

Stochastic-Based Models for Electricity Market Analysis with High Wind Energy Penetration

by

Sebastián Martín

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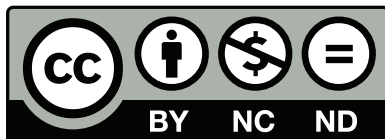
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that SEBASTIÁN MARTÍN has conducted under his supervision and guidance the Thesis entitled STOCHASTIC-BASED MODELS FOR ELECTRICITY MARKET ANALYSIS WITH HIGH WIND ENERGY PENETRATION presented in this memoir, that it meets all the legal requirements to qualify for the degree of PHILOSOPHY DOCTOR WITH INTERNATIONAL MENTION, and he grants permission to submit and proceed to public defense of this Thesis

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that SEBASTIÁN MARTÍN has conducted under his supervision and guidance the Thesis entitled STOCHASTIC-BASED MODELS FOR ELECTRICITY MARKET ANALYSIS WITH HIGH WIND ENERGY PENETRATION presented in this memoir, that it meets all the legal requirements to qualify for the degree of PHILOSOPHY DOCTOR WITH INTERNATIONAL MENTION, and he grants permission to submit and proceed to public defense of this Thesis

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I, Sebastián Martín, declare that this thesis titled, “Stochastic-Based Models for Electricity Market Analysis with High Wind Energy Penetration” and the work presented in it are my own. I confirm that:

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“Les hommes sont poussés par une curiosité si aveugle, que souvent ils dirigent leur esprit dans des voies inconnues, sans aucun espoir fondé, mais seulement pour essayer si ce qu’ils cherchent n’y seroit pas ; à peu près comme celui qui, dans l’ardeur insensée de découvrir un trésor, parcourrait perpétuellement tous les lieux pour voir si quelque voyageur n’y en a pas laissé un;”

René Descartes, Règles pour la direction de l’esprit.
Règle quatrième. Nécessité de la méthode dans la recherche de la vérité.
Texte de l’édition de 1826 par Victor Cousin.

“So blind is the curiosity by which mortals are possessed, that they often conduct their minds along unexplored routes, having no reason to hope for success, but merely being willing to risk the experiment of finding whether the truth they seek lies there.”

Translation by Elizabeth S. Haldane and G.R.T. Ross,
published in “Descartes. Key philosophical writings”,
Wordsworth Classics of World Literature

“The battles that count aren’t the ones for gold medals. The struggles within yourself - the invisible, inevitable battles inside all of us - that’s where it’s at.”

Jesse Owens
Blackthink: My Life as Black Man and White Man (1970)

Abstract

Stochastic-Based Models for Electricity Market Analysis with High Wind Energy Penetration

SEBASTIÁN MARTÍN , YVES SMEERS & JOSÉ A. AGUADO

Submitted as partial fulfillment of the requirements for
the Doctor of Philosophy Degree in Engineering with International Mention
University of Malaga

Renewable energy is now seen as an almost indispensable instrument to overcome or at least mitigate climate change. Wind and solar energy are among the most generally quoted renewable energy forms that are envisaged to offer the quantitative potential contribution to decarbonization, and between them, wind energy is the one usually considered to be closest to being economic. A system of incentives has been, and remains, necessary to foster the development of intermittent sources with the view of increasing their penetration into generation systems, sometimes at levels that are unjustified by current market conditions. The effects of incentive policies of the subsidy type are usually difficult to monitor, and unintended consequences should not come as a surprise. This is the case in the European Union, which has been at the forefront of the use of renewable energy with the result that subsidized intermittent capacities are now jeopardizing the short term economics of conventional units to a level that puts the adequacy of the system in question, with many new conventional plants being mothballed or dismantled because they are not profitable.

This thesis concentrates on the situation going on in some European countries, where the high penetration of renewable energy, combined with energy conservation and other events related to the economic crisis have lead to a reduction of wholesale electricity prices that questions the survival of conventional plants in the market. The main questions addressed are the loss of conventional assets value, the cost of the subsidies implied by the current policies, and the influence of the technical constraints (reserve, ramping constraints and uncertainty in wind generation) for the system operation.

The methodology consist of using equilibrium models based on stochastic programming. Two kinds of models are considered: *i)* a complementarity formulation for a multi-firm configuration that accounts for the separation between the PX and the TSO, and *ii)* a welfare maximization problem for a single firm configuration. All the models assume price taking agents and no market power with the objective to simplify the economic discussion and concentrate on the economic and physical issues of market design.

The use of the models is illustrated on two questions motivated by the current phenomena observed in Europe, that consist of conventional plants, necessary for providing services, are driven out of the market because of low energy prices. The common wisdom (and the observation of the market) is that renewable energies induce a decrease of energy prices together with a reduction of the activity, and the profit, of the conventional units. The models show that this phenomenon indeed seems rather stable under different structural assumptions (premium to wind generation and risk aversion), but it may also crucially depend on the demand for ancillary services (here frequency maintenance) induced by renewable energies and on their pricing by the market design. We find that a higher demand for load following reserve and an economically sound pricing (marginal cost pricing) restore the revenue of the conventional plants. The question of the sustainability of conventional plants then leads to the proper identification of the demand for services and the acceptance that they will be properly remunerated.

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Acronyms

CCGT	Combined Cycle Gas Turbine
CVaR	Conditional Value at Risk / Valor Condicional en Riesgo
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEC	Equilibrium Problem with Equilibrium Constraints
FOM	Fixed Operation and Maintenance cost
GENCO	Generation Company
ISO	Independent System Operator
KKT	Karush-Kuhn-Tucker
MISO	Midcontinent Independent System Operator
MPEC	Mathematical Problem with Equilibrium Constraints
OCGT	Open Cycle Gas Turbine
PX	Power Exchange
REE	Red Eléctrica de España
TSO	Transmission System Operator

Notation

Indices and sets

f, h, F	Indices and set for firms, $f, h \in F$.
G	Set of all generators.
G_f	Set of generators belonging to firm f .
g	Index for dispatchable generators, $g \in G$.
l	Index for wind generators, $l \in G$.
k, Ω	Index and set for scenarios, $k \in \Omega$.
t, T	Index and set for periods, $t \in T$.
w, Ξ	Index and set for the wind patterns, $w \in \Xi$.

Parameters

$\bar{A}$	Upper bound for the requirement of committed upward reserve. In the Spanish System $\bar{A} = 110\%$.
$\underline{A}$	Lower bound for the requirement of committed upward reserve. In the Spanish System $\underline{A} = 90\%$.
B	Lower rate for committed downward reserve respect to the committed upward reserve. In the Spanish System $B = 40\%$.
cg_g	Linear coefficient of generation cost for dispatchable generator g , [€/MWh].
D	Exogenous fixed value for energy demand in day ahead [MWh].
D_t	Exogenous fixed value for energy demand in day ahead for period t , [MWh].
m_y	Balancing reserve factor for wind turbines.
m_x	Balancing reserve factor for dispatchable generators.
Pr^k	Probability of scenario k .
$\text{Pr}(\mu_w)$	Probability of the wind pattern with expected wind value μ_w .
$\text{Pr}(\mu_w)^k$	Probability of the scenario k in the wind pattern with expected wind value μ_w .
Pri_f^k	Recalculated probability for the scenario k used in the iterative CVaR calculation for firm f .
$\bar{R}_g$	Upward ramping slope respect to the generation capacity for dispatchable generator g , usually $\bar{R}_g \in [0.02, 0.53]$ per hour.
$\underline{R}_g$	Downward ramping slope respect to the generation capacity for dispatchable generator g , usually $\underline{R}_g \in [0.02, 0.53]$ per hour.
$\bar{X}_g$	Maximum generation capacity of dispatchable generator g , [MW].

$\underline{X}_g$	Must-run capacity of dispatchable generator g , [MW]. In the case study $\underline{X}_g = 0$.
$\overline{Y}_l^k$	Maximum generation capacity available for wind turbine l in scenario k , [MW].
$\overline{Y}_{l,t}^k$	Maximum generation capacity available for wind turbine l in scenario k and period t , [MW].
$\overline{Y}_l^{max}$	Installed capacity of wind turbine l , [MW].
$\underline{Y}_l^k$	Must-run capacity of wind turbine l in scenario k , [MW]. In the case study $\underline{Y}_l^k = 0$.
$\underline{Y}_{l,t}^k$	Must-run capacity of wind turbine l in scenario k and period t , [MW]. In the case study $\underline{Y}_{l,t}^k = 0$.
α_0	Slope of the inverse demand function [$\text{€}/(\text{MWh})^2$].
$\alpha_{0,t}$	Slope of the inverse demand function at period t , [$\text{€}/(\text{MWh})^2$].
θ_f	Confidence level for firm f CVaR, $\theta_f \in (0, 1)$.
$\theta_{f,t}$	Confidence level for firm f CVaR at period t , $\theta_{f,t} \in (0, 1)$.
λ_f	Level of risk aversion, $\lambda_f \in [0, 1]$, $\lambda_f = 0$ risk neutral.
$\lambda_{f,t}$	Level of risk aversion for firm f at period t , $\lambda_{f,t} \in [0, 1]$, $\lambda_{f,t} = 0$ is risk neutral.
ρ_0	Independent coefficient of the inverse demand function, [$\text{€}/\text{MWh}$].
$\rho_{0,t}$	Independent coefficient of the inverse demand function at period t , [$\text{€}/\text{MWh}$].
ρ^+	Premium associated with the scheduled energy produced by a wind turbine, [$\text{€}/\text{MWh}$].
Δ_t^u	Total requirement of up ramp capability (reserve + ramping products) at period t in the configuration with MISO products, [MW].
Δ_t^d	Total requirement of down ramp capability (reserve + ramping products) at period t in the configuration with MISO products, [MW].

Primal variables

$d_{f,t}$	Energy sales of firm f at period t in day ahead, [MWh].
d_f	Energy sales of firm f in day ahead, [MWh].
$drc_{g,t}$	Ramping product for down ramp capability committed from dispatchable generator g at period t , [MW].
$Q_f^{k,-}$	Auxiliary variable for $CVaR_\theta$ computation [€].
$rd_{g,t}$	Committed downward reserve from dispatchable generator g at period t , [MW].
rd_g	Committed downward reserve from dispatchable generator g , [MW].
$ru_{g,t}$	Committed upward reserve from dispatchable generator g at period t , [MW].
ru_g	Committed upward reserve from dispatchable generator g , [MW].

$s_{g,t}^k$	Upward reserve energy deployed from dispatchable generator g at scenario k and period t , [MWh].
s_g^k	Upward reserve energy deployed from dispatchable generator g at scenario k , [MWh].
$u_{g,t}^k$	Downward reserve energy deployed from dispatchable generator g at scenario k and period t , [MWh].
u_g^k	Downward reserve energy deployed from dispatchable generator g at scenario k , [MWh].
$urc_{g,t}$	Ramping product for up ramp capability committed from dispatchable generator g at period t , [MW].
$v_{l,t}^k$	Wind energy in excess over the scheduled generation for wind turbine l at scenario k and period t , [MWh].
v_l^k	Wind energy in excess over the scheduled generation for wind turbine l at scenario k , [MWh].
$x_{g,t}$	Scheduled generation of dispatchable unit g at period t , [MWh].
x_g	Scheduled generation of dispatchable unit g , [MWh].
$y_{l,t}$	Scheduled generation of wind turbine l at period t , [MWh].
y_l	Scheduled generation of wind turbine l , [MWh].
$z_{l,t}^k$	Energy bought by wind turbine l at scenario k and period t , [MWh].
z_l^k	Energy bought by wind turbine l at scenario k , [MWh].
ζ_f	Auxiliary variable for $CVaR_\theta$ calculation.

Dual variables

$\bar{\gamma}$	Upper bound for committed upward reserve.
$\bar{\gamma}_t$	Upper bound for committed upward reserve at period t .
$\underline{\gamma}$	Upper bound for committed downward reserve.
$\underline{\gamma}_t$	Upper bound for committed downward reserve at period t .
$\bar{\delta}_g$	Upper bound for upward reserve that each generator can supply. Ramping constraint.
$\bar{\delta}_{g,t}$	Upper bound for upward reserve that each dispatchable generator g can supply at period t . Upward ramping constraint.
$\underline{\delta}_g$	Upper bound for downward reserve that each generator can supply. Ramping constraint.
$\underline{\delta}_{g,t}$	Lower bound for upward reserve that each dispatchable generator g can supply at period t . Upward ramping constraint.

$\bar{\epsilon}_{g,t}$	Upper bound for downward reserve that each dispatchable generator g can supply at period t . Downward ramping constraint.
$\underline{\epsilon}_{g,t}$	Lower bound for downward reserve that each dispatchable generator g can supply at period t . Downward ramping constraint.
$\bar{\eta}_g^k$	Upper bound for the energy from the committed upward reserve, dispatch. generator g , scenario k .
$\bar{\eta}_{g,t}^k$	Upper bound for the energy from the committed upward reserve, dispatchable generator g , scenario k and period t .
$\underline{\eta}_g^k$	Upper bound for the energy from the committed downward reserve, dispatch. generator g , scenario k .
$\underline{\eta}_{g,t}^k$	Upper bound for the energy from the committed downward reserve, dispatchable generator g , scenario k and period t .
$\bar{t}_l^k$	Upper bound for purchases of wind turbine l at scenario k .
$\bar{t}_{l,t}^k$	Upper bound for purchases of wind turbine l at scenario k and period t .
$\underline{t}_l^k$	Lower bound for purchases of wind turbine l at scenario k .
$\underline{t}_{l,t}^k$	Lower bound for purchases of wind turbine l at scenario k and period t .
$\bar{\kappa}$	Lower bound for committed upward reserve [€/MWh].
$\bar{\kappa}_t$	Lower bound for committed upward reserve at period t , [€/MWh].
$\underline{\kappa}$	Lower bound for committed downward reserve [€/MWh].
$\underline{\kappa}_t$	Lower bound for committed downward reserve at period t , [€/MWh].
ν_f	Power balance of firm f .
$\nu_{f,t}$	Power balance of firm f at period t .
ξ_l^k	Upper bound for sales in excess of wind turbine l at scenario k .
$\xi_{l,t}^k$	Upper bound for sales in excess of wind turbine l at scenario k and period t .
σ_f^k	$CVaR_\theta$ constraint.
τ_l^k	Constraint that relates the used and the available excess of wind for wind turbine l at scenario k .
$\tau_{l,t}^k$	Constraint that relates the used and the available excess of wind for wind turbine l at scenario k and period t .
$\bar{\phi}_g$	Upper bound capacity constraint of dispatchable generator g .
$\bar{\phi}_{g,t}$	Upper bound capacity constraint of dispatchable generator g at period t .
$\underline{\phi}_g^k$	Lower bound capacity constraint of dispatchable generator g at scenario k .

$\underline{\phi}_{g,t}^k$	Lower bound capacity constraint of dispatchable generator g at scenario k and period t .
$\bar{\chi}^k, \bar{\pi}^k$	Balancing with excess of wind at scenario k .
$\bar{\pi}_t^k$	Balancing with excess of wind at scenario k and period t .
$\underline{\chi}^k, \underline{\pi}^k$	Balancing with defect of wind at scenario k .
$\underline{\pi}_t^k$	Balancing with defect of wind at scenario k and period t .
$\bar{\psi}_l$	Upper bound capacity constraint of wind turbine l .
$\bar{\psi}_{l,t}$	Upper bound capacity constraint of wind turbine l at period t .
$\underline{\psi}_l^k$	Lower bound capacity constraint of wind turbine l at scenario k .
$\underline{\psi}_{l,t}^k$	Lower bound capacity constraint of wind turbine l at scenario k and period t .
$\bar{\omega}_t$	Total requirement for up ramp capability (reserve + ramping product) at period t in the configuration with MISO products.
ω_t	Total requirement for down ramp capability (reserve + ramping product) at period t in the configuration with MISO products.

Dedicated to all the people that believe a better world is possible, and especially to those who work for a sustainable future.

Chapter 1

Introduction

1.1 Overall Introduction

Renewable energy is now seen as an almost indispensable instrument to overcome or at least mitigate climate change. The concern is global even if its implementation still depends on local attitudes in the different regions of the world. Wind and solar energy are among the most generally quoted renewable energy forms that are thought to offer the quantitative potential contribution to decarbonization, and between them, wind energy is the one usually considered to be closest to being economic, at least when compared to conventional sources in “levelized cost” terms. But levelized costs only offer a very imperfect picture of the competitiveness of wind energy and other intermittent (non dispatchable) sources in generation systems (Joskow [1–3]), with the result that special incentives have been and remain necessary to foster the development of intermittent sources into generation systems, sometimes at levels that are unjustified by current market conditions. Incentive policies of the subsidy type, whether for fossil (IMF Report [4]) or renewable energy are always difficult to monitor, and unintended consequences should not come as a surprise. This is the case in the European Union, which has been at the forefront of the use of renewable energy with the result that subsidized intermittent capacities are now jeopardizing the short term economics of conventional units to a level that puts the adequacy of the system in question.

This thesis concentrates on a small, but potentially important, point of the evolution currently going on in some European countries. Specifically the high penetration of renewable, combined with energy conservation and other events related to the economic crisis have lead to a reduction of wholesale electricity prices that questions the survival of conventional plants in the market. The problem would be limited to a (already dramatic) loss of conventional assets value and (equally dramatic) cost of the subsidies implied by this policy, if it were not for the much more global adequacy problem that would emerge if it turns out that the generation system cannot survive without these conventional plants. Several studies indeed pointed to the limitations of the penetration of renewable energies in generation system because of their current poor performance for the supply of system services such as frequency and voltage control [5–12].

Basic economic reasoning tells us that this situation should not occur. A shortage of grid services because of the mothballing or dismantling of conventional units due to lower energy prices should increase the market value of these system services, and hence the additional remuneration of the plants that provide them. The two possible outcomes are then: *i*) either intermittent plants can provide the services and the elimination of conventional units will continue; *ii*) or the conventional units are better positioned to provide those services, and a

proper market design that remunerates these plants for the provision of services will keep (at least a fraction of) them on line. This thesis presents several models that try to look into that problem.

All the models of this thesis assume price taking agents. Several arguments can be put forward to justify this assumption; we only refer to two: *(i)* invoking market power requires assumptions on how this market power is exercised, and there are too many of these assumptions (especially when there are several products such in our models) for the discussion to remain unambiguous, *(ii)* the assumption of price taking agents simplifies the economic discussion and allows one to concentrate on basic economic and physical issues of market design.

With the aim of providing a framework for studying several factors affecting wind generation and its impact on the rest of the generation system, we elaborate our models on the basis of general market principles, but where wind policy and some specific features (e.g. balancing, ramping products) are inspired by the Spanish system or the Midcontinent Independent System Operator (MISO) [13, 14]. Resorting to particular implementations is unavoidable when dealing with questions that are not yet standardized in the industry.

Because of the importance of incentive policies in renewable energy regulation and the attention put on feed-in premium in the history of the Spanish system and in current European discussions [15], the model has been constructed on the basis of that policy, but with the view of also studying the effect of a several other relevant factors present in real systems. The factors considered are listed in what follows:

- 1) Premium to wind generation.
- 2) Level of wind availability.
- 3) Firms' risk aversion.
- 4) Wind power forecast error distribution.
- 5) Reserve requirement set by the Transmission System Operator (TSO).
- 6) Level of demand with respect to the installed power capacity.
- 7) Mothballing of existing power plants.
- 8) Pricing scheme for capacity of balancing reserve.
- 9) Pricing scheme for energy from balancing reserve.
- 10) Number of firms.
- 11) Technical capacity for ramping.
- 12) Organization of the balancing mechanism.
- 13) Myopia on the perception of balancing cost in day ahead market.

We consider three modeling approaches that correspond to different market organizations. One is a standard stochastic cost minimization model with fixed demand and single firm with stochastic wind generation. This would have been the reference model during the regulatory period; it is known that it can be interpreted as describing a perfectly competitive market where all agents, including wind generators, pay for the resources that they use and are

remunerated for the goods and services that they provide. The second model considers price responsive demand and a single firm; compared to the first model and in the context of wind penetration, it can be interpreted as a model where the variability of wind can be at least partially accommodated by some demand side system. This second approach is posed as a stochastic program maximizing the social welfare. This model also assumes a perfectly competitive market. The third approach extends this latter model to a equilibrium model with several firms and some market imperfections. It is posed as a complementarity problem, [16–31]. The interest of this extension is to allow for the fact that the uncertainties due to wind generation and its price effect are not necessarily internalized in a single firm model (or alternatively in a model where short run risk can be traded). A multi-firm model such as presented here accounts of the fact that, barring a sophisticated intraday market or some financial market of the virtual bidding type, this trading is not possible. Each one of these approaches is considered here in two settings, single period and multi-period, thus we study six basic models.

For the sake of presentation, these models are presented in reverse order: The multi-firm equilibrium model is the most general one and is presented first; the single firm equilibrium model is a particular case, which is itself a generalization of the single firm cost minimization model.

1.2 Methodology and Contributions

We construct different models trying to capture some important features of real markets, and we apply these models in a number of situations to develop some insight on the impact of these features on the outcome of the market. This section consists of four subsections: the main features to be modeled are described in the first subsection; the modeling approach is discussed in the second section; the philosophy for the case study is summarized next and finally the conclusions close this section.

1.2.1 Market and Model Features

We try to only include in the models some elements necessary to emulate the behaviour of the real markets with the view of building the capability to analyze some impact of wind penetration. The following summarizes the main elements of the models.

We consider firms that can own two type of units, dispatchable units (conventional generators) or wind turbines (non-dispatchable). Incentives to wind generation are modeled as a feed-in premium, that is an exogenous parameter ρ^+ . The models represent short term markets and are thus constructed with exogenous capacities. Because we are interested in the undergoing accelerated plant retiring process, the models are tested with different compositions of the generation park, in particular the difference is in the total dispatchable capacity installed. We also consider two models for demand, fixed demand (exogenous parameter) or price responsive demand (using a linear inverse demand function). Fixed demand model are of the “energy only” type and rely on a price cap represented by a “Backup generator” that sets an upper bound for the energy price in day ahead.

Regarding uncertainty, the models are formulated as two stages with wind generation being the only uncertainty. We consider different wind forecasts μ (expected wind) scenarios and deviations with respect to these forecasts that we represent on the event tree. These deviations are accommodated in a real time through a balancing mechanism that we model by taking inspiration from the Spanish system and some literature ([32]). The wind uncertainty

is explicitly taken into account by the firms, that manage the associated risk including the CVaR on the correction cost in their objective function. The firms define their position with respect to risk through an exogenous parameter λ , from risk neutral ($\lambda = 0$) to complete risk aversion ($\lambda = 1$).

We believe that we contribute to the literature by introducing a simplified, but still comparatively involved model of the reserve market and balancing mechanisms. Both are inspired by the Spanish system but the approach could be adapted to other situations. The previous features are included in all models. When relevant and possible, we also introduce ramping constraints that relate the generation capacity with the scheduled generation and the ramping capability available. These are constructed on the basis of the literature and an analysis of ramping products in the MISO system. These increase the system operational flexibility at a low cost.

These models are used in simulations under different assumptions on feed-in premium ρ^+ , level of risk aversion λ , wind forecast μ , ramping capability the price cap to energy in day ahead.

1.2.2 Modeling Approaches

The models of this thesis are posed either as stochastic optimization programs or as complementarity problems depending on the problems we want to focus on and computational possibilities. We believe that our complementarity formulation of the stochastic equilibrium model of the short term market contributes to the literature. In contrast with most of the literature that poses the problem of wind accommodation through stochastic (e.g. [33, 34]) or robust (e.g. [35]) optimization, we state it in equilibrium terms with risk averse agents and only consider optimization versions of the problem as particular cases. We justify the departure from optimization on several grounds. The first one is that wind penetration is generally supported by instruments that distort the market away from perfect competition and hence from a pure optimization formulation. This is the case of the feed in premium, which is the favorite EU proposal for reforming supports to renewable, as well as the feed in tariff which has been the rule in many European countries. These instruments imply market distortions that are incompatible with the perfect competition conditions implied by the pure optimization formulation of the short term power markets (e.g. two prices for the same product in a single market).

Instruments such as feed-in premium or tariffs also generate risk exposures that can be quite different for conventional and wind generators. Barring a mechanism of the virtual bidding type that does not exist in Europe, these risks are not tradable. This requires a multi-agent setting where agents face different non tradable risks. This is not amenable to a single agent representation (whether by stochastic, robust or risk function optimization) of the problem. Last European systems contain idiosyncrasies that further distort the market away from the perfect competition paradigm. One of them treated here implies non backward recursive payoffs in the sense that day ahead prices are also used in balancing notwithstanding the state of the world in real time. This forward passing of price is the opposite of the backward mechanisms that states day ahead prices as expectation of real time prices in stochastic programming. This again departs from what can be done by optimization formulations. We thus believe that the equilibrium formulation is a significant and useful departure from the more classical optimization approach at least for considering the European market design.

We work also with pure optimization problems in a single firm setting. The main reason is computational as explained below. The economic counterpart of this simpler set up is

twofold: the trade of risk between wind turbines and dispatchable generators is implicitly included in the optimization formulation (which eliminates one cause of non convexity) and both types of units pay for the ancillary services (only reserve in our models) according to their participation in the market (which eliminates a second cause of non convexity).

The pure optimization approach has also two main variants depending on the model used for demand. In the case of fixed demand the problem is posed as a cost minimization problem, and in the case of price responsive demand, the problem is posed as a welfare maximization problem. Another variant consist of the introduction of ramping products as they were proposed at MISO, these products are defined on several periods and add operational flexibility on top of the reserve. The idea of this products is to get a greater provision of ramping capability committed well in advance to avoid the high cost of committing ramp capability in a short time only when it is necessary. The advantage is that these products reduce the average cost of the energy from reserve, and the disadvantage is that we are paying for some products that we will use only with a low probability. We believe that the inclusion of the ramping products is new in the literature.

1.2.3 Case Studies

We apply the models to explore factors and market features that could affect the energy price and the firms' profits. The lowering of electricity prices as a result of wind penetration and the losses that it implied on the generator profits are indeed at the origin of the dramatic asset impairment incurred by the utilities. The main objective of our case studies is thus to understand how various factors and market features can affect these electricity prices and the generators' profits. The studies are summarized here with respect to what came out to be the main driving factors of this analysis, namely the excess generation capacity and the ramping possibilities. We refer to them as structural assumptions. For each structural assumption (that is assumption of generation capacity and ramping possibility) we consider the impact of different factors that we analyze systematically through the same four cases, namely:

- Impact of the wind forecast on the electricity price and revenue of wind and conventional generators.
- Effect of the premium on the electricity price and revenue of wind and conventional generators.
- Effect of risk aversion on the electricity price and revenue of wind and conventional generators.
- Effect of the demand for reserve on the electricity price and revenue of wind and conventional generators.

Each case consists of two situations corresponding to lower and upper bounds on the relevant parameter. These cases are defined in Section 4.4.5. All simulations were conducted on the same set of data; these data include the common parameters for the reserve constraints, the demand elasticity, the confidence level for the CVaR, and other parameters that are described in detail in Chapter 4.

This analysis is first conducted with the stochastic equilibrium model in complementarity formulation (referred to as Case study 1). This model better account for the economic market imperfections resulting from the market design. Besides the impact of the generation system, which was expected to be a major determinant of electricity prices and conventional generates

profits, the demand for reserve and the ramping capabilities turn out to be crucial factors. We believe that this analysis is a contribution to the literature for three main reasons. Besides showing the key role of the combination of ramping capabilities and demand for reserve as well as the modeling problem that it creates, it also reveals the important economic and numerical consequences of market imperfections. These appear through a multiplicity of isolated equilibria (an undesirable phenomenon) and through numerical difficulties with the very efficient PATH code, which required some numerical developments. The deep cause of both phenomena lies in the non convexities implied by the market imperfections.

The demand for reserve and the modeling of ramping are multi hourly problems that require a dynamic model. The above mentioned numerical difficulties encountered in the complementarity models could not be handled in this dynamical set up. The optimization formulation of the equilibrium problem drops some of these market imperfections: as stated above the trade of risk between wind turbines and dispatchable generators is implicitly included in the optimization formulation and both types of units pay for the ancillary services according to their participation in the market. This makes the problem easily amenable to a dynamic treatment that includes a better representation of ramping as well as the MISO ramping products. This is handled in a second set of studies (referred to as Case Study 2), The analysis here reveals the crucial role of the price cap on the revenue of the generators; this is admittedly not a new results but the novelty of our analysis maybe that it here arises from a much more realistic treatment of reserve and ramping. A by product of this analysis is to also reveal the origin of the subsidies that are now underlying the creation of strategic reserves to guarantee adequacy in Europe. Last we observe the changing role of the ramping products depending on whether we work with a price responsive or fixed demand model.

1.2.4 Conclusion

To summarize, we study a number of representations of the market for single period and multi-period, with price responsive or fixed demand, with price cap or without it, and with ramping products or without them. All these models and structural assumptions are described in detail in the next chapters.

While the thesis develops six theoretical models only three are used in the simulations. Future work will concentrate on numerical development to extend the dynamical treatment to the complementarity formulation and hence the use of the other models.

1.3 Thesis Organization

The Thesis consists of five chapters and two appendices, Chapter 1 is the present chapter. It starts with an overall introduction that puts the subject of the Thesis in context and gives the motivation for the study. It continues with a description of the methodology and a summary of the contributions. The next section is this outline of the document, and Chapter 1 ends with a brief literature review. The outline for the rest of the document is described in what follows:

- Chapter 2: The detailed description of the proposed models begins in this chapter. The chapter is devoted to a first type of equilibrium models that are posed as complementarity problems. The market features included in the models in this chapter are described in detail, with in particular: The modeling of wind uncertainty implemented, the ramping constraints, the day ahead market, the reserve market, the balancing mechanism for correcting deviations, and the scenario trees for wind.

Three variants of the models are discussed, together with a theoretical analysis of the operating mode of these models depending on the wind forecast and the reserve constraints. Finally, a description of the solution strategy implemented for the complementarity problems closes this chapter.

- Chapter 3: An extension of the models of Chapter 2 is described in this chapter. Only the new features with respect to the previous models are presented: in particular, the ramping constraints, and the new ramping products (following the proposals at MISO). Three models are described also in this chapter, the first one is posed as a complementarity problem, the other two are posed as pure optimization problems.
- Chapter 4: This chapter presents the case studies. It consists of three main parts:
 - The first part contains three sections: In the first section, various formula used to assess the outcome of the market are given. The second section is devoted to the description of the dismantling process of the dispatchable units; finally the third section reports the data used in the simulations for all the case studies.
 - The second part uses the models described in Chapter 2 to assess the impact of various policy of market characteristics on the outcome of the market (mainly the energy price in day ahead and the firm's profit).
 - Finally the last section in the chapter is focused on the case studies conducted with the models described in Chapter 4. It examines the dismantling process of the dispatchable units, how it is affected by the market features, and how it impacts the market outcome (energy price in day ahead and firm's profits).
- Chapter 5: This chapter summarizes the proceeding discussions. It also includes a summary of the particular contributions and the planned future lines of activities.
- Appendix A: This appendix contains additional data from the simulations; these data are not directly relevant for the discussions of the previous chapters, but they give additional details and complements.
- Appendix B: This appendix consists of an extended abstract of the Thesis in Spanish language.

The symbols and the acronyms used along the text are listed and described in the Notation and the Acronyms respectively.

1.4 Background

Because renewable energy contributes to reduce pollution and diversify energy supply, many countries have provided incentives to foster their penetration, in particular for wind and

⁵Configuration for dispatchable generation is described in Section 4.4, Tables 4.6 and 4.7.

⁶The parameters' values for cases 1 to 4 are described in Section 4.4, and a short summary is listed in Table 4.12.

⁷We consider two alternatives for demand: Price responsive demand (using a linear inverse demand function) or fixed demand.

⁸"B. Gen." stands for the generation cost of the Backup Generator in €/MWh, and it represents a price cap for the energy price in the system, it is described with more detail in Section 4.3.

⁹In this context "optimal" means the minimum value of the price cap (cost of the backup generator) that gives the minimum energy price in day ahead, this is explain with detail in Section 4.6.3.

Table 1.1: Summary of the models studied

Single Period	Multi-firm	Fix. dem.	P. Ramp. ¹	No MISO products ³	Backup gen. ⁴
		Price responsive	Parametric Ramping ¹	No MISO products ³	Backup gen. ⁴ (2.4)
					No Backup gen. ⁴ (2.4)
	Single firm	Fix. dem.	P. Ramp. ¹	No MISO products ³	Backup gen. ⁴ (2.6)
		Price responsive	Parametric Ramping ¹	No MISO products ³	Backup gen. ⁴ (2.5)
					No Backup gen. ⁴ (2.5)
Multi-Period	Multi-firm	Fixed demand	Common Ramping ²	MISO products ³	Backup gen. ⁴
				No MISO products ³	Backup gen. ⁴
		Price responsive demand	Common Ramping ²	MISO products ³	Backup gen. ⁴ (3.3)
					No Backup gen. ⁴ (3.3)
				No MISO products ³	Backup gen. ⁴ (3.3)
					No Backup gen. ⁴ (3.3)
	Single firm	Fixed demand	Common Ramping ²	MISO products ³	Backup gen. ⁴ (3.5)
				No MISO products ³	Backup gen. ⁴ (3.5)
		Price responsive demand	Common Ramping ²	MISO products ³	Backup gen. ⁴ (3.4)
					No Backup gen. ⁴ (3.4)
				No MISO products ³	Backup gen. ⁴ (3.4)
					No Backup gen. ⁴ (3.4)

Table 1.2: Summary of the case studies for the single period configuration.

Model	Param. Ramp. ¹	Gen. ⁵	Cases 1 to 4 ⁶
Single firm, single period, price responsive demand, no backup gen., no MISO products, (Section 2.5)	Ramping with $\Lambda = 1$	B2.1	Table 4.13
		B9.6	Table 4.15
	Ramping with $\Lambda = 0$	B2.1	Table 4.14
		B9.7	Table 4.16

Table 1.3: Summary of the case studies for the multi-period configuration.

Model	Demand ⁷	B. Gen. ⁸	Gen. ⁵	Cases 1 to 4 ⁶
Multi-period, single firm, with MISO products	Responsive (Sect. 3.4)	-	B9.5	Table 4.26
	Fixed demand (Section 3.5)	100	B9.5	Table 4.27
		300	B9.5	Table 4.28
		1000	B9.4	Table 4.29
		Optimal ⁹	B9.4	Table 4.30
	Responsive (Sect. 3.4)	-	B9.5	Table A.29
Multi-period, single firm, without MISO products	Fixed demand (Section 3.5)	100	B9.5	Table A.17
		300	B9.5	Table A.20
		1000	B9.4	Table A.23
		Optimal ⁹	B9.4	Table A.26

solar energy resources. Several countries in Europe, like Denmark (4.16 GW of installed wind power and a 27% of wind power share over total electricity consumption, data from 2012, [36]), Spain (22.21 GW, 16%), and Germany (29.06 GW, 11%), already show a high penetration of wind energy in their electricity generation mix. This trend is expected to extend to many other countries in the future.

High rates of wind and solar generation in power systems pose new challenges to policy makers, system operators and generation firms. As pointed out in [37–39], challenges include the impact of incentive policies, market design and operation issues (balancing market and operational flexibility). Agents' bidding behavior, the real cost of the wind power and the modeling of the wind power generation have also an important role.

Green Targets, Feed-in Tariffs, or Feed-in Premiums, [40] are the most common incentive policies. Their effects for wind are studied in [38] for the UK electricity market, and [41] shows how subsidies to wind can, under certain conditions, lead to bids with negative prices, greater global cost and emission increases.

The main operational problem associated with a high wind penetration comes from intermittency and unpredictability [42, 43]. In the case of large scale wind generation, which is the case considered here, wind power is no longer intermittent but remains highly variable. Balancing markets and operational flexibility are key elements of wind power integration. Conditions for an optimal balancing market have been studied by several authors, who conclude that cost-reflectiveness with respect to the imbalance price is a key condition for a balancing market to be optimal [32, 40].

The balancing market can be modeled through econometric relations giving balancing prices as functions of energy or through fundamental processes that could include an unit commitment [44]. Because balancing is an evolving process subject to continuous discussion, we do not rely on an econometric representation but introduce a fundamental equilibrium model (without explicit unit commitment). This model can be adapted, sometimes at the cost of additional computational manipulation, to different market designs (e.g. different pricing schemes). This is discussed in more detail in Section 2.4.4.

We refer to “flexibility reserve” as the reserve used in balancing to correct deviations due to wind forecast errors. The determination of the optimal quantity and price of the flexibility reserve is a question of great interest and a number of different solutions have been reported. In [45] a methodology that takes into account the uncertainty in the load and wind power forecasts and also the probability of generation failures is proposed to quantify the requirement for system reserve given a certain level of system reliability. The proposed methodology is applied to the all Ireland power system as a case study. A common approach to deal with uncertainty is to rely on stochastic programming, as in [33, 34]. The value of the operational flexibility is an other important notion, which has been studied, for instance, in [46]. In [47] it is shown how to optimize the operation in a short-term forward electricity market using the concept of “stochastic security”.

Regarding agents' behavior, a number of strategies for optimal bidding have been proposed in the academic literature. These strategies focus on uncertainty in the system and are often based on stochastic programming. In [48], a model to derive the best offering strategy for a wind power producer is initially posed as a mixed-integer nonlinear programming and, finally, reformulated and solved as an equivalent linear programming. More micro analysis of the behaviour of individual agents operating under uncertainty can be found in the literature such as in [49].

The use of stochastic programming for determining optimal offering strategies of wind power producers under uncertainty gives results more accurate than other methods that

consider less information. This is shown in [50], and also in [51], where the model is posed as a two-stage stochastic programming taking into account network constraints and a pool with a significant number of wind producers. In [52], optimal offers in quantity are calculated for wind power producers through a two-stage stochastic programming in which the information of prices and wind energy available are incorporated as exogenous parameters using a scenario tree. The CVaR is used as a measure for risk management.

Other approaches include second-order cone programming as in [35] where it was used to solve an optimal self-scheduling problem for a single firm based on a security constrained optimal power flow and considering risk management through the CVaR.

Chapter 2

Single Period Models

2.1 Introduction to Single Period Models

In this chapter we describe the framework for the definition of the models used to study the market. The framework is described simultaneously with the definition of three models for a single period configuration. Afterwards, this setting is extended to define the multi-period models. The framework includes:

- The modeling of wind uncertainty in Section 2.2. Wind generation is the only source of uncertainty considered here. It is modeled by mean of a probability distribution for the wind power forecast error. The two approaches discussed are those based on a Normal distribution or on a Beta distribution. We use the approach based on the Beta distribution.
- A representation of the ramping constraints adapted to the single period configuration, Section 2.3.
- A representation of the day ahead market (Section 2.4.2), the reserve market (Section 2.4.3), the balancing mechanism (Section 2.4.4), and the scenario for wind forecast (Section 2.4.5).

Three single period models of the short term power market (day ahead and real time) are presented in this chapter. They proceed from a multi-firm equilibrium model to a single firm optimization model. These models differ by some small modeling pieces that are described in detail in the next sections:

- 1) The most general model is posed as a multi-firm equilibrium problem, this model is described in Section 2.4, their equations are listed in Section 2.4.6, and the corresponding KKT conditions are summarized in Section 2.4.7. The model represents an industry of price taking agents facing a linear inverse demand function. Each firm owns dispatchable generators and wind turbines (non dispatchable generators). Wind speed cannot be foreseen in day ahead and is taken here as the only uncertain element in the model. It impacts the cash flow accruing to firms in balancing and hence introduces a risk for those firms. This uncertainty is modeled using a scenario tree and the corresponding risk captured in each firm's Conditional Value at Risk (CVaR) calculated on the correction cost. Firms sell at marginal cost and minimize their operation cost, including the balancing cost measured through their Conditional Value at Risk (CVaR). Each firm therefore solves a two stage stochastic programming problem. The overall model is posed as a complementarity

problem that includes the KKT conditions of the firms and market clearing equations. Specifically the model comprises:

- a) The Karush-Kuhn-Tucker (KKT) conditions from each firm's problem.
 - b) The global balance equations of the market, that in this case correspond to the reserve requirements in the system with price responsive demand or the reserve requirements and the total demand balancing in the case of fixed demand. The reserve requirements are set by the TSO. Global equations for energy balance are not needed in the case of price responsive demand because an energy balance equation is included in the problem of each firm, and total generation automatically meets total demand. In contrast, in the case of fixed demand, a global equation is needed to set total generation equal to total demand¹.
 - c) The KKT conditions of the problem of minimizing the generation cost from reserves. This problem is posed as a single price auction organized by the TSO with the objective of minimizing the cost of correcting deviations (mismatches between scheduled generation and scheduled demand). In this model only deviations due to the uncertainty associated to wind generators are considered.
- 2) Section 2.5 describes a single firm equilibrium model obtained from the previous model by setting the number of firms to one. Having a single firm does not mean introducing a monopoly as one assumes that the firm is regulated to sell at marginal cost. The single firm problem is simpler to use and also has a simpler economic interpretation in the sense that a single generator internalizes the risks associated to both conventional and wind generators. Except for this point, the single and multi-firm models are identical.
 - 3) The last model in this chapter is described in Section 2.6. It can be seen as representing an integrated company that minimizes its cost subject to an exogenous fixed demand. As before, the firm owns dispatchable generators and wind turbines (non dispatchable generators); it minimizes the operation cost. The operation cost includes the balancing cost, that is measured through the Conditional Value at Risk (CVaR) in the objective function. The problem is posed as a two stage risk function stochastic problem. This third model is the only one that can be formulated as an optimization problem. The formulation as a cost minimization problem indeed bypasses some of the intricacies of price formation (both in day ahead and balancing) present in the other models as will be discussed later.

Finally the chapter closes with Section 2.7, where several operation modes that can be described by the models in this chapter are discussed, and Section 2.8 where the solving strategy implemented for the complementarity problems in this chapter is described.

2.2 Modeling Wind Uncertainty in Single Period Models

2.2.1 Introduction

In this section we discuss and describe the model used for representing wind uncertainty, which is the only source of uncertainty considered in the models studied in this thesis. The

¹In the case of single firm configuration and fixed demand, the global balance equation for demand can be included in the firm's problem because the firm's generation has to meet the total fixed demand.

models are posed and solved for a short term horizon, hence we focus the discussion on the wind forecast error distribution instead of the wind forecast distribution.

In general (Giebel et al [43]), the methods for wind forecasting usually involve approaches based on Numerical Weather Prediction (NWP), as described in [53], and/or statistical approaches, [54]. A key feature of the wind forecasting models is the time scale, it is determined usually by the constraints associated with the technical operation of the system and/or the economic operation of the markets, for instance some of the activities listed in what follows:

- Turbine control itself: Milliseconds to seconds.
- Integration of wind power in the electrical grid: From minutes to weeks but usually in the range of hours. This time scale is determined by the time constants in the grid that depend on the typical activities in the grid, as described in [43]. The common activities include:
 - Allocation of reserves in day ahead based on wind forecast. For instance in Spain this is done between 32 h and 4 h in advance, [55] (Spanish grid code, in Spanish, Operation Procedure P.O. 3.1, Generation Scheduling, points 5.21, and 5.22 and Appendix I).
 - Optimal economic dispatch of conventional power plants. The time needed to schedule these plants depends on the generation technology and usually is in the range of 3-10 hours.
 - Optimization of the firms' strategies in the electricity market. In this case the time constant depends on the scheduling of market processes, like for instance the auctions in day ahead and intra-day markets, which in most European countries are in the range of 0-48 hours.
 - Maintenance planning, that usually requires longer time scales such as several weeks. But the wind forecast is not taken into account usually for more than one week because of the insufficient accuracy for time horizons longer than one week.

Two types of errors in predictions are usually considered, [43, 53]:

- Level errors: Referred to the amplitude of the values.
- Phase errors: Difference in the time when the expected values happen.

A number of authors, [43, 53, 54, 56–58], have identified the following factors as important for wind power forecast error:

- Prediction horizon. Typical prediction horizon in the market operation are in the range 1h to 48h.
- Spatial dispersion. Correlation between the error values in different wind farms are related with the distance separating them.
- Load factor = $\frac{\text{power output}}{\text{installed power}}$. The generation curve that relates the wind speed with the power output of wind generators is non-linear, and hence transforms the wind speed error, that usually fits a normal distribution, into a non-normal distribution of the power output error. The non-linearity of the generation curve is one of the main reasons of the dependence of power output error on the load factor. The dependence on the load factor of the error variance of the power output was studied in [54, 56].

The wind power forecast error seems to fit well to a beta distribution in the case of a single firm, [54, 57, 59], and to a normal distribution in the case of large scale wind generation, [44, 45, 47, 60, 61]. The main problem with the normal distribution is that it has an infinite range, while the error is bounded because the power output is in the range between zero and the installed power.

2.2.2 Wind Power Scenarios with Error Distribution $N(0, \sigma_N)$

In the case of large scale wind integration the wind power forecast error is assumed to be a normal distribution $N(0, \sigma_N)$ with zero average and standard deviation σ_N that, according to [54, 57, 60], depends on the forecast power output p_F , the prediction horizon and the installed wind power $\bar{P}$. Values for σ_N depending on these parameters are given graphically in [54, 57], and a linear fit for a prediction horizon of 24 hours given in [60] is reproduced here:

$$\sigma_N = \frac{1}{5}p_F + \frac{1}{50} \cdot \bar{P} \quad (2.2.1)$$

The wind power generation is modeled as a random variable $p = p_F + \epsilon_w$, where p_F is the forecast power output and $\epsilon_w \sim N(0, \sigma_N)$ is the error in the forecast power output.

We simplify by considering the standard normal distribution. The standard value of the error, z , is calculated dividing the original value by σ_N , $z = \frac{\epsilon_w}{\sigma_N} \sim N(0, 1)$, thus $\epsilon_w = z \cdot \sigma_N$.

The wind power output must be in the range between the must-run power $\underline{P}$, and the total installed wind power $\bar{P}$, these conditions set an upper bound and a lower bound for z :

- Upper bound: $\bar{P} \geq p = p_F + \epsilon_w = p_F + z \cdot \sigma_N \Rightarrow z \leq \frac{\bar{P} - p_F}{\sigma_N} \geq 0$.
- Lower bound: $\underline{P} \leq p = p_F + \epsilon_w = p_F + z \cdot \sigma_N \Rightarrow z \geq \frac{\underline{P} - p_F}{\sigma_N} \leq 0$.

The standardized variable z can takes values in the range $\left[\frac{\underline{P} - p_F}{\sigma_N}, \frac{\bar{P} - p_F}{\sigma_N}\right]$. Assuming a number n of scenarios, we divide the range for z in n segments using $n + 1$ points, $\frac{\underline{P} - p_F}{\sigma_N} = z_1 < z_2 < \dots < z_{n+1} = \frac{\bar{P} - p_F}{\sigma_N}$. Let be k the index for scenario, $k = 1, 2, \dots, n$, then each scenario k is associated with the segment $z \in [z_k, z_{k+1}]$, and the value and the probability of scenario k are:

- a) Value of scenario k : $\epsilon_w(k) = \sigma_N \int_{z_k}^{z_{k+1}} \frac{x}{\sqrt{2\pi}} e^{-\frac{x^2}{2}} dx = \frac{\sigma_N}{\sqrt{2\pi}} \left(e^{-\frac{z_k^2}{2}} - e^{-\frac{z_{k+1}^2}{2}} \right)$, that is the expected value on the segment that defines the scenario.
- b) Probability of scenario k , $pr(k) = \int_{z_k}^{z_{k+1}} \frac{1}{\sqrt{2\pi}} e^{-\frac{x^2}{2}} dx$, value of the probability density function integral of the standard normal distribution on the segment associated with the scenario.

Three strategies have been tested to build the points $\frac{\underline{P} - p_F}{\sigma_N} = z_1 < z_2 < \dots < z_{n+1} = \frac{\bar{P} - p_F}{\sigma_N}$:

- a) Uniform partition: All the segments of equal length, $l = z_{k+1} - z_k$, $k = 1, 2, \dots, n$.
- b) Segments with equal probability: $pr = \int_{z_k}^{z_{k+1}} \frac{1}{\sqrt{2\pi}} e^{-\frac{x^2}{2}} dx$, $k = 1, 2, \dots, n$.
- c) Segments with equal probability and an upper bound for the segment length. Minimizing the number of points with the following constraints:

- Probability: $\int_{z_k}^{z_{k+1}} \frac{1}{\sqrt{2\pi}} e^{-\frac{x^2}{2}} dx \leq pr, k = 1, 2, \dots, n.$
- Length of the segment: $z_{k+1} - z_k \leq l_{max}, k = 1, 2, \dots, n.$

For the three strategies the mean of the discretized distribution is equal to the mean of the original distribution because each segment is represented by its expected value. However, the variance could be different from the value for the original distribution. A comparison between the value of the variance for the discretized distribution σ' and the value for the original distribution σ as a quality measure $100 \frac{\sigma' - \sigma}{\sigma}$, for a given number of scenarios equal for the three strategies. The three strategies have been tested for values of $q \in [0.04, 0.65]$ that is a realistic range for large scale wind generation, and the results are:

- The strategy based on segments of equal probability gives better results than the strategy based on a combination of probability and segment length and this last approach is better than the uniform partition.
- For twelve scenarios the relative errors in variance (discretized distribution versus original distribution) are: Less than 1% for the segments with equal probability, less than 3% for the uniform partition, and a value between 1% and 3% (close to 1%) for the strategy that combines probability and an upper bound for segment lengths. Only the bounds are given for the errors because the particular values depend on the value of the expected power output p_F .

One of the advantages of using the normal distribution for wind power forecast error is that the load forecast error is also normal, and both random variables can be considered together using the jointly probability distribution, that is also normal. On the other hand the main disadvantage is that the range of the normal distribution is infinite while the error is bounded.

2.2.3 Wind Power Scenarios with Case Error Distribution $Beta(\alpha, \beta)$

This is the approach we use in the case studies. In [54] a beta distribution is proposed to represent the error distribution for wind power output. The proposal is supported by experimental data from wind farms in Northern Germany. Another conclusion based on the experimental analysis is that the dispersion of the error distribution depends strongly on the forecast value of the load factor for wind generators. As described in [54], the main advantages of the beta distribution to model wind power error distribution are:

1. It seems to fit quite well the experimental data.
2. The distribution is defined by only two parameters that can be calculated using explicit expressions based on the average and the variance of the error.
3. The range of the distribution is $[0, 1]$, that is the same that the range for the load factor.

Let be q load factor forecast, then according to [54] and [57] the load factor taking into account the error is a random variable that fits a Beta distribution with probability density function:

$$f_q(x) = \frac{\Gamma(\alpha + \beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} \quad (2.2.2)$$

where the parameters α and β depend on q , and $\frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)}$ is a scale factor such as $\int_0^1 f_q(x) dx = 1$.

The parameters α and β in the beta distribution for the load factor can be calculated given the values of the expectation μ and the standard deviation σ of the beta distribution. The method is described in [57] and [59], and it is summarized here.

The values of mean μ and variance σ of the $Beta(\alpha, \beta)$ distribution can be expressed in terms of the parameters α and β :

$$\mu = \frac{\alpha}{\alpha + \beta} \quad (2.2.3)$$

$$\sigma = \frac{\alpha\beta}{(\alpha + \beta)^2(\alpha + \beta + 1)} \quad (2.2.4)$$

The value of μ is the forecasted value for the load factor q , and the standard deviation σ is estimated usually from historical data for a given prediction horizon. According to [54, 57, 60] σ depends on q , the prediction horizon and the installed wind power $\bar{P}$. Values for σ_N depending on these parameters are given graphically in [54, 57], and a linear fit for a prediction horizon of 24 hours given in [60] is reproduced here (normalized by the installed power):

$$\sigma = \frac{1}{5}q + \frac{1}{50} \quad (2.2.5)$$

The values of the parameters α and β can be expressed in terms of the mean μ and variance σ of the $Beta(\alpha, \beta)$ distribution:

$$\alpha = \mu^2 \frac{1 - \mu}{\sigma^2} - \mu = q^2 \frac{1 - q}{\sigma^2} - q \quad (2.2.6)$$

$$\beta = \alpha \left(\frac{1}{\mu} - 1 \right) = \alpha \left(\frac{1}{q} - 1 \right) \quad (2.2.7)$$

To build the scenarios we divide the range $[0, 1]$ into segments and associate each scenario with a segment. Let be n the number of scenarios, k the index for scenario and $z_k \in [0, 1]$, then the range $[0, 1]$ is discretized using $n + 1$ points, $0 = z_1 < z_2 < \dots < z_{n+1} = 1$. the value and the probability of scenario k are:

- Value of scenario k : $x(k) = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^\alpha (1-x)^{\beta-1} dx$, that is the expected value on the segment that defines the scenario.
- Probability of scenario k , $pr(k) = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx$, value of the probability density function integral of the beta distribution on the segment associated with the scenario.

Three strategies have been tested to build the points $0 = z_1 < z_2 < \dots < z_{n+1} = 1$:

- Uniform partition: All the segments of equal length, $l = z_{k+1} - z_k$, $k = 1, 2, \dots, n$.
- Segments with equal probability: $pr = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx$, $k = 1, 2, \dots, n$.
- Segments with equal probability and an upper bound for the segment length. Minimizing the number of points with the following constraints:
 - Probability: $\int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx \leq pr$, $k = 1, 2, \dots, n$.
 - Length of the segment: $z_{k+1} - z_k \leq l_{max}$, $k = 1, 2, \dots, n$.

For the three strategies the mean of the discretized distribution is equal to the mean of the original distribution because each segment is represented by its expected value. However the variance could be different from the value for the original distribution. A comparison between the value of the variance for the discretized distribution σ' and the value for the original distribution σ as a quality measure $100 \frac{\sigma' - \sigma}{\sigma}$, for a given number of scenarios equal for the three strategies. The three strategies have been tested for values of $q \in [0.04, 0.65]$ that is a realistic range for large scale wind generation, and the results are:

- The strategy based on segments of equal probability gives better results than the strategy based on a combination of probability and segment length and this last approach is better than the uniform partition.
- For twelve scenarios the relative errors in variance (discretized distribution versus original distribution) are: Less than 2% for the segments with equal probability, less than 5% for the uniform partition, and a value between 2% and 5% (close to 2%) for the strategy that combines probability and an upper bound for segment lengths. Only the bounds are given for the errors because the particular values depend on the value of the expected load factor q .

2.3 Parametric Ramping

Here we describe the ramping constraints used in the single period setting. In what follows we first recall the ramping constraints commonly used in the unit commitment problem, following [62], second the adaptation from multi-period to single period is described, and finally the “parametric ramping” model implemented in the single period setting is defined. The parametric ramping comes from the introduction of a parameter Λ in the ramping constraints adapted to single period, with the objective to model different levels of ramping capability.

Ramping constraints in the unit commitment problem

The commonly used ramping constraints in the unit commitment problem involves multi-period and usually are defined as follows [62]:

- 1) The ramping capacity of a particular generator g is a fixed quantity that does not depend on the generation level at each time. In our model, the upward ramping capacity for generator g is $\bar{R}_g \cdot \bar{X}_g$, and the downward ramping capacity is $\underline{R}_g \cdot \bar{X}_g$.
- 2) The available ramping capacity at some time period is constrained by the total generation capacity, hence high levels of scheduled generation can reduce the available ramping capacity. The ramping constraints for a generator g are then:

$$x_{g,t} - x_{g,t-1} \leq \bar{R}_g \cdot \bar{X}_g \quad (\text{in case of increasing generation}) \quad (2.3.1)$$

$$x_{g,t-1} - x_{g,t} \leq \underline{R}_g \cdot \bar{X}_g \quad (\text{in case of decreasing generation}) \quad (2.3.2)$$

where $x_{g,t}$ is the scheduled power output of generator g at period t .

Adaptation to single period setting

In the single period models we do not have the information on the ramp capability used in scheduled dispatchable generation $(x_{g,t+1} - x_{g,t})$. To take this into account in the single period model we consider that its value is proportional to the current scheduled generation x_g , that is an endogenous variable in the model. In particular, we approximated the value of the ramping capacity used to change the scheduled generation by:

- $\bar{R}_g \cdot x_g$ in the case of the upward ramp capability.
- $\underline{R}_g \cdot x_g$ in the case of the downward ramp capability.

Thus, in the case of a single period model the ramping constraints are:

$$ru_g \leq \bar{R}_g \cdot (\bar{X}_g - x_g) \quad (2.3.3)$$

$$rd_g \leq \underline{R}_g \cdot (\bar{X}_g - x_g) \quad (2.3.4)$$

On the other hand, the available ramping capacity is also subject to the generator's capacity bounds:

$$ru_g \leq \bar{X}_g - x_g \quad (2.3.5)$$

$$rd_g \leq x_g - \underline{X}_g \quad (2.3.6)$$

To summarize, the remaining available ramping capabilities adapted to single period are:

$$ru_g \leq \min \{ \bar{X}_g - x_g, \bar{R}_g \cdot (\bar{X}_g - x_g) \} \quad (2.3.7)$$

$$rd_g \leq \min \{ x_g - \underline{X}_g, \underline{R}_g \cdot (\bar{X}_g - x_g) \} \quad (2.3.8)$$

Parametric ramping constraints

Finally we introduce a parameter $\Lambda \in [0, 1]$ in the previous ramping constraints for single period, (2.3.3) and (2.3.4), to consider the variability of ramping capacity used in the scheduled generation, $(x_{g,t+1} - x_{g,t})$. The following parametric ramping constraints are the ramping constraints we use in the single period models:

$$ru_g \leq \bar{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g) \quad (2.3.9)$$

$$rd_g \leq \underline{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g) \quad (2.3.10)$$

In the simulations we consider only two values for the parameter Λ : *i*) $\Lambda = 1$ that models a low ramping capability because it assumes that a significant amount of ramping capability is already used in scheduled generation, and *ii*) $\Lambda = 0$ that models a high ramping capability, because it assumes the extreme case in which no ramping capability is used in scheduled generation.

