# High Wind Generation and Revenue of Conventional Generators using A Stochastic Two Settlement Equilibrium Model for Electricity Markets with Wind Generation

Yves Smeers[1,2]

The Economics of Energy Markets
IDEI, Toulouse

5 and 6 June 2014

[1] CORE, Université catholique de Louvain, Louvain La Neuve, Belgium.

[2] These notes are based on joint work with S. Martín (Universidad de Málaga), and J. A. Aguado (Universidad de Málaga). Errors and shortcomings in this presentation are mine.

# Outline

# Problem Statement

# Context

Massive impairment of conventional generation capacities in Europe:

- a system based on energy price,
- leads to mothballing or dismantling of non subsidized conventional units
- when energy price tumble as a result of subsidized wind penetration.

But conventional plants provide some of the flexibility demanded by wind generation:

- and hence they (or at least part of them) should remain in the system.
- The question is to remunerate these services
- which implies quantifying the demand of these services and pricing them.

This may be difficult:

- "There's plenty of flexibility-but so far it has no value" (Agora Energiewende, February 2013);

# Focus

Intermittent sources raise several questions and corresponding modeling difficulties.

- Macro questions: subsidies may not always be easy to control (and model):
  - we use Feed in Premium and parametrize on the premium.
- Micro questions: generation variability and forecasting errors require particular services:
  - we concentrate (still very partially) on balancing and flexibility reserve due to wind.

This is work in progress in the following sense:

- we believe we have a rather general modeling set up;
  - but not general enough for certain issues (a proper modeling of ramping);
- we believe we have a reasonable case study.
  - but it raises more questions than it solves (as Agora Energiewende: where is the value of flexibility?)

# Economic issues

We look for certain policy induced market imperfections:

- "Renewable support schemes" EC, November 2013.
    - The feed in premium (FIP) is meant to replace the Feed in Tariff;
        - The premium is received when it is economical to produce
        - but the premium can also induce to uneconomic production.
    - Equal access to the grid: wind and conventional capacities may require different services; but the cost of these services is socialized to guarantee equal access:
        - conventional plants are paid for the flexibility that they provide;
        - conventional and wind plants pay and are paid for balancing;
        - but neither conventional nor wind plants pay for the reservation of flexibility reserve in day ahead.
    - Imperfect two settlement systems (see below)
- Is it really difficult to get the money of flexibility?
- Can market imperfection create havoc in the system?

No discussion of market power!

# The Market and the Model

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.

# The Agents

Conventional and wind generators:

- trade energy and flexibility reserve;
- consume and produce balancing services.

Final consumer:

- price sensitive but shielded from balancing risk; pays for socialized flexibility reserve (out of model).

Government:

- subsidizes wind through FIP.

EU Market design:

- the PX deals with the energy market,
- the TSO deals with flexibility reserve and balancing (here: reserve due to wind only; no congestion).

All agents are price taker!

# The Short run market (1)

A two settlement hourly system (for the time being):

**In day ahead**:

- PX runs a zonal energy market; clearing and settlement in day ahead.
  - plant indivisibilities in energy through bloc bids (supposed to be an unimportant and hence linearized);
  - generators (conventional and wind) and consumers submit bids;
  - the market clears and determines the day ahead prices; wind generators receive the energy price plus the FIP.
- The TSO runs an auction for upward and downward flexibility reserve
  - that satisfies certain constraints (in general idiosyncratic to the system)
  - based on scheduled wind and conventional generators
  - where flexibility reserve needs may differ by generator type.

# The Short run market (2)

**In real time**:

- the TSO deals with deviation and operates balancing to minimize ramp up and ramp down energy costs, using flexibility reserve committed in day ahead. This gives upward and downward balancing price.
- For balancing.
  - Wind turbine that under delivers pays the upward balancing price plus the FIP on the deviation (it doe not receive the premium for the scheduled but undelivered wind).
  - Wind turbine that over delivers receives the day ahead price (but not the premium) and pays for the downward balancing price.
  - Conventional generator that ramps up receives the upward balancing price.
  - Conventional generator that ramps down receives the downward balancing price but has to give up the day ahead energy price.

# Wind and its insertion in the market design (1)

**Focus on the short term market in this paper**:

- FIP remunerates wind above market to facilitate penetration; this is not discussed here.
- We only look at FID as an incentives for wind to bid in day ahead (FIP lost for wind generated in balancing).
- We focus on reserve
  - needed to compensate for error forecast (the focus of this paper)
  - but also for providing ramping gradient for several hours.
  - Our treatment of this second objective is very approximate.

**But we are also interested in imperfections of market design**

- Cash flows in balancing involving day ahead price
  - this violates the usual backward recursive processing of expectations
  - a common feature in Europe.
  - a market power mitigation scheme if the model had market power .

# Wind and its insertion in the market design (2)

Wind uncertainty

**Over the year**:

- A distribution of wind-days:
  - the more wind, the lower the electricity price and the utilization of conventional power plants;
  - wind days distribution and wind generation capacity thus impact
    - cash flow in the energy market
    - and the demand for flexibility reserve.

**Within a day**

- A forecast of wind generation at some time (horizon of wind forecast determines error forecast)
  - The wind forecast error must be compensated in real time.
  - The larger the error (in fact the longer the forecast horizon) the larger the demand for flexibility reserve.

# Wind and its insertion in the market design (3)

In order to simplify the presentation (not for computational purposes) we assume that only wind forecast error and variability induce a need for reserve.

- Flexibility reserve: for (i) wind forecast error between forecast time and real time and (ii) variability over several hours intervals (ramping).
- Need for flexibility reserve dynamically determined by TSO and committed in day ahead. For illustrative and comparison purposes in this presentation:
    - stylized TSO criteria modeled by (strong) balancing reserve factors (Mw of reserve/Mw scheduled) (0.02 conventional; 0.15 wind).
- Conventional plants remunerated for providing flexibility reserve at opportunity cost (dual variables of some constraints in the equilibrium problem but other versions of model assume otherwise).
- Committed flexibility reserve cost (not balancing) paid by final consumer (through network charge, and hence not part of the problem): market imperfection.

# Technicalities

# Model Structure

A complementarity problem that consists of three groups of equations:

1. Day ahead market clearing of day ahead of
   - flexibility reserve by the TSO.
   - energy by the PX
2. Real time market clearing of balancing (or cost minimization of balancing) by the TSO: The KKT conditions representing the minimization of balancing cost using committed flexibility reserve
3. Firms' risk adjusted profit maximization over day ahead and real time: The KKT conditions of the risk adjusted profit maximization problem of each firm; they only include the conditions for which the firm makes explicit decisions, taking market prices (energy, committed reserve capacity and balancing energy) as given.

