Remuneration of Flexibility through Scarcity Pricing

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Complex Energy Systems Workshop

Outline

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  - Nuclear capacity in Belgium
  - The Belgian scarcity pricing studies
- Background
  - Paying for capacity in electricity markets
  - The shift of value in electricity markets
  - Operating reserve demand curves, a.k.a. scarcity pricing
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- Results
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- Conclusions and Perspectives

Motivation

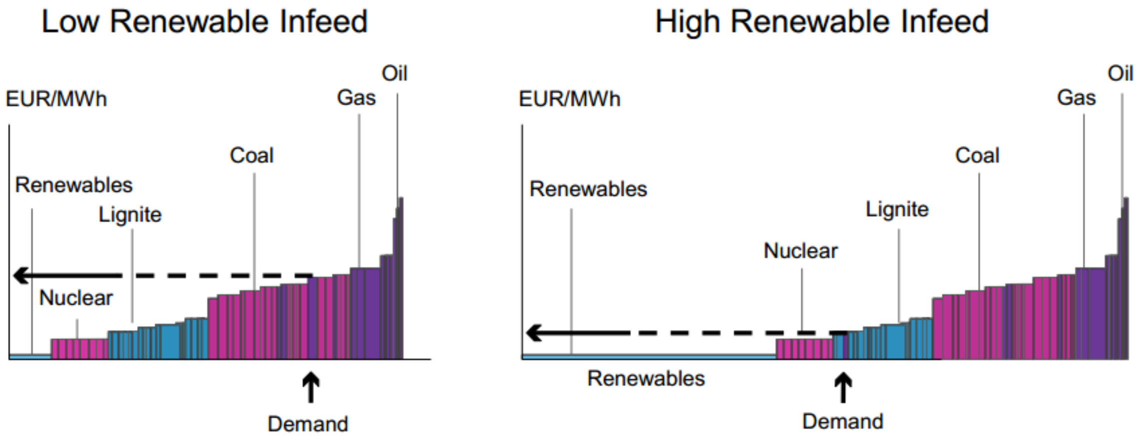
Renewable energy integration

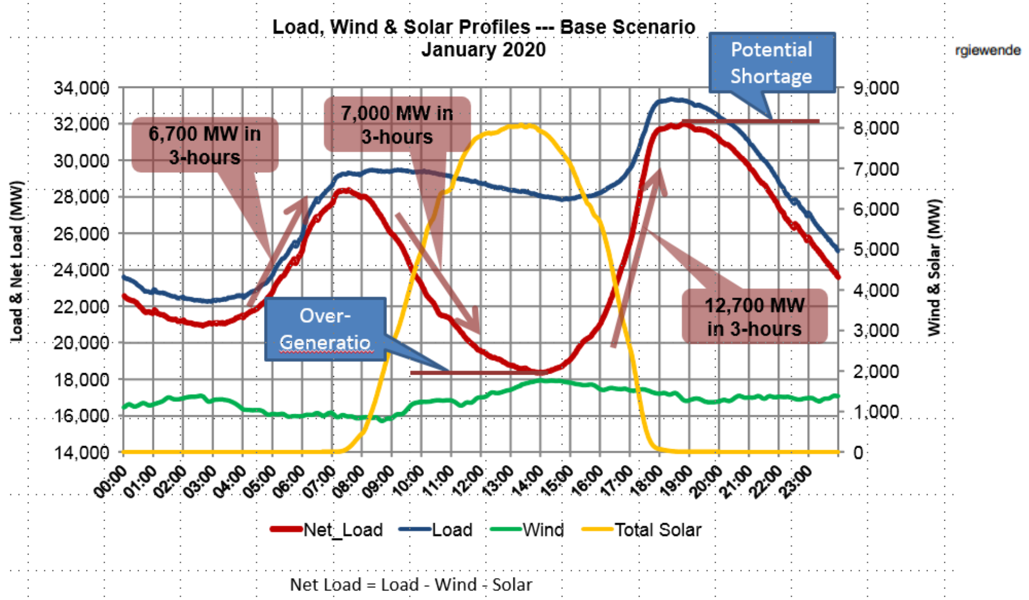
Nuclear capacity in Belgium

The Belgian scarcity pricing studies

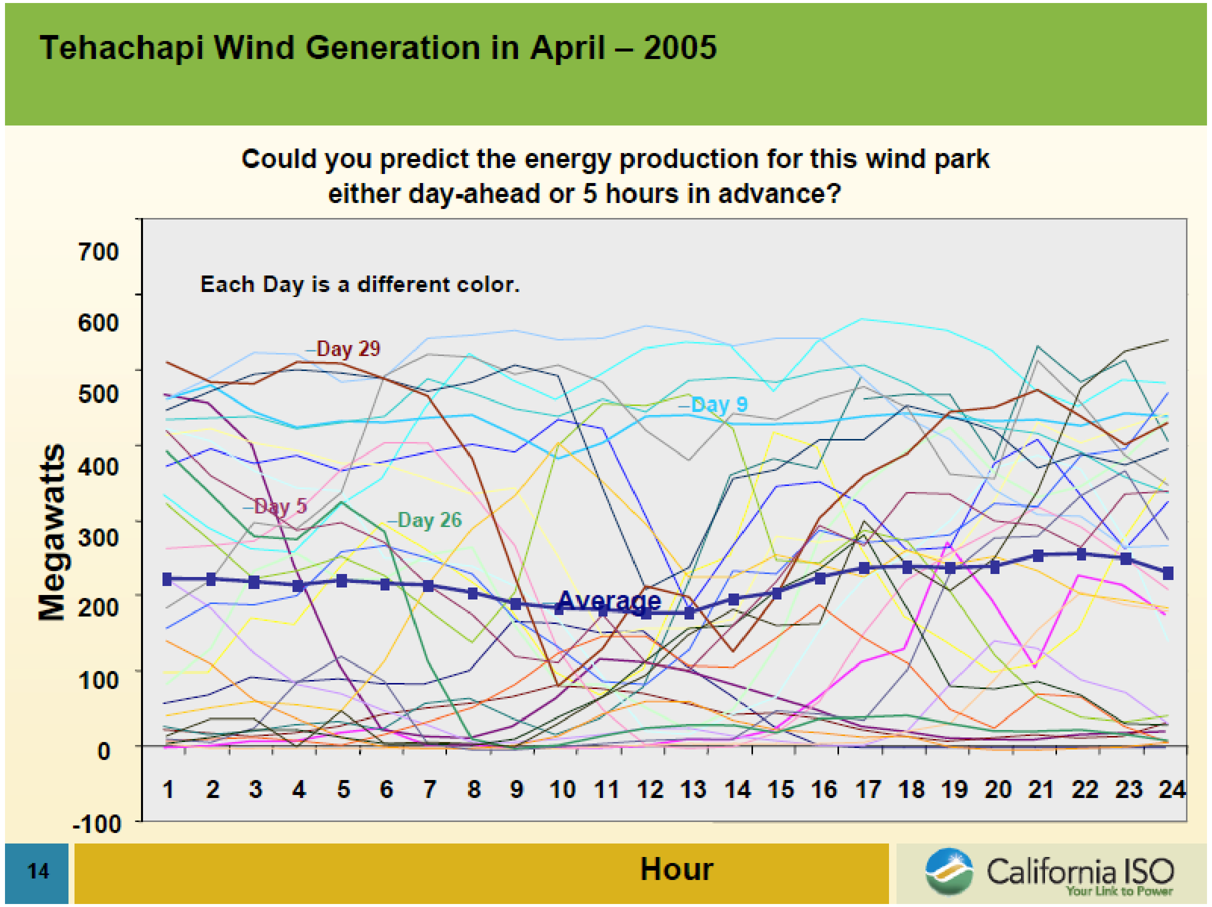
Challenges of Renewable Energy Integration

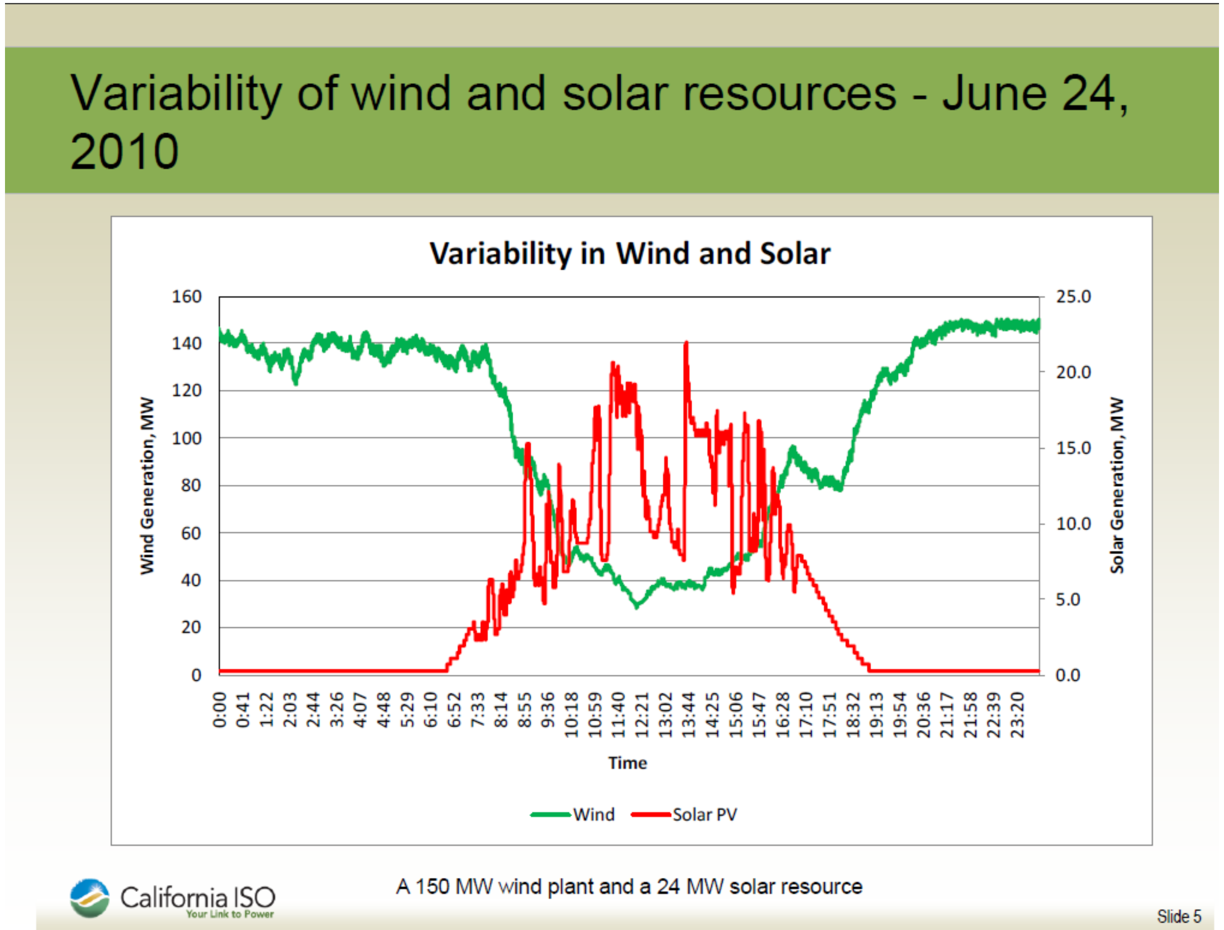
- Renewable energy integration
  - depresses electricity prices
  - requires flexibility due to
    - uncertainty,
    - variability,
    - non-controllability of output
- Demand is unresponsive
- Supply-demand must be balanced instantaneously