To summarize, the ramping constraint used in the single period models is taken from a model commonly used in the unit commitment but after adaptation to the available information. In order to illustrate the importance of ramping, we conduct variations of the case studies by also adopting this parametric formulation of ramping and comparing the result for low and high ramping in Section 4.5.

2.4 The Multi-Firm Equilibrium Problem with Price Responsive Demand

2.4.1 Introduction

Electricity markets around the world show a wide range of organizations for handling wind integration. The model presented in this section is inspired by the Spanish case but may also be of interest to other countries in view of current European plans for supporting renewable energy [15].

We consider a two settlements system with a day ahead energy market and a real time balancing mechanism. The Power eXchange (PX) clears the energy market in day-ahead under imperfect wind forecast. The TSO deals with reserves; these appear in two markets namely the “market for reserve” and “balancing”. The “market for reserves” takes place in day ahead and results in committed upward and downward capacity reserves ru_g and rd_g . Balancing uses the capacities committed for reserve in real time². Here we focus on the operation mechanism in an hour, and simplify the treatment by not explicitly considering any intra-day market.

Reserve and balancing deal with deviations with respect to scheduled quantities in day ahead. We focus on deviations due to wind. Deviations, up and down, are cleared by dispatchable generators within the reserve capacities committed in day ahead. Deviations are modeled through a scenario tree with each scenario representing the wind power output realization in one hour³. The model is set up for a day ahead time horizon with an hourly time granularity. All these assumptions give our model a standard two stage structure. The reader can easily convince himself that many of these simplifications can be technically removed in order to scale up the model.

Generators, consumers, and the TSO are the agents in the model. Generators operate dispatchable (conventional) generators with linear cost (without fixed operating cost) and wind turbines with zero generation cost. Generators are risk averse, with their behavior described by a *CVaR* function computed on the correction cost. Consumers are represented by a linear inverse demand function in the day ahead energy market. They are charged a fraction of the socialized cost of the reserve capacity through an ex-post network charge that, for the sake of simplicity, is not taken into account in the model. The government subsidizes scheduled wind generation through a premium that is financed by the general budget. Premium can be related to the spot price but it is here taken as an exogenous parameter in order to both simplify the presentation and allow for sensitivity analysis.

Agents are price takers in the day ahead energy and reserve market and in the real time balancing market. The energy market is typically modeled by a technology driven supply curve (marginal cost) and a linear demand function (marginal willingness to pay). The need for reserves is represented by a set of upper and lower bound constraints, that equate the supply and demand of that energy in balancing (see (2.4.9) and (2.4.10) in Section 2.4.4).

This version of the model relies on a complementarity representation of the pricing mechanism for balancing energy from reserve (see (2.4.8)-(2.4.12) in Section 2.4.4). Finally, network constraints are not considered; in this model the TSO is involved only in the organization of

²In some electricity markets, like the Spanish market, there exists an intra-day market with intermediate auctions in the time between day ahead and real time; these auctions contribute to reduce the cost associated with the wind forecast error [48, 63].

³Deviations of demand and generation contingencies can be included in the scenario tree at the cost of additional technical developments. We simplify the presentation by considering wind deviations as the only stochastic elements.

the reserve market and the balancing mechanism.

2.4.2 Day Ahead Market and Premium

The PX clears the energy and the TSO clears the market for reserves committed, both on an hourly basis in day ahead. We assume imperfect wind forecast. Day ahead outcomes depend on an imperfect wind forecast but not on real time wind realization.

The energy market is modeled by a standard technology driven supply curve (marginal cost) and a linear demand function (marginal willingness to pay) represented by the inverse demand function

$$\rho = \rho_0 - \alpha_0 \cdot d_T \quad (2.4.1)$$

where ρ is the price for energy in day ahead and d_T is the total demand. The clearing of the day ahead energy market determines sales d_h , scheduled wind y_l and dispatchable generation x_g .

Scheduled wind generation y_l receives a feed-in premium ρ^+ (exogenous parameter), that adds to the equilibrium price in the generators' revenue. It is not directly paid by customers but charged to the general budget. Only the scheduled wind generation that is actually generated in real time receives the feed-in premium; the wind that was scheduled, but finally not generated, loses the feed-in premium in the balancing mechanism. No feed-in premium is paid to the wind energy that is generated in real time but was not scheduled.

In the Spanish market this premium was given until 12th July 2013, by a piecewise linear function with a floor and a cap, as described in [64]. We simplify the mechanism and assume a fixed premium ρ^+ .

The contribution of the day ahead energy market to the revenue of firm f is:

$$\sum_{l \in G_f} y_l \cdot (\rho^+ + \rho^*) + \sum_{g \in G_f} x_g \cdot (\rho^* - cg_g) \quad (2.4.2)$$

where ρ^* is the value of the price ρ , cleared by the energy market. $\sum_{l \in G_f} y_l \cdot (\rho^+ + \rho^*)$ is the revenue accruing to scheduled wind (feed-in premium and equilibrium price) and $\sum_{g \in G_f} x_g \cdot (\rho^* - cg_g)$ is the revenue collected by the scheduled dispatchable generation (equilibrium price minus generation cost).

2.4.3 Reserve Model

The TSO clears the market for committed flexible reserves on an hourly basis in day ahead. Different types of reserves are used in real power systems. It is convenient to classify them in two groups: i) those intervening for load-frequency control are usually very fast (seconds) and automatically operated; ii) those devoted to load-following operate on longer times (hours) and are part of the market [65]. This model concentrates on a load-following requirements due to wind that we call flexibility reserve; these imply ramping requirements and balancing for accommodating deviations from wind forecast. Flexibility reserve is procured by the TSO from dispatchable generators in day ahead and results in two products: capacities of committed upward (ru_g) and downward (rd_g) reserves in the day ahead.

In real power systems the requirement of flexibility reserves is usually based on deterministic and/or simple probabilistic approaches [66] with more than one criteria commonly used for sizing the load-following reserves. We here follow [67] and dynamically determine the required flexibility reserve on the basis of the generation scheduled from different units.

We use the linear function $R_u = m_y \sum_{l \in G} y_l + m_x \sum_{g \in G} x_g$ of the scheduled generation to determine the upward reserve requirement R_u by the TSO. The committed upward reserve must meet $\underline{A} \cdot R_u \leq \sum_g ru_g \leq \bar{A} \cdot R_u$. On the other hand, the amount of committed downward reserve rd_g is set by the amount of committed upward reserve and several constraints inspired by the operation of real power systems, in particular the Spanish system. The coefficients m_y and m_x appearing in this relation, called balancing reserve factors, are exogenous and reflect the uncertain need for reserve associated with each technology. The whole set of constraints for reserve in the model is as follows (2.4.3)-(2.4.6):

$$\sum_{g \in G} ru_g \geq \underline{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right], \quad (\bar{\kappa}), \quad (2.4.3)$$

$$\sum_{g \in G} rd_g \geq B \cdot \sum_{g \in G} ru_g, \quad (\underline{\kappa}), \quad (2.4.4)$$

$$\sum_{g \in G} ru_g \leq \bar{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right], \quad (\bar{\gamma}), \quad (2.4.5)$$

$$\sum_{g \in G} rd_g \leq \sum_{g \in G} ru_g, \quad (\underline{\gamma}). \quad (2.4.6)$$

where (2.4.3) and (2.4.4) are the upper bound constraints for the upward and the downward reserve capacities respectively, and (2.4.5), (2.4.6) are the corresponding lower bound constraints. These constraints are inspired by the operation of real power systems, in particular the Spanish system.

The revenue accruing to firm f from committing flexibility reserve in the TSO day ahead reserve market is:

$$\sum_{g \in G_f} (ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) \quad (2.4.7)$$

where $\bar{\kappa} + \bar{\gamma}$ (€/MW) is the shadow price of capacity for committed upward reserve, and $\underline{\kappa} + \underline{\gamma}$ (€/MW) is the shadow price of capacity for committed downward reserve.

2.4.4 Balancing Mechanism Model

The balancing of real power systems must accommodate demand prediction errors, system contingencies, uncertainty of non dispatchable generation and forecast errors. We simplify the discussion by considering only wind power forecast errors, which are usually the largest demand for load following in the short term in system with high wind penetration [45]. The standard economic paradigm is that these services should be charged at marginal reserve cost to those that demand them, and paid at the same value to those that produce them. Other pricing mechanisms such as penalization factors on the market prices [38], [32] can be also applied.

Here, we consider a simplified and economically standard approach where the price and the amount of balancing energy from committed reserve result from a perfectly competitive market. The market is modeled as an optimization problem that minimizes the generation cost of balancing energy. This problem represents an auction organized by the TSO. From a modeling point of view, the result of this auction is integrated in the equilibrium through its KKT conditions. Let s_g^k and u_g^k be respectively the energy deployed from upward and

downward flexible reserve ru_g and rd_g in real time. Let also z_l^k and v_l^k be the energy bought or sold by wind turbines in real time to compensate the discrepancy between what had been scheduled in day head and what could be delivered in real time. The energy that can be deployed from reserves is limited by the amount of reserves committed. The auction is modeled, for each scenario k , as the following optimization problem:

$$\underset{s_g^k, u_g^k}{\text{minimize}} \sum_{g \in G} (s_g^k \cdot cg_g - u_g^k \cdot cg_g) \quad (2.4.8)$$

$$\text{subject to: } \sum_{g \in G} s_g^k = \sum_{l \in G} z_l^k, \quad (\bar{\pi}^k) \quad (2.4.9)$$

$$\sum_{g \in G} u_g^k = \sum_{l \in G} v_l^k, \quad (\underline{\pi}^k) \quad (2.4.10)$$

$$s_g^k \leq ru_g, \quad (\bar{\eta}_g^k) \quad (2.4.11)$$

$$u_g^k \leq rd_g, \quad (\underline{\eta}_g^k) \quad (2.4.12)$$

where the variables are s_g^k and u_g^k , and the fixed input data are the committed upward ru_g and downward rd_g reserve determined in real time, as well as the real time demand and supply of energy z_l^k and v_l^k by wind units. The constraints are the balancing between the energy used by wind turbines and energy provided by dispatchable generators for downward reserve (2.4.9), and upward reserve (2.4.10). Each unit can provide balancing energy only from the capacity that has been previously committed in the reserve market (2.4.11), (2.4.12). The objective function (2.4.8) minimizes the generation cost from reserves using the committed generators with the minimum generation cost for upward reserve and those with the maximum cost for the downward reserve to supply the energy from reserves.

The effect of balancing on revenue and cost differs depending on whether wind realization is short or in excess. This is taken into account by the balancing cost for firm f at scenario k given by the recourse function Q_f^k :

$$\begin{aligned} Q_f^k = & \sum_{g \in G_f} \left[s_g^k \cdot (cg_g - \bar{\pi}^k) + u_g^k \cdot (\rho^* - cg_g - \underline{\pi}^k) \right] + \\ & + \sum_{l \in G_f} \left[z_l^k \cdot (\rho^* + \bar{\pi}^k) + v_l^k \cdot (\underline{\pi}^k - \rho^*) \right] \end{aligned} \quad (2.4.13)$$

where ρ^* is the energy price on the day ahead market and $\bar{\pi}^k$ and $\underline{\pi}^k$ are the energy prices from committed upward and downward reserve respectively from (2.4.9) and (2.4.10).

In case of wind shortage, the cost incurred by wind turbine l that is short by z_l^k in scenario k is $z_l^k \cdot (\bar{\pi}^k + \rho^*)$: The plant loses the premium for the energy committed in the day ahead market and has to substitute it by conventional energy in balancing at the equilibrium price of committed upward reserve. On the other hand, the cost of a dispatchable generator g for providing the upward reserve energy s_g^k is $s_g^k \cdot (cg_g - \bar{\pi}^k)$, which is the unitary generation cost cg_g minus the price of the committed upward reserve $\bar{\pi}^k$.

In case of wind in excess, a wind turbine can sell an amount v_l^k in excess on its scheduled generation (ranging from zero to the available excess). Its revenue is $v_l^k \cdot (\rho^* - \underline{\pi}^k)$, which involves the unitary cost of downward reserve energy $\underline{\pi}^k$ and the revenue from selling the energy at the equilibrium price ρ^* . Alternatively, the cost incurred by the dispatchable generator g in scenario k to down u_g^k from its committed downward reserve to incorporate the additional wind is $u_g^k \cdot (\rho^* - cg_g - \underline{\pi}^k)$. The unitary cost is the equilibrium price ρ^* , which

was already incorporated in the day ahead revenue, from which one subtracts the generation cost cg , minus the non generated energy and the price of downward balancing energy π^k .

Summing up the balancing model uses a two-price settlement with one price for the upward energy and other price for the downward energy. The wind turbines do not lose the equilibrium price in balancing but they do not get the premium for quantities that they scheduled in day ahead and do not deliver in real time.

2.4.5 Scenario Tree

The output of wind turbines is the only uncertainty considered in the model. It is represented by a scenario tree where each branch stands for a realization of the wind power output for one hour.

We use a Beta distribution to model the wind power forecast error [54, 57]. Let the load factor for wind generation be $q = \frac{\text{Power output}}{\text{Rated power}} \in [0, 1]$, then according to [54, 57] this load factor fits a Beta distribution:

$$f(q) = \frac{\Gamma(\alpha + \beta)}{\Gamma(\alpha)\Gamma(\beta)} q^{\alpha-1} (1-q)^{\beta-1}, \quad q \in [0, 1] \quad (2.4.14)$$

where $\frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)}$ is a scale factor such as $\int_0^1 f(x)dx = 1$, and the parameters α and β are directly related with the mean (μ) and the standard deviation (σ) of the distribution:

$$\alpha = \mu^2 \frac{1-\mu}{\sigma^2} - \mu, \quad \beta = \alpha \left(\frac{1}{\mu} - 1 \right) \quad (2.4.15)$$

The analysis of empirical data shows that σ properly fits a linear function of μ , $\sigma = k_1 \mu + k_2$, [54, 57, 60], where the coefficients k_1 and k_2 depend mainly on the time horizon and the geographic dispersion of the wind turbines. Here we use the expression given in [60] for a time horizon of 24 h and large scale generation (normalized by the wind capacity installed):

$$\sigma = \frac{1}{5} \mu + \frac{1}{50} \quad (\text{in per unit}) \quad (2.4.16)$$

To build the scenarios, we divide the range $[0, 1]$ for the load factor into segments and associate each scenario with a segment. Let n be the number of scenarios, k the index for scenario and $z_k \in [0, 1]$, then the range $[0, 1]$ is discretized using $n + 1$ points, $0 = z_1 < z_2 < \dots < z_{n+1} = 1$. the value and the probability of scenario k are:

- a) Value of scenario k : $\mu(k) = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx$, that is the expected value on the segment that defines the scenario.
- b) Probability of scenario k , $pr(k) = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx$, integral value of the probability density function of the Beta distribution on the segment associated with the scenario.

The rule to select the points $0 = z_1 < z_2 < \dots < z_{n+1} = 1$ is to get segments of equal probability: $\frac{1}{n} = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1} (1-x)^{\beta-1} dx$, $k = 1, 2, \dots, n$.

2.4.6 Model Equations

The multi-firm equilibrium problem with responsive demand is described by equations (2.4.17)-(2.4.38). The model is cast as a complementarity problem [18, 28, 29, 31, 68] defined by the KKT conditions (2.4.42)-(2.4.60) described in Section 2.4.7, and it consists of three groups of equations:

1. Global constraints (2.4.3)-(2.4.6): They are the reserve constraints described in Section 2.4.3. They represent the reserve capacity constraints of the market cleared by the TSO. Generators trade in this market at the prevailing clearing prices. These constraints are not included in the firms' KKT conditions but their dual variables appear in the objective functions of the firms.
2. The KKT conditions (2.4.46)-(2.4.51) for the minimization of generation cost for energy from reserve associated with the clearing of the balancing energy market (2.4.8)-(2.4.12) are described in Section 2.4.4.
3. The KKT conditions (2.4.52)-(2.4.60) for the problem of each firm, that is represented by (2.4.17)-(2.4.29) and next described. The optimization problem for each firm includes only the conditions for which the firm can make explicit decisions, taking market prices (energy, committed reserve capacity, ramping contracts and balancing energy) as given.

Each firm f poses a two stage stochastic programming with $E - CVaR[Profit_f^k] = (1 - \lambda_f) \cdot E[Profit_f^k] + \lambda_f \cdot CVaR[Profit_f^k]$ as the objective function to maximize, where $E[\square] = \sum_k \Pr^k \cdot \square$ is the expectation on the scenarios, $\lambda_f \in [0, 1]$ is the level of risk aversion ($\lambda_f = 0$ is risk neutral) and $Profit_f^k$ is the net profit for firm f at scenario k . $Profit_f^k = P_f - Q_f^k$ where P_f is the net profit of firm f in the first stage, that does not depend on the scenarios, and Q_f^k is the value of the recourse function (2.4.13) described in Section 2.4.4. Taking into account the previous definitions we can write the objective function (2.4.17) as $P_f - (1 - \lambda_f) \cdot E[Q_f^k] - \lambda_f \cdot CVaR[Q_f^k]$.

The net profit in the first stage P_f includes the incomes from energy sales $(\rho_0 - \alpha_0 \sum_{h \in F} d_h) \cdot d_f$, from committed reserve $\sum_{g \in G_f} (ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma}))$, from the feed-in premium to wind generation $\sum_{l \in G_f} y_l \cdot \rho^+$, and the cost of dispatchable generation $\sum_{g \in G_f} x_g \cdot cg_g$. The optimization problem for each firm f is:

$$\begin{aligned} \max_{d, x, y, z, rd, ru, v, \zeta, Q^-} & \left\{ (\rho_0 - \alpha_0 \cdot \sum_{h \in F} d_h) \cdot d_f + \sum_{l \in G_f} y_l \cdot \rho^+ + \sum_{g \in G_f} (ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) \right. \\ & \left. - \sum_{g \in G_f} x_g \cdot cg_g - (1 - \lambda_f) \cdot \sum_k \Pr^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \Pr^k \cdot Q_f^{k,-} \right) \right\} \end{aligned} \quad (2.4.17)$$

$$\text{subject to: } x_g + ru_g \leq \bar{X}_g, \quad (\bar{\phi}_g) \quad (2.4.18)$$

$$x_g + s_g^k - rd_g \geq \underline{X}_g, \quad (\underline{\phi}_g^k) \quad (2.4.19)$$

$$y_l \leq \bar{Y}_l^{\max}, \quad (\bar{\psi}_l) \quad (2.4.20)$$

$$y_l - z_l^k \geq \underline{Y}_l^k, \quad (\underline{\psi}_l^k) \quad (2.4.21)$$

$$\sum_{g \in G_f} x_g + \sum_{l \in G_f} y_l = d_f, \quad (\nu_f) \quad (2.4.22)$$

$$z_l^k \leq \bar{Y}_l^{\max} - \bar{Y}_l^k, \quad (\bar{\tau}_l^k) \quad (2.4.23)$$

$$y_l - z_l^k \leq \bar{Y}_l^k, \quad (\bar{\tau}_l^k) \quad (2.4.24)$$

$$v_l^k \leq \bar{Y}_l^k, \quad (\xi_l^k) \quad (2.4.25)$$

$$v_l^k + y_l - z_l^k \leq \bar{Y}_l^k, \quad (\tau_l^k) \quad (2.4.26)$$

$$ru_g \leq \bar{R} \cdot (\bar{X}_g - x_g), \quad (\bar{\delta}_g) \quad (2.4.27)$$

$$rd_g \leq \underline{R} \cdot (\bar{X}_g - x_g), \quad (\underline{\delta}_g) \quad (2.4.28)$$

$$\zeta_f + Q_f^{k,-} \geq Q_f^k \quad (\sigma_f^k) \quad (2.4.29)$$

where $d, x, y, z, rd, ru, s, u, v, Q_f^{k,-}$ are positive variables.

Equations (2.4.18)-(2.4.29) comprise upper and lower bounds for dispatchable plants (2.4.18), (2.4.19), and wind turbines (2.4.20), (2.4.21), energy sales in day ahead (2.4.22), upper and lower bounds for the purchases of wind turbines due to shortage of wind (2.4.23), (2.4.24). Wind in excess cannot be greater than available wind (2.4.25). Energy balance for wind turbines (2.4.26). Ramping for upward (2.4.27) and downward (2.4.28) reserve, with $\underline{A}$, $\bar{A}$, B , $\bar{R}$ and $\underline{R}$ being exogenous parameters. Constraint (2.4.29) is an auxiliary constraint for the CVaR calculation. The model is implemented and solved using the software PATH in GAMS [69]. To summarize, the rest of equations that complete the definition of the multi-firm equilibrium model are:

- Global constraints (described in detail in Section 2.4.3):

$$\underline{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right] \leq \sum_{g \in G} ru_g, \quad (\bar{\kappa}), \quad (2.4.30)$$

$$B \cdot \sum_{g \in G} ru_g - \sum_{g \in G} rd_g \leq 0, \quad (\underline{\kappa}), \quad (2.4.31)$$

$$\bar{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right] \geq \sum_{g \in G} ru_g, \quad (\bar{\gamma}), \quad (2.4.32)$$

$$\sum_{g \in G} rd_g - \sum_{g \in G} ru_g \leq 0, \quad (\underline{\gamma}) \quad (2.4.33)$$

- Optimization problem, one problem for each scenario k , for minimization of generation cost from reserves (described in detail in Section 2.4.4):

$$\underset{s_g^k, u_g^k}{\text{minimize}} \sum_{g \in G} (s_g^k \cdot cg_g - u_g^k \cdot cg_g) \quad (2.4.34)$$

$$\text{subject to: } \sum_{g \in G} s_g^k = \sum_{l \in G} z_l^k, \quad (\bar{\pi}^k) \quad (2.4.35)$$

$$\sum_{g \in G} u_g^k = \sum_{l \in G} v_l^k, \quad (\underline{\pi}^k) \quad (2.4.36)$$

$$s_g^k \leq ru_g, \quad (\bar{\eta}_g^k) \quad (2.4.37)$$

$$u_g^k \leq rd_g, \quad (\underline{\eta}_g^k) \quad (2.4.38)$$

One can note that the formulation of the profit of the firm in this model

$$\begin{aligned} Profit_f = & \rho^* \cdot d_f + \sum_{l \in G_f} y_l \cdot \rho^+ + \sum_{g \in G_f} (ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) \\ & - \sum_{g \in G_f} x_g \cdot cg_g - \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^k \end{aligned} \quad (2.4.39)$$

involves an equilibrium price ρ^* intervening both in day ahead and balancing (see definition of Q_f^k in (2.4.13)). This differs from standard stochastic optimization that relies on a strict backward recursive formulation. It implies this first model cannot therefore be restated as an optimization problem. This mathematically unattractive formulation is justified by the need to represent features of the market design that are true market distortions but motivated by compromises among stakeholders. Allowing for these features is thus necessary in order to accommodate real markets.

The model presents another difficulty in the sense that it involves different firms, each driven by its own CVaR criterion. In [70] is argued that this leads to a incomplete market (in economic parlance) and to non convexities in mathematical programming terms. This fact in itself would also prevent the problem to be formulated as an optimization problem. It also creates numerical difficulties, a discussion of techniques for overcoming them are presented in Chapter 2.8.

2.4.7 KKT Conditions

This section summarizes the whole set of equations of the equilibrium problem. Let be $\mathcal{L}_f$ the Lagrangian function for firm f , $\mathcal{L}_B$ the Lagrangian function for the problem of minimization of generation cost from reserve.

Taking into account the equations (2.4.17)-(2.4.29) in the previous section, the Lagrangian function $\mathcal{L}_f$ for a firm f is:

$$\begin{aligned}
& \mathcal{L}_f(d_f, rd_g, ru_g, v_l^k, x_g, y_l, z_l^k, Q_f^{k,-}, \zeta_f, \\
& \bar{\delta}_g, \underline{\delta}_g, \bar{v}_l^k, \underline{v}_l^k, \nu_f, \xi_l^k, \sigma_f^k, \tau_l^k, \bar{\phi}_g, \underline{\phi}_g, \bar{\psi}_l, \underline{\psi}_l^k) = \\
& - \left[(\rho_0 - \alpha_0 \cdot \sum_{h \in F} d_h) \cdot d_f + \sum_{g \in G_f} (-x_g \cdot cg_g + ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) \right. \\
& + \sum_{l \in G_f} y_l \cdot \rho^+ \left. \right] + \left[\lambda_f \cdot (\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-}) + (1 - \lambda_f) \cdot \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^k \right] \\
& + \sum_{g \in G_f} (\bar{\phi}_g \cdot (x_g + ru_g - \bar{X}_g) + \bar{\delta}_g \cdot (ru_g - \bar{R} \cdot (\bar{X}_g - x_g)) + \underline{\delta}_g (rd_g - \underline{R} \cdot (\bar{X}_g - x_g))) \\
& + \sum_{l \in G_f} \bar{\psi}_l \cdot (y_l - \bar{Y}_l^{\max}) + \sum_{l \in G_f} \sum_{k \in \Omega} \underline{\psi}_l^k \cdot (-y_l + z_l^k + \underline{Y}_l^k) + \nu_f \cdot (\sum_{g \in G_f} x_g + \sum_{l \in G_f} y_l - d_f) \\
& + \sum_{l \in G_f} \sum_{k \in \Omega} (\bar{v}_l^k \cdot (z_l^k - \bar{Y}_l^{\max} + \bar{Y}_l^k) + \underline{v}_l^k \cdot (y_l - z_l^k - \bar{Y}_l^k)) + \\
& + \sum_{l \in G_f} \sum_{k \in \Omega} (\xi_l^k \cdot (v_l^k - \bar{Y}_l^k) + \tau_l^k \cdot (v_l^k - \bar{Y}_l^k + y_l - z_l^k)) \\
& + \sum_{g \in G_f} \sum_{k \in \Omega} \underline{\phi}_g^k \cdot (\underline{X}_g - x_g - s_g^k + rd_g) + \sum_{k \in \Omega} \sigma_f^k \cdot (Q_f^k - \zeta_f - Q_f^{k,-}).
\end{aligned} \tag{2.4.40}$$

where the primal variables are $d_f, rd_g, ru_g, v_l^k, x_g, y_l, z_l^k, Q_f^{k,-}, \zeta_f$, and the dual variables are $\bar{\delta}_g, \underline{\delta}_g, \bar{v}_l^k, \underline{v}_l^k, \nu_f, \xi_l^k, \sigma_f^k, \tau_l^k, \bar{\phi}_g, \underline{\phi}_g, \bar{\psi}_l, \underline{\psi}_l^k$.

The Lagrangian function $\mathcal{L}_B$ for the problem, (2.4.8)-(2.4.12), of minimization cost of

generation from reserves is:

$$\begin{aligned} \mathcal{L}_B(s_g^k, u_g^k; \bar{\pi}^k, \underline{\pi}^k, \bar{\eta}_g^k, \underline{\eta}_g^k) = & \sum_{g \in G} (s_g^k \cdot cg_g - u_g^k \cdot cg_g) + \\ & + \bar{\pi}^k \cdot \left(\sum_{l \in G} z_l^k - \sum_{g \in G} s_g^k \right) + \underline{\pi}^k \cdot \left(\sum_{l \in G} v_l^k - \sum_{g \in G} u_g^k \right) \\ & + \sum_{g \in G} \left[\bar{\eta}_g^k \cdot (s_g^k - ru_g) + \underline{\eta}_g^k \cdot (u_g^k - rd_g) \right] \end{aligned} \quad (2.4.41)$$

where the primal variables are s_g^k, u_g^k , and the dual variables are: $\bar{\pi}^k, \underline{\pi}^k, \bar{\eta}_g^k, \underline{\eta}_g^k$.

The whole equilibrium problem consists of three groups of equations: 1) The global constraints, 2) The KKT conditions for the minimization of generation cost from reserves, and 3) The KKT conditions for each firm f .

1) The global constraints are:

$$\sum_{g \in G} ru_g \geq \underline{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right], \quad (\bar{\kappa}), \quad (2.4.42)$$

$$\sum_{g \in G} rd_g \geq B \cdot \sum_{g \in G} ru_g, \quad (\underline{\kappa}), \quad (2.4.43)$$

$$\sum_{g \in G} ru_g \leq \bar{A} \cdot \left[m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l \right], \quad (\bar{\gamma}), \quad (2.4.44)$$

$$\sum_{g \in G} rd_g \leq \sum_{g \in G} ru_g, \quad (\underline{\gamma}). \quad (2.4.45)$$

2) The KKT conditions for the minimization of generation cost from reserves are:

$$\frac{\partial \mathcal{L}_B}{\partial s_g^k} = cg_g - \bar{\pi}^k + \bar{\eta}_g^k \geq 0, \quad \perp \quad s_g^k \geq 0 \quad (2.4.46)$$

$$\frac{\partial \mathcal{L}_B}{\partial u_g^k} = -cg_g - \underline{\pi}^k + \underline{\eta}_g^k \geq 0, \quad \perp \quad u_g^k \geq 0 \quad (2.4.47)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\pi}^k} = \sum_{l \in G} z_l^k - \sum_{g \in G} s_g^k = 0, \quad \bar{\pi}^k \text{ free} \quad (2.4.48)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\pi}^k} = \sum_{l \in G} v_l^k - \sum_{g \in G} u_g^k = 0, \quad \underline{\pi}^k \text{ free} \quad (2.4.49)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\eta}_g^k} = s_g^k - ru_g \leq 0, \quad \perp \quad \bar{\eta}_g^k \geq 0 \quad (2.4.50)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\eta}_g^k} = u_g^k - rd_g \leq 0, \quad \perp \quad \underline{\eta}_g^k \geq 0 \quad (2.4.51)$$

3) The KKT conditions for the primal variables of each firm f are:

$$\frac{\partial \mathcal{L}_f}{\partial d_f} = -(\rho_0 - \alpha_0 \sum_{h \in F} d_h) - \nu_f \geq 0 \quad \perp \quad d_f \geq 0 \quad (2.4.52)$$

$$\frac{\partial \mathcal{L}_f}{\partial r d_g} = -(\underline{\kappa} + \underline{\gamma}) + \sum_{k \in \Omega} \underline{\phi}_g^k + \underline{\delta}_g \geq 0 \quad \perp \quad r d_g \geq 0 \quad (2.4.53)$$

$$\frac{\partial \mathcal{L}_f}{\partial r u_g} = -(\bar{\kappa} + \bar{\gamma}) + \bar{\phi}_g + \bar{\delta}_g \geq 0 \quad \perp \quad r u_g \geq 0 \quad (2.4.54)$$

$$\frac{\partial \mathcal{L}_f}{\partial v_l^k} = \left((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k \right) \cdot (\underline{\pi}^k - \rho^*) + \xi_l^k + \tau_l^k \geq 0 \quad \perp \quad v_l^k \geq 0 \quad (2.4.55)$$

$$\frac{\partial \mathcal{L}_f}{\partial x_g} = c g_g + \bar{\phi}_g - \sum_{k \in \Omega} \underline{\phi}_g^k + \nu_f + \underline{R} \cdot \underline{\delta}_g + \bar{R} \cdot \bar{\delta}_g \geq 0 \quad \perp \quad x_g \geq 0 \quad (2.4.56)$$

$$\frac{\partial \mathcal{L}_f}{\partial y_l} = -\rho^+ + \bar{\psi}_l + \sum_{k \in \Omega} (\tau_l^k + \underline{L}_l^k - \underline{\psi}_l^k) + \nu_f \geq 0 \quad \perp \quad y_l \geq 0 \quad (2.4.57)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial z_l^k} &= \left((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k \right) \cdot (\bar{\pi}^k + \rho^+) + \underline{\psi}_l^k + \\ &\quad + \bar{L}_l^k - \underline{L}_l^k - \tau_l^k \geq 0 \quad \perp \quad z_l^k \geq 0 \end{aligned} \quad (2.4.58)$$

$$\frac{\partial \mathcal{L}_f}{\partial Q_f^{k,-}} = \frac{\lambda_f}{1 - \theta_f} \text{Pr}^k - \sigma_f^k \geq 0 \quad \perp \quad Q_f^{k,-} \geq 0 \quad (2.4.59)$$

$$\frac{\partial \mathcal{L}_f}{\partial \zeta_f} = \lambda_f - \sum_{k \in \Omega} \sigma_f^k = 0; \quad \zeta_f \quad \text{free} \quad (2.4.60)$$

2.4.8 Discussion on Firms' Profit and Energy Price in Day Ahead

The energy price in the model described in this section is discussed following two approaches, first a sensitivity analysis on the firms' optimization problem for certain relevant parameters, and second we look at the KKT conditions that include explicitly the energy price in day ahead.

Sensitivity analysis for firm's profit

The sensitivity analysis is performed on the firm's optimization problem, for the parameters: Wind forecast $\bar{Y}_l^k$, feed-in premium to wind generation ρ^+ , and the level of risk aversion λ . We apply the extension of the envelope theorem to non-convex optimization problems described in [71]. This way we can get the derivatives of the result of firm's optimization problem from the derivatives of its Lagrangian function $\mathcal{L}_f$.

The objective function in the firm's optimization problem is the E-CVaR of the firm's profit, this magnitude is directly related with the firm's profit. We consider the sensitivity analysis for the E-CVaR[Profit] instead of the profit, to simplify the analysis. The optimization problem of each firm is posed as a minimization problem, hence a negative value of the derivative means that an increase of the parameter value tends to increase the E-CVaR[Profit] of the firm. The discussion for the three parameters, $\bar{Y}_l^k$, ρ^+ and λ , is described in what follows:

- a) The sensitivity of the Lagrangian function respect to the expected wind $\bar{Y}_l^k$ is:

$$\frac{\partial \mathcal{L}_f}{\partial \bar{Y}_l^k} = -i_l^k - \xi_l^k - \tau_l^k \leq 0 \quad (2.4.61)$$

We observe two opposite effects, on one hand a reduction of the generation cost because generation from wind replaces the generation from the most expensive dispatchable generators, and on the other hand a reduction on the energy price that reduces the incomes, so that the net effect is an increase of the E-CVaR[Profit].

- b) The sensitivity of the firm's Lagrangian function respect to the feed-in premium ρ^+ is:

$$\frac{\partial \mathcal{L}_f}{\partial \rho^+} = - \sum_{l \in G} y_l + \sum_{k \in \Omega} \left[(1 - \lambda_f) \cdot \text{Pr}^k + \lambda_f \cdot \text{Pri}_f^k \right] z_l^k \quad (2.4.62)$$

where λ is the level of risk aversion, Pr^k is the probability of scenarios and Pri_f^k is the probability of the scenarios in the CVaR.

The sign of this derivative depends on the balance between the incomes from the feed-in premium to the scheduled wind and the cost to buy energy due to a shortage of wind. The cost depends on the risk position and the scenarios in the CVaR (confidence level of the CVaR), in practical terms it depends on the relation between the value of the scheduled wind generation and the wind forecast. The ρ^+ increases the CVaR[Profit] when the derivate is negative, what in turn requires values of scheduled wind not far above the wind forecast (low risk positions).

- c) The sensitivity of the Lagrangian function respect to the level of risk aversion λ is:

$$\frac{\partial \mathcal{L}_f}{\partial \lambda_f} = \sum_{k \in \Omega} (\text{Pri}_f^k - \text{Pr}^k) Q_f^k = \text{CVaR}[Q_f] - E[Q_f] \geq 0 \quad (2.4.63)$$

This derivative is always greater or equal to zero, that means that increasing the risk aversion leads to a reduction of the CVaR[Profit]. We have observed in the results from the simulations that increasing the risk aversion reduces the total generation and, in particular, the scheduled wind. Because the risk aversion λ is the weight of the $\text{CVaR}[Q]$ in the objective function, and the firm's reaction to an increase in λ is to reduce the balancing cost, what in turn strongly depends on the scheduled wind.

Discussion of the KKT conditions with energy price

We look now at the KKT conditions in which the equilibrium price, $\rho^* = \rho_0 - \alpha_0 \cdot \sum_f d_f$, appears explicitly, that are the KKT conditions for: *i*) demand (2.4.52), *ii*) dispatchable generation (2.4.56), and *iii*) wind generation (2.4.57). With this analysis we can infer how certain market features affect the equilibrium price of energy in day ahead.

The KKT condition for demand (2.4.52) sets that the equilibrium price is equal to minus the value of the dual variable for the generation-demand balancing constraint (2.4.22), $-\nu$, whenever demand is different from zero. The generation-demand balancing constraint in this case stands for the equality constraint that states generation equals demand, and it involves three groups of variables: 1) the demand d_f , 2) the scheduled dispatchable generation x_g , and 3) the scheduled wind generation y_l . Therefore we look at those equations:

a) The KKT condition for the scheduled dispatchable generation (2.4.56) relates the dual variable $-\nu$, and therefore the equilibrium price ($\rho^* = -\nu$ if $d \neq 0$), with:

- 1) the generation cost (fuel cost for each dispatchable generator),
- 2) the dual variable for the lower bound constraint for upward reserve ($\bar{\kappa}$),
- 3) minus the value of the dual variable for the upper bound constraint for downward reserve ($\bar{\gamma}$),
- 4) the dual variable for the upper bound constraint of dispatchable generation capacity,
- 5) minus the value of the dual variable for the lower bound constraint of dispatchable generation (the must-run generation constraint).

The positive values (a.1, a.2, a.4) contribute to increase the energy price in day ahead, and the negative values (a.3, a.5) contribute to reduce that price. Thus the generation cost and the activation of the upper bound of the dispatchable generation capacity constraint, contribute to increase the energy price in day ahead, on the other hand to have as much downward reserve as possible and to keep the must-run generation contributes to reduce the equilibrium price.

b) The KKT condition for the scheduled wind generation (2.4.57) relates the dual variable $-\nu$ (energy price in day ahead) with:

- 1) minus the value of the premium to wind generation ρ^+ ,
- 2) the dual variable of the upper bound constraint for the wind availability, (potential wind generation)
- 3) the dual variable for the lower bound constraint for upward reserve ($\bar{\kappa}$),
- 4) the dual variable for the scheduled-excess balancing for wind generation, this constraint is active when the wind generator has to buy energy to fulfill its delivery or it sells the wind excess until reach the total available wind generation.
- 5) the dual variable for the constraint of wind balancing in case of wind shortage, this constraint is active if the wind generator has to buy energy to fulfill its delivery.
- 6) minus the value of the dual variable for the upper bound constraint for downward reserve ($\bar{\gamma}$),
- 7) minus the value of the dual variable for the lower bound constraint for wind generation,

The positive values (b.2, b.3, b.4, b.5) contribute to increase the equilibrium price, while the negative values (b.1, b.6, b.7) contribute to reduce the equilibrium price.

In general the sensitivities respect to the values of the dual variables in (a) and (b) are different because these dual variables are multiplied by different coefficients in each case. To summarize, the energy price in day ahead is:

- Reduced by: The premium, the availability of downward reserve (the more the downward reserve the better), and the lower bound for wind generation, that is the must-run capacity, in our simulations it is fixed to zero, but it could be greater to zero for technical reasons.
- Increased by: Shortage of wind respect to the system capacity to integrate wind, the lack of downward reserve, shortage of wind respect to the scheduled wind generation,

upper capacity bound of wind turbines if it limits the real wind generation (available wind power that can not be converted to electrical power), the dispatchable generation cost, not enough upward reserve, not enough dispatchable generation capacity.

The equilibrium price is also affected by the downward reserve energy price through the KKT conditions for energy deployed from upward reserve and for energy deployed from downward reserve.

2.5 The Single Firm Equilibrium Problem with Price Responsive Demand

We get the single firm equilibrium model with price responsive demand from the previous model (2.4.17)-(2.4.38) by fixing the index f for firms to a value of 1. In this case we can remove the index f in the model equations, and the recourse function Q^k is simplified to the following expression, due to the fact that all generators belong to the same firm:

$$Q^k = \sum_{g \in G} c g_g \cdot (s_g^k - u_g^k) + \sum_{g \in G} z_l^k \cdot \rho^+ \quad (2.5.1)$$

A single firm model does not necessarily represent a monopoly exercising market power. Our formulation of the model supposes that firms continues to sell at marginal cost, an assumption that goes back to the early days of the regulated monopoly in the power economic literature. Besides being easier to interpret in terms of result, the formulation also assume that wind and conventional generators internalize wind risk. Preliminary numerical experiments conducted but not thoroughly analyzed with the single and multi versions of the model show that single and multiform models indeed do not behave in the same way. The results reported in this thesis are all obtained with single firm models.

2.6 Single Firm Equilibrium Problem with Fixed Demand

The use of a demand curve in a short term model such as balancing reflects a price responsive demand. This is today more a project than a reality as all the activity on smart grid shows. The use of a demand curve also makes it easy to introduce some special features on the use of price mechanisms that differ from the standard perfect competition assumption paradigm. We already observed before (see equation (2.4.39)) that this is the case with the appearance of the day ahead equilibrium price in both day ahead and balancing profits. It thus makes sense to consider a version of the single firm model with fixed demand that corresponds to the standard assumption of a perfect competition. The formulation implies that energy prices are no longer obtained from a demand function but from the dual variables of energy balance equations. The model is described by modifying the equations of the multi-firm equilibrium model with responsive demand (2.4.17)-(2.4.38) as follows:

- 1) The index for firms, f is fixed to a value of 1, and it can be removed from the equations.
- 2) Due to the fact that all the generators belong to the same firm, the recourse function Q^k is simplified to:

$$Q^k = \sum_{g \in G} c g_g \cdot (s_g^k - u_g^k) + \sum_{g \in G} z_l^k \cdot \rho^+ \quad (2.6.1)$$

- 3) The term of the inverse demand function (2.4.17) in the objective function of the firm's optimization problem is removed, resulting the following objective function for the firm's problem:

$$\begin{aligned} \max_{\substack{d,x,y,z,rd, \\ ru,v,\zeta,Q^-}} \left\{ \sum_{l \in G_f} y_l \cdot \rho^+ + \sum_{g \in G_f} (ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) - \sum_{g \in G_f} x_g \cdot cg_g \right. \\ \left. - (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \end{aligned} \quad (2.6.2)$$

- 4) The balancing equation (2.4.22) that relates generation and demand in the firm's optimization problem is changed by replacing the responsive demand d by the fixed demand D :

$$\sum_{g \in G} x_g + \sum_{l \in G} y_l = D \quad (2.6.3)$$

2.7 Discussion on Operating Regions regarding Reserve and Wind

Forecast error is a subject of considerable attention in wind studies. The question must be put in perspective with the flexibility of the machines and the horizon necessary to commit them for adapting to the error. We here recall that for instance in the Spanish system reserve is committed between 32 h and 4 h in advance, [55], with respect to the time in which they could be deployed (see Section 2.2.1). We here briefly discuss two main assumptions and their implications in modeling. From a practical point of view we can refer to two extreme approaches:

- For a time horizon of 6 hours or less, typically in operations of committing energy for balancing, the uncertainty is low and to take into account the wind power forecast error it is sufficient to consider the value of the expected error. In practical terms the standard deviation σ of the wind power forecast error for the time horizon considered can be used. This defines a range for the possible wind power output values that is relatively narrow, $[\mu - \sigma, \mu + \sigma]$, where μ is the expected value for wind and usually $\sigma < \frac{1}{5}\mu$.
- For a time horizon in which an unit commitment has to be done, it is typically about 24 hours, the variability of the error distribution must be considered. This means considering values of the wind generation with a non negligible probability and not only the expected value of the error. In the case of the typical Beta distribution for wind power forecast error with mean μ and standard deviation $\sigma = \frac{1}{5}\mu + \frac{1}{50}W$, being W the installed wind power capacity, the interval for variability is typically $[0.5\mu, 1.5\mu]$. Therefore, considering the variability implies to take into account a range of approximately $\pm 60\%$ over the expected value μ .

Depending on the amount of available reserve, the committed reserve, the expected wind and the variability of wind, a number of configurations have been observed in the model. These configurations are summarized in what follows:

- Scheduled wind limited by committed reserve: (scheduled wind) - (lowest wind scenario) $\leq$ (committed upward reserve), in this case the premium ρ^+ to wind generation has not effect on the value of scheduled wind.

- 2) Committed reserve is not limiting the amount of scheduled wind. In this case the premium ρ^+ to wind generation has an strong impact on the valued of scheduled wind. Example: Configuration with the lowest wind $\mu = 4\%$, $m_1 = 0.6$, and $m_2 = 0.02$, in this case an increase in the premium leads to a significant increase in the value of scheduled wind and also to what is counterintuitive, an increase in the value of the equilibrium price ρ^* .
- 3) Dispatchable generators have not enough capacity to satisfy simultaneously the requirement for energy demand and reserve commitment. Firms have to make a decision about using the generation capacity of dispatchable generators for reserve or for generation of energy in day ahead, they do not have enough capacity to fulfill completely both things simultaneously, but only partially.
- 4) Committed reserve hits the technical limit.
- 5) Committed reserve exceeds the maximum value of the wind forecast, even taking into account the error distribution. In this case, for the single firm configuration, the wind turbines schedule a value of wind higher than the maxim value of the expected wind production, just to get revenues from the dispatchable generators for the commitment of additional reserve.

This discussion is expanded later in Section 4.5 where the effect of wind forecast is discussed jointly with other factors like the risk aversion λ , the feed-in premium to wind generation ρ^+ and the requirement of reserve from wind generation m_y .

2.8 Solving Strategy

2.8.1 Introduction

This section is focused on the model for single period, multi-firm and price responsive demand posed as a complementarity problem, that is described in Section 2.4. This problem is non-linear and some terms in the KKT conditions are non-convex, these terms come from the recourse function Q_f^k and the CVaR constraint that includes the recourse function. All the non-convex terms are bilinear and, in particular, they come:

- From the recourse function Q_f^k : $s_g^k \cdot \bar{\pi}^k$, $u_g^k \cdot \underline{\pi}^k$, $u_g^k \cdot d_f$, $z_l^k \cdot \bar{\pi}^k$, $v_l^k \cdot \underline{\pi}^k$, $v_l^k \cdot d_f$.
- From the CVaR constraint (2.4.29):
 - KKT condition for v_l^k : $\sigma_f^k \cdot \underline{\pi}^k$, $\sigma_f^k \cdot d_h$, with $f, h \in F$ (both stand for the same set).
 - KKT condition for z_l^k : $\sigma_f^k \cdot \bar{\pi}^k$.

We have used the solver PATH under the software GAMS [69] to solve the complementarity problem. We encountered some problems of convergence with the initial formulation described in Section 2.4. To overcome these convergence difficulties we have used an iterative approach that we describe here. The iterative approach consists of simplify the CVaR constraints and linearize the non-convex terms in the KKT conditions to get a sequence of linear complementarity problems that approaches the initial problem iteratively.

The key points of this approach are described in detail in the next three sections, first the simplification of the CVaR constraint is described, second the linearization of the non-convex terms in the recourse function, and finally, is discussed how those previous approaches are used to solve the problem iteratively, with a particular focus on the convergence criteria and how the linearized terms are updated.

2.8.2 Iterative Approach for CVaR Calculation

The objective of the iterative approach for the CVaR calculation is to simplify the CVaR constraint (2.4.29) and to remove the non-convex terms in the KKT conditions associated with this constraint. In the following sections we describe the complete process, first the changes in the initial model and the corresponding KKT conditions are described, second how the iterative algorithm for the CVaR calculation works is described and discussed.

Changes in the initial approach

The changes are illustrated for the complementarity problem of multi-firm, single period and price responsive demand described in Section 2.4. A similar scheme can be applied to the complementarity problem for multi-firm, multi-period and price responsive demand described in Section 3.3. The changes in the initial model, in particular in the firms' problem (2.4.17)-(2.4.29), are:

- 1) The term of the CVaR in the objective function (2.4.17) for each firm f :

$$\lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \quad (2.8.1)$$

is replaced by

$$\lambda_f \cdot \sum_{k \in \Omega} \text{Pri}_f^k \cdot Q_f^k \quad (2.8.2)$$

Where Pri_f^k is an exogenous parameter calculated iteratively as is described in this section. This parameter is interpreted as a recalculated probability that takes into account which scenarios are included in the CVaR.

- 2) The initial constraint for CVaR calculation (2.4.29) is no longer necessary. Therefore it is removed from the model, what in turn removes the non-convex terms associate with this constraint, that are: $\sigma_f^k \cdot \bar{\pi}^k$, $\sigma_f^k \cdot \underline{\pi}^k$, and $\sigma_f^k \cdot d_h$, with $f, h \in F$.

The KKT conditions (2.4.59) and (2.4.60) in the initial problem also disappear.

- 3) The primal variables $Q_f^{k,-}$, and ζ_f , and the dual variable σ_f^k are no longer necessary. The relation between the initial problem and the iterative approach gives $\sigma_f^k = \lambda_f \cdot \text{Pri}_f^k$.

This modification allows to move the non convexities (essentially the recourse function) from the constraints to the objective function. This is remarkable because the new feasible region for the problem of each firm becomes a convex set with this change, and this feasible region does not depend on the iteration to calculate the CVaR.

New KKT conditions with iterative CVaR calculation

Only the KKT for the firms' variables in the recourse function, z_l^k and v_l^k , are affected by the simplification of the CVaR constraints, and their new expressions are:

$$\frac{\partial \mathcal{L}_f}{\partial v_l^k} = \left((1 - \lambda_f) \cdot \text{Pr}^k + \lambda_f \cdot \text{Pri}_f^k \right) \cdot (\underline{\pi}^k - \rho^*) + \xi_l^k + \tau_l^k \geq 0 \quad \perp \quad v_l^k \geq 0 \quad (2.8.3)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial z_l^k} &= \left((1 - \lambda_f) \cdot \text{Pr}^k + \lambda_f \cdot \text{Pri}_f^k \right) \cdot (\bar{\pi}^k + \rho^+) + \underline{\psi}_l^k + \\ &+ \bar{v}_l^k - \underline{v}_l^k - \tau_l^k \geq 0 \quad \perp \quad z_l^k \geq 0 \end{aligned} \quad (2.8.4)$$

These new expressions for the KKT conditions result from the initial equations where σ_f^k is replaced by $\lambda_f \cdot \text{Pri}_f^k$. The other primal variables in the recourse function, u_g^k and s_g^k , are not decision variables for the firms, hence their KKT conditions are not affected.

Iterative Calculation of the CVaR

The iterative CVaR calculation consist of the calculation of the probabilities Pri_f^k , that is made iteratively until a stationary value for these probabilities is reached. The blocks in the iterative scheme are the Master Problem and the Subproblem, that are described in what follows:

- Master Problem is the whole model with the simplification for the CVaR constraints previously described.
- Subproblem is the following linear optimization program in which the values of Pri_f^k are calculated:

$$\underset{\text{Pri}_f^k}{\text{minimize}} \sum_{k \in \Omega} \text{Pri}_f^k \cdot Q_f^k \quad (2.8.5)$$

$$\text{subject to: } \sum_{k \in \Omega} \text{Pri}_f^k = 1 \quad (2.8.6)$$

$$\text{Pri}_f^k \leq \frac{\text{Pr}^k}{1 - \theta_f} \quad (2.8.7)$$

$$\text{Pri}_f^k \geq 0 \quad (2.8.8)$$

In this problem the Pri_f^k are the variables and the rest are data (fixed values). In particular are data: The initial probability of the scenarios, Pr^k , the confidence level θ_f for the CVaR, and the values of the recourse function Q_f^k .

To simplify the algorithmic description of the complete iterative CVaR calculation, that is given in Table 2.1, we define the following functions:

- $[Q] = \text{MasterProblem}(\text{Pri})$: function that takes as argument the probability distribution for scenarios, Pri or Pr, and gives as result the values of the recourse function, Q , $\forall f \in F, \forall k \in \Omega$.
- $[\text{Pri}_f] = \text{SubProblem}(Q_f)$: function that takes as argument the values of the recourse function for a particular firm f , for all the scenarios, $k \in \Omega$, and gives as result the probability of the scenarios included in the CVaR for firm f . For the scenarios not included in the CVaR, $\text{Pri}_f^k = 0$.

2.8.3 Linearization of the Non-Convex Terms in the KKT Conditions

After the simplification of the CVaR constraints previously described, all the remaining non-convex terms in the KKT conditions come from the recourse function. We have linearized these terms in order to have a linear complementarity problem, because the available solving algorithms for linear complementarity problems are more robust than those for non-linear complementarity problems with non-convexities.

The remaining non-convex terms in the complementarity problem are the bilinear expressions: $s_g^k \cdot \pi^k$, $u_g^k \cdot \pi^k$, $u_g^k \cdot d_f$, $z_l^k \cdot \pi^k$, $v_l^k \cdot \pi^k$, $v_l^k \cdot d_f$. All these terms are in the recourse function

Table 2.1: Iterative CVaR algorithm

```

Data: tolerance; //Tolerance for convergence
For  $f \in F$  Do
|    $\text{Pri}_f = \text{Pr}$ ; //initialization
|    $\text{Pri0}_f = 0 \cdot \text{Pr}$ ; //for checking convergence
|    $\Delta \text{Pri}_f = \|\text{Pri}_f - \text{Pri0}_f\|_\infty$ ;
End
While  $\|\Delta \text{Pri}\|_\infty \geq \text{tolerance}$  Do
|    $[Q] = \text{MasterProblem}(\text{Pri})$ ; // update  $Q_f^k$ 
|   For  $f \in F$  Do
|   |    $[\text{Pri}_f] = \text{SubProblem}(Q_f)$ ; // update  $\text{Pri}_f^k$ 
|   |    $\Delta \text{Pri}_f = \|\text{Pri}_f - \text{Pri0}_f\|_\infty$ ;
|   |    $\text{Pri0}_f = \text{Pri}_f$ ; // update for checking convergence
|   End
End

```

Q_f^k . The linearization strategy implemented consists of fixing the value of d_f , $\bar{\pi}^k$ and $\underline{\pi}^k$, just inside the recourse function, to the values in the previous iteration. Thus the non-convex terms linearized at iteration $(i+1)$ are: $s_g^k \cdot \bar{\pi}^{k,(i)}$, $u_g^k \cdot \underline{\pi}^{k,(i)}$, $u_g^k \cdot d_f^{(i)}$, $z_l^k \cdot \bar{\pi}^{k,(i)}$, $v_l^k \cdot \underline{\pi}^{k,(i)}$, $v_l^k \cdot d_f^{(i)}$, and the new values $d_f^{(i+1)}$, $\bar{\pi}^{k,(i+1)}$ and $\underline{\pi}^{k,(i+1)}$ are obtained after solving for iteration $(i+1)$. The variables d_f , $\bar{\pi}^k$ and $\underline{\pi}^k$ are fixed only in the bilinear terms, but not when they appear alone.

2.8.4 Convergence Criteria and Iterative Scheme to Update the Linearized Terms

The proposed strategy consists of the simplification of the CVaR constraint and the linearization of the remaining non-convex terms, and it leads to a sequence of linear complementarity problems which solution is a solution of the initial problem. The question, that remains as a future work, is whether one can develop a method to find all the solutions of the problem. The problem is non convex and there thus maybe several equilibria (as in EPEC or MPEC problems), and the interesting questions are obviously (i) to find them and (ii) to characterized them in economic terms. The strategy is robust for the simulations reported in the case study, but we have indeed found several equilibria for some configurations, see Section 4.5.3 and Figs. 4.8 and 4.9.

The convergence criteria are based on tolerance values for consecutive iterations, in particular the iterative calculation of the CVaR stops when $\sum_{f \in F} \sum_{k \in \Omega} \text{Pri}_f^k \leq 10^{-6}$, and the iterations to update the linearized values stops when $|d_f^{(i+1)} - d_f^{(i)}| \leq 10^{-6}$ and $|\bar{\pi}^{k,(i+1)} - \bar{\pi}^{k,(i)}| \leq 10^{-6}$ and $|\underline{\pi}^{k,(i+1)} - \underline{\pi}^{k,(i)}| \leq 10^{-6}$. There is also a limit in the total number of iterations.

In each iteration all the values, Pri_f^k , d_f , $\bar{\pi}^k$ and $\underline{\pi}^k$ are updated simultaneously. The algorithmic description of the complete iterative scheme is listed in Table 2.2 using the definitions of Master Problem and Subproblem in the previous Section 2.2. In this case the Master Problem includes the linearization of the bilinear terms, and therefore it is a linear complementarity problem.