Note : No MPEC or EPEC model: we stick to price taking agents.

# Model Flexibility

Market structure:

1. Several firms in competition: the idea is to test the impact of generation structure and risk aversion.
2. This has been tested numerically but not on a case study. We here work with a single firm that owns all generation assets
3. Ownership is not important under assumption of perfect competition. Our model assumes price taking agents, but not complete risk trading. Ownership is thus relevant under our assumptions.

Parameters

1. Generation structure
2. Wind scenario, FIP, Agent's risk aversion Risk aversion, MW of reserve/MW of scheduling requirements

# Risk exposures

Recall wind generation is uncertain: conventional and wind generators are risk averse (*CVaR*) :

- Deterministic cost and revenue in day ahead; *CVaR* adapted balancing cost and revenue in real time; parameterized risk aversion.

Final consumer:

- No risk exposure: day ahead surplus.

Government:

- No risk exposure, only pays FIP for day ahead wind energy.

TSO:

- Risk neutral with respect to balancing cost

# All this may imply non convexities

From market design:

- Equal grid access: providers of flexibility reserve providers are remunerated, but consumers of flexibility reserve are not charged for that consumption
- Energy price determined in day ahead intervenes in balancing cost in real time cash flows.

Non convexities due to different valuation of risk

- Endogenous pricing kernel of the generators different from exogenous pricing kernel of TSO

Possible consequence: PATH did not always solve the problem; we had to devise some iterative procedure (recursive use of PATH) to find equilibria

# Case Study

# Case Study Description. Generators Data

**Recall: a single firm owns all generation assets in this paper**:

| Technology | Net Capa. $\overline{X}_g$ (MW) | N. of units | Aver. age (years) | $cg_g$ (€/MWh) | $\overline{R}_g = \underline{R}_g$ % of $\overline{X}_g$ |
|---|---|---|---|---|---|
| CCGT | 4395.86 | 10 | 10.7 | 45.82 | 53.33 |
| CCGT | 21265.40 | 43 | 6.2 | 43.45 | 53.33 |
| Nuclear | 1519.23 | 2 | 32.2 | 10.91 | 2.08 |
| Nuclear | 6053.35 | 6 | 28.0 | 10.29 | 2.08 |
| Coal | 2035.89 | 4 | 25.1 | 37.50 | 20.00 |
| Coal | 5119.13 | 18 | 34.8 | 38.44 | 25.00 |
| Coal | 1198.12 | 4 | 34.8 | 19.77 | 25.00 |
| Coal | 1945.51 | 5 | 34.8 | 20.24 | 25.00 |
| Wind | 22573.00 | - | - | - | - |
| **Total** | **66105.49** | | | | **16315.53** |

# Case Study Description. Uncertainty Modeling

| 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 |
| $\mu$ (%)[1] | 4.01 | 23.83 | 46.70 | 65.00 |
| $\sigma$ (%)[1] | 2.73 | 6.66 | 11.20 | 14.83 |
| max. (base $\mu$) | 2.64 | 1.57 | 1.45 | 1.37 |
| min. (base $\mu$) | 0.15 | 0.53 | 0.57 | 0.55 |

# Results

1. High wind lowers energy price but does not increase reserve price!
2. High FIP and high risk aversion (respectively positive and negative incentive to wind) do not have much impact (single firm?).
3. But a change of error forecast/ramping requirement can have a significant effect:
   - error forecast and committing flexible reserve longer in advance imply more reserve per wind scheduling and higher price for flexibility reserve
   - but impact disappears with more flexible reserve.
4. as stated by Agora Energiewende it is difficult to get paid for reserve at least when residual capacity is or can quickly become abundant.
5. Implying that plant retiring is likely to continue except if reserve needs to be committed long in advance (24 hours).
6. More intriguing: equilibrium maybe driven by reserve constraints (TSO) more than energy (PX) when demand for reserve is high.
7. With an unexpected consequence: tight reserve constraints with improper payment by those that require it can lead to a multiplicity of isolated equilibrium.

# High wind reduces energy price without increasing reserve price

High wind lowers both energy and reserve price:

- lowering of energy price was expected;
- lowering of reserve price more surprising ex ante but reasonable ex spot: high wind releases conventional plants for reserve.

| | | |
|---|---|---|
| $\mu$ (%) expected wind | 4.01 | 65.00 |
| $\rho^+$ (€/MWh) premium | 30.00 | 30.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 |
| Demand day ahead (Mwh) | 27988.89 | 29639.08 |
| Schedu. win. gen. (Mwh) | 873.91 | 9696.58 |
| Schedu. dispat. gen. (Mwh) | 27114.99 | 19942.50 |
| Equilibrium price (€/MWh) | 52.71 | 43.45 |
| Reserve requirement (MW) | 673.39 | 1853.34 |
| Up. reserve commit. (MW) | 740.72 | 1671.87 |
| Down. reser. commit. (MW) | 590.69 | 668.76 |
| Max. available reserve (MW) | 740.72 | 4565.81 |
| PROFIT (€) | | |
| Total (wind + dispatch.) | 679970.16 | 1090024.90 |
| Total dispatch. | 624575.12 | 400575.62 |

High generation capacity, 28.5 GW and low ramping (43.45 is the fuel cost of the marginal CCGT).

# Incentive/disincentive to bid wind does not drastically change the outcome

Note: recall this is a single firm case study dealing with the sole short term.

| | Wind premium | | Risk aversion | |
|---|---|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 | 30.00 | 30.00 |
| $\lambda$ risk aversion | 0.40 | 0.40 | 0.00 | 1.00 |
| Demand day ahead (Mwh) | 29639.08 | 29639.08 | 29639.08 | 29639.08 |
| Schedu. win. gen. (Mwh) | 3839.26 | 3850.16 | 4088.30 | 3548.96 |
| Schedu. dispat. gen. (Mwh) | 25799.82 | 25788.92 | 25550.78 | 26090.12 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 | 43.45 | 43.45 |
| Reserve requirement (MW) | 1091.89 | 1093.30 | 1124.26 | 1054.15 |
| Up. reserve commit. (MW) | 986.04 | 996.94 | 1235.07 | 1159.56 |
| Down. reser. commit. (MW) | 395.94 | 398.79 | 1235.07 | 463.83 |
| Max. available reserve (MW) | 1442.10 | 1447.92 | 1574.92 | 1287.29 |
| PROFIT (€) | | | | |
| Total (wind + dispatch.) | 537760.04 | 838180.53 | 676816.04 | 632872.83 |
| Total dispatch. | 377902.41 | 384151.89 | 418413.39 | 375904.33 |

High generation capacity, 28.5 GW and low ramping (43.45 is the fuel cost of the marginal CCGT). More sensitivity with low capacity but the overall effect remains unimportant.

