B(x^U)x^L - d(x^U)] \perp \delta^{PC} \geq 0 \tag{1.49}$$

$$0 \leq x^L \perp \xi^x \geq 0 \tag{1.50}$$

$$0 \leq \mu \perp \xi^\mu \geq 0 \tag{1.51}$$

$$0 \leq \zeta \perp \xi^\zeta \geq 0 \tag{1.52}$$

Constraints (1.48) - (1.52) are the KKT complementarity constraints related to MPEC's inequalities.

$$\alpha^U : \text{free} \tag{1.53}$$

$$\gamma^{PC} : \text{free} \tag{1.54}$$

$$\epsilon^{DC} : \text{free} \tag{1.55}$$

$$\phi^{SD} : \text{free} \tag{1.56}$$

Conditions (1.53) - (1.54) state that dual variable vectors related to MPEC's equalities are free.

The optimality conditions of the EPEC stem from the joint consideration of all the MPECs' optimality conditions. The solution to the latter provides the solution of the EPEC.

Chapter 2

Pool-based market

2.1 Day-ahead and balancing market

For the development of the bi-level complementarity models proposed in Chapters 3, 4 and 5 we consider short-term trading floor through an electricity pool-based market. The electricity pool involves two markets: the DA and the balancing or RT market. The DA market , which usually takes place 24-hours before the energy delivery, is necessary for conventional generation units like coal and nuclear plants to schedule their production efficiently and reliably and avoid technical limitations on their operation flexibility. In this stage, power producers submit their offers (a series of energy blocks - selling price pairs), and consumers and retailers submit their bids (a series of energy blocks - buying price pairs) in an hourly auction. Using an optimization algorithm, either ISO or MO clears the market under security constrained economic dispatch defining scheduled production and DA market clearing prices. With the term economic dispatch, we mean the optimal output of power generation units to meet demand at the lowest cost. The RT market constitutes a mechanism to cope with energy imbalances due to high penetration and uncertain production of RES. Thus, the market allows conventional producers to adjust their DA scheduled production by providing upward or downward reserves to cover unexpected shortage or surplus of renewable power production at RT. The RT market is cleared by the ISO in a similar way defining reserve

deployments and RT market clearing prices.

Considering reserve requirements, they can be scheduled by means of different heuristic methods which are based on historical data of the contingencies or the intermittent production as well as on the capacity of the largest generating unit connected to the network. Other approaches introduce an elastic reserve demand according to which the reserve needs are computed based on the reserve prices (Wang et al., 2003; Arroyo and Galiana, 2005; Huang et al., 2006). However, there are also approaches that schedule reserve requirements based on probabilistic methods. These methods optimize the social welfare taking into account the expected load not served (ELNS) (Galiana, 2005; Wang et al., 2006; Aminifar et al., 2009; Amjady et al., 2009) The ELNS is a stochastic security metric directly related to reserves, and it is added to the objective function of ISO. It depicts the weighted average energy value in the form of lost load and accounts for the probability of contingencies and damages caused to the system (Conejo et al. 2010).

Two methods are proposed for the trading of reserves in electricity markets. The first one refers to a sequential reserve procurement through a series of auctions taking place as soon as the energy dispatch has been scheduled in DA market. The idea behind this mechanism is that the reserve capacity which has not been accepted in one auction can be offered in the next; therefore, the successfully accepted reserve capacity in one auction is not consider in the following ones. The second method co-optimizes energy dispatch and reserve capacity, and it is based on an algorithm that captures the strong coupling between scheduled energy and reserve capacity supplies. Compared to sequential optimization, the jointly cleared energy and reserve markets derive more efficient dispatch under an economic perspective, but the auction process is complicated seeing that the power producers should state their units' technical constraints (Gonzales et al., 2014).

2.2 Nomenclature

This section provides the nomenclature which is used in the mathematical formulation of the market clearing mechanism presented in section 2.3, as well as, in the proposed models of Chapter 3, 4 and 5.

Indices and sets:

n, m	indices for system buses
s	index for strategic producers
i	index of conventional generating units
j	index of wind generating units
d	index of demands
b	index of energy blocks offered by unit i
f	index of energy blocks offered by unit j
k	index of load blocks bid by demand d
ω	index of wind generation scenarios
I^S	set of indices of units i owned by the strategic producer
I^O	set of indices of units i owned by non-strategic producers
I_n^S	set of indices of units i owned by the strategic producer and located at bus n
I_n^O	set of indices of units i owned by non-strategic producers and located at bus n
I_n	set of indices of units i located at bus n ($I_n = I_n^S \cup I_n^O$)
J^S	set of indices of units j owned by the strategic producer
J^O	set of indices of units j owned by non-strategic producers
J_n^S	set of indices of units j owned by the strategic producer and located at bus n

J_n^O	set of indices of units j owned by non-strategic producers and located at bus n
J_n	set of indices of unit j located at bus n ($J_n = J_n^S \cup J_n^O$)
D_n	set of indices of demands d located at bus n
Θ_n	set of buses m connected with bus n

Parameters:

c_{ib}	cost offer of energy block b of unit i [€/MWh]
c_{jf}	cost offer of energy block f of unit j [€/MWh]
u_{dk}	utility cost of load block k of demand d [€/MWh]
P_{ib}^{MAX}	upper limit of energy block b of unit i [MWh]
W_{jf}^{MAX}	upper limit of energy block f of unit j [MWh]
L_{dk}^{MAX}	upper limit of load block k of demand d [MWh]
c_i^{up}	cost offer of upward reserve of unit i [€/MWh]
c_i^{down}	cost offer of downward reserve of unit i [€/MWh]
RES_i^{UP}	upward reserve capacity of unit i [MW]
RES_i^{DOWN}	downward reserve capacity of unit i [MW]
$W_{j\omega}^{RT}$	scenario dependent generation of unit j [MWh]
c_j^{RT}	cost offer of generating unit j in RT market [€/MWh]
$VOLL_d$	value of lost load d [€/MWh]
T_{nm}^{MAX}	transmission capacity of circuit line $n-m$
B_{nm}	susceptance of line $n-m$
π_ω	occurrence probability of scenario ω
M^{pP}	constant associated to generation and demand
M^{pC}	constant associated to power flow
M^{pV}	constant associated to voltage angle

M^{vP}	constant associated to generation and demand limits
M^{vC}	constant associated to power flow bounds
M^{vV}	constant associated to voltage angle bounds
N^{p}	constant associated to offer prices
N^{v}	constant associated to offer prices limits

Decision variables:

P_{ib}^{DA}	energy produced by block b of unit i in DA market [MWh]
O_{ib}^{DA}	offer of energy block b of unit $i \in I^S$ in DA market [€/MWh]
W_{jf}^{DA}	energy produced by block f of unit j in DA market [MWh]
O_{jf}^{DA}	offer of energy block f of unit $j \in J^S$ in DA market [€/MWh]
L_{dk}^{DA}	energy consumed by load k of demand d in DA market [MWh]
$r_{i\omega}^{up}$	upward reserve deployment of unit i under scenario ω [MWh]
$r_{i\omega}^{down}$	downward reserve deployment of unit i under scenario ω [MWh]
O_{i}^{up}	offer of upward reserve of unit $i \in I^S$ in RT market [€/MWh]
O_{i}^{down}	offer of downward reserve of unit $i \in I^S$ in RT market [€/MWh]
O_{j}^{RT}	offer of energy shortage/surplus of unit j in RT market [€/MWh]
$W_{j\omega}^{sp}$	energy spillage of unit j under scenario ω [MWh]
$L_{d\omega}^{sh}$	load shedding of demand d under scenario ω [MWh]
δ_{n}^{O}	voltage angle at bus n in DA stage
$\delta_{n\omega}$	voltage angle at bus n in RT stage under scenario ω

Dual variables of lower-level problem:

λ_{n}^{DA}	energy balance at bus n in DA stage
$\lambda_{n\omega}^{RT}$	energy balance at bus n under scenario ω in RT stage

α_{ib}^{min}	lower energy production of block b of unit i
α_{ib}^{max}	upper energy production of block b of unit i
β_{jf}^{min}	lower energy production of block f of unit j
β_{jf}^{max}	upper energy production of block f of unit j
γ_{dk}^{min}	lower energy consumption of block k of demand d
γ_{dk}^{max}	upper energy consumption of block k of demand d
$\epsilon_{i\omega}^{min}$	lower positive reserve output of unit i under scenario ω
$\epsilon_{i\omega}^{max}$	upper positive reserve output of unit i under scenario ω
$\theta_{i\omega}^{min}$	lower negative reserve output of unit i under scenario ω
$\theta_{i\omega}^{max}$	upper negative reserve output of unit i under scenario ω
$\mu_{i\omega}^{min}$	lower power output of unit i under scenario ω
$\mu_{i\omega}^{max}$	upper power output of unit i under scenario ω
$\kappa_{j\omega}^{min}$	lower spillage of unit j under scenario ω
$\kappa_{j\omega}^{max}$	upper spillage of unit j under scenario ω
$\nu_{d\omega}^{min}$	lower load shedding of demand d under scenario ω
$\nu_{d\omega}^{max}$	upper load shedding of demand d under scenario ω
ξ_{nm}^{min}	transmission capacity of line $m-n$ in DA stage
ξ_{nm}^{max}	transmission capacity of line $n-m$ in DA stage
$\xi_{nm\omega}^{min}$	transmission capacity of line $m-n$ under scenario ω in RT stage
$\xi_{nm\omega}^{max}$	transmission capacity of line $n-m$ under scenario ω in RT stage
ρ_{n}^{min}	lower limit of the voltage angle δ_n^o at bus n in DA stage
ρ_{n}^{max}	upper limit of the voltage angle δ_n^o at bus n in DA stage
$\rho_{n\omega}^{min}$	lower limit of the voltage angle $\delta_{n\omega}$ at bus n under scenario ω
$\rho_{n\omega}^{max}$	upper limit of the voltage angle $\delta_{n\omega}$ at bus n under scenario ω
$\phi_{(n1)}^{o}$	voltage angle at bus $n1$ in DA stage
$\phi_{(n1)\omega}$	voltage angle at bus $n1$ under scenario ω in RT stage

Dual variables of MPEC problem:

$\widehat{o}^{p}_{sib}$	associated to offer of energy block b of unit $i \in I^S$ in DA market
$\widehat{o}^{w}_{sjf}$	associated to offer of energy block f of unit $j \in J^S$ in DA market
$\widehat{o}^{up}_{si}$	associated to offer of upward reserve of unit $i \in I^S$ in RT market
$\widehat{o}^{down}_{si}$	associated to offer of downward reserve of unit $i \in I^S$ in RT market
$\widehat{o}^{rt}_{sj}$	associated to offer of shortage/surplus of unit $j \in J^S$ in RT market
$\widehat{\lambda}^{DA}_{sn}$	energy balance at bus n in DA stage
$\widehat{\lambda}^{RT}_{sn\omega}$	energy balance at bus n under scenario ω in RT stage
$\widehat{\alpha}^{min}_{sib}$	lower energy production of block b of unit $i \in I^S$
$\widehat{\alpha}^{max}_{sib}$	upper energy production of block b of unit $i \in I^S$
$\widehat{\beta}^{min}_{sjf}$	lower energy production of block f of unit $j \in J^S$
$\widehat{\beta}^{max}_{sjf}$	upper energy production of block f of unit $j \in J^S$
$\widehat{\gamma}^{min}_{sdk}$	lower energy consumption of block k of demand d
$\widehat{\gamma}^{max}_{sdk}$	upper energy consumption of block k of demand d
$\widehat{\epsilon}^{min}_{si\omega}$	lower positive reserve output of unit $i \in I^S$ under scenario ω
$\widehat{\epsilon}^{max}_{si\omega}$	upper positive reserve output of unit $i \in I^S$ under scenario ω
$\widehat{\theta}^{min}_{si\omega}$	lower negative reserve output of unit $i \in I^S$ under scenario ω
$\widehat{\theta}^{max}_{si\omega}$	upper negative reserve output of unit $i \in I^S$ under scenario ω
$\widehat{\mu}^{min}_{si\omega}$	lower power output of unit $i \in I^S$ under scenario ω
$\widehat{\mu}^{max}_{si\omega}$	upper power output of unit $i \in I^S$ under scenario ω
$\widehat{\kappa}^{min}_{sj\omega}$	lower spillage of unit $j \in J^S$ under scenario ω
$\widehat{\kappa}^{max}_{sj\omega}$	upper spillage of unit $j \in J^S$ under scenario ω
$\widehat{\nu}^{min}_{sd\omega}$	lower load shedding of demand d under scenario ω
$\widehat{\nu}^{max}_{sd\omega}$	upper load shedding of demand d under scenario ω
$\widehat{\xi}^{min}_{snm}$	transmission capacity of line $m-n$ in DA stage
$\widehat{\xi}^{max}_{snm}$	transmission capacity of line $n-m$ in DA stage

$\widehat{\xi}^{max}_{snm\omega}$	transmission capacity of line $n-m$ under scenario ω in RT stage
$\widehat{\rho}^{min}_{sn}$	lower limit of the voltage angle δ^o_n at bus n in DA stage
$\widehat{\rho}^{max}_{sn}$	upper limit of the voltage angle δ^o_n at bus n in DA stage
$\widehat{\rho}^{min}_{sn\omega}$	lower limit of the voltage angle $\delta_{n\omega}$ at bus n under scenario ω
$\widehat{\rho}^{max}_{sn\omega}$	upper limit of the voltage angle $\delta_{n\omega}$ at bus n under scenario ω
$\widehat{\phi}^{o}_{s(n1)}$	voltage angle at bus $n1$ in DA stage
$\widehat{\phi}_{s(n1)\omega}$	voltage angle at bus $n1$ under scenario ω in RT stage
$\widehat{\lambda}^{DT}_{S}$	associated to primal - dual equality
$\widehat{\psi}^{\,p}_{sib}$	associated to partial derivative of the Lagrangian function with respect to prime variables P^{DA}_{ib}
$\widehat{\psi}^{\,w}_{sjf}$	associated to partial derivative of the Lagrangian function with respect to prime variables W^{DA}_{jf}
$\widehat{\psi}^{\,l}_{sdk}$	associated to partial derivative of the Lagrangian function with respect to prime variables L^{DA}_{dk}
$\widehat{\psi}^{\,up}_{si\omega}$	associated to partial derivative of the Lagrangian function with respect to prime variables $r^{up}_{i\omega}$
$\widehat{\psi}^{\,down}_{si\omega}$	associated to partial derivative of the Lagrangian function with respect to prime variables $r^{down}_{i\omega}$
$\widehat{\psi}^{\,sp}_{sj\omega}$	associated to partial derivative of the Lagrangian function with respect to prime variables $W^{sp}_{j\omega}$
$\widehat{\psi}^{\,sh}_{sd\omega}$	associated to partial derivative of the Lagrangian function with respect to prime variables $W^{sp}_{j\omega}$
$\widehat{\psi}^{\,o}_{sn}$	associated to partial derivative of the Lagrangian function with respect to prime variables δ^o_n
$\widehat{\psi}_{sn\omega}$	associated to partial derivative of the Lagrangian function with respect to prime variables $\delta_{n\omega}$

$\overline{\alpha}_{sib}^{min}$	associated to lower energy production of block b of unit $i \in I^S$
$\overline{\alpha}_{sib}^{max}$	associated to upper energy production of block b of unit $i \in I^S$
$\overline{\beta}_{sjf}^{min}$	associated to lower energy production of block f of unit $j \in J^S$
$\overline{\beta}_{sjf}^{max}$	associated to upper energy production of block f of unit $j \in J^S$
$\overline{\gamma}_{sdk}^{min}$	associated to lower energy consumption of block k of demand d
$\overline{\gamma}_{sdk}^{max}$	associated to upper energy consumption of block k of demand d
$\overline{\epsilon}_{si\omega}^{min}$	associated to lower positive reserve output of unit $i \in I^S$ under ω
$\overline{\epsilon}_{si\omega}^{max}$	associated to upper positive reserve output of unit $i \in I^S$ under ω
$\overline{\theta}_{si\omega}^{min}$	associated to lower negative reserve output of unit $i \in I^S$ under ω
$\overline{\theta}_{si\omega}^{max}$	associated to upper negative reserve output of unit $i \in I^S$ under ω
$\overline{\mu}_{si\omega}^{min}$	associated to lower power output of unit $i \in I^S$ under ω
$\overline{\mu}_{si\omega}^{max}$	associated to upper power output of unit $i \in I^S$ under ω
$\overline{\kappa}_{sj\omega}^{min}$	associated to lower spillage of unit $j \in J^S$ under ω
$\overline{\kappa}_{sj\omega}^{max}$	associated to upper spillage of unit $j \in J^S$ under ω
$\overline{\nu}_{sd\omega}^{min}$	associated to lower load shedding of demand d under ω
$\overline{\nu}_{sd\omega}^{max}$	associated to upper load shedding of demand d under ω
$\overline{\xi}_{snm}^{min}$	associated to transmission capacity of line $m-n$ in DA stage
$\overline{\xi}_{snm}^{max}$	associated to transmission capacity of line $n-m$ in DA stage
$\overline{\xi}_{snm\omega}^{max}$	associated to transmission capacity of line $n-m$ under ω in RT stage
$\overline{\rho}_{sn}^{min}$	associated to lower limit of the voltage angle δ_n^o at bus n in DA stage
$\overline{\rho}_{sn}^{max}$	associated to upper limit of the voltage angle δ_n^o at bus n in DA stage
$\overline{\rho}_{sn\omega}^{min}$	associated to lower limit of the voltage angle at bus n under ω
$\overline{\rho}_{sn\omega}^{max}$	associated to upper limit of the voltage angle $\delta_{n\omega}$ at bus n under ω

binary variables:

z	binary variables $\{0,1\}$ associated to disjunctive constraints

2.3 A jointly cleared energy and reserve pool market

A jointly cleared energy end reserve pool can be set financially through a single auction process and can be described as a single-settlement scheme since the energy traded in both DA and RT and the related clearing prices are simultaneously defined in one round. Formulating the clearing process, the integration of wind power producers in the market leads inevitably in a two-stage stochastic programming. The first stage clears the DA market and derives anticipated dispatch (scheduled production) and DA clearing prices, which are received as dual variables of the energy balance constraint at DA stage. The second stage clears the RT market through the realization of a set of plausible wind power production scenarios and derives RT dispatch (reserve deployments) and RT clearing prices, which are received as dual variables of the energy balance constraint at RT stage. In addition, as the model is network-constrained, both DA and RT clearing prices are LMPs. Even though each country has its own regulatory framework, the main principles of the model are common and based on the so called *standard model* (Pereira et al. 2005). The model incorporates wind energy generation in the standard model and has similarities to those employed by the ISO-New England (Zheng and Litvinov, 2006) and Pennsylvania-New Jersey-Maryland (PJM) (Ott, 2003) markets.

2.3.1 Assumptions and considerations

The following are the primal assumptions in relation to pool market formulation:

1) Despite the fact that alternating current (AC) models are more realistic they are also much more complicated, as they include non-linear constraints; therefore, a linearized DC approximation is used to model the process as it provides satisfactory results with lower computational cost (Cheung et al. 1999).

2) Network losses and reactive power are neglected as it is common practice in market clearing procedures (Morales et al., 2012).
3) It is regarded that future contracts are already settled in the market, defining the final capacity of the generating units.
4) To avoid nonconvexity issues and accommodate mathematical derivations zero minimum power productions and linear operation costs are considered for conventional and wind power units.
5) Linear step-wise offering curves are explicitly modeled for producers and consumers respectively at DA market.
6) The model takes into consideration only the wind generation uncertainty, which is realized through a set of plausible wind power generation scenarios.
7) Wind generation spillage conducted by ISO is deemed cost free.
8) Due to the fact that there are no additional intrinsic costs for the producers associated with supplying reserve capacity, energy-only market settlement is applied (Papavasiliou et al., 2011). This way, the market compensates only power that is actually produced.
9) To further align the algorithm with energy-only markets and prevent multiple solutions of the market clearing process a premium is applied on cost offers in balancing markets. Economically speaking, this implies that $c_i^{up} > max\{c_{ib}\}$ and $c_i^{down} < min\{c_{ib}\}$.

2.3.2 Pool market clearing algorithm

Considering energy-only market settlement, the market clearing process does not incorporate any reserve requirement constraint. To that end, a two-stage stochastic programming with recourse is employed (Birge and Louveaux, 2011). The scheduled energy productions are calculated as *here and now* or first stage decision variables by explicitly formulating the RT operation as second stage with recourse, where the *wait and see* decision variables of reserve deployments take their values after the probabilistic realization of the wind generation uncertainty (Morales et al., 2013).

Regarding competitive markets where all the participants act as price takers offering at their marginal cost, the two-stage stochastic programming is modeled though the following network-constrained linear optimization problem.

$$\underset{\Xi}{minimize} \quad \sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{i\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{i\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{jf} c_{jf}^{DA} W_{jf}^{DA} + \sum_{j\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) - \sum_{dk} u_{dk} L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \tag{2.1}$$

$$subjected\ to \quad - \sum_{(i\in I_n)b} P_{ib}^{DA} - \sum_{(j\in J_n)f} W_{jf}^{DA} + \sum_{(d\in D_n)k} L_{dk}^{DA} + \sum_{m\in\Theta_n} B_{nm}\left(\delta_n^o - \delta_m^o\right) = 0 \quad : \left[\lambda_n^{DA}\right], \quad \forall n \tag{2.2}$$

$$- \sum_{i\in I_n} r_{i\omega}^{up} + \sum_{i\in I_n} r_{i\omega}^{down} - \sum_{d\in D_n} L_{d\omega}^{sh} - \left(\sum_{j\in J_n} W_{j\omega}^{RT} - \sum_{(j\in J_n)f} W_{jf}^{DA} - \sum_{j\in\Psi_n^j} W_{j\omega}^{sp} \right) + \sum_{m\in\Theta_n} B_{nm}\left(\delta_{n\omega} - \delta_n^o + \delta_m^o - \delta_{m\omega}\right) = 0 \quad : \left[\lambda_{n\omega}^{RT}\right], \quad \forall n, \forall\omega \tag{2.3}$$

$$0 \le P_{ib}^{DA} \le P_{ib}^{MAX} \quad : \left[\alpha_{ib}^{min}, \alpha_{ib}^{max}\right] \quad \forall i, \forall b \tag{2.4}$$

$$0 \le W_{jf}^{DA} \le W_{jf}^{MAX} \quad : \left[\beta_{jf}^{min}, \beta_{jf}^{max}\right] \quad \forall j, \forall f \tag{2.5}$$

$$0 \le L_{dk}^{DA} \le L_{dk}^{MAX} \quad : \left[\gamma_{dk}^{min}, \gamma_{dk}^{max}\right] \quad \forall d, \forall k \tag{2.6}$$

$$0 \le r_{i\omega}^{up} \le RES_i^{UP} \quad : \left[\epsilon_{i\omega}^{min}, \epsilon_{i\omega}^{max}\right] \quad \forall i, \forall\omega \tag{2.7}$$

$$0 \le r_{i\omega}^{down} \le RES_i^{DOWN} \quad : \left[\theta_{i\omega}^{min}, \theta_{i\omega}^{max}\right] \quad \forall i, \forall\omega \tag{2.8}$$

$$\sum_b P_{ib}^{DA} + r_{i\omega}^{up} \le \sum_b P_{ib}^{MAX} \quad : \left[\mu_{i\omega}^{max}\right] \quad \forall i, \forall\omega \tag{2.9}$$

$$r_{i\omega}^{down} - \sum_b P_{ib}^{DA} \le 0 \quad : \left[\mu_{i\omega}^{min}\right] \quad \forall i, \forall\omega \tag{2.10}$$

$$0 \le W_{j\omega}^{sp} \le W_{j\omega}^{RT} \quad : \left[\kappa_{j\omega}^{min}, \kappa_{j\omega}^{max}\right] \quad \forall j, \forall\omega \tag{2.11}$$

$$0 \leq L_{d\omega}^{sh} \leq \sum_{k} L_{dk}^{DA} \qquad : \left[\nu_{d\omega}^{min}, \nu_{d\omega}^{max}\right] \quad \forall d, \forall \omega \tag{2.12}$$

$$-T_{nm}^{MAX} \leq B_{nm}\left(\delta_n^o - \delta_m^o\right) \leq T_{nm}^{MAX} \qquad : \left[\xi_{nm}^{min}, \xi_{nm}^{max}\right] \quad \forall n, \forall m \in \Theta_n \tag{2.13}$$

$$-T_{nm}^{MAX} \leq B_{nm}\left(\delta_{n\omega} - \delta_{m\omega}\right) \leq T_{nm}^{MAX} \qquad : \left[\xi_{nm\omega}^{min}, \xi_{nm\omega}^{max}\right] \forall n, \forall m \in \Theta_n, \forall \omega \tag{2.14}$$

$$-\pi \leq \delta_n^o \leq \pi \qquad : \left[\rho_n^{min}, \rho_n^{max}\right] \quad \forall n \tag{2.15}$$

$$-\pi \leq \delta_{n\omega} \leq \pi \qquad : \left[\rho_{n\omega}^{min}, \rho_{n\omega}^{max}\right] \quad \forall n, \forall \omega \tag{2.16}$$

$$\delta_{n1}^o = 0 \qquad : \left[\phi_n^o\right] \quad n = n1 \quad \text{(slack bus)} \tag{2.17}$$

$$\delta_{(n1)\omega} = 0 \qquad : \left[\phi_{n\omega}\right] \quad n = n1, \forall \omega \tag{2.18}$$

Where $\Xi = \{P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, r_{i\omega}^{up}, r_{i\omega}^{down}, W_{j\omega}^{sp}, L_{d\omega}^{sh}, \delta_n^o, \delta_{n\omega}\}$ is the set of all ISO's decision variables. The objective function (2.1) clears the DA and RT market maximizing the total social welfare or reversely minimizing the total expected cost of the system operation which consists of the following: a) the scheduled thermal and wind production cost at the DA market, and b) the cost or savings of the scenario dependent positive or negative regulation, the wind surplus or shortfall power production, and finally the cost of load shedding in RT operation. Constraint (2.2) correlates with the *here and now* decision variables $P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}$ and δ_n^o, and it applies the energy balance at each bus enforcing transmission capacity limits at DA market (first stage). Hence, the total energy injected into bus n minus the energy consumed in it should be equal to energy flowing away from the bus. The term $B_{nm}\left(\delta_n^o - \delta_m^o\right)$ expresses the power flowing through the transmission line $n-m$ which connects the sending bus n to the receiving bus m. The dual variable λ_n^{DA} shown in brackets beside the constraint expresses the DA market clearing price. Constraint (2.3) correlates with the *wait and see* decision variables $r_{i\omega}^{up}, r_{i\omega}^{down}, W_{j\omega}^{sp}, L_{d\omega}^{sh}$ and $\delta_{n\omega}$, and it offsets the imbalances caused by the scenario dependent stochastic wind production in RT (second stage) arranging reserve deployment, wind power spillage and load curtailment. The dual variable $\lambda_{n\omega}^{RT}$ of the constraint represents the RT market clearing price. Constraints (2.4) and (2.5) define the upper and lower limits of the offered energy blocks in DA market for both conventional and wind generating units. Constraint (2.6) defines the relevant limits of the demand energy blocks.

Constraints (2.7) and (2.8) define the bounds of the upward and downward reserves offered by each conventional unit i. Constraints (2.9) and (2.10) capture the strong coupling between scheduled production and deployed reserves ensuring that energy production of unit i is over zero (downward reserve cannot exceed scheduled energy) and under maximum capacity (scheduled energy and upward reserve cannot exceed unit's capacity). Constraints (2.11) and (2.12) specify that the wind spillage cannot outdo the real wind energy production, and the load shedding cannot surpass the actual energy consumption. Constraints (2.13) and (2.14) apply transmission capacity limits to network lines. Constraints (2.15) and (2.16) enforce the voltage angle range of each bus. Finally, constraints (2.17) and (2.18) define the bus $n1$ as a slack bus at DA and balancing stage respectively.

2.3.3 Pool market pricing scheme

The pricing scheme resulting from the market clearing process prices the energy transaction as follows:

• Each conventional unit i and wind farm j located at node n is paid for its scheduled energy block production P_{ib}^{DA} and W_{jf}^{DA} respectively in the DA market at a marginal price λ_n^{DA}. The price λ_n^{DA} is received as a dual variable associated with the DA energy balance constraint.

• Each demand d located at node n is charged for its scheduled energy block consumption L_{dk}^{DA} in the DA market at a marginal price λ_n^{DA}.

• Each conventional unit i located at bus n is paid for its overproduction (upward reserve) $r_{i\omega}^{up}$ in the balancing market at a marginal price $\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$under scenario ω. The value $\lambda_{n\omega}^{RT}$ is received as dual variable associated with the RT energy balance constraint.

• Each conventional unit i located at bus n is charged for its power withdrawal (downward reserve) $r_{i\omega}^{down}$ in the balancing market at a marginal price $\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$under scenario ω.

• Each wind farm j located at bus n is paid/charged for its surplus/shortfall production $(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp})$ in the balancing market at a marginal price $\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$under scenario ω.

- Each demand d located at bus n is paid for its involuntary curtailed load $L_{d\omega}^{sh}$ in balancing market at a marginal price (value of lost load) $VOLL_d$.

Chapter 3

Optimal offering strategies for a conventional generation portfolio

In this Chapter, based on the single-leader single-follower Stackelberg game, a stochastic bi-level model is proposed to provide optimal offering strategies for a conventional producer (leader) participating in a pool with high penetration of wind power production. The upper-level problem maximizes the expected profits of the strategic producer while the lower-level problem represents the market clearing process conducted by the ISO (follower). The bi-level problem is recast into an MPEC which is then reformulated into an equivalent MILP. These transformations occur using the KKT optimality conditions, the strong duality theory, and disjunctive constraints. The suggested model provides optimal offering strategies based on the endogenous formation of LMPs considering network constraints and different wind power penetration levels.

3.1 Introduction

In recent years the electricity generation industry has experienced a remarkable penetration of renewable energy resources (Hatziargyriou and Zervos, 2001). However, the inherently uncontrollable fluctuations of renewable generation have resulted in the change

of operational framework, the development of new tools to handle the stochastic nature of non-dispatchable (wind power) production, and the redesign of market clearing algorithms (Conejo et al., 2011; Pierre et al., 2011; Dowling et al., 2017)

The aforementioned nature of renewable resources increases the need for more responsive and expensive reserves to secure the network reliability, thus causing the conventional (thermal) electric power generators to operate intermittently to deal with the frequent imbalances (Heuberger et al., 2017). This affects their efficiency and operational cost negatively. Concerning the strong penetration of renewable sources supported by a generous mechanism of subsidized production and priority dispatch, the role of conventional energy production is diminishing. Nevertheless, due to the variability of the generation, the congestions of the network, and the fluctuations of the electric power fed in the system, the ISOs are enforced to trade in RT to correct the imbalances which depend on the ability of a thermal plant to supply energy under demand (Koltsaklis et al., 2014; Koltsaklis et al., 2015).

Although the market recognises the critical role of the thermal plants as capacity providers (Guo et al., 2017), the latter are faced with unequal treatment and have to adopt specific strategic behaviour to ensure competitiveness. Within the above context, and considering the conventional energy production, this thesis investigates the strategic reaction of an incumbent firm and examines its incentives to exert market power and ensure its dominant position to avoid energy profit losses.

Based on the cost optimization linear programming of the clearing market mechanism presented in Chapter 2, this Chapter proposes a bi-level complementarity model within an optimization-based methodological framework to derive optimal offering strategies in an environment of imperfect competition. The constructed MPEC, contrary to the relative formulations proposed by Baringo and Conejo (2013) and Kazempour and Zareipour (2014), considers a strategic conventional producer participating in a pool market together with other conventional and wind power producers. Furthermore, the model derives not only the DA optimal offers at DA, but also the RT optimal offers for positive and negative regula-

tions. Finally, the proposed algorithm, compared to the model introduced by Kazempour and Zareipour (2014), incorporates transmission network constraints expanding the computational effort of the model and giving the strategic producer the ability to use the network congestions to his advantage.

In the above context, the contributions of this Chapter are fivefold:

i) to provide a novel bi-level complementarity model as well as a methodological framework to determine the optimal offering strategies of a conventional power producer participating in a jointly cleared energy and balancing pool where other conventional and wind power producers are concerned as competitors.

ii) to efficiently recast the MPEC into a mixed integer linear programming problem based on a systematic methodology for its linearization through the use of disjunctive constraints and solvable to global optimality by commercial solvers.

iii) to derive robust DA and balancing market prices, through a formal methodology, as dual variables of the energy balance constraints.

iv) to provide a new modelling framework and a methodology in order to systematically analyze behaviour adjustments of the strategic producer depending on wind production uncertainty.

v) to offer a novel framework that determines the impact of the strategic producer's behaviour on the LMPs under stochastic production.

3.2 Bi-level model

3.2.1 Problem statement

This Chapter analyses the optimal offering strategies of a conventional (thermal) power producer which participates with other conventional as well as wind power producers in a jointly cleared energy and balancing auction under network constraints. It is considered

that this producer has dominant position in the market since they own a significant number of generation units and can thus influence the market prices. A bi-level complementarity model is developed based on single-leader single-follower Stackelberg hypothesis. The strategic producer, called leader, chooses its output first and the ISO, called follower, make its best choice. Thus using backward induction and based on the assumption of rational and responsive behaviour the leader firm maximizes its profit realizing the follower's subsequent output choice (Dutta, 1999). Figure 3.1 illustrates the game structure.

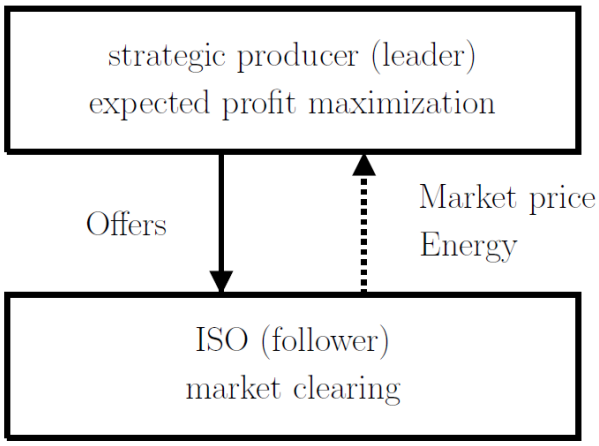

Figure 3.1: Single-leader single-follower game

According to proposed bi-level model, the upper-level problem determines expected profit maximization of the considered strategic producer which depend on clearing LMPs of DA and RT market obtained at the lower level problem. On the other hand, the lower-level problem represents the clearing price process ensuing the least cost of energy dispatch conducted by the SO. Thus, the lower-level problem is formulated in a linearized DC network as two-stage stochastic programming. The first stage facilitates the DA market and results in the optimal anticipated dispatch (DA scheduled energy production), and the LMPs received as dual variables (Morales et al., 2013). The second stage represents the balancing market under the realization of all the plausible wind production scenarios and derives RT dispatch

(reserve deployments) and RT prices (Morales et al., 2012). Subsequently, assuming the continuity and convexity of the lower problem, the bi-level problem is reduced to an MPEC through first-order KKT optimality conditions. Using the Fortuny-Amat and McCarl (1981) linearization process and the strong duality theorem, the MPEC is reformed in an MILP solvable by commercial solvers such as GAMS/CPLEX (Rosenthal, 2018).

3.2.2 Bi-level model formulation

Given that a conventional strategic producer participates in a jointly-cleared energy and balancing market with high penetration of wind production, a bi-level stochastic optimization model is formulated to derive its optimal offers as follows:

Upper-level problem

$$\underset{\Xi^S \cup \Xi^O}{maximize} \quad \sum_{(i\in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} - \sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} + \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \tag{3.1}$$

Lower-level problem

$$\begin{aligned}\underset{\Xi}{minimize} \quad & \sum_{(i\in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\ & + \sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\ & + \sum_{(j\in J^O)f} c_{jf}^{DA} W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\ & - \sum_{dk} u_{dk} L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh}\end{aligned} \tag{3.2}$$

$$\textit{subjected to} \qquad (2.3) - (2.18) \tag{3.3}$$

The objective function of upper-level problem (3.1) optimizes the expected profit of the strategic producer, and it is defined by the revenues from the DA and RT markets minus the actual incurred cost. The set $\Xi^S = \{P^{DA}_{(i\in I^S)b}, r^{up}_{(i\in I^S)\omega}, r^{down}_{(i\in I^S)\omega}\}$ contains the strategic producer's decision variables considering production energy blocks and the $\Xi^O = \{O^{DA}_{(i\in I^S)b}, O^{up}_{(i\in I^S)}, O^{down}_{(i\in I^S)}\}$ contains the strategic producer's decision variables considering offering prices which are explicitly associated with the lower-level problem. The objective function is non-linear since the revenues depend on the DA market clearing prices λ^{DA}_n and RT market clearing prices $\frac{\lambda^{RT}_{n\omega}}{\pi_\omega}$. The market prices are created endogenously and received as dual variables from the energy balance constraints of the lower-level problem. It should be noted that the third and the fifth terms of (3.1) are derived from $\sum_{(i\in I^S_n)\omega} \pi_\omega \frac{\lambda^{RT}_{n\omega}}{\pi_\omega} r^{up}_{i\omega}$ and $\sum_{(i\in I^S_n)\omega} \pi_\omega \frac{\lambda^{RT}_{n\omega}}{\pi_\omega} r^{down}_{i\omega}$ respectively. The objective function of the lower-level problem (3.2) optimizes the expected cost of the power system operation conducted by ISO. It consists of the scheduled production cost and the scenario dependent reserve deployment, wind surplus/shortfall generation, and shedding load cost in RT operation. The set $\Xi = \{P^{DA}_{ib}, W^{DA}_{jf}, L^{DA}_{dk}, r^{up}_{i\omega}, r^{down}_{i\omega}, W^{sp}_{j\omega}, L^{sh}_{d\omega}, \delta^o_n, \delta_{n\omega}\}$ includes all ISO's decision variables. The objective function (3.2) is also non-linear since it is directly depended on strategic producer's decision variables $O^{DA}_{(i\in I^S)b}, O^{up}_{(i\in I^S)}$, and $O^{down}_{(i\in I^S)}$. Finally constraint (3.3) refers to all technical constraints (2.3) − (2.18) associated to network and generating units as illustrated in section 2.3.2.

3.2.3 MPEC formulation

Considering that the continuity and the differentiability requirements are satisfied by the lower nonlinear constrained optimization problem, the auxiliary Lagrangian function can be introduced to recast the initial problem into an unconstrained one. In this case, the Lagrange multipliers have the same meaning with the dual variables in linear programming (LP) (Floudas, 1995). In addition, the decisions variables $O^{DA}_{(i\in I^S)b}, O^{up}_{(i\in I^S)}$, and $O^{down}_{(i\in I^S)}$ are received as parameters from the ISO in the objective function (3.2), and thus the lower

problem is defined as linear and therefore convex (Gabriel, 2012). In the above context the lower problem can be substituted for its KKT optimality conditions transforming the bi-level problem (3.1) − (3.3) into a single-level non-linear MPEC as follows:

$$\underset{\Xi \cup \Xi^O \cup \Xi^D}{maximize} \qquad (3.1) \tag{3.4}$$

subjected to KKT equality constraints

$$O_{ib}^{DA} - \lambda_n^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^S, \forall b \tag{3.5}$$

$$c_{ib} - \lambda_n^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^O, \forall b \tag{3.6}$$

$$c_{jf}^{DA} - c_j^{RT} - \lambda_n^{DA} + \sum_{\omega} \lambda_{n\omega}^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} = 0 \qquad \forall j \in J_n^O, \forall f \tag{3.7}$$

$$-u_{dk} + \lambda_n^{DA} + \gamma_{dk}^{max} - \gamma_{dk}^{min} - \sum_{\omega} \nu_{d\omega}^{max} = 0 \qquad \forall d \in D_n, \forall k \tag{3.8}$$

$$\pi_\omega O_i^{up} - \lambda_{n\omega}^{RT} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} = 0 \qquad \forall i \in I_n^S, \forall \omega \tag{3.9}$$

$$\pi_\omega c_i^{up} - \lambda_{n\omega}^{RT} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} = 0 \qquad \forall i \in I_n^O, \forall \omega \tag{3.10}$$

$$-\pi_\omega O_i^{down} + \lambda_{n\omega}^{RT} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^S, \forall \omega \tag{3.11}$$

$$-\pi_\omega c_i^{down} + \lambda_{n\omega}^{RT} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^O, \forall \omega \tag{3.12}$$

$$-\pi_\omega c_j^{RT} + \lambda_{n\omega}^{RT} + \kappa_{j\omega}^{max} - \kappa_{j\omega}^{min} = 0 \qquad \forall j \in J_n^O, \forall \omega \tag{3.13}$$

$$\pi_\omega VOLL_d - \lambda_{n\omega}^{RT} + \nu_{d\omega}^{max} - \nu_{d\omega}^{min} = 0 \qquad \forall d \in D_n, \forall \omega \tag{3.14}$$

$$\begin{aligned} &\sum_{m \in \Theta_n} B_{nm}\big(\lambda_n^{DA} - \lambda_m^{DA}\big) + \sum_{(m \in \Theta_n)\omega} B_{nm}\big(-\lambda_{n\omega}^{RT} + \lambda_{m\omega}^{RT}\big) + \sum_{m \in \Theta_n} B_{nm}\big(\xi_{nm}^{max} - \xi_{mn}^{max}\big) \\ &- \sum_{m \in \Theta_n} B_{nm}\big(\xi_{nm}^{min} - \xi_{mn}^{min}\big) + \rho_n^{max} - \rho_n^{min} + \phi_{(n1)}^{o} = 0 \qquad \forall n \end{aligned} \tag{3.15}$$

$$\begin{aligned} &\sum_{m \in \Theta_n} B_{nm}\big(\lambda_{n\omega}^{RT} - \lambda_{m\omega}^{RT}\big) + \sum_{m \in \Theta_n} B_{nm}\big(\xi_{nm\omega}^{max} - \xi_{mn\omega}^{max}\big) \\ &- \sum_{m \in \Theta_n} B_{nm}\big(\xi_{nm\omega}^{min} - \xi_{mn\omega}^{min}\big) + \rho_{n\omega}^{max} - \rho_{n\omega}^{min} + \phi_{(n1)\omega} = 0 \qquad \forall n, \forall \omega \end{aligned} \tag{3.16}$$

$$-\sum_{(i \in I_n)b} P_{ib}^{DA} - \sum_{(j \in J_n)f} W_{jf}^{DA} + \sum_{(d \in D_n)k} L_{dk}^{DA} + \sum_{m \in \Theta_n} B_{nm}\big(\delta_n^o - \delta_m^o\big) = 0 \quad \forall n \tag{3.17}$$

$$-\sum_{i\in I_n} r_{i\omega}^{up} + \sum_{i\in I_n} r_{i\omega}^{down} - \left(\sum_{j\in J_n} W_{j\omega}^{RT} - \sum_{(j\in J_n)f} W_{jf}^{DA} - \sum_{j\in J_n} W_{j\omega}^{sp}\right)$$
$$-\sum_{d\in D_n} L_{d\omega}^{sh} + \sum_{m\in\Theta_n} B_{nm}\big(\delta_{n\omega} - \delta_n^o + \delta_m^o - \delta_{m\omega}\big) = 0 \qquad \forall n, \forall\omega \tag{3.18}$$

$$\delta_{(n1)}^o = 0 \qquad n = n1 \quad \text{(slack bus)} \tag{3.19}$$

$$\delta_{(n1)\omega} = 0 \qquad n = n1, \forall\omega \tag{3.20}$$

subjected to KKT complementarity constraints

$$0 \le P_{ib}^{DA} \perp \alpha_{ib}^{min} \ge 0 \qquad \forall i, \forall b \tag{3.21}$$

$$0 \le P_{ib}^{MAX} - P_{ib}^{DA} \perp \alpha_{ib}^{max} \ge 0 \qquad \forall i, \forall b \tag{3.22}$$

$$0 \le W_{jf}^{DA} \perp \beta_{jf}^{min} \ge 0 \qquad \forall j, \forall f \tag{3.23}$$

$$0 \le W_{jf}^{MAX} - W_{jf}^{DA} \perp \beta_{jf}^{max} \ge 0 \qquad \forall j, \forall f \tag{3.24}$$

$$0 \le L_{dk}^{DA} \perp \gamma_{dk}^{min} \ge 0 \qquad \forall d, \forall k \tag{3.25}$$

$$0 \le L_{dk}^{MAX} - L_{dk}^{DA} \perp \gamma_{dk}^{max} \ge 0 \qquad \forall d, \forall k \tag{3.26}$$

$$0 \le r_{i\omega}^{up} \perp \epsilon_{i\omega}^{min} \ge 0 \qquad \forall i, \forall\omega \tag{3.27}$$

$$0 \le RES_i^{UP} - r_{i\omega}^{up} \perp \epsilon_{i\omega}^{max} \ge 0 \qquad \forall i, \forall\omega \tag{3.28}$$

$$0 \le r_{i\omega}^{down} \perp \theta_{i\omega}^{min} \ge 0 \qquad \forall i, \forall\omega \tag{3.29}$$

$$0 \le RES_i^{DOWN} - r_{i\omega}^{down} \perp \theta_{i\omega}^{max} \ge 0 \qquad \forall i, \forall\omega \tag{3.30}$$

$$0 \le \sum_b P_{ib}^{MAX} - \sum_b P_{ib}^{DA} - r_{i\omega}^{up} \perp \mu_{i\omega}^{max} \ge 0 \qquad \forall i, \forall\omega \tag{3.31}$$

$$0 \le \sum_b P_{ib}^{DA} - r_{i\omega}^{down} \perp \mu_{i\omega}^{min} \ge 0 \qquad \forall i, \forall\omega \tag{3.32}$$

$$0 \le W_{j\omega}^{sp} \perp \kappa_{j\omega}^{min} \ge 0 \qquad \forall j, \forall\omega \tag{3.33}$$

$$0 \le W_{j\omega}^{RT} - W_{j\omega}^{sp} \perp \kappa_{j\omega}^{max} \ge 0 \qquad \forall j, \forall\omega \tag{3.34}$$

$$0 \le L_{d\omega}^{sh} \perp \nu_{d\omega}^{min} \ge 0 \qquad \forall d, \forall\omega \tag{3.35}$$

$$0 \le \sum_k L_{dk}^{DA} - L_{d\omega}^{sh} \perp \nu_{d\omega}^{max} \ge 0 \qquad \forall d, \forall\omega \tag{3.36}$$

$$0 \le B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \perp \xi_{nm}^{min} \ge 0 \qquad \forall n, \forall m \in \Theta_m \tag{3.37}$$

$$0 \le T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \perp \xi_{nm}^{max} \ge 0 \qquad \forall n, \forall m \in \Theta_m \tag{3.38}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \perp \xi_{nm\omega}^{min} \geq 0 \qquad \forall n, \forall m \in \Theta_m \forall \omega \tag{3.39}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \perp \xi_{nm\omega}^{max} \geq 0 \qquad \forall n, \forall m \in \Theta_m \forall \omega \tag{3.40}$$

$$0 \leq \delta_n^o + \pi \perp \rho_n^{min} \geq 0 \qquad \forall n \tag{3.41}$$

$$0 \leq \pi - \delta_n^o \perp \rho_n^{max} \geq 0 \qquad \forall n \tag{3.42}$$

$$0 \leq \delta_{n\omega} + \pi \perp \rho_{n\omega}^{min} \geq 0 \qquad \forall n, \forall \omega \tag{3.43}$$

$$0 \leq \pi - \delta_{n\omega} \perp \rho_{n\omega}^{max} \geq 0 \qquad \forall n, \forall \omega \tag{3.44}$$

Where $\Xi^D = \{\lambda_n^{DA}, \lambda_{n\omega}^{RT}, \alpha_{ib}^{max}, \alpha_{ib}^{min}, \beta_{jf}^{max}, \beta_{jf}^{min}, \gamma_{dk}^{max}, \gamma_{dk}^{min}, \epsilon_{i\omega}^{max}, \epsilon_{i\omega}^{min}, \theta_{i\omega}^{max}, \theta_{i\omega}^{min}, \mu_{i\omega}^{max}, \mu_{i\omega}^{min}, \kappa_{j\omega}^{max}, \kappa_{j\omega}^{min}, \nu_{d\omega}^{max}, \nu_{d\omega}^{min}, \xi_{nm}^{max}, \xi_{nm}^{min}, \xi_{nm\omega}^{max}, \xi_{nm\omega}^{min}, \rho_n^{max}, \rho_n^{min}, \rho_{n\omega}^{max}, \rho_{n\omega}^{min}, \phi_{(n1)}^o, \phi_{(n1)\omega}\}$ is the set of all dual variables. The objective function (3.4) of the MPEC is the objective function of strategic producer (3.1). KKT equalities (3.5) − (3.16) are constructed by the derivation of the Lagrangian function with respect to prime variables P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, $r_{i\omega}^{up}$, $r_{i\omega}^{down}$, $W_{j\omega}^{sp}$, $L_{d\omega}^{sh}$, δ_n^o and $\delta_{n\omega}$.KKT equalities (3.17) − (3.20) are the equality constraints of the lower level problem (2.2), (2.3), (2.17) and (2.18).