The solutions found with the iterative approach are solutions of the initial problem because of the following facts:

Table 2.2: Complete algorithm

Data: $tolCVaR, tolLinear, MaxItera$; //Tolerance for convergence
 $i = 1$; // Initial iteration
 $Pri_f^{(i)} = Pr$; //initialization
 $d_f^{(i)} = \frac{\rho_0}{2\alpha_0}$; //Only in bilinear terms
 $\bar{\pi}^{k,(i)} = 0$; //Only in bilinear terms
 $\underline{\pi}^{k,(i)} = 0$; //Only in bilinear terms
While $((\sum_{f \in F} \sum_{k \in \Omega} Pri_f^k \geq tolCVaR$ or $\max\{\|d_f^{(i+1)} - d_f^{(i)}\|_\infty,$
 $\|\bar{\pi}^{k,(i+1)} - \bar{\pi}^{k,(i)}\|_\infty, \|\underline{\pi}^{k,(i+1)} - \underline{\pi}^{k,(i)}\|_\infty\} \geq tolLinear)$ and $i \leq MaxItera)$
Do
| $[Q^{(i)}, d_f, \bar{\pi}^k, \underline{\pi}^k] = MasterProblem(Pri^{(i)}, d_f^{(i)}, \bar{\pi}^{k,(i)}, \underline{\pi}^{k,(i)})$;
| $d_f^{(i+1)} = d_f$; //Update fixed value of d_f in bilinear terms
| $\bar{\pi}^{k,(i+1)} = \bar{\pi}^k$; //Update fixed value of $\bar{\pi}^k$ in bilinear terms
| $\underline{\pi}^{k,(i+1)} = \underline{\pi}^k$; //Update fixed value of $\underline{\pi}^k$ in bilinear terms
| **For** $f \in F$ **Do**
| | $[Pri_f^{(i+1)}] = SubProblem(Q_f^{(i)})$; // update Pri_f^k
| **End**
| $i = i + 1$; //Iteration count
End

- The value of σ_f^k in the initial problem is given in the iterative approach by $\sigma_f^k = \lambda_f \cdot Pri_f^k$.
- The KKT conditions in the initial problem and in the iterative approach are essentially the same except for the two KKT associated with the CVaR calculation in the original problem that are not present in the iterative approach. These KKT conditions are:

$$\frac{\partial \mathcal{L}_f}{\partial Q_f^{k,-}} = \frac{\lambda_f}{1 - \theta_f} Pri^k - \sigma_f^k \geq 0 \quad \perp \quad Q_f^{k,-} \geq 0 \quad (2.8.9)$$

$$\frac{\partial \mathcal{L}_f}{\partial \zeta_f} = \lambda_f - \sum_{k \in \Omega} \sigma_f^k = 0; \quad \zeta_f \text{ free} \quad (2.8.10)$$

If this KKT conditions are met for the solution found with the iterative approach then that solution is also a solution of the initial problem.

- In fact the conditions (2.8.9) and (2.8.10) in the initial problem are met with the values from the iterative approach, because if we replace σ_f^k in these equations by $\lambda_f \cdot Pri_f^k$ we get:

- From (2.8.9): $\frac{\lambda_f}{1 - \theta_f} Pri^k - \sigma_f^k = \frac{\lambda_f}{1 - \theta_f} Pri^k - \lambda_f \cdot Pri_f^k \geq 0$, that is met when $\lambda_f = 0$ and it is the constraint (2.8.7) in the iterative approach when $\lambda_f > 0$.
- From (2.8.10): $\lambda_f - \sum_{k \in \Omega} \sigma_f^k = \lambda_f - \sum_{k \in \Omega} \lambda_f \cdot Pri_f^k = 0$, that is met when $\lambda_f = 0$ and it is the constraint (2.8.6) in the iterative approach when $\lambda_f > 0$.

To summarize, every solution of the iterative approach is a solution of the initial problem.

Chapter 3

Multi-Period Models

3.1 Introduction

Case studies conducted with the single period model (see Section 4.5 reveal the importance of the formulation of ramping constraints. Because ramping is typically a multi-period problem, it maybe relevant to extend the preceding model to include a daily representation of the market. This is the objective of this section. We again formulate three versions of the model of which we use only two in the case studies.

The proposed multi-period models are described in detail in the next sections, here we summarized the main changes with respect to the previous single-period multi-firm equilibrium model with price responsive demand (2.4.17)-(2.4.38):

- A new index t representing the time period is added to all the primal and dual variables, except to those related to the CVaR, ζ_f , $Q_f^{k,-}$ and σ_f^k , because they do not depend on the time period.
- The value of the objective function is calculated as a sum on the set of periods, both in the optimization problem for each firm and in the problem for minimizing the generation cost from reserves (for each scenario k).
- The ramping constraints include explicitly the ramp capability used to change the scheduled dispatchable generation, that is an information available from endogenous variables in the model.
- New ramping products that take into account operational flexibility between periods, like those proposed at MISO [14, 72], can be included in the model.

The rest of the chapter is organized as follows, first the ramping constraints for multi-period and the MISO ramping products are described in the next section. The model for multi-period, multi-firm and price responsive demand is presented in Section 3.3. The model for multi-period, single firm and price responsive demand is described in Section 3.4. And finally the description of the model for multi-period, single firm and fixed demand in Section 3.5 closes the chapter. We consider two versions, one with ramping products and the other without ramping products, for each one these three models.

3.2 Modeling Ramping

3.2.1 Ramping Products

A new kind of ramping products has been proposed at MISO, [13, 14, 72]. These new ramping products include the up ramp capability $urc_{g,t}$ (from dispatchable generator g , at period t), and the down ramp capability $drc_{g,t}$. They involve more than one period (t), therefore they can be properly implemented only in the multi-period setting (here they are implemented only in some multi-period models). The overall idea is to commit ramp capability well in advance to increase the scheduled operational flexibility of the system, with the intent of avoiding the use of the expensive fast units to provide that flexibility. There is a cost associated with these new ramping products, that are committed in day ahead, but this cost is smaller, on average, than the cost from the sporadic use of the fast units for ramping.

Variability is a key concept in the definition of the new ramping products; we define it with some detail in the following:

- In the context of new ramping products, the concept of variability in real power systems stands for the range of possible values that the net demand can take in the system. Because there is some uncertainty on the net demand for future periods at the time it is forecast in the current period.
- We have a range of possible values for the net demand in future periods. This range can be defined by a confidence interval for a given value of confidence level. It can alternatively be defined as $[\mu - K_d \cdot \sigma, \mu + K_u \cdot \sigma]$, as suggested by MISO, where μ is the expected value of the net demand, σ is the standard deviation of the probability distribution for net demand at the forecast horizon, and K_u and K_d are exogenous constants for upward and downward ramping respectively that implicitly define the confidence level. The proposal at MISO suggests a value $K_u = K_d = 2.5$.
- The variability is the difference between the extreme value of the interval and the expected value, hence we have two values for variability, the upward variability $K_u \cdot \sigma$ and the downward variability $K_d \cdot \sigma$. In the case of MISO the proposed values are 2.5σ for the upward and for the downward variability.
In our case study the uncertainty is only in the wind generation, therefore we consider the wind power forecast error distribution to estimate the value in future periods, particularly we use a beta distribution (a different one for each period) and a confidence level of about 90%, this results in a variability range of approximately $[0.5\mu, 1.5\mu]$.

- The requirement for the new ramping products for each period t is defined as the difference between the expected value of net demand plus the variability, both at period $t + 2$, (the extreme value of the range considered for period $t + 2$) and the expected value of net demand at period t .

In MISO's proposal this requirement is satisfied only by the new ramping products, in the current implementation of our model we assume that previous reserve products can also contribute to satisfy this requirement, because in our model the different kinds of reserve are mixed in only one type, while MISO relies on a clear separation of reserves. We could separate the previous reserve and the new ramping products in the requirements leaving only the variables for the new ramping products in equations (3.3.76) and (3.3.77). We simplify the implementation of these constraints by considering just the wind variability at each period.

We thus summarize MISO's proposal for the new ramping products [72] through the following points:

- 1) Motivation: To reduce the operation cost in the short-run (one day) by (quoted from [72]) *"keeping enough rampable capacity in the system to go after the net load variability and uncertainty"*.
The scarcity of ramp capability can lead to very high costs, because of the use of fast generators to supply the energy in case of something unforeseen happens and a fast response is needed, hence these scarcity conditions only happen for a few hours intervals. The stochastic nature of this scarcity and its short duration makes that firms do not plan for that demand. Therefore the current configuration is not given an actionable market signal. The proposed ramping products solve this issue because they create a stable demand for this service with a value well known in advance. The disadvantage is that we are paying for something we will use only with low probability.
- 2) These new ramp products are intended for operational flexibility and not to solve contingencies, because the traditional reserve products cover that purpose.
- 3) The new products will be supplied by dispatchable generators under market incentives. The market incentives are that firms can get profit by providing these services in an, almost deterministic environment without no risk instead of waiting for an unforeseen scarcity event.
- 4) These ramp products are co-optimized with energy and ancillary services.
- 5) The price of these products is determined by (time varying) resource opportunity cost.
- 6) Existing energy and ancillary services products are not changed.
- 7) Ramp products in real time "act as a buffer to absorb forecasted and unexpected operational variability". These ramp products are intended for energy dispatch.
- 8) "Demand curve pricing allows automatic trade off between reserving ramp capacity for a future interval and using the ramp to meet current system needs." A flat curve pricing is proposed.
- 9) Deployed ramp capability is paid to product clearing price (for instance the energy price in day ahead).
- 10) "Load charges are increased to compensate for ramp capability payments to resources, however reduced scarcity pricing decreases load payments, causing an overall production cost saving."
- 11) Ramp capability products are committed in day ahead and deployed in real time.

In the adaptation of the MISO proposal for new ramping products to our model we assume:

- a) The ramp capability products are committed in day ahead and deployed in real time, exactly as proposed at MISO.
- b) The cost of committing ramp capability products is charged to loads in a post-market process, and therefore this cost is not taken into account explicitly in the model.

- c) Only dispatchable generators can supply ramp capability products, as proposed at MISO.
- d) Committed ramp capability products are remunerated according to a flat demand function (fixed price), as proposed at MISO.
- e) Energy deployed from these products in real time is remunerated at the day-ahead market price, as proposed at MISO.
- f) The requirement of ramp capability products is calculated based on a confidence range for the variability of wind generation in real time. This interval is estimated in day-ahead. This is a simplification of MISO's proposal, that takes into account the variability of the net demand and suggests to use a value for the variability of 2.5 times the standard deviation of the net demand distribution for the period considered.

On the other hand, the ramping constraints in the model take into account the ramp capability needed due to the change in the scheduled dispatchable generation. This requirement of ramp capability due to scheduled dispatchable generation is low in the case of price responsive demand, because in that situation the only condition that changes from period to period is the wind forecast, and that usually has a small impact on the scheduled generation, except for cases with very high wind forecast. On the contrary, in the case of fixed demand the changes in demand of ramp capability due to changes in scheduled dispatchable generation can be quite remarkable because of the changes of energy demand in day ahead.

In order to include the ramping products in the models, we have to add some new variables, some new constraints and some terms in the objective function and previous related to these products, we describe these elements in what follows:

- Two new primal variables are needed to define the ramping products:
 - $urc_{g,t}$: Up ramp capability provided by generator g at period t .
 - $drc_{g,t}$: Down ramp capability provided by generator g at period t .
- Also two new constraints, and the corresponding two new dual variables, are added in relation with the ramping products:

$$\sum_{g \in G} (ru_{g,t} + urc_{g,t}) = \Delta_{t+2}^u \quad (3.2.1)$$

$$\sum_{g \in G} (rd_{g,t} + drc_{g,t}) = \Delta_{t+2}^d \quad (3.2.2)$$

where Δ_{t+2}^u and Δ_{t+2}^d account for the uncertainty in the variability of demand at period $t+2$ estimated at period t . The values Δ_{t+2}^u and Δ_{t+2}^d do not depend on the scenarios because they correspond to the extremes of the variability range in which the system is expected to operate with a high confidence level (extreme values in the set of scenarios). The description of the particular expressions adopted for Δ_{t+2}^u and Δ_{t+2}^d , is included in the description of the models in which the ramping products are integrated.

- The additional terms in the objective function are related to the remuneration of these ramping products. The expressions for this additional terms in the objective function, and the constraints that are modified by the introduction of ramping products are described in detail for each model in which the ramping products are integrated (in the next sections in this chapter).

In our models, the up ramp capability and the down ramp capability are remunerated with the same mechanism that the upward ramp capacity and the downward reserve capacity, what is in accordance with the principle 5) previously defined, price determined by resource opportunity cost. There exist other proposals that consider a fixed price for the ramping products, but we do not implement these proposals in our models.

3.2.2 Ramping Constraints

Here we adopt the model for ramping constraints commonly used in the literature for the unit commitment problem, and add the ramping products to that model. We introduce two new variables for the ramping products proposed at MISO, as described in Section 3.2.1, we recall that the new variables are: $urc_{g,t}$ for up ramp capability provided by generator g at period t , and $drc_{g,t}$ for down ramp capability. The model used here for the ramping constraints in multi-period has the following features, following [62]:

- 1) The ramping capacity of a particular generator g is a fixed quantity; therefore it does not depend on the generation level at each time. In our model, the upward ramping capacity for generator g is $\bar{R}_g \cdot \bar{X}_g$, and the downward ramping capacity is $\underline{R}_g \cdot \bar{X}_g$.
- 2) The ramping constraints for a generator g are:

$$x_{g,t} - x_{g,t-1} \leq \bar{R}_g \cdot \bar{X}_g \quad (\text{in case of increasing generation}) \quad (3.2.3)$$

$$x_{g,t-1} - x_{g,t} \leq \underline{R}_g \cdot \bar{X}_g \quad (\text{in case of decreasing generation}) \quad (3.2.4)$$

where $x_{g,t}$ is the scheduled power output of generator g at period t .

We use the previous expressions to set the bounds for the remaining ramp capability of each dispatchable generator after discounting the ramp capability used in scheduled generation ($x_{g,t+1} - x_{g,t}$).

$$ru_{g,t} + urc_{g,t} \leq \bar{R}_g \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (3.2.5)$$

$$ru_{g,t} + urc_{g,t} \leq \bar{R}_g \cdot \bar{X}_g, \quad (3.2.6)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R}_g \cdot \bar{X}_g, \quad (3.2.7)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R}_g \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}) \quad (3.2.8)$$

- 3) The available ramp capacity is subject to the generator's capacity bounds:

$$ru_{g,t} + urc_{g,t} \leq \bar{X}_g - x_{g,t} \quad (3.2.9)$$

$$rd_{g,t} + drc_{g,t} \leq x_{g,t} - \underline{X}_g \quad (3.2.10)$$

To summarize we have:

$$ru_{g,t} + urc_{g,t} \leq \min \{ \bar{X}_g - x_{g,t}, \bar{R}_g \cdot \bar{X}_g, \bar{R}_g \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}) \} \quad (3.2.11)$$

$$rd_{g,t} + drc_{g,t} \leq \min \{ x_{g,t} - \underline{X}_g, \underline{R}_g \cdot \bar{X}_g, \underline{R}_g \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}) \} \quad (3.2.12)$$

3.3 Multi-Firm Multi-Period Equilibrium Model with Price Responsive Demand

In this section are described two extensions of the single period model of Section 2.4 (Subsection 2.4.6) that are made in turn; the first extension introduces an horizon of several successive hours (multi-period), and the second extension adds ramping products in that horizon.

3.3.1 Extension to Multi-Period without Ramping Products

In this subsection we describe the extension of the model in Section 2.4, to a multi-period setting. The result is a multi-period, multi-firm model with price responsive demand, and posed as a complementarity problem. Because of some bilinear terms in the KKT conditions, the complementarity problem is non-linear. One of the main reasons to extend the model to multi-period is to study the effect of the ramping constraints over several hours.

For the sake of simplicity, we divide the whole equilibrium problem in three groups of equations: 1) The global constraints, 2) The KKT conditions for the minimization of generation cost from reserves, and 3) The KKT conditions for each firm f . We keep the same notation as in other parts of the text, and call $\mathcal{L}_f$ to the Lagrangian function for firm f , and $\mathcal{L}_B$ to the Lagrangian function for the problem of minimization of generation cost from reserve.

The extension to multi-period can be done under different assumptions that lead to different modeling alternatives. We describe the assumptions and the corresponding alternatives by successively referring to each one of the three groups of equations in what follows.

1) Global constraints

The global constraints are those that are not associated with any particular agent in the system, in this model they are the reserve constraints. Two reasonable approaches for the value of the committed reserve capacity are:

- a) a fixed value (the same value) for a number of hours in a time horizon;
- b) a different value for each hour.

Here we consider that the committed reserve capacity can be different for each hour, but it is subject to the ramping constraints, that limit its change from hour to hour. The equations for the reserve constraints extended to multi-period are:

$$\sum_{g \in G} ru_{g,t} \geq \underline{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\kappa}_t), \quad (3.3.1)$$

$$\sum_{g \in G} rd_{g,t} \geq B \cdot \sum_{g \in G} ru_{g,t}, \quad (\underline{\kappa}_t), \quad (3.3.2)$$

$$\sum_{g \in G} ru_{g,t} \leq \bar{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\gamma}_t), \quad (3.3.3)$$

$$\sum_{g \in G} rd_{g,t} \leq \sum_{g \in G} ru_{g,t}, \quad (\underline{\gamma}_t). \quad (3.3.4)$$

2) TSO's problem for minimizing the generation cost from reserves

In the TSO's problem for minimizing the generation cost from reserves we have, at least, two apparently different alternatives regarding the number of periods on which the optimization is performed:

- a) Optimize for each hour. In this case the objective function is

$$\underset{s_{g,t}^k, u_{g,t}^k}{\text{minimize}} \sum_{g \in G} cg_g \cdot (s_{g,t}^k - u_{g,t}^k).$$

We have an optimization problem for each hour t and scenario k .

- b) Optimize for all the hours t in a set of periods T . In this case the objective function is
- $$\underset{s_{g,t}^k, u_{g,t}^k}{\text{minimize}} \sum_{t \in T} \sum_{g \in G} cg_g \cdot (s_{g,t}^k - u_{g,t}^k).$$

We have an optimization problem for each scenario k .

Both alternatives lead to the same KKT conditions. Then we write the problem as an optimization for the whole set of hours, because that is the objective of the TSO (minimize the total cost for the whole set of hours). The TSO's problem of minimizing the generation cost from reserve is modeled, for each scenario k , as the following optimization problem:

$$\underset{s_{g,t}^k, u_{g,t}^k}{\text{minimize}} \sum_{t \in T} \sum_{g \in G} (s_{g,t}^k \cdot cg_g - u_{g,t}^k \cdot cg_g) \quad (3.3.5)$$

$$\text{subject to: } \sum_{g \in G} s_{g,t}^k = \sum_{l \in G} z_{l,t}^k, \quad (\bar{\pi}_t^k) \quad (3.3.6)$$

$$\sum_{g \in G} u_{g,t}^k = \sum_{l \in G} v_{l,t}^k, \quad (\underline{\pi}_t^k) \quad (3.3.7)$$

$$s_{g,t}^k \leq ru_{g,t}, \quad (\bar{\eta}_{g,t}^k) \quad (3.3.8)$$

$$u_{g,t}^k \leq rd_{g,t}, \quad (\underline{\eta}_{g,t}^k) \quad (3.3.9)$$

where the variables are $s_{g,t}^k$ and $u_{g,t}^k$, and the fixed input data are: The committed upward $ru_{g,t}$ and downward $rd_{g,t}$ reserve as well as the demand of energy from the upward $z_{l,t}^k$ and downward $v_{l,t}^k$ reserve.

The interpretation of this problem is straightforward: Minimizing the cost (3.3.5) implies using the generators with the minimum generation cost for upward reserve and the generators with the maximum cost for the downward reserve. The KKT conditions for TSO's problem of minimizing the generation cost from reserves are:

$$\frac{\partial \mathcal{L}_B}{\partial s_{g,t}^k} = cg_g - \bar{\pi}_t^k + \bar{\eta}_{g,t}^k \geq 0, \quad \perp \quad s_{g,t}^k \geq 0 \quad (3.3.10)$$

$$\frac{\partial \mathcal{L}_B}{\partial u_{g,t}^k} = -cg_g - \underline{\pi}_t^k + \underline{\eta}_{g,t}^k \geq 0, \quad \perp \quad u_{g,t}^k \geq 0 \quad (3.3.11)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\pi}_t^k} = \sum_{l \in G} z_{l,t}^k - \sum_{g \in G} s_{g,t}^k = 0, \quad \bar{\pi}_t^k \text{ free} \quad (3.3.12)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\pi}_t^k} = \sum_{l \in G} v_{l,t}^k - \sum_{g \in G} u_{g,t}^k = 0, \quad \underline{\pi}_t^k \text{ free} \quad (3.3.13)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\eta}_{g,t}^k} = s_{g,t}^k - ru_{g,t} \leq 0, \quad \perp \quad \bar{\eta}_{g,t}^k \geq 0 \quad (3.3.14)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\eta}_{g,t}^k} = u_{g,t}^k - rd_{g,t} \leq 0, \quad \perp \quad \underline{\eta}_{g,t}^k \geq 0 \quad (3.3.15)$$

3) Firms' problems

In the multi-period setting, the change of scheduled dispatchable generation has to meet also the ramping constraints. That means that the ramping constraints affect directly the scheduled dispatchable generation and the energy deployed from reserve. In the individual

firm's problem, the main modification occurs in the ramping constraints that change from

$$ru_g \leq \bar{R} \cdot (\bar{X}_g - x_g), \quad (\bar{\delta}_g) \quad (3.3.16)$$

$$rd_g \leq \underline{R} \cdot (\bar{X}_g - x_g), \quad (\underline{\delta}_g) \quad (3.3.17)$$

to

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (\bar{\delta}_{g,t}) \quad (3.3.18)$$

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\bar{\delta}_{g,t}) \quad (3.3.19)$$

$$rd_{g,t} \leq \underline{R} \cdot \bar{X}_g, \quad (\bar{\epsilon}_{g,t}) \quad (3.3.20)$$

$$rd_{g,t} \leq \underline{R} \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \quad (\underline{\epsilon}_{g,t}) \quad (3.3.21)$$

The rationale behind these ramping constraints is that the reserve for each hour is limited by the technical ramping capacity ($\bar{R} \cdot \bar{X}_g$ or $\underline{R} \cdot \bar{X}_g$) and also by the ramping capacity that is used to change the scheduled dispatchable generation ($x_{g,t+1} - x_{g,t}$). Four constraints cover the four cases that come from the combination of upward and downward reserve and increasing or decreasing the scheduled dispatchable generation.

For the first and the last hour, the previous ramping constraints contain references to terms outside the range, these terms are $x_{g,0}$ for the first hour ($t = 1$) and $x_{g,T+1}$ for the last hour ($t = T$). The common approaches to deal with these terms are:

- Circular configuration, $x_{g,T+1} = x_{g,1}$ and $x_{g,0} = x_{g,T}$.
- Include additional fixed values for the points outside the range, a usual condition is to consider the value of the point outside the range equal to the value of the closest point inside the range, in this case $x_{g,0} = x_{g,1}$ and $x_{g,T+1} = x_{g,T}$.

In our models we consider the second approach, $x_{g,0} = x_{g,1}$ and $x_{g,T+1} = x_{g,T}$, because the circular approach can lead to artificial constraints. Also the same criteria applies to the dual variables for the ramping constraints, $\bar{\delta}_{g,t}$, $\underline{\delta}_{g,t}$, $\bar{\epsilon}_{g,t}$ and $\underline{\epsilon}_{g,t}$. And, in general, to all the primal and dual variables that depend on the index t if they are referenced outside the range $\{1, 2, \dots, T\}$.

Continuing with the adaptation, the expression of the recourse function for firm f at scenario k in the multi-period setting is:

$$Q_f^k = \sum_{t \in T} \left[\sum_{g \in G_f} \left[s_{g,t}^k \cdot (cg_g - \bar{\pi}_t^k) + u_{g,t}^k \cdot (\rho_t^* - cg_g - \underline{\pi}_t^k) \right] + \right. \\ \left. + \sum_{l \in G_f} \left[z_{l,t}^k \cdot (\rho^+ + \bar{\pi}_t^k) + v_{l,t}^k \cdot (\underline{\pi}_t^k - \rho_t^*) \right] \right] \quad (3.3.22)$$

Finally, the optimization problem for each firm f extended to multi-period is:

$$\max_{d,x,y,z,rd,ru,s,u,v,\zeta,Q^-} \sum_{t \in T} \left\{ (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} d_{h,t}) \cdot d_{f,t} + \sum_{g \in G_f} (ru_{g,t} \cdot (\bar{\kappa}_t + \bar{\gamma}_t) + rd_{g,t} \cdot (\underline{\kappa}_t + \underline{\gamma}_t)) + \right. \\ \left. + \sum_{l \in G_f} y_{l,t} \cdot \rho^+ - \sum_{g \in G_f} x_{g,t} \cdot cg_g \right. \\ \left. - (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \quad (3.3.23)$$

$$\text{subject to: } x_{g,t} + ru_{g,t} \leq \bar{X}_g, \quad (\bar{\phi}_{g,t}) \quad (3.3.24)$$

$$x_{g,t} + s_{g,t}^k - rd_{g,t} \geq \underline{X}_g, \quad (\underline{\phi}_{g,t}^k) \quad (3.3.25)$$

$$y_{l,t} \leq \bar{Y}_l^{\max}, \quad (\bar{\psi}_{l,t}) \quad (3.3.26)$$

$$y_{l,t} - z_{l,t}^k \geq \underline{Y}_l^k, \quad (\underline{\psi}_{l,t}^k) \quad (3.3.27)$$

$$\sum_{g \in G_f} x_{g,t} + \sum_{l \in G_f} y_{l,t} = d_{f,t}, \quad (\nu_{f,t}) \quad (3.3.28)$$

$$z_{l,t}^k \leq \bar{Y}_l^{\max} - \bar{Y}_{l,t}^k, \quad (\bar{\tau}_{l,t}^k) \quad (3.3.29)$$

$$y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\bar{\tau}_{l,t}^k) \quad (3.3.30)$$

$$v_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\xi_{l,t}^k) \quad (3.3.31)$$

$$v_{l,t}^k + y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\tau_{l,t}^k) \quad (3.3.32)$$

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (\bar{\delta}_{g,t}) \quad (3.3.33)$$

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\bar{\delta}_{g,t}) \quad (3.3.34)$$

$$rd_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\bar{\epsilon}_{g,t}) \quad (3.3.35)$$

$$rd_{g,t} \leq \bar{R} \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \quad (\epsilon_{g,t}) \quad (3.3.36)$$

$$\zeta_f + Q_f^{k,-} \geq Q_f^k, \quad (\sigma_f^k) \quad (3.3.37)$$

where $d, x, y, z, rd, ru, s, u, v, Q_f^{k,-}$ are positive variables.

Equations (3.3.24)-(3.3.37) comprise the constraints for the firms problem. These constraints are: The upper and lower bounds for dispatchable plants (3.3.24), (3.3.25), and wind turbines (3.3.26), (3.3.27), the balancing for energy sales in day ahead (3.3.28), the upper and lower bounds for the purchases of wind turbines due to shortage of wind (3.3.29), (3.3.30), the bound for the bids of wind in excess (they cannot be greater than available wind) (3.3.31), the energy balance for wind turbines (3.3.32), the ramping constraints for reserve and scheduled dispatchable generation (3.3.33)-(3.3.36), and, finally, the constraint (3.3.37) for the CVaR calculation.

The KKT conditions for the primal variables in the the firm's problem in the multi-period setting are:

$$\frac{\partial \mathcal{L}_f}{\partial d_{f,t}} = -(\rho_0 - \alpha_0 \sum_{h \in F} d_{h,t}) - \nu_{f,t} \geq 0 \quad \perp \quad d_{f,t} \geq 0 \quad (3.3.38)$$

$$\frac{\partial \mathcal{L}_f}{\partial rd_{g,t}} = -(\kappa_t + \gamma_t) + \sum_{k \in \Omega} \underline{\phi}_{g,t}^k + \bar{\epsilon}_{g,t} + \epsilon_{g,t} \geq 0 \quad \perp \quad rd_{g,t} \geq 0 \quad (3.3.39)$$

$$\frac{\partial \mathcal{L}_f}{\partial ru_{g,t}} = -(\bar{\kappa}_t + \bar{\gamma}_t) + \bar{\phi}_{g,t} + \bar{\delta}_{g,t} + \underline{\delta}_{g,t} \geq 0 \quad \perp \quad ru_{g,t} \geq 0 \quad (3.3.40)$$

$$\frac{\partial \mathcal{L}_f}{\partial v_{l,t}^k} = \left((1 - \lambda_f) \cdot \Pr^k + \sigma_f^k \right) \cdot (\pi_t^k - \rho_t^*) + \xi_{l,t}^k + \tau_{l,t}^k \geq 0 \quad \perp \quad v_{l,t}^k \geq 0 \quad (3.3.41)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial x_{g,t}} &= cg_g + \bar{\phi}_{g,t} - \sum_{k \in \Omega} \underline{\phi}_{g,t}^k + \nu_{f,t} + \bar{\delta}_{g,t-1} - \bar{\delta}_{g,t} \\ &\quad - \underline{\delta}_{g,t-1} + \underline{\delta}_{g,t} + \bar{\epsilon}_{g,t-1} - \bar{\epsilon}_{g,t} - \epsilon_{g,t-1} + \epsilon_{g,t} \geq 0 \quad \perp \quad x_{g,t} \geq 0 \end{aligned} \quad (3.3.42)$$

$$\frac{\partial \mathcal{L}_f}{\partial y_{l,t}} = -\rho^+ + \bar{\psi}_{l,t} + \sum_{k \in \Omega} (\tau_{l,t}^k + \underline{\tau}_{l,t}^k - \underline{\psi}_{l,t}^k) + \nu_{f,t} \geq 0 \quad \perp \quad y_{l,t} \geq 0 \quad (3.3.43)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial z_{l,t}^k} &= \left((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k \right) \cdot (\bar{\pi}_t^k + \rho^+) + \underline{\psi}_{l,t}^k + \\ &\quad + \bar{v}_{l,t}^k - \underline{v}_{l,t}^k - \tau_{l,t}^k \geq 0 \quad \perp \quad z_{l,t}^k \geq 0 \end{aligned} \quad (3.3.44)$$

$$\frac{\partial \mathcal{L}_f}{\partial Q_f^{k,-}} = \frac{\lambda_f}{1 - \theta_f} \text{Pr}^k - \sigma_f^k \geq 0 \quad \perp \quad Q_f^{k,-} \geq 0 \quad (3.3.45)$$

$$\frac{\partial \mathcal{L}_f}{\partial \zeta_f} = \lambda_f - \sum_{k \in \Omega} \sigma_f^k = 0; \quad \zeta_f \text{ free} \quad (3.3.46)$$

3.3.2 Extension to Multi-Period with Ramping Products

In this subsection is described the model that results to add the ramping products to the previous multi-period model. As in the previous subsection, we consider the model divided in three groups of equations, and focus the description in the differences respect to the previous model.

1) Global constraints

The global are not affected by the introduction of the ramping products, then we have the same global constraints than in the previous model:

$$\sum_{g \in G} ru_{g,t} \geq \underline{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\kappa}_t), \quad (3.3.47)$$

$$\sum_{g \in G} rd_{g,t} \geq B \cdot \sum_{g \in G} ru_{g,t}, \quad (\underline{\kappa}_t), \quad (3.3.48)$$

$$\sum_{g \in G} ru_{g,t} \leq \bar{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\gamma}_t), \quad (3.3.49)$$

$$\sum_{g \in G} rd_{g,t} \leq \sum_{g \in G} ru_{g,t}, \quad (\underline{\gamma}_t). \quad (3.3.50)$$

2) TSO's problem for minimizing the generation cost from reserves

In the TSO's problem for minimizing the generation cost from reserves there are changes in some constraints, because the energy that can be deployed for operational flexibility is now the energy from the committed reserves and the committed ramping products. The optimization problem for each scenario k is:

$$\underset{s_{g,t}^k, u_{g,t}^k}{\text{minimize}} \quad \sum_{t \in T} \sum_{g \in G} \left(s_{g,t}^k \cdot cg_g - u_{g,t}^k \cdot cg_g \right) \quad (3.3.51)$$

$$\text{subject to:} \quad \sum_{g \in G} s_{g,t}^k = \sum_{l \in G} z_{l,t}^k, \quad (\bar{\pi}_t^k) \quad (3.3.52)$$

$$\sum_{g \in G} u_{g,t}^k = \sum_{l \in G} v_{l,t}^k, \quad (\underline{\pi}_t^k) \quad (3.3.53)$$

$$s_{g,t}^k \leq ru_{g,t} + urc_{g,t}, \quad (\bar{\eta}_{g,t}^k) \quad (3.3.54)$$

$$u_{g,t}^k \leq rd_{g,t} + drc_{g,t}, \quad (\underline{\eta}_{g,t}^k) \quad (3.3.55)$$

where the variables are $s_{g,t}^k$ and $u_{g,t}^k$, and the fixed input data are: The committed upward $ru_{g,t}$ and downward $rd_{g,t}$ reserve, the up ramp capability $urc_{g,t}$, the down ramp capability $drc_{g,t}$, as well as the demand of energy from the upward $z_{l,t}^k$ and downward $v_{l,t}^k$ reserve.

As in the previous model, minimizing the cost (3.3.51) implies using the generators with the minimum generation cost for upward energy and the generators with the maximum cost for downward energy. The KKT conditions for this problem are:

$$\frac{\partial \mathcal{L}_B}{\partial s_{g,t}^k} = cg_g - \bar{\pi}_t^k + \bar{\eta}_{g,t}^k \geq 0, \quad \perp s_{g,t}^k \geq 0 \quad (3.3.56)$$

$$\frac{\partial \mathcal{L}_B}{\partial u_{g,t}^k} = -cg_g - \underline{\pi}_t^k + \underline{\eta}_{g,t}^k \geq 0, \quad \perp u_{g,t}^k \geq 0 \quad (3.3.57)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\pi}_t^k} = \sum_{l \in G} z_{l,t}^k - \sum_{g \in G} s_{g,t}^k = 0, \quad \bar{\pi}_t^k \text{ free} \quad (3.3.58)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\pi}_t^k} = \sum_{l \in G} v_{l,t}^k - \sum_{g \in G} u_{g,t}^k = 0, \quad \underline{\pi}_t^k \text{ free} \quad (3.3.59)$$

$$\frac{\partial \mathcal{L}_B}{\partial \bar{\eta}_{g,t}^k} = s_{g,t}^k - ru_{g,t} - urc_{g,t} \leq 0, \quad \perp \bar{\eta}_{g,t}^k \geq 0 \quad (3.3.60)$$

$$\frac{\partial \mathcal{L}_B}{\partial \underline{\eta}_{g,t}^k} = u_{g,t}^k - rd_{g,t} - drc_{g,t} \leq 0, \quad \perp \underline{\eta}_{g,t}^k \geq 0 \quad (3.3.61)$$

3) Firms' problems

In the multi-period setting with ramping products, the changes in the firm's problem are in the objective function, the capacity constraints for dispatchable generators, the ramping constraints, and two new constraints for the ramping products. The recourse function is not affected by the introduction of ramping products, and remains the same expression as before (3.3.22). The optimization problem for each firm f extended to multi-period and with ramping products is:

$$\begin{aligned} \max_{d,x,y,z,rd,ru,s,u,v,\zeta,Q^-} \sum_{t \in T} \left\{ \left(\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} d_{h,t} \right) \cdot d_{f,t} + \sum_{g \in G_f} (ru_{g,t} + urc_{g,t}) \cdot (\bar{\kappa}_t + \bar{\gamma}_t) + \right. \\ \left. + \sum_{g \in G_f} (rd_{g,t} + drc_{g,t}) \cdot (\underline{\kappa}_t + \underline{\gamma}_t) + \right. \\ \left. + \sum_{l \in G_f} y_{l,t} \cdot \rho^+ - \sum_{g \in G_f} x_{g,t} \cdot cg_g + \right. \\ \left. - (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \end{aligned} \quad (3.3.62)$$

$$\text{subject to: } x_{g,t} + ru_{g,t} + urc_{g,t} \leq \bar{X}_g, \quad (\bar{\phi}_{g,t}) \quad (3.3.63)$$

$$x_{g,t} + s_{g,t}^k - rd_{g,t} - drc_{g,t} \geq \underline{X}_g, \quad (\underline{\phi}_{g,t}^k) \quad (3.3.64)$$

$$y_{l,t} \leq \bar{Y}_l^{\max}, \quad (\bar{\psi}_{l,t}) \quad (3.3.65)$$

$$y_{l,t} - z_{l,t}^k \geq \underline{Y}_l^k, \quad (\underline{\psi}_{l,t}^k) \quad (3.3.66)$$

$$\sum_{g \in G_f} x_{g,t} + \sum_{l \in G_f} y_{l,t} = d_{f,t}, \quad (\nu_{f,t}) \quad (3.3.67)$$

$$z_{l,t}^k \leq \bar{Y}_l^{max} - \bar{Y}_{l,t}^k, \quad (\bar{\tau}_{l,t}^k) \quad (3.3.68)$$

$$y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\underline{\tau}_{l,t}^k) \quad (3.3.69)$$

$$v_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\xi_{l,t}^k) \quad (3.3.70)$$

$$v_{l,t}^k + y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\tau_{l,t}^k) \quad (3.3.71)$$

$$ru_{g,t} + urc_{g,t} \leq \bar{R} \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (\bar{\delta}_{g,t}) \quad (3.3.72)$$

$$ru_{g,t} + urc_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\underline{\delta}_{g,t}) \quad (3.3.73)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R} \cdot \bar{X}_g, \quad (\bar{\epsilon}_{g,t}) \quad (3.3.74)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R} \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \quad (\underline{\epsilon}_{g,t}) \quad (3.3.75)$$

$$\sum_{g \in G} (ru_{g,t} + urc_{g,t}) = \Delta_{t+2}^u, \quad (\bar{\omega}_t) \quad (3.3.76)$$

$$\sum_{g \in G} (rd_{g,t} + drc_{g,t}) = \Delta_{t+2}^d, \quad (\underline{\omega}_t) \quad (3.3.77)$$

$$\zeta_f + Q_f^{k,-} \geq Q_f^k, \quad (\sigma_f^k) \quad (3.3.78)$$

where $d, drc, x, y, z, rd, ru, s, u, urc, v, Q_f^{k,-}$ are positive variables.

Equations (3.3.63)-(3.3.78) comprise the constraints for the firms problem. These constraints are: The upper and lower bounds for dispatchable plants (3.3.63), (3.3.64), and wind turbines (3.3.65), (3.3.66), the balancing for energy sales in day ahead (3.3.67), the upper and lower bounds for the purchases of wind turbines due to shortage of wind (3.3.68), (3.3.69), the bound for the bids of wind in excess (they cannot be greater than available wind) (3.3.70), the energy balance for wind turbines (3.3.71), the ramping constraints for reserve and scheduled dispatchable generation (3.3.72)-(3.3.75), the requirement for the new ramping products and reserve (new constraints) (3.3.76), (3.3.77), and, finally, the constraint (3.3.78) for the CVaR calculation.

The values for Δ_t^u and Δ_t^d that we consider in the model come from a trade off between the ramping capability technically available $\bar{R}_g \cdot \bar{X}_g$ and the wind variability considered, the particular expressions are:

$$\Delta_t^u = \min \left\{ 0.9 \cdot \sum_{g \in G} \bar{R}_g \cdot \bar{X}_g, \sum_{l \in G} \left[\max_k \{\bar{Y}_{l,t}^k\} - \sum_{k \in \Omega} \text{Pr}^k \cdot \bar{Y}_{l,t}^k \right] \right\} \quad (3.3.79)$$

$$\Delta_t^d = \min \left\{ 0.9 \cdot \sum_{g \in G} \underline{R}_g \cdot \bar{X}_g, \sum_{l \in G} \left[\sum_{k \in \Omega} \text{Pr}^k \cdot \bar{Y}_{l,t}^k - \min_k \{\bar{Y}_{l,t}^k\} \right] \right\} \quad (3.3.80)$$

where $\bar{Y}_{l,t}^k$ is the available wind for wind turbine l at period t in scenario k .

The KKT conditions for the primal variables in the the firm's problem in the multi-period setting with ramping products are:

$$\frac{\partial \mathcal{L}_f}{\partial d_{f,t}} = -(\rho_0 - \alpha_0 \sum_{h \in F} d_{h,t}) - \nu_{f,t} \geq 0 \quad \perp \quad d_{f,t} \geq 0 \quad (3.3.81)$$

$$\frac{\partial \mathcal{L}_f}{\partial drc_{g,t}} = -(\underline{\kappa}_t + \underline{\gamma}_t) + \sum_{k \in \Omega} \underline{\phi}_{g,t}^k + \bar{\epsilon}_{g,t} + \underline{\epsilon}_{g,t} + \underline{\omega}_t \geq 0 \quad \perp \quad drc_{g,t} \geq 0 \quad (3.3.82)$$

$$\frac{\partial \mathcal{L}_f}{\partial rd_{g,t}} = -(\underline{\kappa}_t + \underline{\gamma}_t) + \sum_{k \in \Omega} \underline{\phi}_{g,t}^k + \bar{\epsilon}_{g,t} + \underline{\epsilon}_{g,t} + \underline{\omega}_t \geq 0 \quad \perp \quad rd_{g,t} \geq 0 \quad (3.3.83)$$

$$\frac{\partial \mathcal{L}_f}{\partial ru_{g,t}^k} = -(\bar{\kappa}_t + \bar{\gamma}_t) + \bar{\phi}_{g,t} + \bar{\delta}_{g,t} + \underline{\delta}_{g,t} + \bar{\omega}_t \geq 0 \quad \perp \quad ru_{g,t} \geq 0 \quad (3.3.84)$$

$$\frac{\partial \mathcal{L}_f}{\partial urc_{g,t}} = -(\bar{\kappa}_t + \bar{\gamma}_t) + \bar{\phi}_{g,t} + \bar{\delta}_{g,t} + \underline{\delta}_{g,t} + \bar{\omega}_t \geq 0 \quad \perp \quad urc_{g,t} \geq 0 \quad (3.3.85)$$

$$\frac{\partial \mathcal{L}_f}{\partial v_{l,t}^k} = \left((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k \right) \cdot (\underline{\pi}_t^k - \rho_t^*) + \xi_{l,t}^k + \tau_{l,t}^k \geq 0 \quad \perp \quad v_{l,t}^k \geq 0 \quad (3.3.86)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial x_{g,t}} &= cg_g + \bar{\phi}_{g,t} - \sum_{k \in \Omega} \underline{\phi}_{g,t}^k + \nu_{f,t} + \bar{\delta}_{g,t-1} - \bar{\delta}_{g,t} \\ &\quad - \underline{\delta}_{g,t-1} + \underline{\delta}_{g,t} + \bar{\epsilon}_{g,t-1} - \bar{\epsilon}_{g,t} - \underline{\epsilon}_{g,t-1} + \underline{\epsilon}_{g,t} \geq 0 \quad \perp \quad x_{g,t} \geq 0 \end{aligned} \quad (3.3.87)$$

$$\frac{\partial \mathcal{L}_f}{\partial y_{l,t}} = -\rho^+ + \bar{\psi}_{l,t} + \sum_{k \in \Omega} (\tau_{l,t}^k + \underline{l}_{l,t}^k - \underline{\psi}_{l,t}^k) + \nu_{f,t} \geq 0 \quad \perp \quad y_{l,t} \geq 0 \quad (3.3.88)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial z_{l,t}^k} &= \left((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k \right) \cdot (\bar{\pi}_t^k + \rho^+) + \underline{\psi}_{l,t}^k + \\ &\quad + \bar{l}_{l,t}^k - \underline{l}_{l,t}^k - \tau_{l,t}^k \geq 0 \quad \perp \quad z_{l,t}^k \geq 0 \end{aligned} \quad (3.3.89)$$

$$\frac{\partial \mathcal{L}_f}{\partial Q_f^{k,-}} = \frac{\lambda_f}{1 - \theta_f} \text{Pr}^k - \sigma_f^k \geq 0 \quad \perp \quad Q_f^{k,-} \geq 0 \quad (3.3.90)$$

$$\frac{\partial \mathcal{L}_f}{\partial \zeta_f} = \lambda_f - \sum_{k \in \Omega} \sigma_f^k = 0; \quad \zeta_f \text{ free} \quad (3.3.91)$$

3.4 Multi-Period Single Firm Equilibrium Model with Price Responsive Demand

The model described in this section is posed as a pure optimization problem, in contrast with the complementarity formulation used in the previous sections and chapters. In this case the model consists of only one optimization problem with an objective function and a set of constraints that includes the market features described in the previous models. The resulting problem is a quadratic program, because of the presence of quadratic terms in the objective function, the constraints are linear. The recourse function Q^k has a linear expression for a single firm in this case:

$$Q^k = \sum_{t \in T} \sum_{g \in G} cg_g \cdot (s_{g,t}^k - u_{g,t}^k) + \sum_{t \in T} \sum_{l \in G} z_{l,t}^k \cdot \rho^+ \quad (3.4.1)$$

To summarize, the model is posed as a welfare maximization problem, a two stage stochastic program, for a single firm f that is a price taking in a multi-period setting, with price responsive demand. The firms are risk averse and use the CVaR of the recourse function as a measure of risk. The main changes respect to the previous models are:

- Welfare maximization approach, that implies the inclusion of the term $\sum_{t \in T} \int_0^{d_{f,t}} (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} w_{h,t}) \cdot dw_{f,t}$ in the objective function, that replaces the term $\sum_{t \in T} (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} d_{h,t}) \cdot d_{f,t}$ in the previous models.

- The terms that explicitly include dual variables are removed, in the objective function and the constraints.
- The problems of the different agents, that were already described in the previous sections, are all included together in the set of constraints, in particular: 1) The firm's constraints (3.4.3)-(3.4.16), 2) the constraints for the TSO's minimization problem for the generation cost from reserves (3.4.17)-(3.4.20), and 3) the global constraints (3.4.21)-(3.4.24).

We consider two variants of this model, the model without ramping products and the model with ramping products.

1) Model without ramping product:

$$\begin{aligned} \max_{\substack{d,x,y,z,rd, \\ ru,s,u,v,\zeta,Q^-}} \left\{ \sum_{t \in T} \left[\int_0^{d_{f,t}} (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} w_{h,t}) \cdot dw_{f,t} + \sum_{l \in G_f} y_{l,t} \cdot \rho^+ - \sum_{g \in G_f} x_{g,t} \right] \right. \\ \left. - (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \end{aligned} \quad (3.4.2)$$

$$\text{subject to: } x_{g,t} + ru_{g,t} \leq \bar{X}_g, \quad (\bar{\phi}_{g,t}) \quad (3.4.3)$$

$$x_{g,t} - rd_{g,t} \geq \underline{X}_g, \quad (\underline{\phi}_{g,t}) \quad (3.4.4)$$

$$y_{l,t} \leq \bar{Y}_l^{\max}, \quad (\bar{\psi}_{l,t}) \quad (3.4.5)$$

$$y_{l,t} - z_{l,t}^k \geq \underline{Y}_l^k, \quad (\underline{\psi}_{l,t}^k) \quad (3.4.6)$$

$$\sum_{g \in G_f} x_{g,t} + \sum_{l \in G_f} y_{l,t} = d_{f,t}, \quad (\nu_{f,t}) \quad (3.4.7)$$

$$z_{l,t}^k \leq \bar{Y}_l^{\max} - \bar{Y}_{l,t}^k, \quad (\bar{t}_{l,t}^k) \quad (3.4.8)$$

$$y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\underline{t}_{l,t}^k) \quad (3.4.9)$$

$$v_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\xi_{l,t}^k) \quad (3.4.10)$$

$$v_{l,t}^k + y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\tau_{l,t}^k) \quad (3.4.11)$$

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (\bar{\delta}_{g,t}) \quad (3.4.12)$$

$$ru_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\underline{\delta}_{g,t}) \quad (3.4.13)$$

$$rd_{g,t} \leq \underline{R} \cdot \bar{X}_g, \quad (\bar{\epsilon}_{g,t}) \quad (3.4.14)$$

$$rd_{g,t} \leq \underline{R} \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \quad (\underline{\epsilon}_{g,t}) \quad (3.4.15)$$

$$\zeta_f + Q_f^{k,-} \geq Q_f^k, \quad (\sigma_f^k) \quad (3.4.16)$$

$$\sum_{g \in G} s_{g,t}^k = \sum_{l \in G} z_{l,t}^k, \quad (\bar{\pi}_t^k) \quad (3.4.17)$$

$$\sum_{g \in G} u_{g,t}^k = \sum_{l \in G} v_{l,t}^k, \quad (\underline{\pi}_t^k) \quad (3.4.18)$$

$$s_{g,t}^k \leq ru_{g,t}, \quad (\bar{\eta}_{g,t}^k) \quad (3.4.19)$$

$$u_{g,t}^k \leq rd_{g,t}, \quad (\underline{\eta}_{g,t}^k) \quad (3.4.20)$$

$$\sum_{g \in G} ru_{g,t} \geq \underline{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\kappa}_t) \quad (3.4.21)$$

$$\sum_{g \in G} rd_{g,t} \geq B \cdot \sum_{g \in G} ru_{g,t}, \quad (\underline{\kappa}_t) \quad (3.4.22)$$

$$\sum_{g \in G} ru_{g,t} \leq \bar{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\gamma}_t) \quad (3.4.23)$$

$$\sum_{g \in G} rd_{g,t} \leq \sum_{g \in G} ru_{g,t}, \quad (\underline{\gamma}_t) \quad (3.4.24)$$

where $d, x, y, z, rd, ru, s, u, v, Q_f^{k,-}$ are positive variables.

2) Model with ramping products:

This model has the same objective function and recourse function Q^k than the model without ramping products, but some constraints change, and new variables $(urc_{g,t}, drc_{g,t})$ and constraints (3.4.48) and (3.4.49) are included in the problem.

$$\begin{aligned} \max_{\substack{d, x, y, z, rd, \\ ru, s, u, v, \zeta, Q^-}} & \left\{ \sum_{t \in T} \left[\int_0^{d_{f,t}} (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} w_{h,t}) \cdot dw_{f,t} + \sum_{l \in G_f} y_{l,t} \cdot \rho^+ - \sum_{g \in G_f} x_{g,t} \right] \right. \\ & \left. - (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k - \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \end{aligned} \quad (3.4.25)$$

$$\text{subject to: } x_{g,t} + ru_{g,t} + urc_{g,t} \leq \bar{X}_g, \quad (\bar{\phi}_{g,t}) \quad (3.4.26)$$

$$x_{g,t} - rd_{g,t} - drc_{g,t} \geq \underline{X}_g, \quad (\underline{\phi}_{g,t}) \quad (3.4.27)$$

$$y_{l,t} \leq \bar{Y}_l^{\max}, \quad (\bar{\psi}_{l,t}) \quad (3.4.28)$$

$$y_{l,t} - z_{l,t}^k \geq \underline{Y}_l^k, \quad (\underline{\psi}_{l,t}^k) \quad (3.4.29)$$

$$\sum_{g \in G_f} x_{g,t} + \sum_{l \in G_f} y_{l,t} = d_{f,t}, \quad (\nu_{f,t}) \quad (3.4.30)$$

$$z_{l,t}^k \leq \bar{Y}_l^{\max} - \bar{Y}_{l,t}^k, \quad (\bar{\iota}_{l,t}^k) \quad (3.4.31)$$

$$y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\underline{\iota}_{l,t}^k) \quad (3.4.32)$$

$$v_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\xi_{l,t}^k) \quad (3.4.33)$$

$$v_{l,t}^k + y_{l,t} - z_{l,t}^k \leq \bar{Y}_{l,t}^k, \quad (\tau_{l,t}^k) \quad (3.4.34)$$

$$ru_{g,t} + urc_{g,t} \leq \bar{R} \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \quad (\bar{\delta}_{g,t}) \quad (3.4.35)$$

$$ru_{g,t} + urc_{g,t} \leq \bar{R} \cdot \bar{X}_g, \quad (\underline{\delta}_{g,t}) \quad (3.4.36)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R} \cdot \bar{X}_g, \quad (\bar{\epsilon}_{g,t}) \quad (3.4.37)$$

$$rd_{g,t} + drc_{g,t} \leq \underline{R} \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \quad (\underline{\epsilon}_{g,t}) \quad (3.4.38)$$

$$\zeta_f + Q_f^{k,-} \geq Q_f^k, \quad (\sigma_f^k) \quad (3.4.39)$$

$$\sum_{g \in G} s_{g,t}^k = \sum_{l \in G} z_{l,t}^k, \quad (\bar{\pi}_t^k) \quad (3.4.40)$$

$$\sum_{g \in G} u_{g,t}^k = \sum_{l \in G} v_{l,t}^k, \quad (\underline{\pi}_t^k) \quad (3.4.41)$$

$$s_{g,t}^k \leq ru_{g,t} + urc_{g,t}, \quad (\bar{\eta}_{g,t}^k) \quad (3.4.42)$$

$$u_{g,t}^k \leq rd_{g,t} + drc_{g,t}, \quad (\underline{\eta}_{g,t}^k) \quad (3.4.43)$$

$$\sum_{g \in G} ru_{g,t} \geq \underline{A} \cdot \left[m_x \cdot \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\kappa}_t) \quad (3.4.44)$$

$$\sum_{g \in G} rd_{g,t} \geq B \cdot \sum_{g \in G} ru_{g,t}, \quad (\underline{\kappa}_t) \quad (3.4.45)$$

$$\sum_{g \in G} ru_{g,t} \leq \bar{A} \cdot \left[m_x \cdot \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right], \quad (\bar{\gamma}_t) \quad (3.4.46)$$

$$\sum_{g \in G} rd_{g,t} \leq \sum_{g \in G} ru_{g,t}, \quad (\underline{\gamma}_t) \quad (3.4.47)$$

$$\sum_{g \in G} (ru_{g,t} + urc_{g,t}) = \Delta_{t+2}^u, \quad (\bar{\omega}_t) \quad (3.4.48)$$

$$\sum_{g \in G} (rd_{g,t} + drc_{g,t}) = \Delta_{t+2}^d, \quad (\underline{\omega}_t) \quad (3.4.49)$$

where $d, x, y, z, rd, ru, s, u, v, Q_f^{k,-}$ are positive variables.

The values for Δ_t^u and Δ_t^d considered are a trade off between the technical capacity for ramping $\bar{R}_g \cdot \bar{X}_g$ and the variability of wind taking into account. The expressions for these values are:

$$\Delta_t^u = \min \left\{ 0.9 \cdot \sum_{g \in G} \bar{R}_g \cdot \bar{X}_g, \sum_{l \in G} \left[\max_k \{\bar{Y}_{l,t}^k\} - \sum_{k \in \Omega} \text{Pr}^k \cdot \bar{Y}_{l,t}^k \right] \right\} \quad (3.4.50)$$

$$\Delta_t^d = \min \left\{ 0.9 \cdot \sum_{g \in G} \bar{R}_g \cdot \bar{X}_g, \sum_{l \in G} \left[\sum_{k \in \Omega} \text{Pr}^k \cdot \bar{Y}_{l,t}^k - \min_k \{\bar{Y}_{l,t}^k\} \right] \right\} \quad (3.4.51)$$

where $\bar{Y}_{l,t}^k$ is the available wind for wind turbine l at period t in scenario k .

3.5 Multi-Period Single Firm Equilibrium Model with Fixed Demand

In this section we adapt the model of the previous section by changing the demand model from price responsive demand to fixed demand, the resulting model is a linear program. Thus, the inverse demand function is replaced by a curve for total demand D_t based on historical data. In this section first the adaptation process from price responsive demand to fixed demand is described, and then two variants of the model, one without ramping products and the other with ramping products are described (as in the previous sections).

In the adaptation process from price responsive demand to fixed demand, we remove the endogenous variable for demand $d_{f,t}$ that represents the demand that is supplied by each

firm, because in the case of single firm $d_{f,t} = D_t$. One advantage of the fixed demand model is that we can set a variability pattern for demand taking into account exogenous factors not included in the model. Most of the equations in the previous model remain unchanged, the changes concentrate in:

- 1) The term with the inverse demand function in the objective function (3.4.2) is removed, thus the new objective function is:

$$\min_{\substack{d,x,y,z,rd, \\ ru,s,u,v,\zeta,Q^-}} \left\{ \sum_{t \in T} \left[- \sum_{l \in G_f} y_{l,t} \cdot \rho^+ + \sum_{g \in G_f} x_{g,t} \cdot c_{g_g} \right] + \right. \\ \left. + (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k + \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) \right\} \quad (3.5.1)$$

- 2) The energy balance constraint is changed to:

$$\sum_{g \in G} x_{g,t} + \sum_{l \in G} y_{l,t} = D_t \quad (3.5.2)$$

We include here only the equations of the model because the description of the equations has been included in the previous Section 3.3:

- Equations for the model without ramping products: Equations (3.4.2)-(3.4.24), replacing equation (3.4.2) by (3.5.1) and equation (3.4.7) by (3.5.2).
- Equations for the model with ramping products: Equations (3.4.25)-(3.4.49), replacing equation (3.4.25) by (3.5.1) and equation (3.4.30) by (3.5.2).

For illustrative purposes we include in what follows a description of the Lagrangian function and the KKT conditions for the model with ramping products.