# Conventional plants recover when the demand for reserve increases

Higher demand for reserve can result from higher forecast error (time to commit) or higher ramping requirement (more hours to ramp).

| | Feed-in Premium and 6 hours to commit $m_y = 15\%$ | | Feed-in Premium and 24 hours to commit $m_y = 60\%$ | |
|---|---|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 | 0.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 | 0.40 | 0.40 |
| Demand day ahead (Mwh) | 29639.08 | 29639.08 | 27667.11 | 27717.02 |
| Schedu. win. gen. (Mwh) | 3839.26 | 3850.16 | 4578.05 | 7012.83 |
| Schedu. dispat. gen. (Mwh) | 25799.82 | 25788.92 | 23089.06 | 20704.18 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 | 54.52 | 54.24 |
| Reserve requirement (MW) | 1091.89 | 1093.30 | 3208.61 | 4621.78 |
| Up. reserve commit. (MW) | 986.04 | 996.94 | 2887.75 | 4159.60 |
| Down. reser. commit. (MW) | 395.94 | 398.79 | 1162.93 | 1673.49 |
| Max. available reserve (MW) | 1442.10 | 1447.92 | 2887.75 | 4159.60 |
| PROFIT (€) | | | | |
| Total (wind + dispatch.) | 537760.04 | 838180.53 | 941590.72 | 1398010.31 |
| Total dispatch. | 377902.41 | 384151.89 | 705004.20 | 672048.76 |

High generation capacity, 28.5 GW and low ramping (43.45 is the fuel cost of the marginal CCGT).
Important note: the equilibrium is now driven by the tightness of reserve (which is not properly priced in this market design)

# But not if plants are also more flexible

Impact of ramping and time needed to commit reserve .

| | Feed-in Premium and 6 hours to commit $m_y = 15\%$ | | Feed-in Premium and 24 hours to commit $m_y = 60\%$ | |
|---|---|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 | 0.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 | 0.40 | 0.40 |
| Demand day ahead (Mwh) | 29639.08 | 29639.08 | 29639.08 | 29639.08 |
| Schedu. win. gen. (Mwh) | 3835.48 | 3847.65 | 4849.80 | 7085.21 |
| Schedu. dispat. gen. (Mwh) | 25803.60 | 25791.43 | 24789.28 | 22553.87 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 | 43.45 | 43.45 |
| Reserve requirement (MW) | 1091.39 | 1092.98 | 3405.66 | 4702.20 |
| Up. reserve commit. (MW) | 982.26 | 994.43 | 3065.10 | 4231.98 |
| Down. reser. commit. (MW) | 624.94 | 994.22 | 1226.04 | 1692.79 |
| Max. available reserve (MW) | 2700.33 | 2712.50 | 3714.65 | 5950.06 |
| PROFIT (€) | | | | |
| Total (wind + dispatch.) | 534467.58 | 844864.32 | 561937.27 | 1014924.34 |
| Total dispatch. | 374710.28 | 382622.68 | 363950.35 | 361765.11 |

Price is down and reserve is no longer tight.

# As expected, lower capacity increases prices and restores the profit of the conventional generators.

Impact of excess capacity with respect to feed in premium .

| | High capacity (28.5 GW) $m_y = 15\%$ | | Low capacity (25 GW) $m_y = 15\%$ | |
|---|---|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 | 0.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 | 0.40 | 0.40 |
| Demand day ahead (Mwh) | 29639.08 | 29639.08 | 27148.44 | 27182.23 |
| Schedu. win. gen. (Mwh) | 3839.26 | 3850.16 | 3979.04 | 4027.11 |
| Schedu. dispat. gen. (Mwh) | 25799.82 | 25788.92 | 23169.40 | 23155.11 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 | 57.43 | 57.24 |
| Reserve requirement (MW) | 1091.89 | 1093.30 | 1060.24 | 1067.17 |
| Up. reserve commit. (MW) | 986.04 | 996.94 | 1166.27 | 1173.89 |
| Down. reser. commit. (MW) | 395.94 | 398.79 | 1088.09 | 472.17 |
| Max. available reserve (MW) | 1442.10 | 1447.92 | 1166.27 | 1173.89 |
| PROFIT (€) | | | | |
| Total (wind + dispatch.) | 537760.04 | 838180.53 | 968664.03 | 1259699.89 |
| Total dispatch. | 377902.41 | 384151.89 | 747454.78 | 733187.01 |

Results with low ramping capability. But the equilibrium is of a different nature: Price increases because lower capacity tightens the reserve constraints.

# This could already be observed with high capacity and high demand for reserve.

High demand for reserve ($m_y = 60\%$) leading to tight reserve constraints may induce a multiplicity of disjoint equilibria. Results with high generation capacity (28.5 GW) and low ramping.

| | High capacity (28.5 GW), Low ramping, $m_y = 60\%$ | | | |
|---|---|---|---|---|
| | Algor. 1 | Algor. 2 | Algor. 1 | Algor. 2 |
| $\mu$ (%) expected wind | 23.83 | 23.83 | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 0.00 | 80.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 | 0.40 | 0.40 |
| Demand day ahead (Mwh) | 22620.46 | 27717.02 | 26836.06 | 27717.02 |
| Schedu. win. gen. (Mwh) | 9256.57 | 7012.83 | 6979.66 | 7012.83 |
| Schedu. dispat. gen. (Mwh) | 13363.89 | 20704.18 | 19856.41 | 20704.18 |
| Equilibrium price (€/MWh) | 82.85 | 54.24 | 59.18 | 54.24 |
| Reserve requirement (MW) | 5821.22 | 4621.78 | 4584.92 | 4621.78 |
| Up. reserve commit. (MW) | 6403.34 | 4159.60 | 4126.43 | 4159.60 |
| Down. reser. commit. (MW) | 2561.34 | 1664.78 | 4126.43 | 1663.91 |
| Max. available reserve (MW) | 6403.34 | 4159.60 | 4126.43 | 4159.60 |
| PROFIT (€) | | | | |
| Total (wind + dispatch.) | 2711129.55 | 972551.61 | 1766091.85 | 1392235.88 |
| Total dispatch. | 2159419.19 | 680619.90 | 1030837.04 | 686784.65 |

Results with low ramping capability. But the equilibrium is of a different nature: Price increases because lower ramping capacity tightens the reserve constraints.