3.2.4 MPEC linearization

The non-linear KKT complementarity conditions (3.21) - (3.44), of the general form:

$$0 \leq g(x) \perp \mu \geq 0 \tag{3.45}$$

can be replaced by the following equivalent linear disjunctive formulation (Fortuny-Amat and McCarl, 1981):

$$0 \leq g(x), \quad 0 \leq \mu, \quad g(x) \leq M^p z, \quad \mu \leq M^v(1-z) \tag{3.46}$$

where $z \in \{0, 1\}$ is binary variable and M^p and M^v are parameters related to prime and dual variables respectively. The selection of parameters' values is of paramount importance because a choice of large values could induce the solver (CPLEX) to run into numerical issues rendering the model intractable while a choice of small values could cut out optimal solutions. A heuristic method for the calculation of the parameters is given in Chapter 6 (Computational issues).

Subsequently, the remaining non-linear terms $\lambda_n^{DA} P_{ib}^{DA}$, $\lambda_{n\omega}^{RT} r_{i\omega}^{up}$ and $\lambda_{n\omega}^{RT} r_{i\omega}^{down}$ in objective function (3.4) can be removed using some of the KKT equalities and complementarity conditions as stated in Appendix A.1. The new objection function (A.1.18) derived from the process mentioned above is still non-linear, and the non-linear terms $O_{ib}^{DA} P_{ib}^{DA}$, $O_i^{up} r_{i\omega}^{up}$ and $O_i^{down} r_{i\omega}^{down}$ are eliminated by applying the strong duality theorem to the lower-level optimization problem as shown in equality (A.1.19). Thus, the non-linear objective function (A.1.18) is transformed into linear (A.1.21), and the MPEC model is recast into the following equivalent MILP formulation:

$$
\begin{aligned}
\underset{\Xi \cup \Xi^O \cup \Xi^D}{maximize} \quad & -\sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& - \sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& - \sum_{(j\in J^O)f} c_{jf}^{DA} W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
& + \sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \\
& - \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} \\
& - \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} \\
& - \sum_{(i\in I^O)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX} \right) - \sum_{(j\in J^O)\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
& - \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
& - \sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned} \tag{3.47}
$$

$$
\textit{subjected to} \qquad (3.5) - (3.20) \tag{3.48}
$$

$$
0 \le P_{ib}^{DA} \le M^{pP} z_{ib}^1 \qquad \forall i, \forall b \tag{3.49}
$$

$$
0 \le \alpha_{ib}^{min} \le M^{vP} (1 - z_{ib}^1) \qquad \forall i, \forall b \tag{3.50}
$$

$$0 \leq P_{ib}^{MAX} - P_{ib}^{DA} \leq M^{pP} z_{ib}^{2} \qquad \forall i, \forall b \tag{3.51}$$

$$0 \leq \alpha_{ib}^{max} \leq M^{vP}(1 - z_{ib}^{2}) \qquad \forall i, \forall b \tag{3.52}$$

$$0 \leq W_{jf}^{DA} \leq M^{pP} z_{jf}^{3} \qquad \forall j, \forall f \tag{3.53}$$

$$0 \leq \beta_{jf}^{min} \leq M^{vP}(1 - z_{jf}^{3}) \qquad \forall j, \forall f \tag{3.54}$$

$$0 \leq W_{jf}^{MAX} - W_{jf}^{DA} \leq M^{pP} z_{jf}^{4} \qquad \forall j, \forall f \tag{3.55}$$

$$0 \leq \beta_{jf}^{max} \leq M^{vP}(1 - z_{jf}^{4}) \qquad \forall j, \forall f \tag{3.56}$$

$$0 \leq L_{dk}^{DA} \leq M^{pP} z_{dk}^{5} \qquad \forall d, \forall k \tag{3.57}$$

$$0 \leq \gamma_{dk}^{min} \leq M^{vP}(1 - z_{dk}^{5}) \qquad \forall d, \forall k \tag{3.58}$$

$$0 \leq L_{dk}^{MAX} - L_{dk}^{DA} \leq M^{pP} z_{dk}^{6} \qquad \forall d, \forall k \tag{3.59}$$

$$0 \leq \gamma_{dk}^{max} \leq M^{vP}(1 - z_{dk}^{6}) \qquad \forall d, \forall k \tag{3.60}$$

$$0 \leq r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{7} \qquad \forall i, \forall \omega \tag{3.61}$$

$$0 \leq \epsilon_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{7}) \qquad \forall i, \forall \omega \tag{3.62}$$

$$0 \leq RES_{i}^{UP} - r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{8} \qquad \forall i, \forall \omega \tag{3.63}$$

$$0 \leq \epsilon_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{8}) \qquad \forall i, \forall \omega \tag{3.64}$$

$$0 \leq r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{9} \qquad \forall i, \forall \omega \tag{3.65}$$

$$0 \leq \theta_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{9}) \qquad \forall i, \forall \omega \tag{3.66}$$

$$0 \leq RES_{i}^{DOWN} - r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{10} \qquad \forall i, \forall \omega \tag{3.67}$$

$$0 \leq \theta_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{10}) \qquad \forall i, \forall \omega \tag{3.68}$$

$$0 \leq \sum_{b} P_{ib}^{MAX} - \sum_{b} P_{ib}^{DA} - r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{11} \qquad \forall i, \forall \omega \tag{3.69}$$

$$0 \leq \mu_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{11}) \qquad \forall i, \forall \omega \tag{3.70}$$

$$0 \leq \sum_{b} P_{ib}^{DA} - r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{12} \qquad \forall i, \forall \omega \tag{3.71}$$

$$0 \leq \mu_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{12}) \qquad \forall i, \forall \omega \tag{3.72}$$

$$0 \leq W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{13} \qquad \forall j, \forall \omega \tag{3.73}$$

$$0 \leq \kappa_{j\omega}^{min} \leq M^{vP}(1 - z_{j\omega}^{13}) \qquad \forall j, \forall \omega \tag{3.74}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{14} \qquad \forall j, \forall \omega \tag{3.75}$$

$$0 \leq \kappa_{j\omega}^{max} \leq M^{vP}(1 - z_{j\omega}^{14}) \qquad \forall j, \forall \omega \tag{3.76}$$

$$0 \leq L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{15} \qquad \forall d, \forall \omega \tag{3.77}$$

$$0 \leq \nu_{d\omega}^{min} \leq M^{vP}(1 - z_{d\omega}^{15}) \qquad \forall d, \forall \omega \tag{3.78}$$

$$0 \leq \sum_{k} L_{dk}^{DA} - L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{16} \qquad \forall d, \forall \omega \tag{3.79}$$

$$0 \leq \nu_{d\omega}^{max} \leq M^{vP}(1 - z_{d\omega}^{16}) \qquad \forall d, \forall \omega \tag{3.80}$$

$$0 \leq B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm}^{17} \qquad \forall n, \forall m \in \Theta_m \tag{3.81}$$

$$0 \leq \xi_{nm}^{min} \leq M^{vC}(1 - z_{nm}^{17}) \qquad \forall n, \forall m \in \Theta_m \tag{3.82}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \leq M^{pC} z_{nm}^{18} \qquad \forall n, \forall m \in \Theta_m \tag{3.83}$$

$$0 \leq \xi_{nm}^{max} \leq M^{vC}(1 - z_{nm}^{18}) \qquad \forall n, \forall m \in \Theta_m \tag{3.84}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm\omega}^{19} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{3.85}$$

$$0 \leq \xi_{nm\omega}^{min} \leq M^{vC}(1 - z_{nm\omega}^{19}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{3.86}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \leq M^{pC} z_{nm\omega}^{20} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{3.87}$$

$$0 \leq \xi_{nm\omega}^{max} \leq M^{vC}(1 - z_{nm\omega}^{20}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{3.88}$$

$$0 \leq \delta_n^o + \pi \leq M^{pV} z_n^{21} \qquad \forall n \tag{3.89}$$

$$0 \leq \rho_n^{min} \leq M^{vV}(1 - z_n^{21}) \qquad \forall n \tag{3.90}$$

$$0 \leq \pi - \delta_n^o \leq M^{pV} z_n^{22} \qquad \forall n \tag{3.91}$$

$$0 \leq \rho_n^{max} \leq M^{vV}(1 - z_n^{22}) \qquad \forall n \tag{3.92}$$

$$0 \leq \delta_{n\omega} + \pi \leq M^{pV} z_{n\omega}^{23} \qquad \forall n, \forall \omega \tag{3.93}$$

$$0 \leq \rho_{n\omega}^{min} \leq M^{vV}(1 - z_{n\omega}^{23}) \qquad \forall n, \forall \omega \tag{3.94}$$

$$0 \leq \pi - \delta_{n\omega} \leq M^{pV} z_{n\omega}^{24} \qquad \forall n, \forall \omega \tag{3.95}$$

$$0 \leq \rho_{n\omega}^{max} \leq M^{vV}(1 - z_{n\omega}^{24}) \qquad \forall n, \forall \omega \tag{3.96}$$

3.3 Offer building process

The aforementioned MILP model delivers optimal offers O_{ib}^{DA} for the dispatched energy blocks P_{ib}^{DA}, as well as optimal offers O_i^{up} and O_i^{down} for upward $res_{i\omega}^{up}$ and downward $res_{i\omega}^{down}$ reserves respectively. The O_{ib}^{DA} for a unit i settled at a bus n always coincides with the clearing market price λ_n^{DA} of this bus at DA. Similarly, the O_i^{up} and O_i^{down} of the units i;

which are accepted by the SO to provide balancing regulations, coincide with the clearing prices $\lambda_{n\omega}^{RT}$ at RT. However, offering all energy blocks at the obtained LMPs results in flat offer curves which lead to *multiple solutions and degeneracy* (Ruiz and Conejo, 2009).

In order to receive increasing offer curves, this Chapter follows an offer building process similar to the one proposed by Ruiz and Conejo (2009). According to this process the accepted (filled) energy blocks are offered at their marginal cost except those (marginal blocks) that actually set the clearing price and are offered at the equivalent λ_n^{DA} (LMPs):

1) If the energy block is fully accepted $P_{ib}^{DA} = P_{ib}^{MAX}$, then this block is offered at its marginal cost $O_{ib}^{f,DA} = c_{ib}$ to guarantee its acceptance.
2) If the energy block is partially accepted $0 < P_{ib}^{DA} < P_{ib}^{MAX}$ then this block is offered at a price $O_{ib}^{f,DA} = \lambda_n^{DA} - \epsilon$ where ϵ could be a small number e.g. 10^{-3}.
3) If the energy block is not accepted $P_{ib}^{DA} = 0$ and its marginal cost is lower than the clearing price $c_{ib} < \lambda_n^{DA}$, then it is offered at $O_{ib}^{f,DA} = \lambda_n^{DA}$ ensuring its rejection.
4) If the energy block is not accepted $P_{ib}^{DA} = 0$, and its marginal cost is higher than the clearing price, then it is offered at $O_{ib}^{f,DA} = c_{ib}$ ensuring that it remains non-accepted.

Additionally, for upward reserve a similar process is followed:

5) If the full capacity of upward reserve is accepted $res_{i\omega}^{up} = RES_i^{up}$, then it is offered at its marginal cost $O_i^{f,up} = c_i^{up}$.
6) If the accepted upward reserve is less than the maximum capacity $0 < res_{i\omega}^{up} < RES_i^{up}$, then it is offered at a price $O_i^{f,up} = \lambda_{n\omega}^{RT} - \epsilon$.
7) If the strategic unit does not provide any upward reserve $res_{i\omega}^{up} = 0$ and $c_i^{up} < \lambda_{n\omega}^{RT}$, then it offers positive regulation at a price of $O_i^{f,up} = \lambda_{n\omega}^{RT}$.
8) If the strategic unit does not provide any upward reserve $res_{i\omega}^{up} = 0$ and $c_i^{up} > \lambda_{n\omega}^{RT}$, then it offers positive regulation at a price of $O_i^{f,up} = c_i^{up}$.

Finally, for downward reserve the below offering process is followed:

9) If the full capacity of downward reserve is accepted $res_{i\omega}^{down} = RES_i^{down}$, then it is offered at its marginal cost $O_i^{f,down} = c_i^{down}$.

10) If the accepted reserve is less than the maximum capacity $0 < res_{i\omega}^{down} < RES_i^{down}$, then it is offered at a price $O_i^{f,down} = \lambda_{n\omega}^{RT} + \epsilon$.

11) If the strategic unit does not provide any downward reserve $res_{i\omega}^{down} = 0$ and $c_i^{down} < \lambda_{n\omega}^{RT}$, then it offers negative regulation at a price of $O_i^{f,down} = c_i^{down}$.

12) If the strategic unit does not provide any downward reserve $res_{i\omega}^{down} = 0$ and $c_i^{down} > \lambda_{n\omega}^{RT}$, then it offers negative regulation at a price of $O_i^{f,down} = \lambda_{n\omega}^{RT}$.

It can be seen that the offering process for downward reserve works in an opposite way compared with the process for upward reserve. This is because the SO seeks low clearing prices for upward reserve to reduce the system cost and high clearing prices for downward reserve to increase its savings.

3.4 6-bus system case

3.4.1 System data

The proposed clearing market formulation is applied in a six-node system sketched in Figure 3.2. The conventional generating units $i1$, $i2$, $i3$ and $i4$ belong to the strategic producer and the $i5$, $i6$, $i7$ and $i8$ belong to non-strategic producers. Technical data are provided in Table 3.1. Each column makes reference to a specific conventional generation unit. The second row indicates the location of each unit. The third row accommodates the power capacity of each unit. The following eight rows refer to a maximum size of four power blocks offered by each unit and to their respective marginal costs. The eleventh and the twelfth rows provide the upward and downward reserve limits of each unit, and the last two rows contain the marginal cost of the respective reserve deployments. It can be noticed that units $i1$, $i3$, $i6$ and $i7$ are cheap but slightly flexible, units $i4$ and $i8$ are cheap and relatively

flexible, and units $i2$ and $i5$ are expensive but very flexible.

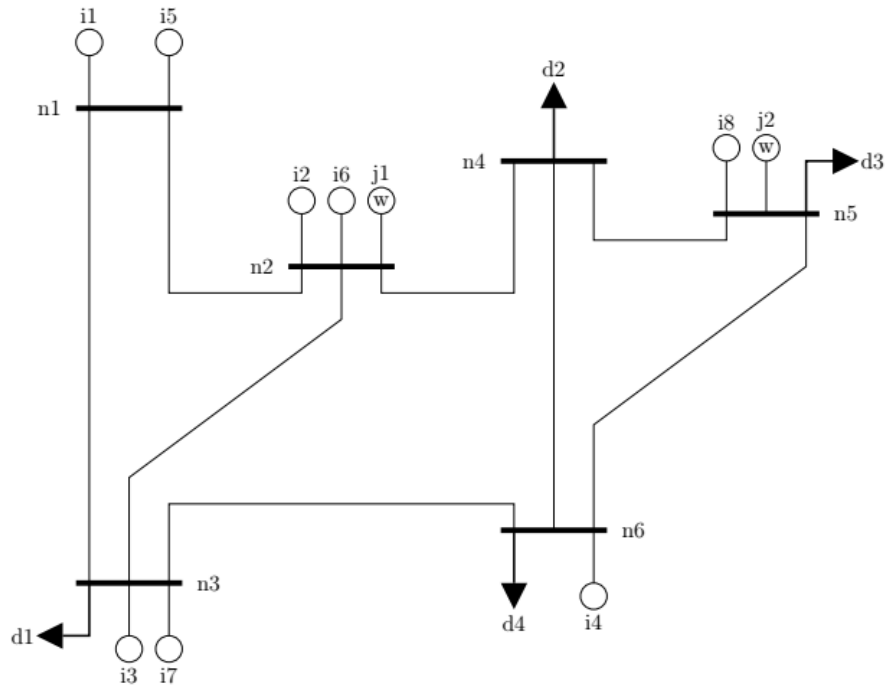

Figure 3.2: 6-bus system

Two wind farms $j1$ and $j2$, located at bus $n2$ and $n5$, have installed capacity of 100 MW and 70 MW, and their scheduled power production W_{jf}^{DA} is offered in one block with zero marginal cost. Wind farms' uncertain power production is realized through three scenarios, $\omega 1$ (high production) with 100 MWh and 70 MWh, $\omega 2$ (medium production) with 50 MWh and 35 MWh, and $\omega 3$ (low production) with 20 MWh and 15 MWh while occurrence probability of each scenario is 0.2, 0.5 and 0.3 respectively.

A total demand of 1 GWh is allocated and distributed according to Table 3.2. Additionally, Table B.1 (Appendix B) gives information about demand bids (energy blocks and their utility marginal costs) for each period of time. Thus, each column correlates the five

Table 3.1: Data for conventional generating units

units		$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$
location		$n1$	$n2$	$n3$	$n6$	$n1$	$n2$	$n3$	$n5$
P	$[MW]$	155	100	155	197	350	197	197	155
$P_{i,b1}^{MAX}$	$[MWh]$	54.25	25	54.25	68.95	140	68.95	68.95	54.25
$P_{i,b2}^{MAX}$	$[MWh]$	38.75	25	38.75	49.25	97.50	49.25	49.25	38.75
$P_{i,b3}^{MAX}$	$[MWh]$	31	20	31	39.4	52.50	39.4	39.4	31
$P_{i,b4}^{MAX}$	$[MWh]$	31	20	31	39.4	70	39.4	39.4	31
$c_{i,b1}$	$[€/MWh]$	9.92	18.60	9.92	10.08	19.20	10.08	10.08	9.92
$c_{i,b2}$	$[€/MWh]$	10.25	20.03	10.25	10.66	20.32	10.66	10.66	10.25
$c_{i,b3}$	$[€/MWh]$	10.68	21.67	10.68	11.09	21.22	11.09	11.09	10.68
$c_{i,b4}$	$[€/MWh]$	11.26	22.72	11.26	11.72	22.13	11.72	11.72	11.26
RES_i^{UP}	$[MW]$	20	100	20	40	120	10	20	30
RES_i^{DOWN}	$[MW]$	20	100	20	40	120	10	20	30
c_i^{up}	$[€/MWh]$	12.40	23.22	12.40	12.23	23.63	12.23	12.23	12.40
c_i^{down}	$[€/MWh]$	9.28	8.96	9.28	9.57	8.92	9.57	9.57	9.28

Table 3.2: Location and distribution of demand

demand	$d1$	$d2$	$d3$	$d4$
bus	$n3$	$n4$	$n5$	$n6$
factor [%]	19	27	27	27

load blocks with a time period from 1 to 24 and each row links the bidding prices with the relative load blocks while the value of the involuntary load reduction is 200 €/MWh for all demands. Finally, all the connecting lines have a transmission capacity of 500 MW with susceptance equal to 9.412 per unit.

3.4.2 Uncongested network solution

Based on the above information the proposed MILP model is applied to the system and solved using GAMS/CPLEX. When the strategic producer offers at marginal cost, the

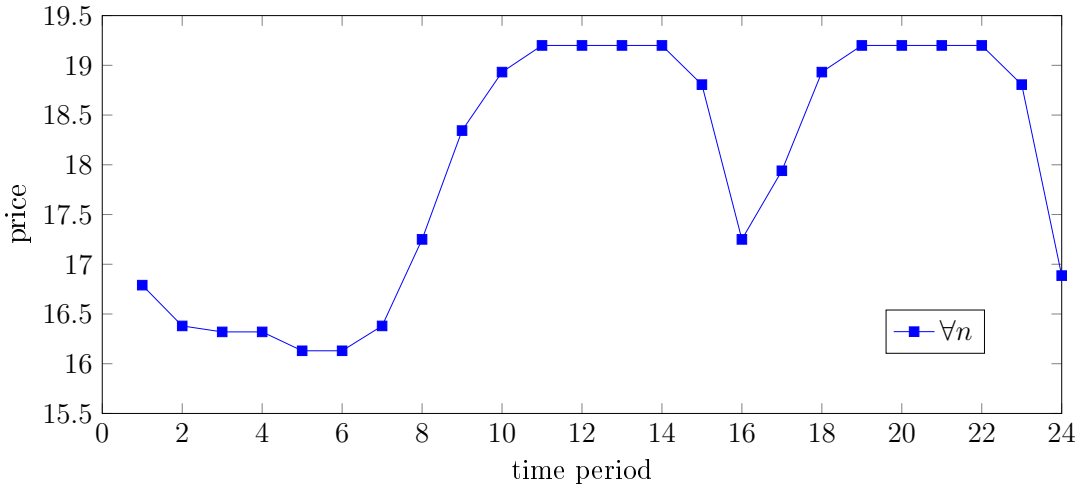

Figure 3.3: Day-ahead clearing prices in uncongested network

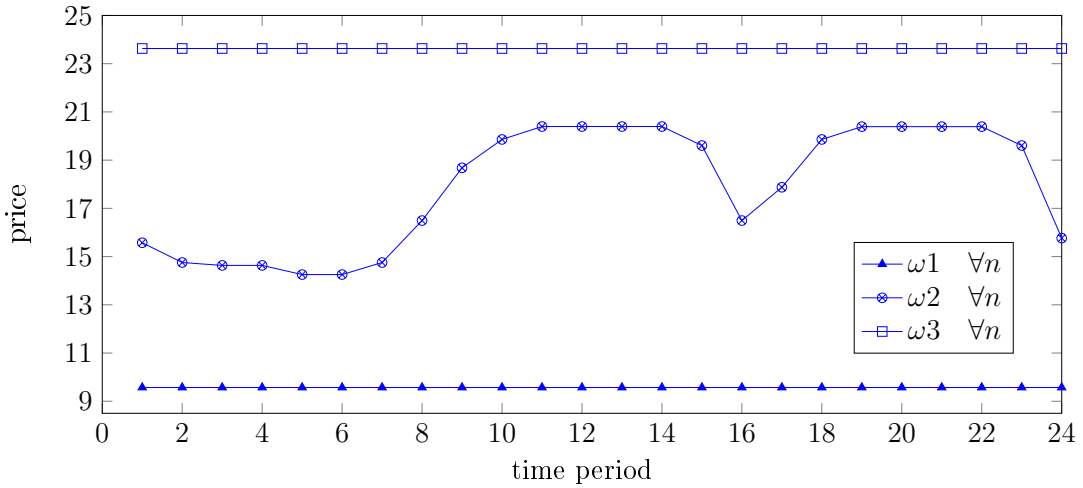

Figure 3.4: Real time clearing prices in uncongested network

DA clearing price is constant throughout the 24 period time at a level of 11.260 €/MWh. However, when the strategic producer exerts its market power the DA clearing price is raised,

while fluctuating between 16.130 and 19.200 €/MWh as shown in Figure 3.3. Similarly, the RT clearing prices are raised too. More specifically, in high wind scenario $\omega 1$ realization the RT price increases from 9.280 to 9.570 €/MWh, in medium wind scenario $\omega 2$ the RT clearing price leaves the level of 11.470 €/MWh and moves in a range between 14.254 and 20.394 €/MWh, and in low wind scenario $\omega 3$ the price rockets from 12.230 to 23.630 €/MWh as presented in Figure 3.4. In both cases, the prices are the same in all buses at each time period. This is due to the fact that there is enough line capacity, which facilitates the energy transaction at the DA stage and the reserve deployment at the RT stage while keeping the system uncongested in all wind production scenarios.

Table 3.3: Cleared market energy production [MWh] of strategic units and wind farms and price [€/MWh] outcomes under marginal cost offers in uncongested network at time t12

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega 1$	$\omega 2$	$\omega 3$	$\omega 1$	$\omega 2$	$\omega 3$			$\omega 1$	$\omega 2$	$\omega 3$
$i1$	132.2	.	.	.	15	.	.					
$i2$	.	.	.	.	.	.	.	$\forall n$	11.260	9.280	11.470	12.230
$i3$	155.0	.	.	.	.	.	.					
$i4$	157.6	.	.	15	40	.	.					
$W_{j1}^{DA} = 85, \quad W_{j2}^{DA} = 0$										$W_{j\omega}^{sp} = 0, \quad L_{d\omega}^{sh} = 0$		

Looking in more detail at time period $t12$ from the perspective of strategic producer and under marginal cost offering the scheduled energy production of strategic units i is 444.8 MWh and is paid at a price of 11.260 €/MWh as shown in Table 3.3. In this case the strategic producer's total expected profits are 388 €. When the producer acts as price maker curtails the scheduled production in all units at the level of 375 MWh making space for an increase in wind energy production from 85 MWh to 115 MWh as depicted in Table 3.4. However, even if the total scheduled is reduced , it is now paid at the price of 19.200 €/MWh. Furthermore,

Table 3.4: Cleared market energy production [MWh] of strategic units and wind farms and price [€/MWh] outcomes under strategic offers in uncongested network at time t12

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	123.8	.	.	.	.	.	.					
$i2$	.	.	.	.	.	.	.	$\forall n$	19.200	9.570	20.394	23.630
$i3$	124.0	.	.	.	.	.	.					
$i4$	118.2	.	.	35	25	.	.					
$W_{j1}^{DA} = 45, \quad W_{j2}^{DA} = 70$										$W_{j\omega}^{sp} = 0, \quad L_{d\omega}^{sh} = 0$		

Table 3.5: Expected profits [€] of strategic producer in uncongested network

	marginal cost offer				strategic offer			
i	profit per scenario			expected profit	profit per scenario			expected profit
	$\omega1$	$\omega2$	$\omega3$		$\omega1$	$\omega2$	$\omega3$	
$i1$	3,346	3,115	3,115	3,161	21,284	22,651	23,696	22,691
$i2$	0	0	0	0	0	0	0	0
$i3$	3,116	3,116	3,116	3,116	21,363	22,707	24,208	22,889
$i4$	3,591	2,823	3,067	3,049	21,935	21,986	21,986	21,976
				9,326				67,556

Table 3.6: Total scheduled and reserve production [MWh] of strategic units

	scheduled	upward reserve			downward reserve		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$
marginal cost offer	10,675.2	.	.	360.2	1,320.0	.	.
strategic offer	8,700.0	.	8.8	848.8	636.0	.	.

considering the reserves, the strategic producer based on the probabilistic expectations of wind power production at real time recognizes an arbitrage opportunity. It can be seen that in the low wind scenario $\omega 3$, where the energy shortage is now bigger, the upward reserve supply increases (unit $i4$ provides 35 instead of 15 MWh), and it is paid almost at double price. On the other hand, in the high wind scenario $\omega 1$, although the producer is charged at a higher price, the downward reserve supply is lower (25 MWh instead of 55 MWh). As a result, the total expected profits of strategic units i rocket at 3,405 €. The producer's revenues are determined by the uncertain reserve deployments, which in turn are inherently depended on the stochastic nature of wind production. Nevertheless, the market settlement formulated by ISO optimization problem guarantees cost recovery in expectation of every generation unit (Morales et al., 2012). The proposed model results in an increase in the total expected profit of the strategic producer as shown in Table 3.5 even if the strategic producer's power supply in the system is lower as shown in Table 3.6.

3.4.3 Building up offer curves

Table 3.7 and Table 3.8 present market clearing prices and strategic units' energy and reserve outcomes for the time period t20. Taking as an example the unit $i3$, it can be seen that the energy blocks $b1$, $b2$ are fully dispatched, $b3$ is partially dispatched while $b4$ is not dispatched. Building up the offer curve, and according to section 3.2.5, the first two blocks are offered at their marginal cost 9.92, and 10.25 €/MWh respectively, the third one is offered at price $19.200 - \epsilon$ €/MWh and the last one at a price 19.200 €/MWh. Concerning the reserves, the strategic unit does not provide upward reserve at the balancing stage in the high and medium wind scenarios but gives 10 MWh in the low wind scenario. The upward reserve is offered at a price of $23.630 - \epsilon$ €/MWh, which is higher than the RT clearing prices of scenarios $\omega 1$ and $\omega 2$, in which cases the offer is rejected, and lower than the RT clearing prices of the scenario $\omega 3$, in which case it is accepted. On the other hand, the strategic unit $i3$ does not provide any downward reserve; therefore negative regulation is offered at its

Table 3.7: Clearing market prices [€/MWh] under strategic behaviour in uncongested network at time t20

bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega 1$	$\omega 2$	$\omega 3$
$\forall n$	19.200	9.570	20.394	23.630

Table 3.8: Cleared market energy [MWh], Reserve [MWh] and offer [€/MWh] outcomes in uncongested network at time t20

units	$P_{i,b1}^{DA}$	$O_{i,b1}^{DA}$	$P_{i,b2}^{DA}$	$O_{i,b2}^{DA}$	$P_{i,b3}^{DA}$	$O_{i,b3}^{DA}$	$P_{i,b4}^{DA}$	$O_{i,b4}^{DA}$	$r_{i,\omega}^{up}$			O_i^{up}	$r_{i,\omega}^{down}$			O_i^{down}
									$\omega 1$	$\omega 2$	$\omega 3$		$\omega 1$	$\omega 2$	$\omega 3$	
$i1$	54.25	[19.200]	38.75	[19.200]	31.00	[19.200]	.	[19.200]	.	.	.	[23.630]	.	.	.	[9.280]
$i2$	.	[19.200]	.	[19.200]	.	[19.200]	.	[19.200]	.	.	.	[23.630]	.	.	.	[8.960]
$i3$	54.25	[19.200]	38.75	[19.200]	30.80	[19.200]	.	[19.200]	.	.	10	[23.630]	.	.	.	[9.280]
$i4$	68.95	[19.200]	49.25	[19.200]	.	[19.200]	.	[19.200]	.	.	40	[23.630]	25	.	.	[9.570]

Table 3.9: Offer [€/MWh] building for strategic unit $i3$ in uncongested network at time t20

block	$c_{i1,b}$	$P_{i1,b}^{DA}$	λ_{n1}^{DA}	$O_{i1,b}^{filled,DA}$	ω	c_{i1}^{up}	$res_{i1,\omega}^{up}$	$\frac{\lambda_{n1,\omega}^{RT}}{\pi_\omega}$	$O_{i1}^{filled,up}$	c_{i1}^{down}	$res_{i1,\omega}^{down}$	$\frac{\lambda_{n1,\omega}^{RT}}{\pi_\omega}$	$O_{i1}^{filled,down}$
b1	9.92	54.25	19.20	9.92	$\omega 1$	12.40	.	9.57	23.630$-\epsilon$	9.28	.	9.57	9.28
b2	10.25	38.75	19.20	10.25	$\omega 2$	12.40	.	20.394	23.630$-\epsilon$	9.28	.	20.394	9.28
b3	10.68	30.80	19.20	19.20$-\epsilon$	$\omega 3$	12.40	10	23.63	23.630$-\epsilon$	9.28	.	23.63	9.28
b4	11.26	.	19.20	19.20									

marginal cost 9,28 €/MWh, a price that guarantees the rejection as it is lower than the

Table 3.10: Offer [€/MWh] building for strategic unit $i4$ in uncongested network at t12

block	$c_{i4,b}$	$P^{DA}_{i4,b}$	λ^{DA}_{n6}	$O^{filled,DA}_{i4,b}$	ω	c^{up}_{i4}	$res^{up}_{i4,\omega}$	$\frac{\lambda^{RT}_{n6,\omega}}{\pi_\omega}$	$O^{filled,up}_{i4}$	c^{down}_{i4}	$res^{down}_{i4,\omega}$	$\frac{\lambda^{RT}_{n6,\omega}}{\pi_\omega}$	$O^{filled,down}_{i4}$
b1	10.08	68.95	19.20	10.08	$\omega 1$	12.23	.	9.57	23.63	9.57	25	9.57	9.57
b2	10.66	49.05	19.20	$19.20-\epsilon$	$\omega 2$	12.23	.	14.75	23.63	9.57	.	14.75	9.57
b3	11.09	.	19.20	19.20	$\omega 3$	12.23	40	23.63	23.63	9.57	.	23.63	9.57
b4	11.72	.	19.20	19.20									

RT clearing price of all scenarios. The offer building process for unit $i3$ is illustrated in Table 3.9. Similarly, considering strategic unit $i4$, the first and the second blocks are fully dispatched and are offered at their marginal costs 10.08 and 10.66€/MWh respectively, the third and fourth blocks are non-dispatched; consequently, they are offered at a price of 19.200 €/MWh. Additionally, the strategic unit provides its maximum capacity of upward reserve in low wind scenario; therefore, it can offer positive regulation at a price of 23.630 €/MWh, thus it guarantees that the offer is rejected in high and medium wind scenarios and accepted in low wind scenario. Finally, under high wind scenario the unit provides 25 MWh of downward reserve at its marginal cost 9.57 €/MWh. The offer coincides with the RT clearing price of the relative scenario guaranteeing the reserve acceptance, and it is lower than the RT clearing prices of medium and low wind scenarios ensuring the reserve rejection. Table 3.10 presents the building offer process for unit $i4$.

3.4.4 Congested network solution

In uncongested network case the maximum power flow through line $3-6$ is 227 MW. If the line capacity is reduced at the level of 240 MW, slightly above the maximum flow, the results remain the same when the strategic producer acts as price taker. However, the proposed MILP formulation shows that the strategic producer can make offers in such a way that the system becomes congested resulting in different LMPs of DA and RT clearing prices

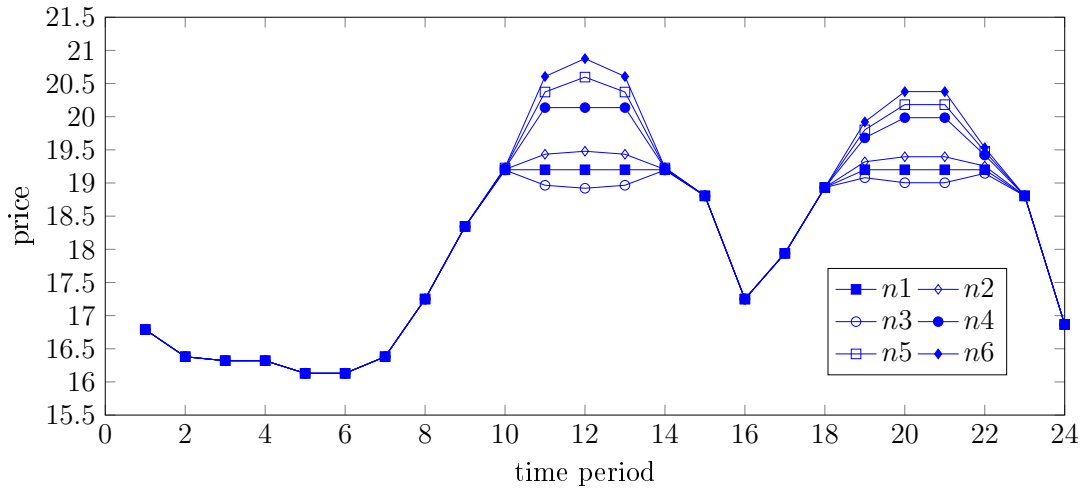

Figure 3.5: Day-ahead clearing prices in congested line $n3 - n6$

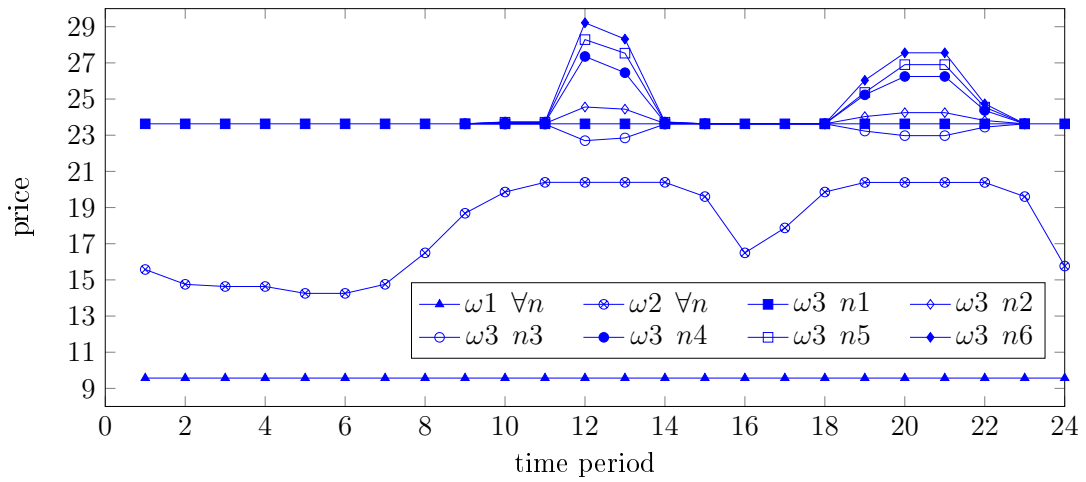

Figure 3.6: Real-time clearing prices [€/MWh] in congested line $n3 - n6$

at specific time periods as illustrated in Figure 3.5 and Figure 3.6 respectively. It can be seen that bus $n6$ exhibits the highest price giving the strategic producer the opportunity to increase the profit of unit $i4$. Table 3.11 provides the total expected profits of the strategic producer, which are slightly higher compared to those of uncongested network. Considering the strategic producer's attitude towards line $3 - 6$ the line is classified as *congestable*. The

characteristic of this line is that its capacity is not sufficiently large, and the strategic producer make offers in order to congest it increasing its profits.

Table 3.11: Expected profits [€] of strategic producer in congested line $3-6$

	uncongested network				congested line $3-6$			
i	profit per scenario			expected profit	profit per scenario			expected profit
	$\omega 1$	$\omega 2$	$\omega 3$		$\omega 1$	$\omega 2$	$\omega 3$	
$i1$	21,284	22,651	23,696	22,691	21,028	22,534	23,873	22,635
$i2$	0	0	0	0	0	0	0	0
$i3$	21,363	22,707	24,208	22,889	21,644	21,668	23,283	22,498
$i4$	21,935	21,986	21,986	21,976	22,118	22,872	23,784	22,997
				67,556				68,130

Table 3.12: Scheduled production [MWh] of strategic units and expected profits [€] in congested line $4-6$

	scheduled production				total production	expected profit
	$i1$	$i2$	$i3$	$i4$	[MWh]	[€]
uncongested network	2,728	0	2,725	2,816	8,269	67,556
congested line $4-6$	3,038	0	3,068	2,133	8,239	67,200

Additionally, in the uncongested case the maximum power flow through line $4-6$ is 24 MW. If the capacity of the line is reduced to 20 MW, slightly below the maximum flow, the network becomes congested under cost offer optimization, resulting in different LMPs and profit losses for the strategic producer. However, applying the proposed MILP formulation, the strategic producer chooses offers to modify each unit's production making the line uncongested. As a result, the total scheduled production, as well as the total profit, remains almost the same compared to the uncongested case as shown in Table 3.12. From the strategic producer's point of view the line $4-6$ is classified as *noncongestable* (Ruiz and

Conejo, 2009), and the strategic producer changes the mixture of units' production in an attempt to keep the line uncongested and the profit high.

3.4.5 Wind power production increment

In this case, the level of wind power penetration increases from 10% to 14.16% of the total installed capacity. More specifically, the power production of the wind farms $j1$ and $j2$ is 150 MW and 100 MW respectively in high wind scenario $\omega 1$, 75 MW and 50 MW in medium wind scenario $\omega 2$, and 30 MW and 20 MW in low wind scenario $\omega 3$. It can be seen in Figure 3.7 that the expected profits of units $i1$ and $i2$ are reduced in all wind scenarios.

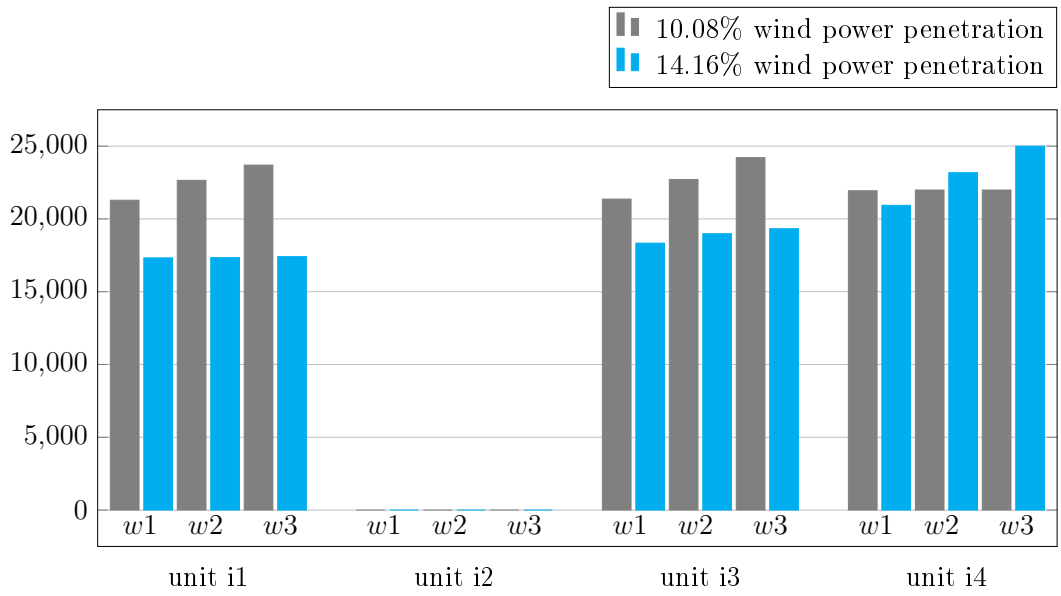

Figure 3.7: Expected profits [€] of strategic units under different level of wind power penetration

Considering unit $i4$ the expected profits decrease in high wind scenario $\omega 1$; however, the expected profits increase in medium and low wind scenarios as the unit becomes more involved in reserve supply. Nevertheless, even if the total expected profits of unit $i4$ rise, the total expected profits of strategic producer decrease from 67,556 € to 59,589 €, as illustrated in Table 3.13, indicating that wind power production can be used as a tool for market power mitigation.

Table 3.13: Expected profit of strategic units [€]

wind power penetration	$i1$	$i2$	$i3$	$i4$	Total expected profit
10.08%	22,691	0	22,889	21,976	67,556
14.16%	17,358	0	18,957	23,274	59,589

3.5 Reliability test system (RTS) case

3.5.1 RTS data

To test the applicability of the proposed model in a more sophisticated system the MILP is applied on the IEEE one-area (24-bus system) Reliability Test System (RTS) described in Reliability system task force (1999). The system contains 32 conventional units i and 3 wind units j. Conventional units $i1$ to $i8$ belong to strategic producer while $i9$ to $i32$ together with wind units j belong to non-strategic producers. The distribution of the generating units in the grid is shown in Figure C.1 (Appendix C). Technical data for the conventional units are provided in Table C.3. The three wind power units $j1$, $j2$ and $j3$ have installed capacity 200 MW, 150 MW and 150 MW respectively accounting for the 12.82% of the 3.9 GW total installed capacity. The wind farms' uncertain power production is actualized through three scenarios, $\omega1$ (high) with 200 MWh, 150 MWh and 150 MWh, $\omega2$ (medium) with 100 MWh, 75 MWh and 75 MWh, and $\omega3$ (low) with 50 MWh, 30 MWh and 30 MWh. The occurrence probability of each scenario is 0.2, 0.5 and 0.3 respectively. In addition, a total demand of 2.85 GWh are considered. The demand follows the utility cost depicted on Table B.1 (Appendix B) and is shared among 17 buses through five energy blocks k as indicated in Table C.4.

3.5.2 RTS solution

When the strategic producer acts as price taker the DA market clearing price is 15.079 €/MWh throughout the 24-hour period. Nevertheless, when the producer offers strategically,

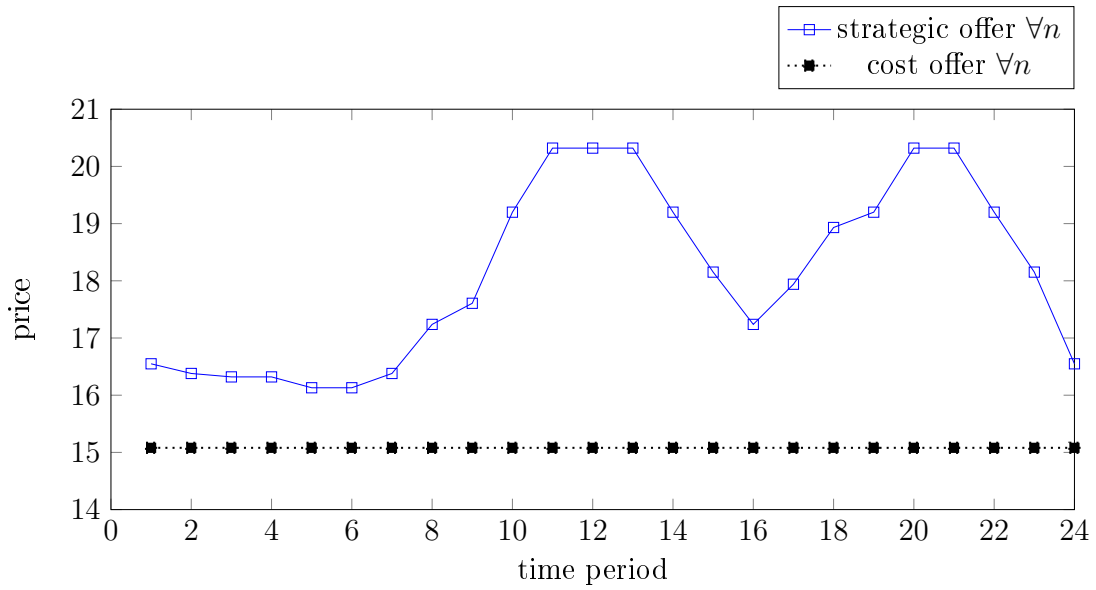

Figure 3.8: Day-ahead clearing prices in RTS case

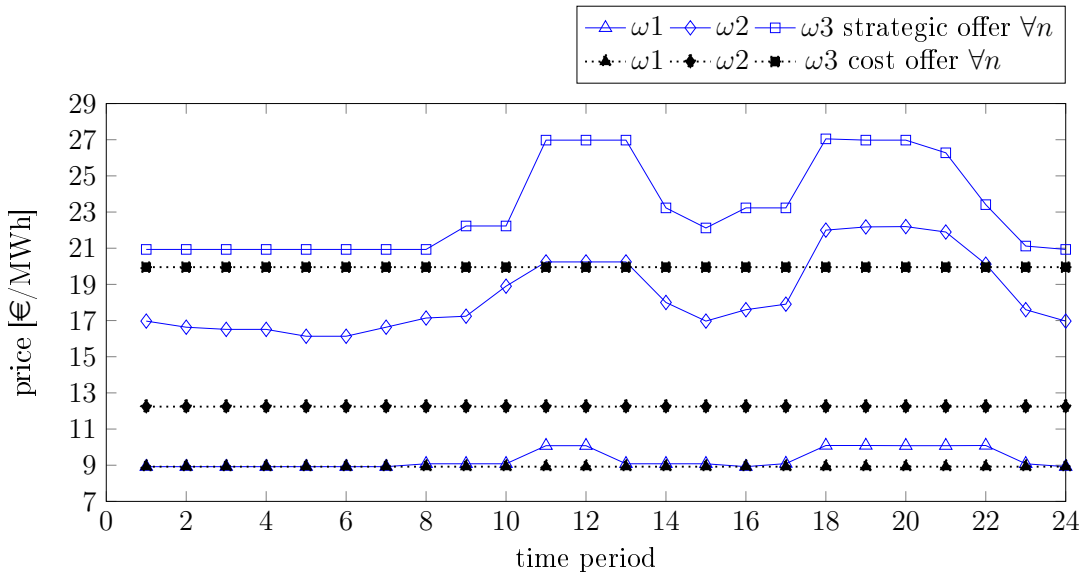

Figure 3.9: Real-time clearing prices in RTS case

Table 3.14: Scheduled production [MWh] of strategic units in RTS case

	$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$	total
cost offer	1,377.6	1,459.2	1,104.0	0.0	4,728.0	3,720.0	9,600.0	3,720.0	25,708.8
strategic offer	903.6	796.6	865.6	0.0	4,467.2	3,458.0	9,600.0	3,413.4	23,504.4

Table 3.15: Expected profit [€] of strategic producer in RTS case

	$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$	total
cost offer	5,192	5,057	5,644	0	20,473	17,322	92,309	17,322	163,319
strategic offer	5,454	4,553	5,285	0	33,439	26,785	120,737	26,383	222,636

the DA market clearing price increases and oscillates between 16.130 €/MWh and 20.320 €/MWh as shown in Figure 3.7. Similarly, there is an increase for RT market clearing prices in all wind production scenarios as shown in Figure 3.8. Considering energy dispatch and profits, as expected, exercising market power results in curtailed scheduled production and increased expected profits compared to these received under marginal cost offering as illustrated in Table 3.14 and Table 3.15 respectively.

3.6 Computational issues

The final MILP (3.47) − (3.96) is solved using CPLEX 24.1.3 under GAMS on an Intel Core i7 at 2.7 GHz and 16 GB RAM. The computational (central processing unit, CPU) time depends on the sophisticated representation of the network-constrained model. This representation is associated with the number of complementarity constraints which double the number of the introduced binary variables at the MILP formulation rendering the problem computationally intractable. However, it is important to note that during the MPEC formulations and the construction of the auxiliary Lagrangian function, the *here and now* variables P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA} and δ_n^o of the first stage of the stochastic programming are also

treated as variables and not as parameters in the second stage. Proceeding in this way, all the non-linear terms of the objective functions are eliminated. If this is not the case, the linearization processes cannot eliminate the non-linear terms $O_i^{up} r_{i\omega}^{up}$, $O_i^{down} r_{i\omega}^{down}$, $O_j^{RT} \sum_f W_{jf}^{DA}$ and $O_j^{RT} W_{j\omega}^{sp}$. At this point, the use of a binary expansion method (Barroso et al., 2006a) will install a considerably large number of binary variables in the final MILP for the discretization of the W_{jf}^{DA}, $r_{i\omega}^{up}$, $r_{i\omega}^{down}$ and $W_{j\omega}^{sp}$; thereby rendering more sophisticated network cases like RTS unsolvable.