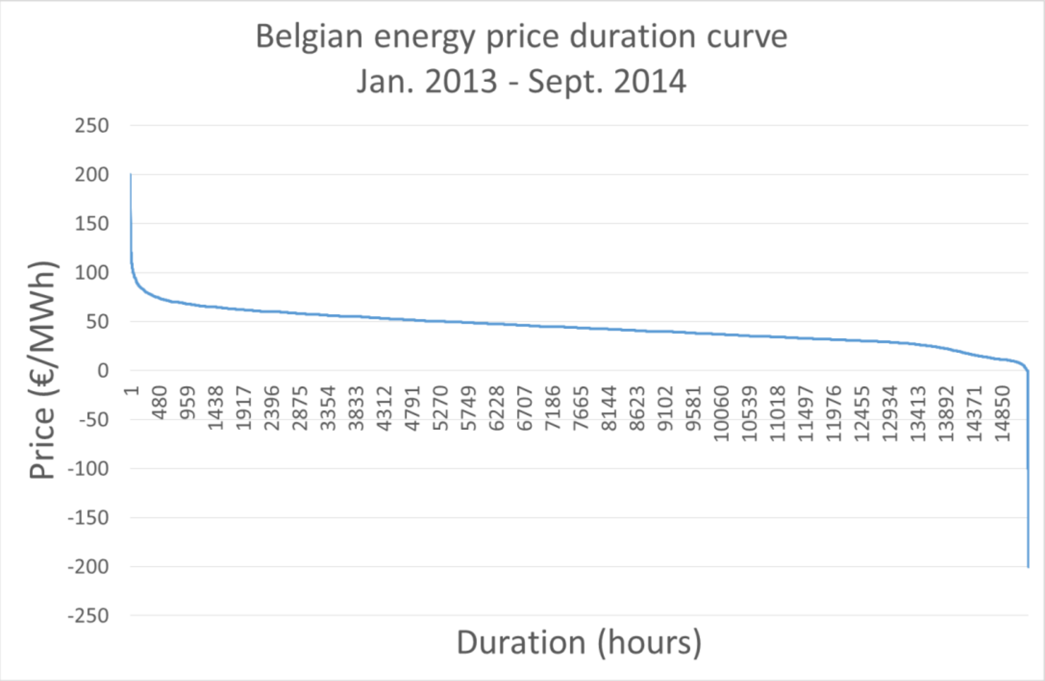


Challenges of Renewable Energy (II)





A Paradox



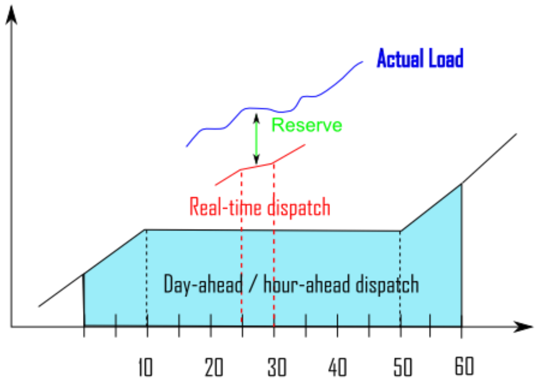
Technology	Inv. cost (€/MWh)	Marginal cost (€/MWh)	Min. load cost (€/MWh)	Energy market profit (€/MWh)	Profit (€/MWh)
Biomass	27.9	5.6	0	35.6	7.7
Nuclear	31.8	7.0	0	34.2	2.4
Gas	5.1	50.2	20	0.1	-5
Oil	1.7	156.0	20	0	-1.7

- Gas and oil units are
  - extremely flexible (ramp rates, up/down times) => needed now more than ever
  - characterized by high marginal cost => mothballed or retired now more than ever

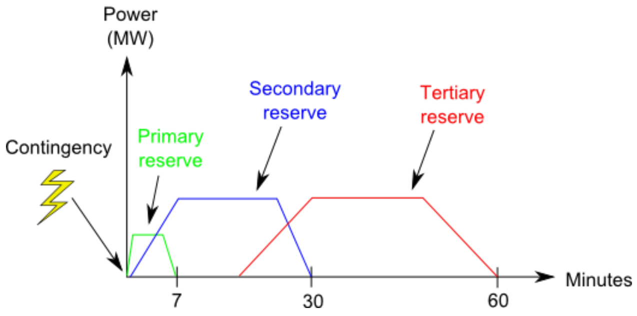
Definition of Flexibility for *This* Talk

- We are interested in resources that provide:
  - Secondary reserve: reaction in a few seconds, full response in 7 minutes
  - Tertiary reserve: available within 15 minutes
- In Belgium, these are (mostly) combined cycle gas turbines
- Great financial strain due to renewable energy integration
- We will *not* be addressing sources of flexibility for which ORDC is not designed to compensate (e.g. seasonal renewable supply scarcity)

Forecast errors

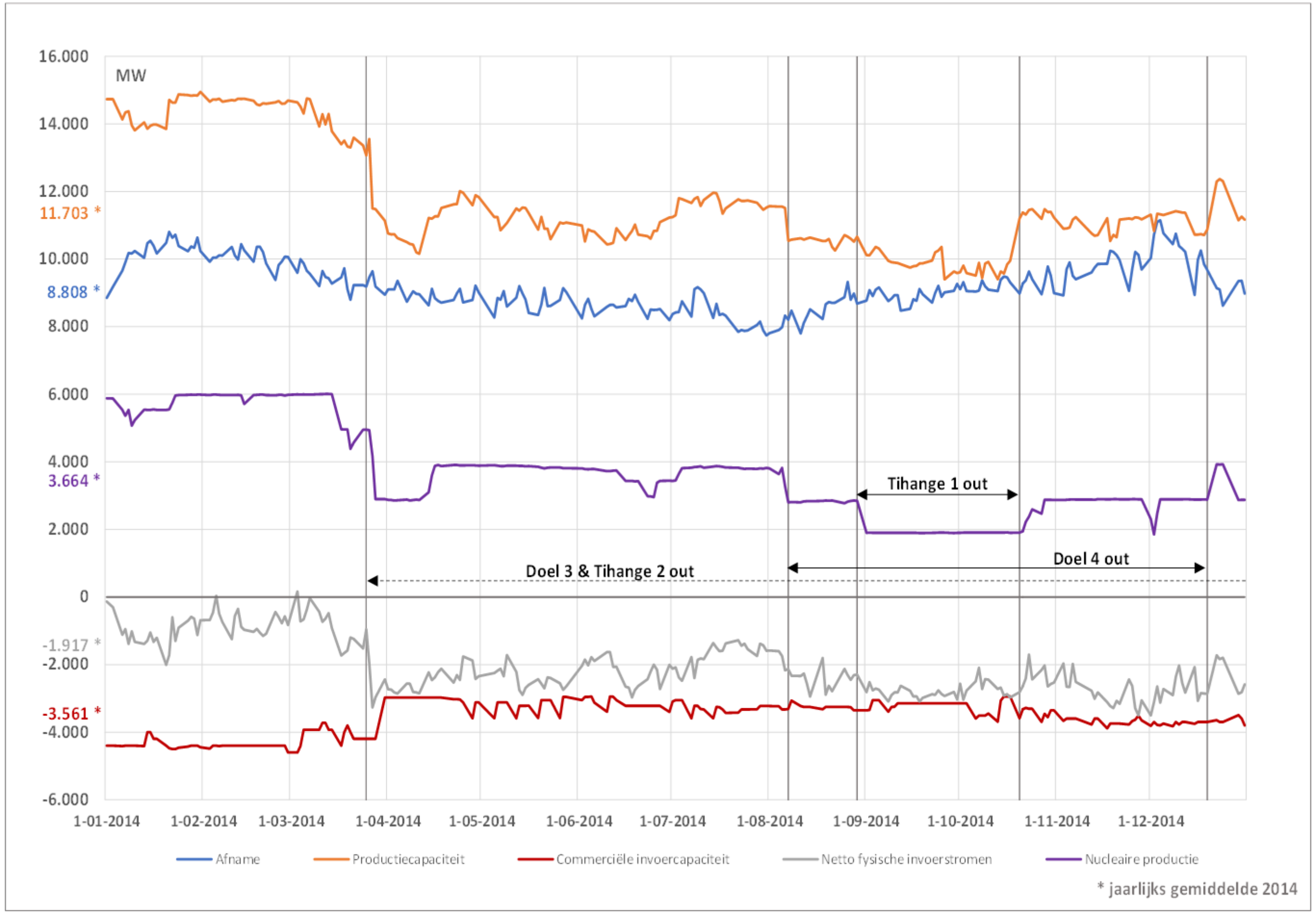


Contingencies



Nuclear Outages in Belgium (2014)

- Belgian power production capacity: 14765 MW
- September 2014 – mid-October 2014
  - 4 nuclear units out of order simultaneously
  - Total <u>unplanned</u> outage: 4000 MW



First Scarcity Pricing Study (2015)

- Commission de Régulation de l’électricité et du Gaz (CREG) raised concerns about whether adequate incentives are in place in order to attract investment in **flexible** power generation in Belgium
- Question addressed in the first study: *How would electricity prices change if we introduce ORDC (Hogan, 2005) in the Belgian market*
- Results: A. Papavasiliou, Y. Smeers, ‘Remuneration of Flexible Capacity under Conditions of Scarcity’. *The Energy Journal*, vol. 38, no. 6, pp. 105-135, 2017.

(Hogan, 2005) W. Hogan, *On an Energy-Only Electricity Market Design for Resource Adequacy*. Center for Business and Government, JFK School of Government, Harvard University, September 2005.

Second Scarcity Pricing Study (2016)

- In February 2016, nuclear capacity was completely restored back to service
- Questions addressed in the second study: how does scarcity pricing depend on
  - Strategic reserve (akin to reliability must-run units)
  - Value of lost load
  - Restoration of nuclear capacity
  - Day-ahead (instead of month-ahead) clearing
- Results: A. Papavasiliou, Y. Smeers, G. Bertrand ‘An Extended Analysis on the Remuneration of Capacity under Scarcity Conditions’. *Under review*.

European Commission Guidelines on State Aid for Environmental Protection and Energy

- Paragraph 219: "*Measures for generation adequacy can be designed in a variety of ways, in the form of investment and operating aid (in principle only rewarding the commitment to be available to deliver electricity), and can pursue different objectives. They may for example aim at addressing short-term concerns brought about by the lack of flexible generation capacity to meet sudden swings in variable wind and solar production, or they may define a target for generation adequacy, which Member States may wish to ensure regardless of short-term considerations.*"
- Paragraph 231: "*The measure should be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded.*"

Third Scarcity Pricing Study (2017)

- Recent European Commission (EC) legislation is generally favorable towards scarcity pricing:
  - EC Network Codes on electricity balancing (2016) advocate co-optimization of energy and reserves
  - EC guidelines on State Aid (2014) paragraphs 219, 231 describe what resembles to a scarcity adder
- But can we take a US-inspired design and just plug it into the existing European market?
- Questions to be addressed in the third study: in order to **back-propagate** scarcity signal,
  - When can/should day-ahead auctions be conducted? Before, during, or after energy clearing?
  - Do we need co-optimization in real time?
  - Do we need virtual bidding?