# Conclusion

# Conclusions (1)

- Some phenomena are expected: wind decreases price and the profits of conventional generator.
  - this derives from the functioning of the PX and is a direct result of the inception of the renewable policy in the electricity restructuring.
- Possibly less obvious: the demand for reserve does not generally offer a compensation
  - because existing plants not used for energy provide the reserve at no opportunity cost "flexibility... so far has no value".
- Analysis shows that the outcome depends on the demand for reserve.
  - that itself depends on (i) the time between committing the reserve and real time and (ii) MW of reserve/Mw of scheduled wind requirement.
  - the design of the intraday market moving from a pure energy to an energy/capacity intraday) may reduce the former but is unlikely to change the latter.
- But even that result is not robust
  - because more flexible plants can easily respond to the demand.
  - The question is thus whether one is willing to install more flexible plant that run the risk of being stranded after a few years.

# Conclusions (2)

- In short "The major challenge in accomplishing this is not about technical implementation, but about providing effective incentives (Agora Energiewende February 2013) "
  - In the meantime there is no other choice but impairing the idle plants and wait for what will happen.
- But other problems may come up
  - that we illustrated on an other case of high demand for reserve
- Reserve constraints become tight and drive the equilibrium price
- But reserve constraints are not priced properly because of the "equality of access" principle
- This leads to a multiplicity of equilibria, which is not what one expects from a well designed market.
- (again not a surprise: "equality of access" explicitly introduces an externality in the system)

# Back up slides

# Model Overview

# Global View

## Day ahead

given wind forecast
find the energy equilibrium $x$, $y$, $d$
and the flexible reserve equilibrium $ru$, $rd$
**s.t.** energy balance
and idiosyncratic flexibility reserve constraints

## Real time

given wind realization
balance energy

**s.t.** availability from flexible reserve

| | | |
|---|---|---|
| consumer | willingness to pay | |
| producer | profit in day ahead price of energy and flexibility reserve | producer E-CVaR of cost/profit from adjustment |

# Groups of Equations in the model

Modelled as equilibrium, not as optimization problem.

**Firms' Problems:maximize profit s.t.**

- Units' capacity constraints
- Ramping constraints

**Efficiently balancing the system from reserves s.t.**:

- Restriction to the reserve capacity committed.
- Market clearing from day ahead is an input data.

**Global constraints:**

- Balancing generation-energy sales in day ahead
- Requirement for upward and downward reserves in day ahead
- Balancing energy in real time

# Some Detail

# Wind Uncertainty

# Wind Uncertainty (1)

We use a Beta distribution to model the wind power forecast error (2002 Bofinger and 2005 Fabbri). Let the load factor for wind generation be $q = \frac{\text{Power output}}{\text{Rated power}} \in [0, 1]$:

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

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 $\alpha$ and $\beta$ are directly related with the mean ($\mu$) and the standard deviation ($\sigma$) of the distribution:

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

The analysis of empirical data shows that $\sigma$ properly fits a linear function of $\mu$, $\sigma = k_1 \cdot \mu + k_2$, (2002 Bofinger, 2005 Fabbri and 2009 Ortega) 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 (2009 Ortega) for a time horizon of 24 h and large scale generation (normalized by the wind capacity installed):

$$\sigma = \frac{1}{5}\mu + \frac{1}{50} \quad \text{(in per unit)} \tag{3}$$

# Wind Uncertainty (2)

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 $k$: $\mu(k) = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha}(1-x)^{\beta-1} dx$, 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: $\frac{1}{n} = \int_{z_k}^{z_{k+1}} \frac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} x^{\alpha-1}(1-x)^{\beta-1} dx$, $k = 1, 2, \dots, n$.

# The Markets

# Day Ahead Market

- Two main purposes.
  - Clearing of energy market: Sales $d$, and scheduled wind generation $y$, and dispatchable generation $x$.
  - Commitment of flexibility reserve for balancing mechanism (upward $ru$, and downward $rd$).
- Day-ahead variables are not contingent on wind scenarios:
  - The equilibrium price, $\rho^*$, the sales, $d$, and capacity for upward $ru$ and downward $rd$ flexibility reserve are fixed in day ahead, and are not modified by the balancing mechanism.
  - But the anticipation of the balancing outcomes (in the different wind scenarios) affects the day ahead market.
- If there are differences between the scheduled and real time wind generations, then the flexibility reserve (upward or downward) is deployed, and the value of the total sales $d$ is not altered.
- Scheduled wind generation, $y$, receives a subsidy as a premium, $\rho^+$, that is additive to the equilibrium price.
- This premium and the organization of balancing affect the arbitrage between day ahead and real time.

# The Reserve Market (1)

**Global constraints** (Dual variables in brackets)

$$\sum_{g \in G} ru_g \geq 0.9(m_x \cdot \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l), \qquad (\overline{\kappa}) \qquad (4)$$

$$\sum_{g \in G} rd_g \geq 0.4 \cdot \sum_{g \in G} ru_g, \qquad (\underline{\kappa}) \qquad (5)$$

$$\sum_{g \in G} ru_g \leq 1.1(m_x \cdot \sum_{g \in G} x_g + m_y \cdot \sum_{l \in G} y_l), \qquad (\overline{\gamma}) \qquad (6)$$

$$\sum_{g \in G} rd_g \leq \sum_{g \in G} ru_g, \qquad (\underline{\gamma}) \qquad (7)$$

**Ramping constraints. They are in the firms' problems, and $\Lambda \in \{0, 1\}$**

$$ru_g \leq A_{3_g} \cdot (\overline{X}_g^{max} - \Lambda \cdot x_g), \qquad (\bar{\delta}_g) \quad \text{(ramp up)} \qquad (8)$$

$$rd_g \leq A_{5_g} \cdot (\overline{X}_g^{max} - \Lambda \cdot x_g), \qquad (\underline{\delta}_g) \quad \text{(ramp down)} \qquad (9)$$

where $A_3 = A_5 = 0.1$ for 10% ramping, and $A_3 = A_5 = 0.2$ for 20% ramping.