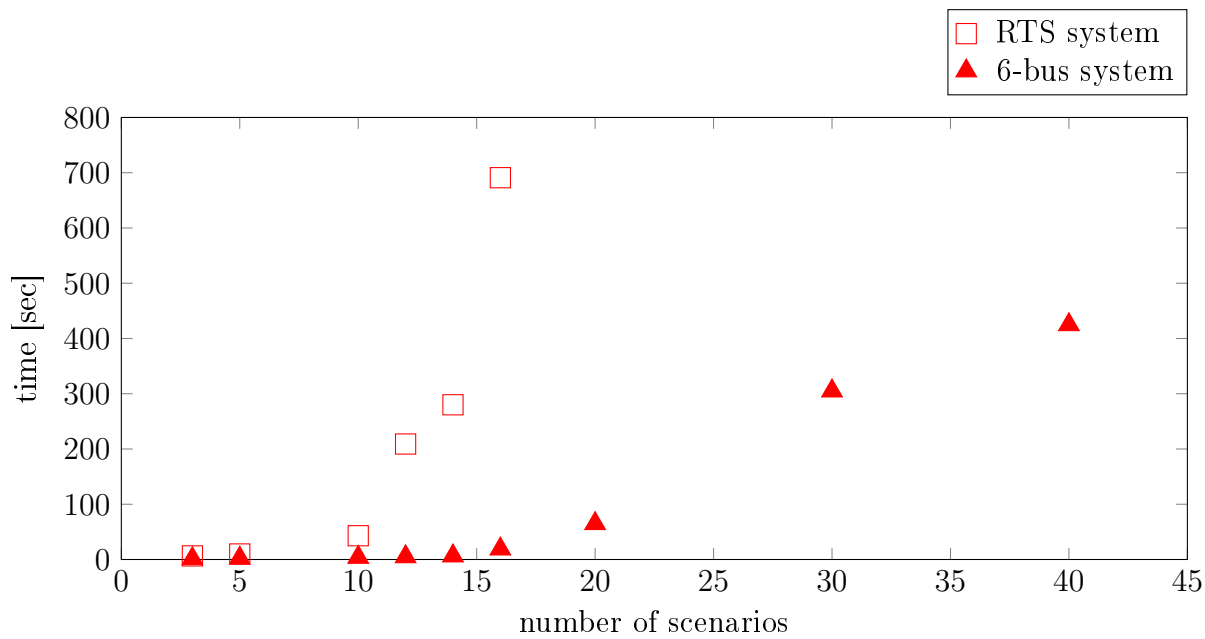

Figure 3.10: CPU time

Figure 3.10 presents the computational time required for solving both cases, 6-bus system and RTS, under realization of different wind scenario numbers. Furthermore, the computational efficiency is highly connected with the size of the linearization constants M. The selection of these values is of paramount importance because a choice of large value could induce the CPLEX to run into numerical issues while a choice of small value could restrain the feasible region of the problem cutting out optimal solutions. It can be noticed that the constants M^{pP}, M^{pC} and M^{pV} are associated with power generation and demand, power

flow, and voltage angle variables respectively, and their values can be defined based on the physical characteristics (upper bounds) of these variables (Gabriel and Leuthold, 2010). Finally, the calculation of the value of the constants M^{vP}, M^{vC} and M^{vV}, which are associated with the dual variables, is more complicated and the heuristic process proposed by Ruiz and Conejo (2009) is followed:

i) Solve the linear programming (2.1)−(2.18) where all the producers offer at marginal cost.

ii) Receive the shadow price of each resource constraint, and thus a value associated with the dual variable of the this constraint.

iii) Calculate the relevant constant M as M = (shadow price + 1) × 100.

3.7 Conclusions

In this Chapter, based on the single-leader single-follower Stackelberg hypothesis, a mixed integer linear programming model is developed to derive optimal offer strategies for a conventional power producer participating in a jointly cleared energy and reserve market under high penetration of wind power production. The model concerns energy-only markets. Co-optimizing energy dispatch and reserve deployments through a two-stage stochastic programming, it gives insight information on market clearing prices and the way they are configured when the strategic producer exercises its dominant position in the market. Based on these prices, the strategic producer build up optimal offering curves to maximize its expected profits. Furthermore the model provides information about how line capacities and network congestions can be used for the benefit of the strategic producer. The following Chapter will introduce an expanded version of the proposed algorithm where the strategic producer's generation portfolio also includes wind power production.

Chapter 4

Optimal offering strategies for a conventional and wind generation portfolio

This Chapter addresses the optimal offering problem of a conventional and wind generation portfolio in a pool market. The proposed stochastic bi-level model is an extension of the one proposed in the previous Chapter as the producer can now exercise market power with wind generation as well. The model is recast into an MPEC and subsequently into a tractable MILP. Two cases show the effectiveness of the proposed algorithm.

4.1 Introduction

The share of wind power generation in electricity industry is increasing rapidly worldwide. Considering the high penetration of wind power resources, their financially subsidized generation and the prioritized dispatch (merit order) have resulted in reduced conventional production volumes and suppressed electricity prices. Following this, a question arises about the sustainability of the existing thermal units. In addition, a second question arises about the attainability of future investments not only for the conventional units but also for the

wind power facilities as the continuous growth of the latter leads to further suppressed electricity prices. Within the above framework, this study extends the model in Chapter 3 and looks into the strategic reaction of a power producer whose generation portfolio consists of thermal and wind power production. Having a significant number of thermal and wind power generation units, the aforementioned producer exercises market power with both types of units by means of capacity withholding and transmission-related strategies to offset expected profit losses.

Having this in mind, this Chapter investigates the optimum scheduled generation and offering strategies for an electricity producer participating in a pool-based market. As opposed to the relative formulations presented in works of Ruiz and Conejo (2009), Baringo and Conejo (2013), Zungo et al. (2013) and Delikaraoglou et al. (2015) the developed MPEC takes into consideration a strategic producer with thermal and wind generation portfolio. In comparison to work of Kazempour and Zareipour (2014) the algorithm derives optimal offers for upward and downward reserves separately. In addition, it includes transmission network limitations thus extending the computational effort of the model and providing the strategic producer with the ability to exploit network congestions for its own gain. Furthermore, in relation to Kazempour and Zareipour (2014) and Dai and Qiao (2017) the proposed MPEC is linearized without using binary expansion methods which increase the number of variables. Thereby, the final MILP renders more sophisticated network cases solvable.

On the basis of the aforementioned framework, this study makes the following contributions:

i) it develops a bi-level complementarity model to ascertain optimal capacity withholding strategies for a conventional and wind generation portfolio of an incumbent producer who participates in a jointly cleared energy and reserve pool-based market.

ii) it efficiently reformulates the bi-level model into an MPEC and then into an equivalent MILP model solvable to global optimality utilizing KKT conditions, disjunctive constraints, and the strong duality theorem with parallel avoidance of any BE method.

iii) it derives optimal thermal and wind scheduled production for the DA market considering wind generation uncertainty.

iv) it constructs best offering curves based on the formulated DA and balancing clearing prices which are received as dual variables from the energy balance constraints.

v) it analyzes and discusses the effects of wind uncertainty, network congestions, and different levels of wind power penetration on the behaviour of the strategic producer within a wide range of case studies.

4.2 Bi-level model

Problem statement

The proposed bi-level complementarity model based on the Stackelberg hypothesis of the single-leader single-follower game (Dutta, 1999) derives optimal capacity withholding strategies for a producer with thermal and wind generation portfolio. The assumption is made that this strategic producer holds a dominant position in the market as it possesses a large amount of energy generating facilities and can therefore impact the prices (price maker). The producer competes with other non-strategic conventional as well as wind energy producers (price takers) in a jointly cleared energy and balancing pool-based market. In the market producers submit their production offers, and consumers and retailers submit their consumption bids in a network-constrained auction. The market is cleared by the ISO one day in advance and on an hourly basis providing LMPs and energy quantities which are bought and sold (Gomez-Exposito et al., 2018). The upper-level of the model establishes the expected profit optimization of the strategic producer (leader), which depend on the DA and RT clearing market prices acquired endogenously in the lower-level problem. Conversely, the lower-level problem is representative of the market clearing procedure conducted by the ISO (follower). The aim of the ISO is to determine the dispatch amount of production and consumption maximizing the social welfare, the difference between the total consumption

utility bids and the total production cost offers, or equivalently to minimize the total social cost (economic dispatch). The lower-level of the model is constructed in the form of a linearized DC network as two-stage stochastic programming (Kirschen and Strbac, 2004; Zavala et al., 2017). The first stage enables the DA market and leads to optimization of the expected dispatch (scheduled generation) while the DA market clearing prices are taken as dual variables (Morales et al., 2013). The second stage is representative of the balancing market in which the stochastic nature of wind generation is considered through the realization of all the plausible wind power production scenarios. The clearing of the balancing market results in balancing dispatch (reserve deployments) and RT market prices (Morales et al., 2012). Following this and presuming the continuity and convexity of the lower problem, it is possible to reduce the bi-level model to an MPEC model via Karush-Kuhn-Tucker first order optimality conditions. Finally, by utilizing disjunctive constraints (Fortuny-Amat and McCarl, 1981) as well as the strong duality theorem, the MPEC can be recast into an equivalent MILP model.

4.2.1 Bi-level model formulation

The following bi-level model is developed to derive optimal offering strategies for a conventional and wind power producer participating in a jointly cleared energy and balancing pool.

Upper-level problem

$$\begin{aligned}
\underset{\Xi_w^S \cup \Xi_w^O}{maximize} \quad & \sum_{(i\in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} - \sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} + \sum_{(j\in J_n^S)f} \lambda_n^{DA} W_{jf}^{DA} \\
& + \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} \\
& - \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& + \sum_{(j\in J_n^S)\omega} \lambda_{n\omega}^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right)
\end{aligned} \tag{4.1}$$

Lower-level problem

$$
\begin{aligned}
\underset{\Xi}{minimize} \quad & \sum_{(i\in I^S),b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i\in I^S),\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S),\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\
& + \sum_{(j\in J^S),f} O_{jf}^{DA} W_{jf}^{DA} + \sum_{(j\in J^S),\omega} \pi_\omega O_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
& + \sum_{(i\in I^O),b} c_{ib} P_{ib}^{DA} + \sum_{(i\in I^O),\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^O),\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& + \sum_{(j\in J^O),f} c_{jf} W_{jf}^{DA} + \sum_{(j\in J^O),\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
& - \sum_{d,k} u_{dk} L_{dk}^{DA} + \sum_{d,\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \qquad (4.2)
\end{aligned}
$$

$$
\textit{subjected to} \qquad (2.3) - (2.18) \qquad (4.3)
$$

The objective function (4.1) maximizes the expected profits of the strategic producer which are determined by the revenues of its thermal and wind generating units from the DA market, the revenues (gain or losses) from the supply of upward or downward reserve deployments and the wind power surplus or shortfall generation in balancing market minus the actual incurred cost. We should note that the fourth, the sixth and the seventh terms of (4.1) are derived from $\sum_{(i\in I_n^S),\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} r_{i\omega}^{up}$, $\sum_{(i\in I_n^S),\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} r_{i\omega}^{down}$ and $\sum_{(j\in J_n^S),\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right)$ respectively. $\Xi_w^S = \{P_{(i\in I^S)b}^{DA}, W_{(j\in J^S)f}^{DA}, r_{(i\in I^S)\omega}^{up}, r_{(i\in I^S)\omega}^{down}, W_{(j\in J^S)\omega}^{sp}\}$ and $\Xi_w^O = \{O_{(i\in I^S)b}^{DA}, O_{(i\in I^S)}^{up}, O_{(i\in I^S)}^{down}, O_{(j\in J^S)f}^{DA}, O_{(j\in J^S)}^{RT}\}$ are the sets of all strategic producer's decision variables. Compared to objective function (3.1) and the sets Ξ^S and Ξ^O the new objective function (4.1) and the sets Ξ_w^S and Ξ_w^O contain decision variables associated with wind production and offering as the strategic producer now exercises market power with wind units as well. The objective function (4.2) clears the DA and RT markets maximizing the total social welfare. Actually, the ISO seeks to minimize the total expected cost of the system operation which consists of the following: a) the scheduled thermal and wind production cost at the DA market, and b) the cost or savings of the scenario dependent positive or negative regulation,

the wind surplus or shortfall power production, and finally the cost of wind power spillage and load shedding in real time operation. $\Xi = \{P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, r_{i\omega}^{up}, r_{i\omega}^{down}, W_{j\omega}^{sp}, L_{d\omega}^{sh}, \delta_n^o, \delta_{n\omega}\}$ is the set of all ISO's decision variables. Finally, the constraint (4.3) refers to technical constraints (2.3) − (2.18) which consider the market clearing process as presented in section 2.3.2.

4.2.2 MPEC formulation

Making the same assumptions with the MPEC formulation in section 3.2.3 that the lower non-linear constrained minimization problem is continuous and differential, the Lagrangian function can be used to transform the lower problem into an unconstrained one. Additionally, the prime variables O_{ib}^{DA}, O_{jf}^{DA}, $O_{i\omega}^{up}$, $O_{i\omega}^{down}$ and O_j^{RT} are encountered as parameters by the ISO in the objective function (4.2) of the lower problem rendering the latter linear and consequently convex. Within the above framework, the lower problem can be replaced by its KKT first order optimality conditions recasting the bi-level problem (4.1) – (4.3) into a single continuous non-linear MPEC as follows:

$$\underset{\Xi \cup \Xi_w^O \cup \Xi^D}{maximize} \qquad (4.1) \tag{4.4}$$

subjected to KKT equality constraints

$$O_{ib}^{DA} - \lambda_n^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^S, \forall b \tag{4.5}$$

$$c_{ib} - \lambda_n^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^O, \forall b \tag{4.6}$$

$$O_{jf}^{DA} - O_j^{RT} - \lambda_n^{DA} + \sum_{\omega} \lambda_{n\omega}^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} = 0 \qquad \forall j \in J_n^S, \forall f \tag{4.7}$$

$$c_{jf}^{DA} - c_j^{RT} - \lambda_n^{DA} + \sum_{\omega} \lambda_{n\omega}^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} = 0 \qquad \forall j \in J_n^O, \forall f \tag{4.8}$$

$$-u_{dk} + \lambda_n^{DA} + \gamma_{dk}^{max} - \gamma_{dk}^{min} - \sum_{\omega} \nu_{d\omega}^{max} = 0 \qquad \forall d \in D_n, \forall k \tag{4.9}$$

$$\pi_\omega O_i^{up} - \lambda_{n\omega}^{RT} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} = 0 \qquad \forall i \in I_n^S, \forall \omega \tag{4.10}$$

$$\pi_\omega c_i^{up} - \lambda_{n\omega}^{RT} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} = 0 \qquad \forall i \in I_n^O, \forall \omega \tag{4.11}$$

$$-\pi_\omega O_i^{down} + \lambda_{n\omega}^{RT} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^S, \forall \omega \tag{4.12}$$

$$-\pi_\omega c_i^{down} + \lambda_{n\omega}^{RT} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} = 0 \qquad \forall i \in I_n^O, \forall \omega \tag{4.13}$$

$$-\pi_\omega O_j^{RT} + \lambda_{n\omega}^{RT} + \kappa_{j\omega}^{max} - \kappa_{j\omega}^{min} = 0 \qquad \forall j \in J_n^S, \forall \omega \tag{4.14}$$

$$-\pi_\omega c_j^{RT} + \lambda_{n\omega}^{RT} + \kappa_{j\omega}^{max} - \kappa_{j\omega}^{min} = 0 \qquad \forall j \in J_n^O, \forall \omega \tag{4.15}$$

$$\pi_\omega vLOL_d - \lambda_{n\omega}^{RT} + \nu_{d\omega}^{max} - \nu_{d\omega}^{min} = 0 \qquad \forall d \in D_n, \forall \omega \tag{4.16}$$

$$\begin{aligned}&\sum_{m\in\Theta_n} B_{nm}\big(\lambda_n^{DA} - \lambda_m^{DA}\big) + \sum_{(m\in\Theta_n)\omega} B_{nm}\big(-\lambda_{n\omega}^{RT} + \lambda_{m\omega}^{RT}\big) + \sum_{m\in\Theta_n} B_{nm}\big(\xi_{nm}^{max} - \xi_{mn}^{max}\big)\\ &- \sum_{m\in\Theta_n} B_{nm}\big(\xi_{nm}^{min} - \xi_{mn}^{min}\big) + \rho_n^{max} - \rho_n^{min} + \phi_{(n1)}^o = 0 \qquad \forall n\end{aligned} \tag{4.17}$$

$$\begin{aligned}&\sum_{m\in\Theta_n} B_{nm}\big(\lambda_{n\omega}^{RT} - \lambda_{m\omega}^{RT}\big) + \sum_{m\in\Theta_n} B_{nm}\big(\xi_{nm\omega}^{max} - \xi_{mn\omega}^{max}\big)\\ &- \sum_{m\in\Theta_n} B_{nm}\big(\xi_{nm\omega}^{min} - \xi_{mn\omega}^{min}\big) + \rho_{n\omega}^{max} - \rho_{n\omega}^{min} + \phi_{(n1)\omega} = 0 \qquad \forall n, \forall \omega\end{aligned} \tag{4.18}$$

$$-\sum_{(i\in I_n)b} P_{ib}^{DA} - \sum_{(j\in J_n)f} W_{jf}^{DA} + \sum_{(d\in D_n)k} L_{dk}^{DA} + \sum_{m\in\Theta_n} B_{nm}\big(\delta_n^o - \delta_m^o\big) = 0 \quad \forall n \tag{4.19}$$

$$\begin{aligned}&-\sum_{i\in I_n} r_{i\omega}^{up} + \sum_{i\in I_n} r_{i\omega}^{down} - \left(\sum_{j\in J_n} W_{j\omega}^{RT} - \sum_{(j\in J_n)f} W_{jf}^{DA} - \sum_{j\in J_n} W_{j\omega}^{sp}\right)\\ &- \sum_{d\in D_n} L_{d\omega}^{sh} + \sum_{m\in\Theta_n} B_{nm}\big(\delta_{n\omega} - \delta_n^o + \delta_m^o - \delta_{m\omega}\big) = 0 \qquad \forall n, \forall \omega\end{aligned} \tag{4.20}$$

$$\delta_{(n1)}^o = 0 \qquad n = n1 \quad \text{(slack bus)} \tag{4.21}$$

$$\delta_{(n1)\omega} = 0 \qquad n = n1, \forall \omega \tag{4.22}$$

subjected to KKT complementarity constraints

$$0 \le P_{ib}^{DA} \perp \alpha_{ib}^{min} \ge 0 \qquad \forall i, \forall b \tag{4.23}$$

$$0 \le P_{ib}^{MAX} - P_{ib}^{DA} \perp \alpha_{ib}^{max} \ge 0 \qquad \forall i, \forall b \tag{4.24}$$

$$0 \le W_{jf}^{DA} \perp \beta_{jf}^{min} \ge 0 \qquad \forall j, \forall f \tag{4.25}$$

$$0 \le W_{jf}^{MAX} - W_{jf}^{DA} \perp \beta_{jf}^{max} \ge 0 \qquad \forall j, \forall f \tag{4.26}$$

$$0 \leq L_{dk}^{DA} \perp \gamma_{dk}^{min} \geq 0 \qquad \forall d, \forall k \tag{4.27}$$

$$0 \leq L_{dk}^{MAX} - L_{dk}^{DA} \perp \gamma_{dk}^{max} \geq 0 \qquad \forall d, \forall k \tag{4.28}$$

$$0 \leq r_{i\omega}^{up} \perp \epsilon_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{4.29}$$

$$0 \leq RES_{i}^{UP} - r_{i\omega}^{up} \perp \epsilon_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{4.30}$$

$$0 \leq r_{i\omega}^{down} \perp \theta_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{4.31}$$

$$0 \leq RES_{i}^{DOWN} - r_{i\omega}^{down} \perp \theta_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{4.32}$$

$$0 \leq \sum_{b} P_{ib}^{MAX} - \sum_{b} P_{ib}^{DA} - r_{i\omega}^{up} \perp \mu_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{4.33}$$

$$0 \leq \sum_{b} P_{ib}^{DA} - r_{i\omega}^{down} \perp \mu_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{4.34}$$

$$0 \leq W_{j\omega}^{sp} \perp \kappa_{j\omega}^{min} \geq 0 \qquad \forall j, \forall \omega \tag{4.35}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \perp \kappa_{j\omega}^{max} \geq 0 \qquad \forall j, \forall \omega \tag{4.36}$$

$$0 \leq L_{d\omega}^{sh} \perp \nu_{d\omega}^{min} \geq 0 \qquad \forall d, \forall \omega \tag{4.37}$$

$$0 \leq \sum_{k} L_{dk}^{DA} - L_{d\omega}^{sh} \perp \nu_{d\omega}^{max} \geq 0 \qquad \forall d, \forall \omega \tag{4.38}$$

$$0 \leq B_{nm}\big(\delta_{n}^{o} - \delta_{m}^{o}\big) + T_{nm}^{MAX} \perp \xi_{nm}^{min} \geq 0 \qquad \forall n, \forall m \in \Theta_{m} \tag{4.39}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n}^{o} - \delta_{m}^{o}\big) \perp \xi_{nm}^{max} \geq 0 \qquad \forall n, \forall m \in \Theta_{m} \tag{4.40}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \perp \xi_{nm\omega}^{min} \geq 0 \qquad \forall n, \forall m \in \Theta_{m} \forall \omega \tag{4.41}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \perp \xi_{nm\omega}^{max} \geq 0 \qquad \forall n, \forall m \in \Theta_{m} \forall \omega \tag{4.42}$$

$$0 \leq \delta_{n}^{o} + \pi \perp \rho_{n}^{min} \geq 0 \qquad \forall n \tag{4.43}$$

$$0 \leq \pi - \delta_{n}^{o} \perp \rho_{n}^{max} \geq 0 \qquad \forall n \tag{4.44}$$

$$0 \leq \delta_{n\omega} + \pi \perp \rho_{n\omega}^{min} \geq 0 \qquad \forall n, \forall \omega \tag{4.45}$$

$$0 \leq \pi - \delta_{n\omega} \perp \rho_{n\omega}^{max} \geq 0 \qquad \forall n, \forall \omega \tag{4.46}$$

Where $\Xi^{D} = \{\lambda_{n}^{DA}, \lambda_{n\omega}^{RT}, \alpha_{ib}^{max}, \alpha_{ib}^{min}, \beta_{jf}^{max}, \beta_{jf}^{min}, \gamma_{dk}^{max}, \gamma_{dk}^{min}, \epsilon_{i\omega}^{max}, \epsilon_{i\omega}^{min}, \theta_{i\omega}^{max}, \theta_{i\omega}^{min}, \mu_{i\omega}^{max}, \mu_{i\omega}^{min}, \kappa_{j\omega}^{max}, \kappa_{j\omega}^{min}, \nu_{d\omega}^{max}, \nu_{d\omega}^{min}, \xi_{nm}^{max}, \xi_{nm}^{min}, \xi_{nm\omega}^{max}, \xi_{nm\omega}^{min}, \rho_{n}^{max}, \rho_{n}^{min}, \rho_{n\omega}^{max}, \rho_{n\omega}^{min}, \phi_{(n1)}^{o}, \phi_{(n1)\omega}\}$ is the set of all dual variables. The objective function (4.4) of the MPEC is identical to that of the bi-level problem (4.1). The KKT equalities (4.5) - (4.18) are constructed by the derivation of the Lagrangian function with respect to prime variables P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, $r_{i\omega}^{up}$,

$r_{i\omega}^{down}$, $W_{j\omega}^{sp}$, $L_{d\omega}^{sh}$, δ_n^o and $\delta_{n\omega}$. The KKT equalities (4.19) - (4.22) are taken by the derivation of Lagrangian function with respect to dual variables λ_n^{DA}, $\lambda_{n\omega}^{RT}$, $\phi_{(n1)}^o$ and $\phi_{(n1)\omega}$.

4.2.3 MPEC linearization

The non-linear complementarity constraints (4.23) − (4.46) are substituted with equivalent linear disjunctive constraints following the same process used in section 3.2.4. The remaining non-linear terms $\lambda_n^{DA}P_{ib}^{DA}$, $\lambda_n^{DA}W_{jf}^{DA}$, $\lambda_{n\omega}^{RT}r_{i\omega}^{up}$, $\lambda_{n\omega}^{RT}r_{i\omega}^{down}$, $\lambda_{n\omega}^{RT}W_{jf}^{DA}$ and $\lambda_{n\omega}^{RT}W_{j\omega}^{sp}$ in MPEC objective function of the strategic producer (4.4) can be eliminated with the use of some KKT equality and complementarity conditions as illustrated in Appendix A.2. However, the received objective function (A.2.28) is still non-linear due to the non-linear terms $O_{ib}^{DA}P_{ib}^{DA}$, $O_{jf}^{DA}W_{jf}^{DA}$, $O_i^{up}r_{i\omega}^{up}$, $O_i^{down}r_{i\omega}^{down}$, $O_j^{RT}W_{jf}^{DA}$ and $O_j^{RT}W_{j\omega}^{sp}$. Now by applying the strong duality theorem to the lower-level problem the last non-linear terms are withdrawn and the objective function (A.2.28) is recast into a linear one (A.2.31). Hence, the non-linear MPEC model (4.4) - (4.46) is converted into an equivalent MILP formulation as follows:

$$
\begin{aligned}
\underset{\Xi \cup \Xi^O \cup \Xi^D}{maximize} \quad & -\sum_{(i\in I^S)b} c_{ib}P_{ib}^{DA} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& - \sum_{(i\in I^O)b} c_{ib}P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& - \sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{RT} - \sum_{(j\in J^O)f} c_{jf} W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{RT} \\
& + \sum_{(j\in J^O)f} c_j^{RT} W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{sp} + \sum_{dk} u_{dk} L_{dk}^{DA} \\
& - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} - \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} \\
& - \sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} \\
& - \sum_{(i\in I^O)\omega} \mu_{i\omega}^{max} \left(\sum_b P_{ib}^{MAX} \right) - \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(j\in J^O),\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
& - \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n),\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right)
\end{aligned}
$$

$$-\sum_{n}\pi\big(\rho_n^{min}+\rho_n^{max}\big)-\sum_{n\omega}\pi\big(\rho_{n\omega}^{min}+\rho_{n\omega}^{max}\big) \tag{4.47}$$

subjected to $$(4.5)-(4.22) \tag{4.48}$$

$$0\le P_{ib}^{DA}\le M^{pP}z_{ib}^{1}\qquad \forall i,\forall b \tag{4.49}$$

$$0\le \alpha_{ib}^{min}\le M^{vP}(1-z_{ib}^{1})\qquad \forall i,\forall b \tag{4.50}$$

$$0\le P_{ib}^{MAX}-P_{ib}^{DA}\le M^{pP}z_{ib}^{2}\qquad \forall i,\forall b \tag{4.51}$$

$$0\le \alpha_{ib}^{max}\le M^{vP}(1-z_{ib}^{2})\qquad \forall i,\forall b \tag{4.52}$$

$$0\le W_{jf}^{DA}\le M^{pP}z_{jf}^{3}\qquad \forall j,\forall f \tag{4.53}$$

$$0\le \beta_{jf}^{min}\le M^{vP}(1-z_{jf}^{3})\qquad \forall j,\forall f \tag{4.54}$$

$$0\le W_{jf}^{MAX}-W_{jf}^{DA}\le M^{pP}z_{jf}^{4}\qquad \forall j,\forall f \tag{4.55}$$

$$0\le \beta_{jf}^{max}\le M^{vP}(1-z_{jf}^{4})\qquad \forall j,\forall f \tag{4.56}$$

$$0\le L_{dk}^{DA}\le M^{pP}z_{dk}^{5}\qquad \forall d,\forall k \tag{4.57}$$

$$0\le \gamma_{dk}^{min}\le M^{vP}(1-z_{dk}^{5})\qquad \forall d,\forall k \tag{4.58}$$

$$0\le L_{dk}^{MAX}-L_{dk}^{DA}\le M^{pP}z_{dk}^{6}\qquad \forall d,\forall k \tag{4.59}$$

$$0\le \gamma_{dk}^{max}\le M^{vP}(1-z_{dk}^{6})\qquad \forall d,\forall k \tag{4.60}$$

$$0\le r_{i\omega}^{up}\le M^{pP}z_{i\omega}^{7}\qquad \forall i,\forall \omega \tag{4.61}$$

$$0\le \epsilon_{i\omega}^{min}\le M^{vP}(1-z_{i\omega}^{7})\qquad \forall i,\forall \omega \tag{4.62}$$

$$0\le RES_{i}^{UP}-r_{i\omega}^{up}\le M^{pP}z_{i\omega}^{8}\qquad \forall i,\forall \omega \tag{4.63}$$

$$0\le \epsilon_{i\omega}^{max}\le M^{vP}(1-z_{i\omega}^{8})\qquad \forall i,\forall \omega \tag{3.64}$$

$$0\le r_{i\omega}^{down}\le M^{pP}z_{i\omega}^{9}\qquad \forall i,\forall \omega \tag{4.65}$$

$$0\le \theta_{i\omega}^{min}\le M^{vP}(1-z_{i\omega}^{9})\qquad \forall i,\forall \omega \tag{4.66}$$

$$0\le RES_{i}^{DOWN}-r_{i\omega}^{down}\le M^{pP}z_{i\omega}^{10}\qquad \forall i,\forall \omega \tag{4.67}$$

$$0\le \theta_{i\omega}^{max}\le M^{vP}(1-z_{i\omega}^{10})\qquad \forall i,\forall \omega \tag{4.68}$$

$$0\le \sum_{b}P_{ib}^{MAX}-\sum_{b}P_{ib}^{DA}-r_{i\omega}^{up}\le M^{pP}z_{i\omega}^{11}\qquad \forall i,\forall \omega \tag{4.69}$$

$$0\le \mu_{i\omega}^{max}\le M^{vP}(1-z_{i\omega}^{11})\qquad \forall i,\forall \omega \tag{4.70}$$

$$0\le \sum_{b}P_{ib}^{DA}-r_{i\omega}^{down}\le M^{pP}z_{i\omega}^{12}\qquad \forall i,\forall \omega \tag{4.71}$$

$$0 \leq \mu_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{12}) \qquad \forall i, \forall \omega \tag{4.72}$$

$$0 \leq W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{13} \qquad \forall j, \forall \omega \tag{4.73}$$

$$0 \leq \kappa_{j\omega}^{min} \leq M^{vP}(1 - z_{j\omega}^{13}) \qquad \forall j, \forall \omega \tag{4.74}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{14} \qquad \forall j, \forall \omega \tag{4.75}$$

$$0 \leq \kappa_{j\omega}^{max} \leq M^{vP}(1 - z_{j\omega}^{14}) \qquad \forall j, \forall \omega \tag{4.76}$$

$$0 \leq L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{15} \qquad \forall d, \forall \omega \tag{4.77}$$

$$0 \leq \nu_{d\omega}^{min} \leq M^{vP}(1 - z_{d\omega}^{15}) \qquad \forall d, \forall \omega \tag{4.78}$$

$$0 \leq \sum_{k} L_{dk}^{DA} - L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{16} \qquad \forall d, \forall \omega \tag{4.79}$$

$$0 \leq \nu_{d\omega}^{max} \leq M^{vP}(1 - z_{d\omega}^{16}) \qquad \forall d, \forall \omega \tag{4.80}$$

$$0 \leq B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm}^{17} \qquad \forall n, \forall m \in \Theta_m \tag{4.81}$$

$$0 \leq \xi_{nm}^{min} \leq M^{vC}(1 - z_{nm}^{17}) \qquad \forall n, \forall m \in \Theta_m \tag{4.82}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \leq M^{pC} z_{nm}^{18} \qquad \forall n, \forall m \in \Theta_m \tag{4.83}$$

$$0 \leq \xi_{nm}^{max} \leq M^{vC}(1 - z_{nm}^{18}) \qquad \forall n, \forall m \in \Theta_m \tag{4.84}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm\omega}^{19} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{4.85}$$

$$0 \leq \xi_{nm\omega}^{min} \leq M^{vC}(1 - z_{nm\omega}^{19}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{4.86}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \leq M^{pC} z_{nm\omega}^{20} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{4.87}$$

$$0 \leq \xi_{nm\omega}^{max} \leq M^{vC}(1 - z_{nm\omega}^{20}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{4.88}$$

$$0 \leq \delta_n^o + \pi \leq M^{pV} z_n^{21} \qquad \forall n \tag{4.89}$$

$$0 \leq \rho_n^{min} \leq M^{vV}(1 - z_n^{21}) \qquad \forall n \tag{4.90}$$

$$0 \leq \pi - \delta_n^o \leq M^{pV} z_n^{22} \qquad \forall n \tag{4.91}$$

$$0 \leq \rho_n^{max} \leq M^{vV}(1 - z_n^{22}) \qquad \forall n \tag{4.92}$$

$$0 \leq \delta_{n\omega} + \pi \leq M^{pV} z_{n\omega}^{23} \qquad \forall n, \forall \omega \tag{4.93}$$

$$0 \leq \rho_{n\omega}^{min} \leq M^{vV}(1 - z_{n\omega}^{23}) \qquad \forall n, \forall \omega \tag{4.94}$$

$$0 \leq \pi - \delta_{n\omega} \leq M^{pV} z_{n\omega}^{24} \qquad \forall n, \forall \omega \tag{4.95}$$

$$0 \leq \rho_{n\omega}^{max} \leq M^{vV}(1 - z_{n\omega}^{24}) \qquad \forall n, \forall \omega \tag{4.96}$$

4.3 6-bus system case

4.3.1 System data

The proposed algorithm is applied to the six-bus system introduced in Figure 3.2 (section 3.4.1). However, the strategic producer apart from the conventional units $i1$ to $i4$ now also possesses the wind unit $j1$. The technical data for the conventional units are similar to those provided in Table 3.1 (section 3.3). The scheduled production of wind units is offered through three energy blocks and the uncertainty of wind power production is realized through three scenarios: high production $\omega 1$, medium production $\omega 2$, and low production $\omega 3$, with occurrence probability 0.2, 0.5 and 0.3 respectively. Allocation, offered energy blocks W_{jf}^{MAX}, cost offers c_j/c_j^{RT}, and scenario productions $W_{j\omega}^{RT}$ of wind units are provided in Table 4.1.

Table 4.1: Location capacity [MW] offered energy blocks [MWh] production scenarios [MWh] and cost offers [€/MWh] of wind generating units

wind units j	location	capacity	$W_{j,f1}^{MAX}$	$W_{j,f2}^{MAX}$	$W_{j,f3}^{MAX}$	$W_{j,\omega 1}^{RT}$	$W_{j,\omega 2}^{RT}$	$W_{j,\omega 3}^{RT}$
$j1$	$n2$	100	40	30	30	100	50	30
$j2$	$n5$	70	30	20	20	70	35	20
cost c_{jf} | c_j^{RT}			0	0	0	0	0	0

Moreover, the same total demand of 1 GWh is allocated and distributed as shown in Table 3.2 (section 3.4.1) while the correlation between marginal utility cost (bids) and demand energy blocks for the 24-hour period is presented in Table B.1 (Appendix B). Finally, the value of the lost load $VOLL_d$ is defined at 200 €/MWh for all demands d and all the circuit lines have transmission capacity T_{nm}^{MAX} and susceptance B_{nm} equal to 500 MW and 9.412 per unit respectively.

4.3.2 Uncongested network solution

On the basis of the above information three cases are examined using GAMS/CPLEX. In the first case, the strategic producer acts as price taker making cost offers. In the second case, the producer acts strategically only with the conventional units i. In the last case, the producer offers also strategically and with the wind generation unit $j1$. Under cost offer optimization the DA clearing price is unwavering throughout the 24-hours at the floor of 11.260 €/MWh. Nevertheless, when the strategic producer exercises market

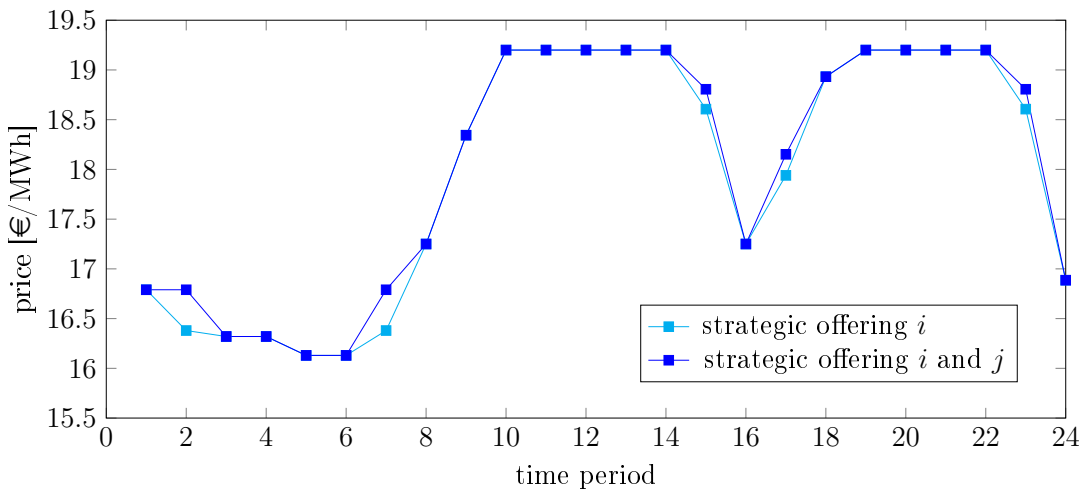

Figure 4.1: DA market prices in uncongested network

power, the DA market prices are moved away from the cost offer competitive equilibrium while fluctuating almost identically between 16.130 and 19.200 €/MWh in both the second and the third case as shown in Figure 4.1. Similarly, the expected RT market prices are elevated too as depicted in Figure 4.2 and 4.3. Especially in third case and under low wind scenario $\omega 3$, the strategic producer, taking advantage of the anticipated higher volatility of the system, increases the RT price at the level of 37 €/MWh. In all cases, the market clearing prices are equal in all buses at each time period. This results from the fact that the system remains uncongested under all wind scenarios as the network line capacity can facilitate the

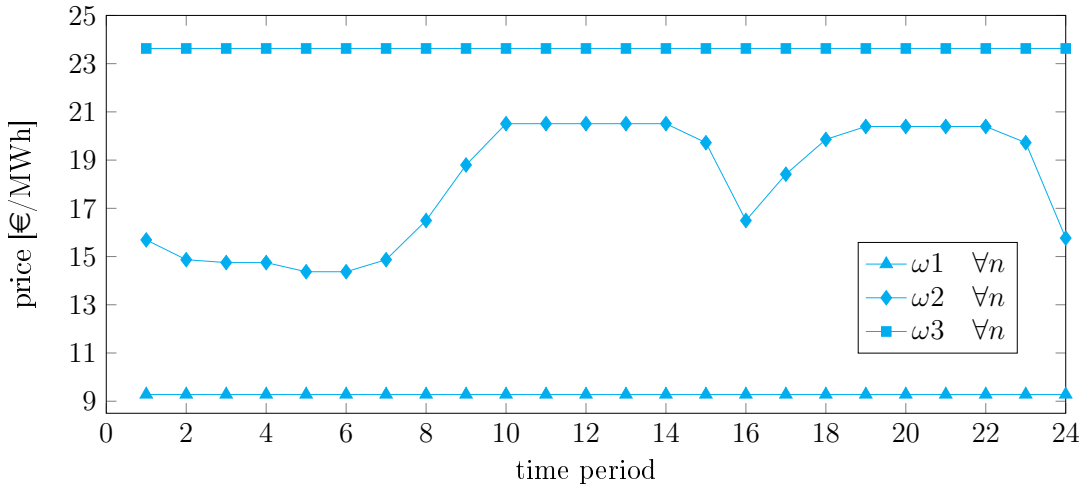

Figure 4.2: RT market prices under only i strategic offering in uncongested network

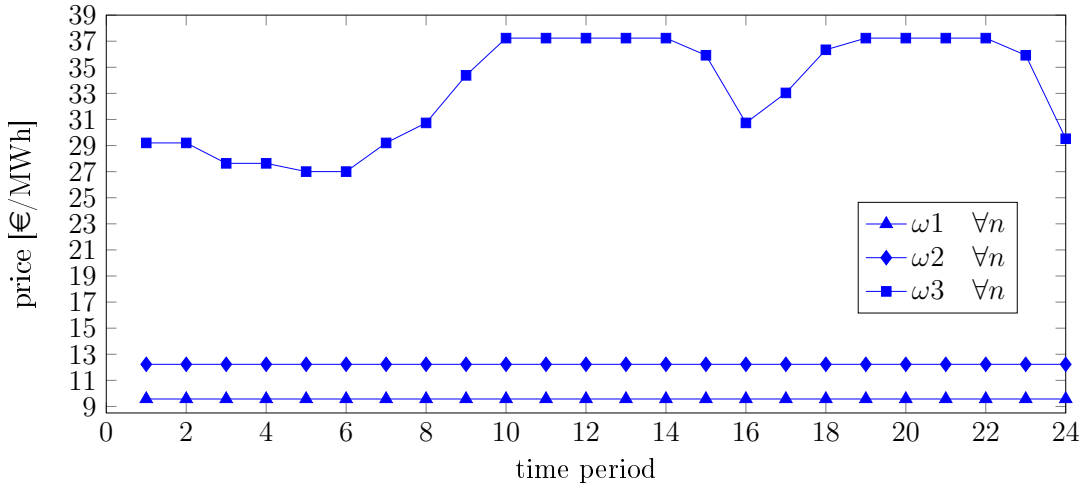

Figure 4.3: RT market prices under i and j strategic offering in uncongested network

energy transaction between buses in both DA and balancing stage. Looking more closely at time period $t12$, from the perspective of the strategic producer and under perfect competition, the scheduled energy production of conventional units i and wind generation unit $j1$ is 444.8 and 15 MWh respectively. Both productions are dispatched at a price of 11.260

Table 4.2: Energy [MWh] and price [€/MWh] outcomes under cost offering of units i and $j1$ in uncongested network at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	132.2	.	.	.	15.0	.	.					
$i2$	.	.	.	.	.	.	.					
$i3$	155.0	.	.	.	.	.	.					
$i4$	157.6	.	.	15.0	40.0	.	.	$\forall n$	11.260	9.280	11.470	12.230
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	15.0	.	.	.	85.0	35.0	15.0					

Table 4.3: Energy [MWh] and price [€/MWh] outcomes under strategic offering of units i only in uncongested network at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	123.8	.	.	.	.	.	.					
$i2$	.	.	.	.	.	.	.					
$i3$	124.0	.	.	.	.	.	.					
$i4$	118.2	.	.	35.0	25.0	.	.	$\forall n$	19.200	9.570	20.394	23.630
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	45.0	.	.	15.0	55.0	5.0	.					

€/MWh as shown in Table 4.2. The relevant expected profits are 388 and 582 € respectively. In the second case, the strategic producer curtails the scheduled production in all conventional units i at the level of 375 MWh making space for a probable increase of $j1$ wind unit's scheduled production from 15 to 45 MWh as depicted in Table 4.3. However, even

if the total scheduled production is reduced, it is now paid at the price of 19.200 €/MWh. Considering the reserves, it can be seen that in the low wind scenario $\omega 3$, where the energy shortage is now bigger, the upward reserve supply increases (unit $i4$ provides 35 instead of 15 MWh), and it is paid almost at double price. On the other hand, in the high wind scenario $\omega 1$, although the producer is charged at a higher price, the downward reserve supply is lower. As a result, the total expected profits of strategic units i and $j1$ rocket at 3,405 and 914 € respectively. It should be noticed, that the results of scheduled energy and reserves of conventional units as well as the results of DA and RT market clearing prices in Table 4.3 are identical with those in Table 3.4 of section 3.4.2 since in both cases the strategic producer exercises market power only with the conventional units.

Table 4.4: Energy [MWh] and price [€/MWh] outcomes under strategic offering of units i and $j1$ in uncongested network at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega 1$	$\omega 2$	$\omega 3$	$\omega 1$	$\omega 2$	$\omega 3$			$\omega 1$	$\omega 2$	$\omega 3$
$i1$	108.8	.	.	10.0	.	.	.					
$i2$	.	.	.	.	.	.	.					
$i3$	124.0	.	.	.	.	.	.					
$i4$	118.2	.	10.0	40.0	40.0	.	.	$\forall n$	19.200	9.570	12.230	37.237
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega 1$	$\omega 2$	$\omega 3$	$\omega 1$	$\omega 2$	$\omega 3$					
$j1$	60.0	.	10.0	30.0	40.0	.	.					

Finally, when the wind unit $j1$ also offers strategically, the strategic producer recognizes a further arbitrage opportunity. As a result, the producer increases the scheduled production of wind unit $j1$ at 60 MWh by curtailing the dispatched energy of conventional units i even more as shown in Table 4.4. Compared to the previous case, even though the total

Table 4.5: Total scheduled and reserve production [MWh] of strategic producer

	scheduled	scheduled	upward reserve			downward reserve		
	$[i]$	$[j]$	$\omega 1$	$\omega 2$	$\omega 3$	$\omega 1$	$\omega 2$	$\omega 3$
marginal cost offer	10675.2	360.0	.	.	360.0	1320.0	.	.
strategic offer [only i]	8700.0	1088.8	.	8.8	848.8	636.0	.	.
strategic offer [i and j]	8324.0	1440.0	.	100.0	1200.0	960.0	.	.

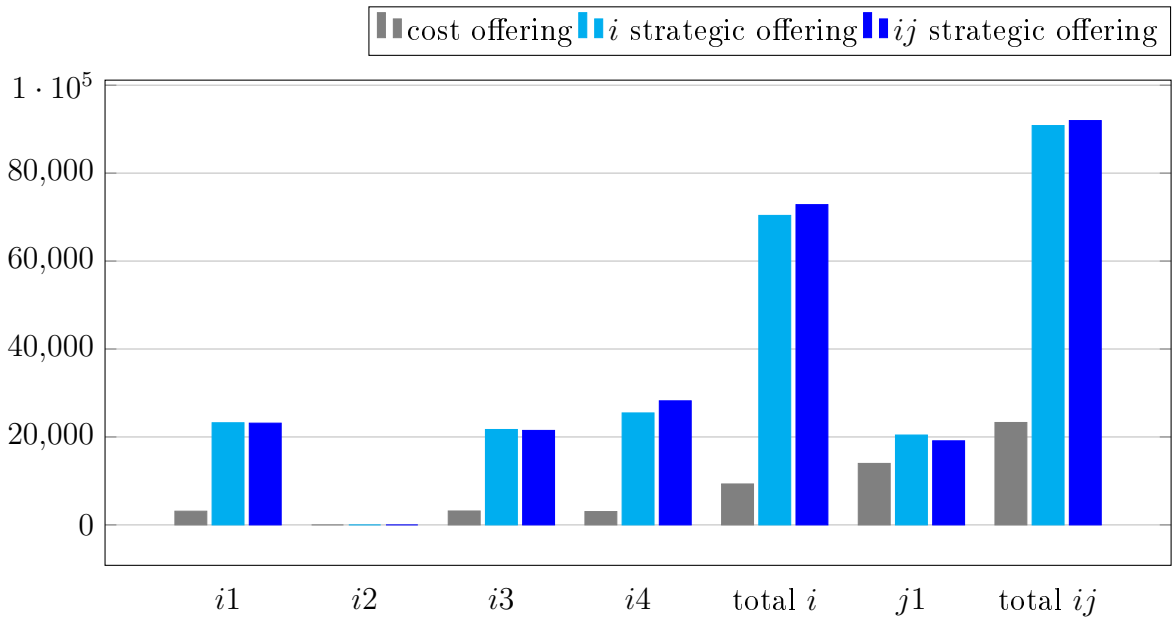

Figure 4.4: Expected profit [€] of strategic producer's generation units

expected profit of $j1$ is lessened to 832 €, the strategic producer raises the total expected profits as the increased wind energy shortfalls in medium $\omega 2$ and low $\omega 3$ wind scenarios are now covered by the offered upward reserves of units $i1$ and $i4$ at a higher price. Hence, the positive regulation of 50 MWh, which is paid at the price of 37.237 €/MWh in low wind scenario, increases the total expected profits of conventional production from 3,405 to 3,541 € overcoming the reduced expected profits of wind production. It should be noted that the market pricing scheme formulated by the lower level problem is revenue adequate in

expectation; therefore, it guarantees the recovery of the expected cost of each conventional or stochastic generation unit. Thus, even if the wind unit $j1$ suffers from incurred losses $-10\times12.230=-122.30$ and $-30\times37.237=-1117.11$ € at balancing stage in medium $\omega2$ and low $\omega3$ wind scenarios respectively, the expected profit of the wind unit is equal to 832.23 €. The above findings apply throughout the 24-hour period; therefore, even though the dispatched production of the conventional units i is reduced as depicted in Table 4.5, the total expected profits grow remarkably when the producer offers strategically as can be seen in Figure 4.4.