Background

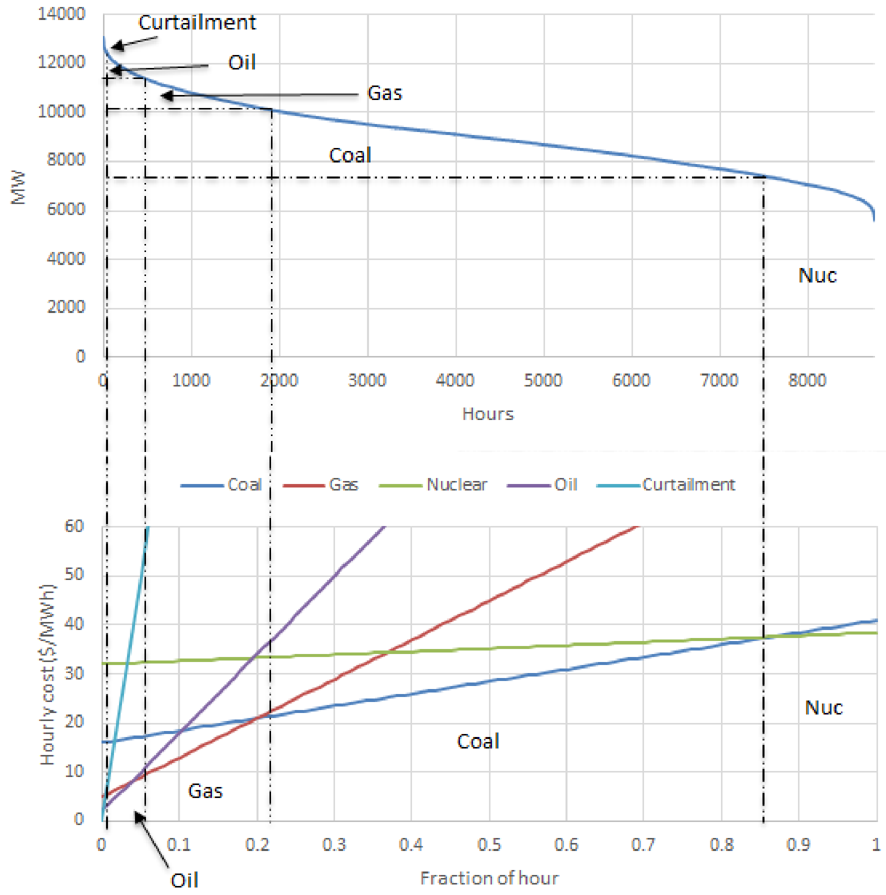
Paying for capacity in electricity markets

The shift of value in electricity markets

Operating Reserve Demand Curves

The Missing Money Problem

- Electricity demand is extremely inelastic
- Even if demand is perfectly predictable, a competitive equilibrium entails some degree of load curtailment, at which time the price of electricity is very high
- Due to market power concerns, electricity price is capped => <u>missing money</u>

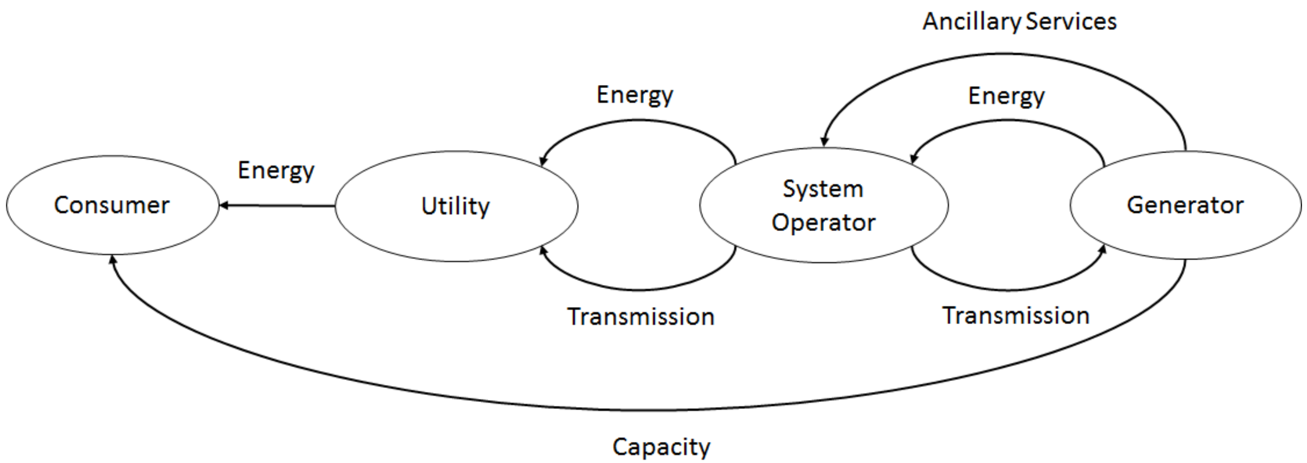


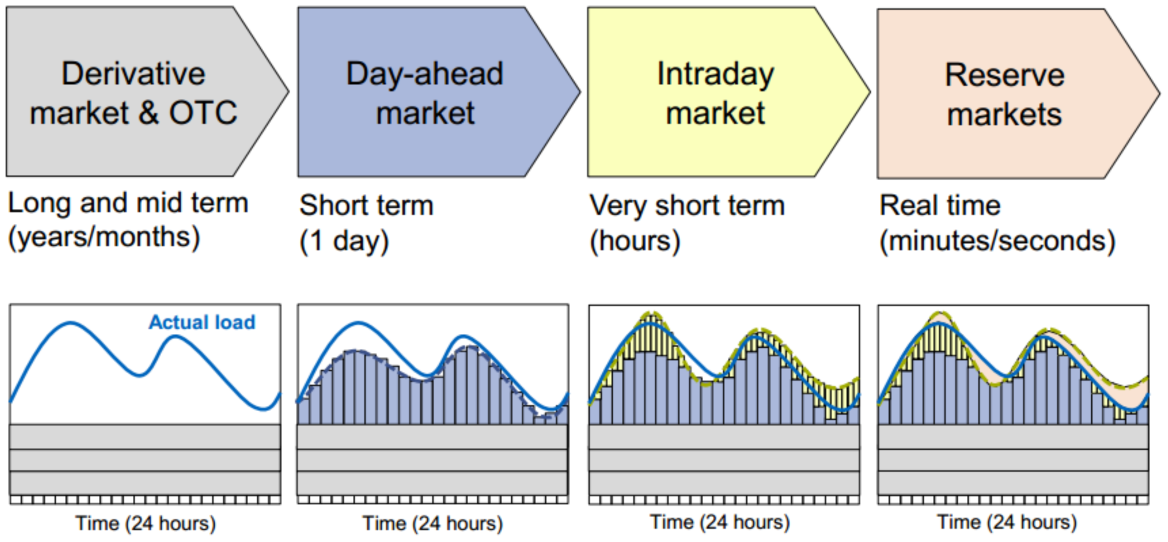
Mechanisms for Compensating Capacity

- Energy-only markets
  - The energy market without price caps is the only source of revenue
  - Risky for investors (-), politically contentious (-)
- Installed capacity requirements
  - Regulator decides on a target capacity and procures it through annual auctions
  - Safer for investors (+), capacity target is contestable/non-transparent (-), does not ensure flexibility (-), complex variations among member states (-)
- Capacity payments
  - Energy prices are uplifted by capacity payment
  - Installed capacity may err significantly (-)

Revenue Streams in Electricity Markets

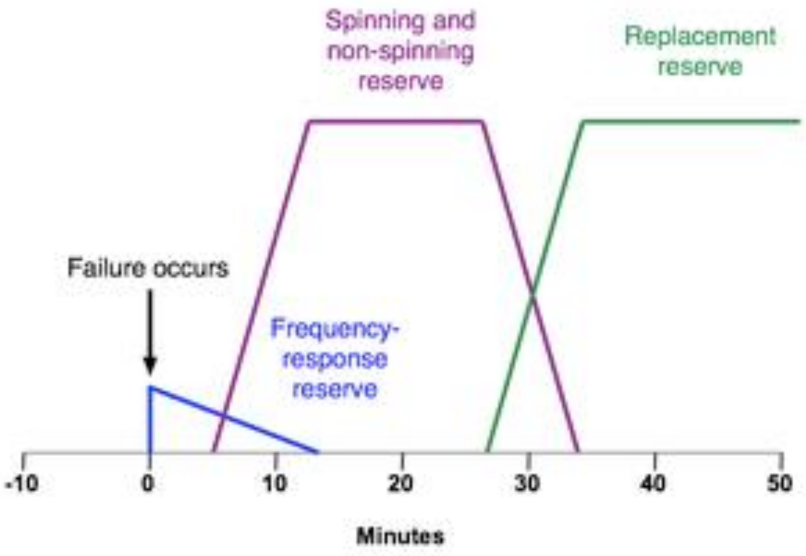
- Energy
  - Day-ahead 'uniform price' auction
- Reserve
  - Monthly procurement of reserve *capacity*
  - Real-time procurement of reserve *energy* (ideally)
- Capacity
  - Auctioned annually in <u>some</u> markets
- Recent migration of value away from energy markets and into flexibility (reserves)

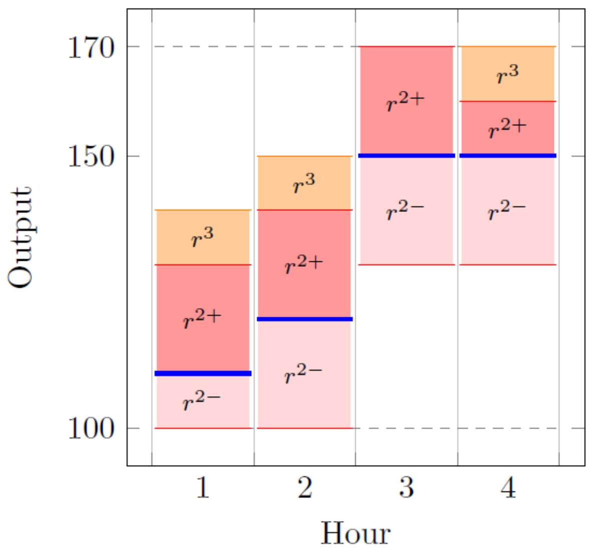




Reserves

- Primary reserve: immediate response to change in frequency
- Secondary reserve: reaction in a few seconds, full response in 7 minutes
- Tertiary reserve: available within 15 minutes
- Commitment of reserve induces opportunity cost because it displaces energy sales