# The Reserve Market (2)

**Assumptions in the Implemented Reserve Market**

- Only load-following reserve to be used in balancing due to wind forecast errors:
  - Short term: 24h to 4h (reserve tradable in the market).
  - Only deviations from wind forecast errors.
- They are called Flexibility Reserve in the model

| | **Capacity** | **Energy** |
|---|---|---|
| **Price** | Lagrange multipliers for reserve constraints, $(\overline{\kappa}+\overline{\gamma})$ and $(\underline{\kappa}+\underline{\gamma})$ | Lagrange multipliers for energy from reserve constraints, $\overline{\chi}^k$ and $\underline{\chi}^k$ |
| **Quantity** | Lower and upper bounds. Estimations based on flexibility reserve factors. Equilibrium result | From balancing (uncertainty in wind availability). Equilibrium result |

# The Reserve Market (3)

Comment on reserve model:

- Constraints (4)-(7) are meant to represent TSO rules; constraints (8) and (9) are crucial technical constraints (ramping).
- **Balancing reserve factors** model:
  - Balancing reserve factors are meant to reflect the uncertainty affecting each kind of technology: 1) Time horizon $\leq$ 6h, 15% for wind, 2% for dispatchable, 2) Time horizon 24h, 60% wind, 2% dispatchable.
  - Reserve up in $\pm 10\%$, $[0.9, 1.1]$, of the requirement, equations (4) and (6), inspired by Spanish TSO rules.
  - Lower bound for downward reserve 40% of the reserve up, eq. (5), and upper bound of downward reserve eq. (7).

# The Balancing Market (1)

**Case of wind shortage**

1) The additional energy required is taken from the upward flexibility reserve.
2) Wind turbines have to pay the balancing price for the energy that they require (Lagrange multiplier associated with the constraint of upward flexibility reserve in balancing). In addition, the wind turbine looses the premium for the energy taken from the flexibility reserve.
3) The dispatchable generators that provide the energy get the balancing payed by wind turbines; but they incur their generating cost.

# The Balancing Market (2)

**Case of wind excess**

1) The decreased conventional energy required is taken from the downward flexibility reserve.
2) Wind turbines only receive the feed-in premium for the scheduled generation, and not for the wind in excess.The premium they received for the schedule generation comes on top of the market equilibrium price.
3) Dispatchable generators loose the equilibrium price for their decreased generation but receive the energy price from downward flexibility reserve. They also save the generation cost. The operation is generally profitable for dispatchable generators.

# The Balancing Market (3)

The price and amount of balancing energy from committed flexibility reserve results from a perfectly competitive market modeled as an optimization problem that minimizes the generation cost of balancing energy. An auction organized by the TSO is modeled, for each scenario $k$ as an optimization problem.

$$\underset{s_g^k, u_g^k}{\text{minimize}} \sum_{g \in G} \left( s_g^k \cdot cg_g - u_g^k \cdot cg_g \right) \tag{10}$$

$$\text{subject to: } \sum_{g \in G} s_g^k = \sum_{l \in G} z_l^k, \qquad (\underline{\chi}^k) \tag{11}$$

$$\sum_{g \in G} u_g^k = \sum_{l \in G} v_l^k, \qquad (\overline{\chi}^k) \tag{12}$$

$$s_g^k \leq ru_g, \qquad (\overline{\eta}_g^k) \tag{13}$$

$$u_g^k \leq rd_g, \qquad (\underline{\eta}_g^k) \tag{14}$$

# The Balancing Market (4)

In the problem of minimization of generation cost from flexibility reserves:

- The variables are $s_g^k$ (energy from upward flexibility reserve) and $u_g^k$ (energy from downward reserve).
- The data are: The committed upward ($ru_g$) and downward ($rd_g$) reserve as well as the demand of energy from the upward ($z_l^k$) and downward ($v_l^k$) reserve.
- The interpretation is: Minimizing the cost implies using the generators with the minimum generation cost for upward reserve and the generators with the maximum cost for the downward reserve.
- The constraints in the problem are: The balancing equations for energy used by wind turbines and energy provided by dispatchable generators for downward reserve, upward reserve. And the upper bound for energy from committed upward reserve and committed downward reserve.
- Price for energy from upward reserve: $\overline{\pi}^k = \underline{\chi}^k$.
- Price for energy from downward reserve: $\underline{\pi}^k = \overline{\chi}^k$.

# The Balancing Market (5): Summing Up

- Objectives:
  - solve deviations using the flexibility reserve.
  - assign a price to deviations and charge the corresponding cost of corrections to each firm $f$ through the Recourse Function, $Q_f$.
- Four groups of terms in the firm's Recourse Function (in profit terms):

| | Dispatchable generators | Wind turbines |
|---|---|---|
| Wind shortage | $s_g^k \cdot (\overline{\pi}^k - cg_g)$ | $-z_l^k \cdot (\overline{\pi}^k + \rho^+)$ |
| Wind excess | $u_g^k \cdot (cg_g + \underline{\pi}^k - \rho^*)$ | $v_l^k \cdot (\rho^* - \underline{\pi}^k)$ |

- The cash flows appearing in the second step of firms' $f$ objective functions are assembled in risk adjusted valuations through $CVaR$:

$$-(1-\lambda) \cdot E[Q_f] - \lambda \cdot CVaR_\theta(Q_f) \quad \text{in profit terms} \tag{15}$$

where $\lambda$ is the level of risk aversion.

# Summing up: the Pay-offs

To sum up: payoff of generator $f$ owning both conventional ($g$) and/or wind ($l$) plants.

In **day ahead**:

- Energy: cash flow from energy sales.

$$(\rho_0 - \alpha_0 \cdot \sum_{h \in F} d_h) \cdot d_f + \sum_{l \in G_f} y_l \cdot \rho^+ - \sum_{g \in G_f} x_g \cdot cg_g \qquad (16)$$

- Flexibility reserve market: cash flow from capacities.

$$\sum_{g \in G_f} (ru_g \cdot (\overline{\kappa} + \overline{\gamma}) + rd_g \cdot (\underline{\kappa} + \underline{\gamma})) \qquad (17)$$

In **real time**, balancing (cost in scenario $k$):

- Wind shortage

$$\sum_{g \in G_f} s_g^k \cdot (cg_g - \overline{\pi}^k) + \sum_{l \in G_f} z_l^k \cdot (\overline{\pi}^k + \rho^+) \qquad (18)$$

- Wind excess

$$\sum_{g \in G_f} u_g^k \cdot (\rho^* - cg_g - \underline{\pi}^k) + \sum_{l \in G_f} v_l^k \cdot (\underline{\pi}^k - \rho^*) \qquad (19)$$

# Technical Issues

# Solving Approach (1)

The 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 $Q_f^k$.
- From the CVaR constraint:
  - KKT condition for the wind energy generated in excess $v_l^k$.
  - KKT condition for the energy bought by the wind turbines, due to wind shortage, in order to fulfill their delivery, $z_l^k$.