4.3.3 Building strategic offering curves

The proposed algorithm provides optimal offers O_{ib}^{DA} and O_{jf}^{DA} for the dispatched conventional and wind energy blocks respectively in DA market. These optimal offers for a generation unit settled at bus n always coincide with the DA market clearing price λ_n^{DA} of this bus. Nevertheless, as mentioned in section 3.2.5, offering all energy blocks at the received market price introduces flat curves which lead to "multiple solutions and degeneracy" (Ruiz and Conejo, 2009). With the objective to receive upward stepwise offering curves this thesis follows a process similar to that presented in section 3.2.5. Table 4.6 and Table 4.7 show the DA and RT market prices as well as the energy dispatch and reserve deployment outcomes at period $t12$. Taking conventional unit $i1$ as an example, it can be observed that energy blocks $b1$ and $b2$ are fully dispatched, block $b3$ is partially dispatched while block $b4$ is not dispatched at all. Building up the offer curve of unit $i1$ at DA, energy blocks $b1$ and $b2$ are offered at their marginal cost, which is 9.92 and 10.25 €/MWh respectively. Block $b3$ is offered at a price slightly below the market price $19.200-\epsilon$ €/MWh. Actually, this block $b3$ offer is one of the strategic producer's offers that defines the DA market price higher (financial withholding) than the price originating from cost offer creating a mark-up of $19.200-11.260=7.940$ €/MWh. Finally, block $b4$ is offered at a price 19.200 €/MWh or

Table 4.6: Market prices [€/MWh] under strategic offering in uncongested network at $t20$

bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega 1$	$\omega 2$	$\omega 3$
$\forall n$	19.200	9.570	12.230	37.237

Table 4.7: Energy [MWh] and offer [€/MWh] outcomes under strategic offering in uncongested network at period $t12$

units	$P_{i,b1}^{DA}$	$O_{i,b1}^{DA}$	$P_{i,b2}^{DA}$	$O_{i,b2}^{DA}$	$P_{i,b3}^{DA}$	$O_{i,b3}^{DA}$	$P_{i,b4}^{DA}$	$O_{i,b4}^{DA}$	$r_{i,\omega}^{up}$			O_i^{up}	$r_{i,\omega}^{down}$			O_i^{down}
									$\omega 1$	$\omega 2$	$\omega 3$		$\omega 1$	$\omega 2$	$\omega 3$	
$i1$	54.25	[19.200]	38.75	[19.200]	15.80	[19.200]	.	[19.200]	.	.	10	[37.237]	.	.	.	[9.280]
$i2$	.	[19.200]	.	[19.200]	.	[19.200]	.	[19.200]	.	.	.	[37.237]	.	.	.	[8.960]
$i3$	54.25	[19.200]	38.75	[19.200]	31.00	[19.200]	.	[19.200]	.	.	.	[37.237]	.	.	.	[0.000]
$i4$	68.95	[19.200]	49.25	[19.200]	.	[19.200]	.	[19.200]	.	10	40	[12.230]	40	.	.	[9.570]
	$W_{j,f1}^{DA}$	$O_{j,f1}^{DA}$	$W_{j,f2}^{DA}$	$O_{j,f2}^{DA}$	$W_{j,f3}^{DA}$	$O_{j,f3}^{DA}$			wind shortfall				wind surplus			O_j^{RT}
									$\omega 1$	$\omega 2$	$\omega 3$		$\omega 1$	$\omega 2$	$\omega 3$	
$j1$	40	[19.200]	20	[19.200]	.	[19.200]			.	10	30		40	.	.	[0.000]

Table 4.8: Strategic offers [€/MWh] for unit $i1$ in uncongested network at time $t12$

block	$c_{i1,b}$	$P_{i1,b}^{DA}$	λ_{n1}^{DA}	$O_{i1,b}^{filled,DA}$	ω	c_{i1}^{up}	$res_{i1,\omega}^{up}$	$\frac{\lambda_{n1,\omega}^{RT}}{\pi_\omega}$	$O_{i1}^{filled,up}$	c_{i1}^{down}	$res_{i1,\omega}^{down}$	$\frac{\lambda_{n1,\omega}^{RT}}{\pi_\omega}$	$O_{i1}^{filled,down}$
b1	9.92	54.25	19.20	9.92	$\omega 1$	12.40	.	9.57	$37.24-\epsilon$	9.28	.	9.57	9.28
b2	10.25	38.75	19.20	10.25	$\omega 2$	12.40	.	12.23	$37.24-\epsilon$	9.28	.	12.23	9.28
b3	10.68	15.80	19.20	$19.20-\epsilon$	$\omega 3$	12.40	10	37.24	$37.24-\epsilon$	9.28	.	37.24	9.28
b4	11.26	.	19.20	19.20									

higher. This way, the strategic producer ensures the block's rejection. In point of fact, this offer has the same outcome as physical withholding (production curtailment). Considering

the redispatch, unit $i1$ does not supply any positive regulation at balancing stage under high $\omega 1$ and medium $\omega 2$ wind scenarios, but it provides 10 MWh of positive regulation in low $\omega 3$ wind scenario. In this case, the upward reserves are offered at a price of $37.237-\epsilon$ €/MWh which renders them not accepted by the market operator for scenarios $\omega 1$ and $\omega 2$ as the offer is higher than the relevant RT clearing prices of these scenarios and accepted in scenario $\omega 3$ as now the offer is lower than the RT clearing price. Additionally, unit $i1$ does not supply any downward reserves; therefore, the reserves are offered at their marginal cost 9.28 €/MWh, which guarantees their rejection as the offer is beneath the RT clearing prices of all wind production scenarios. The offer building process of unit $i1$ is presented in Table 4.8.

Table 4.9: Strategic offers [€/MWh] for unit $j1$ in uncongested network at time period $t20$

block	$c_{j1,f}$	$W^{DA}_{j1,f}$	λ^{DA}_{n2}	$O^{filled,DA}_{j1,f}$	ω	c^{RT}_{j1}	wind shortfall	wind surplus	$\frac{\lambda^{RT}_{n6,\omega}}{\pi_\omega}$	$O^{filled,RT}_{j1}$
b1	0	40	19.20	0.00	$\omega 1$	0	40	.	9.57	0.00
b2	0	20	19.20	$19.20-\epsilon$	$\omega 2$	0	.	10	12.23	0.00
b3	0	.	19.20	19.20	$\omega 3$	0	.	30	37.24	0.00

Along the same line, concerning strategic wind unit $j1$ at DA, the first energy block is fully accepted and is offered at its marginal cost, which is 0 €/MWh. Block $f2$ is partially accepted and is offered at a price $19.200-\epsilon$ €/MWh, end the last block is not accepted; hence it is offered at price 19.200 €/MWh. Finally at balancing stage, surplus or shortfall of wind production are offered at zero price. Table 4.9 illustrates the building offer process of wind unit $j1$.

4.3.4 Congested line 3 − 6

When the network is uncongested, the maximum power flow from bus $n3$ to bus $n6$ is 207.98 MW. In case the line capacity is dropped at the level of 240 MW, relatively above themaximum flow, the received results under cost offer remain similar to those of the uncongested system as expected. Nevertheless, applying the proposed MILP the strategic producer

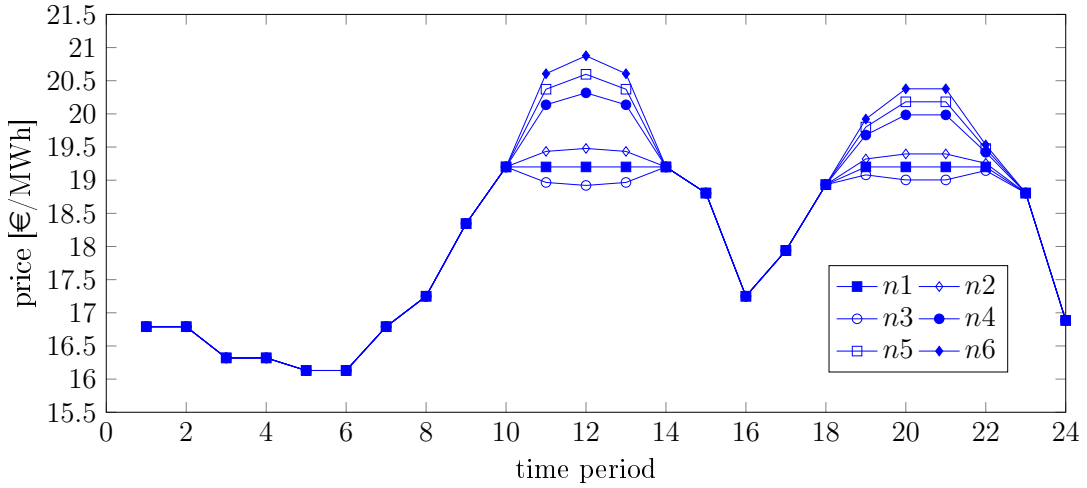

Figure 4.5: DA prices with line 3 − 6 capacity limited to 240 MW

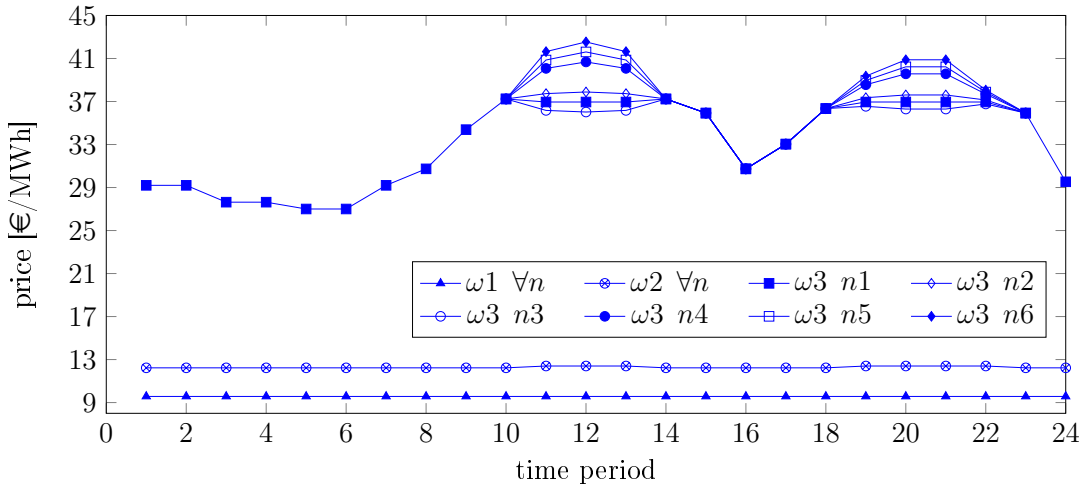

Figure 4.6: RT prices [€/MWh] with line 3 − 6 capacity limited to 240 MW

Table 4.10: Energy [MWh] and price [€/MWh] outcomes under strategic offering with line $3-6$ capacity limited to 240 MW at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	124.0	.	.	16.5	.	.	.	$n1$	19.200	9.570	12.400	36.953
$i2$	.	.	.	.	.	.	.	$n2$	19.479	9.570	12.400	37.884
$i3$	124.0	.	15.0	20.0	.	.	.	$n3$	18.921	9.570	12.400	36.022
$i4$	103.0	.	.	13.5	40.0	.	.	$n6$	20.876	9.570	12.400	42.540
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	60.0	.	10.0	30.0	40.0	.	.	$n2$	19.479	9.570	12.400	37.884

Table 4.11: Scheduled production [MWh] and expected profits [€] of strategic producer with line $3-6$ capacity limited to 240 MW

	scheduled production [MWh]					total scheduled	expected profit
	$i1$	$i2$	$i3$	$i4$	$j1$	[MWh]	[€]
Line 3-6 550 MW	2,817.6	0.0	2,669.6	2,836.8	1440.0	9,764.0	91,950
Line 3-6 240 MW	2,893.6	0.0	2,700.0	2,730.4	1440.0	9,764.0	92,759

Table 4.12: Scheduled production [MWh] and expected profits [€] of strategic producer with line $3-6$ capacity limited to 240 MW and relocation of wind unit $j1$ to bus $n6$

$j1$	scheduled production [MWh]					total scheduled	expected profit
location	$i1$	$i2$	$i3$	$i4$	$j1$	[MWh]	[€]
$n2$	2,893.6	0.0	2,700.0	2,730.4	1,440.0	9,764.0	92,759
$n6$	2,954.3	0.0	2,777.0	2,592.7	1,440.0	9,764.0	92,725

can change the mixture of the conventional units production rendering the system congested and yielding different DA and RT LMP's at particular time periods as can be observed in Figure 4.5 and Figure 4.6. Taking a closer look in period $t12$ as shown in Table 4.10 and comparing to that in the uncongested case (Table 4.4) the strategic producer maintains the scheduled production of unit $i3$ and wind unit $j1$ at 120 and 60 MWh respectively; however, now the dispatched production of unit $i1$ is raised from 103.8 to 120 MWh with a simultaneous decrease in scheduled production of unit $i4$ from 118.2 to 103 MWh. Considering the expected profits, the unit $i4$ occurs losses due to its reduced production; however, bus $n6$ exhibits the highest price mitigating the unit's losses. On the other hand, the increased production of unit $i1$, and therefore its increased revenues, not only cover the losses but also raise slightly the total expected profits of strategic producer compared to those of the uncongested case as depicted in Table 4.11. It should be noticed that the total scheduled production remains the same in both cases. In the previous case, if the wind unit $j1$ is relocated to bus $n6$, the configuration of DA and balancing prices remain identical as the strategic producer, following the same policy, rearranges again the mixture of the conventional units' production congesting the system at the same time periods. In Table 4.12 it can be seen that the energy dispatch of unit $i4$ is reduced further, keeping the scheduled energy of stable companion wind unit $j1$ at the same volume. Synchronously, the producer additionally increases the dispatch of units $i1$ and $i3$ maintaining the scheduled production and profitability at the prior levels.

Table 4.13: Scheduled production [MWh] and expected profits [€] of strategic producer with line $3-6$ limited to 120 MW and relocation of wind unit $j1$ to bus $n6$

$j1$	scheduled production [MWh]					total scheduled	expected profit
location	$i1$	$i2$	$i3$	$i4$	$j1$	[MWh]	[€]
$n2$	1,844.6	0.0	0.0	3,782.4	1,665.6	7,292.6	81,263
$n6$	2,670.9	0.0	0.0	3,768.0	1,440.0	7,878.9	87,108

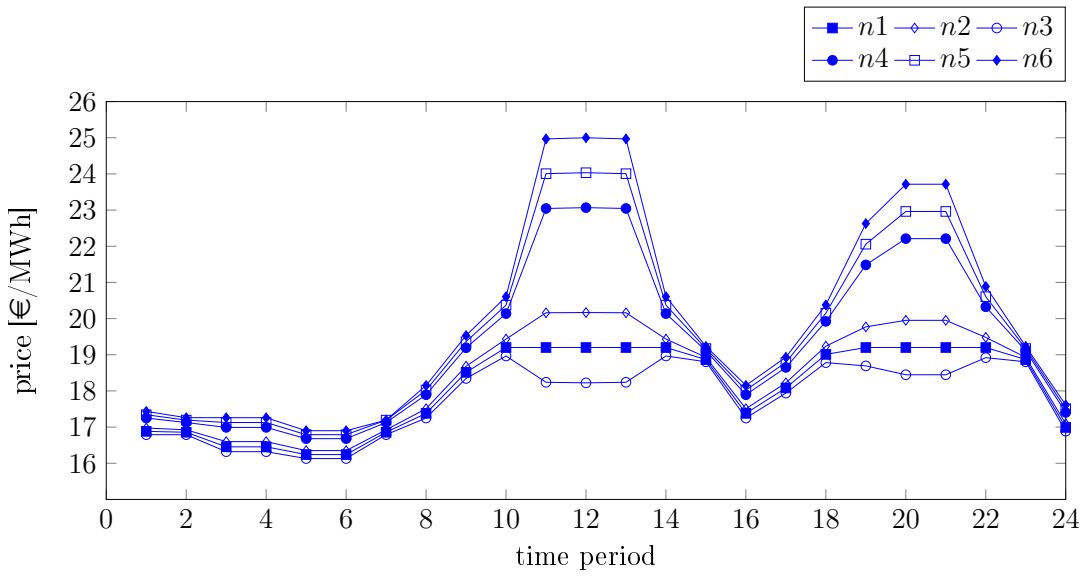

Figure 4.7: DA prices with line $3-6$ capacity limited to 120 MW

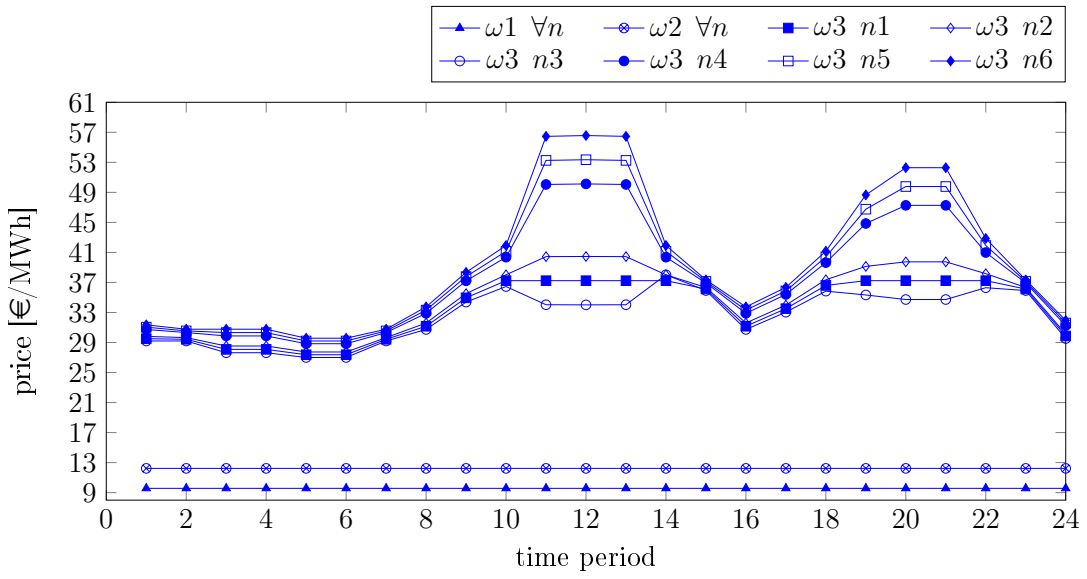

Figure 4.8: RT prices [€/MWh] with line $3-6$ capacity limited to 120 MW

If the line capacity is reduced to 120 MW, the system becomes congested resulting in different LMP's at DA and balancing market throughout the 24-hour period as depicted in Figure 4.7 and Figure 4.8. The situation now is detrimental compared to the previous case since the congestion leads to decreased production volumes in the left part of the network;

hence the shut-down of unit $i3$. However, the removal of wind unit $j1$ to bus $n6$, at the right part of the network, where the demand prevails, would be more beneficial for the strategic producer. As shown in Table 4.13, the relocation of $j1$ gives unit $i1$ the chance to increase its production and wind unit $j1$ the opportunity to sell energy at a higher price growing the total expected profit.

4.3.5 Congested line 4 − 6

When the network is uncongested, the power flow from bus $n6$ to $n4$ is 22.453 MW. If the line capacity is limited to 20 MW, just below the maximum flow, and under optimal cost offer, the network is rendered congested and results in different LMP's which are proved unprofitable for the strategic producer. Nonetheless, the producer, based on the proposed MILP formulation, can change its offering strategy modifying the units' production in such a way as to render the system uncongested. Examining the time period $t12$ as shown in Table 4.14 and comparing it to the initial uncongested case (Table 4.4), the strategic

Table 4.14: Energy [MWh] and price [€/MWh] outcomes under strategic offering with line $4-6$ capacity limited to 20 MW at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	135.0	.	.	20.0	.	.	.					
$i2$	.	.	.	.	.	.	.					
$i3$	134.7	.	15.0	20.0	.	.	.					
$i4$	81.3	.	.	.	40.0	.	.	$\forall n$	19.200	9.570	12.400	36.953
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	60.0	.	10.0	30.0	40.0	.	.					

Table 4.15: Scheduled production [MWh] and expected profits [€] of strategic producer with line $4-6$ capacity limited to 20 MW

	scheduled production [MWh]					total scheduled	expected profit
	$i1$	$i2$	$i3$	$i4$	$j1$	[MWh]	[€]
Line 4-6 550 MW	2,817.6	0.0	2,669.6	2,836.8	1,440.0	9,764.0	91,950
Line 4-6 20 MW	3,185.0	0.0	3,178.7	1,945.3	1,430.0	9,739.0	91,809

producer increases the dispatched energy and the upward reserve supply from units $i1$ and $i3$ while keeping the production of wind unit $j1$ stable. On the other hand, the producer lowers the scheduled production and discontinues the offered upward reserve supply from unit $i4$; thereby reducing the power flow from bus $n6$ to $n4$ at the level of 16.667 MW. Now, the system becomes uncongested, and all buses have the same prices at each time period similar to those in Figure 4.1 and Figure 4.3 for DA and balancing market respectively. Hence, as illustrated in Table 4.15, rearranging the energy dispatch of conventional units proceeding with a small reduction of the total scheduled production, the strategic producer manages to prevent profit losses.

4.3.6 Wind generation increment

Two cases of wind power increment are examined. In the first case, the wind power penetration increases proportionally for both wind units j from 10.08% to 18.42% of the total installed capacity. In particular, the energy provided by wind generation units $j1$ and $j2$ is 200 MWh and 100 MWh in high wind scenario $\omega1$, 100 MWh and 50 MWh in medium wind scenario $\omega2$, and 60 MWh and 40 MWh respectively in low wind scenario $\omega3$.

Considering the time period $t12$ in Table 4.16, the strategic unit $j1$ increases its DA scheduled production at the expense of the strategic conventional units' dispatch. However, the units i covering the wind production shortfall in low wind scenario $\omega3$ give, as expected, more upward reserves at a higher price mitigating their losses. In the second case,

Table 4.16: Energy [MWh] and price [€/MWh] outcomes under strategic offering with 18.42% wind power penetration at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	93.0	.	.	10.0	10	.	.					
$i2$	.	.	.	.	.	.	.					
$i3$	93.0	.	.	20.0	.	.	.					
$i4$	95.0	.	.	40.0	40.0	.	.	$\forall n$	19.200	6.700	12.400	38.867
	$\sum_f W_{jf}^{DA}$	wind shortfall			wind surplus							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	90.0	.	.	30.0	110.0	10.0	.					

Table 4.17: Energy [MWh] and price [€/MWh] outcomes under strategic offering with 24.93% wind power penetration at period $t12$

units	$\sum_b P_{ib}^{DA}$	$r_{i\omega}^{up}$			$r_{i\omega}^{down}$			bus	λ_n^{DA}	$\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$		
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$			$\omega1$	$\omega2$	$\omega3$
$i1$	77.80	.	.	20.0	20.0	.	.					
$i2$	.	.	.	20.0	.	.	.					
$i3$	54.25	.	.	20.0	20.0	.	.					
$i4$	68.95	.	.	40.0	40.0	.	.	$\forall n$	19.200	0.000	12.400	43.333
	$\sum_f W_{jf}^{DA}$	wind shortfall [$W_{j\omega}^{sp}$]			wind surplus [$W_{j\omega}^{sp}$]							
		$\omega1$	$\omega2$	$\omega3$	$\omega1$	$\omega2$	$\omega3$					
$j1$	110.0	.	.	20.0	190.0 [50.0]	40.0	.					

the penetration of wind power increases similarly to the first case at the level of 24.93% of the total installed capacity. As shown in Table 4.17, the strategic units i reduce their scheduled production further giving space for more wind generation dispatch. Yet, due to the higher wind generation volatility the expensive unit $i2$ is now involved in the provision of 20 MWh

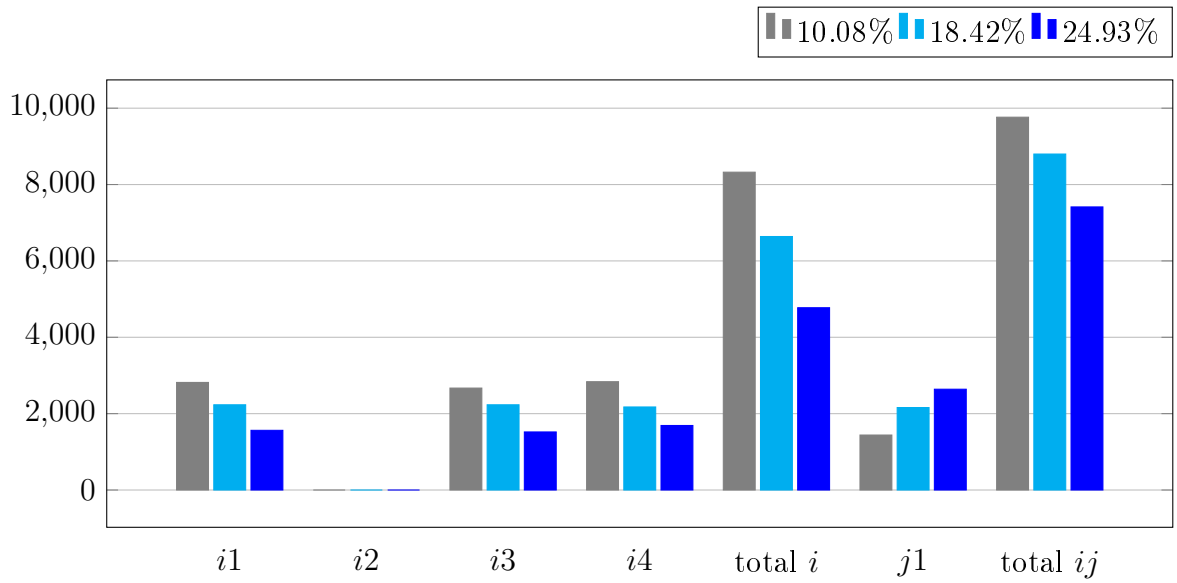

Figure 4.9: Scheduled production [MWh] under different levels of wind power penetration

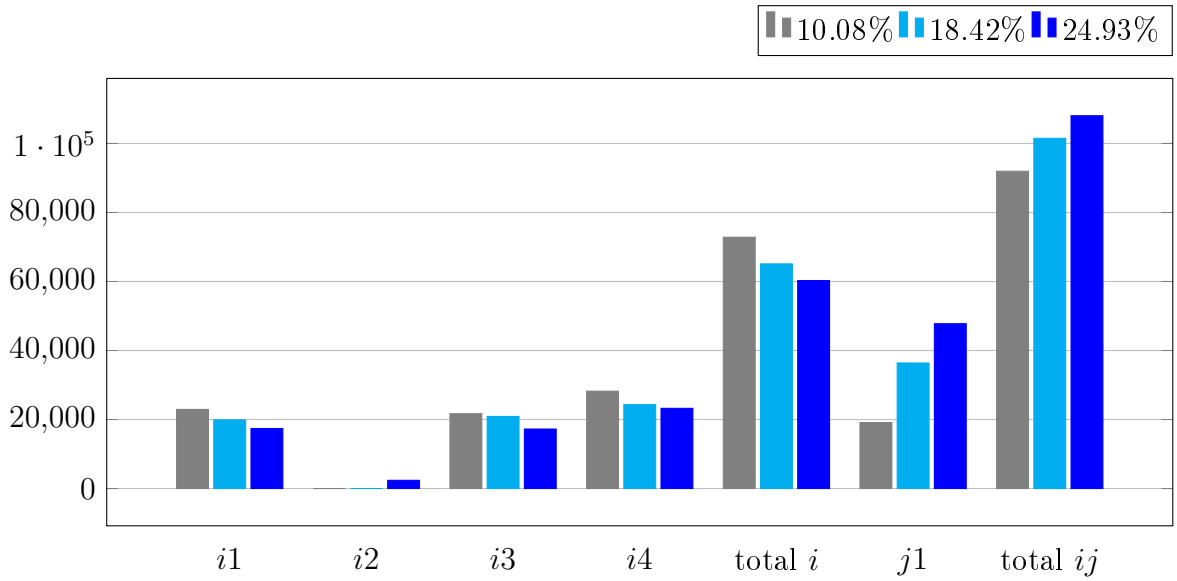

Figure 4.10: Expected profit [€] under different levels of wind power penetration

upward reserve raising the RT market clearing price in scenario $\omega 3$ at a level of 43.333 €/MWh. The high volatility also can cause wind power spillage as a result of insufficient system reserves. More precisely, in high wind scenario $\omega 1$ the offered negative regulation

of the system cannot cover the wind production surplus of 190 MWh, which may lead the strategic wind unit $j1$ to spill 50 MWh of its production. Nevertheless, as illustrated in Figure 4.9 and Figure 4.10 the strategic producer following the installed capacity increment of wind generation and offering strategically raises the total expected profits even though the conventional units show losses due to their declined scheduled production.

4.4 Reliability test system (RTS) case

4.4.1 RTS data

The proposed algorithm is applied to a new case based on the IEEE one-area RTS presented in Figure C.2 (Appendix C). Now, the system includes four wind generating units j of which $j1$ belongs to strategic producer. Thus, not only the conventional units $i1 - i8$ but also the wind unit $j1$ can be used by strategic producer for exercising market power.

Table 4.18: Capacity [MW] energy blocks [MWh] production scenarios [MWh] and cost offers [€/MWh] of wind power units j

wind power units j	capacity	W_{jf1}^{MAX}	W_{jf2}^{MAX}	W_{jf3}^{MAX}	$W_{j\omega1}^{RT}$	$W_{j\omega2}^{RT}$	$W_{j\omega3}^{RT}$
$j1$ (strategic)	200	100	60	40	200	100	50
$j2$ (non-strategic)	200	100	60	40	200	100	50
$j3, j4$ (non-strategic)	150	80	50	20	150	75	30
cost $c_{jf} \mid c_j^{RT}$		0	0	0	0	0	0

The total wind power capacity is 700 MW representing the 17.07 % of the total 4.1 GW installed capacity. The uncertainty of wind production is realized through three scenarios $\omega1$, $\omega2$ and $\omega3$ with occurrence probability 0.2, 0.5 and 0.3 respectively. Information for total capacity, offered energy blocks, real time production scenarios, and their relevant costs

is presented in Table 4.18. Information for conventional units' technical data is given in Table C.3. Additionally, a total demand of five energy blocks 2.35, 0.1, 0.1, 0.1 and 0.1 GWh respectively is distributed among 17 buses as depicted in Table C.4. Each demand block follows the utility cost shaped in Table B.1(Appendix B).

4.4.2 RTS results

Applying the proposed MILP, the clearing prices in both DA and balancing markets are raised compared to those under marginal cost offer. Figure 4.11 and Figure 4.12 show the market price formation for DA and RT market respectively throughout the 24-hour period. Considering scheduled production and profits, when the strategic producer exerts market power, it reduces the dispatch energy of the conventional units i making room for more scheduled wind generation. However; the total scheduled production of units i and $j1$ is lower as presented in Table 4.19. On the other hand, the total profits, as expected, show a truly remarkable growth as can be seen in Table 4.20.

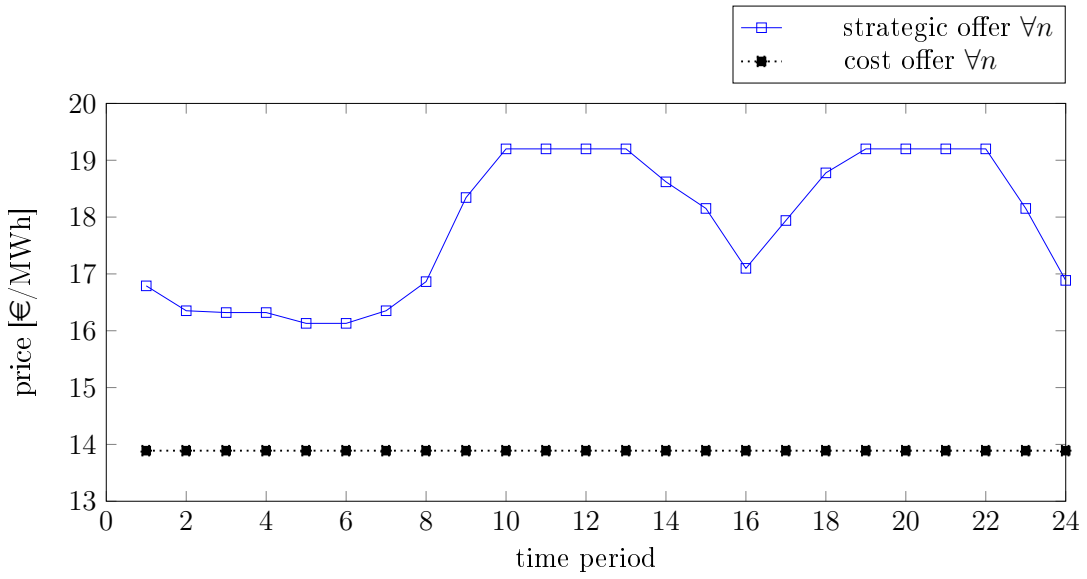

Figure 4.11: Day-ahead market clearing prices in RTS case

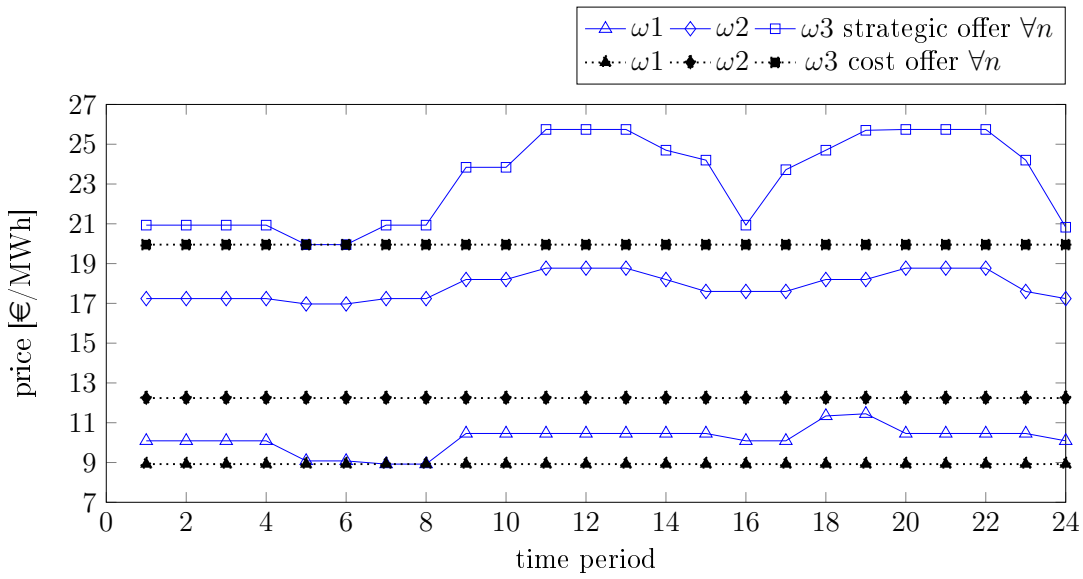

Figure 4.12: Balancing market clearing prices in RTS case

Table 4.19: Scheduled production [MWh] of strategic units in the one area RTS case

	$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$	total i	$j1$	total ij
cost offer	1,104.0	984.0	1,104.0	0.0	4,152.0	3,720.0	9,600.0	3,720.0	24,384.0	3,000.0	27,384.0
strategic offer	782.0	784.4	683.0	0.0	3,690.2	3,041.4	9,257.2	3,068.4	21,306.6	4,147.2	25,453.8

Table 4.20: Expected profit [€] of strategic producer in the one area RTS case

	$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$	total i	$j1$	total ij
cost offer	3,169	3,169	3,169	0	15,162	13,043	80,894	12,976	131,581	30,434	162,016
strategic offer	5,487	5,498	4,541	0	29,720	27,381	118,657	27,024	218,307	39,225	257,533

4.5 Computational issues

The proposed MILP (4.47) − (4.96) has been solved on an Intel Core i7 at 2.7 GHz and 16 GB RAM using CPLEX 12.5.1/GAMS 24.1.3. Similarly to the algorithm presented in Chapter 3, the computational time increases with the number of the wind generation scenarios and the complexity of the network. However, the existence of the decision variables W_{jf}^{DA} and $W_{j\omega}^{sp}$

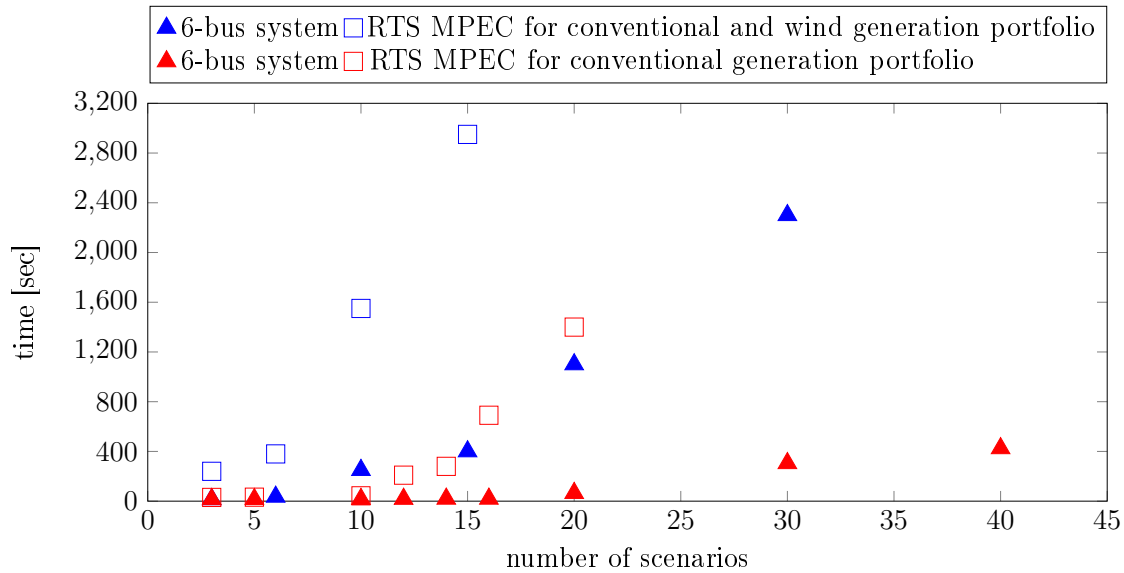

Figure 4.13: CPU time [sec] for MPEC models under different number of wind scenarios

in the objective function (4.1) of the strategic producer introduces new KKT equality constraints in the MPEC. In addition to the above, the existence of the non-linear terms $\lambda_n^{DA} W_{jf}^{DA}$, $\lambda_{n\omega}^{RT} W_{jf}^{DA}$ and $\lambda_{n\omega}^{RT} W_{j\omega}^{sp}$ in the same objective function and $O_{jf}^{DA} W_{jf}^{DA}$, $O_j^{RT} W_{jf}^{DA}$ and $O_j^{RT} W_{j\omega}^{sp}$ in the objective function (4.2) of the ISO increases the mathematical burden of linearization process, thereby increasing further the computational time shown in Figure 4.13. Finally, the process for the calculation of the constants M associated with the disjunctive constraints of the proposed MILP is similar to the process presented in section 3.6.

4.6 Conclusions

In this Chapter an MPEC model is proposed to derive optimal offering strategies for a conventional and wind generation portfolio of a producer who participates in a pool-based electricity market. The model considering energy-only markets optimizes jointly energy dispatch and balancing regulation through a two-stage stochastic programming and generates endogenously local marginal prices as dual variables of the energy balance constraints at day-

ahead and balancing stage. The model is also based on stepwise supply and demand function curves and takes into account only wind power production uncertainty. The application of the proposed algorithm on two different networks results in higher profits for the strategic producer identifying the optimal offer prices for both dispatch and reserve procurements. It also gives information about how by changing the blend of the conventional production the producer can use line capacities and system congestions for its benefit, thus maintaining or even increasing the expected profits. Finally, the model provides details about the way the producer can take advantage of a probable increment in wind power installed capacity rearranging the mixture of scheduled production and raising the expected profits even in case of wind power production spillage.

Based on the proposed MPEC, the following Chapter will introduce an EPEC to model the interaction between more than one strategic producer (multi-leader single-follower game) and identify market equilibria under line congestions and different levels of wind power penetration.

Chapter 5

Nash equilibria in pool market

This Chapter investigates the interaction between power producers with conventional and wind generation portfolios participating in a network-constrained pool-based market. A stochastic bi-level problem is introduced to model the strategic behavior of each single producer. The upper-level problem maximizes the producers' expected profits and the lower-level problem optimizes the jointly cleared energy and balancing market under economic dispatch. Market participants' offers are modeled using linear stepwise curves, and the stochastic wind power generation is realized through a set of plausible wind scenarios. The bi-level problem is recast into an MPEC with primal-dual formulation using the KKT optimality conditions and the strong duality theorem. The joint solution of all strategic producers' MPECs constitutes an equilibrium program with equilibrium constraints (EPEC). The EPEC is reduced into an equivalent MILP by using disjunctive constraints. Different objective functions are applied to the final MILP to define the range of market equilibria, and a single-iterate diagonalization process is used to justify those equilibria that are meaningful. The proposed model is applied in 2-bus and 6-bus systems.

5.1 Introduction

Sections 3 and 4 present MPEC models for solving single-leader single-follower Stackelberg games when a strategic producer (leader) maximizes its expected profits anticipating the market clearing by the ISO (follower), who receives exogenously the producer's decisions as fixed even if in fact it could affect the leader's decision. However, considering that there are more than one producer who act strategically and recognizing the gaming incentives of these market dominant producers to avoid expected profit losses an EPEC is introduced to model a multi-leader single-follower game. According to the model, strategic producers with conventional and wind generation portfolios compete with each other trying to maximize their expected profits while at the same time seeking any equilibrium among them. Thus, the EPEC formulation concerns the finding of meaningful equilibria in a pool-based market among strategic producers' MPECs which have a common lower level problem. Specifically each MPEC embeds the optimization problem of the ISO which is expressed through its primal-dual conditions.

Contrary to the relative algorithms introduced by Ruiz et al. (2012), the proposed EPEC takes into account wind generation considering a jointly cleared energy and balancing market. In relation to Baringo and Conejo (2013) and Zugno et al. (2013) the wind power producers behave strategically in both DA and RT markets. Regarding Kazempour and Zareipour (2014), the model incorporates multi-bus networks giving the ability to analyze market equilibria under transmission line congestions. Additionally, with the use of stepwise offering functions in DA market the model puts a price premium on upward and downward reserves to further align the algorithm with energy-only markets. Compared to Dai and Qiao (2017), the model incorporates wind power spillage, improving economic and technical specifications of the market clearing mechanism. It also uses a single-iteration diagionalization method to identify market equilibria simplifying the computational process. Finally, in relation to Kazempour and Zareipour (2014) and Dai and Qiao (2017), the algorithm applies several objective functions to EPEC defining the range of market equilibria. In addition, in the

case of the non-linear objective function of producers' total expected profits maximization, the linearization is achieved without using any binary-expansion method, thereby further decreasing the computational burden.

The contribution of this Chapter is fivefold:

i) Development of a stochastic MPEC with primal-dual formulation to model the behavior of each strategic producer participating in a co-optimized energy and balancing pool market.

ii) Construction of an EPEC based on the joint solution of all strategic producers' MPECs to find market equilibria taking into account several types of market competition.

iii) Efficient recast of the EPEC without approximations into an equivalent MILP solvable by commercial solvers.

iv) Consideration of both conventional and wind power generation which is offered by strategic producers through linear stepwise curves.

v) Analysis of the impact of large scale of wind integration on market equilibria considering transmission line congestions, and different levels of wind power penetration and volatility.

5.2 EPEC model

5.2.1 Problem statement

This Chapter investigates the interaction between power producers with conventional and wind power generation portfolios participating in a jointly cleared energy and balancing electricity pool market. To analyze market equilibria, we initially introduce a single-leader single-follower bi-level complementarity model to represent the strategic behaviour of each producer. The upper-level problem maximizes the expected profits of the producer (leader), which depend on the DA and RT market clearing prices received at the lower-level problem.

The lower-level problem represents the market clearing process ensuing the system economic dispatch (minimum cost of energy dispatch) conducted by independent system operator (ISO) (follower). The market clearing process facilitates an hourly auction where producers and consumers submit their offers in form of energy blocks/prices and it is formulated as two-stage stochastic programming co-optimizing energy dispatch and reserve deployments. The first stage accommodates the clearing process of DA market and derives optimal scheduled energy and DA market prices obtained as dual variables. The second stage facilitates the clearing process of RT market, which is conducted through the probabilistic realization of all wind power generation dependent scenarios and derives expected reserve deployments and RT prices (Morales et al., 2012). Subsequently, considering the differentiability and convexity of the lower-level problem, the bi-level model is recast into a single-level MPEC with primal-dual formulation by replacing the lower level problem with its Karush-Kuhn-Tacker (KKT) equality conditions and the associated strong duality equality. The simultaneous formulation

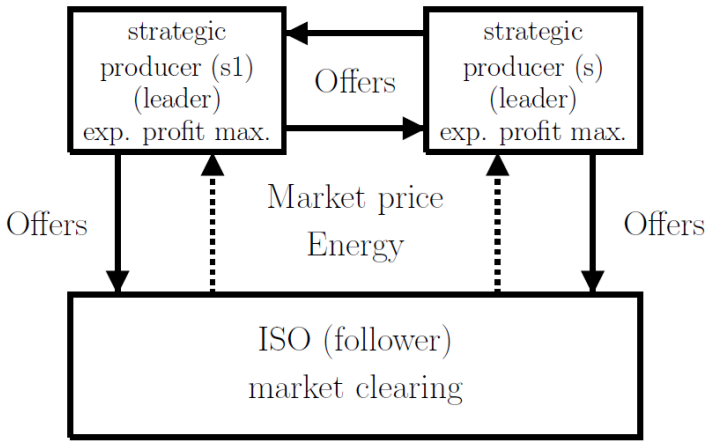

Figure 5.1: Multi-leader single-follower game

of all strategic producers' MPEC constitutes a multi-leader (producers) single-follower (ISO) game and constructs an EPEC model by substituting all the MPEC models with their KKT optimality conditions. Figure 5.1 illustrate the structure of the game. Finally, the resulted

EPEC is linearized by replacing its KKT complementarity constraints with linear disjunctive ones (Fortuny-Amat and McCarl, 1981), thereby reducing further the EPEC in an equivalent MILP solvable by commercial solvers like CPLEX in GAMS.

5.2.2 Bi-level model

To determine the optimal offering strategies for each single producer the following bi-level complementarity problem is proposed:

Upper-level problem

$$\begin{aligned}
\underset{\Xi^S \cup \Xi^O}{minimize} \quad & -\sum_{(i\in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} + \sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} - \sum_{(j\in J_n^S)f} \lambda_n^{DA} W_{jf}^{DA} \\
& - \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} \\
& + \sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
& - \sum_{(j\in J_n^S)\omega} \lambda_{n\omega}^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right)
\end{aligned} \tag{5.1}$$

$$\begin{aligned}
\textit{subjected to} \quad & 0 \le O_{i(b1)}^{DA} && \forall i \in I^S && (5.2)\\
& O_{i(b-1)}^{DA} \le O_{ib}^{DA} && \forall i \in I^S, \forall b > b1 && (5.3)\\
& 0 \le O_{j(f1)}^{DA} && \forall j \in J^S && (5.4)\\
& O_{j(f-1)}^{DA} \le O_{jf}^{DA} && \forall j \in J^S, \forall f > f1 && (5.5)\\
& 0 \le O_i^{up} && \forall i \in I^S && (5.6)\\
& 0 \le O_i^{down} && \forall i \in I^S && (5.7)\\
& 0 \le O_j^{RT} && \forall j \in J^S && (5.8)
\end{aligned}$$

Lower-level problem

$$\begin{aligned} \underset{\Xi}{minimize} \quad & \sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{i\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{i\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\ & + \sum_{jf} O_{jf}^{DA} W_{jf}^{DA} + \sum_{j\omega} \pi_\omega O_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\ & - \sum_{dk} u_{dk} L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \end{aligned} \tag{5.9}$$

$$\textit{subjected to} \qquad (2.3) - (2.18) \tag{5.10}$$

The objective function (5.1) minimizes the negative expected profits of each strategic producer which are determined by the revenues of the conventional and wind generating units in DA market, the revenues (gain or losses) from the upward or downward reserve deployments, and the wind power surplus or shortfall generation in RT market minus the actual incurred cost. The purpose of the negative formulation of the expected profits' maximization is to render the objective function compatible with the mathematical transformations that will follow. $\Xi^S = \{P_{(i\in I^S)b}^{DA}, W_{(j\in J^S)f}^{DA}, r_{(i\in I^S)\omega}^{up}, r_{(i\in I^S)\omega}^{down}, W_{(j\in J^S)\omega}^{sp}\}$ and $\Xi^O = \{O_{(i\in I^S)b}^{DA}, O_{(i\in I^S)}^{up}, O_{(i\in I^S)}^{down}, O_{(j\in J^S)f}^{DA}, O_{(j\in J^S)}^{RT}\}$ are the sets of all prime variables of the upper level problem. It should also be noted that the 4-th, the 6-th and the 7-th term of (1) are derived from $\sum_{(i\in I_n^S)\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} r_{i\omega}^{up}$, $\sum_{(i\in I_n^S)\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} r_{i\omega}^{down}$ and $\sum_{(j\in J_n^S)\omega} \pi_\omega \frac{\lambda_{n\omega}^{RT}}{\pi_\omega} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right)$ respectively. The constraints (5.2)−(5.5) enforce the acceptable offering decisions for the conventional and wind energy blocks as well as the non-decreasing offering curves in DA market. The constraints (5.6)−(5.8) enforce the price decisions for the upward/downward reserves and the wind power offered in RT market. The objective function (5.9) of the lower-level problem clears the DA and RT markets minimizing the total expected cost of the system operation which consists of: a) the scheduled conventional and wind production cost at the DA market, and b) the cost or savings of the scenario dependent upward and downward reserves, the wind surplus or shortfall generation, and finally the cost of wind power spillage and load shedding

in real time operation, minus c) the utility of the demand. Alternatively, the ISO seeks to maximize the total social welfare. $\Xi = \{P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, r_{i\omega}^{up}, r_{i\omega}^{down}, W_{j\omega}^{sp}, L_{d\omega}^{sh}, \delta_n^o, \delta_{n\omega}\}$ is the set of all ISO's decision variables. Finally constraint (5.10) considers all the constraints of the market clearing precess (2.3) − (2.18) as presented in section 2.4.