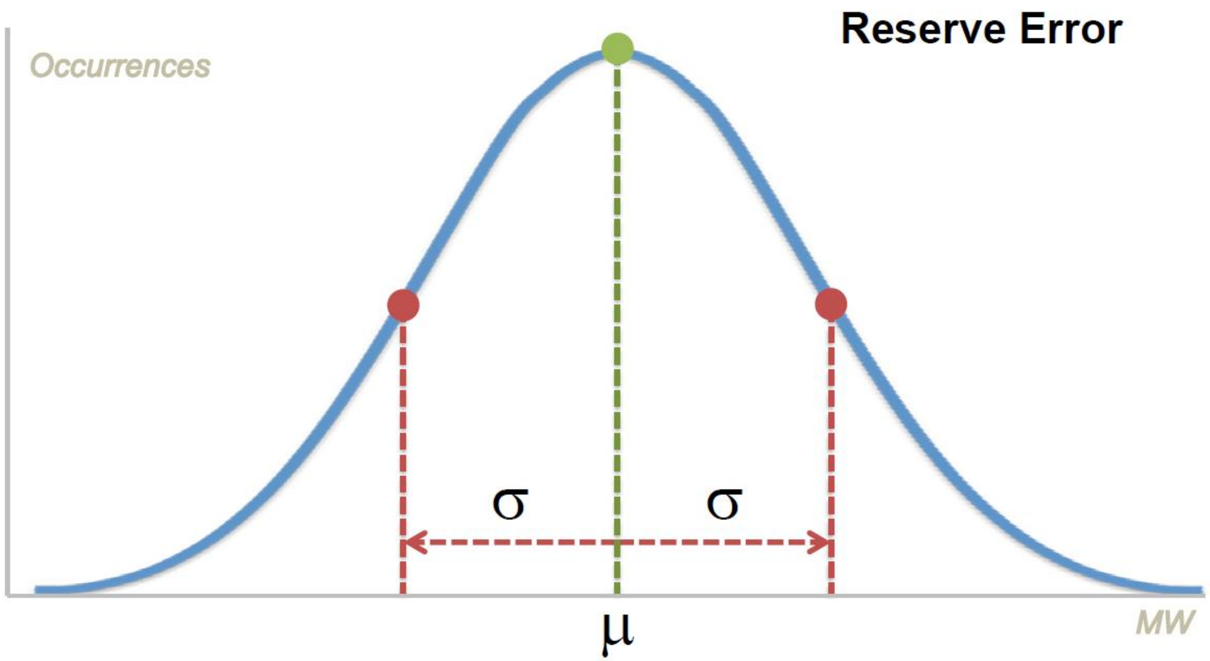


Operating Reserve Demand Curve (ORDC)

- Reserve is procured by the system operator from generators in order to ensure reliability, which is a public good
- Demand for reserve can be driven by its value for dealing with uncertainty, based on engineering principles:
  - Above a max threshold (Qmax), extra reserve offers no additional protection => (P, Q) = (0, Qmax)
  - Below a min threshold (Qmin), operator is willing to curtail demand involuntarily => (P, Q) = (VOLL, Qmin), where VOLL is value of lost load
  - At Qmin < Qi < Qmax , extra reserve increases probability of preventing load curtailment => (P, Q) = ($LOLP \cdot VOLL$, Qi), where LOLP is loss of load probability

Loss of Load Probability

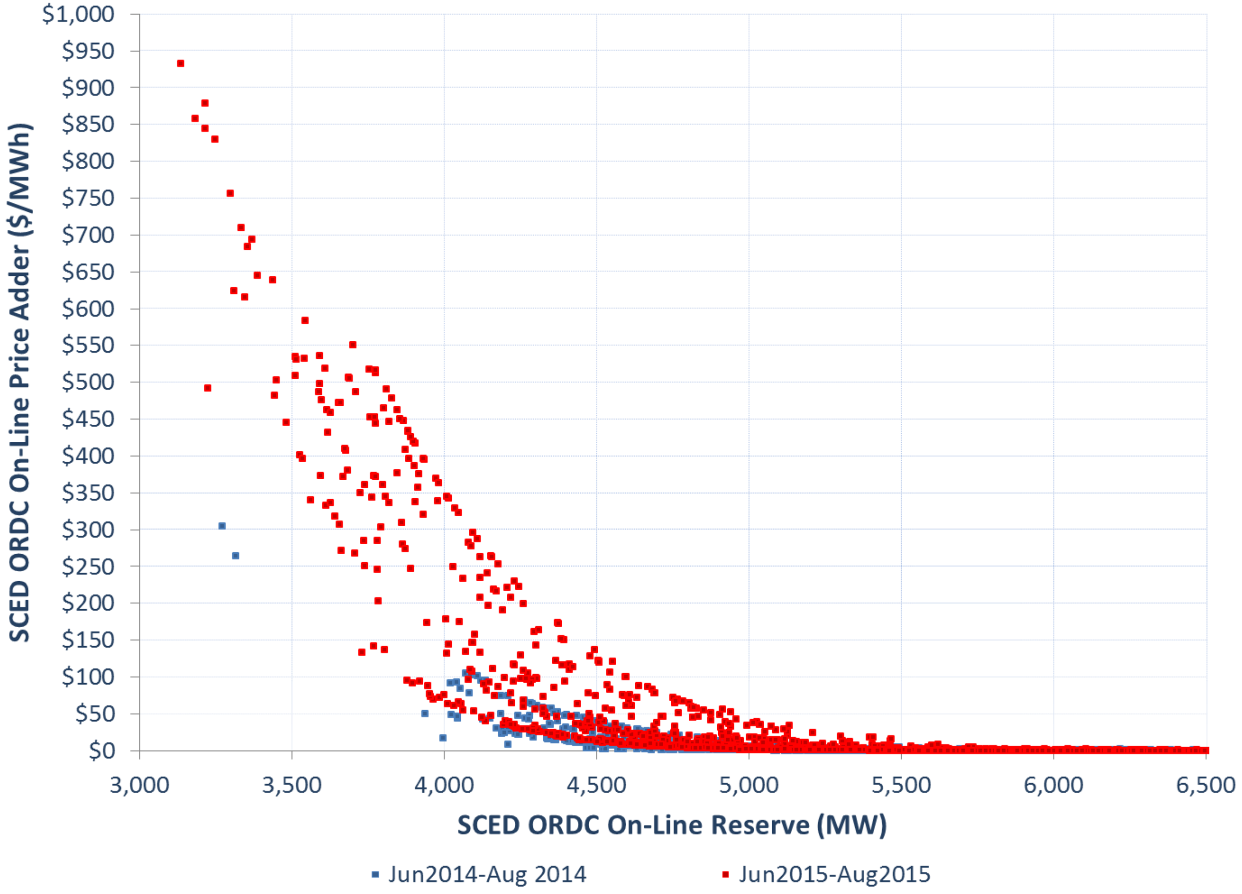
- Uncertainty Δ in real time due to:
  - demand forecast errros
  - import uncertainty
  - unscheduled outages of generators
- $LOLP(x) = Prob(\Delta \geq x)$ is the probability that real-time uncertainty exceeds reserve capacity x

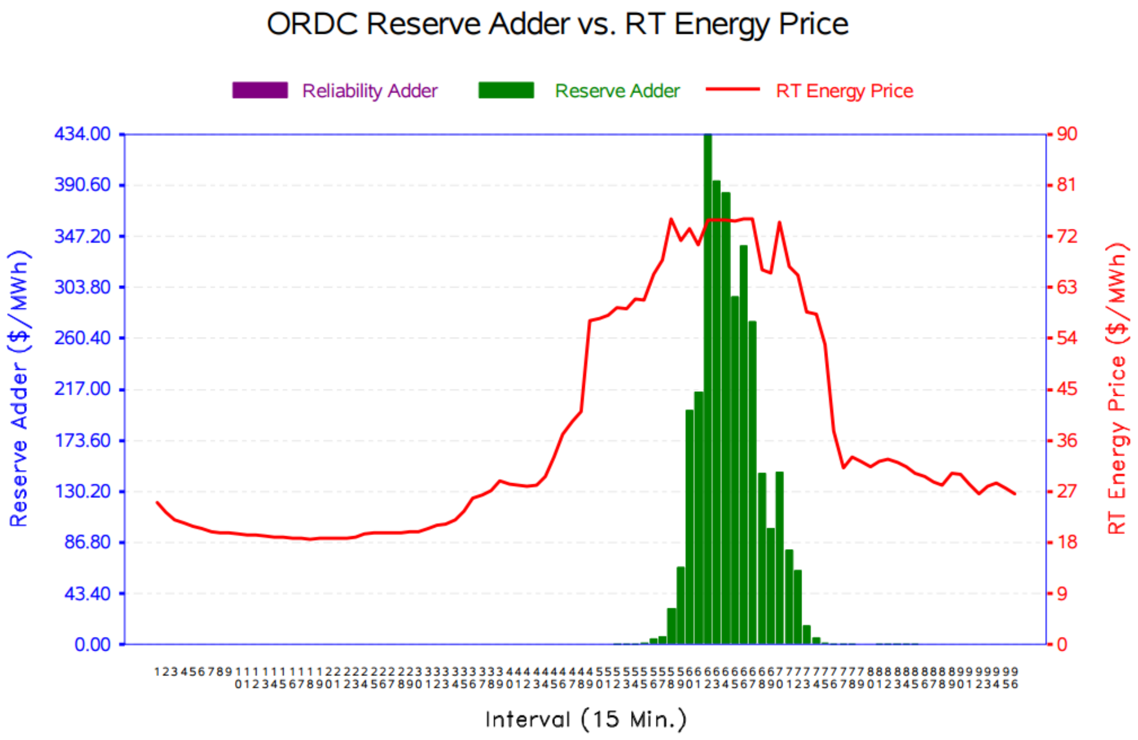


ORDC Price Adders

- Price adder: $\mu = (VOLL - \lambda) \cdot LOLP(R - X)$, where λ is the marginal cost of the marginal producer, R is the available reserve, and X is the minimum threshold of reserve
- This adder would ensure that a price taking agent that offers energy and reserve capacity would, in equilibrium, dispatch its unit according to the optimal schedule
- More frequent, lower amplitude price spikes
- Price spikes can occur even if regulator mitigates bids of suppliers in order to mitigate market power
- Can coexist with capacity markets
- Compatible with demand response, I think of it as training wheels until demand response is (hopefully) eventually fully mobilized