3.5.1 Lagrange Function for the Model with Ramping Products

Lagrange function for the model described by equations (3.4.2)-(3.4.24), replacing equation (3.4.2) by (3.5.1) and equation (3.4.7) by (3.5.2).

$$\mathcal{L}_f(drc_{g,t}, rd_{g,t}, ru_{g,t}, s_{g,t}^k, u_{g,t}^k, urc_{g,t}, v_{l,t}^k, x_{g,t}, y_{l,t}, z_{l,t}^k, Q_f^{k,-}, \zeta_f; \bar{\gamma}_t, \underline{\gamma}_t, \bar{\delta}_{g,t}, \underline{\delta}_{g,t}, \bar{\epsilon}_{g,t}, \underline{\epsilon}_{g,t}, \bar{\eta}_{g,t}^k, \underline{\eta}_{g,t}^k, \bar{v}_{l,t}^k, \underline{v}_{l,t}^k, \bar{\kappa}_t, \underline{\kappa}_t, \nu_{f,t}, \xi_{l,t}^k, \bar{\pi}_t^k, \underline{\pi}_t^k, \sigma_f^k, \tau_{l,t}^k, \bar{\phi}_{g,t}, \underline{\phi}_{g,t}, \bar{\psi}_{l,t}, \underline{\psi}_{l,t}^k, \bar{\omega}_t, \underline{\omega}_t) = \\ \sum_{t \in T} \left[- \sum_{l \in G_f} y_{l,t} \cdot \rho^+ + \sum_{g \in G_f} x_{g,t} \cdot c_{g_g} \right] + \\ + (1 - \lambda_f) \cdot \sum_k \text{Pr}^k Q_f^k + \lambda_f \cdot \left(\zeta_f + \frac{1}{1 - \theta_f} \sum_{k \in \Omega} \text{Pr}^k \cdot Q_f^{k,-} \right) + \\ + \sum_{t \in T} \sum_{g \in G_f} \left[\bar{\phi}_{g,t} \cdot (x_{g,t} + ru_{g,t} + urc_{g,t} - \bar{X}_g) + \underline{\phi}_{g,t} \cdot (\underline{X}_g - x_{g,t} + rd_{g,t} + drc_{g,t}) \right]$$

$$\begin{aligned}
& + \sum_{t \in T} \sum_{l \in G_f} \left[\bar{\psi}_{l,t} \cdot (y_{l,t} - \bar{Y}_l^{\max}) + \sum_{k \in \Omega} \underline{\psi}_{l,t}^k \cdot (Y_l^k - y_{l,t} + z_{l,t}^k) \right] \\
& + \sum_{t \in T} \left[\nu_{f,t} \cdot \left(\sum_{g \in G_f} x_{g,t} + \sum_{l \in G_f} y_{l,t} - D_t \right) \right] \\
& + \sum_{t \in T} \sum_{k \in \Omega} \sum_{l \in G_f} \left[\bar{l}_{l,t}^k \cdot (z_{l,t}^k - \bar{Y}_l^{\max} + \bar{Y}_{l,t}^k) + \underline{l}_{l,t}^k \cdot (y_{l,t} - z_{l,t}^k - \bar{Y}_{l,t}^k) \right] \\
& + \sum_{t \in T} \sum_{k \in \Omega} \sum_{l \in G_f} \left[\xi_{l,t}^k \cdot (v_{l,t}^k - \bar{Y}_{l,t}^k) + \tau_{l,t}^k \cdot (v_{l,t}^k + y_{l,t} - z_{l,t}^k - \bar{Y}_{l,t}^k) \right] \\
& + \sum_{t \in T} \sum_{g \in G_f} \left[\bar{\delta}_{g,t} \cdot (ru_{g,t} + urc_{g,t} - \bar{R}_g \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t})) \right] \\
& + \sum_{t \in T} \sum_{g \in G_f} \left[\underline{\delta}_{g,t} \cdot (ru_{g,t} + urc_{g,t} - \bar{R}_g \cdot \bar{X}_g) + \bar{\epsilon}_{g,t} \cdot (rd_{g,t} + drc_{g,t} - \underline{R}_g \cdot \bar{X}_g) \right] \\
& + \sum_{t \in T} \sum_{g \in G_f} \left[\underline{\epsilon}_{g,t} \cdot (rd_{g,t} + drc_{g,t} - \underline{R}_g \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t})) \right] \\
& + \sum_{k \in \Omega} \sigma_f^k \cdot (Q_f^k - \zeta_f - Q_f^{k,-}) \\
& + \sum_{t \in T} \sum_{k \in \Omega} \left[\bar{\pi}_t^k \cdot \left(\sum_{l \in G} z_{l,t}^k - \sum_{g \in G} s_{g,t}^k \right) + \underline{\pi}_t^k \cdot \left(\sum_{l \in G} v_{l,t}^k - \sum_{g \in G} u_{g,t}^k \right) \right] \\
& + \sum_{t \in T} \sum_{k \in \Omega} \sum_{g \in G_f} \left[\bar{\eta}_{g,t}^k \cdot (s_{g,t}^k - ru_{g,t} - urc_{g,t}) + \underline{\eta}_{g,t}^k \cdot (u_{g,t}^k - rd_{g,t} - drc_{g,t}) \right] \\
& + \sum_{t \in T} \bar{\kappa}_t \cdot \left[\underline{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right] - \sum_{g \in G} ru_{g,t} \right] \\
& + \sum_{t \in T} \kappa_t \cdot \left[B \cdot \sum_{g \in G} ru_{g,t} - \sum_{g \in G} rd_{g,t} \right] \\
& + \sum_{t \in T} \bar{\gamma}_t \cdot \left[\sum_{g \in G} ru_{g,t} - \bar{A} \cdot \left[m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t} \right] \right] \\
& + \sum_{t \in T} \gamma_t \cdot \left[\sum_{g \in G} rd_{g,t} - \sum_{g \in G} ru_{g,t} \right] \\
& + \sum_{t \in T} \sum_{g \in G_f} \left[\bar{\omega}_t \cdot \left(\sum_{g \in G} (ru_{g,t} + urc_{g,t}) - \Delta_{t+2}^u \right) \right] \\
& + \sum_{t \in T} \sum_{g \in G_f} \left[\underline{\omega}_t \cdot \left(\sum_{g \in G} (rd_{g,t} + drc_{g,t}) - \Delta_{t+2}^d \right) \right]
\end{aligned} \tag{3.5.3}$$

The variables in this Lagrangian function are:

- Primal variables: $drc_{g,t}, rd_{g,t}, ru_{g,t}, s_{g,t}^k, u_{g,t}^k, urc_{g,t}, v_{l,t}^k, x_{g,t}, y_{l,t}, z_{l,t}^k, Q_f^{k,-}, \zeta_f$.
- Dual variables: $\bar{\gamma}_t, \underline{\gamma}_t, \bar{\delta}_{g,t}, \underline{\delta}_{g,t}, \bar{\epsilon}_{g,t}, \underline{\epsilon}_{g,t}, \bar{\eta}_{g,t}^k, \underline{\eta}_{g,t}^k, \bar{\iota}_{l,t}^k, \underline{\iota}_{l,t}^k, \bar{\kappa}_t, \underline{\kappa}_t, \nu_{f,t}, \xi_{l,t}^k, \bar{\pi}_t^k, \underline{\pi}_t^k, \sigma_f^k, \tau_{l,t}^k, \bar{\phi}_{g,t}, \underline{\phi}_{g,t}, \bar{\psi}_{l,t}, \underline{\psi}_{l,t}^k, \bar{\omega}_t, \underline{\omega}_t$.

3.5.2 KKT Conditions for the Model with Ramping Products

The KKT conditions for the multi-period single-firm equilibrium model with fixed demand and ramping product come from the Lagrangian function (3.5.3), and they are:

Primal Variables

$$\frac{\partial \mathcal{L}_f}{\partial drc_{g,t}} = \underline{\phi}_{g,t} + \bar{\epsilon}_{g,t} + \underline{\epsilon}_{g,t} - \sum_{k \in \Omega} \underline{\eta}_{g,t}^k + \underline{\omega}_t \geq 0 \quad \perp drc_{g,t} \geq 0 \quad (3.5.4)$$

$$\frac{\partial \mathcal{L}_f}{\partial rd_{g,t}} = \underline{\phi}_{g,t} + \bar{\epsilon}_{g,t} + \underline{\epsilon}_{g,t} - \sum_{k \in \Omega} \underline{\eta}_{g,t}^k - \underline{\kappa}_t + \underline{\gamma}_t + \underline{\omega}_t \geq 0 \quad \perp rd_{g,t} \geq 0 \quad (3.5.5)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial ru_{g,t}} &= \bar{\phi}_{g,t} + \bar{\delta}_{g,t} + \underline{\delta}_{g,t} - \sum_{k \in \Omega} \bar{\eta}_{g,t}^k - \bar{\kappa}_t + B \cdot \underline{\kappa}_t \\ &\quad + \bar{\gamma}_t - \underline{\gamma}_t + \bar{\omega}_t \geq 0 \quad \perp ru_{g,t} \geq 0 \end{aligned} \quad (3.5.6)$$

$$\frac{\partial \mathcal{L}_f}{\partial s_{g,t}^k} = ((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k) \cdot cg_g - \bar{\pi}_t^k + \bar{\eta}_{g,t}^k \geq 0 \quad \perp s_{g,t}^k \geq 0 \quad (3.5.7)$$

$$\frac{\partial \mathcal{L}_f}{\partial u_{g,t}^k} = -((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k) \cdot cg_g - \underline{\pi}_t^k + \underline{\eta}_{g,t}^k \geq 0 \quad \perp u_{g,t}^k \geq 0 \quad (3.5.8)$$

$$\frac{\partial \mathcal{L}_f}{\partial urc_{g,t}} = \bar{\phi}_{g,t} + \bar{\delta}_{g,t} + \underline{\delta}_{g,t} - \sum_{k \in \Omega} \bar{\eta}_{g,t}^k + \bar{\omega}_t \geq 0 \quad \perp urc_{g,t} \geq 0 \quad (3.5.9)$$

$$\frac{\partial \mathcal{L}_f}{\partial v_{l,t}^k} = \xi_{l,t}^k + \tau_{l,t}^k + \underline{\pi}_t^k \geq 0 \quad \perp v_{l,t}^k \geq 0 \quad (3.5.10)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial x_{g,t}} &= cg_g + \bar{\phi}_{g,t} - \underline{\phi}_{g,t} + \nu_{f,t} + (\bar{\delta}_{g,t-1} - \bar{\delta}_{g,t}) \\ &\quad - (\underline{\epsilon}_{g,t-1} - \underline{\epsilon}_{g,t}) + \underline{A} \cdot m_x \cdot \bar{\kappa}_t - \underline{A} \cdot m_x \cdot \bar{\gamma}_t \geq 0 \quad \perp x_{g,t} \geq 0 \end{aligned} \quad (3.5.11)$$

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial y_{l,t}} &= -\rho^+ + \bar{\psi}_{l,t} - \sum_{k \in \Omega} (-\underline{\psi}_{l,t}^k + \underline{\iota}_{l,t}^k + \tau_{l,t}^k) + \\ &\quad + \underline{A} \cdot m_y \cdot \bar{\kappa}_t - \bar{A} \cdot m_y \cdot \bar{\gamma}_t \geq 0 \quad \perp y_{l,t} \geq 0 \end{aligned} \quad (3.5.12)$$

$$\frac{\partial \mathcal{L}_f}{\partial z_{l,t}^k} = ((1 - \lambda_f) \cdot \text{Pr}^k + \sigma_f^k) \cdot \rho^+ + \underline{\psi}_{l,t}^k + \bar{\iota}_{l,t}^k - \underline{\iota}_{l,t}^k + \bar{\pi}_t^k \geq 0 \quad \perp z_{l,t}^k \geq 0 \quad (3.5.13)$$

$$\frac{\partial \mathcal{L}_f}{\partial Q_f^{k,-}} = \frac{\lambda_f \cdot \text{Pr}}{1 - \theta_f} - \sigma_f^k \geq 0 \quad \perp Q_f^{k,-} \geq 0 \quad (3.5.14)$$

$$\frac{\partial \mathcal{L}_f}{\partial \zeta_f} = \lambda_f - \sum_{k \in \Omega} \sigma_f^k = 0 \quad \zeta_f \text{ free} \quad (3.5.15)$$

Chapter 4

Case Studies

4.1 Introduction

This chapter illustrates the use of single period and multi-period models through two stylized case studies. A first analysis examines the impact of various policy, economic and physical characteristics of the market on global and particular market outcomes. The analysis is driven by the attempt to assess the role of plants and flexibility reserves. It is conducted with the single period model operated in single firm mode and with price responsive demand. The analysis is conducted with different assumptions on the generation system in preparation for the second case study.

The second analysis elaborates on the above and is inspired by the current movement in the European Union that sees the decommissioning of new and efficient gas plants because of low electricity prices (partially) induced by energy policy. The question addressed here is whether the services provided by conventional plants might eventually stop this anticipated decommissioning. The analysis is driven by the goal of better understanding the role of ramping capability that emerged as important in the first study. It is conducted with a multi-period model operated in optimization mode; results with fixed demand and price responsive demand are studied and compared.

The rest of the chapter consists of five sections. First the expressions that relate the variables in the models and the results reported on the tables are listed. The following section describes the dismantling process used to construct the various assumptions of generation capacities. The data used in the case studies are given next. The last two sections are respectively devoted to the analysis of the impact of policy and market characteristics using single period models and to the impact of the anticipated dismantling of conventional capacities using multi-period models. All these discussions are conducted in a single firm configuration.

4.2 Market Performance Metrics

In this section we describe the expressions used to calculate the results reported from the simulations. These expressions are refereed with a label in the tables reporting results. A given label can correspond to different expressions depending on the model used (e.g. final demand is given by a different expression depending on whether the model is with fixed or price responsible demand). The expressions and their correspondence with the labels in tables are presented in three successive subsections.

4.2.1 General System Characteristics

In this section the different expressions for the labels in tables are listed. Usually the same label corresponds to different expressions depending on the model used to generate the results. In what follows only the labels with the shortest expressions are listed, the rest of the expressions (information on profits) are described in detail in the next sections.

Labels in Tables	¹	Variables and parameters in the models
Demand day ahead (MWh)	s-p	d (price responsive)
	s-p	D (fixed demand)
	m-p	$\frac{1}{ T } \sum_{t \in T} d_t$ (price responsive)
	m-p	$\frac{1}{ T } \sum_{t \in T} D_t$ (fixed demand)
Schedu. win. gen. (MWh)	s-p	$\sum_{l \in G} y_l$
	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{l \in G} y_{l,t}$
Schedu. dispat. gen. (MWh)	s-p	$\sum_{g \in G} x_g$
	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} x_{g,t}$
Equilibrium price (€/MWh)		ρ^* or $-\nu_f$ or $-\nu$
	s-p	$(\rho_0 - \alpha_0 \cdot \sum_{h \in F} d_h) \cdot d_f$
	m-p	$\frac{1}{\sum_{t \in T} \sum_{f \in F} d_{f,t}} \sum_{t \in T} \sum_{f \in F} (\rho_{0,t} - \alpha_{0,t} \cdot \sum_{h \in F} d_{h,t}) \cdot d_{f,t}$
Reserve requirement (MW)	s-p	$m_x \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l$
	m-p	$\frac{1}{ T } \sum_{t \in T} (m_x \sum_{g \in G} x_{g,t} + m_y \cdot \sum_{l \in G} y_{l,t})$
Up. reserve commit. (MW)	s-p	$\sum_{g \in G} r u_g$
	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} r u_{g,t}$
Down. reser. commit. (MW)	s-p	$\sum_{g \in G} r d_g$
	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} r d_{g,t}$
Up ramp cap. commit. (MW)	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} u r c_{g,t}$
Down ramp cap. com. (MW)	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} d r c_{g,t}$
Max. available reserve (MW) ²	s-p	$\sum_{g \in G} \min\{\bar{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g), \underline{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g), \bar{X}_g - x_g\}$
	m-p	$\frac{1}{ T } \sum_{t \in T} \sum_{g \in G} \min\{\bar{R}_g \cdot \bar{X}_g - (x_{g,t+1} - x_{g,t}), \underline{R}_g \cdot \bar{X}_g + (x_{g,t+1} - x_{g,t}), \bar{X}_g - x_{g,t}\}$

4.2.2 Agents' Profits in the Single Period Setting

Policies, physical and economic characteristics have an impact on the different agents of the economy. Besides global indicators such as electricity prices and total energy demand, it is also important to assess this impact on agents' positions. We therefore compute various profit information, as listed below for the model described in Section 2.5, that is single period, single firm, with price responsive demand and posed as a complementarity problem. This model does not include MISO ramping products because they can be defined only in a multi-period context. Only the information for the single period models used in the simulations are described in what follows. These values are **hourly average**:

- 1) The profit of wind turbines in day ahead is ($-\nu$ is the equilibrium price for energy in day

¹The meaning of "s-p" is single period, and "m-p" means multi-period.

²When the model includes a backup generator, its contribution to the available reserve is not taken into account to calculate the values reported in the tables. Thus when the committed reserve is greater than the available reserve means that the backup generator is providing the additional reserve.

ahead):

$$\sum_{l \in G} y_l \cdot (\rho^+ - \nu) \quad (4.2.1)$$

2) The profit of wind turbines in balancing is:

$$\sum_{k \in \Omega} \sum_{l \in G} \text{Pr}^k \cdot \left[v_l^k \cdot (-\nu - \underline{\chi}^k) + z_l^k \cdot (-\rho^+ - \bar{\chi}^k) \right] \quad (4.2.2)$$

3) The profit accruing to dispatchable generators from energy in day ahead is:

$$\sum_{g \in G} x_g \cdot (-\nu - cg_g) \quad (4.2.3)$$

4) The profit accruing to dispatchable generators from ancillary services is:

$$\begin{aligned} \sum_{g \in G} \left[ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g(\underline{\kappa} + \underline{\gamma}) + \right. \\ \left. + \sum_{k \in \Omega} \text{Pr}^k \cdot \left[s_g^k \cdot (\underline{\chi}^k - cg_g) + u_g^k \cdot (\bar{\chi}^k + cg_g + \nu) \right] \right] \end{aligned} \quad (4.2.4)$$

5) The total profit of dispatchable generators in day ahead (first stage) is:

$$\sum_{g \in G} \left[x_g \cdot (-\nu - cg_g) + ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma}) \right] \quad (4.2.5)$$

6) The profit of dispatchable generators at the second stage is:

$$\sum_{g \in G} \sum_{k \in \Omega} \text{Pr}^k \cdot \left[s_g^k \cdot (\underline{\chi}^k - cg_g) + u_g^k \cdot (\bar{\chi}^k + cg_g + \nu) \right] \quad (4.2.6)$$

7) The total (first and second stage) profit of dispatchable generators, in a system without MISO ramping products (see section 3.2.1), is:

$$\begin{aligned} \sum_{g \in G} \left[x_g \cdot (-\nu - cg_g) + ru_g \cdot (\bar{\kappa} + \bar{\gamma}) + rd_g(\underline{\kappa} + \underline{\gamma}) + \right. \\ \left. + \sum_{k \in \Omega} \text{Pr}^k \cdot \left[s_g^k \cdot (\underline{\chi}^k - cg_g) + u_g^k \cdot (\bar{\chi}^k + cg_g + \nu) \right] \right] \end{aligned} \quad (4.2.7)$$

8) The total profit (first and second stage) of wind generators is:

$$\sum_{l \in G} \left[y_l \cdot (\rho^+ - \nu) + \sum_{k \in \Omega} \text{Pr}^k \cdot \left[v_l^k \cdot (-\nu - \underline{\chi}^k) + z_l^k \cdot (-\rho^+ - \bar{\chi}^k) \right] \right] \quad (4.2.8)$$

4.2.3 Agents' Profit in the Multi-Period Setting

The following expressions give the firm's agents profit for the multi-period models used in the simulations, that are the model presented in Section 3.4 and the model in Section 3.5. The model in Section 3.4 is a multi-period, single firm facing a price responsive demand and posed as a stochastic program that maximizes social welfare. The model in Section 3.5 is a multi-period, single firm facing fixed demand, and posed as a stochastic program that minimizes the firm's operation cost. The same expressions of profits apply in both models, but the interpretations of some variables are slightly different. In particular the dual variable ν_t , that in the case of model with price responsive demand is the equilibrium price (the energy price in day ahead) $-\nu_t = \rho_{0,t} - \alpha_{0,t} \cdot d_t$, in the case of the model with fixed demand it becomes the shadow price of the energy in day ahead (the dual variable of the balance between total demand and generation). We consider the hourly average of the values, which are directly comparable with the results from the single period models. The expressions for the firm's agents profit are as follows:

- 1) The profit for wind turbines at the first stage (day ahead) is:

$$\frac{1}{|T|} \sum_{t \in T} \sum_{l \in G} y_{l,t} \cdot (-\nu_t) \quad (4.2.9)$$

Where $-\nu_t$ is the equilibrium price (the energy price in day ahead).

- 2) The profit of wind turbines at the second stage (balancing) is:

$$\frac{1}{|T|} \sum_{t \in T} \sum_{k \in \Omega} \sum_{l \in G} \text{Pr}^k \cdot \left[v_{l,t}^k \cdot (-\nu_t) + z_{l,t}^k \cdot \rho^+ \right] \quad (4.2.10)$$

- 3) The profit of dispatchable generators at the first stage (day ahead), in a system with MISO ramping products (see section 3.2.1), is:

$$\frac{1}{|T|} \sum_{t \in T} \sum_{g \in G} \left[x_{g,t} \cdot (-\nu_t - cg_g) + (urc_{g,t} + ru_{g,t}) \cdot \bar{\phi}_{g,t} - (drc_{g,t} + rd_{g,t}) \cdot \underline{\phi}_{g,t} \right] \quad (4.2.11)$$

- 4) The profit of dispatchable generators at the first stage (day ahead), in a system without MISO ramping products (see section 3.2.1), is:

$$\frac{1}{|T|} \sum_{t \in T} \sum_{g \in G} \left[x_{g,t} \cdot (-\nu_t - cg_g) + ru_{g,t} \cdot \bar{\phi}_{g,t} - rd_{g,t} \cdot \underline{\phi}_{g,t} \right] \quad (4.2.12)$$

- 5) The profit of dispatchable generators at the second stage (balancing) is:

$$\frac{1}{|T|} \sum_{t \in T} \sum_{g \in G} \sum_{k \in \Omega} \text{Pr}^k \cdot \left[u_{g,t}^k \cdot (-\nu_t - cg_g) - s_{g,t}^k \cdot cg_g \right] \quad (4.2.13)$$

4.3 The Dismantling Process

The European power market is current undergoing a large dismantling process. This takes place in an "energy only" market; we simulate this process by distinguishing between the models with fixed demand and the models with price responsive demand.

In the case of fixed demand we model this market by introducing a price cap for energy: we represent this price cap by a virtual generator, hereafter the “backup generator”. The backup generator is needed in the case of fixed demand to avoid infeasibilities due to the fact that generation capacity becomes lower than the fixed demand because of the dismantling process. In theoretical terms, the backup generator has infinite generation capacity, zero fixed cost and a high generation cost equal to the value of the price cap. In our models the backup generator has a finite capacity of 30 GW, that is very high in comparison to the demand in the system, only a small fraction of this capacity is used in practice. It is assumed that this generator is never dismantled.

In the price responsive case the demand adapts to the available generation capacity and we never have infeasibility problems due to a low generation capacity. The introduction of a price cap for energy (a backup generator) still makes sense in this case, but here we do not study that situation and leave it for future work.

The dismantling process consists of the progressive retirement of the conventional plants with profit lower than their fixed operation and maintenance cost. It stops when all plants cover their fixed operating costs. The process consists of the following sequence of actions:

- 1) The process starts with all the capacity in the system available for generation and the backup generator.
- 2) In each iteration the model is run with the plants that have not been dismantled and the backup generator (if it is included in the system).
- 3) The operation cost of conventional units takes into account only the fuel cost. The profit of each conventional plant is calculated as the difference between its revenues and its operation cost during a whole year. This profit is compared with the plant’s fixed operation and maintenance cost. The Fixed Operation and Maintenance cost (FOM) is taken from [73] and it is a fixed value for each technology. The mathematical expressions for this calculation are described in detail in the next Section 4.3.1.
- 4) In each iteration the difference between the plant’s profit and its FOM is calculated for a period of one year, and depending on the value of this difference we have two cases:
 - a) It has a negative value for at least one conventional unit: Then among these units with negative value the one with the lower value is dismantled, and the process continues with other iteration.
 - b) The value is positive for all the active conventional plants: In this case the dismantling process ends in this iteration.

4.3.1 Calculation of Profitability for Dismantling Decisions

The dismantling decisions are based on the profitability of the dispatchable units. This profitability is calculated as the difference between the profit of the dispatchable unit and its FOM in a period of one year. The wind in one year is represented here by a set of four wind patterns described in Table 4.1. This patterns come from the clustering of historical data for wind in the Spanish System in 2012 [74].

³Percentage over the wind capacity installed.

Table 4.1: Data for wind patterns

Index (w)	1	2	3	4
Expected wind (μ_w % ³)	5.86	22.20	47.09	61.17
Probability ($\Pr^{(\mu_w)}$)	0.13321	0.73160	0.06840	0.06678

The dispatchable units with negative profitability are dismantled. The mathematical expression for the profitability depends on the model used, but the general expression is:

$$\text{ProfitabilityDispatchable}_g = \sum_{w \in \Xi} \text{ProfitDispatchable}_g(\mu_w) - \text{FOMC}_g \quad (4.3.1)$$

where w is the index for the wind pattern, $\text{ProfitDispatchable}_g(\mu_w)$ is the profit of the dispatchable unit g when the wind pattern has a wind expectation of μ_w , and FOMC_g is the fixed operation and maintenance cost in the period. The expressions of each term for each model are described in what follows:

- FOMC_g :

- Single period: In this case the terms in the profitability expression are normalized to an hourly base.

$$\text{FOMC}_g = \frac{1}{24} \bar{X}_g \cdot \text{FOM}_g \quad (4.3.2)$$

FOM_g is the fixed operation and maintenance cost of the dispatchable unit g per day.

- Multi-period: In this case the terms in the profitability expression are normalized to a daily base.

$$\text{FOMC}_g = \bar{X}_g \cdot \text{FOM}_g \quad (4.3.3)$$

- $\text{ProfitDispatchable}_g(\mu_w)$:

- Single period (there is not ramping products in single period):

$$\begin{aligned} & x_g^{(\mu_w)} \cdot (-\nu^{(\mu_w)} - cg_g) + ru_g^{(\mu_w)} \cdot (\bar{\kappa}^{(\mu_w)} + \bar{\gamma}^{(\mu_w)}) + rd_g^{(\mu_w)} (\underline{\kappa}^{(\mu_w)} + \underline{\gamma}^{(\mu_w)}) + \\ & + \sum_{k \in \Omega} \Pr^k \cdot \left[s_g^{(\mu_w),k} \cdot (\underline{\chi}^{(\mu_w),k} - cg_g) + u_g^{(\mu_w),k} \cdot (\bar{\chi}^{(\mu_w),k} + cg_g + \nu^{(\mu_w)}) \right] \end{aligned} \quad (4.3.4)$$

- Multi-period with ramping products:

$$\begin{aligned} & \sum_{t \in T} \left[x_{g,t}^{(\mu_w)} \cdot (-\nu_t^{(\mu_w)} - cg_g) + (urc_{g,t}^{(\mu_w)} + ru_{g,t}^{(\mu_w)}) \cdot \bar{\phi}_{g,t}^{(\mu_w)} \right. \\ & \quad \left. - (drc_{g,t}^{(\mu_w)} + rd_{g,t}^{(\mu_w)}) \cdot \underline{\phi}_{g,t}^{(\mu_w)} \right. \\ & \quad \left. + \sum_{k \in \Omega} \Pr^k \cdot \left[u_{g,t}^{(\mu_w),k} \cdot (-\nu_t^{(\mu_w)} - cg_g) - s_{g,t}^{(\mu_w),k} \cdot cg_g \right] \right] \end{aligned} \quad (4.3.5)$$

– Multi-period without ramping products:

$$\begin{aligned} \sum_{t \in T} \left[x_{g,t}^{(\mu_w)} \cdot (-\nu_t^{(\mu_w)} - cg_g) + ru_{g,t}^{(\mu_w)} \cdot \bar{\phi}_{g,t}^{(\mu_w)} - rd_{g,t}^{(\mu_w)} \cdot \underline{\phi}_{g,t}^{(\mu_w)} \right. \\ \left. + \sum_{t \in T} \sum_{k \in \Omega} \text{Pr}^k \cdot \left[u_{g,t}^{(\mu_w),k} \cdot (-\nu_t^{(\mu_w)} - cg_g) - s_{g,t}^{(\mu_w),k} \cdot cg_g \right] \right] \end{aligned} \quad (4.3.6)$$

The superscript “ $\square^{(\mu_w)}$ ” indicates the values that have been calculated with the wind pattern with wind expectation μ_w .

4.4 Data for Case Studies

In this section we describe the data used for the case studies. For the sake of simplicity the data are grouped in the following blocks: Common Data, Demand Data, Generators Data, Wind Scenarios Data, Cases and Structural Assumptions. In some of the previous blocks the data are different for the single period and the multi-period setting.

4.4.1 Common Data

We refer to Common Data as the data common to all case studies (single period or multi-period), these data are:

- The parameters that set the bounds for committed upward reserve in between 90% – 110% of the TSO requirement: $\underline{A} = 0.9$ and $\bar{A} = 1.1$.
- The parameter that set the lower bound for the committed downward reserve to at least 40% of committed upward reserve, $B = 0.4$.
- The balancing reserve factor for dispatchable generation $m_x = 0.02$ (2%).
- The confidence level for $CVaR_\theta$ to $\theta_f = 0.95$.
- The price elasticity of -0.3 , data from [75], for the energy demand in day ahead, for a reference value for the energy price $\bar{\rho}$ and demand $\bar{d}$, thus $-0.3 = \frac{\bar{\rho}}{\bar{d}} \frac{\partial \bar{d}}{\partial \bar{\rho}} = \frac{\bar{\rho}}{\bar{d}} \left(\frac{-1}{\alpha_0} \right) \Rightarrow \alpha_0 = \frac{10}{3} \frac{\bar{\rho}}{\bar{d}}$.

4.4.2 Demand Data

Single period

The parameters ρ_0 and α_0 in the inverse demand function for the single period setting have been calculated considering two conditions:

- Average price $\bar{\rho}$ for average demand $\bar{d}$, $\bar{\rho} = \rho_0 - \alpha_0 \cdot \bar{d}$.
- An elasticity price of -0.3 (data from [75]) for the average price $\bar{\rho}$ and average demand $\bar{d}$, $-0.3 = \frac{\bar{\rho}}{\bar{d}} \frac{\partial \bar{d}}{\partial \bar{\rho}} = \frac{\bar{\rho}}{\bar{d}} \left(\frac{-1}{\alpha_0} \right) \Rightarrow \alpha_0 = \frac{10}{3} \frac{\bar{\rho}}{\bar{d}}$.

We have used the hourly average values for the Spanish system in 2012 [74], $\bar{\rho} = 48.42$ €/MWh and $\bar{d} = 28753.32$ MWh, to calculate the parameters of the inverse demand function for the simulations in the single period case. The parameters of the inverse demand function for these values are $\rho_0 = 209.82$ €/MWh and $\alpha_0 = 0.0056133$ €/(MWh)².

Multi-period

Two models for demand, fixed demand and price responsive demand, are considered in the multi-period setting:

- a) In the case of fixed demand, for each period t (hour) we use in the simulations the corresponding hourly average value for that hour in the Spanish System in 2012, [74], these values are listed on Table 4.2.
- b) Price responsive demand: in this case the inverse demand function is recalculated for each hour, with the result that the parameters $\rho_{0,t}$ and $\alpha_{0,t}$, can have a different value for each time period t . The values of $\rho_{0,t}$ used in the simulations are listed on Table 4.3, and the values of $\alpha_{0,t}$ are listed on Table 4.4. The value of $\alpha_{0,t}$ is calculated as $\alpha_{0,t} = -\frac{10}{3} \frac{\nu_t}{d_t}$, where $-\nu_t$ is the energy price in day ahead (equilibrium price) for the model with multi-period, single firm, fixed demand and posed as a cost minimization stochastic program (see Section 3.5) for the four wind patterns (5.86%, 22.20%, 47.09% and 61.17%) considered in the simulations, see Table 4.11. And the demand d_t is the corresponding fixed value of demand listed in Table 4.2 and used to calculate ν_t . Finally, the value of $\rho_{0,t}$ is calculated as $\rho_{0,t} = -\nu_t + \alpha_{0,t} \cdot d_t$.

Thus there are four patterns for the values of $\rho_{0,t}$ and $\alpha_{0,t}$, one for each pattern of wind.

Table 4.2: Value of the fixed demand curve for energy in day ahead

Hour (h)	Demand (MWh)	Hour (h)	Demand (MWh)	Hour (h)	Demand (MWh)
1	23639.34	9	29623.35	17	32049.07
2	21979.99	10	30823.20	18	32347.67
3	21143.71	11	32321.24	19	32485.98
4	20832.60	12	33108.09	20	31875.76
5	20747.97	13	33751.60	21	31816.75
6	21351.82	14	33897.57	22	31988.14
7	23235.53	15	32587.76	23	31364.21
8	26203.37	16	32324.67	24	28580.27

4.4.3 Generators Data

Different configurations for the generation park are studied for the single period and the multi-period settings. We only consider conventional non hydro technologies and wind, in particular: Combined Cycle Gas Turbine (CCGT), Nuclear, Coal, and Wind. Only conventional technologies (CCGT, Nuclear and Coal) are assumed dispatchable. The CCGT blocks differ by configuration (dismantling and mothballing has concentrated on CCGT), leading to the following configurations for dispatchable generators:

- B2.0 and B2.1: They are described in Table 4.7. B2 should be interpreted as two blocks of CCGT units, “.0” refers to the initial configuration without dismantling, while “.1” is a configuration where the more expensive CCGT block are dismantled, and the capacity of the other CCGT block reduced to the half of its initial capacity.

Table 4.3: Value of $\rho_{0,t}$ (€/MWh) for multi-period case.

Hour (t)	5.86%	22.20%	μ 47.09%	61.17%	Hour (t)	5.86%	22.20%	μ 47.09%	61.17%
1	188.27	175.27	173.66	115.09	13	188.27	188.27	187.19	173.65
2	188.27	165.79	142.78	80.56	14	188.27	188.27	187.19	170.12
3	187.19	150.67	112.13	74.50	15	188.27	188.27	182.16	167.81
4	187.19	166.74	119.38	73.27	16	188.27	188.27	182.16	167.20
5	187.19	161.34	109.98	73.28	17	188.27	188.27	186.11	156.78
6	188.27	162.26	113.42	77.51	18	188.27	188.27	187.19	171.80
7	188.27	169.54	139.02	105.58	19	188.27	188.27	188.27	169.74
8	188.27	187.19	151.47	137.73	20	188.27	188.27	187.19	168.16
9	188.27	188.27	182.16	170.64	21	188.27	188.27	187.19	159.22
10	188.27	188.27	182.16	166.59	22	188.27	188.27	187.19	170.53
11	188.27	188.27	187.19	169.81	23	188.27	188.27	184.48	168.56
12	188.27	188.27	187.19	180.70	24	188.27	188.27	175.87	143.14

Table 4.4: Value of $\alpha_{0,t}$ (€/(MWh)²) for multi-period case.

Hour (t)	5.86%	22.20%	μ 47.09%	61.17%	Hour (t)	5.86%	22.20%	μ 47.09%	61.17%
1	0.00613	0.00570	0.00565	0.00375	13	0.00429	0.00429	0.00427	0.00396
2	0.00659	0.00580	0.00500	0.00282	14	0.00427	0.00427	0.00425	0.00386
3	0.00681	0.00548	0.00408	0.00271	15	0.00444	0.00444	0.00430	0.00396
4	0.00691	0.00616	0.00441	0.00271	16	0.00448	0.00448	0.00433	0.00398
5	0.00694	0.00598	0.00408	0.00272	17	0.00452	0.00452	0.00447	0.00376
6	0.00678	0.00585	0.00409	0.00279	18	0.00448	0.00448	0.00445	0.00409
7	0.00623	0.00561	0.00460	0.00350	19	0.00446	0.00446	0.00446	0.00402
8	0.00553	0.00550	0.00445	0.00404	20	0.00454	0.00454	0.00452	0.00406
9	0.00489	0.00489	0.00473	0.00443	21	0.00455	0.00455	0.00453	0.00385
10	0.00470	0.00470	0.00455	0.00416	22	0.00453	0.00453	0.00450	0.00410
11	0.00448	0.00448	0.00446	0.00404	23	0.00462	0.00462	0.00452	0.00413
12	0.00437	0.00437	0.00435	0.00420	24	0.00507	0.00507	0.00473	0.00385

- B9.0, B9.4, B9.5, B9.6, B9.7: They are summarized in Table 4.6, B9 should be interpreted as 9 blocks of CCGT units. Configuration B9.0 is described in detail in Table 4.5, configurations B9.6 and B9.7 are described in Table 4.8 and used in single period simulations, and finally configurations B9.4 and B9.5 are described in Table 4.9 and used in multi-period simulations. The “.6” in B9.6 indicates that the 6 blocks of CCGT units with the highest cost are dismantled, and the meaning is similar for the rest of configurations.

The initial total capacity has the same value (43597.49 MW) for both configurations B2.0 and B9.0, and also both configurations have the same value of capacities for each technology (CCGT, Nuclear and Coal). The only difference is in the number of blocks for the CCGT technology; it is divided in two blocs in configuration B2 and in 9 blocs in B9. These reflect different stages of the dismantling process due to assumptions (e.g. dismantling ends on different generation systems depending on ramping capabilities). The blocks for the other technologies, Coal and Nuclear, are identical in all configurations (B2.0, B2.1, B9.0, B9.4,

B9.5, B9.6, and B9.7)

Single period

Table 4.5: Summary of generators' data, configuration B9.

N	Technology	Net Capa. $\bar{X}_g$ (MW)	$\bar{R}_g = \frac{R_g}{\bar{X}_g}$ %/h of $\bar{X}_g$	cg_g (€/MWh)	FOM ⁴ (€/(MW·day))
1	CCGT	2910.81	53.33	46.90	80.00
2	CCGT	1550.05	53.33	46.47	79.00
3	CCGT	1584.44	53.33	46.04	78.00
4	CCGT	3863.34	53.33	45.61	77.00
5	CCGT	5588.25	53.33	45.17	76.00
6	CCGT	2744.32	53.33	44.74	75.00
7	CCGT	3274.98	53.33	44.31	74.00
8	CCGT	2056.58	53.33	43.88	73.00
9	CCGT	2153.50	53.33	43.45	72.00
10	Nuclear	1519.23	2.08	10.91	269.95
11	Nuclear	6053.35	2.08	10.29	264.66
12	Coal	2035.89	20.00	37.50	100.00
13	Coal	5119.13	25.00	38.44	98.00
14	Coal	1198.12	25.00	19.77	97.00
15	Coal	1945.51	25.00	20.24	95.00
16	Backup gen.	30000.00	50.00	100.00	0.00
17	Wind	22573.00	0.00	0.00	0.00

Table 4.6: Summary of dismantling configurations for dispatchable generators with initial configuration B9.0.

g	Tech.	Capacity $\bar{X}_g$ (MW)					cg_g €/MWh
		B9.0	B9.4	B9.5	B9.6	B9.7	
1	CCGT	2910.81	0.00	0.00	0.00	0.00	46.90
2	CCGT	1550.05	0.00	0.00	0.00	0.00	46.47
3	CCGT	1584.44	0.00	0.00	0.00	0.00	46.04
4	CCGT	3863.34	0.00	0.00	0.00	0.00	45.61
5	CCGT	5588.25	5588.25	0.00	0.00	0.00	45.17
6	CCGT	2744.32	2744.32	2744.32	0.00	0.00	44.74
7	CCGT	3274.98	3274.98	3274.98	3274.98	0.00	44.31
8	CCGT	2056.58	2056.58	2056.58	2056.58	2056.58	43.88
9	CCGT	2153.50	2153.50	2153.50	2153.50	2153.50	43.45
10	Nuclear	1519.23	1519.23	1519.23	1519.23	1519.23	10.91
11	Nuclear	6053.35	6053.35	6053.35	6053.35	6053.35	10.29
12	Coal	2035.89	2035.89	2035.89	2035.89	2035.89	37.50
13	Coal	5119.13	5119.13	5119.13	5119.13	5119.13	38.44
14	Coal	1198.12	1198.12	1198.12	1198.12	1198.12	19.77
15	Coal	1945.51	1945.51	1945.51	1945.51	1945.51	20.24
Total (MW)		43597.49	33688.85	28100.60	25356.29	22081.31	

Table 4.7: Summary of generators' data after dismantling, configuration B2.

Tech.	$\bar{X}_g$ (MW)		$\bar{R}_g = \frac{R_g}{\bar{X}_g}$ % of $\bar{X}_g$	cg_g €/MWh	FOM ⁴ €/(MW·day)
	B2.0	B2.1			
CCGT	4395.86	0.00	53.33	45.82	79.65
CCGT	21265.40	10632.70	53.33	43.45	75.20
Nuclear	1519.23	1519.23	2.08	10.91	269.95
Nuclear	6053.35	6053.35	2.08	10.29	264.66
Coal	2035.89	2035.89	20.00	37.50	100.00
Coal	5119.13	5119.13	25.00	38.44	98.00
Coal	1198.12	1198.12	25.00	19.77	97.00
Coal	1945.51	1945.51	25.00	20.24	95.00
Wind	22573.00	22573.00	-	-	-
Total Dispatch.	43597.49	28503.93			

Table 4.8: Summary of generators' data after dismantling, configurations B9 for single period.

g	Tech.	Capacity $\bar{X}_g$ (MW)			cg_g €/MWh	FOM ⁴ €/(MW·day)
		Initial B9.0	Dismantled B9.6	Dismantled B9.7		
1	CCGT	2910.81	0.00	0.00	46.90	80.00
2	CCGT	1550.05	0.00	0.00	46.47	79.00
3	CCGT	1584.44	0.00	0.00	46.04	78.00
4	CCGT	3863.34	0.00	0.00	45.61	77.00
5	CCGT	5588.25	0.00	0.00	45.17	76.00
6	CCGT	2744.32	0.00	0.00	44.74	75.00
7	CCGT	3274.98	3274.98	0.00	44.31	74.00
8	CCGT	2056.58	2056.58	2056.58	43.88	73.00
9	CCGT	2153.50	2153.50	2153.50	43.45	72.00
10	Nuclear	1519.23	1519.23	1519.23	10.91	269.95
11	Nuclear	6053.35	6053.35	6053.35	10.29	264.66
12	Coal	2035.89	2035.89	2035.89	37.50	100.00
13	Coal	5119.13	5119.13	5119.13	38.44	98.00
14	Coal	1198.12	1198.12	1198.12	19.77	97.00
15	Coal	1945.51	1945.51	1945.51	20.24	95.00
16	Backup gen.	30000.00	30000.00	30000.00	100.00	0.00
17	Wind	22573.00	22573.00	22573.00	0.00	0.00
Total dispat. (MW)		43597.49	25356.29	22081.31		

Three compositions of the dispatchable generation park are considered in the simulations for single period, B2.1 (Table 4.7), B9.6 and B9.7 (Table 4.8). Configuration B2.1 has been previously described in this section. The other configurations B9.6 and B9.7 correspond to the final state of dismantling (see Section 4.3) of configuration B9.0 under two different assumptions for ramping. B9.6 is the end result of dismantling for the low ramping ($\Lambda = 1$), and B9.7 for the high ramping assumption ($\Lambda = 0$).

⁴Fixed Operation and Maintenance Cost per day.

Multi-period

Two compositions of the dispatchable generation park are considered in the simulations for multi-period, B9.4 and B9.5 that are described in Table 4.9. These configurations correspond to the final state of the dismantling process for different model assumptions: Fixed demand or price responsive demand, with ramping products or without them, with backup generator or without it.

Table 4.9: Summary of generators' at the final state of dismantling, configurations B9 for multi-period.

g	Tech.	Capacity $\bar{X}_g$ (MW)			c_{g_g} €/MWh	FOM ⁴ €/ (MW·day)
		Initial B9.0	Dismantled B9.4	Dismantled B9.5		
1	CCGT	2910.81	0.00	0.00	46.90	80.00
2	CCGT	1550.05	0.00	0.00	46.47	79.00
3	CCGT	1584.44	0.00	0.00	46.04	78.00
4	CCGT	3863.34	0.00	0.00	45.61	77.00
5	CCGT	5588.25	5588.25	0.00	45.17	76.00
6	CCGT	2744.32	2744.32	2744.32	44.74	75.00
7	CCGT	3274.98	3274.98	3274.98	44.31	74.00
8	CCGT	2056.58	2056.58	2056.58	43.88	73.00
9	CCGT	2153.50	2153.50	2153.50	43.45	72.00
10	Nuclear	1519.23	1519.23	1519.23	10.91	269.95
11	Nuclear	6053.35	6053.35	6053.35	10.29	264.66
12	Coal	2035.89	2035.89	2035.89	37.50	100.00
13	Coal	5119.13	5119.13	5119.13	38.44	98.00
14	Coal	1198.12	1198.12	1198.12	19.77	97.00
15	Coal	1945.51	1945.51	1945.51	20.24	95.00
16	Backup gen.	30000.00	30000.00	30000.00	100.00	0.00
17	Wind	22573.00	22573.00	22573.00	0.00	0.00
Total dispat. (MW)		43597.49	33688.85	28100.60		

4.4.4 Wind Scenarios Data

Single period

In the single period case, uncertainty is modeled through a scenario tree with 12 branches that represent the power output of wind turbines in one hour. The scenarios model the uncertainty from the errors in wind power forecast; the expected wind is a given value μ (exogenous parameter), and the probability distribution comes from the wind power forecast error distribution; here we use a Beta distribution based on μ , see Section 2.2.3. The methodology and assumptions to build the scenarios are described in detail in Section 2.4.5. The scenarios used in the simulation for single period configurations are listed in Table 4.10, these scenarios have representative values based on historical data from the Spanish System, [74]. Each scenario in each tree has the same probability ($\frac{1}{12} \approx 8.33\%$); this results from the particular discretization of the original Beta distribution discussed in Section 2.4.5. Notice that this does not assume an uniform error distribution, in fact the error distribution is assumed to be a Beta distribution, according to [54, 57]. One shall note that the variability

of wind generation is usually in the range $[0.5\mu, 1.5\mu]$ except for very low values of expected wind, see Table 4.10 and Fig. 4.1.

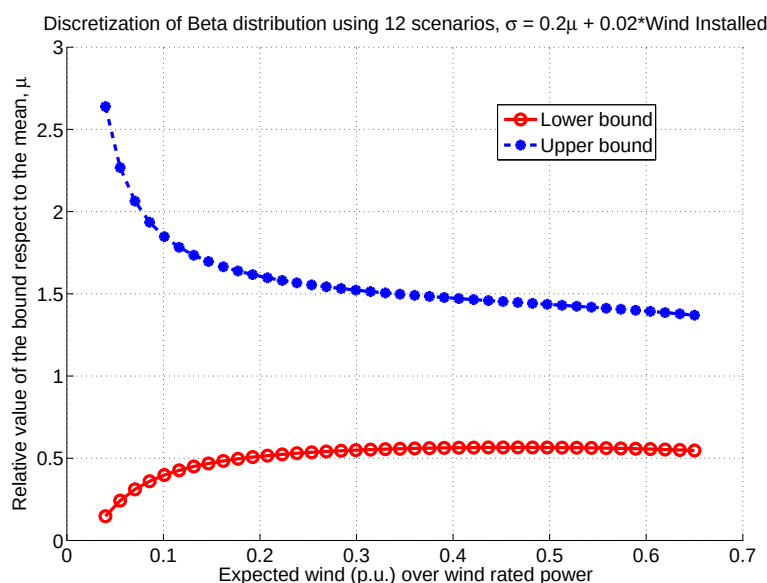


Figure 4.1: Bounds for wind variability in the single period case.

Table 4.10: Data of the scenario tree for wind in single period

Scenario	Normalized power output (%)			
1	0.59	12.64	26.42	35.55
2	1.20	16.13	33.34	46.56
3	1.69	18.12	37.13	52.44
4	2.15	19.76	40.16	56.99
5	2.62	21.24	42.83	60.89
6	3.12	22.66	45.34	64.44
7	3.66	24.09	47.82	67.81
8	4.27	25.60	50.35	71.13
9	5.00	27.27	53.08	74.52
10	5.93	29.24	56.19	78.18
11	7.27	31.86	60.16	82.46
12	10.57	37.34	67.60	89.05
μ (%) ⁵	4.01	23.83	46.70	65.00
σ (%) ⁵	2.73	6.66	11.20	14.83
max. (base μ)	2.64	1.57	1.45	1.37
min. (base μ)	0.15	0.53	0.57	0.55

The curves plotted in Fig. 4.1 correspond to the normalized values for the lowest scenario (lower bound) and the highest scenario (upper bound) for the wind power output distribution for values of wind forecast in the range 4% to 65%. The common base used to normalize the values is the total wind power capacity installed. The probability of being in the interval between the lower and the upper bound is greater than $\frac{10}{12} \approx 0.833$.

⁵Calculated over the wind capacity installed.

Multi-period

The wind uncertainty is modeled in the multi-period case considering four wind patterns, based on historical data for the Spanish system in 2012 [74], that are representative of the patterns for the whole year. The wind patterns, profiles for 24 hours, are clustered to reduce the total number of profiles from 365 to 4, each one of this four patterns has a probability according to the number of profiles grouped on it. The values in each pattern are interpreted as the expected value for each period, these values are listed on Table 4.11. The four patterns are used in the simulations for the progressive dismantling process (Section 4.3). Each wind pattern is identified by the wind forecast, 5.86%, 22.20%, 47.09% or 61.17% (percentage over the total wind capacity installed). For each period and wind pattern, 12 scenarios are generated following the same procedure that in the single period case (see Section 2.2.3) using the value given by the wind pattern as the expected value. The total number of scenarios is $4 \times 24 \times 12$, 4 wind patterns, 24 periods per wind pattern and 12 scenarios per each period, the values of these scenarios are reported on Tables A.30 and A.31 (Section A.4).

Table 4.11: Patterns for wind in multi-period, 24 hours (% on wind capacity installed)

Hour (h)	Low %	Average %	High %	Very High %
1	0.1097	0.3967	0.4132	0.5531
2	0.1066	0.3550	0.4414	0.5640
3	0.0953	0.3340	0.4586	0.5438
4	0.0823	0.3137	0.4337	0.5420
5	0.0653	0.2953	0.4455	0.5271
6	0.0594	0.2797	0.4606	0.5529
7	0.0546	0.2907	0.4833	0.5654
8	0.0487	0.2940	0.5015	0.5878
9	0.0420	0.2836	0.4905	0.5854
10	0.0347	0.2688	0.4834	0.5836
11	0.0268	0.2498	0.4777	0.5880
12	0.0210	0.2263	0.4922	0.5939
13	0.0210	0.2030	0.5044	0.6270
14	0.0232	0.1763	0.5163	0.6468
15	0.0261	0.1577	0.5219	0.6590
16	0.0385	0.1314	0.5280	0.6645
17	0.0472	0.1307	0.5039	0.6646
18	0.0553	0.1330	0.4783	0.6604
19	0.0621	0.1377	0.4464	0.6539
20	0.0695	0.1421	0.4361	0.6553
21	0.0791	0.1351	0.4326	0.6642
22	0.0780	0.1304	0.4426	0.6678
23	0.0755	0.1356	0.4503	0.6694
24	0.0839	0.1272	0.4587	0.6610
Hourly average (%)	0.0586	0.2220	0.4709	0.6117
Probability	0.1332	0.7316	0.0684	0.0668

4.4.5 Cases and Structural Assumptions

The values for the rest of the data, that are not included in the previous sections, are fixed in what we call here “structural assumptions”, thus the structural assumptions assign a particular value to one or more of the following parameters: The feed-in premium ρ^+ , the level of risk aversion λ , the wind forecast μ , the ramping capability in the single period models (that can be low or high in the parametric ramping model), the demand of ramp capability due to scheduled wind generation m_y , and the price cap to energy in day ahead (in the case of a fixed demand model that includes a price cap). We use these structural assumptions through “Cases” to study the effect of a certain parameter on the results. Each Case consists of two test studies, both with the same structural assumptions, except for the value of the parameter under study, that is the only parameter that changes from one test study to the other. We define four Cases that are focused on the following main factors: *i)* Case 1 in the wind forecast μ , *ii)* Case 2 in the feed-in premium ρ^+ , *iii)* Case 3 in the risk aversion λ , and *iv)* Case 4 in demand for flexibility from wind generation m_y . The Cases are tested under different configurations that consist of the composition of the generation park and the ramping possibilities. The values for the parameters in the Cases are listed in Table 4.12, these cases are used for all the simulations, with the objective to have a common base to compare the results.

Table 4.12: Summary of parameters for the configurations compared in each Case.

	Case 1		Case 2		Case 3		Case 4	
m_x	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
m_y	0.15	0.15	0.15	0.15	0.15	0.15	0.60	0.60
μ , (%) expected wind	4.01	65.00	23.83	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh)	30.00	30.00	0.00	80.00	30.00	30.00	0.00	80.00
λ , risk aversion	0.40	0.40	0.40	0.40	0.00	1.00	0.40	0.40

4.5 Case Study 1: Impact of Policy and Market Characteristics

4.5.1 Introduction to Case Study 1

Incentives to foster the penetration of renewable energies are currently discussed in the context of the revision of EU energy and environmental policy [76]. The single period model is used to illustrate the possible insight that could be gained on these questions by using the modeling set up developed in this thesis. As indicated in the preceding sections, the model is inspired by a stylized view of the Spanish electricity system and was designed to explore various questions arising in real markets (see Section 1.1). We here focus on a sample of these issues as later presented in the text. The analysis aims at assessing the potential contribution of the valuation of flexibility reserves to overcome the drop of wholesale prices due to wind generation and excess generation capacity. The model is designed for several firms operating in the market but is only used here with a single company to simplify the discussion. The models in this section use a price responsive demand in all cases, we are using the model described in Section 2.5, that is single period, single firm and it is posed as a complementarity problem.

In the next sections we discuss results in four generation settings. A generation setting is defined by the combination of the generation park composition and a ramping capability assumption. The four generation settings considered here come from the combination of three compositions for the generation park, B2.1 (Table 4.7), B9.6 and B9.7 (Table 4.8), and two assumptions on the ramping capability, that are low ramping ($\Lambda = 1$) and high ramping ($\Lambda = 0$), see Section 2.3. The generation settings considered with their abbreviated reference in parenthesis are listed in what follows:

- (B2.1, 1): B2.1 generation system (high generation capacity) and parametric ramping with $\Lambda = 1$. High generation capacity and low ramping capacity.
- (B2.1, 0): High generation capacity and high ramping capacity, parametric ramping with $\Lambda = 0$.
- (B9.6, 1): B9.6 generation system (low generation capacity) and parametric ramping with $\Lambda = 1$. Low generation capacity and low ramping capacity.
- (B9.7, 0): Low generation capacity and high ramping capacity, parametric ramping with $\Lambda = 0$.

The generation configuration B2.1 corresponds to an intermediate state of dismantling. In this configuration some of the firms still have a profit lower than their fixed operation and maintenance cost, hence it does not correspond to a final state of dismantling. The configuration B2.1 is set without performing a progressive dismantling process. On the other hand, configurations (B9.6, 1) and (B9.7, 0) correspond to a final state of dismantling. In configurations (B9.6, 1) and (B9.7, 0) every not dismantled unit get a profit greater or equal to its fixed operation and maintenance cost. A summary of the values of energy price and the profit margin⁶ at each round of the progressive dismantling process is reported on Tables A.1 to A.4.

This part is organized as follows. In the following sections the results from the model in Section 2.5 for the four Cases and each generation setting are presented and discussed, each one of the four generation settings in one section. After that, the results of the previous four sections are compared in a new section. And finally a section for the conclusions closes this part.

4.5.2 High Generation Capacity (B2.1) and Low Ramping ($\Lambda = 1$)

The results reported in this section are obtained with the model described in Section 2.4 and the data listed in Section 4.4, that consists of a total dispatchable generation capacity of 28503.93 MW (see Table 4.7 column 3). It shows results obtained for four characterizations of the market (Cases described in Table 4.12) that differ by wind forecast, feed-in premium, risk aversion and increased demand for flexibility due to wind generation (m_y).

It is useful at the outset to draw the attention to the wholesale electricity price (row “Equilibrium price €/MWh” in Table 4.13) that is the flagship index of the market. One observes that the wholesales price is equal to the fuel cost of the marginal CCGT in all columns except in the columns 2, 8 and 9 in Table 4.13 where the price is higher than this marginal cost. Referring to standard economic language this means that the system never captures any scarcity rent on top of the fuel cost of the marginal plant except in the cases

⁶This margin is the difference between the profit of the unit minus its fixed operation and maintenance cost. If this value is positive the firm covers its fixed operation and maintenance cost.

described in columns 2, 8 and 9 in Table 4.13. Referring now to standard reasoning in terms of missing money, this means that the system will not cover the fixed operation cost of the marginal CCGT, except possibly in the case corresponding to column 2 (very low wind availability) and columns 8 and 9 (high demand for flexibility) in Table 4.13. This observation serves as background throughout the analysis.

The forecast wind level

Columns 2 and 3 of Table 4.13 report results with different wind forecast μ for average feed-in premium and risk aversion. The unsurprising result is that wind power reduces the equilibrium price. This directly results from wind replacing the most expensive dispatchable generators, which affects the margins made by both conventional and wind plants. Also expected, higher wind forecast increases scheduled wind and lower scheduled conventional generation. The global effect is a significant decrease of the equilibrium price of 17% that combines to the lower scheduled conventional generation in day ahead to decrease margins on the energy market. The outcome is not better for the revenue from the flexibility reserve market where the higher scheduled wind generation also increases the capacity available for flexibility reserve, which reduces the revenue from reserve in day ahead. The end result is that dispatchable generators loose on both the energy and reserve markets leading to a drastic loss of profits (see row “1st stage dispatchable generators” in Table 4.13) in the day ahead market. Revenue from balancing only very partially compensate for that loss (row “2nd stage dispatchable generators” in Table 4.13). Overall, this drastic drop of revenue decreases the incentive to invest in conventional plants and increases the incentive to mothball or even decommission existing capacities.