5.2.3 MPEC formulation with primal-dual constraints

Considering the continuity and differentiability of the non-linear constrained lower-level problem, the auxiliary Lagrangian function can be used to convert the problem into an unconstrained one. Additionally, the decision variables O_{ib}^{DA}, O_{jf}^{DA}, $O_{i\omega}^{up}$, $O_{i\omega}^{down}$ and O_j^{RT} of each producer are received as parameters by the ISO, rendering the objective function (9) of the lower-level problem linear and therefore convex. Within the above context the lower-level problem can be replaced by its first order optimality conditions in the form of the primal-dual formulation instead of the equivalent KKT optimality conditions. The former offers computational advantages reducing the mathematical burden of the forthcoming derivation of strong stationary conditions due to the absence of the KKT complementarity conditions of the lower-level problem with the form $0 \leq g(x) \perp \mu \geq 0$. Thus, the initial bi-level model is recast into the following MPEC model:

$$\underset{\Xi \cup \Xi^O \cup \Xi^D}{minimize} \quad (5.1) \tag{5.11}$$

subjected to :

$$0 \leq O_{i(b1)}^{DA} \quad : \left[\widehat{o}_{si(b1)}^{p}\right] \quad \forall i \in I^S \tag{5.12}$$

$$O_{i(b-1)}^{DA} \leq O_{ib}^{DA} \quad : \left[\widehat{o}_{sib}^{p}\right] \quad \forall i \in I^S, \forall b \geq b2 \tag{5.13}$$

$$0 \leq O_{j(f1)}^{DA} \quad : \left[\widehat{o}_{sj(f1)}^{w}\right] \quad \forall j \in J^S \tag{5.14}$$

$$O_{j(f-1)}^{DA} \leq O_{jf}^{DA} \quad : \left[\widehat{o}_{sjf}^{w}\right] \quad \forall j \in J^S, \forall f \geq f2 \tag{5.15}$$

$$0 \leq O_i^{up} \quad : \left[\widehat{o}_{si}^{up}\right] \quad \forall i \in I^S \tag{5.16}$$

$$0 \leq O_i^{down} \quad : \left[\widehat{o}_{si}^{down}\right] \quad \forall i \in I^S \tag{5.17}$$

$$0 \leq O_j^{RT} \qquad : \left[\widehat{o}_{sj}^{rt}\right] \quad \forall j \in J^S \tag{5.18}$$

$$\begin{aligned} &-\sum_{(i\in I_n)b} P_{ib}^{DA} - \sum_{(j\in J_n)f} W_{jf}^{DA} \\ &+\sum_{(d\in D_n)k} L_{dk}^{DA} + \sum_{m\in\Theta_n} B_{nm}\left(\delta_n^o - \delta_m^o\right) = 0 \quad : \left[\widehat{\lambda}_{sn}^{DA}\right] \quad \forall n \end{aligned} \tag{5.19}$$

$$\begin{aligned} &-\sum_{i\in I_n} r_{i\omega}^{up} + \sum_{i\in I_n} r_{i\omega}^{down} - \sum_{d\in D_n} L_{d\omega}^{sh} \\ &-\left(\sum_{j\in J_n} W_{j\omega}^{RT} - \sum_{(j\in J_n)f} W_{jf}^{DA} - \sum_{j\in J_n} W_{j\omega}^{sp}\right) \\ &+\sum_{m\in\Theta_n} B_{nm}\left(\delta_{n\omega} - \delta_n^o + \delta_m^o - \delta_{m\omega}\right) = 0 \quad : \left[\widehat{\lambda}_{sn\omega}^{RT}\right] \qquad \forall n, \forall\omega \end{aligned} \tag{5.20}$$

$$0 \leq P_{ib}^{DA} \leq P_{ib}^{MAX} \qquad : \left[\widehat{\alpha}_{sib}^{min}, \widehat{\alpha}_{sib}^{max}\right] \quad \forall i, \forall b \tag{5.21}$$

$$0 \leq W_{jf}^{DA} \leq W_{jf}^{MAX} \qquad : \left[\widehat{\beta}_{sjf}^{min}, \widehat{\beta}_{sjf}^{max}\right] \quad \forall j, \forall f \tag{5.22}$$

$$0 \leq L_{dk}^{DA} \leq L_{dk}^{MAX} \qquad : \left[\widehat{\gamma}_{sdk}^{min}, \widehat{\gamma}_{sdk}^{max}\right] \quad \forall d, \forall k \tag{5.23}$$

$$0 \leq r_{i\omega}^{up} \leq RES_i^{UP} \qquad : \left[\widehat{\epsilon}_{si\omega}^{min}, \widehat{\epsilon}_{si\omega}^{max}\right] \quad \forall i, \forall\omega \tag{5.24}$$

$$0 \leq r_{i\omega}^{down} \leq RES_i^{DOWN} \qquad : \left[\widehat{\theta}_{si\omega}^{min}, \widehat{\theta}_{si\omega}^{max}\right] \quad \forall i, \forall\omega \tag{5.25}$$

$$\sum_b P_{ib}^{DA} + r_{i\omega}^{up} \leq \sum_b P_{ib}^{MAX} \qquad : \left[\widehat{\mu}_{si\omega}^{max}\right] \quad \forall i, \forall\omega \tag{5.26}$$

$$r_{i\omega}^{down} - \sum_b P_{ib}^{DA} \leq 0 \qquad : \left[\widehat{\mu}_{si\omega}^{min}\right] \quad \forall i, \forall\omega \tag{5.27}$$

$$0 \leq W_{j\omega}^{sp} \leq W_{j\omega}^{RT} \qquad : \left[\widehat{\kappa}_{sj\omega}^{min}, \widehat{\kappa}_{sj\omega}^{max}\right] \quad \forall j, \forall\omega \tag{5.28}$$

$$0 \leq L_{d\omega}^{sh} \leq \sum_k L_{dk}^{DA} \qquad : \left[\widehat{\nu}_{sd\omega}^{min}, \widehat{\nu}_{sd\omega}^{max}\right] \quad \forall d, \forall\omega \tag{5.29}$$

$$-T_{nm}^{MAX} \leq B_{nm}\left(\delta_n^o - \delta_m^o\right) \leq T_{nm}^{MAX} \qquad : \left[\widehat{\xi}_{snm}^{min}, \widehat{\xi}_{snm}^{max}\right] \quad \forall n, \forall m \in \Theta_n \tag{5.30}$$

$$-T_{nm}^{MAX} \leq B_{nm}\left(\delta_{n\omega} - \delta_{m\omega}\right) \leq T_{nm}^{MAX} \qquad : \left[\widehat{\xi}_{snm\omega}^{min}, \widehat{\xi}_{snm\omega}^{max}\right] \forall n, \forall m \in \Theta_n \forall\omega \tag{5.31}$$

$$-\pi \leq \delta_n^o \leq \pi \qquad : \left[\widehat{\rho}_{sn}^{min}, \widehat{\rho}_{sn}^{max}\right] \quad \forall n \tag{5.32}$$

$$-\pi \leq \delta_{n\omega} \leq \pi \qquad : \left[\widehat{\rho}_{sn\omega}^{min}, \widehat{\rho}_{sn\omega}^{max}\right] \quad \forall n, \forall\omega \tag{5.33}$$

$$\delta_{(n1)}^o = 0 \qquad : \left[\widehat{\phi}_{sn}^o\right] \quad n = n1 \quad \text{(slack bus)} \tag{5.34}$$

$$\delta_{(n1)\omega} = 0 \qquad : \left[\widehat{\phi}_{sn\omega}\right] \quad n = n1 \quad \text{(slack bus)} \tag{5.35}$$

$$
\begin{aligned}
&\sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{i\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{i\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\
&+ \sum_{jf} O_{jf}^{DA} W_{jf}^{DA} + \sum_{j\omega} \pi_\omega O_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
&- \sum_{dk} u_{dk} L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \\
&+ \sum_{(j\in J_n)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} + \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} + \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \\
&+ \sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} + \sum_{i\omega} \theta_{i\omega}^{max} RES_i^{DOWN} \\
&+ \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} + \sum_{j\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} + \sum_{i\omega} \mu_{i\omega}^{max} \left(\sum_b P_{ib}^{MAX} \right) \\
&+ \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) + \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&+ \sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) + \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right) = 0 \qquad : \left[\widehat{\lambda}_s^{DT} \right]
\end{aligned} \tag{5.36}
$$

$$
O_{ib}^{DA} - \lambda_n^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_\omega \mu_{i\omega}^{max} - \sum_\omega \mu_{i\omega}^{min} = 0 \quad : \left[\widehat{\psi}_{sib}^{\ p} \right] \quad \forall i \in I_n, \forall b \tag{5.37}
$$

$$
O_{jf}^{DA} - \lambda_n^{DA} - O_j^{RT} + \sum_\omega \lambda_{n\omega}^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} = 0 \quad : \left[\widehat{\psi}_{sjf}^{\ w} \right] \quad \forall j \in J_n, \forall f \tag{5.38}
$$

$$
-u_{dk} + \lambda_n^{DA} + \gamma_{dk}^{max} - \gamma_{dk}^{min} - \sum_\omega \nu_{d\omega}^{max} = 0 \quad : \left[\widehat{\psi}_{sdk}^{\ l} \right] \quad \forall d \in D_n, \forall k \tag{5.39}
$$

$$
\pi_\omega O_i^{up} - \lambda_{n\omega}^{RT} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} = 0 \quad : \left[\widehat{\psi}_{si\omega}^{\ up} \right] \quad \forall i \in I_n, \forall \omega \tag{5.40}
$$

$$
-\pi_\omega O_i^{down} + \lambda_{n\omega}^{RT} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} = 0 \quad : \left[\widehat{\psi}_{si\omega}^{\ down} \right] \quad \forall i \in I_n, \forall \omega \tag{5.41}
$$

$$
-\pi_\omega O_j^{RT} + \lambda_{n\omega}^{RT} + \kappa_{j\omega}^{max} - \kappa_{j\omega}^{min} = 0 \quad : \left[\widehat{\psi}_{sj\omega}^{\ sp} \right] \quad \forall j \in J_n, \forall \omega \tag{5.42}
$$

$$
\pi_\omega VOLL_d - \lambda_{n\omega}^{RT} + \nu_{d\omega}^{max} - \nu_{d\omega}^{min} = 0 \quad : \left[\widehat{\psi}_{sd\omega}^{\ sh} \right] \quad \forall d \in D_n, \forall \omega \tag{5.43}
$$

$$
\begin{aligned}
&\sum_{m\in\Theta_n} B_{nm} \left(\lambda_n^{DA} - \lambda_m^{DA} \right) + \sum_{(m\in\Theta_n)\omega} B_{nm} \left(-\lambda_{n\omega}^{RT} + \lambda_{m\omega}^{RT} \right) \\
&+ \sum_{m\in\Theta_n} B_{nm} \left(\xi_{nm}^{max} - \xi_{mn}^{max} \right) \\
&- \sum_{m\in\Theta_n} B_{nm} \left(\xi_{nm}^{min} - \xi_{mn}^{min} \right) + \rho_n^{max} - \rho_n^{min} + \phi_{(n|=n1)}^{o} = 0 \quad : \left[\widehat{\psi}_{sn}^{\ o} \right] \quad \forall n
\end{aligned} \tag{5.44}
$$

$$
\begin{aligned}
&\sum_{m\in\Theta_n} B_{nm} \left(\lambda_{n\omega}^{RT} - \lambda_{m\omega}^{RT} \right) + \sum_{m\in\Theta_n} B_{nm} \left(\xi_{nm\omega}^{max} - \xi_{mn\omega}^{max} \right) \\
&- \sum_{m\in\Theta_n} B_{nm} \left(\xi_{nm\omega}^{min} - \xi_{mn\omega}^{min} \right) + \rho_{n\omega}^{max} - \rho_{n\omega}^{min} + \phi_{(n|=n1)\omega} = 0 \quad : \left[\widehat{\psi}_{sn\omega} \right] \quad \forall n, \forall \omega
\end{aligned} \tag{5.45}
$$

$$0 \leq \alpha_{ib}^{min}, \alpha_{ib}^{max} \quad : \left[\overline{\alpha}_{sib}^{min}, \overline{\alpha}_{sib}^{max}\right] \quad \forall i, \forall b \tag{5.46}$$

$$0 \leq \beta_{jf}^{min}, \beta_{jf}^{max} \quad : \left[\overline{\beta}_{sjf}^{min}, \overline{\beta}_{sjf}^{max}\right] \quad \forall j, \forall f \tag{5.47}$$

$$0 \leq \gamma_{dk}^{min}, \gamma_{dk}^{max} \quad : \left[\overline{\gamma}_{sdk}^{min}, \overline{\gamma}_{sdk}^{max}\right] \quad \forall d, \forall k \tag{5.48}$$

$$0 \leq \epsilon_{i\omega}^{min}, \epsilon_{i\omega}^{max} \quad : \left[\overline{\epsilon}_{si\omega}^{min}, \overline{\epsilon}_{si\omega}^{max}\right] \quad \forall i, \forall \omega \tag{5.49}$$

$$0 \leq \theta_{i\omega}^{min}, \theta_{i\omega}^{max} \quad : \left[\overline{\theta}_{si\omega}^{min}, \overline{\theta}_{si\omega}^{max}\right] \quad \forall i, \forall \omega \tag{5.50}$$

$$0 \leq \mu_{i\omega}^{min}, \mu_{i\omega}^{max} \quad : \left[\overline{\mu}_{si\omega}^{min}, \overline{\mu}_{si\omega}^{max}\right] \quad \forall i, \forall \omega \tag{5.51}$$

$$0 \leq \kappa_{j\omega}^{min}, \kappa_{j\omega}^{max} \quad : \left[\overline{\kappa}_{sj\omega}^{min}, \overline{\kappa}_{sj\omega}^{max}\right] \quad \forall j, \forall \omega \tag{5.52}$$

$$0 \leq \nu_{d\omega}^{min}, \nu_{d\omega}^{max} \quad : \left[\overline{\nu}_{sd\omega}^{min}, \overline{\nu}_{sd\omega}^{max}\right] \quad \forall d, \forall \omega \tag{5.53}$$

$$0 \leq \xi_{nm}^{min}, \xi_{nm}^{max} \quad : \left[\overline{\xi}_{snm}^{min}, \overline{\xi}_{snm}^{max}\right] \quad \forall n, \forall m \in \Theta_n \tag{5.54}$$

$$0 \leq \xi_{nm\omega}^{min}, \xi_{nm\omega}^{max} \quad : \left[\overline{\xi}_{snm\omega}^{min}, \overline{\xi}_{snm\omega}^{max}\right] \quad \forall n, \forall m \in \Theta_n, \forall \omega \tag{5.55}$$

$$0 \leq \rho_{n}^{min}, \rho_{n}^{max} \quad : \left[\overline{\rho}_{sn}^{min}, \overline{\rho}_{sn}^{max}\right] \quad \forall n \tag{5.56}$$

$$0 \leq \rho_{n\omega}^{min}, \rho_{n\omega}^{max} \quad : \left[\overline{\rho}_{sn\omega}^{min}, \overline{\rho}_{sn\omega}^{max}\right] \quad \forall n, \forall m \in \Theta_n \tag{5.57}$$

Where $\Xi^D = \{\lambda_n^{DA}, \lambda_{n\omega}^{RT}, \alpha_{ib}^{max}, \alpha_{ib}^{min}, \beta_{jf}^{max}, \beta_{jf}^{min}, \gamma_{dk}^{max}, \gamma_{dk}^{min}, \epsilon_{i\omega}^{max}, \epsilon_{i\omega}^{min}, \theta_{i\omega}^{max}, \theta_{i\omega}^{min}, \mu_{i\omega}^{max}, \mu_{i\omega}^{min}, \kappa_{j\omega}^{max}, \kappa_{j\omega}^{min}, \nu_{d\omega}^{max}, \nu_{d\omega}^{min}, \xi_{nm}^{max}, \xi_{nm}^{min}, \xi_{nm\omega}^{max}, \xi_{nm\omega}^{min}, \rho_n^{max}, \rho_n^{min}, \rho_{n\omega}^{max}, \rho_{n\omega}^{min}, \phi_{(n|=n1)}^{o}, \phi_{(n|=n1)\omega}\}$ is the set of all dual variables of the lower-level problem. Equations (5.12) – (5.18) and (5.19) – (5.35) correspond to the primal constraints of the upper-level and lower-level problem respectively. The constraint (5.36) applies the strong duality theorem which enforces equality between the optimal prime and optimal dual objective functions. The equalities (5.37) – (5.45) which are the partial derivatives of the Lagrangian function with respect to prime variables P_{ib}^{DA}, W_{jf}^{DA}, L_{dk}^{DA}, $r_{i\omega}^{up}$, $r_{i\omega}^{down}$, $W_{j\omega}^{sp}$, $L_{d\omega}^{sh}$, δ_n^o and $\delta_{n\omega}$, and the inequalities (5.46) – (5.57) correspond to the dual constraints of the lower-level problem. Finally, it should also be noticed that contrary to the dual variables of the lower-level problem which are common to all producers (for example the market clearing prices λ_n^{DA} and $\frac{\lambda_{n\omega}^{RT}}{\pi_\omega}$), the dual variables of the MPEC are producer specific which is why they include the subscript s. This way it is more probable to detect market equilibria (Ruiz et al., 2012).

5.2.4 EPEC formulation

To identify market equilibria the MPECs of all producers are solved jointly forming an EPEC model. The latter can be represented by the KKT optimality conditions of all MPEC's as follows:

$$(5.19),\ (5.20),\ (5.34)-(5.45) \tag{5.58}$$

$$\partial\mathcal{L}_s/\partial O^{DA}_{i(b1)} = -\widehat{o}^{\,p}_{si(b1)} + P^{DA}_{si(b1)}\widehat{\lambda}^{DT}_s + \widehat{\psi}^{\,p}_{si(b1)} = 0 \qquad \forall s, \forall i \in I^S \tag{5.59}$$

$$\partial\mathcal{L}_s/\partial O^{DA}_{ib} = -\widehat{o}^{\,p}_{sib} + \widehat{o}^{\,p}_{si(b-1)} + P^{DA}_{sib}\widehat{\lambda}^{DT}_s + \widehat{\psi}^{\,p}_{sib} = 0 \quad \forall s, \forall i \in I^S, \forall b > b1 \tag{5.60}$$

$$\partial\mathcal{L}_s/\partial O^{DA}_{j(f1)} = -\widehat{o}^{\,w}_{sj(f1)} + W^{DA}_{sj(f1)}\widehat{\lambda}^{DT}_s + \widehat{\psi}^{\,w}_{sj(f1)} = 0 \qquad \forall s, \forall j \in J^S \tag{5.61}$$

$$\partial\mathcal{L}_s/\partial O^{DA}_{jf} = -\widehat{o}^{\,w}_{sjf} + \widehat{o}^{\,w}_{sj(f-1)} + W^{DA}_{sjf}\widehat{\lambda}^{DT}_s + \widehat{\psi}^{\,w}_{sjf} = 0 \quad \forall s, \forall j \in J^S, \forall f > f1 \tag{5.62}$$

$$\partial\mathcal{L}_s/\partial O^{up}_{i} = -\widehat{o}^{\,up}_{si} + \pi_\omega r^{up}_{i\omega}\widehat{\lambda}^{DT}_s + \pi_\omega\widehat{\psi}^{\,up}_{si\omega} = 0 \quad \forall s, \forall i \in I^S, \forall \omega \tag{5.63}$$

$$\partial\mathcal{L}_s/\partial O^{down}_{i} = -\widehat{o}^{\,down}_{si} + \pi_\omega r^{down}_{i\omega}\widehat{\lambda}^{DT}_s - \pi_\omega\widehat{\psi}^{\,down}_{si\omega} = 0 \quad \forall s, \forall i \in I^S, \forall \omega \tag{5.64}$$

$$\begin{aligned}\partial\mathcal{L}_s/\partial O^{RT}_{j} = & -\widehat{o}^{\,rt}_{sj} + \pi_\omega\left(W^{RT}_{j\omega} - \textstyle\sum_f W^{DA}_{jf} - W^{sp}_{j\omega}\right)\widehat{\lambda}^{DT}_s \\ & - \sum_f \psi^{\,w}_{sjf} - \pi_\omega\widehat{\psi}^{\,sp}_{sj\omega} = 0 \quad \forall s, \forall j \in J^S, \forall \omega\end{aligned} \tag{5.65}$$

$$\begin{aligned}\partial\mathcal{L}_s/\partial P^{DA}_{ib} = & -\lambda^{DA}_{(n:i\in I_n)} + c_{ib} - \widehat{\lambda}^{DA}_{s(n:i\in I_n)} + \widehat{\alpha}^{max}_{sib} - \widehat{\alpha}^{min}_{sib} + \sum_\omega \widehat{\mu}^{max}_{si\omega} \\ & - \sum_\omega \widehat{\mu}^{min}_{si\omega} + O^{DA}_{ib}\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall i \in I^s, \forall b\end{aligned} \tag{5.66}$$

$$\begin{aligned}\partial\mathcal{L}_s/\partial P^{DA}_{ib} = & -\widehat{\lambda}^{DA}_{s(n:i\in I_n)} + \widehat{\alpha}^{max}_{sib} - \widehat{\alpha}^{min}_{sib} + \sum_\omega \widehat{\mu}^{max}_{si\omega} \\ & - \sum_\omega \widehat{\mu}^{min}_{si\omega} + O^{DA}_{ib}\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall i \notin I^s, \forall b\end{aligned} \tag{5.67}$$

$$\begin{aligned}\partial\mathcal{L}_s/\partial W^{DA}_{jf} = & -\lambda^{DA}_{(n:j\in J_n)} + \sum_\omega \lambda^{RT}_{(n:j\in J_n)\omega} - \widehat{\lambda}^{DA}_{s(n:j\in J_n)} + \sum_\omega \widehat{\lambda}^{RT}_{s(n:j\in J_n)\omega} + \widehat{\beta}^{max}_{sjf} \\ & - \widehat{\beta}^{min}_{sjf} + O^{DA}_{jf}\widehat{\lambda}^{DT}_s - \sum_\omega \pi_\omega O^{RT}_j\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall j \in J^s, \forall f\end{aligned} \tag{5.68}$$

$$\partial\mathcal{L}_s/\partial W^{DA}_{jf} = -\widehat{\lambda}^{DA}_{s(n:j\in J_n)} + \sum_{\omega}\widehat{\lambda}^{RT}_{s(n:j\in J_n)\omega} + \widehat{\beta}^{max}_{sjf} - \widehat{\beta}^{min}_{sjf} + O^{DA}_{jf}\widehat{\lambda}^{DT}_s - \sum_{\omega}\pi_\omega O^{RT}_j\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall j \notin J^s, \forall f \tag{5.69}$$

$$\partial\mathcal{L}_s/\partial L^{DA}_{dk} = \widehat{\lambda}^{DA}_{s(n:d\in D_n)} + \widehat{\gamma}^{max}_{sdk} - \widehat{\gamma}^{min}_{sdk} + \sum_{\omega}\widehat{\nu}^{max}_{sd\omega} - u_{dk}\widehat{\lambda}^{DT}_s = 0 \quad \forall s, \forall k \tag{5.70}$$

$$\partial\mathcal{L}_s/\partial r^{up}_{i\omega} = -\lambda^{RT}_{(n:i\in I_n)\omega} + \pi_\omega c^{up}_i - \widehat{\lambda}^{RT}_{s(n:i\in I_n)\omega} + \widehat{\epsilon}^{max}_{si\omega} - \widehat{\epsilon}^{min}_{si\omega} + \widehat{\mu}^{max}_{si\omega} + \pi_\omega O^{up}_i\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall i \in I^s, \forall \omega \tag{5.71}$$

$$\partial\mathcal{L}_s/\partial r^{up}_{i\omega} = -\widehat{\lambda}^{RT}_{s(n:i\in I_n)\omega} + \widehat{\epsilon}^{max}_{si\omega} - \widehat{\epsilon}^{min}_{si\omega} + \widehat{\mu}^{max}_{si\omega} + \pi_\omega O^{up}_i\widehat{\lambda}^{DT}_s = 0 \qquad \forall, \forall i \notin I^s, \forall \omega \tag{5.72}$$

$$\partial\mathcal{L}_s/\partial r^{down}_{i\omega} = \lambda^{RT}_{(n:i\in I_n)\omega} - \pi_\omega c^{down}_i + \widehat{\lambda}^{RT}_{s(n:i\in I_n)\omega} + \widehat{\theta}^{max}_{si\omega} - \widehat{\theta}^{min}_{si\omega} + \widehat{\mu}^{min}_{si\omega} + \pi_\omega O^{down}_i\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall i \in I^s, \forall \omega \tag{5.73}$$

$$\partial\mathcal{L}_s/\partial r^{down}_{i\omega} = \widehat{\lambda}^{RT}_{s(n:i\in I_n)\omega} + \widehat{\theta}^{max}_{si\omega} - \widehat{\theta}^{min}_{si\omega} + \widehat{\mu}^{min}_{si\omega} + \pi_\omega O^{down}_i\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall i \notin I^s, \forall \omega \tag{5.74}$$

$$\partial\mathcal{L}_s/\partial W^{sp}_{j\omega} = \lambda^{RT}_{(n:j\in J_n)\omega} + \widehat{\lambda}^{RT}_{s(n:j\in J_n)\omega} + \widehat{\kappa}^{max}_{sj\omega} - \widehat{\kappa}^{min}_{sj\omega} - \pi_\omega O^{RT}_j\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall j \in J^s, \forall \omega \tag{5.75}$$

$$\partial\mathcal{L}_s/\partial W^{sp}_{j\omega} = \widehat{\lambda}^{RT}_{s(n:j\in J_n)\omega} + \widehat{\kappa}^{max}_{sj\omega} - \widehat{\kappa}^{min}_{sj\omega} - \pi_\omega O^{RT}_j\widehat{\lambda}^{DT}_s = 0 \quad \forall s, \forall j \notin J^s, \forall \omega \tag{5.76}$$

$$\partial\mathcal{L}_s/\partial L^{sh}_{j\omega} = -\lambda^{RT}_{(n:d\in D_n)\omega} + \widehat{\nu}^{max}_{sd\omega} - \widehat{\nu}^{min}_{sd\omega} + \pi_\omega VOLL_d\widehat{\lambda}^{DT}_s = 0 \qquad \forall s, \forall \omega \tag{5.77}$$

$$\partial\mathcal{L}_s/\partial\delta^o_n = \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\lambda}^{DA}_{sn} - \widehat{\lambda}^{DA}_{sm}\big) + \sum_{(m\in\Theta_n)\omega} B_{nm}\big(-\widehat{\lambda}^{RT}_{sn\omega} + \widehat{\lambda}^{RT}_{sm\omega}\big) + \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\xi}^{max}_{snm} - \widehat{\xi}^{max}_{smn}\big) - \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\xi}^{min}_{snm} - \widehat{\xi}^{min}_{smn}\big) + \widehat{\rho}^{max}_{sn} - \widehat{\rho}^{min}_{sn} + \widehat{\phi}^{o}_{(n|=n1)} = 0 \qquad \forall s, \forall n \tag{5.78}$$

$$\partial\mathcal{L}_s/\partial\delta_{n\omega} = \sum_{(m\in\Theta_n)} B_{nm}\big(\widehat{\lambda}^{RT}_{sn\omega} - \widehat{\lambda}^{RT}_{sm\omega}\big) + \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\xi}^{max}_{snm\omega} - \widehat{\xi}^{max}_{smn\omega}\big) - \sum_{m\in\Theta_n} B_{nm\omega}\big(\widehat{\xi}^{min}_{snm\omega} - \widehat{\xi}^{min}_{smn\omega}\big) + \widehat{\rho}^{max}_{sn\omega} - \widehat{\rho}^{min}_{sn\omega} + \widehat{\phi}_{(n|=n1)\omega} = 0 \qquad \forall s, \forall n, \forall \omega \tag{5.79}$$

$$\partial\mathcal{L}_s/\partial\lambda_n^{DA} = -\sum_{(i\in I_n^S)b} P_{ib}^{DA} - \sum_{(j\in J_n^S)f} W_{jf}^{DA} - \widehat{\psi}^{\,p}_{s(i\in I_n)b} - \widehat{\psi}^{\,w}_{s(j\in J_n)f} + \widehat{\psi}^{\,l}_{s(d\in D_n)k} + \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\psi}^{o}_{sn} - \widehat{\psi}^{o}_{sm}\big) = 0 \qquad \forall s, \forall n \tag{5.80}$$

$$\partial\mathcal{L}_s/\partial\lambda_{n\omega}^{RT} = -\sum_{i\in I_n^s} r_{i\omega}^{up} + \sum_{i\in I_n^s} r_{i\omega}^{down} - \sum_{j\in J_n^S}\left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp}\right) + \sum_{(j\in J_n)f} \widehat{\psi}^{\,w}_{sjf} - \sum_{i\in I_n} \widehat{\psi}^{\,up}_{si\omega} + \sum_{i\in I_n} \widehat{\psi}^{\,down}_{si\omega} + \sum_{j\in J_n} \widehat{\psi}^{\,sp}_{sj\omega} - \sum_{d\in D_n} \widehat{\psi}^{\,sh}_{sd\omega} + \sum_{m\in\Theta_n} B_{nm}\big(-\widehat{\psi}^{o}_{sn} + \widehat{\psi}^{o}_{sm}\big) + \sum_{m\in\Theta_n} B_{nm}\big(\widehat{\psi}_{sn\omega} - \widehat{\psi}_{sm\omega}\big) + \sum_{j\in J_n^S} W_{j\omega}^{RT}\widehat{\lambda}_s^{DT} = 0 \qquad \forall s, \forall n, \forall\omega \tag{5.81}$$

$$\partial\mathcal{L}_s/\partial\alpha_{ib}^{min} = -\widehat{\psi}^{\,p}_{sib} - \overline{\alpha}_{sib}^{min} = 0 \qquad \forall s, \forall i, \forall b \tag{5.82}$$

$$\partial\mathcal{L}_s/\partial\alpha_{ib}^{max} = P_{ib}^{MAX}\widehat{\lambda}_s^{DT} + \widehat{\psi}^{\,p}_{sib} - \overline{\alpha}_{sib}^{max} = 0 \qquad \forall s, \forall i, \forall b \tag{5.83}$$

$$\partial\mathcal{L}_s/\partial\beta_{jf}^{min} = -\widehat{\psi}^{\,p}_{sjf} - \overline{\beta}_{sjf}^{min} = 0 \qquad \forall s, \forall j, \forall f \tag{5.84}$$

$$\partial\mathcal{L}_s/\partial\beta_{jf}^{max} = W_{jf}^{MAX}\widehat{\lambda}_s^{DT} + \widehat{\psi}^{\,w}_{sjf} - \overline{\beta}_{sjf}^{max} = 0 \qquad \forall s, \forall j, \forall f \tag{5.85}$$

$$\partial\mathcal{L}_s/\partial\gamma_{dk}^{min} = -\widehat{\psi}^{\,l}_{sdk} - \overline{\gamma}_{sdk}^{min} = 0 \qquad \forall s, \forall d, \forall k \tag{5.86}$$

$$\partial\mathcal{L}_s/\partial\gamma_{dk}^{max} = L_{dk}^{MAX}\widehat{\lambda}_s^{DT} + \widehat{\psi}^{\,l}_{sdk} - \overline{\gamma}_{sdk}^{max} = 0 \qquad \forall s, \forall d, \forall k \tag{5.87}$$

$$\partial\mathcal{L}_s/\partial\epsilon_{i\omega}^{min} = -\widehat{\psi}^{\,up}_{si\omega} - \overline{\epsilon}_{si\omega}^{min} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.88}$$

$$\partial\mathcal{L}_s/\partial\epsilon_{i\omega}^{max} = RES_i^{UP}\widehat{\lambda}_s^{DT} + \widehat{\psi}^{\,up}_{si\omega} - \overline{\epsilon}_{si\omega}^{max} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.89}$$

$$\partial\mathcal{L}_s/\partial\theta_{i\omega}^{min} = -\widehat{\psi}^{\,down}_{si\omega} - \overline{\theta}_{si\omega}^{min} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.90}$$

$$\partial\mathcal{L}_s/\partial\theta_{i\omega}^{max} = RES_i^{DOWN}\widehat{\lambda}_s^{DT} + \widehat{\psi}^{\,down}_{si\omega} - \overline{\theta}_{si\omega}^{max} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.91}$$

$$\partial\mathcal{L}_s/\partial\mu_{i\omega}^{min} = -\sum_b \widehat{\psi}^{\,p}_{sib} + \widehat{\psi}^{\,down}_{si\omega} - \overline{\mu}_{si\omega}^{min} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.92}$$

$$\partial\mathcal{L}_s/\partial\mu_{i\omega}^{max} = \sum_b P_{ib}^{MAX}\widehat{\lambda}_s^{DT} + \sum_b \widehat{\psi}^{\,p}_{sib} + \widehat{\psi}^{\,up}_{si\omega} - \overline{\mu}_{si\omega}^{max} = 0 \qquad \forall s, \forall i, \forall\omega \tag{5.93}$$

$$\partial\mathcal{L}_s/\partial\kappa^{min}_{j\omega} = \quad -\widehat{\psi}^{\,sp}_{sj\omega} - \overline{\kappa}^{min}_{sj\omega} = 0 \qquad \forall s, \forall j, \forall \omega \tag{5.94}$$

$$\partial\mathcal{L}_s/\partial\kappa^{max}_{j\omega} = \quad W^{RT}_{j\omega}\widehat{\lambda}^{DT}_s + \widehat{\psi}^{\,sp}_{sj\omega} - \overline{\kappa}^{max}_{sj\omega} = 0 \qquad \forall s, \forall j, \forall \omega \tag{5.95}$$

$$\partial\mathcal{L}_s/\partial\nu^{min}_{d\omega} = \quad -\widehat{\psi}^{\,sh}_{sd\omega} - \overline{\nu}^{min}_{sd\omega} = 0 \qquad \forall s, \forall d, \forall \omega \tag{5.96}$$

$$\partial\mathcal{L}_s/\partial\nu^{max}_{d\omega} = \quad \widehat{\psi}^{\,sh}_{sd\omega} - \overline{\nu}^{max}_{sd\omega} = 0 \qquad \forall s, \forall d, \forall \omega \tag{5.97}$$

$$\partial\mathcal{L}_s/\partial\xi^{min}_{nm} = \quad T^{MAX}_{nm}\widehat{\lambda}^{DT}_s - B_{nm}\big(\widehat{\psi}^{o}_{sn} - \widehat{\psi}^{o}_{sm}\big) - \overline{\xi}^{min}_{snm} = 0 \qquad \forall s, \forall n, \forall m \tag{5.98}$$

$$\partial\mathcal{L}_s/\partial\xi^{max}_{nm} = \quad T^{MAX}_{nm}\widehat{\lambda}^{DT}_s + B_{nm}\big(\widehat{\psi}^{o}_{sn} - \widehat{\psi}^{o}_{sm}\big) - \overline{\xi}^{max}_{snm} = 0 \qquad \forall s, \forall n, \forall m \tag{5.99}$$

$$\partial\mathcal{L}_s/\partial\xi^{min}_{nm\omega} = \quad T^{MAX}_{nm}\widehat{\lambda}^{DT}_s - B_{nm}\big(\widehat{\psi}_{sn\omega} - \widehat{\psi}_{sm\omega}\big) - \overline{\xi}^{min}_{snm\omega} = 0 \qquad \forall s, \forall n, \forall m, \forall \omega \tag{5.100}$$

$$\partial\mathcal{L}_s/\partial\xi^{max}_{nm\omega} = \quad T^{MAX}_{nm}\widehat{\lambda}^{DT}_s + B_{nm}\big(\widehat{\psi}_{sn\omega} - \widehat{\psi}_{sm\omega}\big) - \overline{\xi}^{max}_{snm\omega} = 0 \qquad \forall s, \forall n, \forall m, \forall \omega \tag{5.101}$$

$$\partial\mathcal{L}_s/\partial\rho^{min}_{n} = \quad \pi\widehat{\lambda}^{DT}_s - \widehat{\psi}^{o}_{sn} - \overline{\rho}^{min}_{sn} = 0 \qquad \forall s, \forall n \tag{5.102}$$

$$\partial\mathcal{L}_s/\partial\rho^{max}_{n} = \quad \pi\widehat{\lambda}^{DT}_s + \widehat{\psi}^{o}_{sn} - \overline{\rho}^{max}_{sn} = 0 \qquad \forall s, \forall n \tag{5.103}$$

$$\partial\mathcal{L}_s/\partial\rho^{min}_{n\omega} = \quad \pi\widehat{\lambda}^{DT}_s - \widehat{\psi}_{sn\omega} - \overline{\rho}^{min}_{sn\omega} = 0 \qquad \forall s, \forall n, \forall \omega \tag{5.104}$$

$$\partial\mathcal{L}_s/\partial\rho^{max}_{n\omega} = \quad \pi\widehat{\lambda}^{DT}_s + \widehat{\psi}^{o}_{sn\omega} - \overline{\rho}^{max}_{sn\omega} = 0 \qquad \forall s, \forall n, \forall \omega \tag{5.105}$$

$$\partial\mathcal{L}_s/\partial\phi^{o}_{(n1)} = \quad \widehat{\psi}^{o}_{s(n1)} = 0 \qquad \forall s \tag{5.106}$$

$$\partial\mathcal{L}_s/\partial\phi_{(n1)\omega} = \quad \widehat{\psi}_{s(n1)\omega} = 0 \qquad \forall s, \forall \omega \tag{5.107}$$

$$0 \le O^{DA}_{i(b1)} \perp \widehat{o}^{\,p}_{si(b1)} \ge 0 \qquad \forall s, \forall i \in I^S \tag{5.108}$$

$$0 \le O^{DA}_{ib} - O^{DA}_{i(b-1)} \perp \widehat{o}^{\,p}_{sib} \ge 0 \qquad \forall s, \forall i \in I^S, \forall b \ge b2 \tag{5.109}$$

$$0 \le O^{DA}_{j(f1)} \perp \widehat{o}^{\,w}_{sj(f1)} \ge 0 \qquad \forall s, \forall j \in J^S \tag{5.110}$$

$$0 \le O^{DA}_{jf} - O^{DA}_{j(f-1)} \perp \widehat{o}^{\,w}_{sjf} \ge 0 \qquad \forall s, \forall j \in J^S, \forall f \ge f2 \tag{5.111}$$

$$0 \le O^{up}_{i} \perp \widehat{o}^{\,up}_{si} \ge 0 \qquad \forall s, \forall i \in I^S \tag{5.112}$$

$$0 \le O^{down}_{i} \perp \widehat{o}^{\,down}_{si} \ge 0 \qquad \forall s, \forall i \in I^S \tag{5.113}$$

$$0 \le O^{RT}_{j} \perp \widehat{o}^{\,rt}_{sj} \ge 0 \qquad \forall s, \forall j \in J^S \tag{5.114}$$

$$0 \le P^{DA}_{ib} \perp \widehat{\alpha}^{min}_{sib} \ge 0 \qquad \forall s, \forall i \in I^S, \forall b \tag{5.115}$$

$$0 \leq P_{ib}^{MAX} - P_{ib}^{DA} \perp \widehat{\alpha}_{sib}^{max} \geq 0 \qquad \forall s, \forall i \in I^S, \forall b \tag{5.116}$$

$$0 \leq W_{jf}^{DA} \perp \widehat{\beta}_{sjf}^{min} \geq 0 \qquad \forall s, \forall j \in J^S, \forall f \tag{5.117}$$

$$0 \leq W_{jf}^{MAX} - W_{jf}^{DA} \perp \widehat{\beta}_{sjf}^{max} \geq 0 \qquad \forall s, \forall j \in J^S, \forall f \tag{5.118}$$

$$0 \leq L_{dk}^{DA} \perp \widehat{\gamma}_{sdk}^{min} \geq 0 \qquad \forall s, \forall d, \forall k \tag{5.119}$$

$$0 \leq L_{dk}^{MAX} - L_{dk}^{DA} \perp \widehat{\gamma}_{sdk}^{max} \geq 0 \qquad \forall s, \forall d, \forall k \tag{5.120}$$

$$0 \leq r_{i\omega}^{up} \perp \widehat{\epsilon}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i \in I^S, \forall \omega \tag{5.121}$$

$$0 \leq RES_i^{UP} - r_{i\omega}^{up} \perp \widehat{\epsilon}_{si\omega}^{max} \geq 0 \qquad \forall i \in I^S, \forall \omega \tag{5.122}$$

$$0 \leq r_{i\omega}^{down} \perp \widehat{\theta}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i \in I^S, \forall \omega \tag{5.123}$$

$$0 \leq RES_i^{DOWN} - r_{i\omega}^{down} \perp \widehat{\theta}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall i \in I^S, \forall \omega \tag{5.124}$$

$$0 \leq \sum_b P_{ib}^{MAX} - \sum_b P_{ib}^{DA} - r_{i\omega}^{up} \perp \widehat{\mu}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall i \in I^S, \forall \omega \tag{5.125}$$

$$0 \leq \sum_b P_{ib}^{DA} - r_{i\omega}^{down} \perp \widehat{\mu}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i \in I^S, \forall \omega \tag{5.126}$$

$$0 \leq W_{j\omega}^{sp} \perp \widehat{\kappa}_{sj\omega}^{min} \geq 0 \qquad \forall s, \forall j \in J^S, \forall \omega \tag{5.127}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \perp \widehat{\kappa}_{sj\omega}^{max} \geq 0 \qquad \forall s, \forall j \in J^S, \forall \omega \tag{5.128}$$

$$0 \leq L_{d\omega}^{sh} \perp \widehat{\nu}_{sd\omega}^{min} \geq 0 \qquad \forall s, \forall d, \forall \omega \tag{5.129}$$

$$0 \leq \sum_k L_{dk}^{DA} - L_{d\omega}^{sh} \perp \widehat{\nu}_{sd\omega}^{max} \geq 0 \qquad \forall s, \forall d, \forall \omega \tag{5.130}$$

$$0 \leq B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \perp \widehat{\xi}_{snm}^{min} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{5.131}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \perp \widehat{\xi}_{snm}^{max} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{5.132}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \perp \widehat{\xi}_{snm\omega}^{min} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_m \forall \omega \tag{5.133}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \perp \widehat{\xi}_{snm\omega}^{max} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_m \forall \omega \tag{5.134}$$

$$0 \leq \delta_n^o + \pi \perp \widehat{\rho}_{sn}^{min} \geq 0 \qquad \forall s, \forall n \tag{5.135}$$

$$0 \leq \pi - \delta_n^o \perp \widehat{\rho}_{sn}^{max} \geq 0 \qquad \forall s, \forall n \tag{5.136}$$

$$0 \leq \delta_{n\omega} + \pi \perp \widehat{\rho}_{sn\omega}^{min} \geq 0 \qquad \forall s, \forall n, \forall \omega \tag{5.137}$$

$$0 \leq \pi - \delta_{n\omega} \perp \widehat{\rho}_{sn\omega}^{max} \geq 0 \qquad \forall s, \forall n, \forall \omega \tag{5.138}$$

$$0 \leq \alpha_{ib}^{min} \perp \overline{\alpha}_{sib}^{min} \geq 0 \qquad \forall s, \forall i, \forall b \tag{5.139}$$

$$0 \leq \alpha_{ib}^{max} \perp \overline{\alpha}_{sib}^{max} \geq 0 \qquad \forall s, \forall i, \forall b \tag{5.140}$$

$$0 \leq \beta_{jf}^{min} \perp \overline{\beta}_{sjf}^{min} \geq 0 \qquad \forall s, \forall j, \forall f \tag{5.141}$$

$$0 \leq \beta_{jf}^{max} \perp \overline{\beta}_{sjf}^{max} \geq 0 \qquad \forall s, \forall j, \forall f \tag{5.142}$$

$$0 \leq \gamma_{dk}^{min} \perp \overline{\gamma}_{sdk}^{min} \geq 0 \qquad \forall s, \forall d, \forall k \tag{5.143}$$

$$0 \leq \gamma_{dk}^{max} \perp \overline{\gamma}_{sdk}^{max} \geq 0 \qquad \forall s, \forall d, \forall k \tag{5.144}$$

$$0 \leq \epsilon_{i\omega}^{min} \perp \overline{\epsilon}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.145}$$

$$0 \leq \epsilon_{i\omega}^{max} \perp \overline{\epsilon}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.146}$$

$$0 \leq \theta_{i\omega}^{min} \perp \overline{\theta}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.147}$$

$$0 \leq \theta_{i\omega}^{max} \perp \overline{\theta}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.148}$$

$$0 \leq \mu_{i\omega}^{min} \perp \overline{\mu}_{si\omega}^{min} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.149}$$

$$0 \leq \mu_{i\omega}^{max} \perp \overline{\mu}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall i, \forall \omega \tag{5.150}$$

$$0 \leq \kappa_{j\omega}^{min} \perp \overline{\kappa}_{sj\omega}^{min} \geq 0 \qquad \forall s, \forall j, \forall \omega \tag{5.151}$$

$$0 \leq \kappa_{i\omega}^{max} \perp \overline{\kappa}_{si\omega}^{max} \geq 0 \qquad \forall s, \forall j, \forall \omega \tag{5.152}$$

$$0 \leq \nu_{d\omega}^{min} \perp \overline{\nu}_{sd\omega}^{min} \geq 0 \qquad \forall s, \forall d, \forall \omega \tag{5.153}$$

$$0 \leq \nu_{d\omega}^{max} \perp \overline{\nu}_{sd\omega}^{max} \geq 0 \qquad \forall s, \forall d, \forall \omega \tag{5.154}$$

$$0 \leq \xi_{nm}^{min} \perp \overline{\xi}_{snm}^{min} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_n \tag{5.155}$$

$$0 \leq \xi_{nm}^{max} \perp \overline{\xi}_{snm}^{max} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_n \tag{5.156}$$

$$0 \leq \xi_{nm\omega}^{min} \perp \overline{\xi}_{snm\omega}^{min} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_n, \forall \omega \tag{5.157}$$

$$0 \leq \xi_{nm\omega}^{max} \perp \overline{\xi}_{snm\omega}^{max} \geq 0 \qquad \forall s, \forall n, \forall m \in \Theta_n, \forall \omega \tag{5.158}$$

$$0 \leq \rho_{n}^{min} \perp \overline{\rho}_{sn}^{min} \geq 0 \qquad \forall s, \forall n \tag{5.159}$$

$$0 \leq \rho_{nm}^{max} \perp \overline{\rho}_{sn}^{max} \geq 0 \qquad \forall s, \forall n \tag{5.160}$$

$$0 \leq \rho_{n\omega}^{min} \perp \overline{\rho}_{sn\omega}^{min} \geq 0 \qquad \forall s, \forall n, \forall \omega \tag{5.161}$$

$$0 \leq \rho_{nm\omega}^{max} \perp \overline{\rho}_{sn\omega}^{max} \geq 0 \qquad \forall s, \forall n, \forall \omega \tag{5.162}$$

Considering the constraint (5.58), constraints (5.19),(5.20),(5.34) and (5.35) correspond to primal equalities, constraint (5.36) enforces the strong duality theorem equality while constraints (5.37)−(5.45) correspond to dual equalities. Constraints (5.59)−(5.107) are the

KKT equality conditions which correspond to the first order partial derivatives of the Lagrangian function L_s of the MPEC model with respect to its prime variables (which are the prime and dual variables of the bi-level model). Finally, constraints (5.108)-(5.162) are the KKT complementarity conditions of the MPEC model.

5.2.5 EPEC linearization

The constructed EPEC's constraints include non-linearities which stem from:

i) The non-linear terms $O_{ib}^{DA}P_{ib}^{DA}$, $O_{jf}^{DA}W_{jf}^{DA}$, $O_i^{up}r_{i\omega}^{up}$, $O_i^{down}r_{i\omega}^{down}$, $O_j^{RT}W_{jf}^{DA}$ and $O_j^{RT}W_{j\omega}^{sp}$ in equality (5.36).

ii) The complementarity conditions (5.108)−(5.162).

iii) The products of the dual variable $\widehat{\lambda}_s^{DT}$ of the strong duality theorem equality with several variables in equalities (5.59)−(5.69) and (5.71)−(5.76).