Illustration from Texas: July 30, 2015





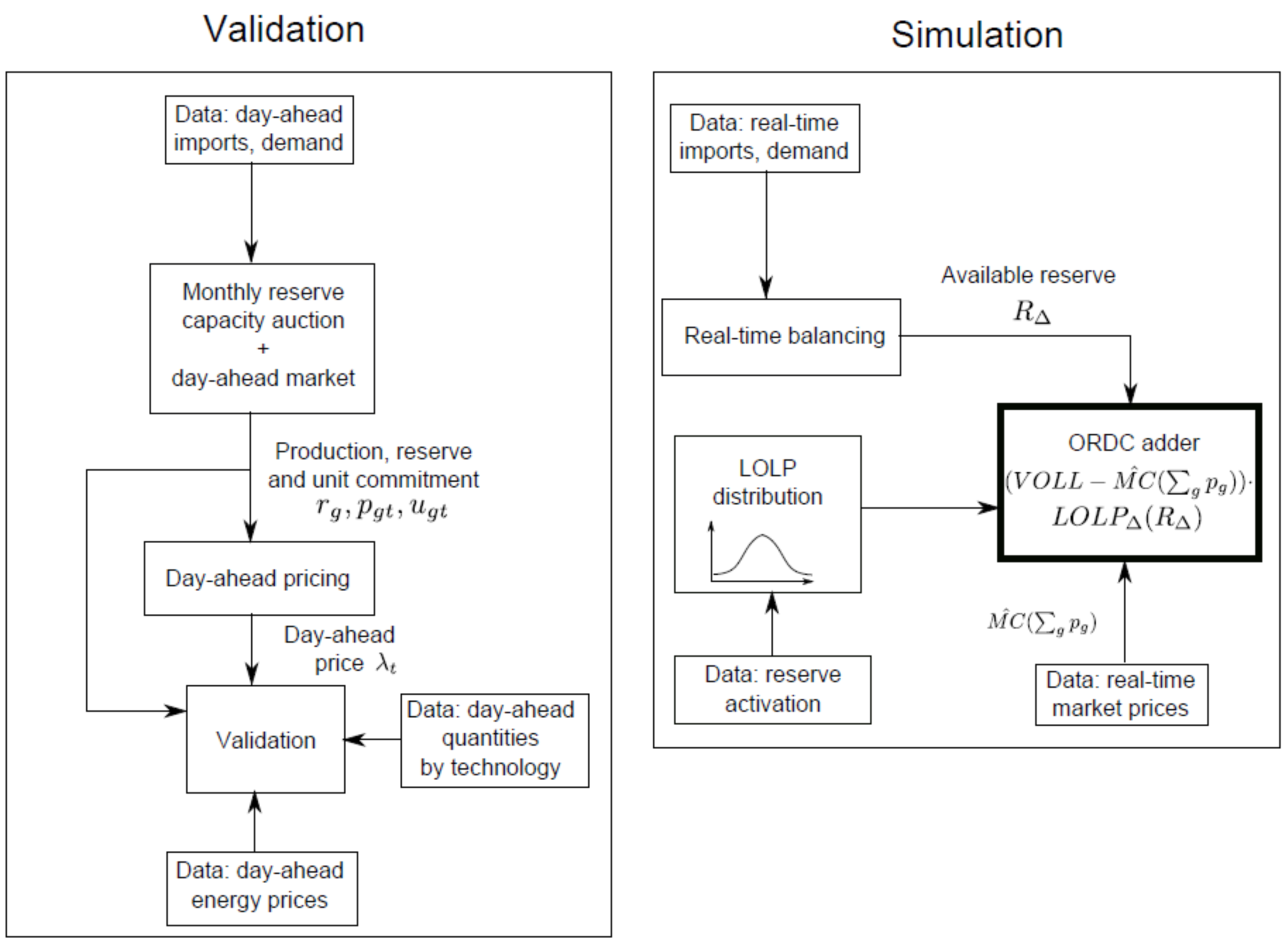
Methodology

Framework

Modeling the Belgian market

The Basic Question

- Objective of first and second study: what would the impact of ORDC be in the Belgian electricity market?
- Steps
  - Calculate reserve commitment for each hour of the study period
  - Estimate LOLP for Belgian system
  - Calculate price adders
- This is an open-loop analysis: we do not attempt to answer the question of how generators would react to the introduction of ORDC (for now)

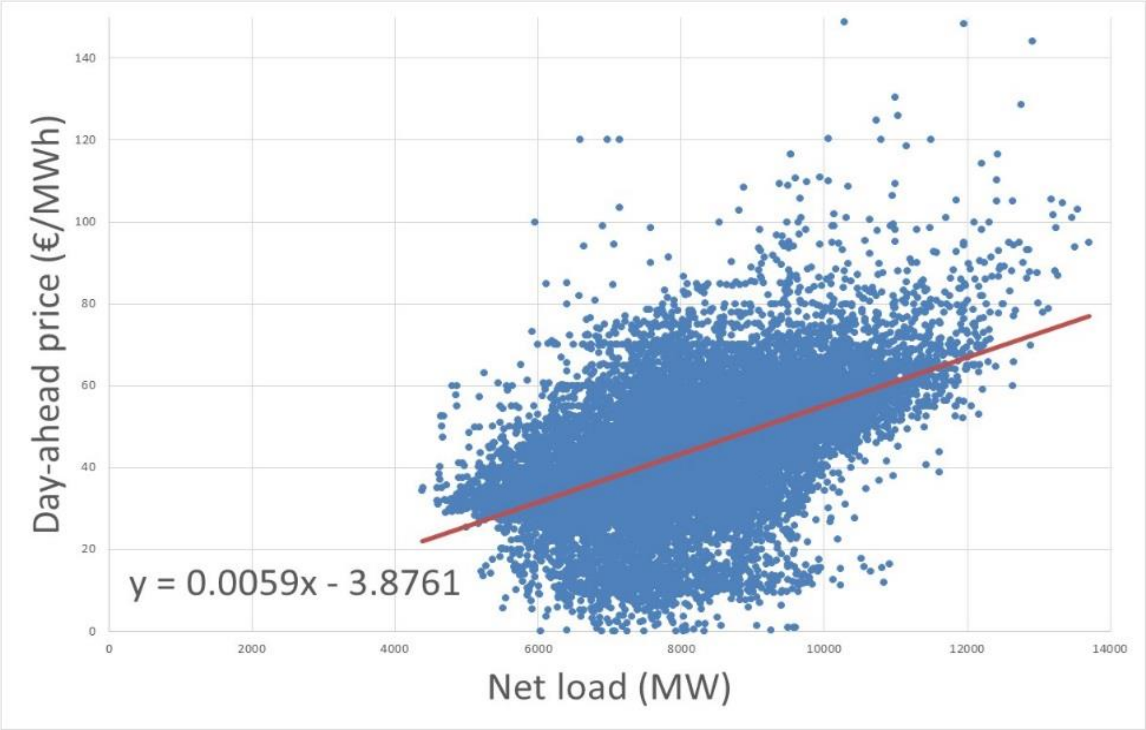


Available Data

- Study interval of first study: January 2013 – September 2014
- Study interval of second study: September 2015 – March 2016
- Day-ahead price
- Day-ahead production *by technology* (not individual units)
- *Unit-by-unit* technical-economic data for coal and combined cycle gas turbine (CCGT) units

Understanding the Belgian Market

- Possible causes for variability of supply function
  - Outages
  - Unit commitment
  - Imports/exports
  - Reserves
  - Distributed renewables (not measured)
  - Pumped storage
  - Combined heat & power, must-take resources
  - Fuel price fluctuations
  - Market power
  - ~~Forward/bilateral commitments~~
  - ~~Demand side bidding~~



Model Description

Classification of market agents

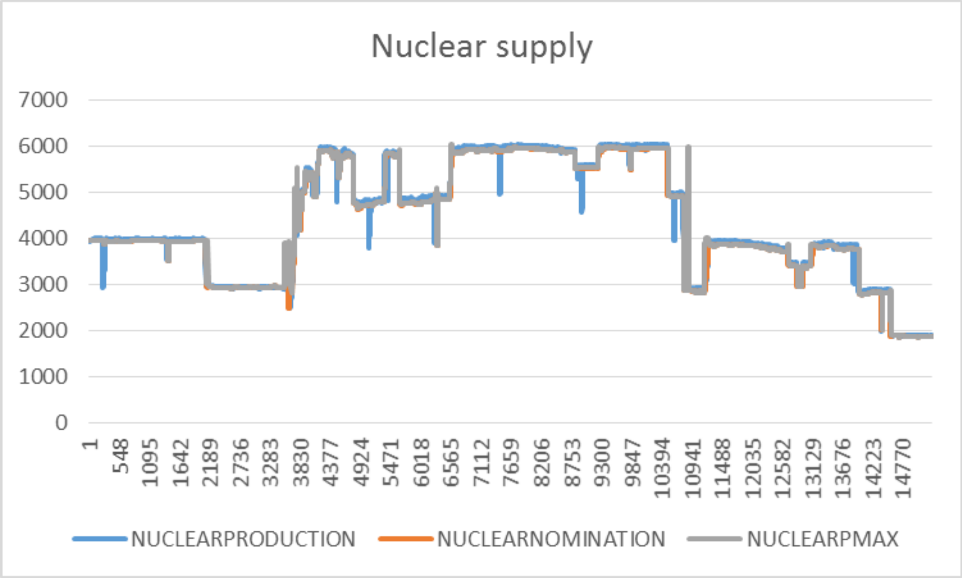
Fit of model to data

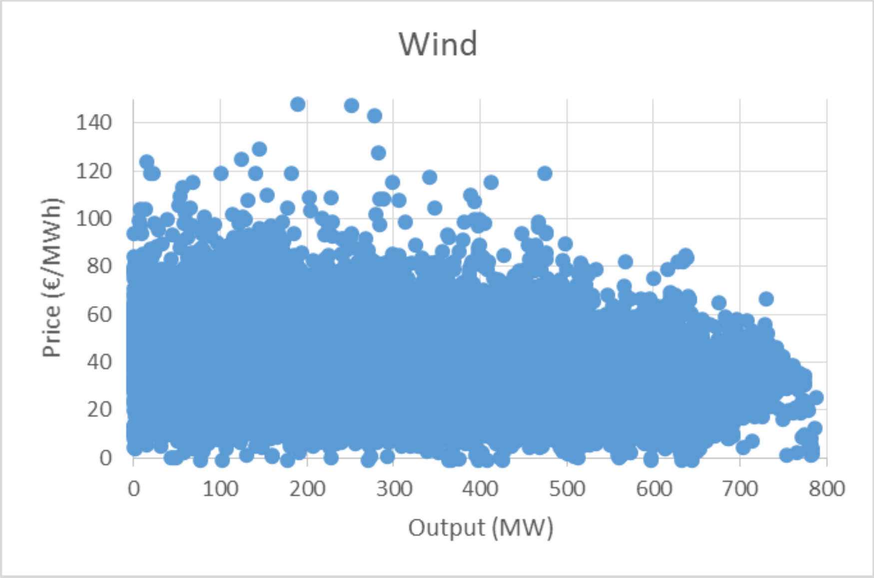
Agents

- Generators
  - Nominated
  - Dispatchable
  - Committed
- Pumped storage
- Neighbors
- Consumers
- System operator