The feed-in premium

The feed-in premium is analyzed with average wind condition and risk aversion. Columns 4 and 5 of Table 4.13 indicate that the premium does not significantly affect the day ahead equilibrium even if it induces a small increase of scheduled wind. The high premium tends to enhance wind scheduling in day ahead but the loss of this premium in balancing, when wind generators are short, makes the payoff more risky, which has an impact on the risk adjusted balancing profit. Increasing the feed-in premium to wind generation obviously increases wind revenue, but this seems to take place without distorting the day ahead market. It is well known however that this efficiency result only can hold when wind generation remains sufficiently low compared to demand so that the electricity price remains positive (see [77])

Table 4.13: (B2.1, 1) Results of Cases 1 to 4 on configuration B2 (two CCGT units) of single firm, single period, complementarity formulation, and parametric ramping with $\Lambda = 1$.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 4	Case 4	Case 4
μ (%) expected wind	4.01	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	30.00	30.00	30.00	30.00	30.00
λ risk aversion (0 is risk neutral)	0.40	0.40	0.40	0.40	0.40	0.40
Demand day ahead (MWh)	27988.89	29639.08	29639.08	29639.08	27667.11	27717.02
Schedu. wind gen. (MWh)	873.91	9696.58	3850.16	4088.30	4578.05	7012.83
Schedu. dispatch. gen. (MWh)	27114.99	19942.50	25788.92	25550.78	23089.06	20704.18
Equilibrium price (€/MWh)	52.71	43.45	43.45	43.45	54.52	54.24
Reserve requirement (MW)	673.39	1853.34	1093.30	1124.26	3208.61	4621.78
Up. reserve commit. (MW)	740.72	1671.87	996.94	1235.07	2887.75	4159.60
Down. reser. commit. (MW)	590.69	668.76	398.79	1235.07	1162.93	1673.49
Max. available reserve (MW)	740.72	4565.81	1447.92	1574.92	2887.75	4159.60
INCOMES (€):						
Energy sales in day ahead	1475320.88	1287758.71	1287758.71	1287758.71	1508332.91	1503289.16
Premium to schedu. wind	26217.14	290897.26	308012.95	122648.97	0.00	561026.53
Supply of up. reser. capa.	12865.72	0.00	0.00	0.00	59938.22	84151.84
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	0.00
COSTS (€):						
Cost of dispatch. gen.	816662.92	505032.92	759047.89	748701.31	641744.35	538126.42
$\lambda_f \cdot CVaR[Q]$	21758.83	49106.75	17132.17	49217.49	29968.62	205372.92
$(1 - \lambda_f) \cdot E[Q]$	10662.40	-9841.11	-5713.64	-15109.68	-9038.36	127398.48
PROFIT (€)						
Total (wind + dispatch.)	679970.16	1090024.90	838180.53	676816.04	941590.72	1398010.31
1st stage wind turbines	72281.48	712194.06	475294.79	300277.37	249582.58	941381.82
2nd stage wind turbines	-16886.44	-22744.77	-21266.15	-41874.72	-3695.82	-215420.27
1st stage dispatch. gen.	625459.34	361428.99	361428.99	361428.99	676944.20	668959.29
2nd stage dispatch. gen.	-884.22	39146.63	22722.90	56984.40	28060.00	3089.47

for an early study of the distortion in the short run of a market with premium and high wind penetration).

The increased risk aversion

The increased risk aversion is examined with average wind condition and feed-in premium to wind generation. One finds from columns 6 and 7 in Table 4.13 that an increase of the level of risk aversion λ of the firms only has a low impact on the short run market. The price in the day ahead market remains at 43.45 €/MWh that corresponds to the operating cost of the marginal CCGT. In contrast with the higher premium that increased scheduled wind, a higher risk aversion decreases scheduled wind, albeit not by a large amount. The bad news is the decreasing margins of both types of plants. Conventional plants produce more than in the case of high wind forecast, but collect the same revenue due to the fact that this additional generation comes from the same CCGT that do not make any profit when at the margin. Because risk aversion also reduces balancing activity, these plants also see their profits reduced on that market. The overall conclusion is that risk aversion further reduces gross margins and hence the incentive to keep conventional plants in the system.

Wind induced demand for flexibility reserve.

Except for column 2 with low wind and hence most conventional capacity committed for generation, none of the above cases shows any tight constraint on flexibility reserve in day ahead; the consequence is a lack of revenue from the day ahead reserve market. Wind increases the demand for reserve but at the same time makes existing capacity available for that reserve. The absence of revenue from flexibility reserve, combined with the lower energy price due to wind generation eventually leads to mothballing and possibly decommissioning of dispatchable capacities. The following explores this mechanism in more detail by considering two situations that differ by the demand for reserve and its impact on flexibility reserve and energy prices. We motivate the analysis by attributing an increased demand for reserve to an increased error on wind forecast over different horizons (due to unit commitment considerations). An alternative motivation, not discussed here, can be made by invoking ramping requirement in more detail than our equations (2.4.27) and (2.4.28). This is done in the second case study by resorting to a multi-period model.

- i) Suppose first that a forecasting period of 6 hours or less is sufficient for committing flexibility reserve and assume that we can move gate closure of the energy and reserve markets to that horizon (through some intraday market that we do not characterize otherwise). Assume that wind forecast is accurate over that horizon. The residual error between the forecast and the realization can be characterized by a standard deviation σ . This defines a range for the possible wind power output values that is relatively narrow, $[\mu - \sigma, \mu + \sigma]$, where μ is the expected value for wind and usually $\sigma < \frac{1}{5}\mu$.
- ii) Alternatively consider a forecasting period of 24 hours, typical of an unit commitment problem, as necessary for committing flexibility reserve. We are then in our generic day ahead/real time context and now need to work with the Beta distribution discussed in section 2.4.5. In case of a forecast error with mean μ and standard deviation $\sigma = \frac{1}{5}\mu + \frac{1}{50}$, (normalized values respect to the wind capacity installed), the interval for variability is typically $[0.5\mu, 1.5\mu]$. This implies taking a range of approximately $\pm 60\%$ over the expected value μ to completely cover the variability.

Depending on the amount of available reserve, the committed reserve, the expected wind and the variability of wind, a number of different behaviors have been observed in the model. We discuss two configurations in this section and list other situations in the following:

- 1) Consider first the case where demand for flexibility reserve is sufficiently small that it never constraints scheduled wind: $(\text{scheduled wind}) - (\text{lowest wind scenario}) \leq (\text{committed upward reserve})$. This situation occurs when the uncertainty on wind generation is small, something that occurs when one can move gate closure close to real time. Wind forecast is then good and balancing can take advantage of a slack reserve market. Observation shows that this is the situation where the premium ρ^+ has little effect on the amount of scheduled wind. This is what happens in the case depicted in columns 4 and 5 of Table 4.13.
- 2) Consider now the situation where the demand for flexibility reserve can constraint scheduled wind. This occurs in situations where a given value of the premium (that could be zero) leads to an amount of the scheduled wind that hits, at least the constraint $(\text{scheduled wind}) - (\text{lowest wind scenario}) \leq (\text{committed upward reserve})$. This occurs when the uncertainty on wind generation is high, for instance because of the need to commit the reserve well in advance. This can be due to a lack of intraday market or to the impossibility to trade capacity in intraday (e.g. in a continuous intraday energy market without intermediate auction). In this case the premium ρ^+ to wind generation may have a strong impact on the amount of scheduled wind.

We analyze this situation in columns 8 and 9 of Table 4.13. The two cases refer to the average wind forecast ($\mu = 23.83\%$) and the average risk aversion ($\lambda = 0.4$); its characteristic is to implicitly assume a longer forecast horizon for wind implying $m_y = 0.6$ (in contrast with $m_y = 0.15$ otherwise), while m_x remains at the value 0.02 used in cases 1 to 3. In short the demand for reserve for load following due to wind is higher. We focus on the impact of changing the feed-in premium to wind generation.

In contrast with case 2 the increase of the feed-in premium to wind generation now implies a significant increase of the scheduled wind generation. But also in contrast with case 2, the two feed-in premium to wind generation cases lead to an increase in the price of electricity compared to those found in all other cases (from 1 to 3). This does not comply with the common wisdom that explicitly sees wind increase as implying a decrease of the electricity price. The justification is to be found in the higher demand for flexibility reserve implied by the longer horizon necessary for forecasting wind production and committing reserve (moving m_y from 0.15 to 0.6). One indeed observes higher upward and downward committed reserves in case 4 compared to all other cases, and an increase of these reserve inside case 4 when the feed-in premium to wind generation increases. The end result is a revenue from committed reserve in the day ahead market that restores the profit accruing to dispatchable generators in day ahead to value obtained in case of low wind as seen by comparing the rows “1st stage dispatchable generators” in columns 8 and 9 to the same information in column 2 (Table 4.13).

Other cases of high demand for reserves

The following circumstances, not further discussed here, can also lead to tight constraints on reserve that, if properly priced, could restore the profits of conventional generators and hence stop the incentive to mothball or dismantle.

- i) Dispatchable generators may not have enough capacity to satisfy simultaneously the requirement for energy demand and reserve commitment. Firms arbitrage between using the generation capacity of dispatchable generators for reserve or for generation of energy in day ahead. This will happen at the end of a mothballing, dismantling or insufficient investment process. It will induce capacity cycles.
- ii) Committed reserve hits technical limits. This depends on the overall flexibility of the remaining dispatchable plants.
- iii) Suppose now a very cautious TSO and consider a case where the requirement for flexibility reserve in day ahead requested by this TSO is sufficiently high to not constraint wind generation over its whole range of variability (e.g. $m_y = m_x = 0.3$). Suppose also that generation capacity is tight with respect to demand (for instance as a result of mothballing). A high enough feed-in premium (for instance $\rho^+ = 80 \text{ €/MWh}$) can make it profitable to supply more demand by scheduling wind even in excess of the highest scenario, at the same time as moving dispatchable generation into flexibility reserve. The incentive for this strategy is twofold. It first results from the premium accruing from total wind generation in day ahead compensating the cost of energy purchased on balancing in case of wind shortage. It also results from the higher demand for reserve flexibility by the TSO that also increases the price of energy. The strategy is only a consequence of market design and does not involve any exercise of market power.

Some of these configurations with a high requirement of flexibility reserve show multiple equilibria, as we have found for the case of single period, single firm, price responsive demand, described in Section 2.5, applied to the configuration with low ramping (B2.1, 1). This case of two equilibria is illustrated in Figures 4.8 and 4.9 and discussed in Section 4.5.8.

4.5.3 High Generation Capacity (B2.1) and High Ramping ($\Lambda = 0$)

The presentation of the models (both single period and multi-periods) has emphasized alternative representations of ramping capabilities here modeled by the parametric ramping constraints (see Section 2.3). As a reminder, the expressions of the parametric constraints described in Section 2.3 are:

$$ru_g \leq \bar{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g) \quad (4.5.1)$$

$$rd_g \leq \underline{R}_g \cdot (\bar{X}_g - \Lambda \cdot x_g) \quad (4.5.2)$$

To illustrate the impact of the representation of ramping possibilities, the results for the model described in Section 3.3 (subsection 2.4.6) restricted to single period and single firm with price responsive demand are compared in Table 4.17 for configurations (B2.1, 1) and (B2.1, 0) with more detailed data reported for (B2.1, 1) in Table 4.13 and for (B2.1, 0) in Table 4.14. They describe an increase of ramping capabilities of the conventional generation system when Λ decreases.

A quick observation of the row “Equilibrium price €/MWh” in Table 4.14 ($\Lambda = 0$) immediately points to the two major differences between these results and those obtained with the low ramping configuration ($\Lambda = 1$). As in the preceding model, the equilibrium price in column 2 (Table 4.14), that corresponds to a low value of wind forecast ($\mu = 4\%$ of the wind capacity installed), is the only one that contains a scarcity rent providing some coverage of the fixed operating costs of the plants. In this case the scarcity rent is smaller

than in the first model, but it is still positive. Second, there is no profit to expect from flexibility reserve in day ahead whatever the case. Balancing activity is significant but not to the extent of having an impact on global conventional plant revenues.

The forecast wind level

The impacts of increased wind forecast for average feed-in premium and risk aversion (columns 2 and 3, Case 1, in Table 4.14) are globally similar to those obtained with low ramping ($\Lambda = 1$) but they now occur with less intensity. Recall that higher ramping possibilities indeed increase flexibility reserves in day ahead. This frees generation capacity that reduces the scarcity rent on the energy market in case of low wind (column 2 in Table 4.14). The result is a lower energy price. This also reduces the price of flexibility reserve, the end result (quantity of reserve times price of reserve) being a decrease of revenue from the day ahead flexibility reserve market accruing to conventional plants in day ahead.

The results under high wind condition are similar to those found with the low ramping model. High wind eliminates the scarcity rent on the energy market, resulting in an energy price equal to the fuel cost of the marginal CCGT at the same time as it also decreases the utilization of conventional plants. This releases conventional capacity in sufficient amount to set the price of flexibility reserve to zero.

Because of the higher wind generation, there is more balancing activity but the end result is that conventional plants are not in a better condition with these increased ramping capabilities that lead to lower profits of dispatchable units in balancing.

The feed-in premium

The impact of the feed-in premium for average wind condition and risk aversion (columns 4 and 5, Case 2, of Table 4.14) is similar to the one of the low ramping model and does not need much elaboration. The high ramping model enlarges flexibility reserves that were already sufficient. It is thus not surprising to find that the revenue of conventional plants in day ahead are identical to those found with the low ramping model. The balancing activity differs a bit but not to an extent significant enough to make any difference in the position of the conventional plants.

The increased risk aversion

The increased risk aversion is examined with average wind condition and feed-in premium to wind generation in columns 6 and 7, Case 3, in Table 4.14. The comments are similar to those made for the feed-in premium. Compared to the results of the low ramping model where reserve flexibility was already sufficient, adding reserve flexibility does not change much. The day ahead revenue of conventional generators is again identical to those obtained in columns 3 to 9 (Table 4.14) with this ramping model and to those of columns 3 to 7 (Table 4.13) with the first ramping model (low ramping). Because risk aversion also reduces balancing activity, these plants also see their profits reduced on that market. The overall conclusion is that risk aversion further reduce gross margins in both ramping configurations and hence the incentive to keep conventional plants in the system.

Wind induced demand for flexibility reserve

The most dramatic impact of the introduction of the high ramping model, results in Table 4.14, arises from commitment considerations becoming irrelevant. The restrictions imposed

by the longer 24 hour horizon to commit flexible reserve are no longer binding as soon as the flexibility reserve is increased as in the high ramping model ($\Lambda = 0$).

Summing up

The adoption of a more flexible ramping model suffices to set the value of flexibility reserve to zero in day ahead for all cases in configuration (B2.1, 0) except for very low wind ($\mu = 4\%$) in column 2. The explanation is that this is the only situation where the ramping constraints are tight ⁷: wind is low and as a consequence conventional generation is allocated to energy with little left for ramping (see rows “Up. reserve commit. (MW)” and “Max. available reserve (MW)” in Table 4.14). Revenues to dispatchable generators in day ahead (first stage) thus have the same low (dismantling inducing) value in all cases with the higher ramping model whether flexible units need to be committed early or not (configurations (B2.1, 0) for columns 3 to 9). This revenue is also identical to the one with low ramping possibilities when flexibility units can be committed close to gate closure ((B2.1, 1) for columns 3 to 7, see rows “B2.1, 0: 1st stage dispat. gen.” and “B2, 1: 1st stage dispat. gen.” in Table 4.17). The ramping model (the capability to ramp) determines the revenue of the conventional plants and significant higher profits of dispatchable generators in day ahead only arise when ramping possibilities are low and flexible units need to be committed sufficiently early (Case 4, columns 8 and 9 in Tables 4.17). Profits are also higher when wind is limited and conventional capacity is largely required for the energy market, as this again implied a tight ramping constraint. Needless to say lower ramping possibilities imply higher profits for conventional generators.

⁷The ramping constraints are tight if and only if some of the values of the committed reserve, rows “Up. reserve commit. (MW)” and “Down. reser. commit. (MW)”, are equal to the value of the maximum reserve available, row “Max. available reserve (MW)”.

Table 4.14: (B2.1, 0) Results of Cases 1 to 4 on configuration B2 (two CCGT units) of single firm, single period, complementarity formulation, and parametric ramping with $\Lambda = 0$.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	4.01	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	0.00	80.00
λ risk aversion (0 is risk neutral)	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	28637.11	29639.08	29639.08	29639.08	29639.08	29639.08
Schedu. win. gen. (MWh)	734.60	9696.58	3847.65	3835.48	4849.80	7085.21
Schedu. dispatch. gen. (MWh)	27902.51	19942.50	25791.43	25803.60	24789.28	22553.87
Equilibrium price (€/MWh)	49.07	43.45	43.45	43.45	43.45	43.45
Reserve requirement (MW)	668.24	1853.34	1091.39	1091.39	3405.66	4702.20
Up. reserve commit. (MW)	601.42	1671.88	982.26	982.26	3065.10	4231.98
Down. reser. commit. (MW)	263.95	668.75	994.22	392.90	1226.04	1692.79
Max. available reserve (MW)	601.42	8300.80	2712.50	2700.33	3714.65	5950.06
INCOMES (€):						
Energy sales in day ahead	1405289.28	1287758.71	1287758.71	1287758.71	1287758.71	1287758.71
Premium to schedu. Wind	22037.89	290897.33	0.00	115064.49	0.00	566816.84
Supply of up. reser. capa.	3382.55	0.00	0.00	0.00	0.00	0.00
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	0.00
COSTS (€):						
Cost of dispatch. gen.	850879.45	505032.81	759156.89	759685.65	715615.85	618491.50
$\lambda_f \cdot CVaR[Q]$	17666.25	49107.95	49093.05	0.00	40162.85	208946.92
$(1 - \lambda_f) \cdot E[Q]$	5811.49	-1675.40	-5070.16	-910.95	6123.35	132695.83
PROFIT (€)						
Total (wind + dispatch.)	570144.46	1076415.57	844864.32	644048.50	561937.27	1014924.34
1st stage wind turbines	58086.24	712194.24	166644.02	281708.56	210713.88	874655.07
2nd stage wind turbines	-11900.04	-22744.81	-6886.72	-12743.43	-4207.44	-221495.84
1st stage dispatch. gen.	521744.03	361428.99	361428.99	361428.99	361428.99	361428.99
2nd stage dispatch. gen.	2214.22	25537.14	13281.29	61717.42	2521.37	336.13

4.5.4 An Alternative Presentation of the Results: Energy Price and Profits, for the High Generation Capacity

In the previous Cases (Cases 1 to 4 defined in Table 4.12) we consider only two extreme values of the parameter studied in each case, and keep the other parameters at their average value. Detailed results for a number of output variables (energy price, energy quantity, reserve price, reserve quantity, profit of each technology, cost of deviations, and other values) are listed in the previous tables. To complete the picture we include curves for a few output variables (energy price in day ahead, total profit, and profit of dispatchable generators) for the generation settings (B2.1, 0) and (B2.1, 1) with the studied parameter in the range defined by the extreme points listed in Table 4.12.

The values used in the figures in this section have been calculated using a version of the PATH solver under GAMS that is different of the version used to calculate the values on the tables. In the cases with multiple equilibria the results reported on the tables and the results on the figures have, sometimes, different values, but we have checked that they always correspond to equilibrium points. As will be explained in the following the existence of several equilibria in case of high demand for reserve appears as an important result of the model.

Case 1, wind forecast, (B2.1, 0) and (B2.1, 1)

Fig. 4.2 compares the impact of ramping in Case 1. It contains two curves for energy price in day ahead with $\mu \in [4\%, 65\%]$, a curve for configuration (B2.1, 0) and other curve for configuration (B2.1, 1) both in Case 1. We observe in Tables 4.13 and 4.14 (columns 2 and 3) that the dispatchable capacity is slightly lower than the potential demand of energy, thus the energy price is high for low values of wind forecast μ , it decreases with μ , and it remains constant when the sum of the wind forecast μ and the dispatchable capacity is enough to satisfy the potential demand of energy. The value of wind forecast necessary to reach the stationary energy price is higher in the case of low ramping (B2.1, 1) than in the case of high ramping (B2.1, 0), because of the requirement of flexibility reserve. This requirement is covered with dispatchable generation capacity, and therefore a higher demand of this service is equivalent to a reduction of the available capacity of dispatchable generation.

The curves for the total profit and the profit of dispatchable units for configurations (B2.1, 0) and (B2.1, 1) in Case 1 are sketched in Fig. 4.3. These curves show that all the profits (total and profit of dispatchable units) decrease initially for low values of wind forecast μ , this is because an increase of wind in this case leads to an increase of satisfied demand that in turns reduces the energy price, and the reduction of incomes for energy sales due to price reduction (see Fig. 4.2) is greater than the increase due to the increasing amount of energy sold (recall that the firm is a price taker under perfect competition and without market power). The second segment on the curves corresponds to the region with constant energy price (see Fig. 4.2) this means that the total amount of energy traded in day ahead is constant. In this case the profit of dispatchable units remains constant but the total profit increases with the wind forecast, this is due to:

- The share of wind in total generation increases with the value of wind forecast.
- The incomes from the feed-in premium to scheduled wind increases with the value of wind forecast.
- There is a reduction of the scheduled dispatchable generation, but this does not imply a decrease of the profit of dispatchable units because the reduction is done on the

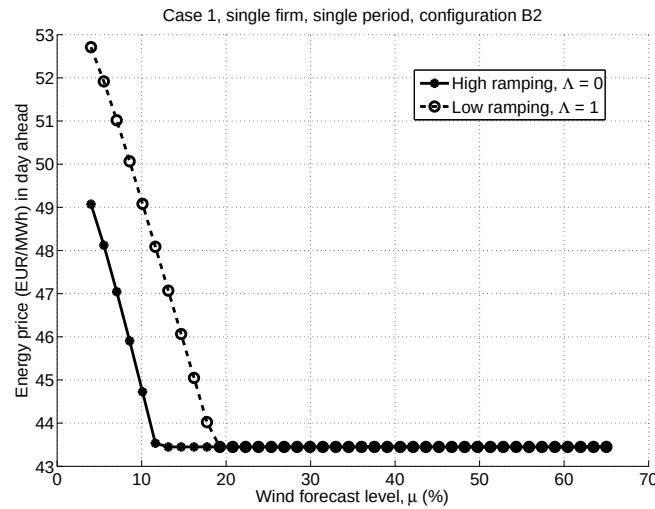


Figure 4.2: Energy price (€/MWh) for Case 1, configurations (B2.1, 1) and (B2.1, 0).

production of the marginal unit. The marginal unit is a dispatchable CCGT unit with a generation cost equal to the energy price in day ahead.

Regarding the effect of the ramping constraints, the effect is significant only for low values of wind forecast, because in those cases the difference on the energy price in day ahead is remarkable. This difference in price is because of total generation capacity is constraining the demand, and this constraint is more restrictive in the case of low ramping than in the case of high ramping, thus the energy prices and the total profit are higher for the low ramping configuration ($\Lambda = 1$) than for the high ramping configuration ($\Lambda = 0$). In the case of low ramping we need to use more dispatchable capacity than in the case of high ramping for a given level of reserve capability.

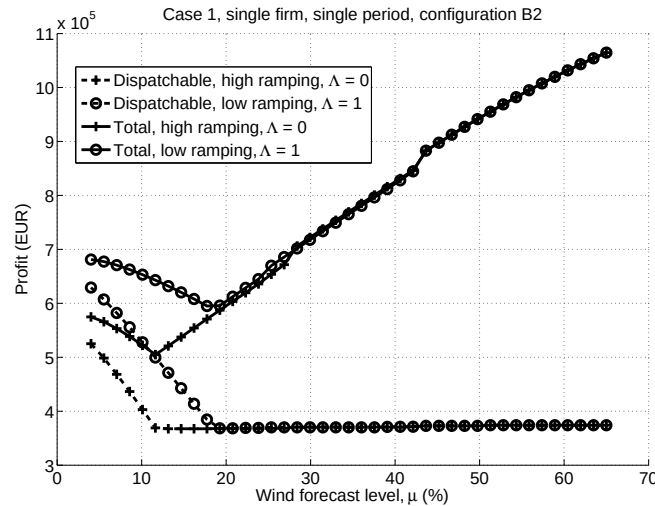


Figure 4.3: Total profit (€) and profit of dispatchable units (€) for Case 1, configurations (B2.1, 1) and (B2.1, 0).

Case 2, feed-in premium, (B2.1, 0) and (B2.1, 1)

Fig. 4.4 illustrates that energy price remains constant for both configurations (B2.1, 0) and (B2.1, 1) when the feed-in premium to wind generation is in the range $\rho^+ \in [0, 80]$ (€/MWh) in Case 2. In this case the amount of wind forecast (μ) plus the capacity of dispatchable generation is enough to not constraint the demand, thus a change the feed-in premium to wind generation does not change the total demand, but it changes the total profit as it is shown in Fig. 4.5.

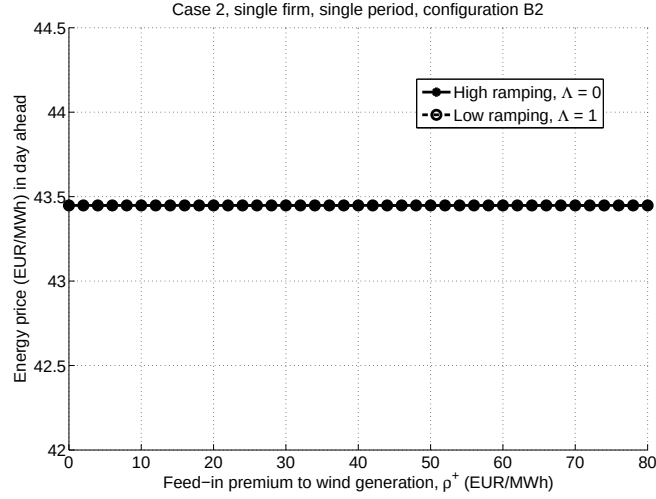


Figure 4.4: Energy price (€/MWh) for Case 2, configurations (B2.1, 1) and (B2.1, 0).

Fig. 4.5 shows the curves of total profit and profit of dispatchable units for Case 2 in configurations (B2.1, 0) and (B2.1, 1). The curves illustrate that the profit of dispatchable units remains constant with the value of the feed-in premium to wind generation, but the total profit increases linearly with that value. The explanation is that the shares of scheduled dispatchable generation and wind generation remain almost constant with the value of the feed-in premium to wind generation, an increase in the share of scheduled wind generation is prevented by the risk averse behaviour of the firm, thus the profit of dispatchable unit does not change (or the change is very small) in this case. Also the energy price in day ahead remains constant with the feed-in premium to wind generation, see Fig. 4.4. To summarize, the main change in the total profit comes from the linear increase of the feed-in premium to wind generation, and the result is not influenced by the type of ramping constraint (low or high) because none of them are constraining the solution in these cases.

Case 3, risk aversion, (B2.1, 0) and (B2.1, 1)

Fig. 4.6 shows that energy price for both configurations (B2.1, 0) and (B2.1, 1) does not depend on the level of risk aversion in Case 3. This is because the amount of wind forecast (μ) plus the capacity of dispatchable generation is enough to not constraint the demand (demand and energy price are directly linked by the inverse demand function). A change in the level of risk aversion change the relative share of wind and dispatchable generation but not the total demand. It changes the profit of dispatchable units, as it is illustrated in Fig. 4.7, because of the reduction in the demand for flexibility reserve.

Fig. 4.7 depicts the curves of total profit and profit of dispatchable units in Case 3 for

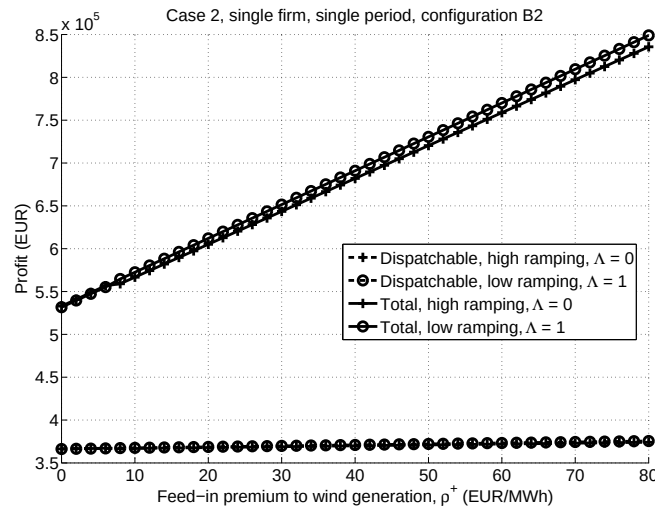


Figure 4.5: Total profit (€) and profit of dispatchable units (€) for Case 2, configurations (B2.1, 1) and (B2.1, 0).

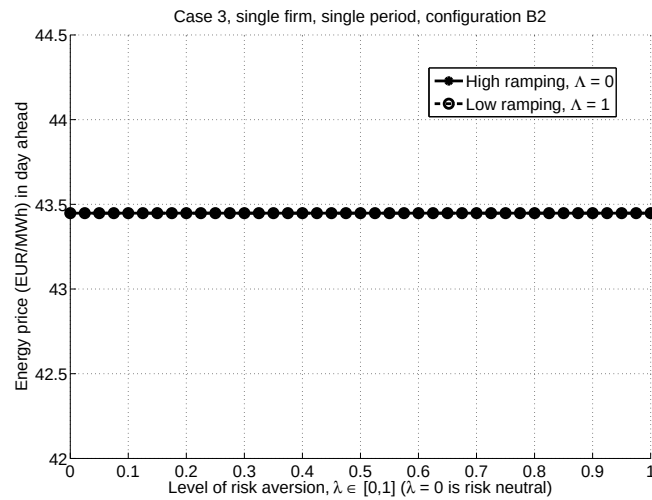


Figure 4.6: Energy price (€/MWh) for Case 3, configurations (B2.1, 1) and (B2.1, 0).

configurations (B2.1, 0) and (B2.1, 1). In these cases the ramping constraints are not tight, and therefore the result does not depend on the ramping model (low or high), we have the same curves for both ramping models. The interesting information from this figure is that the total profit remains almost constant⁸ with the level of risk aversion meanwhile the profit of dispatchable units decreases with the level of risk aversion. The explanation is that we have a single firm configuration and, in this case, the cost of wind turbines on the second stage are almost compensated by the profits of dispatchable units at second stage, keeping the total profit almost constant. The profits in the first stage both for dispatchable generators and wind turbines are almost constant, the main changes are in the values at the second stage as it is illustrated on Tables 4.13 and 4.14. The level of risk aversion leads to a reduction of the scheduled wind generation and that to a reduction of the dispatchable generators incomes at the second stage, while keeping the incomes at the first stage almost constant, this explains

the observed reduction of the profit of dispatchable generators with the level of risk aversion. In terms of the total profit the reduction of incomes of dispatchable generators at second stage is compensated by the reduction of cost of wind turbines also at the second stage, thus we observe an almost constant curve for the total profit.

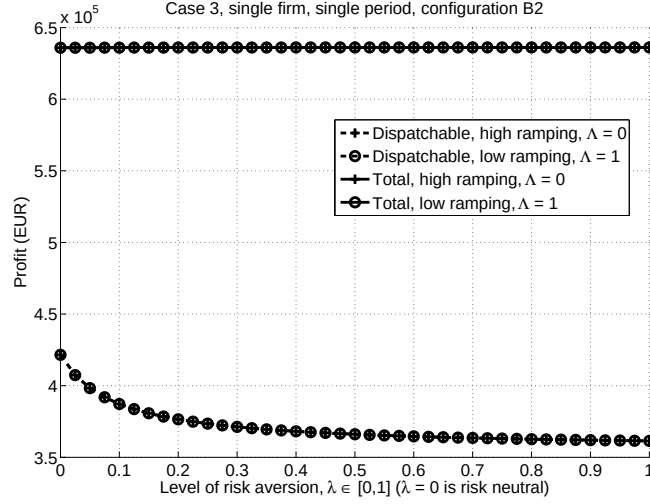


Figure 4.7: Total profit (€) and profit of dispatchable units (€) for Case 3, configurations (B2.1, 1) and (B2.1, 0).

Case 4, demand for flexibility reserve (m_y), (B2.1, 0) and (B2.1, 1)

Fig. 4.8 depicts the curves for energy price for configurations (B2.1, 0) and (B2, 1) with high demand of flexibility reserve due to wind ($m_y = 0.60$), Case 4. There are, at least, two noticeable results on the figure:

- The energy price remains constant with the feed-in premium in the range $\rho^+ \in [0, 80]$ (€/MWh). In this case is valid the same argument used in Case 2. The amount of wind forecast (μ) plus the capacity of dispatchable generation is enough to not constraint the demand; thus a change the feed-in premium to wind generation does not change the total demand, but it changes the total profit as it is shown in Fig. 4.9.
- We have found two equilibria, an equilibrium with high price, that we call “high equilibrium”, and other equilibrium of low price, that we call “low equilibrium”. The points on the curves are calculated iteratively, and the results for one point are used as initial values to calculate the next point. We get the high equilibrium when we made the calculation with the parameter ρ^+ going from zero to 80 €/MWh, and the low equilibrium when we consider the parameter ρ^+ going from 80 €/MWh to zero. Additional information on the multiple equilibria found in the results is included at the end of Section 4.5.8.

The curves for total profit and the profit of dispatchable generators in configurations (B2.1, 0) and (B2.1, 1) for Case 4 are plotted in Fig. 4.9. Like for the cases in Fig. 4.4

⁸The total profit changes with the level of risk aversion, but the change is very small, it is less than 1%, and it is not observable on the figure.

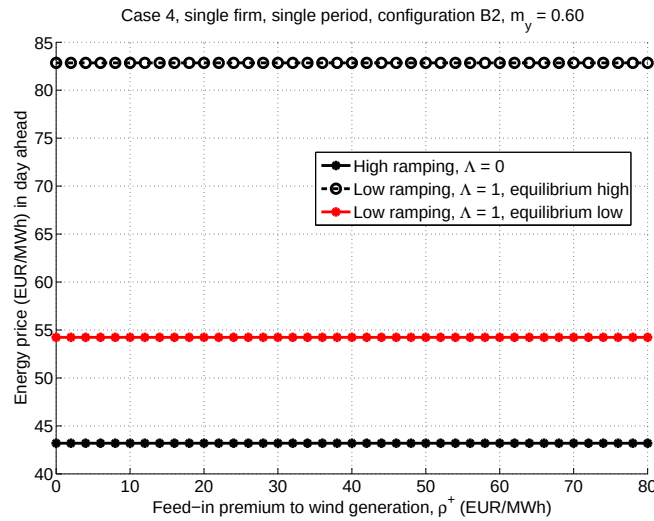


Figure 4.8: Energy price (€/MWh) for Case 4, configurations (B2.1, 1) and (B2.1, 0).

we are studying the influence of the feed-in premium value on the results, but in this case the difference is that the requirement of flexibility reserve for wind m_y is remarkably higher, $m_y = 0.60$, than in the previous case, $m_y = 0.15$. This high value of reserve requirement for wind can be justified on the basis of the expected variability of the wind forecast, that in turn strongly depends on the time horizon for the forecast. Sometimes the time horizon is fixed for the plants that need to be committed well in advance, for instance 24 to 48 hours in advance.

The curves in Fig. 4.9 are similar to those in Fig. 4.4 with the profit of dispatchable units almost constant and the total profit increasing linearly with the feed-in premium to wind generation, the main differences in this case are:

- Despite the fact that the total demand in day ahead remains almost constant, in this case the change in the share of scheduled wind generation and dispatchable generation is remarkable. Scheduled wind generation increases significantly with the value of the feed-in premium, as it is illustrated in Tables 4.13 and 4.14.
- Only in the case of low ramping ($\Lambda = 1$) the reserve constraints are tight, and this leads to a higher energy price in day ahead in the case of low ramping (approximately 54 €/MWh) than in the case of high ramping (approximately 43.45 €/MWh).
- The profit of dispatchable units remains almost constant even with the reduction of their scheduled generation, because the reduction of incomes from scheduled generation is approximately compensated by the increase of incomes from committed reserve capacity at the first stage. The additional reserve capacity is necessary to support the integration of the scheduled wind generation.
- In addition and as mentioned before, in the case of low ramping, that is the most constrained case, we have found two equilibria with similar qualitative behaviour in terms of the shape of the curves for prices and profits, but with significant differences in the values of those variables. We call “high equilibrium” to the equilibrium with the highest prices (approximately 83 €/MWh) and profits and “low equilibrium” to the

other (with an energy price of approximately 55 €/MWh). We get the high equilibrium when we calculate the curves by moving on the domain from the lowest value of the feed-in premium to the highest value, and the low equilibrium when we move on the curve in the other sense.

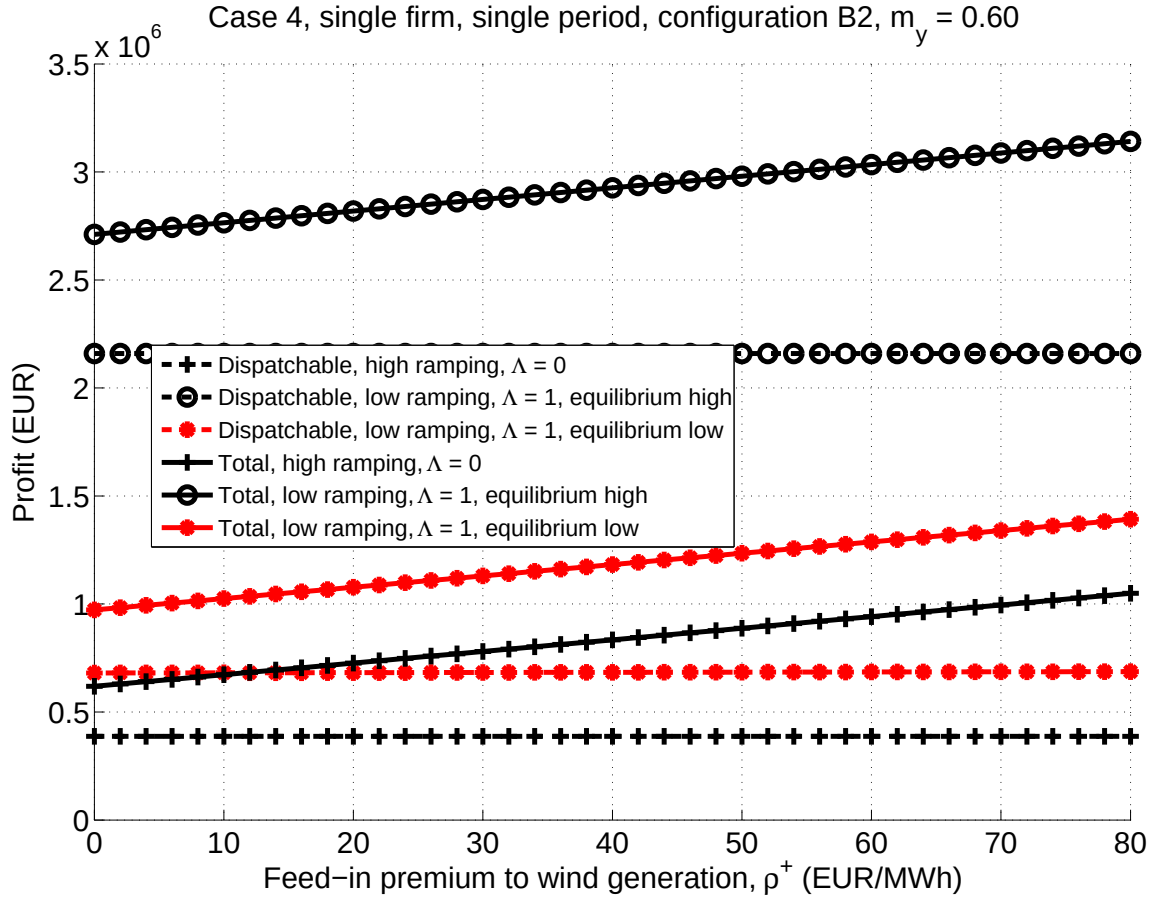


Figure 4.9: Total profit (€) and profit of dispatchable units (€) for Case 4, configurations (B2.1, 1) and (B2.1, 0).

4.5.5 Low Generation Capacity (B9.6) and Low Ramping ($\Lambda = 1$)

The almost complete absence of scarcity rent in the preceding cases signals an excess of capacity. It thus makes sense to examine the impact of a reduction of the existing conventional capacity on the scarcity rent accruing from the energy markets and on the possibility to recoup part of the coverage of the fixed operating cost of the system from ancillary services. The following Table 4.15 adapts the previous analysis to a generation system where the CCGT capacity has been reduced so as to lead to a positive scarcity rent in the average case (average wind condition, average premium and average risk aversion). As described in Section 4.4.3, this configuration is the final state of a process in which the units with fixed cost greater than their profit are progressively dismantled⁹. The total dispatchable capacity of 28503.93 MW used so far could thus be seen as an intermediate step of a dismantling of capacity that had become redundant as a result of weak demand and wind policy, with the new total

capacity of 25356.288 MW being some equilibrium state where the remaining capacity is able to recover its fixed operating cost under average conditions. The standard interpretation is a situation where generators have “cleaned” their balance sheet by eliminating stranded assets (the impairment process in accounting) so as to recoup their fixed costs. It is not a situation where generators are ready to invest except in subsidized capacities. Note also that this impairment process depends on the value of ramping and hence on the ramping model. This subsection has been obtained with low ramping possibilities.

The remaining generators in the system are listed in Table 4.5 taking into account that the first 6 CCGT blocks have been dismantled (the impact of dismantling on the generation system is documented in Table 4.8). The obtained remaining total dispatchable capacity is 25356.288 MW, which is lower than the 28503.93 MW dispatchable capacity considered in the first part of this case study (see Section 4.5.2). As before, results in Table 4.15 are obtained with the single period, multi-firm model described in Section 2.4 used in single firm mode.

A quick observation of the rows “B2.1, 1: Energy price (€/MWh)” and “B9.6, 1: Energy price (€/MWh)” in Table 4.18 immediately points to energy prices more sensitive to the forecast wind level and premium configuration in this configuration (B9.6, 1) after dismantling rather than with high capacity (B2.1, 1). The influence of these factors is discussed in more detail below.

The forecast wind level

As in all cases encountered so far the higher wind forecast (column 3, Case 1, in Tables 4.17, 4.18, 4.19 and 4.15) for configuration (B9.6, 1) sets the energy price equal to the fuel cost of the marginal CCGT, therefore eliminating the scarcity rent on the energy market, at the same time as it also decreases the utilization of conventional plants. This nullifies the effect of the dismantling in case of high wind. This again releases conventional capacity in sufficient amount to set the price of flexibility reserve close to zero (see rows “Supply of up. reser. capa.” and “Supply of down reser. capa.”, column 3, Table 4.15).

Because of the higher wind generation, there is more balancing activity but the end result is that conventional plants are not able to recover their profits compared to the low wind case.

The feed-in premium

The impact of the feed-in premium for average wind condition and risk aversion (columns 4 and 5, Case 2, in Tables 4.17, 4.18, 4.19 and 4.15) is to some extent similar to the one observed for the higher capacity configuration (B2.1, 1). The energy price is indeed almost the same for both values of premium to wind generation. One may be surprised to see that this happen even though this price is not equal to fuel cost of the CCGT. The feed-in premium has some effect on wind generation as it makes it profitable to assume a little bit more risk increasing the amount of scheduled wind generation. In columns 4 and 5 in Table 4.15 of Case 2, the sum of the energy and reserve does not saturate the total dispatchable capacity, but the ramping constraints are tight¹⁰ in both situations (see rows “Up. reserve commit. (MW)” and “Max. available reserve (MW)” in Table 4.15). Ramping, and thus

⁹See Section 4.3 for a description of the dismantling process, and Appendix A.1 for the values of prices and profits in the dismantling process for B9.6 and B9.7.

neither reserve nor energy, is what increases the energy prices beyond the one of fuel cost of the marginal generator.

The increased risk aversion

Except for the electricity price that is now slightly higher than the CCGT fuel cost, the impact of the higher risk aversion (columns 6 and 7, Case 3, in Tables 4.17, 4.18, 4.19 and 4.15) is similar to the one observed before with higher capacity in the sense that it does not significantly affect the equilibrium on the day head market. The effect of increased risk aversion in configuration (B9.6, 1) is small but more significant than in the higher capacity configuration (B2.1, 1). When changing from risk neutral ($\lambda = 0$) to complete risk aversion ($\lambda = 1$) the amount of scheduled wind is reduced, see row “Schedu. win. gen. (MWh)” and column 7 in Table 4.15. At the same time it is profitable to increase the dispatchable generation to compensate part of the reduction in the scheduled wind generation. The sum of the energy and reserve does not saturate the total dispatchable capacity, but the ramping constraints are again tight¹⁰ in both situations (see rows “Up. reserve commit. (MW)” and “Max. available reserve (MW)” in Table 4.15), and this implies that the energy prices are higher than the fuel cost of the marginal generator in these situations (Case 3 columns 6 and 7 in Table 4.15). This increases the dispatchable generation in a greater amount than what is released from reserve due to the reduction of scheduled wind generation. All in all and as expected the total scheduled generation, row “Demand day ahead (MWh)”, and the total profit, row “Total (wind + dispatch.)” in Table 4.15, are lower in the case of high risk aversion ($\lambda = 1$, column 7), than in the risk neutral case ($\lambda = 0$, column 6), because of the influence of risk aversion.

Wind induced demand for flexibility reserve

Results reported on columns 8 and 9, Case 4, in Tables 4.17, 4.17, 4.18, 4.19 and 4.15 document the strong impact of wind induced demand for flexibility reserve (m_y) in this low capacity, low ramping flexibility configuration at the same time as they suggest multiple equilibria. We discuss both in sequence.

Data on column 8 reveal a drastic increase in the price of energy even when the feeding premium is zero. This high price results from a much higher demand for reserve as could be expected from the higher value of m_y . Recall that we are now in a situation where there is no excess capacity (in the sense of capacity not covering fixed operating charges), even though one is still very far from covering both fixed operating and investment capacity charges.

Consider now increasing the feed-in premium. This increases the incentive for schedule more wind in day ahead, which in this case has a higher impact on the demand for ancillary services because of the higher m_y coefficient. Recall that wind does not pay for reserve in this model: this market imperfection reflects the current market design which consists of transferring the cost of ancillary services (implied by wind and received as payment by conventional generators) to the final consumer. Conventional generators receive that payment and are induced to move more capacities from generation to reserve. This should further increase the energy price that was already high, possibly moving to an equilibrium with still less demand. Column 9 indicates that this is not what happens. For some reason the equilibrium is different: wind has decreased together with the price of energy. This

¹⁰The ramping constraints are tight if and only if some of the values of the committed reserve, rows “Up. reserve commit. (MW)” and “Down. reser. commit. (MW)”, are equal to the value of the maximum reserve available, row “Max. available reserve (MW)”.

suggests a multiplicity of equilibria. There are at least two possible reasons that make this situation possible. One is general: the fact that some agents (wind generators) do not pay for the cost that they imply introduces a non convexity and hence opens the possibility of multiple equilibrium. The second reason is that resources that one does not pay for their cost resembles the notion of counterproductive technologies found in Ricardian economics [78], that are known to give rise to multiplicity of equilibrium.

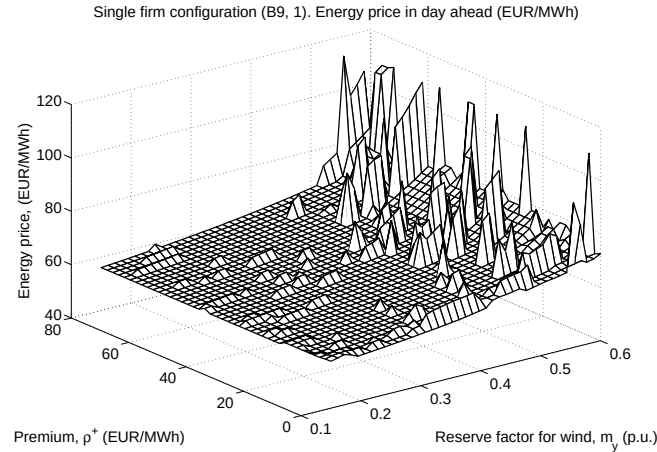


Figure 4.10: Energy price in day ahead (€/MWh) for configuration (B9.6, 1).

A rigorous analysis of this problem is left for further research, but the following test shows the plausibility of this conjecture. Figures 4.10, 4.11 and 4.12 show parametric analysis of the electricity price for varying reserve factor m_y in the range $[0.15, 0.60]$ and the feed-in premium $\rho^+ \in [0, 80]$ €/MWh. Results in the figures correspond to the model for single period, single firm, and price responsive demand posed as a complementarity problem described in Section 2.5, and the data in Case 4 (average wind forecast $\mu = 23\%$, average risk aversion $\lambda = 0.4$). These figures reveal at least two patterns of prices with values of the order of the 110 €/MWh found in Column 8 and lower price between 60 and 80 €/MWh found in Column 9 (see also Figure 4.10). Similar patterns of two price levels are found for reserve prices, see Figures 4.11 and 4.12. The number of equilibrium seems to be equal to two, which some having quite reasonable value (as in the other columns of the Table 4.15) and the other being with very high prices, this is illustrated in Fig. 4.13 for the configuration B9.6 with low ramping ($\Lambda = 1$), also the curves of profit for the same case are depicted in Fig. 4.14. A systematic analysis of this pattern is left for further research but they economic interpretation is quite intuitive: wind is a counterproductive technology when because of market design it does not pay for all its costs. The multiplicity of equilibria is the very unintended effect of the policy.

Figures 4.13 and 4.14 illustrates the values for price and profits respectively for two equilibria founds in Case 4 ($m_y = 60\%$), configuration (B9.6, 1) model of single period, single firm with price responsive demand and posed as a complementarity problem (see Section 2.5). We start at one end of the interval and go toward the other end. A warm starting has been implemented, it consists of using the values of the previous point calculated as initial values to calculate the current point. In the figures, the points in the curves are calculated for values of the feed-in premium in the range $0 \leq \rho^+ \leq 80$ €/MWh. The equilibrium with the lowest price results when we start with the highest feed-in premium (80 €/MWh) and we reduce it progressively until reach the zero value. In the case reported in Figs.4.13 and 4.14

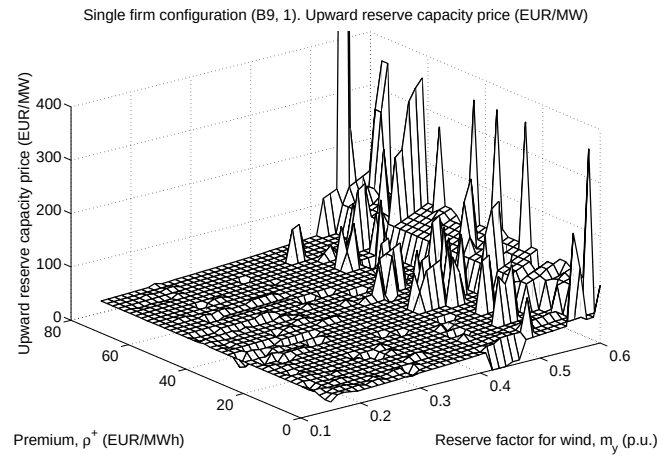


Figure 4.11: Upward reserve capacity price (€/MW) for configuration (B9.6, 1).

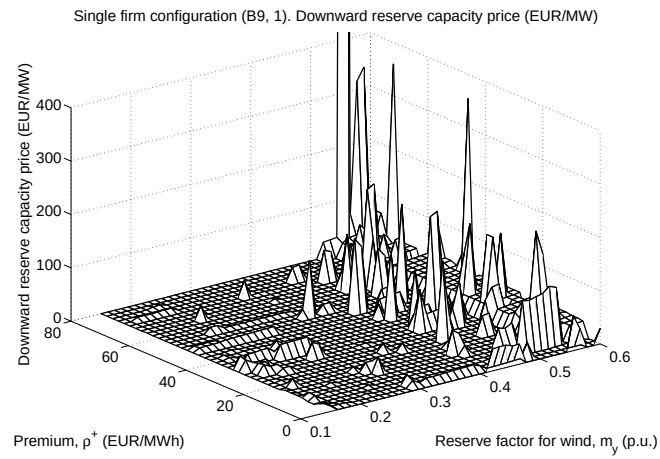


Figure 4.12: Downward reserve capacity price (€/MW) for configuration (B9.6, 1).

the equilibrium depends only on the starting value for the feed-in premium, but after this point has been selected, the equilibrium has the same value for all the values of the feed-in premium in the range.

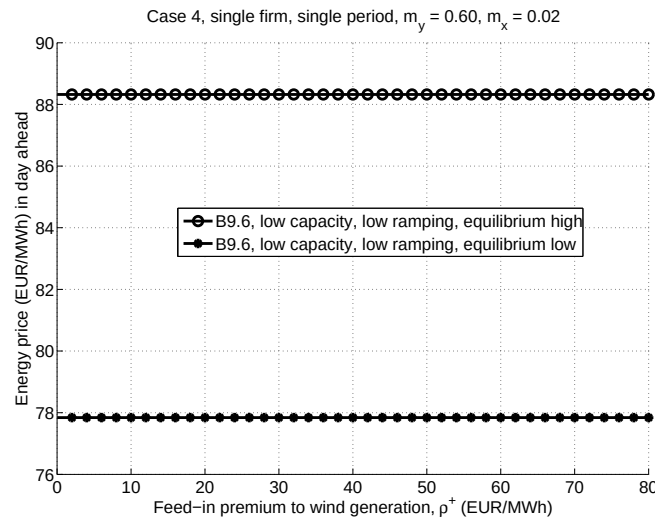


Figure 4.13: Energy price (€/MWh) in day ahead for Case 4 ($m_y = 60\%$), configuration (B9.6, 1), low generation (25 GW) and low ramping.

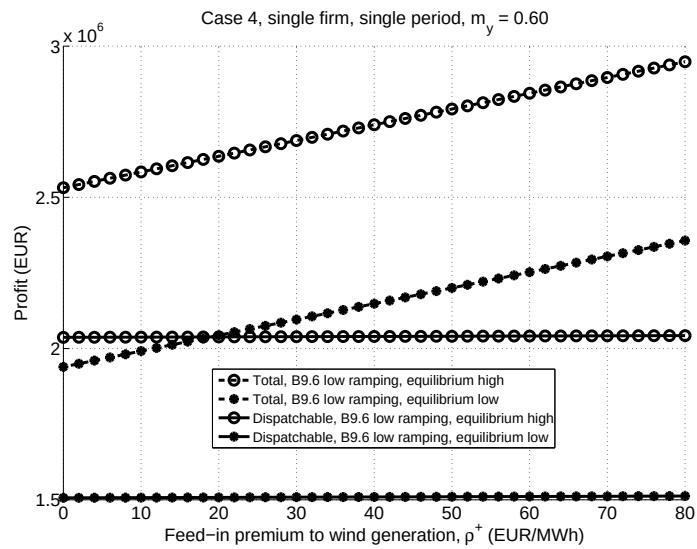


Figure 4.14: Total profit (€) and profit of dispatchable units (€) for Case 4 ($m_y = 60\%$), configuration (B9.6, 1), low generation (25 GW) and low ramping.

Table 4.15: (B9.6, 1) Results of Cases 1 to 4 on configuration B9 (9 CCGT units) of single firm, single period, complementarity formulation, and parametric ramping with $\Lambda = 1$.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	4.01	65.00	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	0.00	80.00
λ risk aversion (0 is risk neutral)	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	25027.55	29612.31	27148.44	27182.23	26993.17	23511.95
Schedu. win. gen. (MWh)	661.02	9691.66	3979.04	4027.11	3264.06	6854.48
Schedu. dispatch. gen. (MWh)	24366.54	19920.65	23169.40	23155.11	23729.11	16657.47
Equilibrium price (€/MWh)	69.33	43.60	57.43	57.24	58.30	77.84
Reserve requirement (MW)	586.48	1852.16	1060.24	1067.17	964.19	4445.84
Up. reserve commit. (MW)	527.84	1666.96	1166.27	1173.89	867.77	4001.26
Down. reser. commit. (MW)	211.24	666.79	1088.09	472.17	456.94	1600.50
Max. available reserve (MW)	527.84	2898.83	1166.27	1173.89	867.77	4001.26
INCOMES (€):						
Energy sales in day ahead	1735253.38	1291045.09	1559097.38	1555882.42	1573706.55	1958591.28
Premium to schedu. Wind	19830.46	290749.91	0.00	322169.07	120813.40	97921.80
Supply of up. reser. capa.	24766.29	0.00	28686.80	28456.69	22762.82	1305342.19
Supply of down. reser. capa.	0.00	187.86	0.00	0.00	0.00	155529.56
COSTS (€):						
Cost of dispatch. gen.	700108.86	504255.54	647062.46	646429.53	671864.04	180960.98
$\lambda_f \cdot CVaR[Q]$	15640.47	49126.18	19835.12	58150.84	0.00	80499.36
$(1 - \lambda_f) \cdot E[Q]$	4037.21	-9861.30	-16765.39	227.26	-3811.47	58948.07
PROFIT (€)						
Total (wind + dispatch.)	1073012.60	1094162.82	968664.03	1259699.89	1062534.45	3140255.25
1st stage wind turbines	65661.13	713289.52	228510.89	552676.86	351321.19	775007.36
2nd stage wind turbines	-13013.28	-22807.30	-7301.64	-26163.98	-79917.18	-215488.08
1st stage dispatch. gen.	1014080.15	364437.80	712210.83	707401.79	734310.08	2463494.68
2nd stage dispatch. gen.	6284.60	39242.80	35243.95	25785.21	83728.65	117241.29

4.5.6 Low Generation Capacity (B9.7) and High Ramping ($\Lambda = 0$)

This last analysis adapts the preceding discussion to the low generation and high ramping model (B9.7, 0). The model is described in Section 2.5, it is single period, single firm, has price responsive demand and is posed as a complementarity problem. As described in Section 4.4.3, the generation system is obtained by the same dismantling process as described in the preceding (B9.6, 1) case but because of high ramping¹¹ ends up with a different capacity¹², data for the prices and profits in the different stages of the dismantling process that leads to configuration B9.7 are listed in Appendix A.1. Total capacity is effectively lower because a high ramping reduces in principle the revenue from reserve and hence requires more dismantling before remaining capacities can recoup their fixed operating costs. The total dispatchable capacity in configuration B9.7 is 22081.31 MW, and this is the lowest value for dispatchable capacity among the configurations considered in the case study.