The non-linear terms of case (i) are eliminated by substituting the strong duality theorem equality (5.36), which derives from the primal-dual formulation, with the equivalent KKT complementarity conditions of the bi-level model's lower-level problem. The aforementioned complementarity constraints are the products of the lower-level model inequalities with their corresponding dual variables as shown below:

$$0 \leq P_{ib}^{DA} \perp \alpha_{ib}^{min} \geq 0 \qquad \forall i, \forall b \tag{5.163}$$

$$0 \leq P_{ib}^{MAX} - P_{ib}^{DA} \perp \alpha_{ib}^{max} \geq 0 \qquad \forall i, \forall b \tag{5.164}$$

$$0 \leq W_{jf}^{DA} \perp \beta_{jf}^{min} \geq 0 \qquad \forall j, \forall f \tag{5.165}$$

$$0 \leq W_{jf}^{MAX} - W_{jf}^{DA} \perp \beta_{jf}^{max} \geq 0 \qquad \forall j, \forall f \tag{5.166}$$

$$0 \leq L_{dk}^{DA} \perp \gamma_{dk}^{min} \geq 0 \qquad \forall d, \forall k \tag{5.167}$$

$$0 \leq L_{dk}^{MAX} - L_{dk}^{DA} \perp \gamma_{dk}^{max} \geq 0 \qquad \forall d, \forall k \tag{5.168}$$

$$0 \leq r_{i\omega}^{up} \perp \epsilon_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{5.169}$$

$$0 \leq RES_i^{UP} - r_{i\omega}^{up} \perp \epsilon_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{5.170}$$

$$0 \leq r_{i\omega}^{down} \perp \theta_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{5.170}$$

$$0 \leq RES_i^{DOWN} - r_{i\omega}^{down} \perp \theta_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{5.171}$$

$$0 \leq \sum_b P_{ib}^{MAX} - \sum_b P_{ib}^{DA} - r_{i\omega}^{up} \perp \mu_{i\omega}^{max} \geq 0 \qquad \forall i, \forall \omega \tag{5.172}$$

$$0 \leq \sum_b P_{ib}^{DA} - r_{i\omega}^{down} \perp \mu_{i\omega}^{min} \geq 0 \qquad \forall i, \forall \omega \tag{5.173}$$

$$0 \leq W_{j\omega}^{sp} \perp \kappa_{j\omega}^{min} \geq 0 \qquad \forall j, \forall \omega \tag{5.174}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \perp \kappa_{j\omega}^{max} \geq 0 \qquad \forall j, \forall \omega \tag{5.175}$$

$$0 \leq L_{d\omega}^{sh} \perp \nu_{d\omega}^{min} \geq 0 \qquad \forall d, \forall \omega \tag{5.176}$$

$$0 \leq \sum_k L_{dk}^{DA} - L_{d\omega}^{sh} \perp \nu_{d\omega}^{max} \geq 0 \qquad \forall d, \forall \omega \tag{5.177}$$

$$0 \leq B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \perp \xi_{nm}^{min} \geq 0 \qquad \forall n, \forall m \in \Theta_m \tag{5.178}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \perp \xi_{nm}^{max} \geq 0 \qquad \forall n, \forall m \in \Theta_m \tag{5.179}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \perp \xi_{nm\omega}^{min} \geq 0 \qquad \forall n, \forall m \in \Theta_m \forall \omega \tag{5.180}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \perp \xi_{nm\omega}^{max} \geq 0 \qquad \forall n, \forall m \in \Theta_m \forall \omega \tag{5.181}$$

$$0 \leq \delta_n^o + \pi \perp \rho_n^{min} \geq 0 \qquad \forall n \tag{5.182}$$

$$0 \leq \pi - \delta_n^o \perp \rho_n^{max} \geq 0 \qquad \forall n \tag{5.183}$$

$$0 \leq \delta_{n\omega} + \pi \perp \rho_{n\omega}^{min} \geq 0 \qquad \forall n, \forall \omega \tag{5.184}$$

$$0 \leq \pi - \delta_{n\omega} \perp \rho_{n\omega}^{max} \geq 0 \qquad \forall n, \forall \omega \tag{5.185}$$

The complementarity constraints (5.108)−(5.162) of case (ii) and the complementarity constrains (5.163) − (5.185) can be substituted with equivalent linear disjunctive constrains of the general form (Fortuny-Amat and McCarl, 1981):

$$0 \leq g(x), \quad 0 \leq \mu, \quad g(x) \leq M^p z, \quad \mu \leq M^v(1-z) \tag{5.186}$$

where M^p and M^v are constants related to prime and dual variables respectively and $z \in \{0, 1\}$ is a binary variable. The full deployment of the EPEC's linear disjunctive constraints

is presented in Appendix A.3. The calculation method of constants is similar to this followed in sections 3.2.4 and 4.2.4 and discussed in detail in section 6. Finally, the non-linearities of case (iii) are eliminated by parameterizing the dual variable $\widehat{\lambda}_s^{DT}$ which is common to all non-linear terms. Moreover, the fact that the variable is unique for each producer s renders its parameterization the most appropriate to define effortlessly the feasible region of the problem (Ruiz at al., 2012).

5.2.6 Market equilibria

The constraints of the EPEC model (74)−(123) and (125) have a mixed-integer linear form; however, the latter keeps all the EPEC's characteristics and can therefore derive multiple solutions. To explore different equilibria, the following problem structure is proposed:

$$\begin{aligned} \Pi(\widehat{\lambda}_s^{DT}): \quad & \underset{\Xi \cup \Xi^O \cup \Xi^D \cup \Xi^{D'}}{maximize} && objective\ function \\ & subjected\ to && (5.58)-(5.107),\ (A.3.1)-(A.3.158) \end{aligned} \tag{5.187}$$

Where $\Xi^{D'}$ is the set of dual variables of the MPEC model. The problem $\Pi(\widehat{\lambda}_s^{DT})$ is parameterized in $\widehat{\lambda}_s^{DT}$ and it can receive several objective functions which define the properties of each contextual equilibrium. In this analysis two objective functions are considered. The first represents the total expected profits (TEP) of all producers:

$$\begin{aligned} \text{TEP} = \quad & \sum_{(i\in I_n)b} \lambda_n^{DA} P_{ib}^{DA} - \sum_{ib} c_{ib} P_{ib}^{DA} + \sum_{(j\in J_n)f} \lambda_n^{DA} W_{jf}^{DA} \\ & + \sum_{(i\in I_n)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} - \sum_{i\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} \\ & - \sum_{(i\in I_n)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} + \sum_{i\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\ & + \sum_{(j\in J_n)\omega} \lambda_{n\omega}^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \end{aligned} \tag{5.188}$$

The aforementioned objective function is non-linear due to the products of the market clearing prices λ_n^{DA} and $\lambda_{n\omega}^{RT}$ (dual variables) with the relative power generation (prime variables). The non-linearities can be eliminated by using the strong duality theorem equality (5.36), the MPEC's equality conditions (5.37), (5.38), (5.40), (5.41), (5.42), and the lower-level problem's complementarity conditions (5.163) − (5.166) and (5.169) − (5.175) and following the process presented in Appendix A.4. Thus, the objective function (5.188) is reduced to an equivalent linear one with the following form:

$$\begin{aligned}
\text{TEP} = \quad & \sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{ib} c_{ib} P_{ib}^{DA} \\
& - \sum_{i\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{i\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} - \sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{RT} \\
& - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} - \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} \\
& - \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max}\right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max}\right) \\
& - \sum_{n} \pi \left(\rho_n^{min} + \rho_n^{max}\right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max}\right)
\end{aligned} \tag{5.189}$$

rendering the non-linear $\Pi(\widehat{\lambda}_s^{DT})$ problem into an MILP problem.

The second objective function represents the total expected social welfare (TESW) of the market and has the form:

$$\begin{aligned}
\text{TESW} = \quad & \sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{ib} c_{ib} P_{ib}^{DA} - \sum_{i\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} \\
& + \sum_{i\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh}
\end{aligned} \tag{5.190}$$

It must be noted that function (5.190) expresses the real total expected social welfare in contrast to function (5.9) as now the producers offer at their marginal cost (wind generation is cost free) instead of their strategic offers $O_{ib}^{DA}, O_{jf}^{DA}, O_i^{up}, O_i^{down}$ and O_j^{RT}.

5.3 2-bus system case

5.3.1 System data

The proposed algorithm is applied in a two-bus system illustrated in Figure 5.2. The conventional unit $i1$ and the wind unit $j1$ belong to the producer $s1$ and the units $i2$ and $j2$ belong to the producer $s2$. Technical data for the conventional units i are provided on Table 5.1. Columns 2 to 5 indicate the two energy blocks offered by each unit and their respective marginal costs. The next two columns indicate limitations in upward and downward reserves, and the last two columns contain the reserve deployment costs respectively.

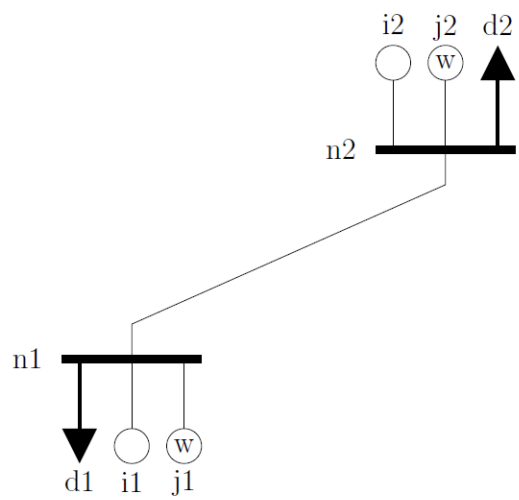

Figure 5.2: 2-bus system

Table 5.1: Data for the conventional generating units

units	$P_{i,b1}^{MAX}$ $[MWh]$	$P_{i,b2}^{MAX}$ $[MWh]$	$c_{i,b1}$ $[€/MWh]$	$c_{i,b2}$ $[€/MWh]$	RES_i^{UP} $[MW]$	RES_i^{DOWN} $[MW]$	c_i^{up} $[€/MWh]$	c_i^{down} $[€/MWh]$
$i1$	25	25	17	21	25	25	21.5	16.5
$i2$	25	25	19	23	25	25	23.5	18.5

Table 5.2: Demand energy blocks and utility costs

demand	$L_{d,k1}^{MAX}$ $[MWh]$	$L_{d,k2}^{MAX}$ $[MWh]$	$u_{d,k1}$ $[€/MWh]$	$u_{d,k2}$ $[€/MWh]$
$d1$	40	20	22	19
$d2$	40	20	25	20

The two wind units j are similar, and each one has installed capacity 10 MWh which is offered in one energy block. Their uncertain production is realized through two wind scenarios $\omega 1$ (high production) 10 MWh, and $\omega 2$ (low production) 2.5 MWh with occurrence probability 50% each. The system has also two demands $d1$ and $d2$. The demand blocks and their respective utility costs are presented in Table 5.2. Finally, the value of lost load is 200 €/MWh for both demands and the line transmission capacity is 100 MW with a susceptance 9.142 per unit.

5.3.2 Uncongested network

Based on the above information, we examine four types of equilibrium. The first type considers perfect competition (competitive equilibrium) where all the producers offer at their marginal cost. The second one corresponds to a monopolistic market (monopoly equilibrium). In this case, all the generating units belong to one producer and the results are obtained by solving the MPEC model. The third and fourth types represent equilibria derived by the EPEC model setting the values of $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$ equal to 3 arbitrarily. The former solves the EPEC opting the (5.190) as objective function maximizing the total expected social welfare (TESW equilibrium), and the latter solves the EPEC using the

Table 5.3: Day-ahead and real-time market clearing prices [€/MWh] in uncongested network

	λ_{n1}^{DA}	λ_{n2}^{DA}	$\frac{\lambda_{n1,\omega1}^{RT}}{\pi_{\omega1}}$	$\frac{\lambda_{n1,\omega2}^{RT}}{\pi_{\omega2}}$	$\frac{\lambda_{n2,\omega1}^{RT}}{\pi_{\omega1}}$	$\frac{\lambda_{n2,\omega2}^{RT}}{\pi_{\omega2}}$
perfect competition	21	21	18.5	21.5	18.5	21.5
monopoly	25	25	0	50	0	50
TESW maximization	22	22	0	44	0	44
TEP maximization	25	25	0	50	0	50

Table 5.4: Energy, reserves and consumption [MWh] in uncongested network

	$P_{i1,b}^{DA}$	$W_{j1,f}^{DA}$	$P_{i2,b}^{DA}$	$W_{j2,f}^{DA}$	$L_{d1,k}^{DA}$	$L_{d2,k}^{DA}$	$r_{i1,\omega2}^{up}$	$r_{i1,\omega1}^{down}$	$r_{i2,\omega2}^{up}$	$r_{i2,\omega1}^{down}$
perfect competition	25;10	10	25;0	10	40;0	40;0	15	0	0	0
monopoly	25;0	0	10;0	5	0;0	40;0	0	5	0	10
TESW maximization	25;10	10	25;0	10	40;0	40;0	15	0	0	0
TEP maximization	25;0	0	10;0	5	0;0	40;0	0	5	0	10

Table 5.5: Expected profits [€] in uncongested network

	$i1$	$j1$	$i2$	$j2$	$s1$	$s2$	Total
perfect competition	103.75	129.38	50.00	129.37	233.13	179.37	412.50
monopoly	242.50	62.50	155.00	62.50	305.00	217.50	522.50
TESW maximization	307.50	55.00	75.00	55.00	362.50	130.00	492.50
TEP maximization	242.50	62.50	155.00	62.50	305.00	217.50	522.50

(5.189) as objective function maximizing the total expected profits of all producers (TEP equilibrium). Table 5.3 depicts the configuration of the DA and RT market clearing prices.

As expected under exercise of capacity withholdings in monopoly and TEP equilibrium, the market exhibits the highest prices. It should be noted that the price of these equilibria coincide. At the same time, the market prices in TESW equilibrium are quite lower than those in monopoly and TEP but higher than those in competitive market. Considering energy production as shown in Table 5.4, under TESW equilibrium, the producers cover demand of 80 MW similar to that in perfect competition. However, exercising financial withholdings, they raise the DA price at 1 €/MWh increasing the total profits in DA market. In addition, in low wind scenario $\omega 2$ the total scheduled wind generation of 20 MWh in DA market creates a need of 15 MWh upward reserve to balance the system which is now paid at 44 €/MWh increasing the total expected profits compared to those of competitive equilibrium as shown in Table 5.5. On the other hand, in monopoly and TEP cases the producers acting identically restrict the DA production meeting only 40 MWh of demand at the price of 25 €/MWh. Additionally, in high wind scenario $\omega 1$, the low scheduled wind generation of 5 MWh results in a surplus of 15 MWh. However, the producers are called to pay for their downward reserve deployments at zero price . As a result, the total expected profits reach the highest level of 522.5 €.

5.3.3 Searching for market equilibria

Scanning the feasible region of the EPEC for probable equilibria the variable $\widehat{\lambda}_s^{DT}$ is parameterized from 0.1 to 3 for both producers $s1$ and $s2$. It should be noted that $\widehat{\lambda}_s^{DT}$ is positive considering the constrains (5.104), (5.105), (5.159) and (5.160). Figure 5.3 presents the EPEC results maximizing the TEP objective function. It can be seen that there are four subsets of $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$ which correspond to four market equilibria. In equilibria (a), (b) and (c) the producers cover a demand of 40 MWh; however, they follow different

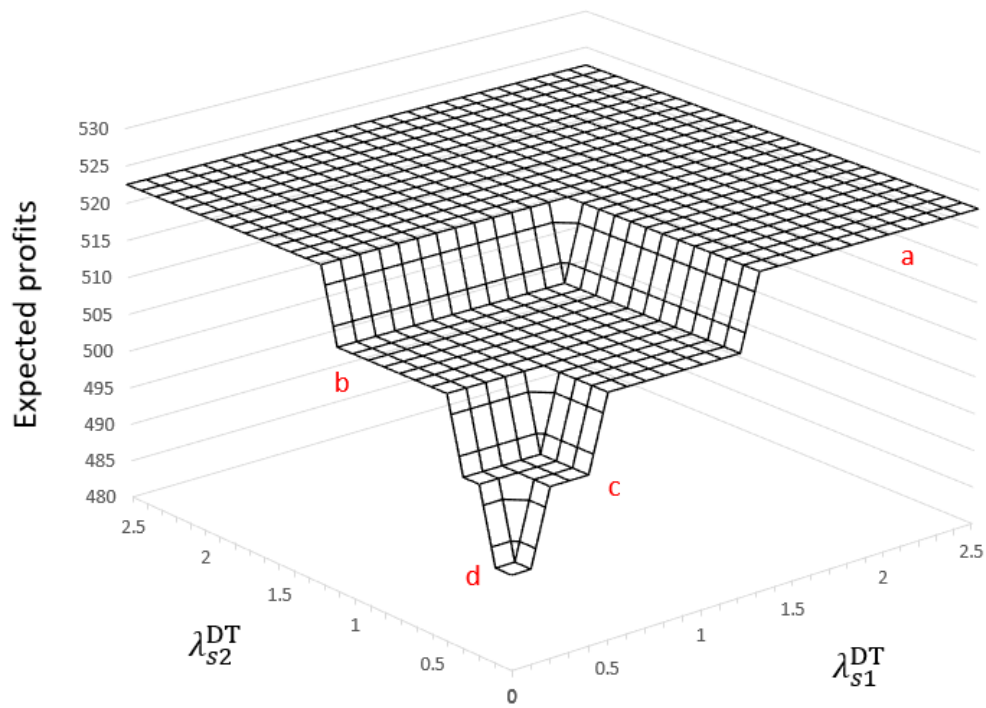

Figure 5.3: Total expected profits as a function of $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$

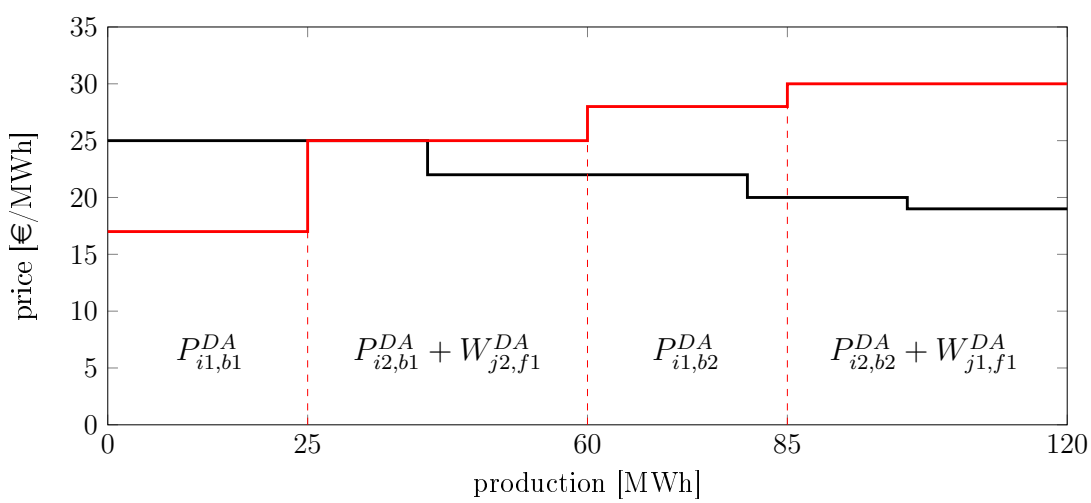

Figure 5.4: Offer curve for (a) equilibrium [$\widehat{\lambda}_{s1}^{DT} = \widehat{\lambda}_{s2}^{DT} = 2.5$]

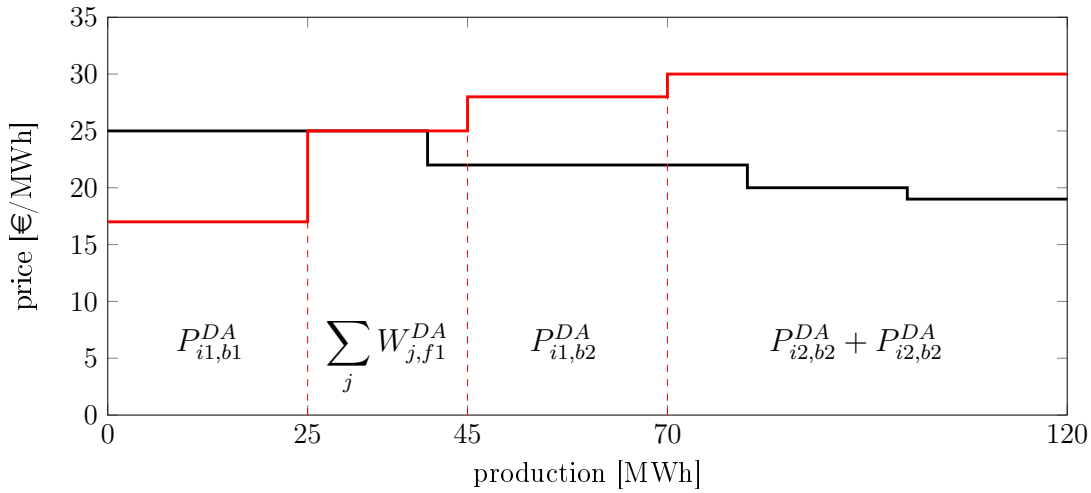

Figure 5.5: Offer curve for (a) equilibrium [$\widehat{\lambda}^{DT}_{s1} = \widehat{\lambda}^{DT}_{s2} = 0.5$]

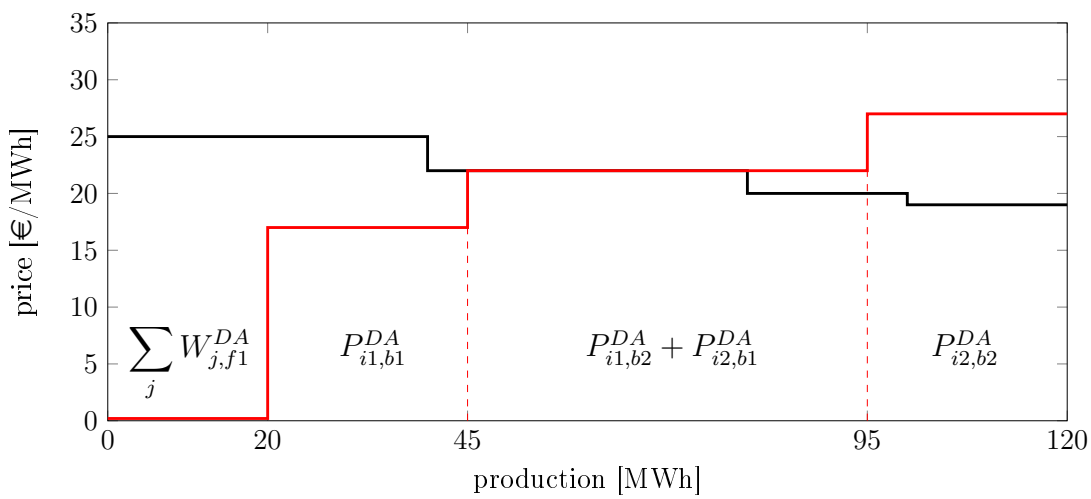

Figure 5.6: Offer curve for (d) equilibrium [$\widehat{\lambda}^{DT}_{s1} = \widehat{\lambda}^{DT}_{s2} = 0.2$]

offering strategies. In equilibrium (a) at DA market as shown in Figure 5.4, producer $s1$ offers the first conventional energy block at marginal cost ensuring the total dispatch of the block and withholds any further production by offering at a price higher than the utility cost of $L^{MAX}_{d2,k1}$. Producer $s2$ covers the rest of the demand block by offering its first conventional and wind energy block at a price equal to utility cost 25 €/MWh defining actually the DA

market price. In equilibrium (c) the producers shape the DA price by offering their wind energy at 25 €/MWh while the producer $s2$ withholds the production of unit $i2$ completely as depicted in Figure 5.5. On the other hand, in equilibrium (d) the producers cover a demand of 80 MWh. In this case, they do not exercise any market power with their wind units whose scheduled generation is offered at zero price; therefore, it is fully dispatched. Finally, the DA market price is formed by the increased offers of the second conventional block of producer $s1$ and the first block of producer $s2$ at the price of 22 €/MWh covering the bid of the $L_{d1,k1}^{MAX}$ demand block as shown in Figure 5.6.

5.3.4 Congested network

Keeping $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$ equal to 3 the line capacity is reduced to 10 MW. In this case under perfect competition and TESW maximization the line still facilitates the energy transmission, and the buses show DA and RT prices similar to those of uncongested network. However, under monopoly and TEP maximization the system becomes congested, and LMPs emerge as presented in Table 5.6. The TEP equilibrium leads the producers to change the mixture of their production covering 65 MWh of demand. As illustrated in Table 5.7, they recognize

Table 5.6: Day-ahead and real-time market clearing prices [€/MWh] in congested network

	λ_{n1}^{DA}	λ_{n2}^{DA}	$\frac{\lambda_{n1,\omega1}^{RT}}{\pi_{\omega1}}$	$\frac{\lambda_{n1,\omega2}^{RT}}{\pi_{\omega2}}$	$\frac{\lambda_{n2,\omega1}^{RT}}{\pi_{\omega1}}$	$\frac{\lambda_{n2,\omega2}^{RT}}{\pi_{\omega2}}$
perfect competition	21	21	18.5	21.5	18.5	21.5
monopoly	22	25	0	44	0	50
TESW maximization	22	22	0	44	0	44
TEP maximization	22	25	0	44	0	50

Table 5.7: Energy, reserves and consumption [MWh] in congested network

	$P^{DA}_{i1,b}$	$W^{DA}_{j1,f}$	$P^{DA}_{i2,b}$	$W^{DA}_{j2,f}$	$L^{DA}_{d1,k}$	$L^{DA}_{d2,k}$	$r^{up}_{i1,\omega 2}$	$r^{down}_{i1,\omega 1}$	$r^{up}_{i2,\omega 2}$	$r^{down}_{i2,\omega 1}$
perfect competition	25;10	10	25;0	10	40;0	40;0	15	0	0	0
monopoly	25;0	5	25;0	10	25;0	40;0	7.5	0	2.5	5
TESW maximization	25;10	10	25;0	10	40;0	40;0	15	0	0	0
TEP maximization	25;0	5	25;0	10	25;0	40;0	7.5	0	2.5	5

Table 5.8: Expected profits [€] in congested network

	$i1$	$j1$	$i2$	$j2$	$s1$	$s2$	Total
perfect competition	103.75	129.38	50.00	129.37	233.13	179.37	412.50
monopoly	211.25	55.00	223.75	62.50	266.25	286.25	552.50
TESW maximization	307.50	55.00	75.00	55.00	362.50	130.00	492.50
TEP maximization	211.25	55.00	223.75	62.50	266.25	286.25	552.50

a further arbitrage opportunity and increase the scheduled wind energy from 5 to 15 MWh compared to uncongested case. Thus, under low wind scenario $\omega 1$ they deploy a total $7.5 + 2.5 = 10$ MWh of upward reserves at price of 50 €/MWh raising their total expected profits at the highest of 552.5 €as shown in Table 5.8. Finally, it should also be noted that once again monopoly and TEP equilibria results coincide.

5.3.5 Justifying market equilibria

The results derived from the EPEC solution do not always constitute Nash equilibrium points as they can be either local maxima or saddle points. Considering game theory, in Nash equilibrium no producer can benefit by changing its actual strategy unilaterally; consequently, an EPEC solution is Nash equilibrium if the received values of set Ξ^O (producers' offering variables) and set Ξ (ISO's decision variables) maximize simultaneously each pro-

ducer's expected profits under system economic dispatch. Therefore, to verify if an obtained solution is equilibrium or not, the below single-iteration diagonalization process is followed. Receiving the EPEC solution for specific $\widehat{\lambda}_s^{DT}$ the results for the producer $s1$ are set fixed and used to solve the MPEC for the producer $s2$. If the EPEC and MPEC results for the producer $s2$ coincide, then the EPEC solution determines a Nash equilibrium.

5.4 6-bus system case

5.4.1 6-bus system data

The proposed EPEC model is also applied to a 6-bus system as depicted in section 3.4.1 Figure 3.2. The system accommodates eight conventional units i two wind power units j and four demands d. Table 5.9 presents technical data for the conventional units.

Table 5.9: Data for conventional generating units

units		$i1$	$i2$	$i3$	$i4$	$i5$	$i6$	$i7$	$i8$
capacity	$[MW]$	155	100	155	197	350	197	197	155
$P_{i,b1}^{MAX}$	$[MWh]$	54.25	25	54.25	68.95	140	68.95	68.95	54.25
$P_{i,b2}^{MAX}$	$[MWh]$	38.75	25	38.75	49.25	97.50	49.25	49.25	38.75
$P_{i,b3}^{MAX}$	$[MWh]$	31	20	31	39.4	52.50	39.4	39.4	31
$P_{i,b4}^{MAX}$	$[MWh]$	31	20	31	39.4	70	39.4	39.4	31
$c_{i,b1}$	$[€/MWh]$	9.92	18.60	9.92	11.09	19.20	10.08	10.08	11.46
$c_{i,b2}$	$[€/MWh]$	10.25	20.03	10.25	11.42	20.32	10.66	10.66	11.96
$c_{i,b3}$	$[€/MWh]$	10.68	21.67	10.68	16.06	21.22	11.09	11.09	13.89
$c_{i,b4}$	$[€/MWh]$	11.26	22.72	11.26	16.24	22.13	11.72	11.72	15.97
RES_i^{UP}	$[MW]$	0	100	10	40	90	20	20	40
RES_i^{DOWN}	$[MW]$	0	100	10	40	90	20	20	40
c_i^{up}	$[€/MWh]$	11.76	23.22	11.76	16.74	23.63	12.22	12.22	16.47
c_i^{down}	$[€/MWh]$	9.42	18.10	9.42	10.59	18.70	9.58	9.58	10.21

Table 5.10: Distribution and data for demand

demands		$d1$	$d2$	$d3$	$d4$
factor	[%]	19	27	27	27
$L_{d,k1}^{MAX}$	$[MWh]$	171	243	243	243
$L_{d,k2}^{MAX}$	$[MWh]$	4.75	6.75	6.75	6.75
$L_{d,k3}^{MAX}$	$[MWh]$	4.75	6.75	6.75	6.75
$L_{d,k4}^{MAX}$	$[MWh]$	4.75	6.75	6.75	6.75
$L_{d,k5}^{MAX}$	$[MWh]$	4.75	6.75	6.75	6.75
$u_{d,k1}$	[€$/MWh$]	19.922	22.628	22.628	25.000
$u_{d,k2}$	[€$/MWh$]	19.532	20.876	20.876	24.968
$u_{d,k3}$	[€$/MWh$]	19.232	20.606	20.606	22.628
$u_{d,k4}$	[€$/MWh$]	18.932	20.378	20.378	20.876
$u_{d,k5}$	[€$/MWh$]	18.806	19.922	19.922	20.606

The first two rows refer to units and their power capacities. The next eight rows refer to the offered energy blocks and their respective marginal costs. The last four rows provide the units' upward and downward generating capacities and their respective deployment costs. It can be seen that, units $i1$, $i3$, $i6$ and $i7$ are cheap with limited reserve flexibility, units $i4$ and $i8$ are cheap with relative reserve flexibility, and units $i2$ and $i5$ are expensive but with high flexibility. The two wind power units $j1$ and $j2$ are located at bus $n2$ and $n5$ with installed capacity 150 MW and 100 MW, and their scheduled production is offered in one block. The units' stochastic generation is modeled through three scenarios, $\omega 1$ (high) with 150 and 100 MWh, $\omega 2$ (medium) with 75 and 50 MWh, and $\omega 3$ (low) with 30 and 20 MWh and occurrence probability 0.2, 0.5 and 0.3 respectively. A total demand of 1 GWh is shared among the buses as presented in Table 5.10. Each demand is bid by five energy blocks (rows from 3 to 7) at their respective utility costs (rows from 8 to 12) with a value of lost load equal to 200 €/MWh for all demands.It should be pointed out that the demand bidding prices in the right area of the system are higher than those in the left area; therefore, power is expected to flow from left to right. Finally, all circuit lines have a transmission capacity of 500 MW with susceptance 9.412 per unit.

5.4.2 Uncongested network

Two strategic producers are considered in a duopoly market. Units units $i1 - i4$ and $j1$ belong to producers $s1$ and units $i5 - i8$ and $j2$ belong to producer $s2$. For the purpose of this study, the values of $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$ are set equal to 2.5. We examine equilibria under cost optimization (competitive market), TESW and TEP maximization. The outcomes for DA and RT market clearing prices, scheduled production, and expected profits are presented in Table 5.11, Table 5.12 and Table 5.13 respectively.

Table 5.11: Day-ahead and real-time market clearing prices [€/MWh] in uncongested network

	λ_n^{DA}	$\frac{\lambda_{n,\omega1}^{RT}}{\pi_{\omega1}}$	$\frac{\lambda_{n,\omega2}^{RT}}{\pi_{\omega2}}$	$\frac{\lambda_{n,\omega3}^{RT}}{\pi_{\omega3}}$
competitive	12.673	9.260	11.760	16.470
TESW max.	18.806	3.510	22.630	22.630
TEP max.	22.628	0	28.285	28.285

Table 5.12: Scheduled conventional and wind production [MWh] in uncongested network

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	155	0	149.8	118.2	30	0	177	177	93	100	453	547	1,000
TESW max.	155	0	149.8	118.2	30	0	177	177	93	100	453	547	1,000
TEP max.	155	0	93	0	73.5	0	0	197	124	100	321.5	421	742.5

Table 5.13: Expected profits [€] in uncongested network

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	349	0	352	182	867	0	391	391	116	578	1,751	1,475	3,226
TESW max.	1,299	0	1,303	956	1,158	0	1,536	1,536	796	772	4,716	4,640	9,356
TEP max.	1,892	0	1,325	220	1,315	60	265	2,380	1,496	876	4,752	5,077	9,829

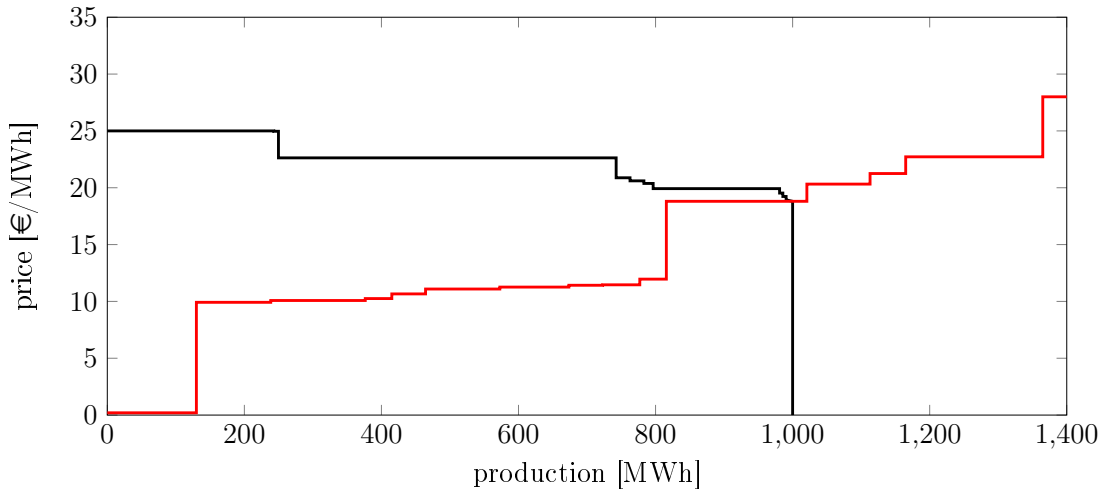

Figure 5.7: Day-ahead cumulative offer curve in TESW equilibrium

Table 5.14: Covered demand [MWh] in uncongested network

	$d1$	$d2$	$d3$	$d4$	Total
competitive	190	270	270	270	1,000
TESW max.	190	270	270	270	1,000
TEP max.	0	243	243	256.5	742.5

In competitive and TESW equilibria the scheduled production is identical covering the 100% of the demand. Nevertheless, in TESW equilibrium the producers are paid at higher prices. As can be seen at Figure 5.7, the cumulative offer curve meets the demand at the price of 18.806 €/MWh, which coincides with the $u_{d1,k5}$, the lowest bid demand energy block. Thus, the total expected profits increase compared to competitive equilibrium. On the other hand, as expected, in TEP equilibrium market price configurations and total expected profits are higher than those in competitive and TESW equilibria. As shown in Table 5.14, the producers meet the 74.25 % of the total demand avoiding coverage of energy blocks of demand $d1$ which are bid at low prices. Figure 5.8 depicts the DA cumulative offer curve

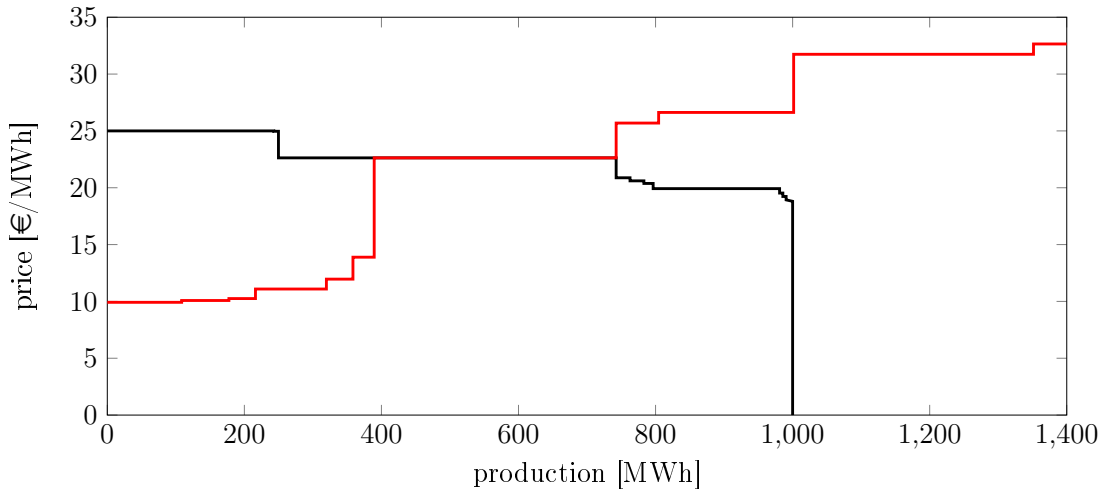

Figure 5.8: Day-ahead cumulative offer curve in TEP equilibrium

in TEP equilibrium. This way, producers cover high offered demand with low cost units as now the medium cost units $i4$ and $i6$ are not scheduled for DA production. However, the latter are involved in provision of upward reserves at the high price of 28.285 €/MWh raising the producers' profits as the increased scheduled production of wind unit $j1$ now creates a further need for positive regulation in medium and low wind scenarios.

5.4.3 Congested network

In uncongested network, the maximum power flow from bus $n3$ to bus $n6$ is 271.56 MW. The line capacity is now reduced at the level of 200 MW. In this case, the system becomes congested leading to different LMP's in all equilibria. As seen in Table 5.15, in competitive and TESW equilibria the producers change the mixture of production covering again all the demand. However, in competitive equilibria, the congested network introduces a more intense competition on the left area of the system, where the generation prevails, resulting in left area average DA market price, as illustrated in Table 5.16, lower than the uniform price 18.806 €/MWh of uncongested case. Thus, even though the generating units $i4$, $i8$ and $j2$, located at the right area, sell at a higher price there is a decrease in the total expected profits of producers as shown in Table 5.17. On the contrary, in TESW equilibrium the congested

Table 5.15: Scheduled production [MWh] with line $3-6$ capacity limited to 200 MW

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	155	0	123.23	131.57	71	0	177	118.2	124	100	480.8	519.2	1,000
TESW max.	155	0	123.23	131.57	71	0	177	118.2	124	100	480.8	519.2	1,000
TEP max.	124	0	54.25	157.55	150	0	118.2	177	0	100	485.8	395.2	881

Table 5.16: Left and right area average DA prices [€/MWh] with line $3-6$capacity limited to 200 MW

	left area average λ_n^{DA}	right area average λ_n^{DA}
competitive	11.448	15.292
TESW max.	18.992	19.922
TEP max.	20.373	22.628

Table 5.17: Expected profits [€] with line $3-6$ capacity limited to 200 MW

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	159	0	67	606	850	0	305	58	404	707	1,682	1,474	3,156
TESW max.	1,328	0	1,090	1,287	1,269	0	1,662	1,065	1,053	861	4,974	4,641	9,615
TEP max.	1,260	12	596	1,820	1,707	0	1,425	1,786	232	1,125	5,395	4,568	9,963

Table 5.18: Covered demand [MWh] with line $3-6$ capacity limited to 200 MW

	$d1$	$d2$	$d3$	$d4$	Total
competitive	190	270	270	270	1,000
TESW max.	190	270	270	270	1,000
TEP max.	155	243	233.25	249.75	881

Table 5.19: Scheduled production [MWh] with line $3-6$ capacity limited to 50 MW

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	155	25	54.25	157	54	0	177	25.75	124	100	445.25	426.75	872
TESW max.	155	0	54.25	157	85	0	177	25.75	124	86	451.25	412.75	864
TEP max.	155	0	0	157	85	57	177	0	93	95	397	422	819

Table 5.20: Expected profits [€] with line $3-6$ capacity limited to 50 MW

	$i1$	$i2$	$i3$	$i4$	$j1$	$i5$	$i6$	$i7$	$i8$	$j2$	$s1$	$s2$	total
competitive	217	27	19	2,311	881	0	718	16	1,539	853	3,455	3,126	6,581
TESW max.	325	0	108	2,216	735	0	824	161	1,400	994	3,384	3,379	6,763
TEP max.	1,542	0	91	2,001	1,446	261	1,995	175	1,243	910	5,080	4,584	9,664

Table 5.21: Covered demand [MWh] with line $3-6$ capacity limited to 50 MW

	$d1$	$d2$	$d3$	$d4$	Total
competitive	190	256	176.25	249.75	872
TESW max.	190	256	168.25	249.75	864
TEP max.	159.25	243	167	249.75	819

line works profitably for the producers as both left and right area average DA market prices are raised compared to uncongested equilibrium increasing slightly the producers' expected profits. Considering the TEP equilibrium, the producers rearrange the scheduled production covering also part of the demand $d1$ as seen in Table 5.18. Hence the increased conventional production in combination with the scheduled over-production of wind unit $j1$, which creates need for more expensive regulation at balancing stage, keeps the total expected profits at high-rise level despite the fact that the formed market prices are lower compared to the

uncongested case. Table 5.19, Table 5.20 and Table 5.21 provide energy and expected profit results when the line $3-6$ capacity is further limited to 50 MW. It can be seen that contrary to the previous case, TESW and TEP equilibria become less profitable. The line bottleneck prevents the cheap energy produced in the left area from being transmitted to the right. Therefore, less demand is covered in the right, and even if units $i4$ and $i8$ are more involved in scheduled production showing the highest earnings in all cases, the total expected profits of producers drop. Nevertheless, as in all previous cases, the TESW equilibrium profits remain higher than those of competitive equilibrium and less than those of TEP one.

5.4.4 Impact of wind generation increment on TEP equilibrium

To study the effect of the wind power penetration on the TEP equilibrium and the expected profits of generating units we consider only the wind unit $j1$ at bus $n2$ and set again the values of $\widehat{\lambda}_{s1}^{DT}$ and $\widehat{\lambda}_{s2}^{DT}$ equal to 2.5. It should be reminded that $i7$ is a low cost unit with limited reserve flexibility while $i4$ and $i8$ are more expensive units but with increased reserve flexibility. The capacity of the wind unit increases gradually from 5% to 30% of the total installed capacity. The uncertain generation at each level of penetration is modeled through three scenarios which correspond to 100%, 50% and 30% of wind unit's capacity with probability occurrence 0.3, 0.5 and 0.2 respectively.

Figure 5.9 presents the scheduled wind unit production in DA market and the expected wind power spillage. It can be seen that, scheduled wind production increases steadily as more wind power is integrated into the system. Up to 12.5% of wind penetration spillage is zero as the system can offer reserves sufficiently. However, as the wind penetration rises further the system becomes inadequate to provide the appropriate balance regulation, thereby increasing the wind spillage. As a result, there is a drop in wind power absorption depicted by the decline of the scheduled production curve gradient just after the 20% of wind penetration. This reflects also on wind unit's expected profits. As shown in Figure 5.10, the profits increase gradually, however, they show a stagnation beyond the 25% of wind penetration increment.

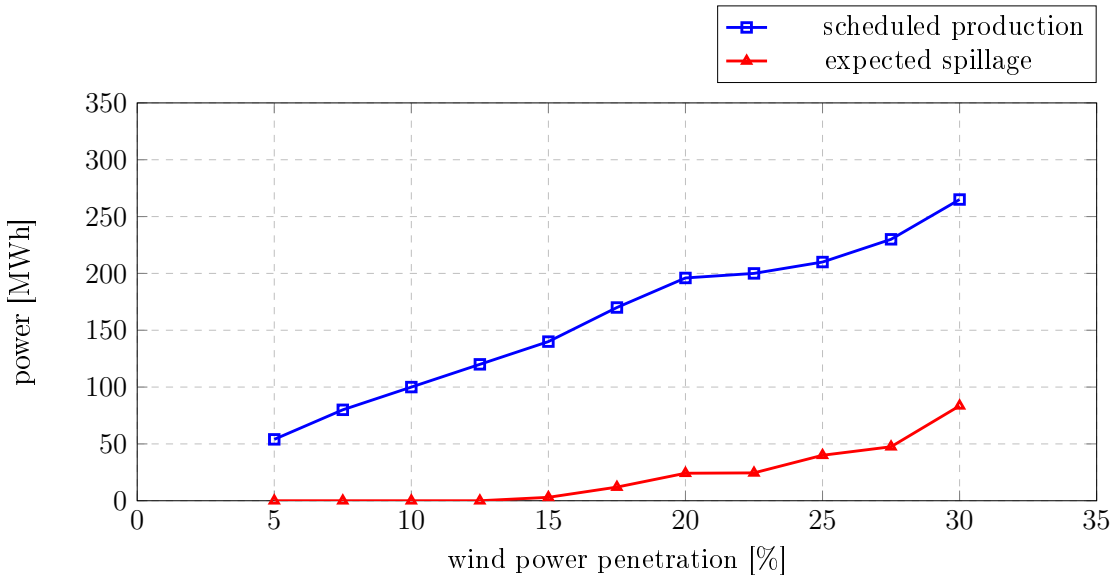

Figure 5.9: Scheduled wind production and expected spillage [MWh]

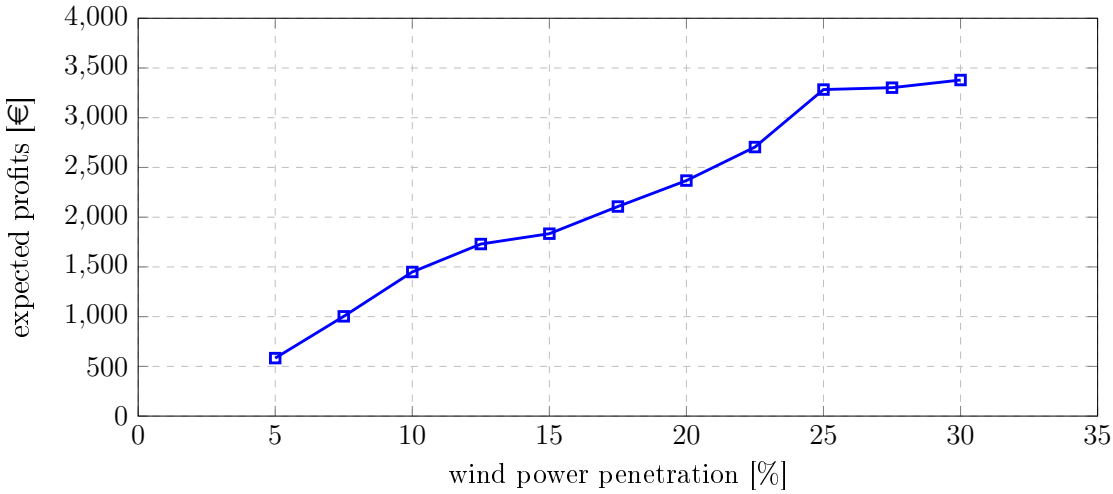

Figure 5.10: Expected profits of wind unit $j1$ [€]

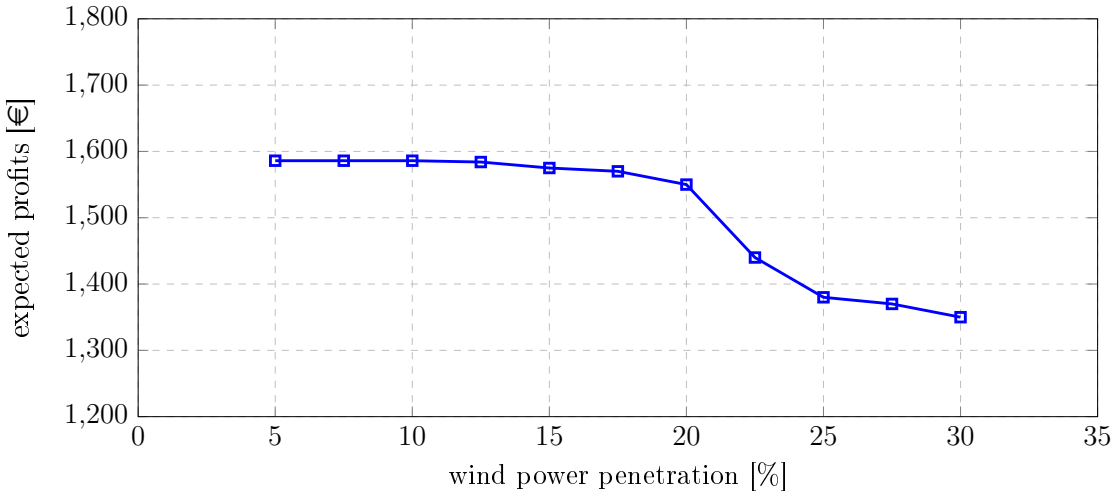

Figure 5.11: Expected profits of unit $i7$ [€]

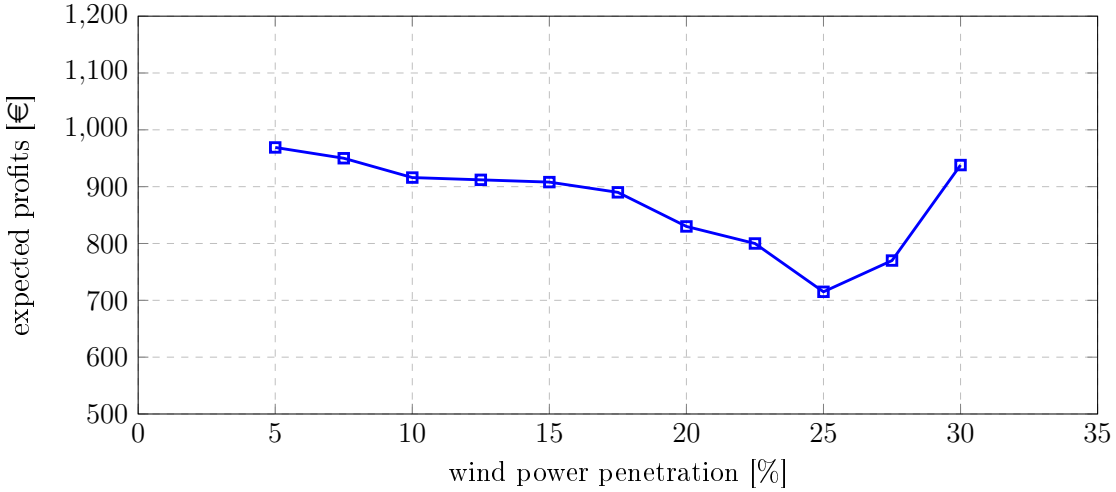

Figure 5.12: Expected profits of unit $i4$ [€]

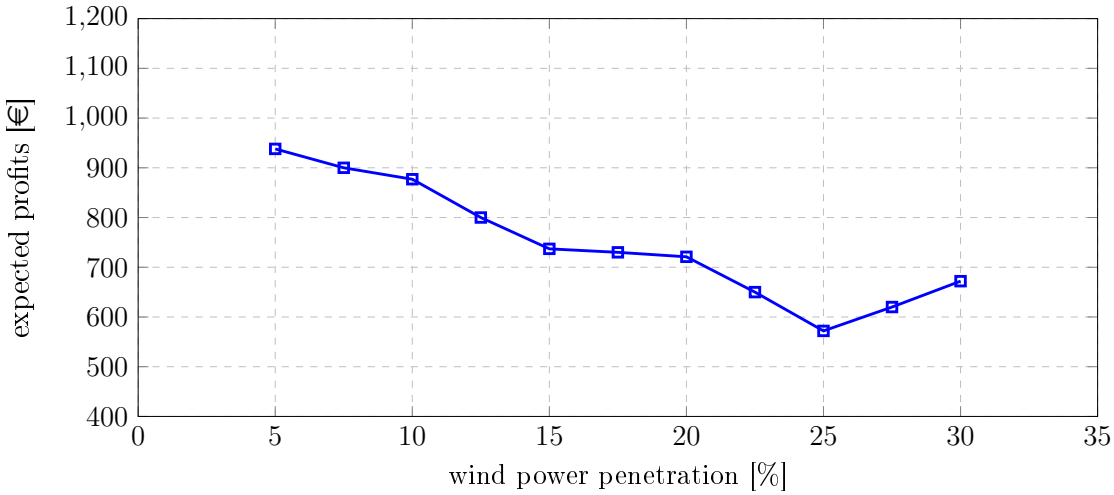

Figure 5.13: Expected profits of unit $i8$ [€]

Considering the conventional unit $i7$, the expected profits shown in Figure 5.11 remain initially stable as the wind power penetration displaces high cost generation. Nevertheless, as the penetration continues to increase, the unit starts to lose business exhibiting a gradual drop in earnings. On the other hand, as presented in Figure 5.12 and Figure 5.13, units $i4$ and $i8$ follow a different pattern. The units are more expensive; thus, their scheduled production reduces from the very low level of wind power integration, leading to a constant fall in expected profits. However, as the need for reserves increase with the increase of wind penetration, the units become more involved in reserve supply, recovering part of their lost expected profits.