Nominations

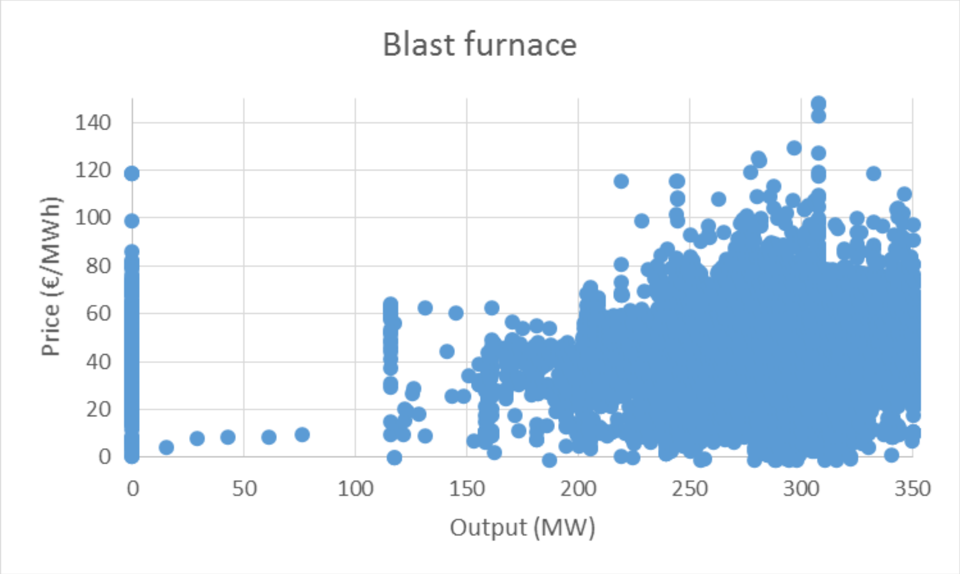
- Nominated resources are resources whose output is not driven by electricity prices
  - Nuclear (6032 MW)
  - Wind (864 MW)
  - Waste (259 MW)
  - Water (101 MW)
- The production of nominated resources is fixed to its historical value





Dispatchable Resources

- Dispatchable resources are <u>aggregated</u> resources whose production is driven by market price
  - Blast furnace (350 MW)
  - Renewable (106 MW)
  - Gas-oil (82 MW)
  - Turbojet (213 MW)
- Dispatchable resource modeling
  - Linear supply functions
  - Time-varying capacity (due to outages)
  - Capable of providing primary, secondary, tertiary reserve
  - Ramp rate equal to 4% of their capacity per minute (based on CCGT)



Dispatchable Resource Model

- λ_t: energy price
- $\lambda FCRU, \lambda FCRD, \lambda aFRRU, \lambda aFRRD, \lambda mFRR$: reserve prices
- $prod_t$: energy production
- $FCRU, FCRD, aFRRU, aFRRD, mFRR$: reserves (fixed over entire month)
- P_t: time-varying capacity
- R: ramp rate (MW/min)

$$\max \sum_t (\lambda_t \cdot prod_t - \int_{x=0}^{prod_t} (a + bx)dx) +$$

$$\lambda FCRU \cdot FCRU + \lambda FCRD \cdot FCRD +$$

$$\lambda aFRRU \cdot aFRRU + \lambda aFRRD \cdot aFRRD +$$

$$\lambda mFRRD \cdot mFRRD$$

$$prod_t \geq FCRD + aFRRD$$

$$prod_t + FCRU + aFRRU + mFRR \leq P_t$$

$$FCRU \leq 0.5 \cdot R, FCRD \leq 0.5 \cdot R$$

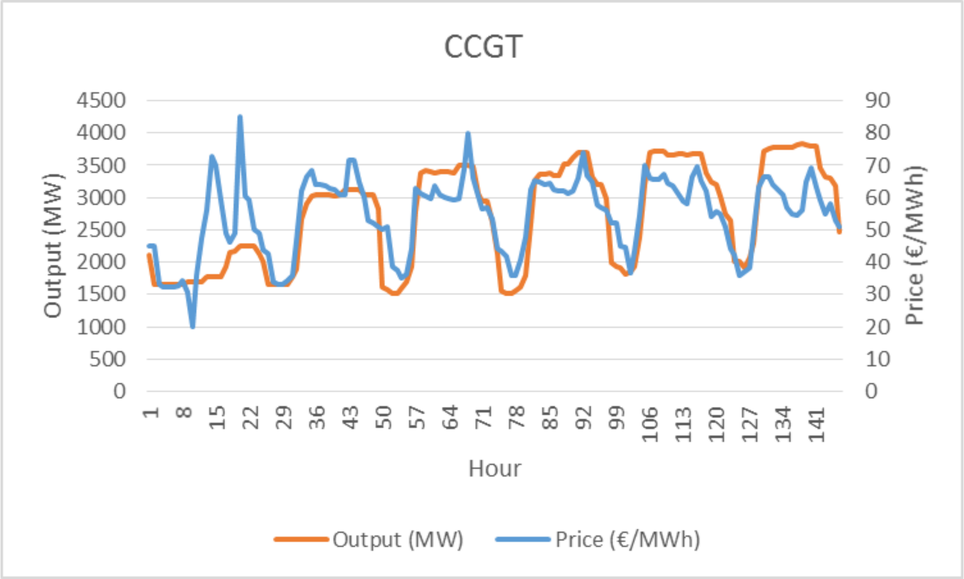
$$aFRRU \leq 7 \cdot R, aFRRD \leq 7 \cdot R$$

$$mFRR \leq 15 \cdot R$$

$$prod_t, FCRU, FCRD, aFRRU, aFRRD, mFRR \geq 0$$

Committed Resources

- Committed resources are resources described by a unit commitment model, whose technical-economic data is available unit-by-unit
  - Coal (972 MW)
  - CCGT (6506 MW)
- Committed resources modeling
  - Technical <u>minimum</u>
  - Time-varying minimum/maximum by unit (outages)
  - Time-varying fuel cost
  - Capable of providing primary, secondary, tertiary reserve
  - Ramp rates
  - Min up/down times
  - Startup cost
  - Min load cost
  - Multi-segment marginal cost



Committed Resources Model

- u_t, su_t, sd_t: unit commitment, startup, shut-down indicator variables
- SUC, MLC: startup/min load cost
- UT/DT: min up/down times
- $ProdMin_t$: minimum production limit

$$\max \sum_t (\lambda_t \cdot prod_t - \int_{x=0}^{prod_t} MC(x)dx - SUC \cdot su_t - MLC \cdot u_t)$$

$$+Reserve\ revenues$$

$$prod_t \geq (ProdMin_t + FCRD + aFRRD) \cdot u_t$$

$$prod_t + FCRU + aFRRU + mFRR \leq ProdMax_t \cdot u_t$$

$$u_t = u_{t-1} + su_t - sd_t$$

$$\sum_{\tau=t-UT+1}^{t} su_\tau \leq u_t, \sum_{\tau=t-DT+1}^{t} su_\tau \leq 1 - u_t$$

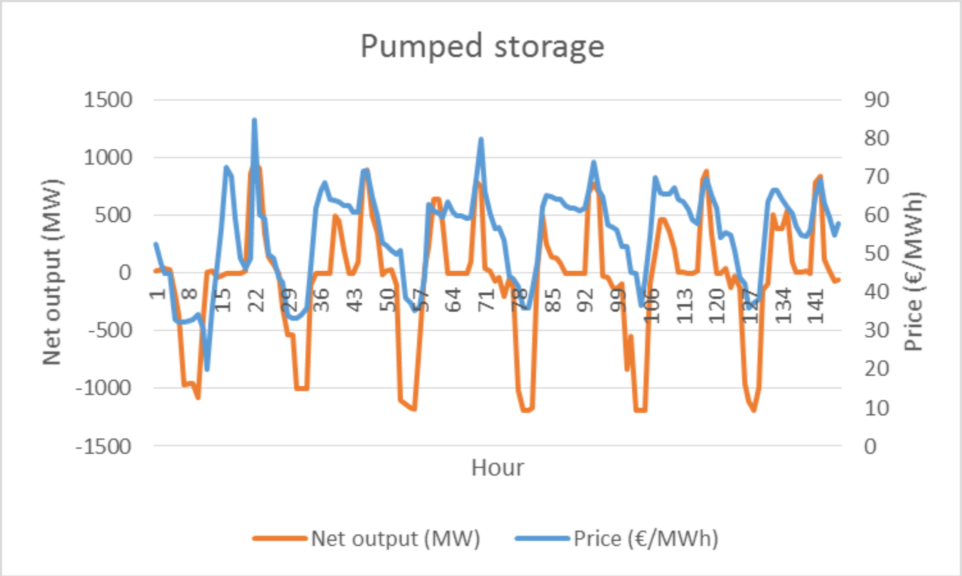
$$Reserve\ limits$$

$$prod_t, FCRU, FCRD, aFRRU, aFRRD, mFRR \geq 0$$

$$u_t, su_t, sd_t \in \{0, 1\}$$

Pumped Storage

- Pumped storage resources pump water when prices are low, release water when prices are high
- Pumped storage modeling
  - Tanks need to be empty in the end of the day
  - Efficiency estimated from data (76.5%)
  - Time-varying pump/production/storage capacity (outages)
  - Storage capacity estimated from data
  - Pump/production ramp rate estimated from data
  - Capable of providing primary, secondary, tertiary reserve



Pumped Storage Model

- $pump_t$: energy pumping
- e_t: stored energy in reservoir
- $ProdMax_t, PumpMax_t, ES_t$: production/pumping/storage capacity
- η: pumping efficiency
- $RampProd_t, RampPump_t$: production and pumping ramp rate

$$\max \sum_t \lambda_t \cdot (prod_t - pump_t)$$

$$prod_t + FCRU_t + aFRRU_t + mFRR_t \leq ProdMax_t$$

$$pump_t \leq PumpMax_t$$

$$e_{t+1} = e_t + \eta \cdot pump_t - prod_t$$

$$e_t \leq ES_t$$

$$e_1 = e_T = 0$$

$$prod_t - prod_{t-1} + FCRU_t + aFRRU_t + mFRR_t \leq RampProd_t$$

$$prod_t - prod_{t-1} - FCRD_t - aFRRD_t \geq -RampProd_t$$

$$pump_t - pump_{t-1} + FCRD_t + aFRRD_t \leq RampPump_t$$

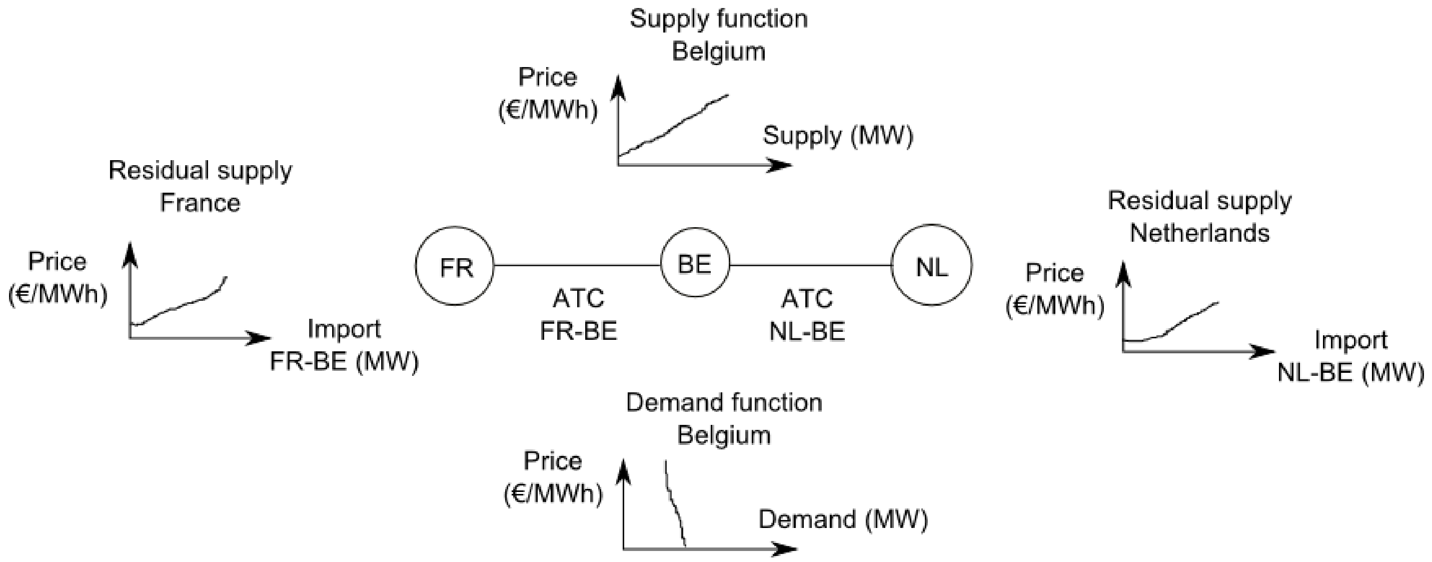
$$pump_t - pump_{t-1} - FCRU_t - -aFRRU_t - mFRR_t \geq -RampPump_t$$