Table 4.17 shows that the results for this configuration (B9.7, 0) are similar to those for the model with higher capacity but similar ramping possibilities (B2.1, 0), in terms of the impact of wind forecast, feed-in premium, risk aversion and the demand for flexibility reserve. The main difference is that prices are higher in this configuration (B9.7, 0) because the generation capacity is smaller. The influence of these factors is discussed in more detail in what follows.

The forecast wind level

This effect is the now usual one. The impact of increased wind forecast for average feed-in premium and risk aversion (columns 2 and 3, Case 1, in Table 4.16) for this high ramping configuration (B9.7, 0) is very significant, even more than it is for the lower ramping (B9.6, 1), because the effect of the wind forecast level is amplified by the reduction in the total dispatchable capacity.

A very high forecast wind level (column 3, Table 4.16) nullifies the effect of the dismantling (wind replaces dispatchable generation) and some units do not cover their fixed operation cost in that scenario. High wind eliminates the scarcity rent on the energy market, resulting in an energy price equal to the fuel cost of the marginal CCGT at the same time as it also decreases the utilization of conventional plants. This releases conventional capacity in sufficient amount to set the price of flexibility reserve close to zero (see row “Supply of up. reser. capa.”, column 3, Table 4.16).

Because of the higher wind generation there is more balancing activity, but the end result is that conventional plants are not in a better condition with these increased ramping capabilities that lead to similar profits of dispatchable units in balancing for both configurations (B9.7, 0) and (B9.6, 1).

The feed-in premium

The impact of the feed-in premium in this configuration, with low generation capacity and high ramping capacity (B9.7, 0), columns 4 and 5, Case 2 reported in Tables 4.17, 4.18, 4.19 and 4.16, is studied for average wind condition and risk aversion. The feed-in premium has only a small effect on the results for this configuration, the values in columns 4 ($\rho^+ = 0$) and column 5 ($\rho^+ = 80$ €/MWh) in Table 4.16 are almost the same except for the total profit and the profit for wind turbines. Total demand, scheduled wind generation, scheduled

¹²See Table 4.8.

¹¹See Section 2.3.

dispatchable generation and committed upward reserve remain the same for low and high feed-in premium. Only the profit for wind turbines in the first stage changes significantly, and that is because of the incomes for the feed-in premium to the scheduled wind generation. To explain the observed values we notice that this configuration has a relatively low dispatchable capacity, which is completely used in both $\rho^+ = 0$ and $\rho^+ = 80$ €/MWh settings (columns 4 and 5). The reserve constraints are also tight, as observed from rows “Up. reserve commit. (MW)” and “Max. available reserve (MW)” that have the same value. The energy price is remarkably higher (69.86 €/MWh) in this configuration with low generation capacity and high ramping capacity, in comparison to the 43.45 €/MWh found for the same case (low and high feed-in premium) with high generation capacity and high (B2.1, 0) or low (B2.1, 1) ramping capacity. The energy price for configuration (B9.6, 1), which also has low generation capacity (but higher than for configuration (B9.7, 0)) and low ramping capacity, is 57 €/MWh (see Table 4.17). This is a high value compared to the configurations with high generation capacity (B2.1, 0) and (B2.1, 1). But it remains lower than the energy price in the more constrained configuration (B9.7, 0), which has the lowest value of dispatchable generation among all the configuration considered. The tight total dispatchable generation capacity is the cause of this high price.

To summarize, the constraints for the total dispatchable capacity¹³ and the constraints for reserve are tight even for $\rho^+ = 0$. The common wisdom says that increasing the feed-in premium should lead to an increase in the scheduled wind generation. But in this case, an increase of the scheduled wind on top of the value for $\rho^+ = 0$ implies a reduction of the scheduled dispatchable generation (to provide the reserve for the additional wind), and what is more important, a remarkable increment of the CVaR (of the correction cost) in the objective function. The feed-in premium is not high enough to compensate the change of the CVaR term in the objective function because the operation is constrained by the total dispatchable generation capacity and the reserve constraints.

The increased risk aversion

The increased risk aversion is examined with average wind condition and feed-in premium to wind generation for configuration (B9.7, 0). The study is based on the results reported in columns 6 and 7, Case 3, in Tables 4.17, 4.18, 4.19 and 4.16. The analysis and conclusions are similar to those discussed in the previous paragraph for the feed-in premium.

We observe almost the same values in column 6 ($\lambda = 0$, risk neutral) and in column 7 ($\lambda = 1$, full risk aversion); the main differences are in the scheduled wind and dispatchable generation. The constraints for the total dispatchable capacity and the reserve constraints are again tight for both simulations (columns 6 and 7) and the energy price in day ahead (approximately 70 €/MWh) is remarkably higher than in other configurations and cases with higher capacity where the constraints for the total dispatchable capacity are not tight, like (B2.1, 0) and (B2.1, 1) with 43 €/MWh in the same case.

As expected, an increase in the level of risk aversion rises the weight of the CVaR of the cost in the objective function and that leads to a reduction of the scheduled wind (recall that wind generation is the only source of uncertainty considered here, and the scheduled wind generation sets the value of the CVaR of the correction cost). At the same time, the reduction in the scheduled wind generation frees some amount of dispatchable generation (it

¹³The constraint for the total dispatchable capacity is tight if and only if the sum of the terms in row “Schedu. dispat. gen. (MWh)” and row “Up. reserve commit. (MW)” is equal to the total dispatchable capacity.

is just the 15% of the scheduled wind dropped, because $m_y = 0.15$), that previously was committed as flexibility reserve associated with that scheduled wind. We observe in Table 4.16 row “Schedu. dispat. gen. (MWh)”, columns 6 and 7, that the amount of dispatchable generation freed from reserve is completely aggregated to the scheduled dispatchable generation in column 7 ($\lambda = 1$) because it is profitable and does not increase the risk exposure (value of the CVaR in the objective function). Thus the total demand for $\lambda = 1$ is reduced with respect to the value for $\lambda = 0$ because only the 15% of the wind reduction is recovered as scheduled dispatchable generation, and it is not possible to increase this quantity of scheduled dispatchable generation because the constraint of total dispatchable generation capacity is already tight. This reduction of the total demand implies an increase of the energy price in day ahead, as it is observed on Table 4.16, row “Equilibrium price (€/MWh)”, columns 6 and 7.

Other question is how the amount of scheduled wind reduction due to the increase varies with the level of risk aversion. We should notice that the amount of scheduled wind in the risk neutral case ($\lambda = 0$), row “Schedu. win. gen. (MWh)” and column 6 in Table 4.16, is close to the lowest value of the scenario tree for wind generation in that case, thus the absolute value of the CVaR of the cost is small. For $\lambda \geq 0$ the value of the CVaR of the cost contributes in the objective function, but as the CVaR was already small for $\lambda = 0$, a small reduction of the scheduled wind generation would suffice to reach the point at which a greater value of the scheduled costs more than it increases revenue.

Wind induced demand for flexibility reserve

The increased wind induced demand for flexibility reserve (m_y) is studied with average wind and level of risk aversion for two extreme values of feed-in premium. The study is based on the data reported in Case 4, columns 8 and 9 in Tables 4.17, 4.18, 4.19 and 4.16.

The increase of the demand for reserve in this case increases the opportunity cost of this reserve. The firm gets more revenue for committing more flexibility reserve (the single firm owns all the reserve in this case); it can also replace dispatchable generation by wind when it is available and hence gets a reduction on its generation cost. The only significant risk for the firm is the loss of the feed-in premium associated with the scheduled wind generation due to the balancing operations. It is this loss, taking into account in the CVaR term in the objective function, that jointly with the total dispatchable capacity generation drives the total amount of scheduled wind generation, when the value of the feed-in premium increases (column 9). This explains why in this case, with $m_y = 0.60$, the scheduled wind generation is remarkably higher than in the other cases with $m_y = 0.15$, in particular in comparison with Case 2 (columns 4 and 5 in Table 4.16) where the only difference is in the value of m_y .

In this case, as in the previous Cases 2 and 3, the constraint for total dispatchable generation capacity and reserve are tight as well as the ramping constraints on the dispatchable units that provide reserve capacity. As a consequence the energy prices in day ahead, row “Equilibrium price (€/MWh)”, are again higher than in other cases where the constraint for the total dispatchable capacity is not tight. The energy price is even higher for $\rho^+ = 0$ (column 8) than for $\rho^+ = 80$ €/MWh (column 9), because for $\rho^+ = 0$ the system has hit the bound of total dispatchable capacity and it is not profitable to increase the amount of scheduled wind generation due to the CVaR term in the objective function (increase of the risk exposure). On the other hand, for $\rho^+ = 80$ €/MWh, the incomes from the feed-in premium compensate the CVaR term in the objective function and allows for a greater integration of

wind in the system, until the dispatchable generation capacity bound is again hit. To summarize, the dispatchable generation capacity bound and the level of risk aversion are driven the energy price in day ahead.

Table 4.16: (B9.7, 0) Results of Cases 1 to 4 on configuration B9 (9 CCGT units) of single firm, single period, complementarity formulation, and parametric ramping with $\Lambda = 0$.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	4.01	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	0.00	80.00
λ risk aversion (0 is risk neutral)	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	22214.49	29562.12	24934.54	24934.54	24416.17	24934.54
Schedu. win. gen. (MWh)	725.67	9690.62	3969.41	3739.58	5804.07	6908.05
Schedu. dispatch. gen. (MWh)	21488.82	19871.50	20965.13	21194.96	18612.10	18026.49
Equilibrium price (€/MWh)	85.12	43.88	69.86	69.86	72.77	69.86
Reserve requirement (MW)	538.63	1851.02	1014.71	984.84	3854.69	4505.36
Up. reserve commit. (MW)	592.49	1665.92	1116.19	886.35	3469.22	4054.83
Down. reser. commit. (MW)	591.20	737.70	1116.17	415.28	1387.69	4054.82
Max. available reserve (MW)	592.49	2209.82	1116.19	886.35	3469.22	4054.83
INCOMES (€):						
Energy sales in day ahead	1890990.28	1297185.76	1741822.95	1741822.95	1776656.82	1741822.95
Premium to schedu. Wind	21770.11	290718.67	0.00	112187.39	0.00	552644.17
Supply of up. reser. capa.	24436.75	719.68	29476.05	23023.75	119069.03	201191.63
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	0.00
COSTS (€):						
Cost of dispatch. gen.	572849.81	502127.45	549878.41	559955.11	453768.74	433872.55
$\lambda_f \cdot CVaR[Q]$	17464.71	48943.97	19491.04	0.00	49130.83	195297.96
$(1 - \lambda_f) \cdot E[Q]$	8576.30	-1334.06	-9092.94	-1177.73	20780.23	116249.20
PROFIT (€)						
Total (wind + dispatch.)	1350053.50	1088720.09	1236575.49	1318256.71	1407323.38	1868037.53
1st stage wind turbines	83542.20	715943.19	277286.66	373418.85	422336.69	1035211.90
2nd stage wind turbines	-15657.04	-22880.31	-9398.48	-76041.46	-54259.86	-209720.53
1st stage dispatch. gen.	1280805.12	370553.48	944133.94	943660.13	1019620.41	1026574.29
2nd stage dispatch. gen.	1363.22	25103.74	24553.37	77219.19	19626.14	15971.87

Summing up for low generation capacity cases (B9.7 and B9.6)

The conclusions summarized here are based on the data reported on Tables 4.17, 4.18, and 4.19 comparing configurations with high generation capacity, (B2.1, 1) and (B2.1, 0), and configurations with low generation capacity, (B9.6, 1) and (B9.7, 0), and on more detailed data in Table 4.15 for configuration (B9.6, 1), and Table 4.16 for (B9.7, 0). On all these configurations, (B2.1, 0), (B2.1, 1), (B9.6, 1) and (B9.7, 0), the model used corresponds to single period, single firm, and price responsive demand, posed as a complementarity problem, as described in Section 2.5.

We observe that in overall terms the energy price in day ahead is remarkably higher in configurations with low generation capacity, (B9.7 and B9.6), than in configurations like B2.1 with more dispatchable capacity (see for example Table 4.17). Also the profits are greater in the configurations with the lower dispatchable capacity. The main contribution that increases the profits comes from dispatchable units at the first stage, namely the scheduled dispatchable generation and the committed flexibility reserve. This is what can be expected from standard economic reasoning.

In configuration (B9.6, 1), low generation (25356 MW of dispatchable generation) and low ramping ($\Lambda = 1$), the reserve constraints are tight for all the cases considered, except for Case 1 with very high wind forecast, $\mu = 65\%$. The energy price in day ahead for those cases is approximately 57 €/MWh in contrast with the approximately 43 €/MWh for the most of the cases in configurations (B2.1, 1) and (B2.1, 0) in which the reserve constraints are not tight.

In configuration (B9.7, 0), low generation (22081 MW of dispatchable generation) and high ramping ($\Lambda = 1$), the reserve constraints and the capacity bounds for dispatchable generators are tight for all the cases considered, except for the Case 1 with very high wind forecast, $\mu = 65\%$. The energy price in day ahead for those cases is approximately 70 €/MWh in contrast with the approximately 43 €/MWh for the most of the cases in configurations (B2.1, 1) and (B2.1, 0) in which the reserve constraints are not tight, and 57 €/MWh in the most of the cases for (B9.6, 1), in which only the reserve constraints and not the capacity bounds constraints for dispatchable generators are tight.

Behaviors are similar for most of the cases in both configurations (B9.6, 1) and (B9.7, 0). Particular circumstances lead to deviations with respect to these common trends such as the high wind forecast in case 1 ($\mu = 65\%$), and Case 4 ($m_y = 0.60$). And the additional factor for these configurations is the risk exposure that is taking into account through the CVaR term in the firm's objective function.

The level of scheduled wind generation for the cases with low generation capacity is similar to those for the cases with high generation capacity. The use of a single firm model contributes to this similarity of values for scheduled wind, because the single firm configuration reduces the risk exposure and remove some asymmetries that could happen in a multi-firm configuration with separate wind turbines and dispatchable units. In particular the risk and the asymmetry associated with the cost of energy deployed from reserve.

Remark on the relation between reserve constraints and the energy price

This subsection gives some analytical detail on the impact of the reserve and ramping constraint and the capacity bound constraints (see Sections 2.5, 2.4.6 and 2.4.7), on the energy price in day ahead.

Consider a situation where the reserve constraints are tight and one or more of the corresponding dual variables ($\bar{\gamma}$, $\bar{\kappa}$, $\underline{\gamma}$, $\underline{\kappa}$) are greater than zero, we explain that this implies

that the capacity bounds and/or the ramping constraints for the particular dispatchable unit providing the reserve are tight. We illustrate this fact with the upward reserve:

- Assume that: $ru_g > 0$, the reserve constraints are tight and $\bar{\gamma} + \bar{\kappa} > 0$.
- Then from the equation for the KKT condition for ru_g (2.4.54) we have $\bar{\phi}_g + \bar{\delta}_g = \bar{\gamma} + \bar{\kappa} > 0$.
- As $\bar{\phi}_g \geq 0$ is the dual variable for the upper capacity bound of dispatchable unit g , and $\bar{\delta}_g \geq 0$ is the dual variable for the ramping constraint of dispatchable unit g , one or both of them must be tight.

On the other hand, if the demand $d > 0$ (no trivial solution), from the KKT condition for demand (2.4.52) we have that the equilibrium price $\rho^* = -\nu$. Finally the KKT condition for the dispatchable generation (2.4.56) relates the equilibrium price with the dual variables for capacity bounds (upper $\bar{\phi}_g$ and lower $\underline{\phi}_g^k$), and the ramping constraints ($\bar{\delta}_g$ and $\underline{\delta}_g$), in particular if $x_g > 0$ we have: $cg_g + \bar{\phi}_g - \sum_{k \in \Omega} \underline{\phi}_g^k + \underline{R} \cdot \bar{\delta}_g + \bar{R} \cdot \underline{\delta}_g = -\nu = \rho^*$.

To summarize, when the capacity bounds and/or the ramping constraints for the dispatchable units that provide committed reserve get tight, that has a direct influence on the energy price in day ahead.

4.5.7 Comparison Among Cases in Single Period

In this section we compare the results for the previous four configurations, each configuration is compared with the rest. To facilitate the comparison, the results previously reported are rearranged in Tables 4.17 to 4.19. Each table is focused on the effect of some feature of the system, in particular:

- Table 4.17 highlights the effect of the ramping model in different configurations that reflect the extent of dismantling of CCGT capacities. It compares (B2.1, 1) with (B2.1, 0) (early stage of dismantling), and (B9.6, 1) with (B9.7, 0) (final stage of dismantling) in terms of energy price, total profit (wind + dispatchable), total profit of dispatchable generators in day ahead (first stage), total profit of dispatchable generators in balancing in real time (second stage), total profit of wind turbines in day ahead (first stage), total profit of wind turbines in balancing in real time (second stage).
- Table 4.18 illustrates the effect of the generation mix (generation level) on the performance of the agents depending on the ramping potential. It compares (B2.1, 1) with (B9.6, 1), and (B2.1, 0) with (B9.7, 0) in terms of energy price, total profit (wind + dispatchable), total profit of dispatchable generators in day ahead (first stage), total profit of dispatchable generators in balancing in real time (second stage), total profit of wind turbines in day ahead (first stage), total profit of wind turbines in balancing in real time (second stage).
- Table 4.19 emphasizes the combined effect of the generation mix (generation level) and the ramping model in the different configurations. It compares (B2.1, 0) with (B2.1, 1), (B9.7, 0) with (B9.6, 1), (B2.1, 1) with (B9.6, 1), and (B2.1, 0) with (B9.7, 0) in terms of total profit (wind + dispatchable), total profit (first stage and second stage) for the set of dispatchable generators, and total profit (first stage and second stage) for the set of wind turbines.

More detailed results including the values for scheduled generation and committed reserve are given for each configuration in Tables 4.13 to 4.16. Table 4.13 is devoted to configuration (B2.1, 1), Table 4.14 to configuration (B2.1, 0), Table 4.15 to (B9.6, 1), and Table 4.16 to (B9, 0).

Table 4.17: Comparison of the value of energy price in day ahead and the profit for the configurations B2 (two CCGT units) and B9 (9 CCGT units) of single firm, single period, complementarity formulation, and the parametric ramping with $\Lambda = 1$ and $\Lambda = 0$, in Cases 1 to 4.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	4.01	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	0.00	30.00	30.00	0.00	80.00
λ risk avers. (0=risk neutral)	0.40	0.40	0.00	0.00	1.00	0.40
B2.1, 1: Energy price (€/MWh)	52.71	43.45	43.45	43.45	54.52	54.24
B2.1, 0: Energy price (€/MWh)	49.07	43.45	43.45	43.45	43.45	43.45
B9.6, 1: Energy price (€/MWh)	69.33	57.24	57.24	58.30	101.44	77.84
B9.7, 0: Energy price (€/MWh)	85.12	69.86	69.86	70.49	72.77	69.86
PROFIT (€)						
B2.1, 1: Total (wind + dispat.)	679970.16	537760.04	838180.53	676816.04	632872.83	941590.72
B2.1, 0: Total (wind + dispat.)	570144.46	534467.58	844864.32	644048.50	639497.21	561937.27
B2.1, 1: 1st stage wind gen.	72281.48	712194.06	166808.32	300277.37	260664.32	249582.58
B2.1, 0: 1st stage wind gen.	58086.24	712194.24	166644.02	281708.56	274770.60	210713.88
B2.1, 1: 2nd stage wind gen.	-16886.44	-22744.77	-6950.69	-41874.72	-3695.82	-12996.07
B2.1, 0: 2nd stage wind gen.	-11900.04	-22744.81	-6886.72	-60806.47	-4207.44	-12726.96
B2.1, 1: 1st stage dispat. gen.	625459.34	361428.99	361428.99	361428.99	361428.99	676944.20
B2.1, 0: 1st stage dispat. gen.	521744.03	361428.99	361428.99	361428.99	361428.99	361428.99
B2.1, 1: 2nd stage dispat. gen.	-884.22	39146.63	16473.43	56984.40	14475.34	28060.00
B2.1, 0: 2nd stage dispat. gen.	2214.22	25537.14	13281.29	61717.42	7505.06	2521.37
B9.6, 1: Total (wind + dispat.)	1073012.60	1094162.82	968664.03	1062534.45	1036905.57	3140255.25
B9.7, 0: Total (wind + dispat.)	1350053.50	1088720.09	1236575.49	1318256.71	1321048.21	1407323.38
B9.6, 1: 1st stage wind gen.	65661.13	713289.52	228510.89	351321.19	288217.06	775007.36
B9.7, 0: 1st stage wind gen.	83542.20	715943.19	277286.66	373418.85	362709.01	422336.69
B9.6, 1: 2nd stage wind gen.	-13013.28	-22807.30	-7301.64	-79917.18	-700.80	-215488.08
B9.7, 0: 2nd stage wind gen.	-15657.04	-22880.31	-9398.48	-76041.46	-6163.56	-54259.86
B9.6, 1: 1st stage dispat. gen.	1014080.15	364437.80	712210.83	707401.79	734310.08	2463494.68
B9.7, 0: 1st stage dispat. gen.	1280805.12	370553.48	944133.94	943660.13	957653.79	1019620.41
B9.6, 1: 2nd stage dispat. gen.	6284.60	39242.80	35243.95	83728.65	15079.24	117241.29
B9.7, 0: 2nd stage dispat. gen.	1363.22	25103.74	24553.37	77219.19	6848.98	19626.14
						15971.87

Table 4.18: Comparison of the value of energy price in day ahead and the profit for the configurations B2 (two CCGT units) and B9 (9 CCGT units) of single firm, single period, complementarity formulation, and the parametric ramping with $\Lambda = 1$ and $\Lambda = 0$, in Cases 1 to 4.

$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)				$m_y = 0.60, m_x = 0.02$				
	Case 1		Case 2		Case 3		Case 4	
μ (%) expected wind	4.01	65.00	23.83	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	30.00	0.00	80.00	30.00	30.00	0.00	80.00
λ risk avers. (0=risk neutral)	0.40	0.40	0.40	0.40	0.00	1.00	0.40	0.40
B2.1, 1: Energy price (€/MWh)	52.71	43.45	43.45	43.45	43.45	43.45	54.52	54.24
B9.6, 1: Energy price (€/MWh)	69.33	43.60	57.43	57.24	57.24	58.30	101.44	77.84
B2.1, 0: Energy price (€/MWh)	49.07	43.45	43.45	43.45	43.45	43.45	43.45	43.45
B9.7, 0: Energy price (€/MWh)	85.12	43.88	69.86	69.86	69.86	70.49	72.77	69.86
PROFIT (€)								
B2.1, 1: Total (wind + dispatch.)	679970.16	1090024.90	537760.04	838180.53	676816.04	632872.83	941590.72	1398010.31
B9.6, 1: Total (wind + dispatch.)	1073012.60	1094162.82	968664.03	1259699.89	1062534.45	1036905.57	3140255.25	2358261.39
B2.1, 0: Total (wind + dispatch.)	570144.46	1076415.57	534467.58	844864.32	644048.50	639497.21	561937.27	1014924.34
B9.7, 0: Total (wind + dispatch.)	1350053.50	1088720.09	1236575.49	1547798.85	1318256.71	1321048.21	1407323.38	1868037.53
B2.1, 1: 1st stage wind gen.	72281.48	712194.06	166808.32	475294.79	300277.37	260664.32	249582.58	941381.82
B9.6, 1: 1st stage wind gen.	65661.13	713289.52	228510.89	552676.86	351321.19	288217.06	775007.36	1081919.49
B2.1, 0: 1st stage wind gen.	58086.24	712194.24	166644.02	474985.07	281708.56	274770.60	210713.88	874655.07
B9.7, 0: 1st stage wind gen.	83542.20	715943.19	277286.66	594839.71	373418.85	362709.01	422336.69	1035211.90
B2.1, 1: 2nd stage wind gen.	-16886.44	-22744.77	-6950.69	-21266.15	-41874.72	-3695.82	-12996.07	-215420.27
B9.6, 1: 2nd stage wind gen.	-13013.28	-22807.30	-7301.64	-26163.98	-79917.18	-700.80	-215488.08	-209761.24
B2.1, 0: 2nd stage wind gen.	-11900.04	-22744.81	-6886.72	-12743.43	-60806.47	-4207.44	-12726.96	-221495.84
B9.7, 0: 2nd stage wind gen.	-15657.04	-22880.31	-9398.48	-18261.89	-76041.46	-6163.56	-54259.86	-209720.53
B2.1, 1: 1st stage dispatch. gen.	625459.34	361428.99	361428.98	361428.99	361428.99	361428.99	676944.20	668959.29
B9.6, 1: 1st stage dispatch. gen.	1014080.15	364437.80	712210.83	707401.79	707401.79	734310.08	2463494.68	1475080.41
B2.1, 0: 1st stage dispatch. gen.	521744.03	361428.99	361428.99	361428.99	361428.99	361428.99	361428.99	361428.99
B9.7, 0: 1st stage dispatch. gen.	1280805.12	370553.48	944133.94	944133.94	943660.13	957653.79	1019620.41	1026574.29
B2.1, 1: 2nd stage dispatch. gen.	-884.22	39146.63	16473.43	22722.90	56984.40	14475.34	28060.00	3089.47
B9.6, 1: 2nd stage dispatch. gen.	6284.60	39242.80	35243.95	25785.21	83728.65	15079.24	117241.29	11022.71
B2.1, 0: 2nd stage dispatch. gen.	2214.22	25537.14	13281.29	21193.70	61717.42	7505.06	2521.37	336.13
B9.7, 0: 2nd stage dispatch. gen.	1363.22	25103.74	24553.37	27087.10	77219.19	6848.98	19626.14	15971.87

Table 4.19: Comparison of the value of energy price in day ahead and the total profit for each technology for the configurations B2 (two CCGT units) and B9 (9 CCGT units) of single firm, single period, complementarity formulation, and the parametric ramping with $\Lambda = 1$ and $\Lambda = 0$, in Cases 1 to 4.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	4.01	23.83	23.83	23.83	23.83	23.83
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
B2.1, 1: Energy price, €/MWh	52.71	43.45	43.45	43.45	54.52	54.24
B2.1, 0: Energy price, €/MWh	49.07	43.45	43.45	43.45	43.45	43.45
B9.6, 1: Energy price, €/MWh	69.33	57.24	57.24	58.30	101.44	77.84
B9.7, 0: Energy price, €/MWh	85.12	69.86	69.86	70.49	72.77	69.86
PROFIT (€)						
B2.1, 1: Total (wind + dispatch.)	679970.16	1090024.90	537760.04	838180.53	676816.04	632872.83
B2.1, 0: Total (wind + dispatch.)	570144.46	1076415.57	534467.58	844864.32	644048.50	639497.21
B9.6, 1: Total (wind + dispatch.)	1073012.60	1094162.82	968664.03	1259699.89	1062534.45	1036905.57
B9.7, 0: Total (wind + dispatch.)	1350053.50	1088720.09	1236575.49	1547798.85	1318256.71	1321048.21
B2.1, 1: Wind (1st + 2nd)	55395.04	689449.29	159857.63	454028.64	258402.65	256968.50
B2.1, 0: Wind (1st + 2nd)	46186.21	689449.44	159757.30	462241.64	220902.09	270563.16
B2.1, 1: Dispatch. (1st + 2nd)	624575.12	400575.62	377902.41	384151.89	418413.39	375904.33
B2.1, 0: Dispatch. (1st + 2nd)	523958.25	386966.13	374710.28	382622.68	423146.41	368934.05
B9.6, 1: Wind (1st + 2nd)	52647.85	690482.23	221209.25	526512.88	271404.01	287516.25
B9.7, 0: Wind (1st + 2nd)	67885.16	693062.88	267888.19	576577.82	297377.39	356545.45
B9.6, 1: Dispatch. (1st + 2nd)	1020364.75	403680.60	747454.78	733187.01	791130.44	749389.32
B9.7, 0: Dispatch. (1st + 2nd)	1282168.34	395657.21	968687.30	971221.03	1020879.32	964502.77
B2.1, 1: Wind (1st + 2nd)	55395.04	689449.29	159857.63	454028.64	258402.65	256968.50
B9.6, 1: Wind (1st + 2nd)	52647.85	690482.23	221209.25	526512.88	271404.01	287516.25
B2.1, 0: Wind (1st + 2nd)	46186.21	689449.44	159757.30	462241.64	220902.09	270563.16
B9.7, 0: Wind (1st + 2nd)	67885.16	693062.88	267888.19	576577.82	297377.39	356545.45
B2.1, 1: Dispatch. (1st + 2nd)	624575.12	400575.62	377902.41	384151.89	418413.39	375904.33
B9.6, 1: Dispatch. (1st + 2nd)	1020364.75	403680.60	747454.78	733187.01	791130.44	749389.32
B2.1, 0: Dispatch. (1st + 2nd)	523958.25	386966.13	374710.28	382622.68	423146.41	368934.05
B9.7, 0: Dispatch. (1st + 2nd)	1282168.34	395657.21	968687.30	971221.03	1020879.32	964502.77

4.5.8 Conclusion

The reduction of the price on the energy market as a result of wind penetration and the lower utilization of CCGT units is the dominant phenomenon observed throughout in the numerical results obtained with both high and low generation capacity. The phenomenon, in the case of high generation capacity, reflects the fact that the marginal unit always sets the energy price in the current market design based on short run marginal cost with excessive capacities. This impacts the CCGT, which see both the price on the energy market and the utilization of their plant drop. The situation results from the downturn of the economic demand and the high penetration of wind. Market characteristics such as risk aversion or feed-in premium barely change these basic phenomena. The phenomenon is intuitively clear, it is observed in reality and it also appears in the results.

On the other hand, the phenomenon in the case of low generation capacity reflects the fact that the energy price in day ahead is greater than the cost of the marginal unit because the ramping constraints and/or the capacity bounds constraints for some dispatchable units are tight. Only a very high wind forecast (for instance $\mu = 65\%$, as in Case 1) changes this situation, because it provides the additional generation capacity necessary to avoid get constrained by the capacity bounds and/or the ramping constraints for dispatchable units.

In the case of high generation capacity, the provision of ancillary services could have offered some hope for CCGTs. But the results show that this is not the case as high wind conditions release CCGT capacity for reserve, at the same time as they reduce the price. Wind indirectly releases more reserve than it demands and the value of that reserve remains zero and hence provides no revenue to the CCGT units. Requiring a long horizon for committing plants for reserve suggests some hope: the change of a single apparently innocuous coefficient (increasing m_y from 0.15 to 0.6) as a result of a longer horizon necessary for commitment plants can completely modify important policy conclusions. But even that solution does not happen very robust: improving ramping possibilities suffices to reset the price of this service to zero, therefore confirming that CCGT need to withdraw from the market.

In a tighter market with low generation capacity, that is the one that results from decommissioning of CCGT capacities, as it is illustrated with configuration (B9.6, 1) and (B9.7, 0) (see Sections 4.5.5 and 4.5.6), we observe that energy price in day ahead and firm's profit are considerably greater than in the similar configurations with high generation capacity, configurations (B2.1, 1) (Section 4.5.2, and configuration (B2.1, 0) Section 4.5.3). This is because the reserve and ramping constraints, and sometimes the capacity bounds constraints, for dispatchable units become tight in configurations with low generation capacity, which makes the energy price greater than the generation cost of the marginal unit. The highest energy prices and firm's profits are obtained with the lower total dispatchable capacity even though ramping capacities are higher, that is (B9.7, 0). In this last case the reserve constraints, the ramping constraints and the upper capacity bound constraints for dispatchable units are tight in the most of the cases considered, in fact they are tight for all the cases considered except for the case with very high wind forecast ($\mu = 65\%$), because of the increase of total generation capacity in this case.

We refer to the composition of the generation system and the flexibility embedded in the ramping model as structural characteristics and here test their global impact and examine how outcomes of the market vary with its structural characteristics. We index the preceding information in Table 4.20. The preceding tables emphasize electricity price and total profits made by conventional generators on the energy and ancillary services markets.

Table 4.20: Summary of tables reporting results for Case Study 1

	Parametric Ramping	
	$\Lambda = 1$	$\Lambda = 0$
B2 (4.7)	Table 4.13	Table 4.14
B9 (4.8)	Table 4.15	Table 4.16

The Impact of the Generation Capacity

One of the structural assumptions considered is the composition of the generation system, which effects we discuss here. By construction the decommissioning of capacity increases the price of electricity, which is an effect that benefits both wind and conventional generators, whatever the ramping model. It is only when the wind forecast level is very high ($\mu = 65\%$, column 3 in Tables 4.17 to 4.16) that the reduction of the conventional capacity does not affect prices, because the wind is enough to replace the decommissioned dispatchable capacity. This points to the fallacy of the existing policy that induces the development of wind power irrespectively of the composition of the conventional generators.

The comparisons between the different structural assumptions reveal a few fundamental features that we discuss in what follows in relation with the generation capacity.

The impact of the wind forecast, feed-in premium and risk aversion are not significantly affected by the structural assumptions, whether capacities are high or low and ramping possibilities ample of restricted. These impacts can be summarized as follows:

- The high wind forecast can drive the price of electricity to the fuel cost of the marginal unit (usually a CCGT unit) and hence put the generation system in a situation where neither energy or reserve can help recover fixed operating costs, see column 3 on Tables 4.17, 4.15 and 4.16. There is no contribution to fixed cost in those circumstances.
- Wind premium does not change much the equilibrium on the energy market, even though this equilibrium is different for the different structural assumptions.
- The same is true for risk aversion even if it seems to play a more important role when capacity is low.

The revenues to conventional plants are quite different depending on the total generation capacity. As it is expected they increase drastically when capacity is dismantled (see results reported on Tables 4.15 and 4.16 and the comparative of profits in Table 4.17).

The Impact of ramping capabilities

The second structural assumption considered is the ramp capability, that we model in the single period configurations using a parametric expression, the so called parametric ramping described in Section 2.3. In the case studies we consider only the two extreme values of the parameter for ramping, $\Lambda = 1$ that corresponds to a low ramp capability, and $\Lambda = 0$ that corresponds to a high ramp capability.

The ramping constraints and the reserve constraints are related, in such a way that if the reserve constraints are tight then the ramping constraints are tight also, the link between these constraints is discussed with more detail in Section 4.5.6.

The simulations results for the single period model illustrate the following facts:

- In the configurations with low ramping like (B2.1, 1) and (B9.6, 1), see column 2 (Case 1, $\mu = 4\%$) on Tables 4.13 and 4.15, the ramping constraints are tight but the capacity constraints are not tight. In contrast with the configurations with high ramping capability like (B9.7, 0), see Table 4.16, where the ramping constraints and the capacity constraints are always simultaneously tight, in fact on Table 4.16 they are tight for all the cases except for $\mu = 65\%$ that corresponds to a very high wind forecast.
- As it was expected, the ramping constraints are more frequently hit in system with low generation capacity like B9.6 (Table 4.15) and B9.7 (Table 4.16) than in systems with high generation capacity like B2.1 (Tables 4.13 and 4.14). In (B9.6, 1) and (B9.7, 0) the ramping constraints are tight for all the cases except for a very high wind forecast ($\mu = 65\%$). In (B9.2, 1) with high generation capacity and low ramping capability, the ramping constraints are hit only in Case 1 for $\mu = 4\%$ and in Case 4 ($m_y = 0.60$). And finally, in (B9.2, 0) with high generation capacity and high ramp capability, the ramping constraint is tight only in Case 1 for $\mu = 4\%$.
- When the ramping constraints are tight, the energy price in day ahead is higher than the generation cost of the marginal unit, as it is illustrated on Table 4.15, for configuration (B9.6, 1) with low generation capacity and low ramping capability, where the capacity constraints are not tight, and only the ramping constraints are hit for all the cases except for Case 1 with $\mu = 65\%$ (very high wind forecast). In the cases where the capacity constraints are also tight the energy prices is even higher, as it illustrated with the results reported on Table 4.16 for (B9.7, 0), system with low generation capacity and high ramping capability.
- The ramping capability has a significant influence on the effect of factors like wind forecast level (μ , Case 1) and the demand for flexibility reserve (in particular m_y , Case 4). In contrast, it has a little influence on the effect of other factors like the feed-in premium (Case 2) and the level of risk aversion (Case 3).

In the case of ramping capability, as in the previous case of generation capacity, a high wind forecast can drive the price of electricity to the generation cost of the marginal unit, as we observed in the results for the case with wind forecast $\mu = 65\%$ (column 3 in Tables 4.17, 4.15 and 4.16). This is because the wind generation replaces dispatchable generation that can be used for ramping and reserve. In this situation neither energy nor reserve can help to recover the fixed operating cost of dispatchable units.

Additional Comments on the Multiple Equilibria

We summarized here the results regarding the multiple equilibria in the cases previously discussed in this section. In all the cases the multiple equilibria were found in Case 4, in some situations we found two equilibria and up to three equilibria in other, two of them by changing ρ^+ from 0 to 80 €/MWh, and ρ^+ from 80 €/MWh to 0, and the third one by using two different versions of the solver PATH. We recall that Case 4 stands for: Average wind forecast ($\mu = 23\%$), average risk aversion ($\lambda = 0.4$), wind induced demand for flexibility reserve ($m_y = 0.60$), and feed-in premium to wind in the range $\rho^+ \in [0, 80] \text{ €/MWh}$. The results for Case 4 are summarized in what follows:

- High generation, low ramping (B2.1, 1): We have three equilibria for $\rho^+ = 0$, with energy prices 82.84 €/MWh, 54.23 €/MWh (see Fig. 4.8) and 54.52 €/MWh (see Table 4.13). In this case the ramping constraints are tight in the three equilibria.

And we found two equilibria for $\rho^+ = 80$ €/MWh, with energy prices 82.84 €/MWh and 54.23 €/MWh (see Fig. 4.8). In this case the ramping constraints are tight in both equilibria.

- High generation, high ramping (B2.1, 0): Only one equilibrium, with energy price 43.45 €/MWh (slack ramping).
- Low generation, low ramping (B9.6, 1): We have three equilibria with for $\rho^+ = 0$, with energy prices 77.84 €/MWh, 88.32 €/MWh (see Fig. 4.13), and 101.44 €/MWh (see Table 4.15). The ramping constraints are tight in the three equilibria.

And we found two equilibria for $\rho^+ = 80$ €/MWh, with energy prices 77.84 €/MWh and 88.32 €/MWh (see Fig. 4.13). The ramping constraints are tight in both equilibria.

- Lower generation, high ramping (B9.7, 0): We have only one equilibrium, with energy price 69.85 €/MWh, but the ramping constraints are also tight in this case.

The conclusion is that we have, at least, three equilibria in some cases, but this multiplicity of equilibria should be studied carefully to explain the causes and if there are more equilibria, this is left as a future work.

4.6 Case Study 2: The Anticipated Dismantling of Conventional Capacities

4.6.1 Introduction to Case Study 2

The European Union is currently undergoing a movement towards the dismantling (or at best mothballing) of existing (sometimes new and highly efficient) conventional plants because of the low electricity price on the energy market. We elaborate on the first case study by extending it to a multi hour framework and investigate the extent to which the process might be stopped by a demand for ancillary services provided by these conventional plants. The question has two facets: one is to assess the capability of ancillary services provided by conventional plants if priced at their market value (opportunity cost) to stop the process. A second issue is the extent to which the current pricing of ancillary services can effectively stop the destruction of asset value. We concentrate on the first question here. Because we assume proper pricing of ancillary services, we further simplify the problem by assuming fixed demand and a single firm that minimizes its cost or price responsive demand and surplus maximization. The more complicated problem of the impact of the current pricing regime requires the full equilibrium formulation used in Case Study 1 for a single hour. It is known that the optimization formulation represents a perfect market (in particular that does not discriminate in favor of wind plants in the use of ancillary services). The optimization model is thus the reference counterfactual to value ancillary services provided by conventional plants.

We formalize the problem as follows. Starting from a given existing capacity we solve the model and compute the remuneration of existing plants. Taking stock of the insight gained in the first case study, we conjecture from the general theory of the “missing money” (Joskow [1]) that the remuneration obtained from the short term market will not cover the fixed operating charge of existing plants as long as existing capacity is sufficient to cover demand in all case (perfect reliability). We thus progressively decrease the existing capacity by dismantling the existing plants that make the largest losses and stop when all capacities break even or make a residual profit. Remaining in the spirit of the energy only model favored by European

authorities, this simulation requires introducing a price cap (or a backup generator) and allowing shortages at that price cap (or operating cost of the backup generator) when shortage occurs in the fixed demand formulation. The process also requires to value ancillary services received by existing conventional plant capacities at their marginal opportunity cost (that is on the basis of dual variables of existing capacities). The relevant valuation formula are given in the previous Section 4.3.1.

The rest of the section is organized as follows, first the settings (model and data) for the simulations are described, second the main results in this section are discussed in three subsections (4.6.3 to 4.6.5) focus on: *i)* the role of the price cap in the dismantling process and its effect on energy price, *ii)* a discussion on how subsidies to dispatchable generation could affect the dismantling of those units, *iii)* numerical details for relevant magnitudes (energy price and installed capacity) at different dismantling stages for several test studies. The following two subsections (4.6.6 and 4.6.7) elaborate shortly on the results for price responsive demand and fixed demand, and the results are reported with the same format used in the previous section (Case Study 1) to facilitate the comparison with the previous results. The conclusion is that results for single period and multi-period are quite similar, at least in qualitative terms, with price responsive or fixed demand. Finally, subsection 4.6.8 compares the results in multi-period with ramping products and without ramping products and closes this part.

4.6.2 Setting for the Simulations

The results discussed here are obtained with the models described in Section 3.4 and Section 3.5. We recall that the model in Section 3.4 is a multi-period, single firm, equilibrium model with price responsive demand posed as a welfare maximization stochastic program. The model in Section 3.5 is a multi-period, single firm, equilibrium model with fixed demand posed as a stochastic program that minimizes the operation cost. These models are applied to the generation park composition (B9.5) and (B9.4), Table 4.9, Section 4.4.3, that correspond to a final state of dismantling and have the following features:

- (B9.5): Total dispatchable capacity of 28100.60 MW, with a total of 10 units out of the initial 15 units. The 5 CCGT units with the highest cost have been dismantled. This is the final dismantling state for the model with price responsive demand (without price cap), and the model with fixed demand and price cap with values 100 €/MWh and 300 €/MWh.
- (B9.4): Total dispatchable capacity of 33688.85 MW, with a total of 11 units out of the initial 15 units. The 4 CCGT units with the highest cost have been dismantled. This is the final dismantling state for the model with fixed demand and price cap with values 1000 €/MWh and 563.78718 €/MWh.

A total of ten test studies are considered here. For the sake of simplicity, each test study is referenced using a short code composed of three elements: *i)* the composition of the generation park, that can be B9.4 or B9.5, *ii)* the value of the price cap, that can be “-” in the case of no price cap (price responsive demand) or, in the case of fixed demand, has the values 100, 300, 1000 or O (optimal value as described in detail in the next Section 4.6.3), *iii)* with ramping products¹⁴ “rp” or without ramping products “nrp”. All the references for the test studies considered in this chapter are listed in Table 4.21.

¹⁴The ramping products are described in Section 3.2.1.

Table 4.21: Summary of the test studies for the multi-period configuration.

	Demand ¹⁵	B. Gen. ¹⁶	Gen.	Reference
With ramping products (rp)	Responsive (Sect. 3.4)	-	B9.5	(B9.5, -, rp), Table 4.26
	Fixed demand (Section 3.5)	100	B9.5	(B9.5, 100, rp), Table 4.27
		300	B9.5	(B9.5, 300, rp), Table 4.28
		1000	B9.4	(B9.4, 1000, rp), Table 4.29
		Optimal ¹⁷	B9.4	(B9.4, O, rp), Table 4.30
Without ramping products (nrp)	Responsive (Sect. 3.4)	-	B9.5	(B9.5, -, nrp), Table A.29
	Fixed demand (Section 3.5)	100	B9.5	(B9.5, 100, nrp), Table A.17
		300	B9.5	(B9.5, 300, nrp), Table A.20
		1000	B9.4	(B9.4, 1000, nrp), Table A.23
		Optimal ¹⁷	B9.4	(B9.4, O, nrp), Table A.26

4.6.3 On the Role of the Price Cap

This section presents an in depth discussion of the mechanism at work during the dismantling process for the fixed demand model. It considers four values, 100, 300, 563.7 and 1000 €/MWh, of the generation cost for the backup generator. Note that the price cap currently coded in European market clearing software is 3000€/MWh (Pan-European Hybrid Electricity Market Integration Algorithm, EUPHEMIA [79, 80]).

The process begins with a first phase where all the capacity in excess of the maximal demand (computed over all hours and scenarios) is dismantled (taking into account the need to satisfy reserve). During that process the energy price does not change because the dismantled generators are those that were not committed for generation because other generators with lower costs can supply the demand. As expected from a transposition of the standard reasoning of the “missing money” (Joskow [1]) to fixed operating costs, several plants are loosing money because they do not cover these costs during that phase. They are thus progressively dismantled until the process enters a second phase where curtailment appears, and the backup generator must be used to (fictitiously) supply demand. The use of backup generator corresponds to a curtailment when the price is set at the cap. Experiment with the model suggests two different outcomes of the dismantling process and their corresponding mechanisms. These are illustrated in the numerical results reported in Tables 4.22 to 4.25, and briefly described in what follows:

- I) The **first mechanism** only resorts to the backup generator for ancillary services in balancing but not to supply energy in day ahead. There is thus no curtailment in the energy market (whether in day ahead or balancing) because of lack of generating capacity. But there is a curtailment due to the lack of ramping or reserve capacity. In other words, there is enough generating capacity but not enough ancillary service capacity.

¹⁵We consider two alternatives for demand: Price responsive demand (using a linear inverse demand function) or fixed demand.

¹⁶“B. Gen.” stands for the generation cost of the Backup Generator in €/MWh, and it represents a price cap for the energy price in the system, it is described with more detail in Section 4.3.

¹⁷In this context “optimal” means the minimum value of the price cap (cost of the backup generator) that gives the minimum energy price in day ahead.

This case happens when the installed capacity that is not yet dismantled, is sufficient to supply the energy demand in day ahead, but not to supply completely the ancillary services needed for the technical operation of the system¹⁸.

The recourse to the back up generator (in other words, the price cap) has two effects on the price of ancillary services:

- 1) Even though the backup generator can (fictitiously) provide ancillary services and has infinite capacity, the shadow price of the committed reserve capacities of conventional plants can be different from zero. The reason is that the model contains separate constraints for the available capacity and for the committed reserve, thus firms can assign values to the scheduled generation and the committed reserve to hit some (or all) of the reserve constraints, even if the capacity constraints are not tight. To summarize, reserve constraints tight does not imply capacity constraints tight.

For instance, in the model in 3.3.2, the reserve constraints are (3.3.47)-(3.3.50), and the capacity constraints for dispatchable generators are (3.3.63) and (3.3.64).

When some of the reserve constraints are tight, the corresponding reserve capacity has a price greater than zero and the firms receive an income from their committed reserve, as we can see in Tables 4.26 to 4.30. On the other hand, the committed reserves set bounds to the scheduled generation, like those described by equation (3.3.47), hence if the capacity constraints are not tight, the firms try to hit the reserve constraints to get some revenues, but at the same time they avoid to introduce additional constraints to the scheduled generation due to a shortage of committed reserve.

- 2) The expected prices of energy from ancillary services increase when the backup generator is used to provide that energy. This price is an expectation of the backup price on a set of scenarios; because the backup generator is usually not used in all the scenarios, the expected price of energy from ancillary services is usually lower than the operating cost of the backup generator.

Depending on the generation cost of the backup generator (the price cap) we observed two possible outcome of this first mechanism:

- a) The increase in the price of energy due to the use of the back up generators in ancillary services is sufficient to stop the mothballing. This only occurred with a cost of 1000 €/MWh for the backup generator and the price of energy in day-ahead increases from 44 €/MWh to 96 €/MWh in some hours (detailed results for prices during dismantling in subsection 4.6.5).
- b) The increase in the price of ancillary services is not sufficient to stop the dismantling, which then continues until the second mechanism is activated.

II) The **second mechanism** consists of using the backup generator to supply energy in day ahead. This means that the day ahead market clears at the price cap (some demand

¹⁸This case could be not possible in all the systems because the capacity is dismantled in blocks of discrete size (the size of each unit), hence the sequence of capacity values during the dismantling process is a finite set of discrete values. The configuration that makes feasible this first mechanism could be in a range between two discrete points in the previous set, in this case the first mechanism will not be possible. In general this mechanism will be feasible in large systems, where the size of dispatchable units is small in comparison to the total energy demand, this is the typical case in real power systems.

had to withdraw) in some hours and the energy price in those hours is equal to the price cap (equal to the backup generator cost).

This second mechanism occurs when the price cap is not high enough to stop the dismantling process with the first mechanism. The dismantling then continues until the capacity of conventional units is no longer sufficient to supply the demand, and as a consequence the backup generator is used in day ahead and the energy price hit the price cap. This is a very costly solution.

The first mechanism leads to a solution of a cost considerably lower than the second mechanism. This may look paradoxical because the highest generation cost leads to the lowest energy price. For instance in the numerical experiments, the total cost is lower for the case with a price cap of 1000 €/MWh than for a price cap of 100 €/MWh and 300 €/MWh. The explanation is that the higher price cap reduces the number of hours of curtailment and it is better to pay a very high price only for a few hours than a high price in many hours.

There exists a threshold value for the cost of the backup generator for which only the first mechanism is active. We can get that value using the model; for instance, the value obtained with the model with single firm, multi-period and fixed demand with ramping products is 563.78718 €/MWh and 563.79699 €/MWh in the configuration without ramping products¹⁹. This threshold value for the price cap minimizes the increase of energy price that is necessary to keep the dispatchable capacity without continue dismantling units. Thus the threshold value for the price cap can be considered as the optimal price for flexibility, in the sense that it minimizes the average energy price.

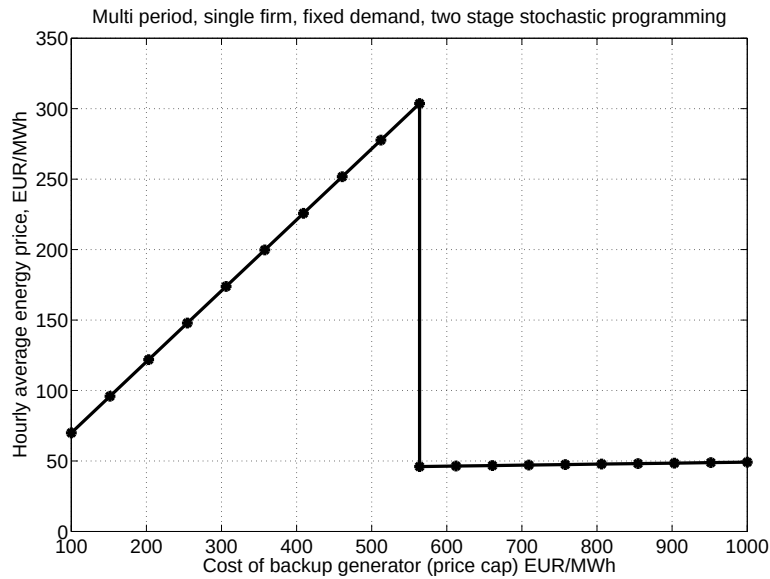


Figure 4.15: Hourly average energy price in day ahead (€/MWh) vs backup generator cost (€/MWh).

The influence of the backup generation cost (price cap) on the hourly average energy price is illustrated in Fig. 4.15, for the system with multi-period, single firm with ramping

¹⁹We are given five decimals digits just for illustrative purposes, and because they are needed to get the profitability margin of the last active generator in the dismantling process greater than zero and lower than 10^{-3} €/h.

products and fixed demand posed as a cost minimization problem (see Section 3.5). We observe on the figure two straight lines with different slopes. The break point corresponds to a value of 563.78718 €/MWh for the price cap. The final dismantling state (B9.5), with total dispatchable capacity 28100.60 MW, is associated with the values of the backup generator cost for the first segment (from left to right). For the other segment the associated configuration is (B9.4), with total dispatchable capacity 33688.85 MW. A low value of the price cap leads to a deeper dismantling and higher energy price than a high value of the price cap, this is explained with more detail in the next Section 4.6.3.

4.6.4 Subsidizing Conventional Plants?

This section raises the question of the possible need to subsidize conventional generators for reasons of security of supply in the context of high wind and low price cap (lower than 563.7 €/MWh in this case). The discussion is based on the previous analysis of the role of the price cap and its representation in terms of backup generator in the dismantling process, we consider two possible situations, one with subsidy to dispatchable generation and the other without subsidy.

The no subsidy range

Dismantling without price cap (or without backup generator) can only reduce losses (by eliminating fixed operating costs) but will not increase the profits of units that are not profitable in the initial configuration, at least as long as demand can be satisfied. This can be explained as follows:

- The energy price depends on the demand and the curve of generation cost for the generation mix. Dismantling removes the part of the curve that is never used in the energy market. The outcome of the energy market is thus unaltered.
- The reserve and ramping products are not altering the outcome of the market because:
 - 1) As long as there is always enough dispatchable capacity to satisfy the peak demand in low wind scenarios, the dispatchable units satisfy both the demand for energy and ancillary services (which is at its lowest level when wind generation is low).
 - 2) When increasing amounts of wind are integrated in the system, the displaced dispatchable generation is usually sufficient to cover the variability of wind as can be seen from the following:
 - Let Δy be the increasing amount of wind. The replaced amount of dispatchable generation is $\Delta x = \Delta y$. Let G_Δ be the set of dispatchable generators affected by this change.
 - The increase in the required reserve is: $m_y \cdot \Delta y$
 - The increase in the available upward reserve is: $\sum_{g \in G_\Delta} \bar{R}_g \cdot \Delta x_g$
 - The increase in the available downward reserve is: $\sum_{g \in G_\Delta} \underline{R}_g \cdot \Delta x_g$
 - To illustrate the situation, assume that $\bar{R}_g = \underline{R}_g = R$. The condition to have sufficient reserve from the newly available dispatchable capacity is $m_y \cdot \Delta y \leq R \cdot \Delta x$ or $m_y \leq R$. The typical values are $m_y = 15\%$ and $R = 53.33\%$ for CCGT units, but to take into account the complete wind variability could require values of m_y up to 60%.

- 3) As the system must be able to satisfy the demand in all scenarios, the dispatchable capacity must be sufficient to satisfy the demand in the worst scenario. In case we consider also scenarios for demand variability, the overall result will differ from the result where we only consider wind scenarios; but as in the case with only wind scenarios the price does not change with the progressive dismantling of dispatchable units as long as the set of dispatchable units in fact used for generation does not change with the dismantling. The dispatchable units in this set meet two conditions:

- They minimize the generation cost to satisfy the demand.
- Their total capacity has the minimum value that can satisfy the demand in the worst scenario with minimum cost.

If we consider the variability of demand we still remain in the region of the cost curve that we cannot mothball, for the same reason that in the first point, the system must satisfy the demand in all the scenarios.

There is thus no reason for subsidizing the plants that have been dismantled so far, as they are necessary neither to provide energy in the day head market nor to provide sufficient backup for balancing. There remains an incentive for dismantling the plants with the highest costs that cannot cover their fixed charges. One shall note that this result is compatible with the standard reasoning of the “missing money” (Joskow [1]). Marginal plant cannot cover their fixed costs as long as there is enough capacity to cover the whole demand. These results simply extend that result to the case of a system with remuneration of energy and ancillary services. This is where the subsidy problem intervenes.

The subsidy range

A certain amount of ramping capability is indeed needed for the technical operation of the system. The main consequence of the current market configuration and the incentive to dismantle is that it is driving to a system that cannot supply the demand. To solve this situation, we have studied the two following alternatives:

- 1) Pay the plants that supply ramping capability (for instance the CCGT). We can use our current model to quantify:
 - The required amount of installed power from these plants.
 - The value of the subsidy to these plants.

This payment is not a capacity payment or a capacity market as it depends on other features than capacity.

- 2) Integrate in the market a proper pricing scheme for flexibility products that takes into account the cost of lost load, and not only the generation cost. This is in line with the theory of the missing money (Joskow [1]) in energy only markets and is explored next. The proposal at MISO takes into account the high cost of the fast units that are used only for peaks, we could also integrate this consideration in the pricing scheme.

4.6.5 Numerical Details for the Dismantling Process in Multi-Period

Here we focus the analysis on two outcomes, the total dispatchable capacity at the end of the dismantling process, and the average energy price at that state for several representative

values of the wind forecast. The results reported in this subsection concentrates on the influence of two main factors on the previous outcomes: *i*) the demand model, fixed demand or price responsive demand, and *ii*) the value of the price cap.

Each row in Tables 4.22 to 4.25 represents a step of the dismantling process, and each column a daily wind pattern (see Table 4.11), from left to right Low, Average, High and Very High wind. We can observe in Tables 4.22 to 4.24 that the energy prices do not change in the beginning of the dismantling process and they only change at the end of the process. This is because the units dismantled in the beginning are those with the highest cost, and they are not used for generation. In contrast, the units dismantled at the end of the dismantling process are units that would be used for generation if they were active. We find:

- a) a curtailment of the demand that increases the energy price in day ahead, in the case of price responsive demand.
- b) The use of the backup generator, that also increases the energy price because of its high generation cost, in the case of fixed demand.