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.

# Solving Approach (2). Iterative *CVaR* calculation (1)

The objective is to simplify the CVaR constraint and to remove the non-convex terms in the KKT conditions associated with this constraint. The term of the CVaR in the objective function for each firm $f$:

$$\lambda_f \cdot \beta_f \cdot (\zeta_f + \frac{1}{1-\theta_f} \sum_{k \in \Omega} \mathrm{Pr}^k \cdot Q_f^{k,-}) \tag{20}$$

is replaced by

$$\lambda_f \cdot \beta_f \cdot \sum_{k \in \Omega} \mathrm{Pri}_f^k \cdot Q_f^k \tag{21}$$

Where $\mathrm{Pri}_f^k$ is an exogenous parameter calculated iteratively as is described in the next slide. The initial constraint for CVaR calculation is no longer necessary. 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.

# Solving Approach (3). Iterative *CVaR* calculation (2)

The parameter $\mathrm{Pri}_f^k$ is interpreted as a recalculated probability that takes into account which scenarios are included in the CVaR. The values of $\mathrm{Pri}_f^k$ result from the following linear program:

$$\underset{\mathrm{Pri}_f^k}{\text{minimize}} \sum_{k \in \Omega} \mathrm{Pri}_f^k \cdot Q_f^k \tag{22}$$

$$\text{subject to:} \sum_{k \in \Omega} \mathrm{Pri}_f^k = 1 \tag{23}$$

$$\mathrm{Pri}_f^k \leq \frac{\mathrm{Pr}^k}{1-\theta_f} \tag{24}$$

$$\mathrm{Pri}_f^k \geq 0 \tag{25}$$

In this problem the $\mathrm{Pri}_f^k$ are the variables and the rest are data (fixed values). In particular are data: The initial probability of the scenarios, $\mathrm{Pr}^k$, the confidence level $\theta_f$ for the *CVaR*, and the values of the recourse function $Q_f^k$. The values of $Q_f^k$ are updated solving the initial problem and then $\mathrm{Pri}_f^k$ recalculated.

# Solving Approach (4). Linearization of the Remaining Bilinear Terms

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.
The remaining non-convex terms in the complementarity problem are the bilinear expressions in the recourse function $Q_f^k$. The linearization strategy implemented consists of fixing the value of the:

- Variables involved in the bilinear terms, (only those involved in the bilinear terms, and only one variable in the couple is fixed).
- Variables that are not decision variables for the firms in the balancing mechanism, that are: Demand $d_f$, and the price of energy from upward and downward reserve, $\overline{\pi}^k$ and $\underline{\pi}^k$.
- The fixed value is taken from the previous iteration and then updated with the value that results from the current iteration.

# Solving Approach (5)

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 if there are other solutions that we are missing with this strategy. The strategy is robust for the simulations reported in the case study, but we have found two equilibria for some configurations.

The convergence criteria are based on tolerance values for consecutive iterations, the value used for tolerance was $10^{-6}$. In each iteration all the values, $\mathrm{Pri}_f^k$, and the linearized terms are updated simultaneously.

# Additional Results in Table form

# The Forecast Wind Level

Results for high generation capacity 28.5 GW and low ramping capability.

| | | |
|---|---|---|
| $\mu$ (%) expected wind | 4.01 | 65.00 |
| $\rho^+$ (€/MWh) premium | 30.00 | 30.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 |
| Energy demand day ahead (MWh) | 27988.89 | 29639.08 |
| Scheduled wind generation (MWh) | 873.91 | 9696.58 |
| Scheduled dispatch. gen. (MWh) | 27114.99 | 19942.50 |
| Equilibrium price (€/MWh) | 52.71 | 43.45 |
| Reserve requirement (MW) | 673.39 | 1853.34 |
| Upward reserve committed (MW) | 740.72 | 1671.87 |
| Downward reserve commit. (MW) | 590.69 | 668.76 |
| Max. available reserve (MW) | 740.72 | 4565.81 |
| INCOMES (€): | | |
| Energy sales in day ahead | 1475320.88 | 1287758.71 |
| Premium to scheduled wind | 26217.14 | 290897.26 |
| Supply of upward reserve capacity | 12865.72 | 0.00 |
| Supply of down. reserve capacity | 0.00 | 0.00 |
| COSTS (€): | | |
| Cost of dispatchable generation | 816662.92 | 505032.92 |
| Contribution of the $\lambda_f \cdot CVaR[Q]$ | 21758.83 | 49106.75 |
| Contribution of the $(1-\lambda_f)\cdot E[Q]$ | 10662.40 | -9841.11 |
| PROFIT (€) | | |
| Total (wind + dispatch.) | 679970.16 | 1090024.90 |
| 1st stage wind turbines | 72281.48 | 712194.06 |
| 2nd stage wind turbines | -16886.44 | -22744.77 |
| 1st stage dispatchable generators | 625459.34 | 361428.99 |
| 2nd stage dispatchable generators | -884.22 | 39146.63 |

# The Feed-in Premium

Results for high generation capacity (B2.1), 28.5 GW and low ramping capability.

| | | |
|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 |
| Energy demand day ahead (MWh) | 29639.08 | 29639.08 |
| Scheduled wind generation (MWh) | 3839.26 | 3850.16 |
| Scheduled dispatch. gen. (MWh) | 25799.82 | 25788.92 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 |
| Reserve requirement (MW) | 1091.89 | 1093.30 |
| Upward reserve committed (MW) | 986.04 | 996.94 |
| Downward reserve commit. (MW) | 395.94 | 398.79 |
| Max. available reserve (MW) | 1442.10 | 1447.92 |
| INCOMES (€): | | |
| Energy sales in day ahead | 1287758.70 | 1287758.71 |
| Premium to scheduled wind | 0.00 | 308012.95 |
| Supply of upward reserve capacity | 0.00 | 0.00 |
| Supply of down. reserve capacity | 0.00 | 0.00 |
| COSTS (€): | | |
| Cost of dispatchable generation | 759521.40 | 759047.89 |
| Contribution of the $\lambda_f \cdot CVaR[Q]$ | 17132.17 | 49217.49 |
| Contribution of the $(1-\lambda_f) \cdot E[Q]$ | -5713.64 | -874.05 |
| PROFIT (€) | | |
| Total (wind + dispatch.) | 537760.04 | 838180.53 |
| 1st stage wind turbines | 166808.32 | 475294.79 |
| 2nd stage wind turbines | -6950.69 | -21266.15 |
| 1st stage dispatchable generators | 361428.98 | 361428.99 |
| 2nd stage dispatchable generators | 16473.43 | 22722.90 |