$$FCRU \leq 0.5 \cdot R, FCRD \leq 0.5 \cdot R, \ldots$$

$$prod_t, pump_t, e_t \geq 0$$

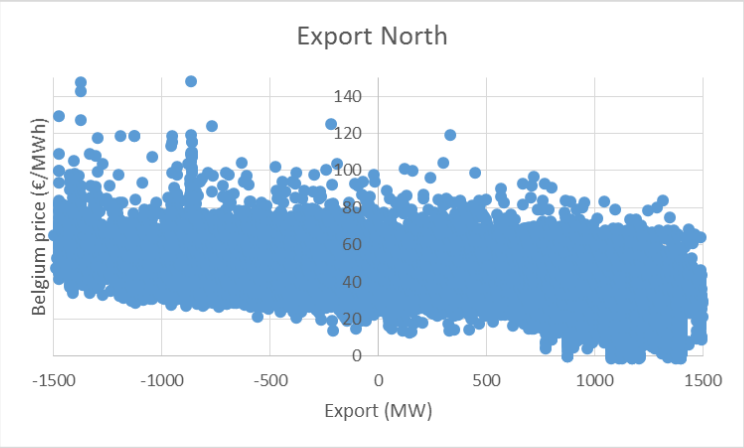
Neighboring Systems

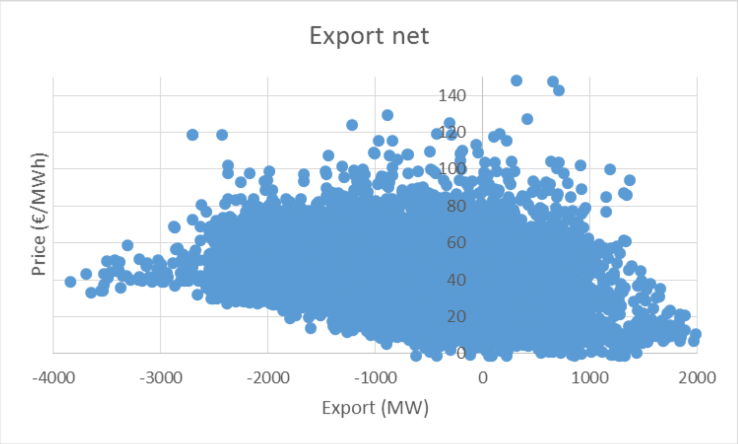
- Belgium is interconnected to France and Netherlands
- Original idea: model neighbors through residual supply functions
- Available transmission capacity (ATC): technical limit on amount of power that can flow over transmission lines that connect BE to neighbors

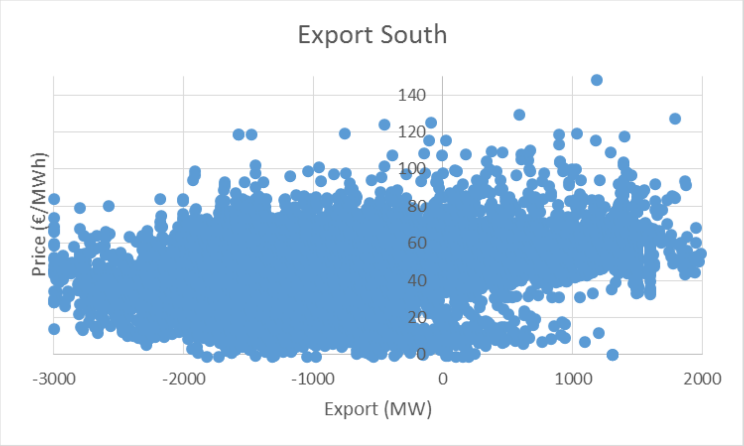


Neighboring Systems (II)

- Southern exports are increasing in price => separate modeling of neighboring countries out of the question
- Net exports are price responsive with statistical significance, but fit of the model worsens dramatically

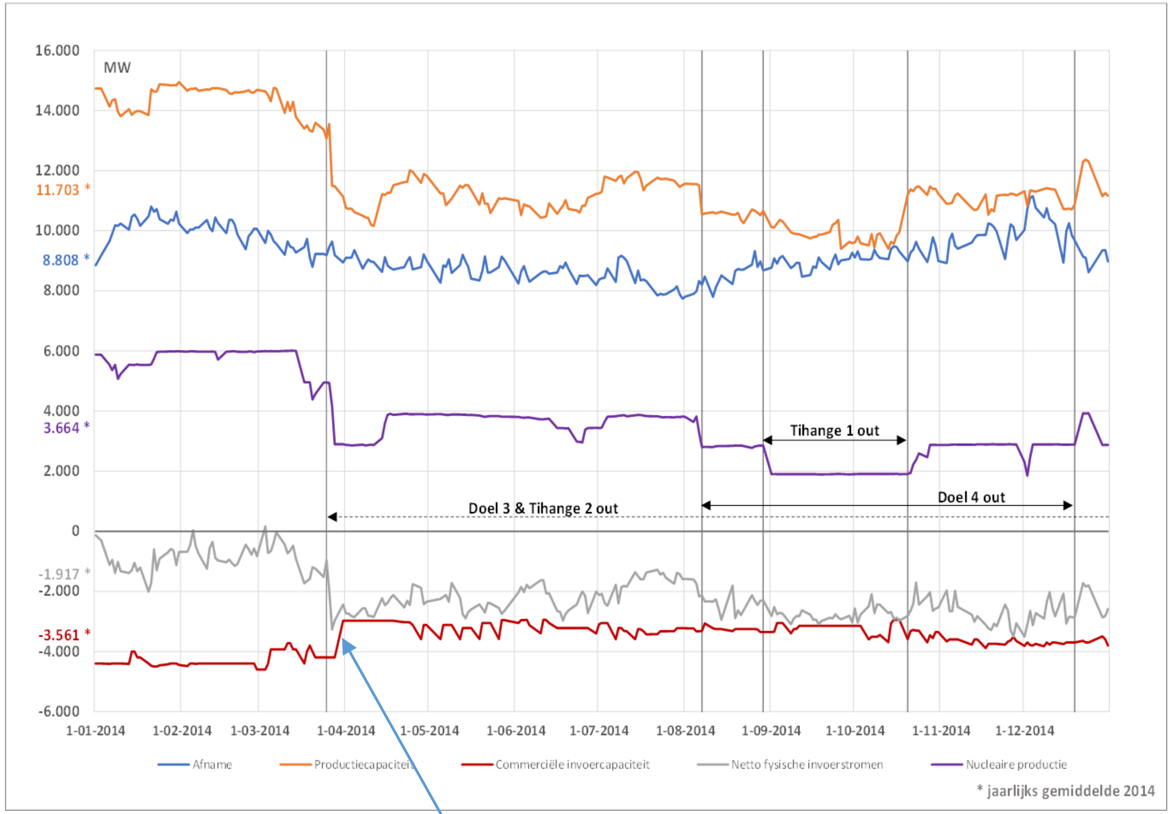






Neighboring Systems Model

- Imports are fixed to their historical values
- Time-varying capacity (representing ATCs)
- Excess capacity above historical value modeled as linear supply function
  - Intercept is equal to the 90th percentile of the day ahead price (70 €/MWh)
  - Slope is such that within 500 MW we reach marginal cost of 300 €/MWh
  - Thus, price-elastic imports are used only in case of supply shortage, with marginal costs rising steeply



Emergency increase in imports after nuclear outage

Consumers

- We assume inelastic demand, due to lack of contrary evidence
- $VOLL$: value of lost load (3000 €/MWh)
- d_t: electricity consumption
- D_t: demand

$$\max \sum_t (VOLL \cdot d_t - \lambda_t \cdot d_t)$$

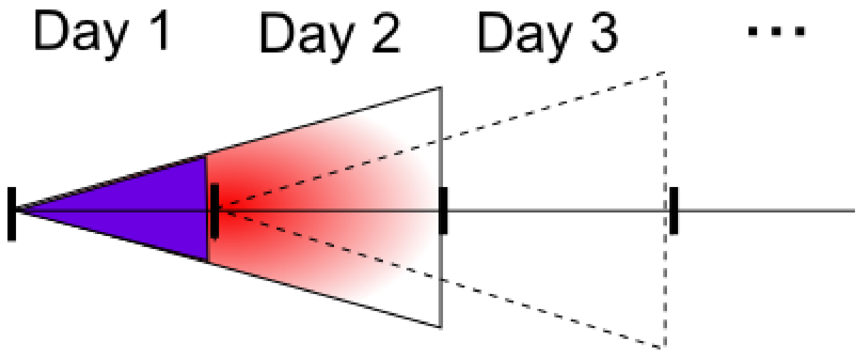
$$0 \le d_t \le D_t$$

Transmission System Operator

- TSO procures 5 types of reserve
  - Primary up/down: 55MW
  - Secondary up/down: 140 MW
  - Tertiary: 350 MW