Table 4.22: Price of energy in day ahead. Configuration of single firm and multi-period starting in B9.0 and ending in B9.4. Cost of back up generator 1000 €/MWh.

Mothballing round	Wind forecast (μ)				Total Capacity MW
	5.86 %	22.20%	47.09%	61.17%	
	€/MWh	€/MWh	€/MWh	€/MWh	
1	44.83	43.37	38.10	32.52	43597.49
2	44.83	43.37	38.10	32.52	40686.68
3	44.83	43.37	38.10	32.52	39136.63
4	44.83	43.37	38.10	32.52	37552.19
5	96.29	43.37	38.10	32.52	33688.85

Table 4.23: Price of energy in day ahead. Configuration of single firm and multi-period starting in B9.0 and ending in B9.5. Cost of back up generator 300 €/MWh.

Mothballing round	Wind forecast (μ)				Total Capacity MW
	5.86 %	22.20%	47.09%	61.17%	
	€/MWh	€/MWh	€/MWh	€/MWh	
1	44.83	43.37	38.10	32.52	43597.49
2	44.83	43.37	38.10	32.52	40686.68
3	44.83	43.37	38.10	32.52	39136.63
4	44.83	43.37	38.10	32.52	37552.19
5	96.29	43.37	38.10	32.52	33688.85
6	708.13	580.20	38.18	32.59	28100.60

We observe that the effect of dismantling is deeper in the scenarios with low wind forecast, because the total available generation capacity is also lower in these situations.

The influence of the price cap value was discussed in general terms previously in Section 4.6.3. We observe in Tables 4.23 and 4.24 that part of the active dispatchable generators are

Table 4.24: Price of energy in day ahead. Configuration of single firm and multi-period starting in B9.0 and ending in B9.5. Cost of back up generator 100 €/MWh.

Mothballing round	Wind forecast (μ)				Total Capacity MW
	5.86 %	22.20%	47.09%	61.17%	
	€/MWh	€/MWh	€/MWh	€/MWh	
1	44.83	43.37	38.10	32.52	43597.49
2	44.83	43.37	38.10	32.52	40686.68
3	44.83	43.37	38.10	32.52	39136.63
4	44.83	43.37	38.10	32.52	37552.19
5	47.76	43.37	38.10	32.52	33688.85
6	82.89	74.19	38.18	32.59	28100.60

Table 4.25: Summary of results, hourly average energy price for each wind day and configuration considered in the final state of dismantling.

	Gen. GW	Cost Backup					Average
Wind average (%)			5.857	22.198	47.087	61.171	
Wind probability			0.133	0.732	0.068	0.067	
			Energy price (€/MWh)				€/MWh
Fixed demand	28.1	100.000	82.894	74.192	37.985	30.580	69.962
Fixed demand	28.1	300.000	221.835	186.638	37.985	30.580	170.737
Fixed demand	33.7	1000.000	96.294	43.369	37.900	30.465	49.184
Fixed demand	33.7	563.787	72.770	43.369	37.900	30.465	46.050
Price responsive	28.1	-	55.064	49.053	38.668	32.171	48.016

dismantled in the last two rounds for low values of the price cap (100 and 300 €/MWh). In contrast, the active generators are affected by dismantling only in the last round in the case of high price cap (1000 €/MWh, Table 4.22). That means that the total dispatchable capacity after dismantling is higher in the situations with high price cap than in the situations with low price cap. This complies with the theory of the missing money. This, in turn, leads to higher energy prices in day ahead with a low price cap than with a high price cap. Illustrative values are summarized in Table 4.25, where the values for the test studies considered are compared, together with the frontier value (563.7 €/MWh) that separates the high price cap and the low price cap. The energy price in day ahead reached a minimum value for the frontier value of the price cap (see Table 4.25), this frontier value is called “optimal price cap” in other parts of the text.

4.6.6 Price Responsive Demand in Multi-Period Setting

We here discuss the results for the model of single firm, multi-period, with price responsive demand and posed as a two stage stochastic problem maximizing the social welfare (see Section 3.4). Results for the test study (B9.5, -, rp) are reported in Table 4.26, we recall that “rp” means “with ramping products”. Additional data on profitability and price for the

dismantling process leading to the generation park composition B9.5 with the assumptions in this test study are presented in Tables A.13 and A.14. Analogous data for test study without ramping products (B9.5, -, nrp) are given in the Appendices, Tables A.27 to A.29.

The behavior of the model through the different Cases 1 to 4 is similar to the one of the single period model and the discussion will not be repeated here. The ramping products add ramping capability on the reserve requirement. Analogously to the single period models, in this case the available ramping capacity binds the committed reserve and ramping products. This fact is sometimes used by the firms to hit the capacity constraints to increase the energy price, and/or to hit the reserve constraints with the objective to increase the reserve capacity price.

The values of the available ramping capability reported in the tables (row “Max. available reserve (MW)”) do not take into account the backup generator, thus when the value of the committed reserve (or committed reserve plus ramping products) is greater than the available reserve, that means the backup generator is providing the difference in ramping capability.

In the pure optimization approach, models in Sections 3.4 and 3.5, wind pays for the reserve that it requires in the pure reserve model (but not for the ramping product), and hence is less likely to saturate the available reserve.

To summarize, we have two opposite effects of the ramping products on the operation cost and energy price: *i)* on one hand, a moderate use of the ramping products reduces the cost of the operational flexibility, because ramping capability is scheduled well in advance to avoid paying the high cost of the fast generators, *ii)* on the other hand, an abuse of the ramping products can lead to higher prices for energy and reserve capacity if these ramping products hit the capacity constraints and/or the reserve constraints.

Table 4.26: (B9.5, -, rp) Results of Cases 1 to 4 for text study with price responsive demand, composition of the generation park B9.5 and ramping products “rp”. All the values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 4	Case 4	Case 4
μ (%) expected wind	5.86	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	26333.08	29446.28	27339.14	27339.54	26876.59	26807.07
Schedu. win. gen. (MWh)	1998.69	12646.21	5521.57	5521.57	4523.99	4526.38
Schedu. dispat. gen. (MWh)	24334.40	16800.07	21817.57	21817.97	22352.60	22280.69
Equilibrium price (€/MWh)	55.06	32.17	49.05	49.05	51.25	51.62
Reserve requirement (MW)	786.49	2232.93	1264.59	1264.59	3161.44	3161.44
Up. reserve commit. (MW)	761.70	2272.87	1258.66	1263.13	2873.45	2875.64
Down. reser. commit. (MW)	475.64	1659.60	892.77	893.77	1361.53	1363.46
Up ramp cap. commit. (MW)	860.90	3051.42	1648.69	1644.23	33.90	31.71
Down ramp cap. com. (MW)	471.54	4527.08	1504.94	1503.86	1036.09	1034.16
Max. available reserve (MW)	2279.14	6462.20	3484.91	3420.29	2948.43	2965.47
INCOMES (€/h):						
Energy sales in day ahead	144992.63	947319.58	1341068.32	1340985.10	1377492.22	1383654.11
Premium to schedu. wind	59960.66	379386.26	0.00	165647.08	0.00	362110.67
Supply of up. reser. capa.	7431.01	994.39	6657.71	6527.39	16701.04	15453.47
Supply of down. reser. capa.	0.00	951.90	18.69	24.90	13.29	13.00
Supply of up. ramp capa.	8261.97	866.05	7768.17	7290.36	214.53	213.65
Supply of down ramp capa.	0.00	3784.44	51.10	53.15	42.53	44.04
COSTS (€/h):						
Cost of dispatch. gen.	699520.12	409723.63	596089.03	595542.44	617095.45	614216.90
$\lambda_f \cdot CVaR[Q]$	1158804.17	3412846.60	3437674.30	0.00	786478.05	2256417.00
$(1 - \lambda_f) \cdot E[Q]$	833849.31	824099.16	573395.64	1639701.51	313075.22	897334.05
PROFIT (€/h):						
Total (wind + dispatch.)	708259.30	486963.61	644852.57	691017.57	755626.82	722846.51
1st stage wind turbines	106267.21	400125.39	253184.66	253216.17	217397.40	219798.96
2nd stage wind turbines	-23349.23	-25036.74	-74806.89	-28052.58	0.00	-40541.98
1st stage dispatch. gen.	659898.29	144067.33	506293.93	506122.30	559970.75	565362.41
2nd stage dispatch. gen.	-34556.97	-32192.37	-39819.14	-40268.31	-21741.33	-21772.88

4.6.7 Fixed Demand in Multi-period Setting

Here we discuss the results for the multi-period single firm problem posed as a two stage stochastic problem for cost minimization with fixed demand and a price cap (see Section 3.5) (welfare maximization with fixed demand is cost minimization). The price cap is fixed by the generation cost of the backup generator. Its impact is discussed in what follows, through the results from simulations with four representative values, 100 (Table 4.27), 300 (Table 4.28), 1000 (Table 4.29) and 563.78718 €/MWh (Table 4.30). In principle each variant could lead to a different generation park composition after the dismantling process, but the results from the simulations show that only two different generation park configurations, B9.4 and B9.5, result from the dismantling process. We get the composition B9.5 for a price cap of 1000 or 563.7 €/MWh, and the composition B9.6 for a price cap of 100 or 300 €/MWh. Additional data of energy price in day ahead and profitability of dispatchable units during the dismantling process for the previous test studies are given in the Appendices, Tables A.5 to A.12. Also the analogous set of results for the test studies without ramping products is included in the Appendices, Tables A.15 to A.26.

The conclusions are the same to those in the previous section (please see Section 4.6.6), and therefore are not repeated here.

Table 4.27: (B9.5, 100, rp) Results of Cases 1 to 4 for a composition of the generation park B9.5, a price cap of 100€/MWh, and ramping products. All the values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	5.86	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1998.69	5514.65	5521.57	5509.45	4458.87	4462.33
Schedu. dispatch. gen. (MWh)	26754.63	23238.67	23231.75	23243.87	24294.45	24290.99
Equilibrium price (€/MWh)	82.89	74.20	74.19	72.33	77.30	78.28
Reserve requirement (MW)	834.90	1291.97	1292.87	1291.30	3161.21	3163.22
Up. reserve commit. (MW)	753.22	1198.28	1188.17	1193.42	2877.31	2907.35
Down. reser. commit. (MW)	314.51	1445.27	596.30	517.31	1150.92	1177.97
Up ramp cap. commit. (MW)	869.38	3215.91	1709.07	1713.93	30.04	0.00
Down ramp cap. com. (MW)	632.67	4741.41	1801.32	1880.31	1246.70	1219.65
Max. available reserve (MW)	1252.93	2304.28	2315.46	2234.94	2058.25	2061.71
INCOMES (€/h):						
Energy sales in day ahead	2383475.68	879266.61	2133422.09	2133268.18	2222674.59	2250791.68
Premium to schedu. Wind	59960.66	365184.84	0.00	441725.54	0.00	356986.10
Supply of up. reser. capa.	43.39	591.73	4620.63	2805.95	42164.22	4368.39
Supply of down. reser. capa.	0.00	886.65	10.27	10.28	8.58	19.95
Supply of up. ramp capa.	128.36	888.31	2869.80	4649.66	44089.55	25.93
Supply of down ramp capa.	0.00	5095.56	62.22	63.20	27.74	44.57
COSTS (€/h):						
Cost of dispatch. gen.	884633.79	407930.88	674779.28	674160.33	736010.08	735768.04
$\lambda_f \cdot CVaR[Q]$	1687697.68	3089361.93	1808214.71	4047041.97	1199978.78	2621648.51
$(1 - \lambda_f) \cdot E[Q]$	1256662.76	718487.59	845944.32	1932036.33	449650.10	1006892.59
PROFIT (€/h):						
Total (wind + dispatch.)	1411745.39	428903.00	1407459.61	1332467.76	1459853.23	1449533.46
1st stage wind turbines	151700.51	366321.28	342351.18	342883.98	336951.80	295670.15
2nd stage wind turbines	-23349.23	-21582.25	0.00	-74806.89	-24287.72	-38455.36
1st stage dispatch. gen.	1347313.13	112476.70	1123854.56	1123752.97	1200191.87	1223786.40
2nd stage dispatch. gen.	-63919.02	-28312.72	-58746.13	-59362.30	-35788.27	-31467.74

Table 4.28: (B9.5, 300, rp) Results of Cases 1 to 4 for a composition of the generation park B9.5, a price cap of 300€/MWh, and ramping products. All the values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	5.86	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1998.69	5521.37	5521.57	4791.22	4459.77	4462.33
Schedu. dispatch. gen. (MWh)	26754.63	23231.95	23231.75	23962.10	24293.55	24290.99
Equilibrium price (€/MWh)	221.84	186.64	186.64	178.21	198.68	199.66
Reserve requirement (MW)	834.90	1292.84	1292.87	1292.87	3161.73	3163.22
Up. reserve commit. (MW)	758.66	1184.99	1176.04	1187.68	2907.35	2907.35
Down. reser. commit. (MW)	318.20	1489.69	567.37	538.75	1166.39	1177.97
Up ramp cap. commit. (MW)	863.94	3196.20	1722.36	1719.67	0.00	0.00
Down ramp cap. com. (MW)	628.99	4696.99	1830.25	1858.87	1231.23	1219.65
Max. available reserve (MW)	1252.93	2310.99	2315.46	2247.06	2054.28	2061.71
INCOMES (€/h):						
Energy sales in day ahead	6378498.39	879266.61	5366625.51	5124263.07	5712779.71	5740896.81
Premium to schedu. Wind	59960.66	365184.84	0.00	165647.08	0.00	356986.10
Supply of up. reser. capa.	488.53	590.08	20516.48	9298.51	19066.41	19258.23
Supply of down. reser. capa.	0.00	895.17	13.32	0.00	3.00	19.95
Supply of up. ramp capa.	29.65	889.96	9850.61	9789.01	0.00	0.00
Supply of down ramp capa.	0.00	5087.04	59.18	89.18	61.52	44.57
COSTS (€/h):						
Cost of dispatch. gen.	1162774.94	407930.88	726662.96	725628.56	853931.18	853519.43
$\lambda_f \cdot CVaR[Q]$	3601323.04	3089361.93	4019076.63	0.00	2776881.46	4200180.40
$(1 - \lambda_f) \cdot E[Q]$	2785893.13	718487.59	1868074.05	3806642.87	993092.22	1552778.52
PROFIT (€/h):						
Total (wind + dispatch.)	5022776.83	428903.00	4540674.77	4259201.09	4809014.73	4798868.29
1st stage wind turbines	379770.29	366321.28	748195.86	705933.54	656664.08	661790.21
2nd stage wind turbines	-23349.23	-21582.25	0.00	-28052.58	0.00	-38455.36
1st stage dispatch. gen.	4836471.34	112476.70	3922206.28	3711877.67	4221315.38	4244909.92
2nd stage dispatch. gen.	-170115.57	-28312.72	-129727.36	-130557.54	-68964.74	-69376.48

Table 4.29: (B9.4, 1000, rp) Results of Cases 1 to 4 for a composition of the generation park B9.4, a price cap of 1000€/MWh, and ramping products. All the values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 4	Case 4	Case 4
μ (%) expected wind	5.86	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1998.69	5521.37	5506.17	5507.02	4458.87	4459.77
Schedu. dispatch. gen. (MWh)	26754.63	23231.95	23247.15	23246.30	24294.45	24293.55
Equilibrium price (€/MWh)	96.29	43.37	43.37	43.26	44.03	45.01
Reserve requirement (MW)	834.90	1292.84	1290.87	1290.98	3161.21	3161.73
Up. reserve commit. (MW)	790.08	1197.28	1207.18	1186.28	2877.31	2907.35
Down. reser. commit. (MW)	378.94	532.99	526.39	485.41	1156.74	1187.76
Up ramp cap. commit. (MW)	832.52	1710.07	1700.17	1721.07	30.04	0.00
Down ramp cap. com. (MW)	568.24	1864.63	1871.23	1912.21	1240.88	1209.87
Max. available reserve (MW)	3807.82	5088.00	5072.20	4868.15	4739.20	4740.10
INCOMES (€/h):						
Energy sales in day ahead	2768761.26	1247164.53	1247010.62	1243890.07	1265932.07	1294049.17
Premium to schedu. Wind	59960.66	0.00	440493.79	165210.49	0.00	356781.64
Supply of up. reser. capa.	34084.53	297.49	356.39	296.14	325.33	270.97
Supply of down. reser. capa.	0.00	0.00	0.02	0.00	12.52	3.48
Supply of up. ramp capa.	22998.20	906.34	741.84	120.50	25.93	0.00
Supply of down ramp capa.	0.00	72.39	73.36	89.74	52.00	61.04
COSTS (€/h):						
Cost of dispatch. gen.	808375.05	659799.41	660382.17	659676.81	703708.90	703596.50
$\lambda_f \cdot CVaR[Q]$	1266793.21	1209557.28	3425023.32	0.00	767466.93	2185772.05
$(1 - \lambda_f) \cdot E[Q]$	866883.60	576489.73	1627539.92	1621041.10	300323.04	852911.92
PROFIT (€/h):						
Total (wind + dispatch.)	1957268.70	425771.16	474776.45	517176.27	541783.17	531558.16
1st stage wind turbines	152402.60	366602.07	231105.46	230218.96	190627.66	195190.54
2nd stage wind turbines	-23349.23	-21718.53	-73575.14	-27616.00	0.00	-38250.90
1st stage dispatch. gen.	1865066.34	109351.45	356694.59	354500.68	372011.28	395597.62
2nd stage dispatch. gen.	-36851.02	-28463.83	-39448.46	-39927.38	-20855.77	-20979.09

Table 4.30: (B9.4, O, rp) Results of Cases 1 to 4 for a composition of the generation park B9.4, a “optimal” price cap of 563.7€/MWh, and ramping products. All the values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2	Case 3	Case 3	Case 4	Case 4
μ (%) expected wind	5.86	22.20	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	0.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	0.40	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1998.69	5521.37	5506.17	5507.02	4458.87	4459.77
Schedu. dispatch. gen. (MWh)	26754.63	23231.95	23247.15	23246.30	24294.45	24293.55
Equilibrium price (€/MWh)	72.77	43.37	43.37	43.26	44.03	45.01
Reserve requirement (MW)	834.90	1292.84	1290.87	1290.98	3161.21	3161.73
Up. reserve commit. (MW)	802.34	1207.41	1207.18	1186.28	2877.31	2907.35
Down. reser. commit. (MW)	336.04	534.61	526.39	485.41	1153.06	1187.76
Up ramp cap. commit. (MW)	820.26	1699.94	1700.17	1721.07	30.04	0.00
Down ramp cap. com. (MW)	611.14	1863.01	1871.23	1912.21	1244.56	1209.87
Max. available reserve (MW)	3807.82	5088.00	5072.20	4868.15	4739.20	4740.10
INCOMES (€/h):						
Energy sales in day ahead	2092370.72	1247164.53	1247010.62	1243890.07	1265932.07	1294049.17
Premium to schedu. Wind	59960.66	0.00	440493.79	165210.49	0.00	356781.64
Supply of up. reser. capa.	18541.95	70.91	356.39	296.14	325.33	270.97
Supply of down. reser. capa.	0.00	0.00	0.02	0.00	3.00	3.48
Supply of up. ramp capa.	12505.14	1160.13	741.84	120.50	25.93	0.00
Supply of down ramp capa.	0.00	72.39	73.36	89.74	61.52	61.04
COSTS (€/h):						
Cost of dispatch. gen.	808375.05	659826.62	660382.17	659676.81	703708.90	703596.50
$\lambda_f \cdot CVaR[Q]$	1219425.03	1209296.05	3425023.32	0.00	767466.93	2185772.05
$(1 - \lambda_f) \cdot E[Q]$	853438.38	576097.89	1627539.92	1621041.10	300323.04	852911.92
PROFIT (€/h):						
Total (wind + dispatch.)	1255776.21	425789.38	474776.45	517176.27	541783.17	531558.16
1st stage wind turbines	123520.51	366602.07	231105.46	230218.96	190627.66	195190.54
2nd stage wind turbines	-23349.23	-21718.53	-73575.14	-27616.00	0.00	-38250.90
1st stage dispatch. gen.	1191522.26	109369.67	356694.59	354500.68	372011.28	395597.62
2nd stage dispatch. gen.	-35917.33	-28463.83	-39448.46	-39927.38	-20855.77	-20979.09

4.6.8 Comparison among Cases in Multi-Period

In this section we compare the results for the previous ten configurations. The results for energy prices and profits for the different cases are rearranged together in Tables 4.31 and 4.32, to facilitate the comparison among configurations. We compare in the multi-period setting results with price responsive demand vs fixed demand, and results with ramping products vs results without ramping products.

The ramping products and the pure reserve criterion used in single period models and transposed here pursue different but overlapping goals. The pure reserve criterion is meant to account for forecasting error. It imposes an amount of reserve that depends on the time span between the commitment of the reserves and real time. It also directly interacts with the scheduling of wind and conventional generation, hence the requirement for reserve that it imposes is dynamic. The ramping products require reserves dedicated to ramping. They introduce a global constraint that reserve must accommodate the largest possible gradient of wind generation over a certain period; this criterion is not dynamic. The two criteria clearly overlap but it is impossible to ascertain how. We here assume that the ramping criterion dominates and that it can be satisfied by the reserve aimed at dealing with forecast uncertainty and some add up. By construction the ramping products therefore impose the total amount of reserve and ramping reserve in each period in the model. Given our assumption of dominance of the ramping criterion, the constraint is here imposed as the sum of the pure reserve requirement and a complement intended for satisfying an exogenously given ramping constraint. In contrast the no ramping product model leaves it to the model to endogenously determine the reserve.

We now compare the impact of inserting the ramping product in the price sensitive model. The comparison of the total reserve in the different cases shows that the insertion of the ramping products leads to over commitment of reserve in Case 1 with low wind and in Cases 2 and 3 compared to the no ramping product model. The opposite is true in Case 1 with high wind and in Case 4. Except for Case 1 the difference of behaviour is due to the coverage factor of wind that is higher in Case 4 and hence induces a high demand for reserve. This demand is constrained by the ramping product requirement in that case. This has in turn an impact on the wind that can be scheduled leading to an increase of the electricity price. Assuming a $m_y = 0.6$ coverage of wind for reason of forecasting difficulty, and at the same time that the global requirement based on ramping is correct, the end result is a decrease of wind generation and an increase of the price of electricity.

In contrast with this under-commitment (compared to the no ramping product model) in Case 4, the ramping product model leads to an over-commitment of reserve in Cases 2 and 3. This now implies an increase of the price of electricity because of the reduction of conventional capacity dedicated to the energy market that it implies. Whether by inducing an over or under commitment of reserve, the introduction of ramping products increases the price of electricity compared to the pure reserve case. The question of the selection of proper criterion for modeling reserve demand is thus important. Consider now the case of the fixed demand model with high price cap. The observed phenomena and their analysis are identical but price differences between the no ramping and ramping producers are much smaller. Recall that a high price cap leads to less dismantling, which increases the capacity available for reserve. The impact of over or under committing reserve is thus of less importance. The case of the fixed demand with smaller price cap lead to similar phenomena albeit in a more ambiguous way. It has been explained before that the lower price cap already lead to curtailment in day ahead. Reserve is thus by nature less abundant with the result that the notion

of over-committing reserve in Cases 2 and 3.

These results signal that an alternative formulation where both the ramping and forecasting error criteria should probably be considered. The modeling could also introduce a way wind should pay for ramping (wind here pays for error forecast but not for ramping). This would justify a full investigation of those ramping products and is left for further research.

Table 4.31: Comparison of the value of energy price in day ahead and the total profit in the configuration B9 (Table 4.9) for the models of multi-period, single firm in the cases of price responsive (Section 3.4) and fixed demand (Section 3.5), with ramping products (RP) and without ramping products (NRP). In the case of fixed demand, a price cap is considered with the values 100, 300, 1000 and 563.79699 €/MWh.

	Case 1 $m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			Case 2			Case 3			Case 4 $m_y = 0.60$, $m_x = 0.02$		
	μ (%)	expected wind	ρ^+ (€/MWh) premium	λ risk aversion	5.86	61.17	22.20	22.20	22.20	22.20	22.20	22.20
					30.00	30.00	0.00	80.00	30.00	0.00	80.00	0.40
					0.40	0.40	0.40	0.40	1.00	0.40	0.40	0.40
Energy demand in day ahead (MWh)												
RP, Fixed demand		28753.32	28753.32		28753.32	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
RP, Price responsive		26333.08	29446.28		27339.14	27339.14	27339.14	27339.14	27237.49	26876.59	26807.07	
NRP, Price responsive		28581.12	27186.14		28547.42	28734.82	28743.37	28405.27		28565.36	28595.03	
Energy price in day ahead (€/MWh)												
RP, Price responsive		55.06	32.17		49.05	49.05	49.05	49.56	49.56	51.25	51.62	
NRP, Price responsive		44.29	39.71		43.24	42.33	42.28	43.93	43.93	43.18	43.04	
RP, Fixed demand, 100		82.89	30.58		74.20	74.19	72.33	77.39	77.39	77.30	78.28	
NRP, Fixed demand, 100		82.39	41.67		75.16	74.24	73.12	77.60	77.60	71.48	71.42	
RP, Fixed demand, 300		221.84	30.58		186.64	186.64	178.21	199.67	199.67	198.68	199.66	
NRP, Fixed demand, 300		221.37	41.67		191.55	190.63	185.58	199.88	199.88	174.52	174.46	
RP, Fixed demand, 1000		96.29	30.47		43.37	43.37	43.26	43.87	43.87	44.03	45.01	
NRP, Fixed demand, 1000		95.79	41.67		43.26	42.33	42.29	44.08	44.08	43.20	43.09	
RP, Fixed demand, 563.79		72.77	30.47		43.37	43.37	43.26	43.87	43.87	44.03	45.01	
NRP, Fixed demand, 563.79		72.26	41.67		43.26	42.33	42.29	44.08	44.08	43.20	43.09	
Total profit (€/MWh) (wind + dispatchable)												
RP, Price responsive		708259.30	486963.61		719659.46	644852.57	691017.57	680514.30	755626.82	722846.51		
NRP, Price responsive		411114.74	649936.90		505850.31	467991.23	473912.82	512640.60	567475.59	322086.03		
RP, Fixed demand, 100		1411745.39	428903.00		1407459.61	1332467.76	1322671.41	1479115.92	1459853.23	1449533.46		
NRP, Fixed demand, 100		1394729.79	708383.30		1374680.26	1336452.28	1311536.60	1442325.07	1406788.69	1162873.29		
RP, Fixed demand, 300		5022776.83	428903.00		4540674.77	4465498.23	4259201.09	4917778.29	4809014.73	4798868.29		
NRP, Fixed demand, 300		4983332.90	708383.30		4542903.55	4504675.57	4366445.97	4782927.07	4466185.94	4220620.50		
RP, Fixed demand, 1000		1957268.70	425771.16		548607.33	474776.45	517176.27	454504.24	541783.17	531558.16		
NRP, Fixed demand, 1000		1921422.14	708383.30		506200.57	467972.59	474063.66	514906.06	567382.26	309971.63		
RP, Fixed demand, 563.79		1255776.21	425789.38		548634.54	474776.45	517176.27	487062.50	541783.17	531558.16		
NRP, Fixed demand, 563.79		1231463.68	708383.30		506200.57	467972.59	474063.66	510914.53	567387.45	311602.00		

Table 4.32: Comparison of the value of profit for wind turbines and for dispatchable units in the configuration B9 (Table 4.9) for the models of multi-period, single firm in the cases of price responsive (Section 3.4) and fixed demand (Section 3.5), with ramping products (RP) and without ramping products (NRP). In the case of fixed demand, a price cap is considered with the values 100, 300, 1000 and 563.79699 €/MWh.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1			Case 3		
	5.86	61.17	22.20	22.20	22.20	22.20
μ (%) expected wind						
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	30.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Energy demand in day ahead (MWh)						
RP, Fixed demand	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
RP, Price responsive	26333.08	29446.28	27339.14	27339.54	27237.49	26807.07
NRP, Price responsive	28581.12	27186.14	28547.42	28743.37	28405.27	28595.03
Profit of dispatchable units (€/h)						
RP, Price responsive	625341.32	111874.96	466474.79	465853.99	481048.75	538229.42
NRP, Price responsive	366392.07	282837.33	346558.63	322680.36	363791.15	241063.58
RP, Fixed demand, 100	1283394.11	84163.98	1065108.43	1018007.20	1166451.84	1168966.16
NRP, Fixed demand, 100	1312364.54	315069.07	1135494.88	1112631.37	1200691.44	911020.20
RP, Fixed demand, 300	4666355.76	84163.98	3792478.91	3792155.40	4194790.62	4152350.65
NRP, Fixed demand, 300	4764054.90	315069.07	4013345.59	3990482.08	3863119.27	3364544.63
RP, Fixed demand, 1000	1828215.32	80887.62	316762.18	317246.13	314573.30	351155.51
NRP, Fixed demand, 1000	1838577.12	315069.07	346613.09	323749.58	322791.99	233760.49
RP, Fixed demand, 563.79	1155604.93	80905.84	316789.39	317246.13	314573.30	351155.51
NRP, Fixed demand, 563.79	1165981.86	315069.07	346613.09	323749.58	322791.99	233919.25
Profit of wind turbines (€/h)						
RP, Price responsive	82917.98	375088.65	253184.66	178377.78	225163.58	217397.40
NRP, Price responsive	44722.67	367099.57	159291.68	144212.81	151232.46	326412.00
RP, Fixed demand, 100	128351.28	344739.02	342351.18	268077.10	304664.21	290887.07
NRP, Fixed demand, 100	82365.24	393314.23	239185.38	223820.91	227015.74	495768.49
RP, Fixed demand, 300	356421.06	344739.02	748195.86	673342.82	677880.96	656664.08
NRP, Fixed demand, 300	219278.00	393314.23	529557.96	514193.49	503326.70	1101641.32
RP, Fixed demand, 1000	129053.38	344883.54	231845.15	157530.32	202602.96	185795.13
NRP, Fixed demand, 1000	82845.01	393314.23	159587.48	144223.01	151271.67	333621.77
RP, Fixed demand, 563.79	100171.28	344883.54	231845.15	157530.32	202602.96	185795.13
NRP, Fixed demand, 563.79	65481.82	393314.23	159587.48	144223.01	151271.67	333468.20

Chapter 5

Conclusion

Renewable energy generation is seen as the best way to curb climate change, and intermittent/variable sources like wind and solar are considered to be those with the highest potential. But the subject remains full of controversies. One of them originates in the use of the leveled cost to measure the competitiveness of these sources: on shore wind should be almost competitive according to that metric. Renowned authors have argued that this is not a good metric because intermittent sources lack the dispatchability properties of conventional plants. This thesis takes up some of the questions related to dispatchability in a setting inspired by the organization of the restructured European electricity market. Many questions arise but we can address only a subset of them here.

In contrast with models designed for the US market that can be cast as full optimization, we must account for the separation of the PX and the TSO that is one of the basic rules of the European market design. This does not mean that one needs to avoid resorting to optimization, but that optimization models should only be considered as intermediate to equilibrium models that represent the interplay between the PX and the TSO. Our reference model is then a multi-firm equilibrium model of which we consider single firm models as a particular case.

While one can discuss whether wind remains an intermittent source or has become a variable source as a result of aggregation of generation on different sites, it remains today a highly variable source affected by a lot of uncertainty. The models should thus account for that characteristics. The equilibrium models should thus be stochastic equilibrium models.

One can sort out the different questions arising with wind penetration along two themes:

- a) Some are due to the physics of the phenomena: Wind may require more reserve for frequency control and certainly more ramping resources.
- b) The other concern originates in the market design and in the many distortions to the planned market mechanisms introduced by stakeholders in that design. These have to do with the remuneration of conventional and wind generation as well with the remuneration and charging for services.

We thus propose a general stochastic equilibrium model that accounts for the separation between the PX and the TSO, allows for multiple firms and the remuneration and charging of services in the presence of high penetration of renewable energy resources. We justify resorting to an equilibrium instead of an optimization approach, even without market power, because of two main reasons. A first reason is that the market is now composed of different firms that trade energy and services; the equilibrium formulation is most natural for this

situation. The second, possibly more compelling reason, is that renewable energy policies are implemented through different market instruments that cannot necessarily be casted in an optimization form. The proposed model is inspired by the Spanish situation but the approach is general. We try to show that the approach can embed general features of market design (a two settlement system), market idiosyncrasies (a somewhat detailed representation of the balancing market) and general economic characteristics of agents like risk aversion. Like stochastic programming, equilibrium models are amenable to a treatment of uncertainty.

The complex problem of renewable energy penetration can only be taken through small steps. We thus illustrate the use of the model on two questions, both motivated by the current European phenomena, that sees how conventional plants necessary for providing services are driven out of the market because of low energy prices. We illustrate the use of the model by focusing on a timely European question, namely the revenue accruing to conventional plants. The common wisdom (and the observation of the market) is that renewable energy induces a decrease of energy prices together with a reduction of the activity and the profit of the conventional units, that puts in question their sustainability in the market. We use the models to illustrate that this phenomenon indeed seems rather stable under different structural assumptions (same orders of magnitude in the loss of revenue for quite different assumptions of wind premium and risk aversion). But we also show that the phenomenon may also crucially depend on the demand for ancillary services (here frequency maintenance) induced by renewable resources integration, and on the pricing of these services by the market design. Both subjects are contentious: The incremental demand of reserve due to renewable resources integration is not well understood [34, 44, 45, 60, 61, 81–83] and the pricing of ancillary services is as diverse as the number of power systems in Europe. We model the demand for reserve through a coefficient and adopt an elementary but sound economic principle for pricing both reserve capacity and energy. We find that a higher demand for load following reserve and an economically sound pricing (marginal cost pricing) restore the revenue of the conventional plants. The question of the sustainability of conventional plants then boils down to the proper identification of the demand for services (taking into account their provision by wind units themselves) and the acceptance that they be properly remunerated.

5.1 Contributions and Reached Objectives

We think that several relevant questions have been discussed and answered, but many other related issues are still waiting; some of them are included in the future lines listed in the next section. The main contributions in this Thesis, which were already announced in general terms in the Introduction (Section 1.2), are summarized here in more concrete terms:

- 1) Formulation of a general stochastic equilibrium model posed as a complementarity problem that accounts for the separation between the PX and the TSO, allows for multiple firms and the testing of different remuneration and charging of services due to high wind. The advantage of the complementarity formulation with respect to the optimization approach is that it allows to model some characteristic of the real markets (like two different prices for the same product) that cannot be modeled using a pure optimization approach.
- 2) Optimal operation with risk management of dispatchable generators and wind turbines in a single firm setting, for a number of structural assumptions that include: Wind forecast, value of the feed-in premium to wind, level of risk aversion, demand requirement of flexibility reserve due to wind generation, ramping capability, ramping products, to-

tal available dispatchable capacity, model for demand (fixed demand or price responsive demand), and value of the price cap to energy in day ahead.

- 3) Influence of the structural assumptions (listed in the previous item) on the profitability of dispatchable units and the corresponding dismantling process, and how it affects the total dispatchable capacity and the energy price. We have found that in the case of fixed demand the more relevant parameter is the value of the price cap to energy in day ahead. Values of the price cap greater than a certain threshold leads to energy price lower than the price in the system with price cap less than that threshold.

The previous contributions and others are explained in detail in the previous chapters, most of the results are concentrated on Chapter 4. The data on the Appendices give additional details for the discussions.

5.2 Future Work

During the development of this Thesis many issues around the initial questions have been raised, some of them are important from the technical point of view, to complete the information on the results, and others have some interest by their application to real systems. We have already addressed some of these issues but many other interesting questions remain only partially treated because of the limited amount of time available. In particular we plan to continue the work to study the following issues:

- 1) Consider situations with several firms and study compositions of the generation park with different ownership of wind turbines and dispatchable generators. For instance one firm with only dispatchable generators and other firm with only wind turbines, and other compositions with different rate between the total dispatchable capacity and the non-dispatchable capacity installed.
- 2) Include a more detailed model of the TSO that goes beyond the sole minimization of generation cost from reserves, in the complementarity formulation for the multi-firm setting. In particular considering additional details of the technical system, like the network constraints, for instance using a direct current linearized approach or an approach base in Power Transfer Distribution Factors (PTDF).
- 3) Study other pricing schemes for reserve (energy and capacity) taking into account different market imperfections, like for instance a myopic valuation of the reserve cost, or distortions in the risk perception.
- 4) Study different balancing schemes, like the particular implementations in different countries with high penetration of non-dispatchable generation around the world, like Germany, Denmark, or some States in the USA.
- 5) Include a more detailed model for the reserve and the ramping constraints, taking into account technical details that are relevant in the technical operation, in particular those related with the start-up and shutdown of the units (time and cost associated with these operations), that usually require the inclusion of binary variables in the problem. Study the options of including binary variables or approximate formulations that do not use binary variables.
- 6) Analyze the effect of a price cap in the models with price responsive demand.

- 7) Include an intra-day market in the models in a similar setting as it has been implemented in some real markets like the Spanish system.
- 8) Extend the models to the long term and use them to study the influence of the incentives to renewables and the cost of CO₂ emissions in the investment (or dismantling) in the different technologies.
- 9) Study in detail the multiple equilibrium, which are the causes and the economic interpretation in terms of the market operation. The idea is to begin with the Lemke's algorithm applied to a linearized version of the complementarity problem and to study the application of the results to the original problem.
- 10) A formal characterization of the solving strategy proposed for the complementarity problem. In particular a characterization of the convergence of the sequence of linear complementarity problems and if we are missing some solutions. For the results reported from the simulations we have checked that the solution found is, in fact, a solution of the initial problem, but we do not have a formal proof.
- 11) Consider agents with different competitive behaviour (price makers, price takers). Here we have reported results for a single firm setting where the firm is a price taker in both the day ahead and the balancing market. It would be interesting to study a number of combinations, like different behaviour of the agents in each settlement (day ahead, balancing), and also in the multi-firm setting, a different behaviour for each firm. The issue of the same agent with different behaviour in day ahead and balancing has been addressed by other authors, like for instance in [84], where they study a wind firm that is a price taker in day ahead but a price maker in the balancing market, they use a framework with significant differences respect to that proposed here, in particular in the modeling of reserve and balancing.

The work in some of the previous topics has already been started, but it is not advanced enough to be included here at the time to present this document.

Appendices

Appendix A

Additional Data

A.1 Single Period, Data for the Dismantling Process of Configurations B9.6 and B9.7 in Case Study 1

In this section are included additional data on the dismantling process that leads to the configurations B9.6 and B9.7 used in the simulations discussed in Case Study 1 (Section 4.5). The dismantling process is described in detail in Section 4.3, to summarize we recall that it consists of a sequential process starting with the total dispatchable capacity that at each stage removes the non-profitable dispatchable unit with the higher generation cost. If a dispatchable unit is profitable or not is determined on the basis of the difference between its profit (incomes minus operation cost) and its fixed operation and maintenance cost (FOM). If the firm's FOM is higher than its profit then the dispatchable unit is considered non-profitable.

The model used in the dismantling process, that is the same model used in the simulations, is described in Section 2.5, it is a single firm, single period model with price responsive demand posed as a complementarity problem.

Table A.1: (B9.6, 1) price of energy in day ahead. Low ramping, $\Lambda = 1$.

Mothballing round	Wind				Total Capacity MW
	61.17%	47.09%	22.20%	5.86 %	
	€/MWh	€/MWh	€/MWh	€/MWh	
1	40.965	43.748	44.461	45.174	43597.488
2	43.598	44.030	44.461	45.174	40686.678
3	43.598	44.030	44.461	45.174	39136.628
4	43.598	44.030	44.461	45.174	37552.188
5	43.598	44.030	44.461	45.174	33688.848
6	43.598	44.030	44.461	54.199	28100.603
7	40.987	44.030	57.239	69.991	25356.288

For the dismantling process in the configuration with low ramping ($\Lambda = 1$), the hourly average energy prices for each wind pattern¹ at each dismantling stage are listed in Table A.1. The total dispatchable capacity is reduced at each dismantling stage and seven stages are needed to reach the final state in which all the active units are profitable. The margin

¹We are using four wind patterns to model the wind patterns in a whole year, see Section 4.4.

profit for all the dispatchable generators at each dismantling stage is listed in Table A.2. We observe in Table A.1 that energy prices rise when the total dispatchable generation capacity is reduced, this effect is more significant in the configurations with the lowest total generation capacity, hence for the wind patterns with the lowest wind forecast, $\mu = 5.86\%$ and $\mu = 22.20\%$, as it is illustrated on the table.

Table A.2: (B9.6, 1), Value of the margin (€/MWh) profit minus fixed operation and maintenance cost, in the progressive dismantling process. Low ramping, $\Lambda = 1$.

g	Dismantling iteration						
	1	2	3	4	5	6	7
1	-8340.2	0.0	0.0	0.0	0.0	0.0	0.0
2	-3733.7	-3473.2	0.0	0.0	0.0	0.0	0.0
3	-3772.5	-3511.0	-3171.2	0.0	0.0	0.0	0.0
4	-11005.8	-10746.2	-10404.7	-9191.8	0.0	0.0	0.0
5	-16295.1	-16036.2	-15692.7	-14474.0	-12937.0	0.0	0.0
6	-7139.9	-7037.5	-6749.0	-7077.8	-6696.3	-3121.6	0.0
7	-8561.3	-8504.1	-8266.8	-8634.7	-8200.2	-4209.0	6672.9
8	-4426.4	-4483.4	-4211.2	-4610.3	-4280.4	-2825.1	1408.6
9	-5058.7	-4980.6	-4957.6	-4924.1	-4855.0	-3552.9	1048.0
10	32457.5	33303.6	33303.6	33303.6	33303.6	34219.2	36620.6
11	134432.6	137803.9	137803.9	137803.9	137803.9	141452.2	151020.6
12	3776.0	4909.8	4909.8	4909.8	4909.8	6136.9	9355.0
13	5088.7	7939.6	7939.6	7939.6	7939.6	11024.9	19116.6
14	23618.2	24285.5	24285.5	24285.5	24285.5	25007.6	26901.4
15	37597.1	38680.6	38680.6	38680.6	38680.6	39853.1	42928.4
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6	25356.3

Table A.3: (B9.7, 0), price of energy in day ahead. High ramping, $\Lambda = 0$.

Mothballing round	Wind				Total Capacity MW
	61.17% €/MWh	47.09 % €/MWh	22.20% €/MWh	5.86 % €/MWh	
1	43.448	43.88	44.621	45.174	43597.488
2	43.448	43.880	44.559	45.174	40686.678
3	43.448	43.880	44.560	45.174	39136.628
4	43.448	43.880	44.621	45.174	37552.188
5	43.448	43.880	44.743	45.174	33688.848
6	43.448	43.880	44.562	51.336	28100.603
7	43.448	43.880	51.473	66.741	25356.288
8	43.880	51.306	69.856	85.124	22081.311

For the configuration with high ramping ($\Lambda = 0$) the necessary dismantling is even deeper than in the case of low ramping, because to get the ramping constraints tight contributes to increase the energy prices, and it is more difficult to get them tight when the ramping capability is higher. In this case eight dismantling stages are needed, as it is shown in Table A.4 and, as it was in the previous case, the effect of dismantling capacity on the energy price is stronger in the cases with the lowest wind forecast ($\mu = 5.86\%$ and $\mu = 22.20\%$).

Table A.4: (B9.7, 0), value of the margin (€/MWh) profit minus fixed operation and maintenance cost, in the progressive dismantling process. High ramping, $\Lambda = 0$.

g	Dismantling iteration							
	1	2	3	4	5	6	7	8
1	-9243.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	-4179.6	-2964.6	0.0	0.0	0.0	0.0	0.0	0.0
3	-3938.3	-1356.0	-3201.9	0.0	0.0	0.0	0.0	0.0
4	-10668.9	-5580.7	-10426.2	-10229.8	0.0	0.0	0.0	0.0
5	-15499.1	-8606.6	-15715.4	-14175.9	-12912.1	0.0	0.0	0.0
6	-6710.7	-3326.7	-6573.0	-6420.0	-6206.4	-2396.2	0.0	0.0
7	-8069.8	-4185.0	-8065.4	-8033.7	-7750.8	-4647.2	4041.0	0.0
8	-4543.0	-1890.2	-4189.0	-4232.1	-3891.2	-2832.2	1073.7	16580.6
9	-5232.4	-2494.6	-5073.0	-5358.8	-5005.5	-4480.3	-1171.2	16732.0
10	33123.2	32633.9	33116.8	33123.2	33135.8	33742.2	36023.2	48139.5
11	137085.1	133587.0	137059.7	137085.1	137135.5	139551.7	148640.1	196917.4
12	4668.1	6579.0	4659.6	4668.1	4685.0	5497.7	8554.3	24791.2
13	7331.8	12219.8	7310.4	7331.8	7374.4	9417.8	17103.5	57930.1
14	24143.2	24328.4	24138.2	24143.2	24153.2	24631.4	26430.2	35985.6
15	38449.6	38591.1	38441.4	38449.6	38465.8	39242.3	42163.3	57679.3
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6	25356.3	22081.3

A.2 Multi-Period with Ramping Products

A.2.1 Multi-Period with Fixed Demand and Ramping Products

Progressive mothballing of multi-period with fixed demand and ramping products, problem posed as a two stage stochastic minimization cost problem for a single firm, with average premium ($\rho^+ = 30$ €/MWh), average risk aversion ($\lambda = 0.4$), $m_y = 0.15$ and $m_x = 0.02$. A price cap is introduced through generation cost of a virtual generator, “backup generator”. Results for different values of the backup generator cost are given in what follows.

Table A.5: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 100 €/MWh.

g	Dismantling iteration					
	1	2	3	4	5	6
1	-232864.8	0.0	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0	0.0
5	-424344.8	-424344.8	-424344.8	-424344.8	-379800.9	0.0
6	-192834.4	-192834.4	-192834.4	-192834.4	-170959.5	1420991.4
7	-204524.4	-204524.4	-204524.4	-204524.4	-178419.5	1721612.4
8	-107864.9	-107864.9	-107864.9	-107864.9	-91471.9	1101681.3
9	-93184.2	-93184.2	-93184.2	-93184.2	-76018.6	1173525.1
10	708709.2	708709.2	708709.2	708709.2	720819.0	1602219.3
11	2946391.8	2946391.8	2946391.8	2946391.8	2994643.0	6506569.7
12	47794.6	47794.6	47933.8	47794.6	64161.9	1245305.9
13	36344.2	36344.2	36344.2	36344.2	77148.7	3047076.0
14	518113.2	518113.2	518113.2	518113.2	527663.4	1222767.7
15	823623.5	823623.5	823623.5	823623.5	839131.2	1967843.2
16	0.0	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6

Table A.6: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 100 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.825	43.369	37.900	30.465	43597.488
2	44.825	43.369	37.900	30.465	40686.678
3	44.825	43.369	37.900	30.465	39136.628
4	44.825	43.369	37.900	30.465	37552.188
5	47.759	43.369	37.900	30.465	33688.848
6	82.894	74.192	37.985	30.580	28100.603

Table A.7: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 300 €/MWh.

g	Dismantling iteration					
	1	2	3	4	5	6
1	-232864.8	0.0	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0	0.0
5	-424344.8	-424344.8	-424344.8	-424344.8	-216018.5	0.0
6	-192834.4	-192834.4	-192834.4	-192834.4	-90528.1	7308966.5
7	-204524.4	-204524.4	-204524.4	-204524.4	-82435.2	8748131.9
8	-107864.9	-107864.9	-107864.9	-107864.9	-31196.9	5514111.3
9	-93184.2	-93184.2	-93184.2	-93184.2	-12903.0	5793896.5
10	708709.2	708709.2	708709.2	708709.2	765345.2	4861753.4
11	2946391.8	2946391.8	2946391.8	2946391.8	3172056.9	19494136.5
12	47794.6	47933.8	47933.8	47933.8	123830.6	5613342.9
13	36344.2	36344.2	36344.2	36344.2	227182.2	14030257.7
14	518113.2	518113.2	518113.2	518113.2	562778.4	3793354.8
15	823623.5	823623.5	823623.5	823623.5	896150.9	6141968.4
16	0.0	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6

Table A.8: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 300 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.825	43.369	37.900	30.465	43597.488
2	44.825	43.369	37.900	30.465	40686.678
3	44.825	43.369	37.900	30.465	39136.628
4	44.825	43.369	37.900	30.465	37552.188
5	58.544	43.369	37.900	30.465	33688.848
6	221.835	186.638	37.985	30.580	28100.603

Table A.9: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 1000 €/MWh.

g	Dismantling iteration				
	1	2	3	4	5
1	-232864.8	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0
5	-424344.8	-424344.8	-424344.8	-424344.8	357220.0
6	-192834.4	-192834.4	-192834.4	-192834.4	190981.9
7	-204524.4	-204524.4	-204524.4	-204524.4	253509.7
8	-107864.9	-107864.9	-107864.9	-107864.9	179765.8
9	-93184.2	-93184.2	-93184.2	-93184.2	208001.6
10	708709.2	708709.2	708709.2	708709.2	921186.8
11	2946391.8	2946391.8	2946391.8	2946391.8	3793005.5
12	47794.6	47933.8	47794.6	47933.8	332531.5
13	36344.2	36344.2	36344.2	36344.2	752299.1
14	518113.2	518113.2	518113.2	518113.2	685680.7
15	823623.5	823623.5	823623.5	823623.5	1095720.1
16	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8

Table A.10: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 1000 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.825	43.369	37.900	30.465	43597.488
2	44.825	43.369	37.900	30.465	40686.678
3	44.825	43.369	37.900	30.465	39136.628
4	44.825	43.369	37.900	30.465	37552.188
5	96.294	43.369	37.900	30.465	33688.848

Table A.11: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 563.78718 €/MWh.

g	Dismantling iteration				
	1	2	3	4	5
1	-232864.8	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0
5	-424344.8	-424344.8	-424344.8	-424344.8	0.0
6	-192834.4	-192834.4	-192834.4	-192834.4	15555.8
7	-204524.4	-204524.4	-204524.4	-204524.4	44161.9
8	-107864.9	-107864.9	-107864.9	-107864.9	48302.1
9	-93184.2	-93184.2	-93184.2	-93184.2	70342.4
10	708709.2	708709.2	708709.2	708709.2	824072.4
11	2946391.8	2946391.8	2946391.8	2946391.8	3406054.5
12	47794.6	47933.8	47794.6	47933.8	202529.7
13	36344.2	36344.2	36344.2	36344.2	425066.6
14	518113.2	518113.2	518113.2	518113.2	609092.8
15	823623.5	823623.5	823623.5	823623.5	971356.3
16	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8

Table A.12: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 563.78718 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.825	43.369	37.900	30.465	43597.488
2	44.825	43.369	37.900	30.465	40686.678
3	44.825	43.369	37.900	30.465	39136.628
4	44.825	43.369	37.900	30.465	37552.188
5	72.770	43.369	37.900	30.465	33688.848

A.2.2 Multi-Period with Price Responsive Demand and Ramping Products

Progressive mothballing of multi-period with price responsive demand, problem posed as a two stage stochastic programming, with average premium ($\rho^+ = 30$ €/MWh), average risk aversion ($\lambda = 0.4$), $m_y = 0.15$ and $m_x = 0.02$.

Single firm maximizing welfare, without price cap, one inverse demand function for each period in each one day (4×24 inverse demand functions). The inverse demand functions are based on:

- Demand elasticity of -0.3 .
- Reference demand from the fixed demand curve.
- Reference price from the dual variable for energy price (shadow price) in the problem with fixed demand, multi-period and initial state without mothballing.

Table A.13: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for a whole day (24 hours), in the progressive dismantling process without price cap (without backup generator).

g	Dismantling iteration					
	1	2	3	4	5	6
1	-232864.8	0.0	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0	0.0
5	-150633.0	-150633.0	-150633.0	-150633.0	-150633.0	0.0
6	1146585.6	1146585.6	1146585.6	1146585.6	1146608.7	867034.0
7	1713617.0	1713617.0	1713617.0	1713617.0	1713617.0	1780736.5
8	1233786.6	1233786.6	1221923.9	1221923.9	1233786.6	1472934.1
9	1521066.2	1521066.2	1516371.4	1521066.2	1521066.2	1783737.7
10	1114383.1	1114383.1	1114635.3	1114635.3	1114635.3	1304490.6
11	4472411.7	4473359.2	4473359.2	4473359.2	4473359.2	5229835.0
12	1700250.6	1700232.7	1700250.6	1700208.8	1700250.6	1952357.6
13	3774167.9	3774192.7	3772489.1	3774192.7	3774192.7	4413922.4
14	1077252.2	1074697.4	1077252.2	1077252.2	1077252.2	1226979.0
15	1741301.3	1741301.3	1741301.3	1741301.3	1741301.3	1980827.3
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6

A.3 Multi-Period without Ramping Products

A.3.1 Multi-Period with Fixed Demand and without Ramping Products

Progressive mothballing of multi-period with fixed demand and without ramping products, problem posed as a two stage stochastic minimization cost problem for a single firm, with average premium ($\rho^+ = 30$ €/MWh), average risk aversion ($\lambda = 0.4$), $m_y = 0.15$ and $m_x = 0.02$. A price cap is introduced through generation cost of a virtual generator, “backup generator”. Results for different values of the backup generator cost are given in what follows.