5.5 Impact of wind generation volatility on TEP equilibrium

To investigate how the wind generation volatility affects the TEP equilibrium results, we consider the previous market settlement of the subsection 5.4.4. The capacity of wind unit $j1$ is now 350 MW corresponding to a 19% of wind power penetration. The expected wind power production is 190 MW with three gradually increasing values of expected standard deviation σ equal to 34.641, 59.431 and 87.187 MW respectively.

Table 5.22: Wind generation volatility impact on TEP equilibrium

	$\sigma = 34.641$	$\sigma = 59.431$	$\sigma = 87.178$
expected wind spillage [MWh]	0	3.27	26.46
wind unit's total expected profits [€]	3,450	2,859	2,751
conventional units' total expected profits [€]	6,658	7,486	7,928
producers' total expected profits [€]	10,118	10,345	10,679

The EPEC outcomes are presented in Table 5.22. It can be seen that, as the volatility increases, the expected wind power spillage increases as well, resulting in a continuous loss of wind unit's expected profits. On the contrary, the unstable wind production gives advantage to conventional units as the increased demand for conventional scheduled energy and reserves expands their expected profits. Finally, the continuous increase of wind generation volatility results also in constant raise of all producers' total expected profits, leading gradually in costlier equilibria.

5.6 Computational issues

The final MILP model has been solved using CPLEX 12.5.1/GAMS 24.1.3 on an Intel Core i7 at 2.7 GHz and 16 GB RAM. Contrary to the MPEC models in Chapters 3 and 4

where the GAMS option OptCR is set 0 in the case of EPEC the OptCR is set 0.1. Thus, actually the relative optimality criterion asking CPLEX to stop when:

$$\frac{(|BP - BF|)}{(1.0e - 10 + |BF|)} < 0.1 \tag{5.191}$$

Where BP determines the best possible integer solution and BF expresses the objective function value of the best integer solution found so far (Rosenthal, 2018). Table 5.23 presents the computational (CPU) time needed at each case. The CPU time increases with the complexity of the network and the objective function as the TEP objective function is more time demanding compared to the TESW one. The CPU time also increases with congestion as well as with larger number of wind scenarios. However, the computational burden is lower compared to Dai and Qiao (2017) since the proposed algorithm does not use any multi-iteration diagonalization process.

Table 5.23: CPU time [sec]

	2-bus system			6-bus system		
	uncongested	congested	12 scenarios	uncongested	congested	12 scenarios
TESW max.	0.195	0.576	0.335	1.800	11.897	63.990
TEP max.	0.368	0.678	2.891	4.720	30.530	4,520.574

Finally, the process for the calculation of the constants M associated with the disjunctive constraints used for the linearization of the proposed EPEC is similar to the process presented in section 3.6.

5.7 Conclusions

This Chapter provides an EPEC model to derive meaningful equilibria in a pool-based market with high penetration of wind power. Initially an MPEC is constructed to explicitly model the strategic behavior of each producer. The MPEC optimizes jointly energy dispatch and reserve procurements through a two-stage stochastic programming. The MPEC generates endogenously LMPs as dual variables associated to the energy balance equalities at DA and RT stage. The algorithm also uses stepwise supply and demand offer functions and considers only wind generation uncertainty. The simultaneous solution of all MPECs formulates an EPEC model. The latter is recast into an equivalent parametrized MILP whose selected objective function determines the characteristics of the derived equilibria. Scanning the results in an ex-post analysis, a single-iteration process is used to justify meaningful equilibria. The received results show that the higher the collusion between producers, the higher the market clearing prices and the higher the expected profits even though the production is lower. The results also show that the producers change the mixture of their production to retain or even increase their expected profits in cases of congested network. In case of wind power increment a slice of the earnings is transferred to wind power producers. However, if the system is not reserve sufficient, part of wind generation may spillage slowing down the expected profit growth of wind power producers. On the contrary, conventional units show losses in profits due to their reduced production volume even if reserve flexible units could retrieve part of them. Finally, high wind generation volatility is less profitable for wind power units as portion of their generation may not be absorbed, thereby increasing dispatch energy and reserves, and as result the expected profits of the conventional units.

Chapter 6

Conclusion and future research

The integration of large scale renewable power generation has brought a paradigm shift in the electricity system operation. The stochastic nature of RES has led the conventional units to run intermittently, increasing their operational cost. In addition, the merit-order effect (prioritization of RES) lowers the market prices and displaces the more expensive conventional units. In the above context, this thesis addresses the price-making behavior of a power producer seeking to offset its expected profit losses. The producer participates in a pool-based market which accommodates significant amounts of wind power generation and clears jointly energy and reserves under economic dispatch. For this purpose, two MPEC models are developed to derive optimal offering strategies for a producer with a conventional only as well as a conventional and wind generation portfolios. Finally, an EPEC model is proposed to investigate the interaction between producers who act strategically and to identify meaningful Nash equilibria in the market.

6.1 Conclusions

Considering the strategic behavior of a price maker producer, the relevant conclusions drawn form the application of the proposed MPEC models are enumerated below:

1) Exercising market power, the strategic producer offers part of its conventional capac-

ity at high price increasing the profits from DA market even if the producer curtails dispatch production. In addition, the producer exploits arbitrage opportunities appearing between DA and RT markets and defines the appropriate reserve deployments to balance the system. This way, the producer has the ability to arrange dispatch and balancing procurements through the coupling between DA and RT stage maximizing its total expected profits.

2) When the strategic producer exercises market power with wind generation portfolio as well, then it recognizes a new arbitrage opportunity. Therefore, the producer proceeds to a further withholding of conventional dispatch and gives space for more DA wind power dispatch anticipating an increase in upward reserve supply at even higher prices. As a result, even if wind power generation profits show a decline, the producer's total expected profits increase.

3) Capacity limits of transmission lines can be used by the strategic producer as a tool to maintain or further increase its expected profits. Thus, there are lines that the strategic producer congests by changing the mixture of its production. This way, LMPs appear at system's buses. Some LMPs are higher than the uncongested network uniform price, thereby increasing the producer's total expected profits. On the other hand, congested lines, which incur losses for the strategic producer, can be rendered uncongested keeping the expected earnings stable.

4) Having a conventional and wind generation portfolio, the strategic producer can take advantage of a probable increment in wind power installed capacity rearranging the mixture of scheduled production and raising the expected profits even in case of wind power production spillages.

Considering the interaction between strategic producers, the results of the EPEC models show that:

5) The lower the degree of competition in the market the higher the prices and the higher

the expected profits. Actually, under maximization of all producers' expected profits the EPEC results coincide with the those of a monopoly.

6) In congested networks, the producers behaving strategically cover more demand with lower prices at some buses compared to uncongested networks, thereby retaining or even increasing their total expected profits.

7) In case of wind power increment, a slice of the earnings is transferred to wind power producers. However, if the system is not reserve sufficient, part of wind generation may spillage slowing down the expected profit growth of wind power producers. On the contrary, conventional units show losses in profits due to their reduced production volume even if reserve flexible units could retrieve part of them.

8) High wind generation volatility is less profitable for wind power units since portion of their generation may not be absorbed, thereby increasing dispatch energy and reserves, and eventually the expected profits of the conventional units.

6.2 Contributions

The main contributions of the thesis are summarized below:

1) In Chapter 3 a stochastic bi-level model is developed to derive optimal offering strategies for an incumbent producer with conventional generation portfolio. The upper-level problem maximizes the expected profits of the aforementioned producer and the lower-level problem minimizes the operational cost of the system.

2) In Chapter 4 the bi-level model is extended considering a strategic producer with conventional and wind generation portfolio.

3) Supply and demand offers are modeled by using linear stepwise curves, and the uncertainty of wind production is realized through a set of plausible wind power production scenarios.

4) The market clearing mechanism is network-constrained, thereby growing the computational abilities of the models.
5) A premium is imposed on generation cost offers in RT markets to reward the producers for balancing the system, thereby aligning further the models with energy-only markets and preventing market clearing multiple solutions.
6) Both bi-level models are efficiently recast into MPEC models by replacing the lower-level problem with its KKT optimality conditions. Following this the KKT complementarity conditions are replaced by linear disjunctive constraints, thereby reforming the MPECs into equivalent MILPs solvable in global optimality by commercial solvers.
7) The objective functions of the MPECs are linearized without any approximations avoiding the introduction of extra binary variables. This way, the proposed algorithms reduce their computational burden rendering more sophisticated networks tractable.
8) Best offering strategies can be developed for the DA market based on the derived scheduled energy dispatch and reserve deployments as well as on the endogenously produced DA and RT market clearing prices. The prices are received as dual variables of their respective energy balance constraints.
9) In Chapter 5, an EPEC model is introduced to find Nash equilibria among price-making producers participating with conventional and wind generation portfolios in a pool market.
10) The EPEC is based on the joint solution of all strategic producers' MPECs which are constructed with a primal-dual formulation to reduce the mathematical and computational load of the algorithm.
11) Diverse objective functions are applied to the EPEC considering the degree of competition in the market to find alternative Nash equilibria.
12) The two MPEC models are illustrated with a 6-bus system, and the analysis is performed taking into consideration wind uncertainty, transmission line congestions, and different levels of wind power penetration. The MPECs are also applied to the more

realistic one-area (24-bus) RTS system to show their applicability.

13) The EPEC model is illustrated in two case studies: 2-bus and 6-bus systems. Since the EPEC identifies stationary points which could be either Nash equilibria, saddle points, or local minima, a single-iteration diagonalization process is used in an ex-post analysis to justify whether the received solution constitutes Nash equilibrium or not.

This thesis also led to three published articles in JCR (Thomson Reuters) journals and one article under publication listed below:

1) Tsimopoulos, E. G., & Georgiadis, M. C. (2019). Strategic offers in day-ahead market co-optimizing energy and reserve under high penetration of wind power production: An MPEC approach. *AIChE Journal*, 65(7), e16495
2) Tsimopoulos, E. G., & Georgiadis, M. C. (2019). Optimal strategic offerings for a conventional producer in jointly cleared energy and balancing markets under high penetration of wind power production. *Applied Energy*, 244, 16-35.
3) Tsimopoulos, E. G., & Georgiadis, M. C. (2020). Withholding strategies for a conventional and wind generation portfolio in a joint energy and reserve pool market: A gaming-based approach. *Computers & Chemical Engineering*, 134, 106692.
4) Tsimopoulos, E. G., & Georgiadis, M. C. (2020). Nash equilibria in electricity pool markets with large scale of wind power integration: An EPEC approach. *European Journal of Operational Research*(under publication).

In addition, parts of this work have been included in international conference proceedings as follows:

1) Tsimopoulos, E. G., & Georgiadis, M. C. (2019). An MPEC model for Strategic Offers in a Jointly Cleared Energy and Reserve Market under Stochastic Production. In *Computer Aided Chemical Engineering* (Vol. 46, pp. 1633-1638). Elsevier.

2) Tsimopoulos, E. G., & Georgiadis, M. C. (2020). Wind and Thermal Generation Portfolio: Optimal strategies in Energy-only Pool Markets under Wind Production Uncertainty. In *Computer Aided Chemical Engineering*. Elsevier. in press

6.3 Recommendations for future research

Exertion of market power is inherently hard to prove whereas the continuous growth of stochastic generation makes this effort much more complicated. The extensions of the proposed models considering the strategic offering problem could be numerous; however, the most notable are summarized below as an entreaty for further research.

1) One drawback of the stochastic bi-level modelling refers to the employment of a parsimonious wind generation scenario range. Thus, an adequate representation of wind generation volatility by the usage of greater number of scenarios and relevant reduction techniques is essential for a more accurate evaluation of the strategic producer performance (Dupacová et al., 2000; Morales et al., 2009; Wang et al., 2012).
2) Considering different degrees of risk-avert offering strategies, conditional value at risk (CVAR) can be incorporated into the formulation of the decision-making problem (Kardakos et al., 2015). Furthermore, for optimal solution in a worst-case realization, the proposed models can involve adaptive robust optimization in a max-min-max structure of the problem substituting the wind power generation scenarios with polyhedral generation uncertainty sets and using a Bender's decomposition hyperplane cutter (Conejo et al., 2006; Bertsimas et al., 2011, 2012; Ning and You, 2019).
3) The proposed models could incorporate inter-temporal constraints such as units' ramp-up and ramp-down limitations extending the scope of the algorithms to multi-period auctions (Moiseeva et al., 2014). They could also involve solving methods to deal with non-convexities such as unit minimum power production limitations and unit commitment decisions of start-up and shut-down (Kleniati and Adjiman, 2015).

4) In this thesis, only wind production uncertainty is considered; however, units' production costs and failure rates as well as consumer demand could also be modeled as uncertainties.

5) Finally, within the context of RES integration, future research could focus on the critical role of energy storage as a hedging tools to offset system imbalances. Thus, the proposed models could be extended including storage in the strategic generation portfolio (Shahmohammadi et al., 2018).

Appendices

Appendix A

Linearization of MPEC and EPEC models

This Appendix illustrates the linearization process of the proposed MPEC and EPEC models. More specific, A.1 and A.2 provide the algebraic transformations of the non-linear strategic producer's objective functions for the MPEC models presented in Chapters 3 and 4 respectively. Similarly, A.4 provides the linearization of the EPEC's objective function which considers the total expected profits (TEP) of all strategic producers and it is presented in Chapter 5. The linearizations are attained with the use of some KKT equality constraints and the application of the strong duality equality corresponding to each bi-level model's lower-level problem.

Finally, A.3 presents the formulation of the non-linear KKT complementarity constraints of the EPEC model as linear disjunctive constraints based on the transformation proposed by Fortuny-Amat and McCarl (1981).

A.1 MPEC's objective function (3.4) linearization

To eliminate the nonlinear terms $\lambda_n^{DA} P_{ib}^{DA}$, $\lambda_{n\omega}^{RT} r_{i\omega}^{up}$ and $\lambda_{n\omega}^{RT} r_{i\omega}^{down}$ of MPEC's objective function (3.4), the below process is followed:

for the term $\lambda_n^{DA} P_{ib}^{DA}$, the KKT equality (3.5) results in

$$\lambda_n^{DA} = O_{ib}^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} \qquad \forall i \in I_n^S, \forall b \tag{A.1.1}$$

multiplying by P_{ib}^{DA} gives

$$\begin{aligned}\sum_{(i \in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} = & \sum_{(i \in I_n^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i \in I_n^S)b} \alpha_{ib}^{max} P_{ib}^{DA} - \sum_{(i \in I_n^S)b} \alpha_{ib}^{min} P_{ib}^{DA} \\ & + \sum_{(i \in I_n^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{DA} - \sum_{(i \in I_n^S)b} \left(\sum_{\omega} \mu_{i\omega}^{min} \right) P_{ib}^{DA}\end{aligned} \tag{A.1.2}$$

from the KKT complementarity condition (3.21)

$$\alpha_{ib}^{min} P_{ib}^{DA} = 0 \qquad \forall i, \forall b \quad \Rightarrow \quad \sum_{ib} \alpha_{ib}^{min} P_{ib}^{DA} = 0 \tag{A.1.3}$$

from the KKT complementarity condition (3.22)

$$\alpha_{ib}^{max} P_{ib}^{DA} = \alpha_{ib}^{max} P_{ib}^{MAX} \qquad \forall i, \forall b \quad \Rightarrow \quad \sum_{ib} \alpha_{ib}^{max} P_{ib}^{DA} = \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} \tag{A.1.4}$$

from the KKT complementarity condition (3.31)

$$\begin{aligned}&\mu_{i\omega}^{max} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{max} \sum_{b} P_{ib}^{MAX} - \mu_{i\omega}^{max} r_{i\omega}^{up} \qquad \forall i, \forall \omega \quad \Rightarrow \\ &\sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{DA} = \sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{i\omega} \mu_{i\omega}^{max} r_{ti\omega}^{up}\end{aligned} \tag{A.1.5}$$

from the KKT complementarity condition (3.32)

$$\mu_{i\omega}^{min} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{min} r_{i\omega}^{down} \qquad \forall i, \forall \omega \Rightarrow \sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{min} \right) P_{ib}^{DA} = \sum_{i\omega} \mu_{i\omega}^{min} \rho_{i\omega}^{down} \tag{A.1.6}$$

hence the (A.1.2) becomes

$$\begin{aligned} \sum_{(i \in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} = & \sum_{(i \in I_n^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i \in I_n^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} \\ & + \sum_{(i \in I_n^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{(i \in I_n^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} - \sum_{(i \in I_n^S)\omega} \mu_{i\omega}^{min} \rho_{i\omega}^{down} \end{aligned} \tag{A.1.7}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{up}$, the KKT equality (3.9) produces

$$\lambda_{n\omega}^{RT} = \pi_{\omega} O_i^{up} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} \qquad \forall i \in I_n^S, \forall \omega \tag{A.1.8}$$

multiplying by $r_{i\omega}^{up}$ gives

$$\sum_{(i \in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{(i \in I_n^S)\omega} \pi_{\omega} O_i^{up} r_{i\omega}^{up} + \sum_{(i \in I_n^S)\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} - \sum_{(i \in I_n^S)\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} + \sum_{(i \in I_n^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \tag{A.1.9}$$

from the KKT complementarity condition (3.27)

$$\epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \qquad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \tag{A.1.10}$$

from the KKT complementarity condition (3.28)

$$\epsilon_{i\omega}^{max} RES_i^{UP} = \epsilon_{i\omega}^{max} r_{i\omega}^{up} \qquad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} = \sum_{i\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} \tag{A.1.11}$$

thus the (A.1.9) becomes

$$\sum_{(i \in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{(i \in I_n^S)\omega} \pi_{\omega} O_i^{up} r_{i\omega}^{up} + \sum_{(i \in I_n^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} + \sum_{(i \in I_n^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \tag{A.1.12}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{down}$, the KKT equality (3.11) leads to

$$-\lambda_{n\omega}^{RT} = -\pi_\omega O_i^{down} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} \qquad \forall i \in I_n^S, \forall \omega \tag{A.1.13}$$

multiplying by $r_{i\omega}^{down}$ gives

$$\begin{aligned} -\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} = &-\sum_{(i\in I_n^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{(i\in I_n^S)\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \\ &- \sum_{(i\in I_n^S)\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} + \sum_{(i\in I_n^S)\omega} \mu_{i\omega}^{min} r_{i\omega}^{down} \end{aligned} \tag{A.1.14}$$

from the KKT complementarity condition (3.29)

$$\theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \qquad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \tag{A.1.15}$$

from the KKT complementarity condition (3.30)

$$\theta_{i\omega}^{max} RES_i^{DOWN} = \theta_{i\omega}^{max} r_{i\omega}^{down} \quad \forall i, \forall \omega \Rightarrow \sum_{i\omega} \theta_{i\omega}^{max} RES_i^{DOWN} = \sum_{i\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \tag{A.1.16}$$

thus the (A.1.14) becomes

$$-\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} = -\sum_{(i\in I_n^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{(i\in I_n^S)\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \tag{A.1.17}$$

Using the expressions (A.1.7), (A.1.12) and (A.1.17), the expected profit of strategic producer equation (3.4) is reformed as follows:

$$\begin{aligned} &\sum_{(i\in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i\in I^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} + \sum_{(i\in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} \\ &+ \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} \\ &- \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \end{aligned} \tag{A.1.18}$$

The application of the strong duality theorem to the ISO's optimization problem (3.2)−(3.3), which states that if a problem is convex, the optimal solution of the primal problem can guarantee an optimal and equal solution for the dual problem, results in the following equality:

$$
\begin{aligned}
&\sum_{(i\in I^S)b} O_{ib}^{DA}P_{ib}^{DA} + \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\
&+ \sum_{(i\in I^o)b} c_{ib}P_{ib}^{DA} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&+ \sum_{(j\in J^O)f} c_{jf}^{DA}W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT}\left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp}\right) \\
&- \sum_{dk} u_d L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \qquad = \\
&- \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} \\
&- \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} \\
&- \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{(i\in I^S)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX}\right) \\
&- \sum_{(i\in I^O)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX}\right) - \sum_{j\omega} \kappa_{(j\in J^O)\omega}^{max} W_{j\omega}^{RT} \\
&- \sum_{n(m\in\Theta_n)} T_{nm}^{MAX}\left(\xi_{nm}^{min} + \xi_{nm}^{max}\right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX}\left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max}\right) \\
&- \sum_n \pi\left(\rho_n^{min} + \rho_n^{max}\right) - \sum_{n\omega} \pi\left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max}\right)
\end{aligned}
\tag{A.1.19}
$$

keeping the non-linear terms on the left part of equality the (A.1.19) is rearranged as:

$$
\begin{aligned}
&\sum_{(i\in I^S)b} O_{ib}^{DA}P_{ib}^{DA} + \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} = \\
&- \sum_{(i\in I^O)b} c_{ib}P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&- \sum_{(j\in J^O)f} c_{jf}^{DA}W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT}\left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp}\right) \\
&+ \sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh}
\end{aligned}
$$

$$
\begin{aligned}
&- \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} \\
&- \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} \\
&- \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{(i\in I^S)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX} \right) \\
&- \sum_{(i\in I^O)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX} \right) - \sum_{(j\in J^O)\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
&- \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&- \sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.1.20}
$$

Substituting the non-linear terms $O_{ib}^{DA} P_{ib}^{DA}$, $O_i^{up} r_{i\omega}^{up}$ and $O_i^{down} r_{i\omega}^{down}$ of (A.1.18) for the right part of equality (A.1.20), the non-linear objective function (3.4) of the strategic producer is reduced to the equivalent linear expression:

$$
\begin{aligned}
&- \sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&- \sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&- \sum_{(j\in J^O)f} c_{jf}^{DA} W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
&+ \sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \\
&- \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} \\
&- \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} \\
&- \sum_{(i\in I^O)\omega} \left(\mu_{i\omega}^{max} \sum_b P_{ib}^{MAX} \right) - \sum_{(j\in J^O)\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
&- \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&- \sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.1.21}
$$

A.2 MPEC's objective function (4.4) linearization

To eliminate the nonlinear terms $\lambda_n^{DA} P_{ib}^{DA}$, $\lambda_n^{DA} W_{jf}^{DA}$, $\lambda_{n\omega}^{RT} r_{i\omega}^{up}$, $\lambda_{n\omega}^{RT} r_{i\omega}^{down}$,$\lambda_{n\omega}^{RT} W_{jf}^{DA}$ and $\lambda_{n\omega}^{RT} W_{j\omega}^{sp}$ of objective function (4.4), we follow the process below:

for the term $\lambda_n^{DA} P_{ib}^{DA}$, the KKT equality (4.5) results in

$$\lambda_n^{DA} = O_{ib}^{DA} + \alpha_{ib}^{max} - \alpha_{ib}^{min} + \sum_{\omega} \mu_{i\omega}^{max} - \sum_{\omega} \mu_{i\omega}^{min} \qquad \forall i \in I_n^S, \forall b \tag{A.2.1}$$

multiplying by P_{ib}^{DA} gives

$$\begin{aligned}\sum_{(i \in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} = & \sum_{(i \in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i \in I^S)b} \alpha_{ib}^{max} P_{ib}^{DA} - \sum_{(i \in I^S)b} \alpha_{ib}^{min} P_{ib}^{DA} \\ & + \sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{DA} - \sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{min} \right) P_{ib}^{DA}\end{aligned} \tag{A.2.2}$$

from the KKT complementarity condition (4.23)

$$\alpha_{ib}^{min} P_{ib}^{DA} = 0 \qquad \forall i \in I^S, \forall b \quad \Rightarrow \quad \sum_{(i \in I^S)b} \alpha_{ib}^{min} P_{ib}^{DA} = 0 \tag{A.2.3}$$

from the KKT complementarity condition (4.24)

$$\alpha_{ib}^{max} P_{ib}^{DA} = \alpha_{ib}^{max} P_{ib}^{MAX} \quad \forall i \in I^S, \forall b \quad \Rightarrow \sum_{(i \in I^S)b} \alpha_{ib}^{max} P_{ib}^{DA} = \sum_{(i \in I^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} \tag{A.2.4}$$

from the KKT complementarity condition (4.33)

$$\begin{aligned}&\mu_{i\omega}^{max} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{max} \sum_{b} P_{ib}^{MAX} - \mu_{i\omega}^{max} r_{i\omega}^{up} \qquad \forall i \in I^S, \forall \omega \quad \Rightarrow \\ &\sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{DA} = \sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{(i \in I^S)\omega} \mu_{i\omega}^{max} r_{ti\omega}^{up}\end{aligned} \tag{A.2.5}$$

from the KKT complementarity condition (4.34)

$$\mu_{i\omega}^{min} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{min} r_{i\omega}^{down} \qquad \forall i \in I^S, \forall \omega \quad \Rightarrow$$
$$\sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{min} \right) P_{ib}^{DA} = \sum_{(i \in I^S)\omega} \mu_{i\omega}^{min} \rho_{\omega}^{down} \tag{A.2.6}$$

hence the (A.2.2) becomes

$$\sum_{(i \in I_n^S)b} \lambda_n^{DA} P_{ib}^{DA} = \sum_{(i \in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i \in I^S)b} \alpha_{ib}^{max} P_{ib}^{MAX} + \sum_{(i \in I^S)b} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{(i \in I^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} - \sum_{(i \in I^S)\omega} \mu_{i\omega}^{min} \rho_{i\omega}^{down} \tag{A.2.7}$$

for the terms $\lambda_n^{DA} W_{jf}^{DA}$ and $\lambda_{n\omega}^{RT} W_{jf}^{DA}$, the KKT equality (4.7) results in

$$\lambda_n^{DA} - \sum_{\omega} \lambda_{n\omega}^{RT} = O_{jf}^{DA} - O_j^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} \qquad \forall j \in J_n^S, \forall f \tag{A.2.8}$$

multiplying by W_{jf}^{DA} gives

$$\sum_{(j \in J_n^S)f} \lambda_n^{DA} W_{jf}^{DA} - \sum_{(j \in J_n^S)\omega} \lambda_{n\omega}^{RT} \left(\sum_{f} W_{jf}^{DA} \right) = \sum_{(j \in J^S)f} O_{jf}^{DA} W_{jf}^{DA} - \sum_{(j \in J^S)f} O_j^{RT} W_{jf}^{DA} + \sum_{(j \in J^S)f} \beta_{jf}^{max} W_{jf}^{DA} - \sum_{(j \in J^S)f} \beta_{jf}^{min} W_{jf}^{DA} \tag{A.2.9}$$

from the KKT complementarity condition (4.25)

$$\beta_{jf}^{min} W_{jf}^{DA} = 0 \qquad \forall j \in J^S, \forall f \quad \Rightarrow \quad \sum_{(j \in J^S)f} \beta_{jf}^{min} W_{jf}^{DA} = 0 \tag{A.2.10}$$

from the KKT complementarity condition (4.26)

$$\beta_{jf}^{max} W_{jf}^{DA} = \beta_{jf}^{max} W_{jf}^{MAX} \;\; \forall i \in J^S, \forall f \Rightarrow \sum_{(j \in J^S)f} \beta_{jf}^{max} W_{jf}^{DA} = \sum_{(j \in J^S)f} \beta_{jf}^{max} W_{jf}^{MAX} \tag{A.2.11}$$

hence the (A.2.9) becomes

$$\sum_{(j\in J_n^S)f} \lambda_n^{DA} W_{jf}^{DA} - \sum_{(j\in J_n^S)\omega} \lambda_{n\omega}^{RT} \left(\sum_f W_{jf}^{DA} \right) = \sum_{(j\in J^S)f} O_{jf}^{DA} W_{jf}^{DA} - \sum_{(j\in J^S)f} O_j^{RT} W_{jf}^{DA} + \sum_{(j\in J^S)f} \beta_{jf}^{max} W_{jf}^{MAX} \tag{A.2.12}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{up}$, the KKT equality (4.10) produces

$$\lambda_{n\omega}^{RT} = \pi_\omega O_i^{up} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} \qquad \forall i \in I_n^S, \forall \omega \tag{A.2.13}$$

multiplying by $r_{i\omega}^{up}$ gives

$$\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \tag{A.2.14}$$

from the KKT complementarity condition (4.29)

$$\epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \qquad \forall i \in I^S, \forall \omega \quad \Rightarrow \quad \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \tag{A.2.15}$$

from the KKT complementarity condition (4.30)

$$\epsilon_{i\omega}^{max} RES_i^{UP} = \epsilon_{i\omega}^{max} r_{i\omega}^{up} \quad \forall i \in I^S, \forall \omega \quad \Rightarrow \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} = \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} \tag{A.2.16}$$

thus the (A.2.14) becomes

$$\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} + \sum_{(i\in I^S)\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \tag{A.2.17}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{down}$, the KKT equality (4.13) leads to

$$-\lambda_{n\omega}^{RT} = -\pi_\omega O_i^{down} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} \qquad \forall i \in I_n^S, \forall \omega \tag{A.2.18}$$

multiplying by $r_{i\omega}^{down}$ gives

$$\begin{aligned} -\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} = &-\sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \\ &- \sum_{(i\in I^S)\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \mu_{i\omega}^{min} r_{i\omega}^{down} \end{aligned} \tag{A.2.19}$$

from the KKT complementarity condition (4.31)

$$\theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \qquad \forall i \in I^S, \forall \omega \quad \Rightarrow \quad \sum_{(i\in I^S)\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \tag{A.2.20}$$

from the KKT complementarity condition (4.32)

$$\theta_{i\omega}^{max} RES_i^{DOWN} = \theta_{i\omega}^{max} r_{i\omega}^{down} \quad \forall i \in I^S, \forall \omega \quad \Rightarrow$$

$$\sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} = \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \tag{A.2.21}$$

thus the (A.2.19) becomes

$$-\sum_{(i\in I_n^S)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} = -\sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{(i\in I^S)\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \tag{A.2.22}$$

for the term $\lambda_{n\omega}^{RT} W_{j\omega}^{sp}$, the KKT equality (4.14) results in

$$-\lambda_{n\omega}^{RT} = -\pi_\omega O_j^{RT} + \kappa_{j\omega}^{max} - \kappa_{j\omega}^{min} \qquad \forall j \in J_n^S, \forall \omega \tag{A.2.23}$$

multiplying by $W_{j\omega}^{sp}$ gives

$$-\sum_{(j\in J_n^S)\omega}\lambda_{n\omega}^{RT}W_{j\omega}^{sp}=-\sum_{(j\in J^S)\omega}\pi_\omega O_j^{RT}W_{j\omega}^{sp}+\sum_{(j\in J^S)\omega}\kappa_{j\omega}^{max}W_{j\omega}^{sp}-\sum_{(j\in J^S)\omega}\kappa_{j\omega}^{min}W_{j\omega}^{sp} \tag{A.2.24}$$

from the KKT complementarity condition (4.35)

$$\kappa_{j\omega}^{min}W_{j\omega}^{sp}=0 \qquad \forall j\in J_n^S,\forall\omega \quad \Rightarrow \quad \sum_{(j\in J^S)\omega}\kappa_{j\omega}^{min}W_{j\omega}^{sp}=0 \tag{A.2.25}$$

from the KKT complementarity condition (4.36)

$$\kappa_{j\omega}^{max}W_{j\omega}^{sp}=\kappa_{j\omega}^{max}W_{j\omega}^{RT} \qquad \forall j\in J_n^S,\forall\omega \Rightarrow \sum_{(j\in J^S)\omega}\kappa_{j\omega}^{max}W_{j\omega}^{sp}=\sum_{(j\in J^S)\omega}\kappa_{j\omega}^{max}W_{j\omega}^{RT} \tag{A.2.26}$$

thus the (A.2.24) becomes

$$-\sum_{(j\in J_n^S)\omega}\lambda_{n\omega}^{RT}W_{j\omega}^{sp}=-\sum_{(j\in J^S)\omega}\pi_\omega O_j^{RT}W_{j\omega}^{sp}+\sum_{(j\in J^S)\omega}\kappa_{j\omega}^{max}W_{j\omega}^{RT} \tag{A.2.27}$$

Using the expressions (A.2.7), (A.2.12), (A.2.17), (A.2.22) and (A.2.27) we reformulate the objective function (4.4) as follows:

$$\begin{aligned}
&\sum_{(i\in I^S)b}O_{ib}^{DA}P_{ib}^{DA}+\sum_{(i\in I^S)b}\alpha_{ib}^{max}P_{ib}^{MAX}\\
&+\textstyle\sum_{(i\in I_n^S)\omega}\mu_{i\omega}^{max}\left(\sum_b P_{ib}^{MAX}\right)-\sum_{(i\in I^S)b}c_{ib}P_{ib}^{DA}\\
&\sum_{(j\in J^S),f}O_{jf}^{DA}W_{jf}^{DA}-\sum_{(j\in J^S)f}O_j^{RT}W_{jf}^{DA}+\sum_{(j\in J^S)f}\beta_{jf}^{max}W_{jf}^{MAX}\\
&+\sum_{(i\in I_n^S)\omega}\pi_\omega O_i^{up}r_{i\omega}^{up}+\sum_{(i\in I^S),\omega}\epsilon_{i\omega}^{max}RES_i^{UP}-\sum_{(i\in I^S)\omega}\pi_\omega c_i^{up}r_{i\omega}^{up}\\
&-\sum_{(i\in I_n^S)\omega}\pi_\omega O_i^{down}r_{i\omega}^{down}+\sum_{(i\in I^S)\omega}\theta_{i\omega}^{max}RES_i^{DOWN}+\sum_{(i\in I^S)\omega}\pi_\omega c_i^{down}r_{i\omega}^{down}\\
&+\sum_{(j\in J_n^S)\omega}\lambda_{n\omega}^{RT}W_{j\omega}^{RT}-\sum_{(j\in J^S)\omega}\pi_\omega O_j^{RT}W_{j\omega}^{sp}+\sum_{(j\in J^S)\omega}\kappa_{j\omega}^{max}W_{j\omega}^{RT}
\end{aligned} \tag{A.2.28}$$

According to strong duality theorem if an optimization problem is convex the duality gap

is zero. Thus, the optimal solution of the primal problem is equal to the optimal solution of the dual problem. Applying the strong duality theorem to the lower-level optimization problem (4.2) – (4.3), the following equality is formed:

$$
\begin{aligned}
&\sum_{(i\in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\
&+ \sum_{(j\in J^S)f} O_{jf}^{DA} W_{jf}^{DA} + \sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
&+ \sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&+ \sum_{(j\in J^O)f} c_{jf} W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} \left(W_{j\omega}^{RT} - \sum_f W_{jf}^{DA} - W_{j\omega}^{sp} \right) \\
&- \sum_{dk} u_{dk} L_{dk}^{DA} + \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \qquad = \\
&- \sum_{(j\in J_n)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \\
&- \sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{i\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{i\omega} \mu_{i\omega}^{max} \left(\sum_b P_{ib}^{MAX} \right) \\
&- \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{j\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
&- \sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&- \sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.2.29}
$$

Transferring the linear terms from the left to the right part of the equality (A.2.29) the latter is rearranged as:

$$
\begin{aligned}
&\sum_{(i\in I^S)b} O_{ib}^{DA} P_{ib}^{DA} + \sum_{(i\in I^S)\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} - \sum_{(i\in I^S)\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} \\
&+ \sum_{(j\in J^S)f} O_{jf}^{DA} W_{jf}^{DA} - \sum_{(j\in J^S)f} O_j^{RT} W_{jf}^{DA} - \sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{sp} \qquad = \\
&- \sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&- \sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{RT} - \sum_{(j\in J^O)f} c_{jf} W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{RT}
\end{aligned}
$$

$$
\begin{aligned}
&+\sum_{(j\in J^O)f} c_j^{RT} W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{sp} \\
&+\sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} \\
&-\sum_{(j\in J_n)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \\
&-\sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{i\omega} \theta_{i\omega}^{max} RES_i^{DOWN} - \sum_{i\omega} \mu_{i\omega}^{max} \left(\sum_b P_{ib}^{MAX} \right) \\
&-\sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{j\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
&-\sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&-\sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.2.30}
$$

Substituting the non-linear terms $O_{ib}^{DA} P_{ib}^{DA}$, $O_i^{up} r_{i\omega}^{up}$, $O_i^{down} r_{i\omega}^{down}$,$O_{jf}^{DA} W_{jf}^{DA}$,$O_j^{RT} W_{jf}^{DA}$ and $O_j^{RT} W_{j\omega}^{sp}$ of (A.2.28) for the left part of equality (A.2.30), the non-linear objective function (4.4) is recast into the following equivalent linear expression:

$$
\begin{aligned}
&-\sum_{(i\in I^S)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^S)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^S)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&-\sum_{(i\in I^O)b} c_{ib} P_{ib}^{DA} - \sum_{(i\in I^O)\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{(i\in I^O)\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} \\
&-\sum_{(j\in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{RT} - \sum_{(j\in J^O)f} c_{jf} W_{jf}^{DA} - \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{RT} \\
&+\sum_{(j\in J^O)f} c_j^{RT} W_{jf}^{DA} + \sum_{(j\in J^O)\omega} \pi_\omega c_j^{RT} W_{j\omega}^{sp} + \sum_{dk} u_{dk} L_{dk}^{DA} \\
&-\sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} - \sum_{(j\in J_n^O)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{(i\in I^O)b} \alpha_{ib}^{max} P_{ib}^{MAX} \\
&-\sum_{(j\in J^O)f} \beta_{jf}^{max} W_{jf}^{MAX} - \sum_{(i\in I^O)\omega} \epsilon_{i\omega}^{max} RES_i^{UP} - \sum_{(i\in I^O)\omega} \theta_{i\omega}^{max} RES_i^{DOWN} \\
&-\sum_{(i\in I^O)\omega} \mu_{i\omega}^{max} \left(\sum_b P_{ib}^{MAX} \right) - \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{(j\in J^O),\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} \\
&-\sum_{n(m\in\Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m\in\Theta_n),\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&-\sum_n \pi \left(\rho_n^{min} + \rho_n^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.2.31}
$$

A.3 EPEC's KKT complementarity constraints linearization

The KKT complementarity constraints of the EPEC model are substituted with equivalent linear disjunctive constrains following the linearization process proposed by Fortuny-Amat and McCarl (1981).