# The Risk Aversion

Results for high generation capacity (B2.1), 28.5 GW and low ramping capability.

| | | |
|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 30.00 | 30.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.00 | 1.00 |
| Energy demand day ahead (MWh) | 29639.08 | 29639.08 |
| Scheduled wind generation (MWh) | 4088.30 | 3548.96 |
| Scheduled dispatch. gen. (MWh) | 25550.78 | 26090.12 |
| Equilibrium price (€/MWh) | 43.45 | 43.45 |
| Reserve requirement (MW) | 1124.26 | 1054.15 |
| Upward reserve committed (MW) | 1235.07 | 1159.56 |
| Downward reserve commit. (MW) | 1235.07 | 463.83 |
| Max. available reserve (MW) | 1574.92 | 1287.29 |
| INCOMES (€): | | |
| Energy sales in day ahead | 1287758.71 | 1287758.71 |
| Premium to scheduled wind | 122648.97 | 106468.93 |
| Supply of upward reserve capacity | 0.00 | 0.00 |
| Supply of down. reserve capacity | 0.00 | 0.00 |
| COSTS (€): | | |
| Cost of dispatchable generation | 748701.31 | 772134.33 |
| Contribution of the $\lambda_f \cdot CVaR[Q]$ | 0.00 | 64999.49 |
| Contribution of the $(1-\lambda_f) \cdot E[Q]$ | -15109.68 | 0.00 |
| PROFIT (€) | | |
| Total (wind + dispatch.) | 676816.04 | 632872.83 |
| 1st stage wind turbines | 300277.37 | 260664.32 |
| 2nd stage wind turbines | -41874.72 | -3695.82 |
| 1st stage dispatchable generators | 361428.99 | 361428.99 |
| 2nd stage dispatchable generators | 56984.40 | 14475.34 |

# Wind Induced Demand for Flexibility Reserve

Results for high generation capacity (B2.1), 28.5 GW and low ramping capability, $m_y = 60\%$.

| | | |
|---|---|---|
| $\mu$ (%) expected wind | 23.83 | 23.83 |
| $\rho^+$ (€/MWh) premium | 0.00 | 80.00 |
| $\lambda$ risk aversion (0 is risk neutral) | 0.40 | 0.40 |
| Energy demand day ahead (MWh) | 27667.11 | 27717.02 |
| Scheduled wind generation (MWh) | 4578.05 | 7012.83 |
| Scheduled dispatch. gen. (MWh) | 23089.06 | 20704.18 |
| Equilibrium price (€/MWh) | 54.52 | 54.24 |
| Reserve requirement (MW) | 3208.61 | 4621.78 |
| Upward reserve committed (MW) | 2887.75 | 4159.60 |
| Downward reserve commit. (MW) | 1162.93 | 1673.49 |
| Max. available reserve (MW) | 2887.75 | 4159.60 |
| INCOMES (€): | | |
| Energy sales in day ahead | 1508332.91 | 1503289.16 |
| Premium to scheduled wind | 0.00 | 561026.53 |
| Supply of upward reserve capacity | 59938.22 | 84151.84 |
| Supply of down. reserve capacity | 0.00 | 0.00 |
| COSTS (€): | | |
| Cost of dispatchable generation | 641744.35 | 538126.42 |
| Contribution of the $\lambda_f \cdot CVaR[Q]$ | 29968.62 | 205372.92 |
| Contribution of the $(1-\lambda_f) \cdot E[Q]$ | -9038.36 | 127398.48 |
| PROFIT (€) | | |
| Total (wind + dispatch.) | 941590.72 | 1398010.31 |
| 1st stage wind turbines | 249582.58 | 941381.82 |
| 2nd stage wind turbines | -12996.07 | -215420.27 |
| 1st stage dispatchable generators | 676944.20 | 668959.29 |
| 2nd stage dispatchable generators | 28060.00 | 3089.47 |

# Additional Results in sensitivity form

# The Forecast Wind Level

High generation capacity, 28.5 GW (B2.1). Case 1, values of the wind forecast level, $4\% \leq \mu \leq 65\%$

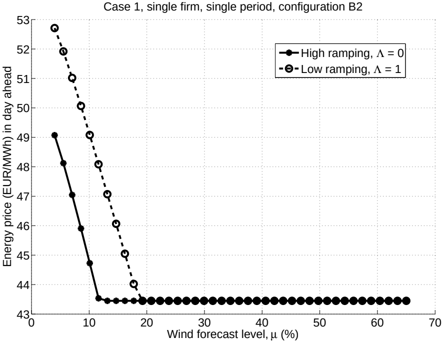


Figure: Energy price in day ahead (€/MWh).

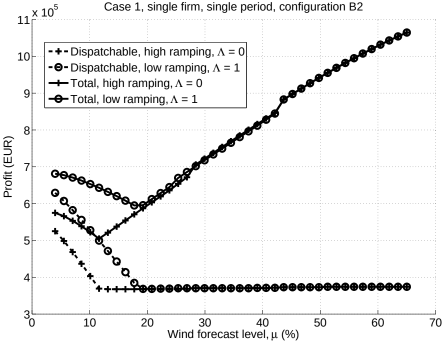


Figure: Profits (€): Total and dispatchable units.

# Overall Comments on The Forecast Wind Level

- High wind power tends to reduce the equilibrium price. This is a direct consequence of wind replacing the most expensive dispatchable generators.
- As expected, higher wind forecast results in higher scheduled wind and lower scheduled conventional generation.
- Significant decrease of the equilibrium price of 17% that combines to the lower scheduled conventional generation in day ahead. At the same time, the higher scheduled wind generation also increases the capacity available for flexibility reserve, which reduces the revenue from reserve in day ahead.
- Drastic loss of profits of dispatchable generators that decreases the incentive to invest in conventional plants and increases the incentive to mothball or even dismantle existing capacities.

# The Feed-in Premium

High generation capacity, 28.5 GW (B2.1). Case 2, vales of the premium $0 \leq \rho^+ \leq 80$ €/MWh

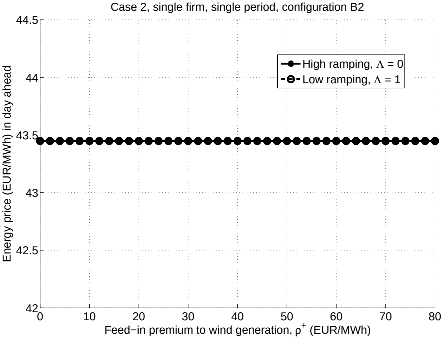


Figure: Energy price in day ahead (€/MWh).