Table A.14: Price of energy in day ahead, single firm, multi-period, price responsive demand, without price cap.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44,789	43,283	38,635	32,171	43597,488
2	44,789	43,283	38,635	32,171	40686,678
3	44,789	43,283	38,635	32,171	39136,628
4	44,789	43,283	38,635	32,171	37552,188
5	44,789	43,283	38,635	32,171	33688,848
6	55,064	49,053	38,668	32,171	28100,603

Table A.15: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 100 €/MWh.

g	Dismantling iteration					
	1	2	3	4	5	6
1	-232864.8	0.0	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0	0.0
5	-424352.9	-424352.9	-424352.9	-424352.9	-379808.9	0.0
6	-192939.1	-192939.1	-192939.1	-192939.1	-171064.2	1483359.4
7	-207027.5	-207027.5	-207027.5	-207027.5	-180922.7	1793490.8
8	-114097.8	-114097.8	-114097.8	-114097.8	-97704.8	1142160.9
9	-100655.4	-100655.4	-100655.4	-100655.4	-83489.8	1214806.1
10	773353.2	773353.2	773353.2	773353.2	785463.0	1701372.0
11	3203964.8	3203964.8	3203964.8	3203964.8	3252216.0	6901642.4
12	83084.4	83084.4	83084.4	83084.4	99312.5	1326704.0
13	103170.3	103170.3	103170.3	103170.3	143974.9	3230181.4
14	562399.8	562399.8	562399.8	562399.8	571950.0	1294269.2
15	895125.0	895125.0	895125.0	895125.0	910632.7	2083536.2
16	0.0	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6

Table A.16: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 100 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.320	42.910	42.010	41.669	43597.488
2	44.320	42.910	42.010	41.669	40686.678
3	44.320	42.910	42.010	41.669	39136.628
4	44.320	42.910	42.010	41.669	37552.188
5	47.253	42.910	42.010	41.669	33688.848
6	82.390	74.814	42.011	41.669	28100.603

Table A.17: (B9.5, 100, nrp) Results of Cases 1 to 4 on configuration (B9.5, 100, nrp), all values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1			Case 3		
μ (%) expected wind	5.86	61.17	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	30.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1176.97	9631.50	3788.56	3788.56	3734.02	8004.51
Schedu. dispatch. gen. (MWh)	27576.35	19121.82	24964.76	24964.76	25019.30	20748.81
Equilibrium price (€/MWh)	82.39	41.67	75.16	73.12	77.60	71.42
Reserve requirement (MW)	728.07	1827.16	1067.58	1067.58	1060.49	5217.68
Up. reserve commit. (MW)	800.88	2009.88	1174.34	1174.34	1119.80	5420.12
Down. reser. commit. (MW)	396.24	908.80	587.70	526.37	503.01	2348.94
Max. available reserve (MW)	983.22	4156.93	1773.82	1679.36	2386.41	4029.89
INCOMES (€/h):						
Energy sales in day ahead	2368994.11	1198129.18	2161099.92	2102523.18	2231297.88	2053621.16
Premium to schedu. Wind	35309.05	288945.11	0.00	113656.67	112020.64	640360.73
Supply of up. reser. capa.	27.79	206.69	343.30	85.62	39198.18	66841.63
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	15.90
COSTS (€/h):						
Cost of dispatch. gen.	946220.74	477709.75	775568.81	775433.30	816202.04	568830.59
$\lambda_f \cdot CVaR[Q]$	859486.68	1410372.75	805635.25	1707525.67	1843174.53	2830867.98
$(1 - \lambda_f) \cdot E[Q]$	404227.71	176296.59	161195.73	375333.62	0.00	2109347.87
PROFIT (€/h):						
Total (wind + dispatch.)	1394729.79	708383.30	1374680.26	1311536.60	1442325.07	1406788.69
1st stage wind turbines	89411.15	398338.92	239185.38	231413.30	246753.95	495768.49
2nd stage wind turbines	-7045.91	-5024.70	0.00	-4397.56	-5120.32	0.00
1st stage dispatch. gen.	1333390.00	322287.20	1146689.03	1095762.21	1207540.07	1057502.69
2nd stage dispatch. gen.	-21025.46	-7218.12	-11194.15	-11241.34	-6848.63	-146482.49

Table A.18: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 300 €/MWh.

g	Dismantling iteration					
	1	2	3	4	5	6
1	-232864.8	0.0	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0	0.0
5	-424352.9	-424352.9	-424352.9	-424352.9	-216026.5	0.0
6	-192939.1	-192939.1	-192939.1	-192939.1	-90632.7	7599497.7
7	-207027.5	-207027.5	-207027.5	-207027.5	-84938.4	9092293.0
8	-114097.8	-114097.8	-114097.8	-114097.8	-37429.7	5725575.6
9	-100655.4	-100655.4	-100655.4	-100655.4	-20374.2	6014220.1
10	773353.2	773353.2	773353.2	773353.2	829989.2	5087215.4
11	3203964.8	3203964.8	3203964.8	3203964.8	3429629.9	20392486.5
12	83084.4	83084.4	83084.4	83084.4	158981.1	5864005.6
13	103170.3	103170.3	103170.3	103170.3	294008.3	14638969.0
14	562399.8	562399.8	562399.8	562399.8	607064.9	3964468.3
15	895125.0	895125.0	895125.0	895125.0	967652.4	6419411.7
16	0.0	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8	28100.6

Table A.19: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 300 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.320	42.910	42.010	41.669	43597.488
2	44.320	42.910	42.010	41.669	40686.678
3	44.320	42.910	42.010	41.669	39136.628
4	44.320	42.910	42.010	41.669	37552.188
5	58.039	42.910	42.010	41.669	33688.848
6	221.370	191.203	42.011	41.669	28100.603

Table A.20: (B9.5, 300, nrp) Results of Cases 1 to 4 on configuration (B9.5, 300, nrp), all values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1			Case 3		
μ (%) expected wind	5.86	61.17	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	30.00	0.00	30.00	30.00	0.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1176.97	9631.50	3788.56	3788.56	3674.77	8015.60
Schedu. dispatch. gen. (MWh)	27576.35	19121.82	24964.76	24964.76	25078.55	20737.72
Equilibrium price (€/MWh)	221.37	41.67	191.55	185.58	199.88	174.52
Reserve requirement (MW)	728.07	1827.16	1067.58	1067.58	1052.79	5103.65
Up. reserve commit. (MW)	800.88	2009.88	1174.34	1174.34	1143.30	5289.06
Down. reser. commit. (MW)	440.59	881.67	500.54	522.48	565.38	2306.73
Max. available reserve (MW)	983.22	4156.93	1773.82	1679.36	2347.55	4102.27
INCOMES (€/h):						
Energy sales in day ahead	6365132.36	1198129.18	5507651.61	5336117.62	5747285.46	5018036.90
Premium to schedu. Wind	35309.05	288945.11	0.00	113656.67	110243.00	0.00
Supply of up. reser. capa.	27.79	206.69	878.30	263.96	144587.03	274101.82
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	15.90
COSTS (€/h):						
Cost of dispatch. gen.	1315559.66	477709.75	936929.38	936793.87	1089038.18	568830.59
$\lambda_f \cdot CVaR[Q]$	1897613.53	1410372.75	1965518.98	0.00	2024806.83	5539813.22
$(1 - \lambda_f) \cdot E[Q]$	954253.29	176296.59	413236.44	795401.47	0.00	3702788.46
PROFIT (€/h):						
Total (wind + dispatch.)	4983332.90	708383.30	4542903.55	4366445.97	4782927.07	4466185.94
1st stage wind turbines	226323.91	398338.92	529557.96	507724.26	551062.25	1101641.32
2nd stage wind turbines	-7045.91	-5024.70	0.00	-4397.56	-5681.24	0.00
1st stage dispatch. gen.	4823276.58	322287.20	4042042.57	3891863.44	4251772.06	3621682.71
2nd stage dispatch. gen.	-59221.68	-7218.12	-28696.97	-28744.17	-14226.00	-257138.09

Table A.21: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 1000 €/MWh.

g	Dismantling iteration				
	1	2	3	4	5
1	-232864.8	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0
5	-424352.9	-424352.9	-424352.9	-424352.9	357211.9
6	-192939.1	-192939.1	-192939.1	-192939.1	190877.3
7	-207027.5	-207027.5	-207027.5	-207027.5	251006.6
8	-114097.8	-114097.8	-114097.8	-114097.8	173533.0
9	-100655.4	-100655.4	-100655.4	-100655.4	200530.3
10	773353.2	773353.2	773353.2	773353.2	985830.8
11	3203964.8	3203964.8	3203964.8	3203964.8	4050578.5
12	83084.4	83084.4	83084.4	83084.4	367821.4
13	103170.3	103170.3	103170.3	103170.3	819125.2
14	562399.8	562399.8	562399.8	562399.8	729967.3
15	895125.0	895125.0	895125.0	895125.0	1167221.5
16	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8

Table A.22: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 1000 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.320	42.910	42.010	41.669	43597.488
2	44.320	42.910	42.010	41.669	40686.678
3	44.320	42.910	42.010	41.669	39136.628
4	44.320	42.910	42.010	41.669	37552.188
5	95.788	42.910	42.010	41.669	33688.848

Table A.23: (B9.4, 1000, nrp) Results of Cases 1 to 4 on configuration (B9.4, 1000, nrp), all values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1			Case 3		
μ (%) expected wind	5.86	61.17	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	30.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1176.97	9631.50	3788.56	3788.56	3743.10	8189.92
Schedu. dispatch. gen. (MWh)	27576.35	19121.82	24964.76	24964.76	25010.22	20563.40
Equilibrium price (€/MWh)	95.79	41.67	42.33	42.29	44.08	43.09
Reserve requirement (MW)	728.07	1827.16	1067.58	1067.58	1061.67	5325.22
Up. reserve commit. (MW)	800.88	2009.88	1174.34	1174.34	1147.45	5580.68
Down. reser. commit. (MW)	337.38	905.02	469.73	476.36	610.24	2262.31
Max. available reserve (MW)	3340.79	7137.14	4469.15	4343.12	5021.58	6994.38
INCOMES (€/h):						
Energy sales in day ahead	2754228.00	1198129.18	1243734.69	1216075.80	1267460.20	1238946.69
Premium to schedu. Wind	35309.05	288945.11	0.00	113656.67	112292.89	0.00
Supply of up. reser. capa.	31808.93	206.69	196.88	19.76	8922.47	9778.78
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	15.90
COSTS (€/h):						
Cost of dispatch. gen.	844973.60	477709.75	731335.03	731188.06	741471.07	564399.90
$\lambda_f \cdot CVaR[Q]$	678492.28	1410372.75	487676.43	1389566.85	1786743.99	2132306.67
$(1 - \lambda_f) \cdot E[Q]$	282833.14	176296.59	92101.93	260968.09	260252.32	1731819.13
PROFIT (€/h):						
Total (wind + dispatch.)	1921422.14	708383.30	506200.57	474063.66	514906.06	567382.26
1st stage wind turbines	89890.92	398338.92	159587.48	155669.22	161886.85	333621.77
2nd stage wind turbines	-7045.91	-5024.70	0.00	-4397.56	-5671.46	0.00
1st stage dispatch. gen.	1851172.41	322287.20	353009.06	329238.28	373024.75	354025.71
2nd stage dispatch. gen.	-12595.28	-7218.12	-6395.97	-6446.29	-14334.07	-120265.22

Table A.24: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for dispatchable generators g . The backup generator is $g = 16$ and its generation cost is 563.79699 €/MWh.

g	Dismantling iteration				
	1	2	3	4	5
1	-232864.8	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0
5	-424352.9	-424352.9	-424352.9	-424352.9	0.0
6	-192939.1	-192939.1	-192939.1	-192939.1	15455.1
7	-207027.5	-207027.5	-207027.5	-207027.5	41663.4
8	-114097.8	-114097.8	-114097.8	-114097.8	42072.2
9	-100655.4	-100655.4	-100655.4	-100655.4	62874.3
10	773353.2	773353.2	773353.2	773353.2	888718.5
11	3203964.8	3203964.8	3203964.8	3203964.8	3663636.1
12	83084.4	83084.4	83084.4	83084.4	237683.2
13	103170.3	103170.3	103170.3	103170.3	491900.1
14	562399.8	562399.8	562399.8	562399.8	653381.0
15	895125.0	895125.0	895125.0	895125.0	1042860.6
16	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8

Table A.25: Price of energy in day ahead. The backup generator is $g = 16$ and its generation cost is 563.79699 €/MWh.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.320	42.910	42.010	41.669	43597.488
2	44.320	42.910	42.010	41.669	40686.678
3	44.320	42.910	42.010	41.669	39136.628
4	44.320	42.910	42.010	41.669	37552.188
5	72.265	42.910	42.010	41.669	33688.848

Table A.26: (B9.4, O, nrp) Results of Cases 1 to 4 on configuration (B9.4, O, nrp), all values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2		Case 3	Case 4	
μ (%) expected wind	5.86	61.17	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	0.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Demand day ahead (MWh)	28753.32	28753.32	28753.32	28753.32	28753.32	28753.32
Schedu. win. gen. (MWh)	1176.97	9631.50	3788.56	3788.56	3666.03	8163.52
Schedu. dispatch. gen. (MWh)	27576.35	19121.82	24964.76	24964.76	25087.28	20589.80
Equilibrium price (€/MWh)	72.26	41.67	42.33	42.29	44.08	43.09
Reserve requirement (MW)	728.07	1827.16	1067.58	1067.58	1051.65	5309.91
Up. reserve commit. (MW)	800.88	2009.88	1174.34	1174.34	1124.39	5554.28
Down. reser. commit. (MW)	320.35	876.56	469.73	469.73	475.70	2324.37
Max. available reserve (MW)	3340.79	7137.14	4469.15	4343.12	4874.64	6967.98
INCOMES (€/h):						
Energy sales in day ahead	2077852.67	1198129.18	1243734.69	1217233.52	1267460.20	1238946.69
Premium to schedu. Wind	35309.05	288945.11	0.00	303084.45	109981.04	653081.84
Supply of up. reser. capa.	17292.13	206.69	196.88	196.88	8412.13	10757.07
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	28.52
COSTS (€/h):						
Cost of dispatch. gen.	844973.60	477709.75	731335.03	731335.03	744194.93	555945.18
$\lambda_f \cdot CVaR[Q]$	631125.17	1410372.75	487676.43	1389566.85	0.00	2130782.57
$(1 - \lambda_f) \cdot E[Q]$	269388.22	176296.59	92101.93	260968.09	0.00	1729532.99
PROFIT (€/h):						
Total (wind + dispatch.)	1231463.68	708383.30	506200.57	467972.59	510914.53	311602.00
1st stage wind turbines	72527.73	398338.92	159587.48	155949.83	158652.66	341782.91
2nd stage wind turbines	-7045.91	-5024.70	0.00	-11726.82	-4397.56	-253954.52
1st stage dispatch. gen.	1177643.46	322287.20	353009.06	330145.54	373024.75	352004.18
2nd stage dispatch. gen.	-11661.61	-7218.12	-6395.97	-6395.97	-15164.70	-128230.57

A.3.2 Multi-Period with Price Responsive Demand and without Ramping Products

Progressive mothballing of multi-period with price responsive demand and no ramping products, problem posed as a two stage stochastic programming, with average premium ($\rho^+ = 30$ €/MWh), average risk aversion ($\lambda = 0.4$), $m_y = 0.15$ and $m_x = 0.02$.

Single firm maximizing welfare, without price cap, one inverse demand function for each period in each one day (4×24 inverse demand functions). The inverse demand functions are based on:

- Demand elasticity of -0.3 .
- Reference demand from the fixed demand curve.
- Reference price from the dual variable for energy price (shadow price) in the problem with fixed demand, multi-period and initial state without mothballing.

Table A.27: Value of the margin (€/MWh) profit minus fixed operation and maintenance cost for a whole day (24 hours), in the progressive dismantling process without price cap (without backup generator).

g	Dismantling iteration				
	1	2	3	4	5
1	-232864.8	0.0	0.0	0.0	0.0
2	-122454.0	-122454.0	0.0	0.0	0.0
3	-123586.3	-123586.3	-123586.3	0.0	0.0
4	-297477.2	-297477.2	-297477.2	-297477.2	0.0
5	368236.2	377801.1	377801.1	377801.1	377801.1
6	1308372.6	1282976.2	1282976.2	1282976.2	1282976.2
7	1860192.5	1857749.4	1857749.4	1857749.4	1857749.4
8	1307281.1	1324595.1	1324595.1	1324608.0	1324595.1
9	1511904.7	1511168.1	1511168.1	1511168.1	1511168.1
10	1133351.5	1133215.9	1133215.9	1133215.9	1133215.9
11	4547874.0	4547333.7	4547333.7	4547333.7	4547333.7
12	1789689.5	1792058.9	1792058.9	1792058.9	1792058.9
13	4303790.4	4303473.2	4303473.2	4303473.2	4303473.2
14	1099268.7	1099161.8	1099161.8	1099161.8	1099161.8
15	1788633.0	1788459.4	1788459.4	1788459.4	1788459.4
16	0.0	0.0	0.0	0.0	0.0
Cap. (MW)	43597.5	40686.7	39136.6	37552.2	33688.8

Table A.28: Price of energy in day ahead, single firm, multi-period, price responsive demand, without price cap.

Mothballing round	Wind				Total Capacity MW
	5.86 % €/MWh	22.20% €/MWh	47.09% €/MWh	61.17% €/MWh	
1	44.289	42.9	41.923	39.705	43597.488
2	44.289	42.896	41.923	39.705	40686.678
3	44.289	42.896	41.923	39.705	39136.628
4	44.289	42.896	41.923	39.705	37552.188
5	44.289	42.896	41.923	39.705	33688.848

Table A.29: (B9.5, -, nrp) Results of Cases 1 to 4 for configuration (B9.5, -, nrp), all values are hourly average and $\lambda = 0$ is risk neutral.

	$m_y = 0.15$ (wind), $m_x = 0.02$ (dispatch. gen.)			$m_y = 0.60, m_x = 0.02$		
	Case 1	Case 2		Case 3		Case 4
μ (%) expected wind	5.86	61.17	22.20	22.20	22.20	22.20
ρ^+ (€/MWh) premium	30.00	30.00	80.00	30.00	30.00	80.00
λ risk aversion	0.40	0.40	0.40	0.00	1.00	0.40
Demand day ahead (MWh)	28581.12	27186.14	28547.42	28734.82	28743.37	28565.36
Schedu. win. gen. (MWh)	1172.55	9591.27	3783.27	3788.08	3788.30	7744.15
Schedu. dispatch. gen. (MWh)	27408.57	17594.87	24764.15	24946.73	24955.07	20821.21
Equilibrium price (€/MWh)	44.29	39.71	43.24	42.33	42.28	43.18
Reserve requirement (MW)	724.05	1790.59	1062.77	1067.15	1067.35	5062.91
Up. reserve commit. (MW)	796.46	1969.65	1169.05	1173.86	1174.08	5229.14
Down. reser. commit. (MW)	543.63	860.96	833.17	823.62	805.58	2152.98
Max. available reserve (MW)	1478.76	4610.19	2351.82	2330.47	2213.59	5398.26
INCOMES (€/h):						
Energy sales in day ahead	1265840.87	1079433.32	1234419.52	1216253.18	1215300.69	1233391.44
Premium to schedu. Wind	35176.43	287738.19	0.00	303046.45	113649.01	0.00
Supply of up. reser. capa.	30.78	1303.80	211.34	183.02	10.81	9940.49
Supply of down. reser. capa.	0.00	0.00	0.00	0.00	0.00	13.16
COSTS (€/h):						
Cost of dispatch. gen.	837377.24	419112.32	722457.20	730353.44	730558.41	563164.70
$\lambda_f \cdot CVaR[Q]$	571650.49	1346446.36	484390.98	1388878.03	0.00	2060561.57
$(1 - \lambda_f) \cdot E[Q]$	250267.33	168305.80	91056.34	260518.00	260166.82	1622949.33
PROFIT (€/h):						
Total (wind + dispatch.)	411114.74	649936.90	505850.31	467991.23	473912.82	567475.59
1st stage wind turbines	51681.47	372023.68	159291.68	155920.50	155624.00	326412.00
2nd stage wind turbines	-6958.80	-4924.12	0.00	-11707.69	-4391.53	0.00
1st stage dispatch. gen.	376812.95	289601.12	352881.98	330162.26	329129.11	353768.40
2nd stage dispatch. gen.	-10420.88	-6763.78	-6323.36	-6383.84	-6448.75	-112704.81

A.4 Data on Wind Scenarios in Multi-Period

Table A.30: Wind scenarios in (%) for $\mu = 5.86\%$ and $\mu = 22.20\%$.

t (h)	Wind forecast $\mu = 5.86\%$. Scenario (k)											
	1	2	3	4	5	6	7	8	9	10	11	12
1	4.6	6.3	7.4	8.4	9.2	10.1	10.9	11.9	12.9	14.2	16.0	19.9
2	4.4	6.1	7.2	8.1	8.9	9.8	10.6	11.5	12.6	13.8	15.6	19.4
3	3.7	5.3	6.2	7.1	7.9	8.7	9.5	10.3	11.3	12.5	14.2	17.9
4	2.9	4.3	5.2	5.9	6.6	7.4	8.1	8.9	9.9	11.0	12.6	16.2
5	1.9	3.0	3.7	4.4	5.0	5.7	6.3	7.1	7.9	9.0	10.4	13.9
6	1.6	2.6	3.3	3.9	4.5	5.1	5.7	6.4	7.3	8.3	9.7	13.1
7	1.3	2.2	2.9	3.5	4.0	4.6	5.2	5.9	6.7	7.7	9.1	12.5
8	1.0	1.8	2.4	2.9	3.5	4.0	4.6	5.3	6.0	7.0	8.4	11.7
9	0.7	1.3	1.9	2.3	2.8	3.3	3.9	4.5	5.2	6.2	7.5	10.8
10	0.4	0.9	1.3	1.7	2.1	2.6	3.1	3.7	4.4	5.3	6.6	9.9
11	0.1	0.4	0.7	1.0	1.3	1.7	2.2	2.7	3.4	4.2	5.5	9.0
12	0.0	0.2	0.3	0.5	0.8	1.1	1.5	1.9	2.6	3.4	4.7	8.3
13	0.0	0.2	0.3	0.5	0.8	1.1	1.5	1.9	2.5	3.4	4.7	8.3
14	0.0	0.2	0.4	0.7	1.0	1.3	1.7	2.2	2.9	3.7	5.0	8.5
15	0.1	0.4	0.6	0.9	1.3	1.6	2.1	2.6	3.3	4.1	5.4	8.9
16	0.5	1.1	1.6	2.0	2.5	3.0	3.5	4.1	4.8	5.7	7.1	10.4
17	0.9	1.7	2.3	2.8	3.3	3.9	4.4	5.1	5.8	6.8	8.2	11.5
18	1.3	2.3	2.9	3.5	4.1	4.7	5.3	6.0	6.8	7.8	9.2	12.5
19	1.7	2.8	3.5	4.1	4.7	5.4	6.0	6.7	7.6	8.6	10.0	13.4
20	2.1	3.3	4.1	4.8	5.4	6.1	6.8	7.5	8.4	9.5	11.0	14.4
21	2.7	4.0	4.9	5.6	6.3	7.1	7.8	8.6	9.5	10.6	12.2	15.7
22	2.6	4.0	4.8	5.5	6.2	6.9	7.7	8.5	9.4	10.5	12.0	15.6
23	2.5	3.8	4.6	5.3	6.0	6.7	7.4	8.2	9.1	10.2	11.7	15.2
24	3.0	4.4	5.3	6.1	6.8	7.5	8.3	9.1	10.0	11.2	12.8	16.4
t	Wind forecast $\mu = 22.20\%$. Scenario (k)											
1	22.3	28.1	31.3	33.9	36.1	38.3	40.4	42.7	45.1	47.9	51.5	58.5
2	19.8	25.0	27.8	30.1	32.2	34.2	36.1	38.1	40.4	42.9	46.3	53.0
3	18.6	23.4	26.1	28.3	30.2	32.1	33.9	35.9	38.0	40.5	43.7	50.2
4	17.3	21.8	24.4	26.5	28.3	30.1	31.8	33.7	35.7	38.1	41.2	47.5
5	16.2	20.5	22.9	24.8	26.6	28.3	30.0	31.7	33.7	35.9	38.9	45.0
6	15.2	19.3	21.6	23.4	25.1	26.7	28.3	30.0	31.9	34.1	37.0	42.9
7	15.9	20.1	22.5	24.4	26.2	27.8	29.5	31.2	33.1	35.4	38.4	44.4
8	16.1	20.4	22.8	24.7	26.5	28.1	29.8	31.6	33.5	35.8	38.8	44.9
9	15.5	19.6	21.9	23.8	25.5	27.1	28.7	30.5	32.3	34.5	37.5	43.5
10	14.5	18.5	20.7	22.5	24.1	25.7	27.2	28.9	30.7	32.8	35.7	41.5
11	13.4	17.0	19.1	20.8	22.3	23.8	25.3	26.8	28.6	30.6	33.3	38.9
12	11.9	15.2	17.1	18.7	20.1	21.5	22.9	24.3	25.9	27.8	30.4	35.7
13	10.4	13.4	15.2	16.6	17.9	19.2	20.5	21.8	23.3	25.1	27.5	32.6
14	8.7	11.4	13.0	14.3	15.4	16.6	17.8	19.0	20.4	22.0	24.2	28.9
15	7.6	10.0	11.4	12.6	13.7	14.8	15.8	17.0	18.3	19.8	21.9	26.4
16	5.9	8.0	9.2	10.3	11.2	12.2	13.2	14.2	15.3	16.7	18.6	22.8
17	5.9	7.9	9.2	10.2	11.2	12.1	13.1	14.1	15.3	16.7	18.6	22.7
18	6.0	8.1	9.4	10.4	11.4	12.3	13.3	14.4	15.5	16.9	18.8	23.0
19	6.3	8.5	9.8	10.8	11.8	12.8	13.8	14.9	16.1	17.5	19.4	23.7
20	6.6	8.8	10.1	11.2	12.3	13.2	14.3	15.3	16.5	18.0	20.0	24.3
21	6.1	8.3	9.5	10.6	11.6	12.6	13.5	14.6	15.8	17.2	19.1	23.3
22	5.8	7.9	9.2	10.2	11.2	12.1	13.1	14.1	15.2	16.6	18.5	22.7
23	6.2	8.3	9.6	10.7	11.6	12.6	13.6	14.6	15.8	17.2	19.2	23.4
24	5.6	7.7	8.9	9.9	10.9	11.8	12.7	13.7	14.9	16.3	18.1	22.2

Table A.31: Wind scenarios in (%) for $\mu = 47.09\%$ and $\mu = 61.17\%$.

t (h)	Wind forecast $\mu = 47.09\%$. Scenario (k)											
	1	2	3	4	5	6	7	8	9	10	11	12
1	23.3	29.3	32.7	35.3	37.7	39.9	42.2	44.5	46.9	49.8	53.5	60.7
2	25.0	31.4	35.0	37.9	40.4	42.8	45.1	47.5	50.2	53.2	57.0	64.3
3	25.9	32.7	36.4	39.4	42.0	44.5	46.9	49.4	52.1	55.2	59.1	66.5
4	24.5	30.9	34.4	37.2	39.7	42.0	44.3	46.7	49.3	52.2	56.0	63.3
5	25.2	31.7	35.4	38.2	40.8	43.2	45.6	48.0	50.6	53.6	57.5	64.9
6	26.1	32.9	36.6	39.6	42.2	44.7	47.1	49.6	52.3	55.4	59.4	66.8
7	27.3	34.5	38.5	41.6	44.4	47.0	49.5	52.1	54.9	58.1	62.2	69.7
8	28.3	35.9	40.0	43.3	46.1	48.8	51.5	54.2	57.0	60.3	64.4	71.9
9	27.7	35.1	39.1	42.3	45.1	47.7	50.3	52.9	55.8	59.0	63.1	70.6
10	27.3	34.6	38.5	41.6	44.4	47.0	49.6	52.2	55.0	58.1	62.2	69.7
11	27.0	34.1	38.0	41.1	43.9	46.4	48.9	51.5	54.3	57.5	61.5	69.0
12	27.8	35.2	39.2	42.4	45.3	47.9	50.5	53.1	56.0	59.2	63.3	70.8
13	28.5	36.1	40.2	43.5	46.4	49.1	51.8	54.5	57.4	60.6	64.8	72.3
14	29.1	37.0	41.2	44.6	47.6	50.3	53.1	55.8	58.8	62.1	66.2	73.8
15	29.4	37.4	41.7	45.1	48.1	50.9	53.7	56.4	59.4	62.7	66.9	74.5
16	29.8	37.8	42.2	45.7	48.7	51.5	54.3	57.1	60.1	63.5	67.7	75.2
17	28.5	36.1	40.2	43.5	46.4	49.1	51.7	54.4	57.3	60.6	64.7	72.2
18	27.1	34.2	38.1	41.2	43.9	46.5	49.0	51.6	54.4	57.5	61.6	69.0
19	25.2	31.8	35.4	38.3	40.9	43.3	45.6	48.1	50.7	53.7	57.6	65.0
20	24.7	31.0	34.6	37.4	39.9	42.2	44.6	47.0	49.6	52.5	56.3	63.6
21	24.5	30.8	34.3	37.1	39.5	41.9	44.2	46.6	49.2	52.1	55.9	63.2
22	25.0	31.5	35.1	38.0	40.5	42.9	45.2	47.7	50.3	53.3	57.1	64.5
23	25.5	32.1	35.8	38.7	41.2	43.7	46.1	48.5	51.2	54.2	58.1	65.5
24	25.9	32.7	36.4	39.4	42.0	44.5	46.9	49.4	52.1	55.2	59.1	66.5
t	Wind forecast $\mu = 61.17\%$. Scenario (k)											
	1	2	3	4	5	6	7	8	9	10	11	12
1	31.1	39.7	44.3	48.0	51.2	54.1	57.0	59.9	63.0	66.5	70.8	78.2
2	31.6	40.4	45.2	49.0	52.2	55.3	58.2	61.2	64.3	67.8	72.1	79.5
3	30.6	39.0	43.5	47.1	50.2	53.2	56.0	58.9	61.9	65.4	69.6	77.1
4	30.5	38.8	43.4	46.9	50.1	53.0	55.8	58.7	61.7	65.1	69.4	76.9
5	29.7	37.8	42.1	45.6	48.6	51.5	54.2	57.0	60.0	63.4	67.6	75.1
6	31.1	39.6	44.3	47.9	51.1	54.1	57.0	59.9	63.0	66.5	70.7	78.2
7	31.7	40.5	45.3	49.1	52.4	55.4	58.4	61.3	64.5	68.0	72.3	79.7
8	32.8	42.2	47.2	51.1	54.6	57.8	60.8	63.9	67.1	70.6	75.0	82.3
9	32.7	42.0	47.0	50.9	54.3	57.5	60.6	63.6	66.8	70.4	74.7	82.0
10	32.6	41.9	46.8	50.8	54.2	57.3	60.3	63.4	66.6	70.1	74.5	81.8
11	32.8	42.2	47.2	51.2	54.6	57.8	60.8	63.9	67.1	70.7	75.0	82.3
12	33.1	42.6	47.7	51.7	55.2	58.4	61.5	64.6	67.8	71.4	75.7	83.0
13	34.6	44.9	50.5	54.8	58.5	61.9	65.2	68.4	71.8	75.4	79.7	86.7
14	35.4	46.3	52.2	56.7	60.6	64.1	67.4	70.7	74.1	77.8	82.1	88.7
15	35.9	47.2	53.2	57.9	61.8	65.4	68.8	72.2	75.6	79.3	83.5	90.0
16	36.1	47.6	53.7	58.4	62.4	66.0	69.5	72.9	76.3	79.9	84.2	90.5
17	36.1	47.6	53.7	58.4	62.4	66.0	69.5	72.9	76.3	79.9	84.2	90.5
18	36.0	47.3	53.3	58.0	62.0	65.6	69.0	72.4	75.8	79.4	83.7	90.1
19	35.7	46.8	52.8	57.4	61.3	64.9	68.3	71.6	75.0	78.7	82.9	89.4
20	35.8	46.9	52.9	57.5	61.4	65.0	68.4	71.8	75.2	78.8	83.1	89.6
21	36.1	47.6	53.7	58.4	62.4	66.0	69.5	72.8	76.3	79.9	84.1	90.5
22	36.2	47.8	54.0	58.7	62.7	66.4	69.9	73.3	76.7	80.3	84.6	90.8
23	36.3	47.9	54.1	58.9	62.9	66.6	70.1	73.4	76.9	80.5	84.7	91.0
24	36.0	47.3	53.4	58.0	62.0	65.7	69.1	72.4	75.9	79.5	83.8	90.2

Appendix B

Resumen Extendido

B.1 Introducción

En el contexto actual, las energías renovables son consideradas un instrumento indispensable para sobrellevar, o al menos mitigar, el cambio climático. Se trata de una cuestión global, cuyo tratamiento, sin embargo, aún depende de las decisiones que a nivel local se toman en las diferentes regiones del planeta. Entre las energías renovables, la energía eólica y la solar, son las formas más extendidas debido a su coste relativamente bajo y a su potencial de generación, que posibilita una contribución significativa en la reducción de emisiones de CO₂. Y entre estas energías, es comúnmente admitido que solamente la energía eólica está próxima a ser rentable, cuando se la compara con las fuentes convencionales en términos de coste normalizado. Pero el coste normalizado, que considera tanto los costes variables de explotación como los costes fijos de inversión y amortización, proporciona sólo una descripción incompleta de la competitividad de la energía eólica y otras fuentes intermitentes (no despachables) en los sistemas de generación (Joskow [1–3]), de forma que un sistema de incentivos ha sido, y sigue siendo, necesario para promover el desarrollo y la integración de las fuentes renovables intermitentes en los sistemas de generación. En ocasiones las políticas de incentivos aplicadas conducen a niveles de integración de fuentes intermitentes que no están en absoluto justificados por las condiciones del mercado y llevan a situaciones difícilmente sostenibles en términos económicos.

Las políticas de incentivos basadas en subsidios, tanto para fuentes basadas en combustibles fósiles (IMF Report [4]) como para fuentes renovables, son habitualmente difíciles de monitorizar, y la aparición de consecuencias inesperadas suele ser la norma. Este es el caso en la Unión Europea, que ha estado a la vanguardia en el uso de energías renovables, con el resultado de que la generación intermitente que fue instalada gracias al incentivo de los subsidios, está ahora poniendo en peligro la economía a corto plazo de las unidades convencionales, hasta el punto de que la idoneidad del sistema está siendo puesta en cuestión.

Esta tesis se centra sobre un punto muy concreto, pero potencialmente importante, en la evolución actual de los sistemas de generación de energía eléctrica en algunos países de la Unión Europea. Los factores comunes en estos sistemas consisten en una alta penetración de energías renovables no despachables, combinada con campañas de ahorro energético (reducción del consumo, incremento de la eficiencia energética, etc.), y otros eventos relacionados con el contexto de crisis económica, que han conducido a una reducción del precio de mercado de la electricidad. Esta reducción del precio de la electricidad ha llegado a un punto en el que pone en cuestión la supervivencia de algunas plantas convencionales en el mercado, en particular las plantas de turbinas de gas de ciclo combinado. El problema estaría

limitado a una (dramática) pérdida de valor de las unidades convencionales y al (también dramático) coste de los subsidios asociados a estas políticas, si no fuera porque adicionalmente las unidades convencionales que dejan de ser rentables resultan necesarias para la operación técnica del sistema, de forma que no es técnicamente posible satisfacer la demanda si esas unidades convencionales son retiradas.

Varios estudios apuntan a las limitaciones a la penetración de energías renovables en los sistemas de generación debido a restricciones técnicas de operación, en particular debido a su pobre desempeño para proporcionar servicios auxiliares al sistema, como reserva, capacidad de rampa, y capacidad de regulación de frecuencia y tensión, [5–12].

Un razonamiento económico básico nos dice que esta situación no debería ocurrir, ya que una escasez de los servicios de red ocasionada por la parada o desmantelamiento de generadores convencionales debido a precios de mercado de la energía eléctrica más bajos debería incrementar el valor de mercado de estos servicios, y en consecuencia, la remuneración de las plantas que los proporcionan. En resumen los dos posibles resultados son: *i)* o los generadores no despachables proporcionan estos servicios y la eliminación de las unidades convencionales continúa; *ii)* o, ya que las unidades convencionales parecen estar mejor posicionadas para proporcionar estos servicios, un adecuado diseño del mercado proporciona una remuneración suficiente a estas plantas convencionales para mantenerlas en funcionamiento. Esta tesis presenta varios modelos con el objetivo de estudiar ese problema, identificando los mecanismos que se ponen en funcionamiento y cómo afectan los diferentes factores en el sistema a los resultados.

Todos los modelos utilizados en esta tesis asumen agentes tomadores de precios. Esta hipótesis se justifica aquí con los siguientes argumentos: *(i)* tener en cuenta el poder de mercado requiere hipótesis adicionales sobre como los agentes ejercen ese poder de mercado, y existe una gran variedad de esas hipótesis, en particular para sistemas en los que se manejan varios productos, como es el caso de los modelos aquí estudiados; *(ii)* la hipótesis de agentes tomadores de precios simplifica la discusión económica de los resultados y permite centrar el estudio en los aspectos físicos y económicos básicos del diseño del mercado, sin las perturbaciones que conlleva el ejercicio de poder de mercado.

B.2 Breve Revisión de la Literatura

Debido a que las fuentes de energía renovables contribuyen a reducir la polución y a diversificar las fuentes de suministro de energía, muchos países han aplicado programas de incentivos para fomentar su desarrollo, en particular los incentivos a la energía eólica y a la energía solar resultan bastante comunes. Varios países en Europa, como por ejemplo Dinamarca con 4.16 GW de capacidad de generación eólica instalada, y una contribución media anual de la energía eólica del 27% sobre el consumo total de energía eléctrica (datos de 2012, [36]), España con 22.21 GW y el 16%, y Alemania con 29.06 GW y el 11%, ya muestran una alta penetración de energía eólica en su parque de generación eléctrica. Se espera que esta tendencia continúe y se extienda a otros muchos países en el futuro próximo.

Altas proporciones de energía eólica y solar en los sistemas de potencia conllevan importantes nuevos retos a los reguladores, los operadores del sistema y las firmas de generación. Como se destaca en [37–39], los principales retos incluyen: el impacto de las políticas de incentivos, el diseño del mercado y cuestiones operacionales (mercado de balance y flexibilidad operacional). El comportamiento estratégico de los agentes, el coste real de la energía eólica y el modelado de la generación eólica tienen también una gran importancia.

“Green Targets”, “Feed-in Tariffs”, o “Feed-in Premiums”, [40] están entre los incentivos

más comunes. Sus efectos sobre la energía eólica son estudiados en [38] para el mercado de la electricidad en Reino Unido, y [41] muestra como los subsidios a la energía eólica junto con la asignación de prioridad en su uso frente a otras energías, puede conducir a las plantas convencionales a ofertar energía a precios negativos, con el objetivo de evitar incurrir en los costes por parada y arranque de la planta, lo que además suele conllevar, paradójicamente, un incremento de los costes globales y de las emisiones contaminantes.

Los principales problemas operacionales asociados con una alta penetración de energía eólica son debidos a la naturaleza intermitente e impredecible (al menos no con precisión) de este tipo de energía [42, 43]. En el caso de generación eólica a gran escala, por ejemplo en el caso de España (muchos parques eólicos sobre un área geográficamente extensa), la generación eólica total no es intermitente, pero aún conserva una elevada variabilidad. De forma que el mercado de balance y la flexibilidad operacional resultan elementos clave para la integración de la energía eólica. Las condiciones para que un mercado de balance resulte óptimo han sido estudiadas por diversos autores, llegando a la conclusión de que una condición esencial para que un mercado de balance sea óptimo es que el precio de la desviación debe reflejar el coste real que supone su corrección, [32, 40].

El mercado de balance puede ser modelado a través de relaciones econométricas para los precios de balance como funciones de la energía, o se puede modelar mediante procesos fundamentales que podrían incluir un “unit commitment” [44]. Considerando que los mecanismos de balance evolucionan con cierta rapidez y están sujetos a una continúa controversia, descartamos la aproximación econométrica y optamos por un modelo de equilibrio (sin un “unit commitment” explícito). Este modelo puede ser adaptado, en muchos casos sólo con ligeros cambios en las ecuaciones, a diferentes diseños de mercado, por ejemplo a diferentes mecanismos de asignación de precios.

Nos referimos aquí con el término “reserva de flexibilidad” a la reserva usada en el balance para corregir las desviaciones debidas a errores en la previsión eólica. La determinación de los valores óptimos para la cantidad y el precio de la reserva de flexibilidad es una cuestión de gran interés, y por ello la comunidad científica ha propuesto diferentes soluciones. En [45] se propone una metodología que tiene en cuenta la incertidumbre asociada a la demanda, la previsión eólica y el fallo de las unidades de generación, para cuantificar la cantidad de reserva necesaria para que el sistema opera con un nivel dado de fiabilidad. Para mostrar la utilidad de su metodología la aplican al sistema de generación eléctrica de Irlanda.

Una aproximación habitual para tratar la incertidumbre en problemas de optimización, es utilizar programación estocástica, como por ejemplo en [33, 34]. El valor de la flexibilidad operativa es otro concepto importante, que ha sido estudiado por ejemplo en [46].

Respecto al comportamiento de los agentes, una amplia variedad de estrategias para realizar ofertas óptimas ha sido descrita en la literatura académica. Estas estrategias suelen centrarse en la incertidumbre en el sistema y con frecuencia están basadas en programación estocástica. Por ejemplo, en [48] se propone un modelo para obtener la mejor estrategia de oferta para un generador eólico, el problema es inicialmente formulado como un problema no lineal entero mixto y finalmente reformulado y resuelto como un problema de optimización lineal equivalente. Otras aproximaciones consideran un micro análisis más detallado del comportamiento individual de los agentes operando bajo incertidumbre, como por ejemplo en [49].

La programación estocástica permite obtener estrategias de operación óptimas para un productor eólico bajo incertidumbre más precisas que otros métodos que consideran menos información. Este hecho se muestra en [50], y también en [51], donde se utiliza un modelo estocástico en dos etapas y se tienen en cuenta las restricciones de red en una subasta con

un número significativo de productores eólicos. En [52], ofertas óptimas en cantidad son calculadas para productores eólicos mediante programación estocástica en dos etapas, en la cual la información sobre los precios y la energía eólica disponible son incorporadas al modelo mediante un árbol de escenarios. Y utilizan el Valor Condicional en Riesgo (CVaR) [85] como medida para la gestión del riesgo.

Otras aproximaciones incluyen programación cónica de segundo orden, como en [35], donde esa técnica fue usada para resolver un problema de auto-programación en un sistema de firma única con restricciones de seguridad basadas en un flujo de cargas óptimo, gestionando adicionalmente el riesgo mediante el uso del CVaR.

B.3 Metodología Aplicada

Se describe aquí la metodología y el marco conceptual utilizado para estudiar los diversos factores que afectan a la integración de la energía eólica en el sistema eléctrico, y como a su vez esa integración afecta al conjunto del sistema eléctrico. La metodología consiste en la definición y uso de modelos del sistema basados en principios generales del mercado, pero que incorporan detalles particulares sobre la regulación aplicada a la energía eólica y reglas de operación (balance, productos de rampa, etc..) inspirados en el mercado eléctrico español o en el Midcontinent Independent System Operator (MISO). Recurrir a implementaciones particulares resulta inevitable en este caso porque tratamos con cuestiones que aún no están estandarizadas en la industria.

Debido a la importancia de las políticas de incentivos en la regulación y operación de las energías renovables, y la particular atención puesta en las primas a la generación renovable en la historia reciente del sistema eléctrico español, así como en las actuales discusiones en el seno de la Unión Europea [15], el modelo se ha construido sobre la base de esa política de incentivos pero con la vista puesta también en el estudio de otros factores relevantes en los sistemas eléctricos reales. En concreto, todos los factores que se han considerado son:

- 1) Prima a la generación eólica.
- 2) Nivel de disponibilidad de la energía eólica.
- 3) Aversión al riesgo de cada empresa.
- 4) Distribución de error para la previsión de generación eólica.
- 5) Demanda de reserva fijada como referencia por el Operador del Sistema (TSO).
- 6) Nivel de demanda respecto a la capacidad total instalada.
- 7) Parada de plantas convencionales en funcionamiento.
- 8) Mecanismo de asignación de precios para la capacidad de reserva usada en las operaciones de balance.
- 9) Mecanismo de asignación de precios para la energía procedente de la reserva (usada en las operaciones de balance).
- 10) Número de firmas.
- 11) Capacidad técnica de rampa de los generadores despachables.

- 12) Mecanismo de balance para corrección de desviaciones respecto a los valores programados.
- 13) Estimación a la baja de los costes reales (no considerar alguno de los costes) por parte de los generadores.

B.4 Descripción de los Modelos

Consideramos seis modelos de base que corresponden a diferentes estructuras de mercado, a su vez para algunos de esos modelos hemos estudiado diferentes variantes cambiando pequeños detalles. Los modelos son los siguientes:

- a) Modelos para un único período. En este caso las restricciones de rampa se han adaptado para considerar únicamente la información disponible (correspondiente a un único período), y el efecto de los otros períodos se ha considerado de forma aproximada mediante la introducción de un parámetro exógeno, dando lugar a lo que hemos llamado “modelo paramétrico de restricciones de rampa”. Dentro de los modelos de período único consideramos tres variantes:
 - 1) Modelo con múltiples firmas, formulado como un problema de complementariedad, y con demanda que responde al precio de la energía.
 - 2) Modelo con una única firma, formulado como un problema estocástico con demanda fija y en el que se minimiza el coste de generación. Éste fue el modelo de referencia utilizado por los reguladores. Este modelo puede interpretarse como una descripción de un mercado perfectamente competitivo, en el que una firma integrada minimiza su coste de operación sujeta a una demanda fija exógena. La firma puede poseer tanto generadores despachables como aerogeneradores y utiliza el CVaR, [85], de su coste de balance como medida de riesgo. El problema es formulado como un problema de optimización estocástico de dos etapas, lo que evita la formulación explícita de los mecanismos de formación de precios que resulta inevitable en los otros modelos considerados.
 - 3) Modelo con una única firma, formulado como un problema estocástico en el que se maximiza el beneficio social, y con demanda que responde al precio de la energía. La capacidad de respuesta de la demanda en este modelo puede ser interpretada, en el contexto de la integración de energía eólica en el sistema, como la actuación de un sistema de gestión de demanda implementado en el sistema y que permite acomodar parte de la variabilidad de la energía eólica mediante ajustes de la demanda.
- b) Modelos para múltiples períodos. En este caso se ha considerado el modelo de restricciones de rampa que se utiliza habitualmente en el problema de “unit commitment” [62], ya que toda la información necesaria para ello se encuentra en el modelo como variables endógenas. Aquí también se han considerado tres variantes, análogas a las descritas anteriormente, siendo las principales diferencias el modelo de restricción de rampa y la introducción de productos de rampa adicionales. Estos productos de rampa están definidos sobre varios períodos y su objetivo es incrementar la flexibilidad operativa del sistema y reducir el coste asociado a esa flexibilidad operativa. Los productos de rampa considerados aquí han sido propuestos en el MISO [14, 72], y todavía no han sido implementados, se encuentran en fase de discusión.
 - 1) Modelo con múltiples firmas, formulado como un problema de complementariedad, y con demanda que responde al precio de la energía. El interés de esta extensión (también

aplicable al modelo con múltiples firmas y período único) consiste en tener en cuenta que las incertidumbres asociadas a la generación eólica y sus efectos sobre el precio de la energía no son necesariamente internalizadas en un modelo de firma única, o alternativamente en un modelo donde el riesgo en el corto plazo puede ser objeto de negocio. Mientras que en un modelo con múltiples firmas, como el presentado aquí, y exceptuando la implementación de un mercado intradiario sofisticado o algún mercado financiero que permita ofertas virtuales, este tipo de gestión del riesgo no es posible.

- 2) Modelo con una única firma, formulado como un problema estocástico con demanda fija y en el que se minimiza el coste de generación.
- 3) Modelo con una única firma, formulado como un problema estocástico en el que se maximiza el beneficio social, y con demanda que responde al precio de la energía.

Seguidamente describimos con más detalle los dos modelos base (período único y múltiples períodos) para múltiples firmas, por contener los principales elementos representativos presentes en todos los modelos estudiados.

El modelo más general es formulado como un problema de equilibrio para múltiples firmas. Este modelo representa una industria en competencia perfecta donde la demanda responde al precio de la energía, esta respuesta es modelada mediante una función de demanda inversa lineal. Cada firma puede ser propietaria de generadores convencionales (despachables) y/o de aerogeneradores (no despachables). La generación eólica disponible en cada instante es el único parámetro con incertidumbre considerado en el modelo. Esta incertidumbre tiene un impacto sobre los ingresos y los costes de las firmas que deben acudir al mecanismo de balance, lo que se traduce en un riesgo para estas firmas. Esta incertidumbre es incorporada al modelo mediante un árbol de escenarios, consistente en diferentes escenarios de energía eólica disponible. Cada firma utiliza el CVaR, [85], como medida de su riesgo asociado a esa incertidumbre. Las firmas venden a su coste marginal y minimizan su coste de operación, incluyendo el coste de balance medido a través de su CVaR. Por lo tanto, cada firma resuelve un problema estocástico de dos etapas, una primera etapa que corresponde a las decisiones en el mercado diario (que no dependen explícitamente de los escenarios) y una segunda etapa para la operación en tiempo real, que corresponde al mecanismo de balance, y en el que las decisiones dependen explícitamente de los escenarios. El modelo en su conjunto es formulado como un problema de complementariedad, que incluye las condiciones de Karush-Kuhn-Tucker (KKT) de los problemas de las firmas y algunas ecuaciones adicionales necesarias para el cierre del mercado. En concreto, el modelo se compone de los tres siguientes grupos de ecuaciones:

- a) Las condiciones de KKT correspondientes a los problemas de cada firma.
- b) Las ecuaciones de balance global del mercado, que en este caso corresponden a la demanda de reserva en el sistema. El valor de referencia para la demanda de reserva es establecido por el TSO. En este caso no es necesario introducir ecuaciones globales para el balance de energía en el sistema porque ese balance se realiza a nivel de cada firma, la cantidad de energía que venden es igual a la cantidad de energía que generan.
- c) Las condiciones de KKT para el problema de minimización del coste de la energía utilizada de la reserva. Este problema representa una subasta de precio único organizada por el TSO con el objetivo de minimizar el coste de la corrección de desviaciones (desajustes entre la generación programada y la demanda programada). En este modelo solamente se consideran las desviaciones debidas a los aerogeneradores (incertidumbre en la generación eólica).

Cuando el modelo para múltiples firmas es particularizado para una sola firma eso no implica que se trate de un monopolio, ya que se sigue manteniendo la hipótesis de competencia perfecta y la firma vende a su coste marginal. El problema para firma única resulta más sencillo de analizar en términos económicos ya que la firma internaliza los riesgos asociados a ambos tipos de generadores, unidades despachables y aerogeneradores.

Los casos estudiados con los modelos de período único ponen de manifiesto la importancia de las restricciones de rampa. Las restricciones de rampa suelen estar definidas habitualmente sobre múltiples períodos, por lo que hemos extendido los modelos de período único para considerar múltiples períodos, en concreto, en los casos de estudio consideramos una representación horaria del mercado durante un día completo (24 períodos de una hora). Los principales cambios de los modelos con períodos múltiples respecto a los modelos de período único son:

- Un nuevo índice t que representa el período de tiempo se añade a las variables primales y duales, excepto a ζ_f , $Q_f^{k,-}$ y σ_f^k .
- El valor de la función objetivo se calcula ahora como la suma sobre el conjunto de períodos.
- Las restricciones de rampa siguen el modelo habitual usado en “unit commitment”, que incluye la capacidad de rampa movilizada para cambiar la generación entre períodos de acuerdo a los valores programados.
- Nuevos productos de rampa, siguiendo las propuestas en MISO, [14, 72], son considerados en algunas de las variantes de los modelos.

B.5 Conclusiones

Las energías renovables son consideradas como una de las mejores opciones para frenar el cambio climático, y entre estas fuentes, la energía eólica y la energía solar parecen ser las alternativas con mayor potencial. No obstante se trata de un tema sobre el que existen muchas controversias. Una de estas controversias a nivel práctico tiene su origen en el uso del “coste normalizado” como una medida de la competitividad de estas fuentes renovables. De acuerdo con este métrica los aerogeneradores instalados en la costa o el territorio interior son “casi” competitivos comparados con los generadores convencionales. Pero renombrados autores han argumentado que el coste normalizado no es una medida completa, ya que no es sólo una cuestión de coste, sino también de operación, y las fuentes intermitentes no son despachables, lo que es una gran desventaja respecto a los generadores convencionales. En esta tesis consideramos algunas de las cuestiones relacionadas con la despachabilidad en el marco de los mercados eléctricos europeos reestructurados. Surgen muchas cuestiones pero solo podemos abordar aquí algunas de ellas.

En contraste con los modelos diseñados para el mercado eléctrico en Estados Unidos, que pueden ser formulados como problemas de optimización completos, nosotros debemos tener en cuenta la separación del mercado de la energía, PX por una parte, y la gestión de la red y los servicios auxiliares, TSO, por otra parte. Porque esta separación es una de las reglas básicas de diseño de los mercados de energía eléctrica en Europa. Esto no significa que no podamos usar los modelos de optimización, sino que debemos considerarlos como una representación parcial (intermedia) en relación a los modelos de equilibrio que tienen en cuenta la interacción entre el PX y el TSO. De esta forma nosotros consideramos aquí

como modelo de referencia un modelo de equilibrio con múltiples firmas, del cual estudiamos algunos casos particulares con una firma única.

Si bien se puede discutir si el viento sigue siendo una fuente intermitente o se ha convertido en una fuente variable como resultado de la agregación de la generación en un área suficientemente extensa, lo cierto es que la generación eólica sigue siendo hoy en día una fuente con alta variabilidad y afectada por una considerable incertidumbre. Así pues, los modelos deben tener en cuenta esas características. De este modo se justifica el uso de un modelo de equilibrio estocástico como el que se utiliza en esta tesis.

Clasificamos aquí las cuestiones que surgen en relación a una alta penetración de energía eólica en los dos grupos siguientes:

- a) Cuestiones debidas principalmente a aspectos físicos y tecnológicos: Una mayor penetración eólica podría requerir una mayor reserva para el control de frecuencia en el sistema y también una mayor capacidad de rampa disponible.
- b) En el otro grupo de cuestiones se encuentran las relacionadas con el diseño del mercado y las modificaciones que las partes interesadas han ido introduciendo en los mecanismos inicialmente propuestos. En concreto en relación a la remuneración de las unidades convencionales y de los generadores eólicos así como la remuneración y las comisiones por los servicios prestados.

Por todo lo anterior, proponemos aquí un modelo general de equilibrio estocástico que tiene en cuenta la separación entre el PX y el TSO, permite múltiples firmas y considerar la remuneración y el cobro de los servicios auxiliares, y todo ello en un sistema con alta penetración de energías renovables, en concreto de energía eólica. Recurrimos a un equilibrio en lugar de a un enfoque de optimización, incluso en este caso sin poder de mercado, debido a las dos siguientes razones. Una primera razón es que el mercado está actualmente formado por diferentes empresas que comercializan la energía y los servicios, y la formulación como equilibrio es la expresión natural para esta situación. La segunda razón, quizá más convincente, es que las políticas sobre energías renovables se implementan a través de diferentes instrumentos de mercado, muchos de los cuales no pueden ser modelados en una forma de optimización. El modelo propuesto se inspira en sistema español, pero el enfoque es general. La aproximación propuesta puede considerar características generales del diseño del mercado (un sistema formado por dos subsistemas, PX y TSO), la idiosincrasia del mercado (una representación hasta cierto punto detallada del mercado de balance) y las características económicas generales de los agentes, en particular su aversión al riesgo. Al igual que en el caso de la programación estocástica, los modelos de equilibrio son susceptibles de incluir un tratamiento de la incertidumbre.

La penetración de energías renovables en el sistema eléctrico es un problema de considerable complejidad, por lo que parece recomendable abordarlo de forma progresiva avanzando en pequeños pasos. De esta forma ilustramos aquí el uso de los modelos propuestos sobre dos cuestiones, ambas motivadas por fenómenos observados en los actuales mercados eléctricos europeos, que ven como plantas convencionales necesarias para proporcionar servicios en el sistema son expulsadas del mercado debido a los bajos precios de la energía, que hacen que esas plantas no sean rentables.

Las principales contribuciones de este trabajo respecto a la literatura existente se resumen a continuación. En contraste con la mayor parte de la literatura en la que el problema de integración eólica se formula como un problema de optimización estocástico (por ejemplo [33, 34]) o robusto (por ejemplo [35]), nosotros lo formulamos en términos de equilibrio con agentes con aversión al riesgo. Justificamos nuestra formulación en las siguientes razones:

- Los incentivos utilizados habitualmente para promover la integración de energía eólica como “Feed-in premium” y “Feed-in Tariffs” implican distorsiones en el mercado que son incompatibles con las condiciones de competencia perfecta que implica una formulación basada puramente en la optimización, como por ejemplo la existencia de dos precios para un mismo producto en un único mercado.
- Los incentivos como “Feed-in premium” y “Feed-in Tariffs” conllevan exposiciones al riesgo que pueden ser muy diferentes para las unidades convencionales y para los aerogeneradores. Exceptuando un mecanismo de ofertas virtuales que no existe actualmente en Europa, estos riesgos no son negociables. Por lo que es necesario considerar varios agentes que se enfrentan a diferentes riesgos no negociables para estudiar el sistema real. Esto no puede hacerse con una formulación de firma única, ya sea estocástica, robusta o de optimización de la función de riesgo, del problema.
- Los sistemas europeos implementan idiosincrasias que introducen distorsiones adicionales en el mercado, como por ejemplo la que se considera en los modelos aquí desarrollados, y que consiste en usar los precios del mercado diario en el mercado de balance independientemente del estado del mundo en tiempo real. Este paso hacia adelante del precio de la energía es justamente lo contrario de lo que sucede en la programación estocástica, en la que los precios en el mercado diario tiene el valor de la esperanza matemática de los precios en tiempo real.

De forma que en resumen creemos que la formulación como modelo de equilibrio es un buen punto de partida que resulta de utilidad para estudiar el diseño de los mercados eléctricos en Europa.

Utilizamos este marco conceptual para indagar en la pérdida de competitividad de las unidades convencionales que ha acompañado al incremento de la penetración de energía eólica en Europa. Examinas el efecto combinado del impacto de las primas a la generación eólica y de una asignación adecuada del precio a la reserva sobre los ingresos de las unidades convencionales, y contrastamos los resultados debidos a ambos factores. La posibilidad de contratar abundante reserva para flexibilidad con escasa antelación a su uso lleva a una pérdida de competitividad de las plantas convencionales, mientras que por el contrario, la necesidad de programar la reserva con muchas horas de antelación lleva a unos ingresos para las plantas convencionales que compensan sus pérdidas en el mercado de la energía.

De esta forma hemos desarrollado un modelo de equilibrio en el corto plazo para sistemas de energía eléctrica con alta penetración de energía eólica, en los que los productores eólicos se benefician de una prima a la generación eólica, y cada agente resuelve un problema de programación estocástica en dos etapas. El mecanismo de balance y el mercado de reserva son gestionados por el TSO. En particular el modelo se usa para estudiar las siguientes cuestiones:

- Operación óptima de los generadores bajo incertidumbre.
- Efecto de la prima a la generación eólica y del nivel de aversión al riesgo de los agentes sobre el equilibrio de mercado.
- Impacto de diferentes factores estructurales sobre los ingresos de los generadores despachables y de los aerogeneradores.

Ilustramos el uso de los modelos propuestos centrándonos en una cuestión que ha estado presente en los mercados eléctricos europeos por un largo período de tiempo y que sigue

estando presente en los mercados actuales, y que consiste en los conceptos por los que las plantas convencionales reciben ingresos. La idea comúnmente admitida actualmente, que coincide con lo que se observa en los mercados, es que un incremento en la penetración de energías renovables en el mercado induce una reducción del precio de la energía y, al mismo tiempo, una reducción de la actividad y de los ingresos de las plantas convencionales, que puede hacer que estas plantas no sean económicamente sostenibles en el mercado. Aquí usamos los modelos para ilustrar que este fenómeno resulta bastante estable ante diferentes hipótesis estructurales, por ejemplo, resulta el mismo orden de magnitud en las pérdidas de ingresos para hipótesis bastante diferentes de primas a la generación eólica y nivel de aversión al riesgo de los agentes. Por otra parte, los modelos también muestran que el fenómeno puede depender fuertemente de la demanda de servicios auxiliares (aquí consideramos únicamente mantenimiento de la frecuencia) inducida por la integración de fuentes renovables, y el mecanismo de asignación de precios a estos servicios auxiliares. Ambas cuestiones son polémicas: el incremento en la demanda de reserva debido a la integración de generación renovable no es una cuestión totalmente resuelta [34, 44, 45, 60, 61, 81–83], y el mecanismo de asignación de precios a los servicios auxiliares presenta tantas variantes como sistemas eléctricos hay en Europa. Aquí modelamos la demanda de reserva mediante un coeficiente exógeno y adoptamos un mecanismo de asignación de precios para los servicios auxiliares, tanto para capacidad de reserva como para energía procedente de la reserva, que es sencillo pero consistente con los principios económicos. Como resultado hemos encontrado que incrementar la demanda de reserva, junto con una asignación de precios económicamente coherente para este servicio (precio a coste marginal) restablece los ingresos de las plantas convencionales. De esta forma la cuestión de la sostenibilidad económica de las plantas convencionales lleva a una adecuada identificación de la demanda de servicios auxiliares (teniendo en cuenta también la posible provisión de estos servicios por los propios aerogeneradores) y la aceptación de que estos servicios sean remunerados apropiadamente.

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