Transformation of KKT complementarity constraints (5.163)−(5.185):

$$0 \leq P_{ib}^{DA} \leq M^{pP} z_{ib}^{1} \qquad \forall i, \forall b \tag{A.3.1}$$

$$0 \leq \alpha_{ib}^{min} \leq M^{vP}(1 - z_{ib}^{1}) \qquad \forall i, \forall b \tag{A.3.2}$$

$$0 \leq P_{ib}^{MAX} - P_{ib}^{DA} \leq M^{pP} z_{ib}^{2} \qquad \forall i, \forall b \tag{A.3.3}$$

$$0 \leq \alpha_{ib}^{max} \leq M^{vP}(1 - z_{ib}^{2}) \qquad \forall i, \forall b \tag{A.3.4}$$

$$0 \leq W_{jf}^{DA} \leq M^{pP} z_{jf}^{3} \qquad \forall j, \forall f \tag{A.3.5}$$

$$0 \leq \beta_{jf}^{min} \leq M^{vP}(1 - z_{jf}^{3}) \qquad \forall j, \forall f \tag{A.3.6}$$

$$0 \leq W_{jf}^{MAX} - W_{jf}^{DA} \leq M^{pP} z_{jf}^{4} \qquad \forall j, \forall f \tag{A.3.7}$$

$$0 \leq \beta_{jf}^{max} \leq M^{vP}(1 - z_{jf}^{4}) \qquad \forall j, \forall f \tag{A.3.8}$$

$$0 \leq L_{dk}^{DA} \leq M^{pP} z_{dk}^{5} \qquad \forall d, \forall k \tag{A.3.9}$$

$$0 \leq \gamma_{dk}^{min} \leq M^{vP}(1 - z_{dk}^{5}) \qquad \forall d, \forall k \tag{A.3.10}$$

$$0 \leq L_{dk}^{MAX} - L_{dk}^{DA} \leq M^{pP} z_{dk}^{6} \qquad \forall d, \forall k \tag{A.3.11}$$

$$0 \leq \gamma_{dk}^{max} \leq M^{vP}(1 - z_{dk}^{6}) \qquad \forall d, \forall k \tag{A.3.12}$$

$$0 \leq r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{7} \qquad \forall i, \forall \omega \tag{A.3.13}$$

$$0 \leq \epsilon_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{7}) \qquad \forall i, \forall \omega \tag{A.3.14}$$

$$0 \leq RES_{i}^{UP} - r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{8} \qquad \forall i, \forall \omega \tag{A.3.15}$$

$$0 \leq \epsilon_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{8}) \qquad \forall i, \forall \omega \tag{A.3.16}$$

$$0 \leq r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{9} \qquad \forall i, \forall \omega \tag{A.3.17}$$

$$0 \leq \theta_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{9}) \qquad \forall i, \forall \omega \tag{A.3.18}$$

$$0 \leq RES_{i}^{DOWN} - r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{10} \qquad \forall i, \forall \omega \tag{A.3.19}$$

$$0 \leq \theta_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{10}) \qquad \forall i, \forall \omega \tag{A.3.20}$$

$$0 \leq \sum_b P_{ib}^{MAX} - \sum_b P_{ib}^{DA} - r_{i\omega}^{up} \leq M^{pP} z_{i\omega}^{11} \qquad \forall i, \forall \omega \tag{A.3.21}$$

$$0 \leq \mu_{i\omega}^{max} \leq M^{vP}(1 - z_{i\omega}^{11}) \qquad \forall i, \forall \omega \tag{A.3.22}$$

$$0 \leq \sum_b P_{ib}^{DA} - r_{i\omega}^{down} \leq M^{pP} z_{i\omega}^{12} \qquad \forall i, \forall \omega \tag{A.3.23}$$

$$0 \leq \mu_{i\omega}^{min} \leq M^{vP}(1 - z_{i\omega}^{12}) \qquad \forall i, \forall \omega \tag{A.3.24}$$

$$0 \leq W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{13} \qquad \forall j, \forall \omega \tag{A.3.25}$$

$$0 \leq \kappa_{j\omega}^{min} \leq M^{vP}(1 - z_{j\omega}^{13}) \qquad \forall j, \forall \omega \tag{A.3.26}$$

$$0 \leq W_{j\omega}^{RT} - W_{j\omega}^{sp} \leq M^{pP} z_{j\omega}^{14} \qquad \forall j, \forall \omega \tag{A.3.27}$$

$$0 \leq \kappa_{j\omega}^{max} \leq M^{vP}(1 - z_{j\omega}^{14}) \qquad \forall j, \forall \omega \tag{A.3.28}$$

$$0 \leq L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{15} \qquad \forall d, \forall \omega \tag{A.3.29}$$

$$0 \leq \nu_{d\omega}^{min} \leq M^{vP}(1 - z_{d\omega}^{15}) \qquad \forall d, \forall \omega \tag{A.3.30}$$

$$0 \leq \sum_k L_{dk}^{DA} - L_{d\omega}^{sh} \leq M^{pP} z_{d\omega}^{16} \qquad \forall d, \forall \omega \tag{A.3.31}$$

$$0 \leq \nu_{d\omega}^{max} \leq M^{vP}(1 - z_{d\omega}^{16}) \qquad \forall d, \forall \omega \tag{A.3.32}$$

$$0 \leq B_{nm}\big(\delta_n^o - \delta_m^o\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm}^{17} \qquad \forall n, \forall m \in \Theta_m \tag{A.3.33}$$

$$0 \leq \xi_{nm}^{min} \leq M^{vC}(1 - z_{nm}^{17}) \qquad \forall n, \forall m \in \Theta_m \tag{A.3.34}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_n^o - \delta_m^o\big) \leq M^{pC} z_{nm}^{18} \qquad \forall n, \forall m \in \Theta_m \tag{A.3.35}$$

$$0 \leq \xi_{nm}^{max} \leq M^{vC}(1 - z_{nm}^{18}) \qquad \forall n, \forall m \in \Theta_m \tag{A.3.36}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T_{nm}^{MAX} \leq M^{pC} z_{nm\omega}^{19} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.37}$$

$$0 \leq \xi_{nm\omega}^{min} \leq M^{vC}(1 - z_{nm\omega}^{19}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.38}$$

$$0 \leq T_{nm}^{MAX} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \leq M^{pC} z_{nm\omega}^{20} \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.39}$$

$$0 \leq \xi_{nm\omega}^{max} \leq M^{vC}(1 - z_{nm\omega}^{20}) \qquad \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.40}$$

$$0 \leq \delta_n^o + \pi \leq M^{pV} z_n^{21} \qquad \forall n \tag{A.3.41}$$

$$0 \leq \rho_n^{min} \leq M^{vV}(1 - z_n^{21}) \qquad \forall n \tag{A.3.42}$$

$$0 \leq \pi - \delta_n^o \leq M^{pV} z_n^{22} \qquad \forall n \tag{A.3.43}$$

$$0 \leq \rho_n^{max} \leq M^{vV}(1 - z_n^{22}) \qquad \forall n \tag{A.3.44}$$

$$0 \leq \delta_{n\omega} + \pi \leq M^{pV} z_{n\omega}^{23} \qquad \forall n, \forall \omega \tag{A.3.45}$$

$$0 \leq \rho_{n\omega}^{min} \leq M^{vV}(1 - z_{n\omega}^{23}) \qquad \forall n, \forall \omega \tag{A.3.46}$$

$$0 \leq \pi - \delta_{n\omega} \leq M^{pV} z_{n\omega}^{24} \qquad \forall n, \forall \omega \tag{A.3.47}$$

$$0 \leq \rho_{n\omega}^{max} \leq M^{vV}(1 - z_{n\omega}^{24}) \qquad \forall n, \forall \omega \tag{A.3.48}$$

Transformation of KKT complementarity constraints (5.108)−(5.162):

$$0 \leq O_{i(b1)}^{DA} \leq N^p z_{si(b1)}^{25} \qquad \forall s, \forall i \in I^S \tag{A.3.49}$$

$$0 \leq \widehat{o}_{si(b1)}^{p} \leq N^v(1 - z_{si(b1)}^{25}) \qquad \forall s, \forall i \in I^S \tag{A.3.50}$$

$$0 \leq O_{ib}^{DA} - O_{i(b-1)}^{DA} \leq N^p z_{sib}^{26} \qquad \forall s, \forall i \in I^S, \forall b \geq b2 \tag{A.3.51}$$

$$0 \leq \widehat{o}_{sib}^{p} \leq N^v(1 - z_{sib}^{26}) \qquad \forall s, \forall i \in I^S, \forall b \geq b2 \tag{A.3.52}$$

$$0 \leq O_{j(f1)}^{DA} \leq N^p z_{sj(f1)}^{27} \qquad \forall s, \forall j \in J^S \tag{A.3.53}$$

$$0 \leq \widehat{o}_{sj(f1)}^{w} \leq N^v(1 - z_{sj(f1)}^{27}) \qquad \forall s, \forall j \in J^S \tag{A.3.54}$$

$$0 \leq O_{jf}^{DA} - O_{j(f-1)}^{DA} \leq N^p z_{sjf}^{28} \qquad \forall s, \forall j \in J^S, \forall f \geq f2 \tag{A.3.55}$$

$$0 \leq \widehat{o}_{sjf}^{w} \leq N^v(1 - z_{sjf}^{28}) \qquad \forall s, \forall j \in J^S, \forall f \geq f2 \tag{A.3.56}$$

$$0 \leq O_{i}^{up} \leq N^p z_{si}^{29} \qquad \forall s, \forall i \in I^S \tag{A.3.57}$$

$$0 \leq \widehat{o}_{si}^{up} \leq N^v(1 - z_{si}^{29}) \qquad \forall s, \forall i \in I^S \tag{A.3.58}$$

$$0 \leq O_{i}^{down} \leq N^p z_{si}^{30} \qquad \forall s, \forall i \in I^S \tag{A.3.59}$$

$$0 \leq \widehat{o}_{si}^{down} \leq N^v(1 - z_{si}^{30}) \qquad \forall s, \forall i \in I^S \tag{A.3.60}$$

$$0 \leq O_{j}^{RT} \leq N^p z_{sj}^{31} \qquad \forall s, \forall j \in J^S \tag{A.3.61}$$

$$0 \leq \widehat{o}_{sj}^{rt} \leq N^v(1 - z_{sj}^{31}) \qquad \forall s, \forall j \in J^S \tag{A.3.62}$$

$$0 \leq P_{ib}^{DA} \leq M^{pP} z_{sib}^{32} \qquad \forall s, \forall i \in I^S, \forall b \tag{A.3.63}$$

$$0 \leq \widehat{\alpha}_{sib}^{min} \leq M^{vP}(1 - z_{sib}^{32}) \qquad \forall s, \forall i \in I^S, \forall b \tag{A.3.64}$$

$$0 \leq P_{ib}^{MAX} - P_{ib}^{DA} \leq M^{pP} z_{sib}^{33} \qquad \forall s, \forall i \in I^S, \forall b \tag{A.3.65}$$

$$0 \leq \widehat{\alpha}_{sib}^{max} \leq M^{vP}(1 - z_{sib}^{33}) \qquad \forall s, \forall i \in I^S, \forall b \tag{A.3.66}$$

$$0 \leq W_{jf}^{DA} \leq M^{pP} z_{sjf}^{34} \qquad \forall s, \forall j \in J^S, \forall f \tag{A.3.67}$$

$$0 \leq \widehat{\beta}_{sjf}^{min} \leq M^{vP}(1 - z_{sjf}^{34}) \qquad \forall s, \forall j \in J^S, \forall f \tag{A.3.68}$$

$$0 \leq W_{jf}^{MAX} - W_{jf}^{DA} \leq M^{pP} z_{sjf}^{35} \qquad \forall s, \forall j \in J^S, \forall f \tag{A.3.69}$$

$$0 \leq \widehat{\beta}^{max}_{sjf} \leq M^{vP}(1 - z^{35}_{sjf}) \qquad \forall s, \forall j \in J^S, \forall f \tag{A.3.70}$$

$$0 \leq L^{DA}_{dk} \leq M^{pP} z^{36}_{sdk} \qquad \forall s, \forall d, \forall k \tag{A.3.71}$$

$$0 \leq \widehat{\gamma}^{min}_{sdk} \leq M^{vP}(1 - z^{36}_{sdk}) \qquad \forall s, \forall d, \forall k \tag{A.3.72}$$

$$0 \leq L^{MAX}_{dk} - L^{DA}_{dk} \leq M^{pP} z^{37}_{sdk} \qquad \forall s, \forall d, \forall k \tag{A.3.73}$$

$$0 \leq \widehat{\gamma}^{max}_{sdk} \leq M^{vP}(1 - z^{37}_{sdk}) \qquad \forall s, \forall d, \forall k \tag{A.3.74}$$

$$0 \leq r^{up}_{i\omega} \leq M^{pP} z^{38}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.75}$$

$$0 \leq \widehat{\epsilon}^{min}_{si\omega} \leq M^{vP}(1 - z^{38}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.76}$$

$$0 \leq RES^{UP}_i - r^{up}_{i\omega} \leq M^{pP} z^{39}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.77}$$

$$0 \leq \widehat{\epsilon}^{max}_{si\omega} \leq M^{vP}(1 - z^{39}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.78}$$

$$0 \leq r^{down}_{i\omega} \leq M^{pP} z^{40}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.79}$$

$$0 \leq \widehat{\theta}^{min}_{si\omega} \leq M^{vP}(1 - z^{40}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.80}$$

$$0 \leq RES^{DOWN}_i - r^{down}_{i\omega} \leq M^{pP} z^{41}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.81}$$

$$0 \leq \widehat{\theta}^{max}_{si\omega} \leq M^{vP}(1 - z^{41}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.82}$$

$$0 \leq \sum_b P^{MAX}_{ib} - \sum_b P^{DA}_{ib} - r^{up}_{i\omega} \leq M^{pP} z^{42}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.83}$$

$$0 \leq \widehat{\mu}^{max}_{si\omega} \leq M^{vP}(1 - z^{42}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.84}$$

$$0 \leq \sum_b P^{DA}_{ib} - r^{down}_{i\omega} \leq M^{pP} z^{43}_{si\omega} \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.85}$$

$$0 \leq \widehat{\mu}^{min}_{si\omega} \leq M^{vP}(1 - z^{43}_{si\omega}) \qquad \forall s, \forall i \in I^S, \forall \omega \tag{A.3.86}$$

$$0 \leq W^{sp}_{j\omega} \leq M^{pP} z^{44}_{sj\omega} \qquad \forall s, \forall j \in J^S, \forall \omega \tag{A.3.87}$$

$$0 \leq \widehat{\kappa}^{min}_{sj\omega} \leq M^{vP}(1 - z^{44}_{sj\omega}) \qquad \forall s, \forall j \in J^S, \forall \omega \tag{A.3.88}$$

$$0 \leq W^{RT}_{j\omega} - W^{sp}_{j\omega} \leq M^{pP} z^{45}_{sj\omega} \qquad \forall s, \forall j \in J^S, \forall \omega \tag{A.3.89}$$

$$0 \leq \widehat{\kappa}^{max}_{sj\omega} \leq M^{vP}(1 - z^{45}_{sj\omega}) \qquad \forall s, \forall j \in J^S, \forall \omega \tag{A.3.90}$$

$$0 \leq L^{sh}_{d\omega} \leq M^{pP} z^{46}_{sd\omega} \qquad \forall s, \forall d, \forall \omega \tag{A.3.91}$$

$$0 \leq \widehat{\nu}^{min}_{sd\omega} \leq M^{vP}(1 - z^{46}_{sd\omega}) \qquad \forall s, \forall d, \forall \omega \tag{A.3.92}$$

$$0 \leq \sum_k L^{DA}_{dk} - L^{sh}_{d\omega} \leq M^{pP} z^{47}_{sd\omega} \qquad \forall s, \forall d, \forall \omega \tag{A.3.93}$$

$$0 \leq \widehat{\nu}^{max}_{sd\omega} \leq M^{vP}(1 - z^{47}_{sd\omega}) \qquad \forall s, \forall d, \forall \omega \tag{A.3.94}$$

$$0 \leq B_{nm}\big(\delta^o_n - \delta^o_m\big) + T^{MAX}_{nm} \leq M^{pC} z^{48}_{snm} \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.95}$$

$$0 \leq \widehat{\xi}^{min}_{snm} \leq M^{vC}(1 - z^{48}_{snm}) \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.96}$$

$$0 \leq T^{MAX}_{nm} - B_{nm}\big(\delta^o_n - \delta^o_m\big) \leq M^{pC} z^{49}_{snm} \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.97}$$

$$0 \leq \widehat{\xi}^{max}_{snm} \leq M^{vC}(1 - z^{49}_{snm}) \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.98}$$

$$0 \leq B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) + T^{MAX}_{nm} \leq M^{pC} z^{50}_{snm\omega} \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.99}$$

$$0 \leq \widehat{\xi}^{min}_{snm\omega} \leq M^{vC}(1 - z^{50}_{snm\omega}) \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.100}$$

$$0 \leq T^{MAX}_{nm} - B_{nm}\big(\delta_{n\omega} - \delta_{m\omega}\big) \leq M^{pC} z^{51}_{snm\omega} \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.101}$$

$$0 \leq \widehat{\xi}^{max}_{snm\omega} \leq M^{vC}(1 - z^{51}_{snm\omega}) \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.102}$$

$$0 \leq \delta^o_n + \pi \leq M^{pV} z^{52}_{sn} \qquad \forall n \tag{A.3.103}$$

$$0 \leq \widehat{\rho}^{min}_{sn} \leq M^{vV}(1 - z^{52}_{sn}) \qquad \forall s, \forall n \tag{A.3.104}$$

$$0 \leq \pi - \delta^o_n \leq M^{pV} z^{53}_{sn} \qquad \forall s, \forall n \tag{A.3.105}$$

$$0 \leq \widehat{\rho}^{max}_{sn} \leq M^{vV}(1 - z^{53}_{sn}) \qquad \forall s, \forall n \tag{A.3.106}$$

$$0 \leq \delta_{n\omega} + \pi \leq M^{pV} z^{54}_{sn\omega} \qquad \forall s, \forall n, \forall \omega \tag{A.3.107}$$

$$0 \leq \widehat{\rho}^{min}_{sn\omega} \leq M^{vV}(1 - z^{54}_{sn\omega}) \qquad \forall s, \forall n, \forall \omega \tag{A.3.108}$$

$$0 \leq \pi - \delta_{n\omega} \leq M^{pV} z^{55}_{sn\omega} \qquad \forall s, \forall n, \forall \omega \tag{A.3.109}$$

$$0 \leq \widehat{\rho}^{max}_{sn\omega} \leq M^{vV}(1 - z^{55}_{sn\omega}) \qquad \forall s, \forall n, \forall \omega \tag{A.3.110}$$

$$0 \leq \alpha^{min}_{ib} \leq M^{vP} z^{56}_{sib} \qquad \forall s, \forall i \in I^s, \forall b \tag{A.3.111}$$

$$0 \leq \overline{\alpha}^{min}_{sib} \leq M^{vP}(1 - z^{56}_{sib}) \qquad \forall s, \forall i \in I^s, \forall b \tag{A.3.112}$$

$$0 \leq \alpha^{max}_{ib} \leq M^{vP} z^{57}_{sib} \qquad \forall s, \forall i \in I^s, \forall b \tag{A.3.113}$$

$$0 \leq \overline{\alpha}^{max}_{sib} \leq M^{vP}(1 - z^{57}_{sib}) \qquad \forall s, \forall i \in I^s, \forall b \tag{A.3.114}$$

$$0 \leq \beta^{min}_{jf} \leq M^{vP} z^{58}_{sjf} \qquad \forall s, \forall j \in J^s, \forall f \tag{A.3.115}$$

$$0 \leq \overline{\beta}^{min}_{sjf} \leq M^{vP}(1 - z^{58}_{sjf}) \qquad \forall s, \forall j \in J^s, \forall f \tag{A.3.116}$$

$$0 \leq \beta^{max}_{jf} \leq M^{vP} z^{59}_{sjf} \qquad \forall s, \forall j \in J^s, \forall f \tag{A.3.117}$$

$$0 \leq \overline{\beta}^{max}_{sjf} \leq M^{vP}(1 - z^{59}_{sjf}) \qquad \forall s, \forall j \in J^s, \forall f \tag{A.3.118}$$

$$0 \leq \gamma^{min}_{dk} \leq M^{vP} z^{60}_{sdk} \qquad \forall s, \forall d, \forall k \tag{A.3.119}$$

$$0 \leq \overline{\gamma}^{min}_{sdk} \leq M^{vP}(1 - z^{60}_{sdk}) \qquad \forall s, \forall d, \forall k \tag{A.3.120}$$

$$0 \leq \gamma^{max}_{dk} \leq M^{vP} z^{61}_{sdk} \qquad \forall s, \forall d, \forall k \tag{A.3.121}$$

$$0 \leq \overline{\gamma}^{max}_{sdk} \leq M^{vP}(1 - z^{61}_{sdk}) \qquad \forall s, \forall d, \forall k \tag{A.3.122}$$

$$0 \leq \epsilon_{i\omega}^{min} \leq M^{vP} z_{si\omega}^{62} \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.123}$$

$$0 \leq \overline{\epsilon}_{si\omega}^{min} \leq M^{vP}(1 - z_{si\omega}^{62}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.124}$$

$$0 \leq \epsilon_{i\omega}^{max} \leq M^{vP} z_{si\omega}^{63} \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.125}$$

$$0 \leq \overline{\epsilon}_{si\omega}^{max} \leq M^{vP}(1 - z_{si\omega}^{63}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.126}$$

$$0 \leq \theta_{i\omega}^{min} \leq M^{vP} z_{si\omega}^{64} \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.127}$$

$$0 \leq \overline{\theta}_{si\omega}^{min} \leq M^{vP}(1 - z_{si\omega}^{64}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.128}$$

$$0 \leq \theta_{i\omega}^{max} \leq M^{vP} z_{si\omega}^{65}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.129}$$

$$0 \leq \overline{\theta}_{si\omega}^{max} \leq M^{vP}(1 - z_{si\omega}^{65}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.130}$$

$$0 \leq \mu_{i\omega}^{max} \leq M^{vP} z_{si\omega}^{66} \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.131}$$

$$0 \leq \overline{\mu}_{si\omega}^{max} \leq M^{vP}(1 - z_{si\omega}^{66}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.132}$$

$$0 \leq \mu_{i\omega}^{min} \leq M^{vP} z_{si\omega}^{67} \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.133}$$

$$0 \leq \overline{\mu}_{si\omega}^{min} \leq M^{vP}(1 - z_{si\omega}^{67}) \qquad \forall s, \forall i \in I^s, \forall \omega \tag{A.3.134}$$

$$0 \leq \kappa_{j\omega}^{min} \leq M^{vP} z_{sj\omega}^{68} \qquad \forall s, \forall j \in J^s, \forall \omega \tag{A.3.135}$$

$$0 \leq \overline{\kappa}_{sj\omega}^{min} \leq M^{vP}(1 - z_{sj\omega}^{68}) \qquad \forall s, \forall j \in J^s, \forall \omega \tag{A.3.136}$$

$$0 \leq \kappa_{j\omega}^{max} \leq M^{vP} z_{sj\omega}^{69} \qquad \forall s, \forall j \in J^s, \forall \omega \tag{A.3.137}$$

$$0 \leq \overline{\kappa}_{sj\omega}^{max} \leq M^{vP}(1 - z_{sj\omega}^{69}) \qquad \forall s, \forall j \in J^s, \forall \omega \tag{A.3.138}$$

$$0 \leq \nu_{sd\omega}^{min} \leq M^{vP} z_{sd\omega}^{70} \qquad \forall s, \forall d, \forall \omega \tag{A.3.139}$$

$$0 \leq \overline{\nu}_{sd\omega}^{min} \leq M^{vP}(1 - z_{sd\omega}^{70}) \qquad \forall s, \forall d, \forall \omega \tag{A.3.140}$$

$$0 \leq \nu_{d\omega}^{max} \leq M^{vP} z_{sd\omega}^{71} \qquad \forall s, \forall d, \forall \omega \tag{A.3.141}$$

$$0 \leq \overline{\nu}_{sd\omega}^{max} \leq M^{vP}(1 - z_{sd\omega}^{71}) \qquad \forall s, \forall d, \forall \omega \tag{A.3.142}$$

$$0 \leq \xi_{nm}^{min} \leq M^{vC} z_{snm}^{72} \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.143}$$

$$0 \leq \overline{\xi}_{snm}^{min} \leq M^{vC}(1 - z_{snm}^{72}) \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.144}$$

$$0 \leq \xi_{nm}^{max} \leq M^{vC} z_{snm}^{73} \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.145}$$

$$0 \leq \overline{\xi}_{snm}^{max} \leq M^{vC}(1 - z_{snm}^{73}) \qquad \forall s, \forall n, \forall m \in \Theta_m \tag{A.3.146}$$

$$0 \leq \xi_{nm\omega}^{min} \leq M^{vC} z_{snm\omega}^{74} \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.147}$$

$$0 \leq \overline{\xi}_{snm\omega}^{min} \leq M^{vC}(1 - z_{snm\omega}^{74}) \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.148}$$

$$0 \leq \xi_{nm\omega}^{max} \leq M^{vC} z_{snm\omega}^{75} \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.149}$$

$$0 \leq \overline{\xi}^{max}_{snm\omega} \leq M^{vC}(1 - z^{75}_{snm\omega}) \qquad \forall s, \forall n, \forall m \in \Theta_m, \forall \omega \tag{A.3.150}$$

$$0 \leq \rho^{min}_{n} \leq M^{vV} z^{76}_{sn} \qquad \forall s, \forall n \tag{A.3.151}$$

$$0 \leq \overline{\rho}^{min}_{sn} \leq M^{vV}(1 - z^{76}_{sn}) \qquad \forall s, \forall n \tag{A.3.152}$$

$$0 \leq \rho^{max}_{n} \leq M^{vV} z^{77}_{sn} \qquad \forall s, \forall n \tag{A.3.153}$$

$$0 \leq \overline{\rho}^{max}_{sn} \leq M^{vV}(1 - z^{77}_{sn}) \qquad \forall s, \forall n \tag{A.3.154}$$

$$0 \leq \rho^{min}_{n\omega} \leq M^{vV} z^{76}_{sn\omega} \qquad \forall s, \forall n, \forall \omega \tag{A.3.155}$$

$$0 \leq \overline{\rho}^{min}_{sn\omega} \leq M^{vV}(1 - z^{76}_{sn\omega}) \qquad \forall s, \forall n, \forall \omega \tag{A.3.156}$$

$$0 \leq \rho^{max}_{n\omega} \leq M^{vV} z^{77}_{sn\omega} \qquad \forall s, \forall n, \forall \omega \tag{A.3.157}$$

$$0 \leq \overline{\rho}^{max}_{sn\omega} \leq M^{vV}(1 - z^{77}_{sn\omega}) \qquad \forall s, \forall n, \forall \omega \tag{A.3.158}$$

A.4 EPEC's objective function TEP (5.188) linearization

To eliminate the nonlinear terms $\lambda^{DA}_n P^{DA}_{ib}$, $\lambda^{DA}_n W^{DA}_{jf}$, $\lambda^{RT}_{n\omega} r^{up}_{i\omega}$, $\lambda^{RT}_{n\omega} r^{down}_{i\omega}$, $\lambda^{RT}_{n\omega} W^{DA}_{jf}$ and $\lambda^{RT}_{n\omega} W^{sp}_{j\omega}$ of the TEP objective function (5.189), we follow the process below:
for the term $\lambda^{DA}_n P^{DA}_{ib}$, the KKT equality (5.37) results in

$$\lambda^{DA}_n = O^{DA}_{ib} + \alpha^{max}_{ib} - \alpha^{min}_{ib} + \sum_{\omega} \mu^{max}_{i\omega} - \sum_{\omega} \mu^{min}_{i\omega} \qquad \forall i \in I_n, \forall b \tag{A.4.1}$$

multiplying by P^{DA}_{ib} gives

$$\begin{aligned}\sum_{(i \in I_n)b} \lambda^{DA}_n P^{DA}_{ib} = &\sum_{ib} O^{DA}_{ib} P^{DA}_{ib} + \sum_{ib} \alpha^{max}_{ib} P^{DA}_{ib} - \sum_{ib} \alpha^{min}_{ib} P^{DA}_{ib} \\ &+ \sum_{ib} \left(\sum_{\omega} \mu^{max}_{i\omega} \right) P^{DA}_{ib} - \sum_{ib} \left(\sum_{\omega} \mu^{min}_{i\omega} \right) P^{DA}_{ib}\end{aligned} \tag{A.4.2}$$

from the KKT complementarity condition (5.163)

$$\alpha^{min}_{ib} P^{DA}_{ib} = 0 \qquad \forall i, \forall b \quad \Rightarrow \quad \sum_{ib} \alpha^{min}_{ib} P^{DA}_{ib} = 0 \tag{A.4.3}$$

from the KKT complementarity condition (5.164)

$$\alpha_{ib}^{max} P_{ib}^{DA} = \alpha_{ib}^{max} P_{ib}^{MAX} \quad \forall i, \forall b \quad \Rightarrow \quad \sum_{ib} \alpha_{ib}^{max} P_{ib}^{DA} = \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} \tag{A.4.4}$$

from the KKT complementarity condition (5.172)

$$\begin{aligned} &\mu_{i\omega}^{max} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{max} \sum_{b} P_{ib}^{MAX} - \mu_{i\omega}^{max} r_{i\omega}^{up} \qquad \forall i, \forall \omega \quad \Rightarrow \\ &\sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{DA} = \sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{i\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \end{aligned} \tag{A.4.5}$$

from the KKT complementarity condition (5.137)

$$\begin{aligned} &\mu_{i\omega}^{min} \sum_{b} P_{ib}^{DA} = \mu_{i\omega}^{min} r_{i\omega}^{down} \qquad \forall i, \forall \omega \quad \Rightarrow \\ &\sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{min} \right) P_{ib}^{DA} = \sum_{i\omega} \mu_{i\omega}^{min} \rho_{\omega}^{down} \end{aligned} \tag{A.4.6}$$

hence the (A.4.2) becomes

$$\begin{aligned} \sum_{(i \in I_n)b} \lambda_n^{DA} P_{ib}^{DA} = &\sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} \\ &+ \sum_{ib} \left(\sum_{\omega} \mu_{i\omega}^{max} \right) P_{ib}^{MAX} - \sum_{i\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} - \sum_{i\omega} \mu_{i\omega}^{min} \rho_{i\omega}^{down} \end{aligned} \tag{A.4.7}$$

for the terms $\lambda_n^{DA} W_{jf}^{DA}$ and $\lambda_{n\omega}^{RT} W_{jf}^{DA}$, the KKT equality (5.38) results in

$$\lambda_n^{DA} - \sum_{\omega} \lambda_{n\omega}^{RT} = O_{jf}^{DA} - O_j^{RT} + \beta_{jf}^{max} - \beta_{jf}^{min} \qquad \forall j \in J_n, \forall f \tag{A.4.8}$$

multiplying by W_{jf}^{DA} gives

$$\begin{aligned} \sum_{(j \in J_n)f} \lambda_n^{DA} W_{jf}^{DA} - \sum_{(j \in J_n)\omega} \lambda_{n\omega}^{RT} \left(\sum_{f} W_{jf}^{DA} \right) = &\sum_{jf} O_{jf}^{DA} W_{jf}^{DA} - \sum_{jf} O_j^{RT} W_{jf}^{DA} \\ &+ \sum_{jf} \beta_{jf}^{max} W_{jf}^{DA} - \sum_{jf} \beta_{jf}^{min} W_{jf}^{DA} \end{aligned} \tag{A.4.9}$$

from the KKT complementarity condition (5.165)

$$\beta_{jf}^{min} W_{jf}^{DA} = 0 \qquad \forall j, \forall f \quad \Rightarrow \quad \sum_{jf} \beta_{jf}^{min} W_{jf}^{DA} = 0 \tag{A.4.10}$$

from the KKT complementarity condition (5.166)

$$\beta_{jf}^{max} W_{jf}^{DA} = \beta_{jf}^{max} W_{jf}^{MAX} \quad \forall j, \forall f \Rightarrow \sum_{jf} \beta_{jf}^{max} W_{jf}^{DA} = \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \tag{A.4.11}$$

hence the (A.4.9) becomes

$$\begin{aligned} \sum_{(j \in J_n) f} \lambda_n^{DA} W_{jf}^{DA} - \sum_{(j \in J_n) \omega} \lambda_{n\omega}^{RT} \left(\sum_f W_{jf}^{DA} \right) = \sum_{jf} O_{jf}^{DA} W_{jf}^{DA} - \sum_{jf} O_j^{RT} W_{jf}^{DA} \\ + \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \end{aligned} \tag{A.4.12}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{up}$, the KKT equality (5.40) produces

$$\lambda_{n\omega}^{RT} = \pi_\omega O_i^{up} + \epsilon_{i\omega}^{max} - \epsilon_{i\omega}^{min} + \mu_{i\omega}^{max} \qquad \forall i, \forall \omega \tag{A.4.13}$$

multiplying by $r_{i\omega}^{up}$ gives

$$\begin{aligned} \sum_{(i \in I_n) \omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{i\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} + \sum_{i\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} \\ - \sum_{i\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} + \sum_{i\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \end{aligned} \tag{A.4.14}$$

from the KKT complementarity condition (5.169)

$$\epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \qquad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \epsilon_{i\omega}^{min} r_{i\omega}^{up} = 0 \tag{A.4.15}$$

from the KKT complementarity condition (5.170)

$$\epsilon_{i\omega}^{max} RES_i^{UP} = \epsilon_{i\omega}^{max} r_{i\omega}^{up} \quad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} = \sum_{i\omega} \epsilon_{i\omega}^{max} r_{i\omega}^{up} \tag{A.4.16}$$

thus the (A.4.14) becomes

$$\sum_{(i \in I_n)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{up} = \sum_{i\omega} \pi_\omega O_i^{up} r_{i\omega}^{up} + \sum_{i\omega} \epsilon_{i\omega}^{max} RES_i^{UP} + \sum_{i\omega} \mu_{i\omega}^{max} r_{i\omega}^{up} \tag{A.4.17}$$

for the term $\lambda_{i\omega}^{RT} r_{i\omega}^{down}$, the KKT equality (5.41) leads to

$$-\lambda_{n\omega}^{RT} = -\pi_\omega O_i^{down} + \theta_{i\omega}^{max} - \theta_{i\omega}^{min} + \mu_{i\omega}^{min} \qquad \forall i \in I_n, \forall \omega \tag{A.4.18}$$

multiplying by $r_{i\omega}^{down}$ gives

$$\begin{aligned} -\sum_{(i \in I_n)\omega} \lambda_{n\omega}^{RT} r_{i\omega}^{down} = &-\sum_{i\omega} \pi_\omega O_i^{down} r_{i\omega}^{down} + \sum_{i\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \\ &- \sum_{i\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} + \sum_{i\omega} \mu_{i\omega}^{min} r_{i\omega}^{down} \end{aligned} \tag{A.4.19}$$

from the KKT complementarity condition (5.170)

$$\theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \qquad \forall i, \forall \omega \quad \Rightarrow \quad \sum_{i\omega} \theta_{i\omega}^{min} r_{i\omega}^{down} = 0 \tag{A.4.20}$$

from the KKT complementarity condition (5.171)

$$\theta_{i\omega}^{max} RES_i^{DOWN} = \theta_{i\omega}^{max} r_{i\omega}^{down} \quad \forall i, \forall \omega \quad \Rightarrow$$

$$\sum_{i\omega} \theta_{i\omega}^{max} RES_i^{DOWN} = \sum_{i\omega} \theta_{i\omega}^{max} r_{i\omega}^{down} \tag{A.4.21}$$

thus the (A.4.19) becomes

$$-\sum_{(i\in I_n)\omega}\lambda_{n\omega}^{RT}r_{i\omega}^{down}=-\sum_{i\omega}\pi_\omega O_i^{down}r_{i\omega}^{down}+\sum_{i\omega}\theta_{i\omega}^{max}r_{i\omega}^{down} \tag{A.4.22}$$

for the term $\lambda_{n\omega}^{RT}W_{j\omega}^{sp}$, the KKT equality (5.42) results in

$$-\lambda_{n\omega}^{RT}=-\pi_\omega O_j^{RT}+\kappa_{j\omega}^{max}-\kappa_{j\omega}^{min}\qquad\forall j,\forall\omega \tag{A.4.23}$$

multiplying by $W_{j\omega}^{sp}$ gives

$$-\sum_{(j\in J_n)\omega}\lambda_{n\omega}^{RT}W_{j\omega}^{sp}=-\sum_{j\omega}\pi_\omega O_j^{RT}W_{j\omega}^{sp}+\sum_{j\omega}\kappa_{j\omega}^{max}W_{j\omega}^{sp}-\sum_{j\omega}\kappa_{j\omega}^{min}W_{j\omega}^{sp} \tag{A.4.24}$$

from the KKT complementarity condition (5.174)

$$\kappa_{j\omega}^{min}W_{j\omega}^{sp}=0\qquad\forall j,\forall\omega\quad\Rightarrow\quad\sum_{j\omega}\kappa_{j\omega}^{min}W_{j\omega}^{sp}=0 \tag{A.4.25}$$

from the KKT complementarity condition (5.175)

$$\kappa_{j\omega}^{max}W_{j\omega}^{sp}=\kappa_{j\omega}^{max}W_{j\omega}^{RT}\qquad\forall j,\forall\omega\Rightarrow\sum_{j\omega}\kappa_{j\omega}^{max}W_{j\omega}^{sp}=\sum_{j\omega}\kappa_{j\omega}^{max}W_{j\omega}^{RT} \tag{A.4.26}$$

thus the (A.4.24) becomes

$$-\sum_{(j\in J_n)\omega}\lambda_{n\omega}^{RT}W_{j\omega}^{sp}=-\sum_{j\omega}\pi_\omega O_j^{RT}W_{j\omega}^{sp}+\sum_{j\omega}\kappa_{j\omega}^{max}W_{j\omega}^{RT} \tag{A.4.27}$$

Using the expressions (A.4.7), (A.4.12), (A.4.17), (A.4.22) and (A.4.27) we reformulate the TEP objective function (5.189) as follows:

$$
\begin{aligned}
&\sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} + \sum_{i\omega} \mu_{i\omega}^{max} \left(\sum_{b} P_{ib}^{MAX} \right) - \sum_{ib} c_{ib} P_{ib}^{DA} \\
&\sum_{jf} O_{jf}^{DA} W_{jf}^{DA} - \sum_{jf} O_{j}^{RT} W_{jf}^{DA} + \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \\
&+ \sum_{i\omega} \pi_{\omega} O_{i}^{up} r_{i\omega}^{up} + \sum_{i\omega} \epsilon_{i\omega}^{max} RES_{i}^{UP} - \sum_{i\omega} \pi_{\omega} c_{i}^{up} r_{i\omega}^{up} \\
&- \sum_{i\omega} \pi_{\omega} O_{i}^{down} r_{i\omega}^{down} + \sum_{i\omega} \theta_{i\omega}^{max} RES_{i}^{DOWN} + \sum_{i\omega} \pi_{\omega} c_{i}^{down} r_{i\omega}^{down} \\
&+ \sum_{j\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{j\omega} \pi_{\omega} O_{j}^{RT} W_{j\omega}^{sp} + \sum_{j\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT}
\end{aligned}
\tag{A.4.28}
$$

Transferring the linear terms from the left to the right part of the strong duality theorem equality (5.36) the latter is rearranged as:

$$
\begin{aligned}
&\sum_{ib} O_{ib}^{DA} P_{ib}^{DA} + \sum_{i\omega} \pi_{\omega} O_{i}^{up} r_{i\omega}^{up} - \sum_{i\omega} \pi_{\omega} O_{i}^{down} r_{i\omega}^{down} \\
&+ \sum_{jf} O_{jf}^{DA} W_{jf}^{DA} - \sum_{jf} O_{j}^{RT} W_{jf}^{DA} - \sum_{j\omega} \pi_{\omega} O_{j}^{RT} W_{j\omega}^{sp} = \\
&\sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{d\omega} \pi_{\omega} VOLL_{d} L_{d\omega}^{sh} - \sum_{j\omega} \pi_{\omega} O_{j}^{RT} W_{j\omega}^{RT} \\
&- \sum_{(j \in J_n)\omega} \lambda_{n\omega}^{RT} W_{j\omega}^{RT} - \sum_{ib} \alpha_{ib}^{max} P_{ib}^{MAX} - \sum_{jf} \beta_{jf}^{max} W_{jf}^{MAX} \\
&- \sum_{i\omega} \epsilon_{i\omega}^{max} RES_{i}^{UP} - \sum_{i\omega} \theta_{i\omega}^{max} RES_{i}^{DOWN} \\
&- \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} - \sum_{j\omega} \kappa_{j\omega}^{max} W_{j\omega}^{RT} - \sum_{i\omega} \mu_{i\omega}^{max} \left(\sum_{b} P_{ib}^{MAX} \right) \\
&- \sum_{n(m \in \Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max} \right) - \sum_{n(m \in \Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max} \right) \\
&- \sum_{n} \pi \left(\rho_{n}^{min} + \rho_{n}^{max} \right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max} \right)
\end{aligned}
\tag{A.4.29}
$$

Substituting the non-linear terms $O_{ib}^{DA} P_{ib}^{DA}$, $O_{i}^{up} r_{i\omega}^{up}$, $O_{i}^{down} r_{i\omega}^{down}$,$O_{jf}^{DA} W_{jf}^{DA}$,$O_{j}^{RT} W_{jf}^{DA}$ and $O_{j}^{RT} W_{j\omega}^{sp}$ of (A.4.28) for the left part of equality (A.4.29), the non-linear TEP objective function (5.189) is recast into the following equivalent linear expression:

$$
\begin{aligned}
&\sum_{dk} u_{dk} L_{dk}^{DA} - \sum_{ib} c_{ib} P_{ib}^{DA} \\
&- \sum_{i\omega} \pi_\omega c_i^{up} r_{i\omega}^{up} + \sum_{i\omega} \pi_\omega c_i^{down} r_{i\omega}^{down} - \sum_{(j \in J^S)\omega} \pi_\omega O_j^{RT} W_{j\omega}^{RT} \\
&- \sum_{d\omega} \pi_\omega VOLL_d L_{d\omega}^{sh} - \sum_{dk} \gamma_{dk}^{max} L_{dk}^{MAX} \\
&- \sum_{n(m \in \Theta_n)} T_{nm}^{MAX} \left(\xi_{nm}^{min} + \xi_{nm}^{max}\right) - \sum_{n(m \in \Theta_n)\omega} T_{nm}^{MAX} \left(\xi_{nm\omega}^{min} + \xi_{nm\omega}^{max}\right) \\
&- \sum_{n} \pi \left(\rho_n^{min} + \rho_n^{max}\right) - \sum_{n\omega} \pi \left(\rho_{n\omega}^{min} + \rho_{n\omega}^{max}\right)
\end{aligned}
\tag{A.4.30}
$$

Appendix B

Marginal utility of demand

This Appendix provides the pattern following the marginal utility (pairs of energy and prices) of the demand through a 24-hour time period. In Table B.1 each column corresponds to a time period of one hour and each row corresponds to a different bid price (€/MWh) while the relevant cells' entries represent the percentage of the total demand bid at this price. It can be seen that the demand is bid by 5 energy blocks, the first of which accommodates the 90% and each of the next four accommodates 2.5% of the total demand. The provided data are used in case studies of 6-bus and one-area RTS systems for both MPEC models presented in Chapters 3 and 4.

Table B.1: Marginal utility cost [€/MWh] of demand energy blocks [GWh] for each period of time

[€/MWh]	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
25.000												0.9												
24.968												0.025	0.9											
23.715											0.9	0.025	0.025							0.9	0.9			
22.628											0.025	0.025	0.025						0.9	0.025	0.025			
20.876											0.025	0.025	0.025						0.025	0.025	0.025	0.9		
20.606											0.025	0.025	0.025	0.9					0.025	0.025	0.025	0.025		
20.378										0.9	0.025			0.025				0.9	0.025	0.025	0.025	0.025		
19.922										0.025				0.025	0.9			0.025	0.025			0.025		
19.532										0.025				0.025	0.025			0.025				0.025		
19.232									0.9	0.025				0.025	0.025			0.025					0.9	
18.932									0.025	0.025					0.025		0.9	0.025					0.025	
18.806									0.025						0.025	0.9	0.025						0.025	
18.344									0.025							0.025	0.025						0.025	
18.152								0.9	0.025							0.025	0.025						0.025	
17.940								0.025								0.025	0.025							
17.612								0.025								0.025								0.9
17.430	0.9							0.025																0.025
17.250	0.025	0.9					0.9	0.025																0.025
17.216	0.025	0.025	0.9	0.9			0.025																	0.025
16.886	0.025	0.025	0.025	0.025	0.9	0.9	0.025																	0.025
16.790	0.025	0.025	0.025	0.025	0.025	0.025	0.025																	
16.380		0.025	0.025	0.025	0.025	0.025	0.025																	
16.320			0.025	0.025	0.025	0.025																		
16.130					0.025	0.025																		

Appendix C

Reliability Test System (RTS) of IEEE

This Appendix provides data for the modified IEEE one-area Reliability Test System (RTS). Figures C.1 and C.2 depict the networks used in case studies of Chapters 3 and 4 respectively. Technical data considering the conventional power generating units are provided in Table C.3. The two first rows indicate the ownership of the units. The third row indicates the type and the power capacity of each unit. The rows from four to eleven refer to the maximum size of the four power blocks offered by each unit and to their respective cost offers. The last four rows present the reserve capacity limits of each unit and the respective deployment cost offers. Finally, Table C.4 provides data for the the 17 demands of the system. The second column shows the location of each demand and the third column provides the load factor [%] of a total demand 2.85 GWh. Each demand is offered as shown in Table B.1. Finally, all the double circuit lines of the RTS are replaced by single ones with the same transmission capacity. The susceptance B_{nm} for all lines is 9.412 per unit, and the value of lost load $VOLL_d$ for each demand is 200 €/MWh .

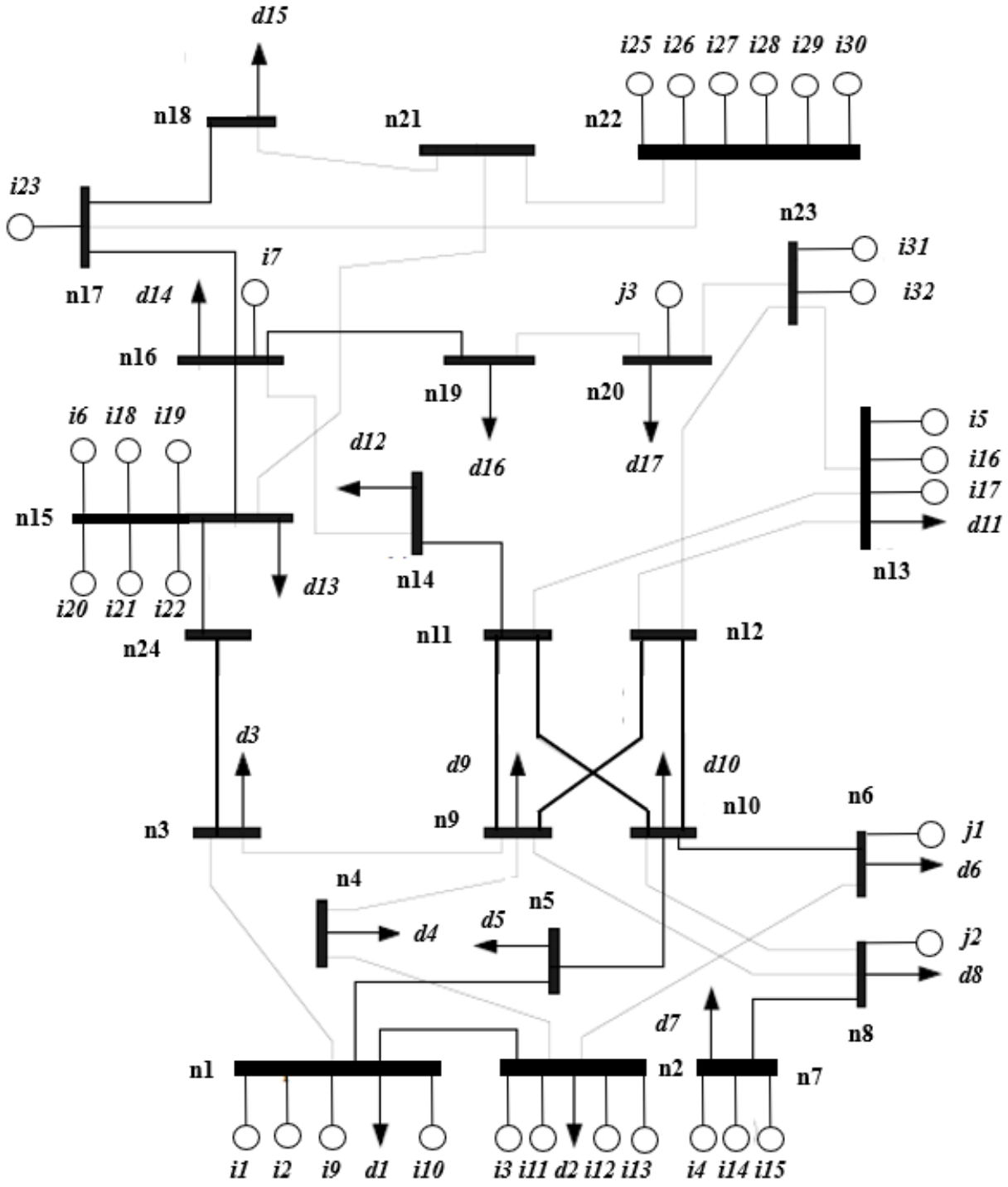

Figure C.1: RTS one-area network with only non-strategic wind generating units

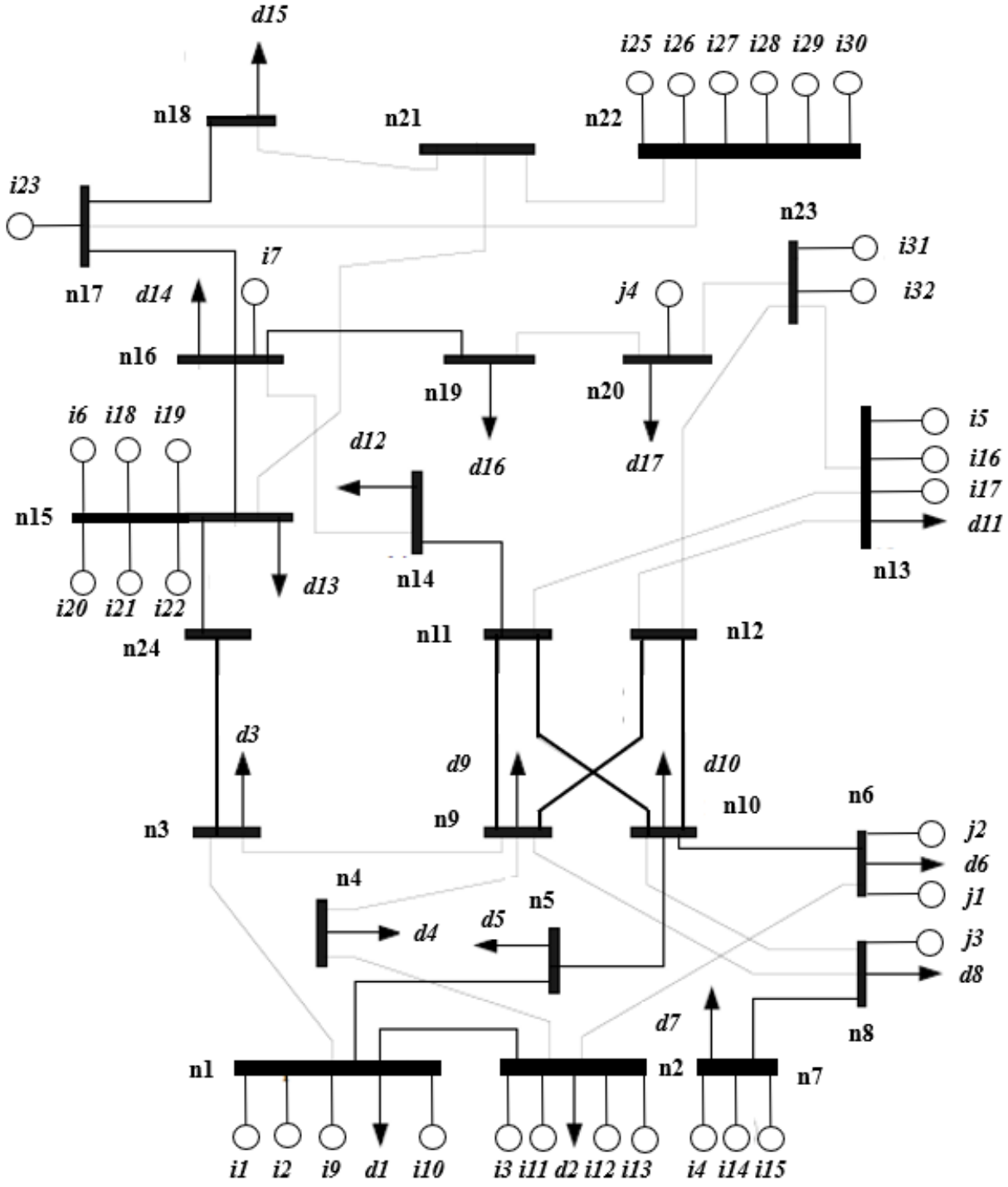

Figure C.2: RTS one-area network with strategic wind generating unit $j1$

Table C.1: Technical data for conventional units in RTS network

strategic units				$i1, i2, i3$	$i4$	$i6, i8$	$i5$		$i7$
non-strategic units	$i18, i19$ $i20, i21, i22$	$i9, i10$ $i11, i12$	$i25, i26, i27$ $i28, i29, i30$	$i13$	$i14, i15$	$i23, i31$	$i16, i17$	$i32$	$i24$
type $[MW]$	oil [12]	oil [20]	hydro [50]	coal [76]	oil [100]	coal [155]	oil [197]	coal [350]	nuclear [400]
$P_{i,b1}^{MAX}$ $[MWh]$	2.4	15.8	15	15.2	25	54.25	68.95	140	100
$P_{i,b2}^{MAX}$ $[MWh]$	3.4	0.2	15	22.8	25	38.75	49.25	97.5	100
$P_{i,b3}^{MAX}$ $[MWh]$	3.6	3.8	10	22.8	20	31	39.4	52.5	120
$P_{i,b4}^{MAX}$ $[MWh]$	2.4	0.2	10	15.2	20	31	39.4	70	80
$c_{i,b1}$ $[€/MWh]$	23.41	11.09	0	11.46	18.60	9.92	10.08	19.20	5.31
$c_{i,b2}$ $[€/MWh]$	23.78	11.42	0	11.96	20.03	10.25	10.66	20.32	5.38
$c_{i,b3}$ $[€/MWh]$	26.84	16.06	0	13.89	21.67	10.68	11.09	21.22	5.53
$c_{i,b4}$ $[€/MWh]$	30.40	16.24	0	15.97	22.72	11.26	11.72	22.13	5.66
RES_i^{UP} $[MW]$	12	20	-	30	90	60	90	90	120
RES_i^{DOWN} $[MW]$	12	20	-	30	90	60	90	90	120
c_i^{up} $[€/MWh]$	31.40	17.24	-	16.97	23.72	12.26	12.72	23.13	4.99
c_i^{down} $[€/MWh]$	22.41	10.09	-	10.46	17.60	8.92	9.57	18.20	6.65

Table C.2: Location and distribution of 2.85 GW total system demand [MW]

demand	bus	load factor [%]
$d1$	$n1$	3.8
$d2$	$n2$	3.4
$d3$	$n3$	6.3
$d4$	$n4$	2.6
$d5$	$n5$	2.5
$d6$	$n6$	4.8
$d7$	$n7$	4.4
$d8$	$n8$	6.0
$d9$	$n9$	6.1
$d10$	$n10$	6.8
$d11$	$n13$	9.3
$d12$	$n15$	6.8
$d13$	$n14$	11.1
$d14$	$n16$	3.5
$d15$	$n18$	11.7
$d16$	$n19$	6.4
$d17$	$n20$	4.5

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