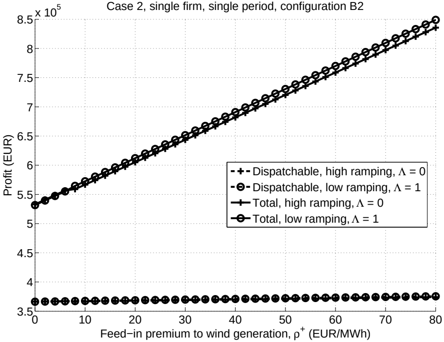


Figure: Profits (€): Total and dispatchable units.

# Overall Comments on The Feed-in Premium

- The premium does not significantly affect the day ahead equilibrium even if it induces a small increase of scheduled wind.
- 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 holds where wind generation remains sufficient low compared to demand so that the electricity price remains positive (see Baldick 2012).
- The reduced revenue of the dispatchable units in the energy and day ahead reserve markets is not compensated by the balancing activity. This again leads to decreased incentives to invest and enhanced mothballing or dismantling.

# The Risk Aversion

High generation capacity, 28.5 GW (B2.1). Case 3, vales of the risk aversion $0 \leq \lambda \leq 1$ ($\lambda = 0$ is risk neutral)

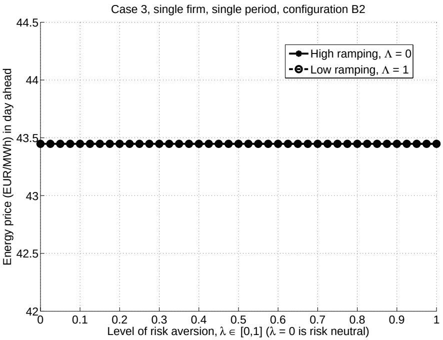


Figure: Energy price in day ahead (€/MWh).

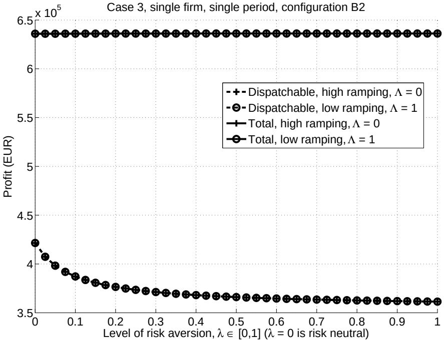


Figure: Profits (€): Total and dispatchable units.

# Overall Comments on The Risk Aversion

- An increase of the level of risk aversion $\lambda$ of the firms only has a low impact on the short run market.
- 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 make the same margin due to the fact that this additional generation is made by the same CCGT that make zero margin when they are marginal.
- Because of the reduction of activity in balancing resulting from the risk aversion, these plants also see their profits reduced on that market.
- The conclusion of these results is that risk aversion would further reduce the incentive to invest.

# Wind Induced Demand for Flexibility Reserve

High generation capacity, 28.5 GW (B2.1). Case 4, vales of the wind induced demand for flexibility reserve, $0.15 \leq m_y \leq 0.60$

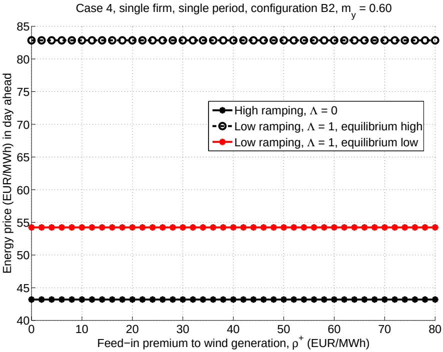


Figure: Energy price in day ahead (€/MWh).

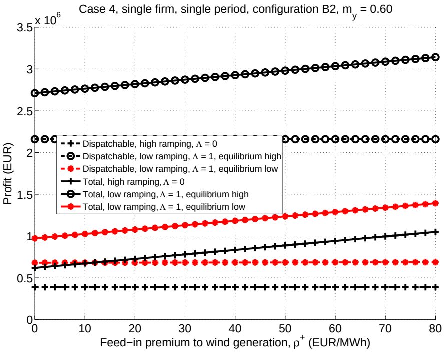


Figure: Profits (€): Total and dispatchable units.

# Overall Comments on Wind Induced Demand for Flexibility Reserve

None of the previous cases shows any constraint on flexibility reserve in day ahead; the consequence is the lack of revenue from the day ahead reserve market. This combined with the lower price in the merit order due to wind generation, is the mechanisms that eventually leads to mothballing and possibly dismantling dispatchable capacities. We consider two situations that differ by the demand for reserve and its impact on energy prices:

1) Forecasting horizon $\leq$ 6h: The residual error between the forecast and the realization can be characterized by a standard deviation $\sigma$, $[\mu - \sigma, \mu + \sigma]$. In this case the premium $\rho^+$ has little effect on the amount of scheduled wind.
2) Forecasting horizon $\approx$ 24h: Typical for an unit commitment problem. Beta distribution with mean $\mu$ 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 $[0.4\mu, 1.6\mu]$.

# Overall Comments on Wind Induced Demand for Flexibility Reserve. Forecasting Horizon $\approx$ 24h

- In this case it is assumed a longer forecast horizon for wind implying $m_y = 0.6$ (in contrast with $m_y = 0.15$ otherwise), $m_x = 0.02$ remains.
- The constraint $(\text{scheduled wind}) - (\text{lowest wind scenario}) \leq (\text{committed upward reserve})$ is tight. This occurs when the uncertainty on wind generation is high, that can be due to a lack of intraday market or to the impossibility to trade capacity in intraday.
- An increase in the premium $\rho^+$ to wind generation increases the scheduled wind generation and also the energy price.
- The increase of energy price is due to the higher demand for flexibility.
- 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 the value obtained in case of low wind.

# Other Cases of High Demand for Reserves

1) Dispatchable generators may not have enough capacity to satisfy simultaneously the requirement for energy demand and reserve commitment.
2) Committed reserve hits technical limits. This depends on the overall flexibility of the remaining dispatchable plants.
3) Consider a case where the requirement for flexibility reserve in day ahead by the 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 $\rho^+ = 80$ €/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: i) Revenues from the premium to wind (expected value), ii) the higher demand for reserve flexibility by the TSO that also increases the price of energy. This is only a consequence of market design and does not involve any exercise of market power.