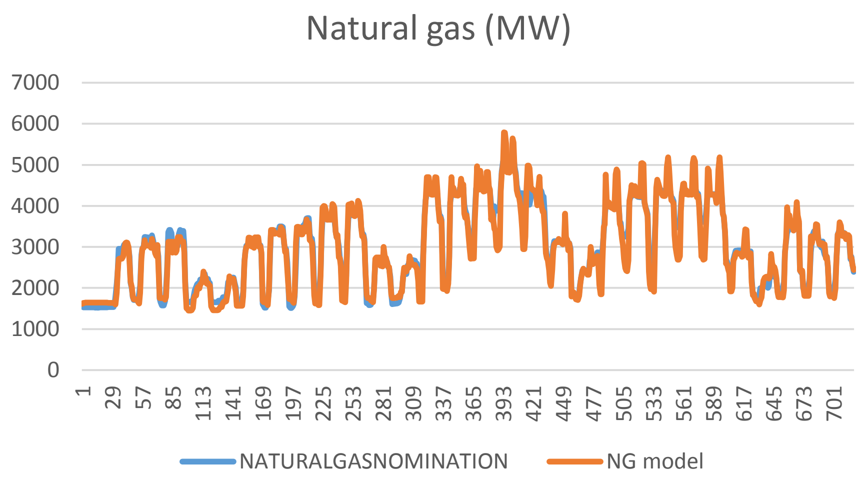
Solution Methodology

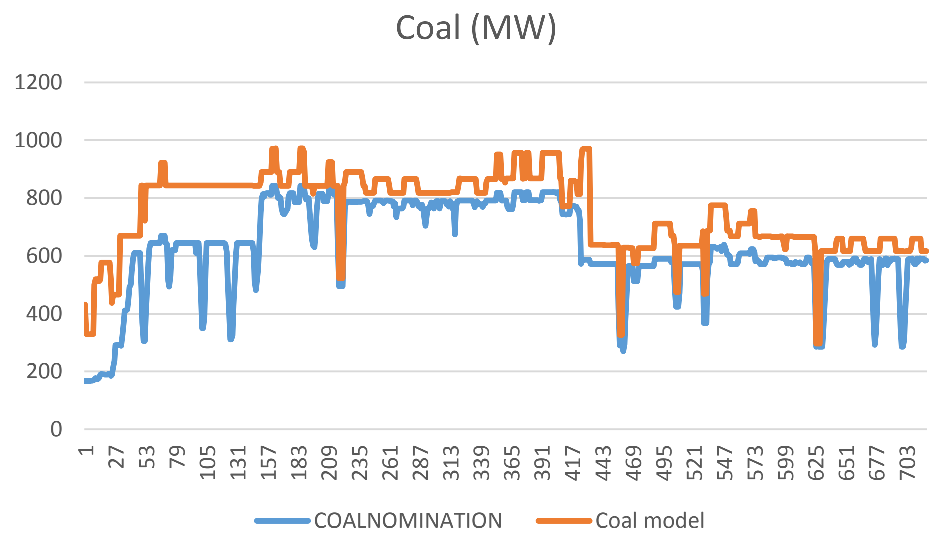
- Unit commitment over an entire month is a time-consuming model
- We attempted four solution methods
  - Direct resolution by branch and bound (too slow)
  - Dual decomposition of coupling constraints (somewhat slow, numerically unstable)
  - Generator decomposition heuristic (poor performance)
  - Receding horizon heuristic (shown to perform well in transmission switching)
- Receding horizon heuristic
  - Initialize the commitment of all units for all hours to 'on'
  - For $iter = 1{:}\,IterLimit$
  - For $day = 1{:}\,30$
    - Solve the entire model for the *entire* horizon, with unit commitment decisions fixed for all days except today <u>and tomorrow</u>
    - Fix commitment for today *only*, step one day forward
- Receding horizon heuristic outperforms alternatives within a few hours of run time
- For the second study this heuristic was not needed since reserve is cleared daily

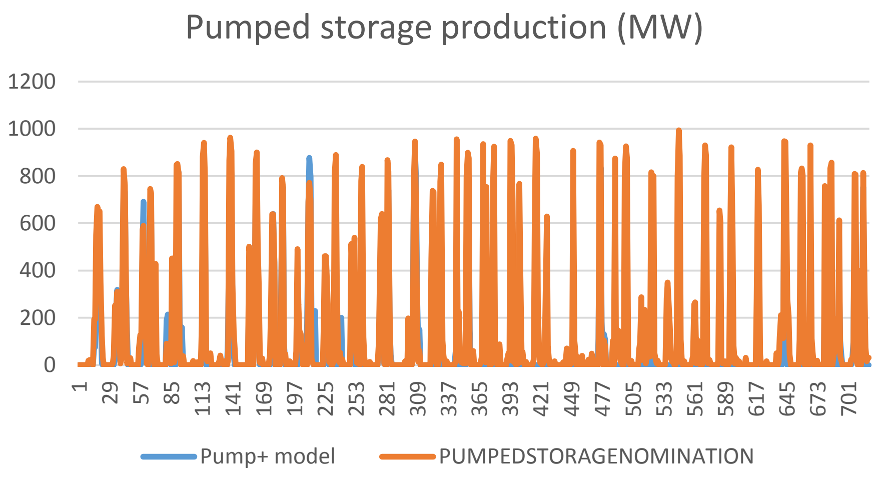


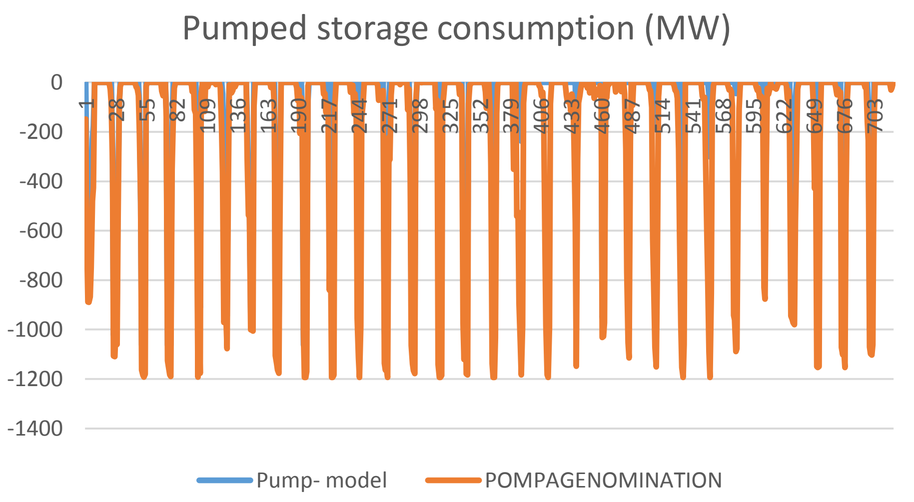
Model Validation

Production by Technology, January 2013

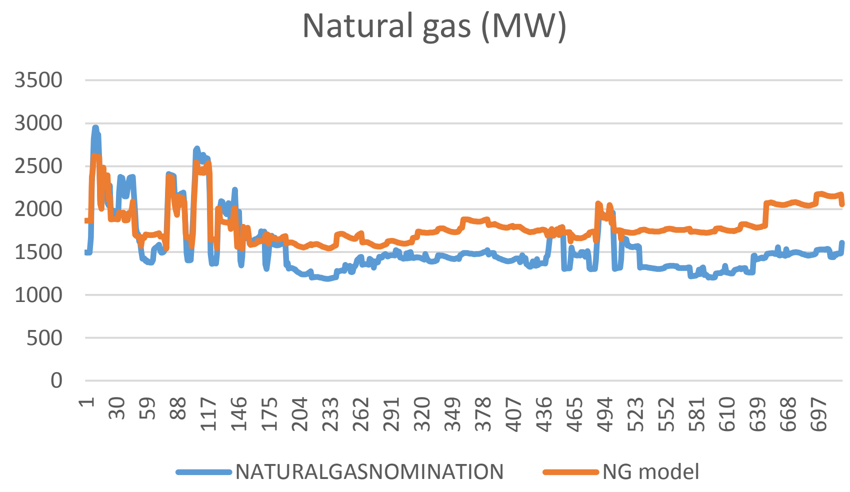


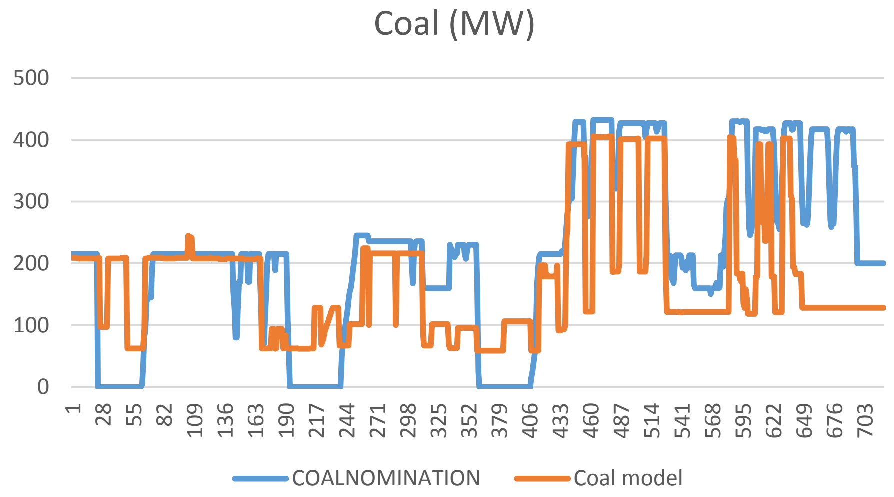


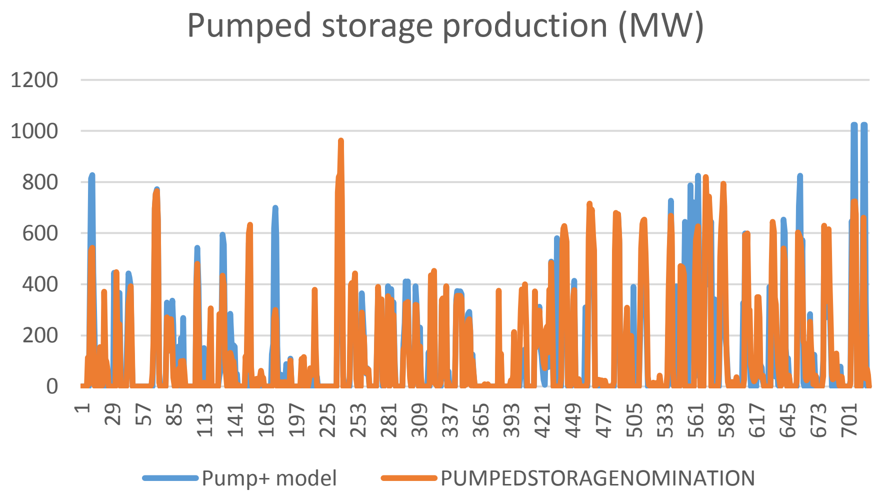


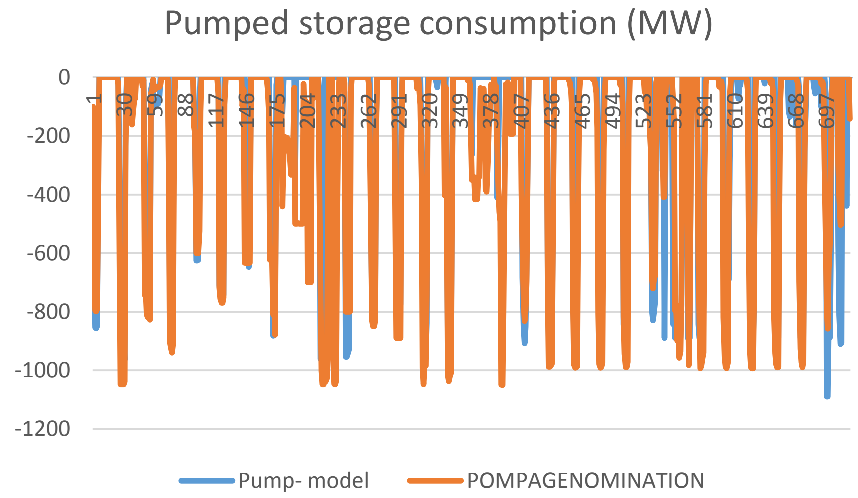


Production by Technology, June 2013

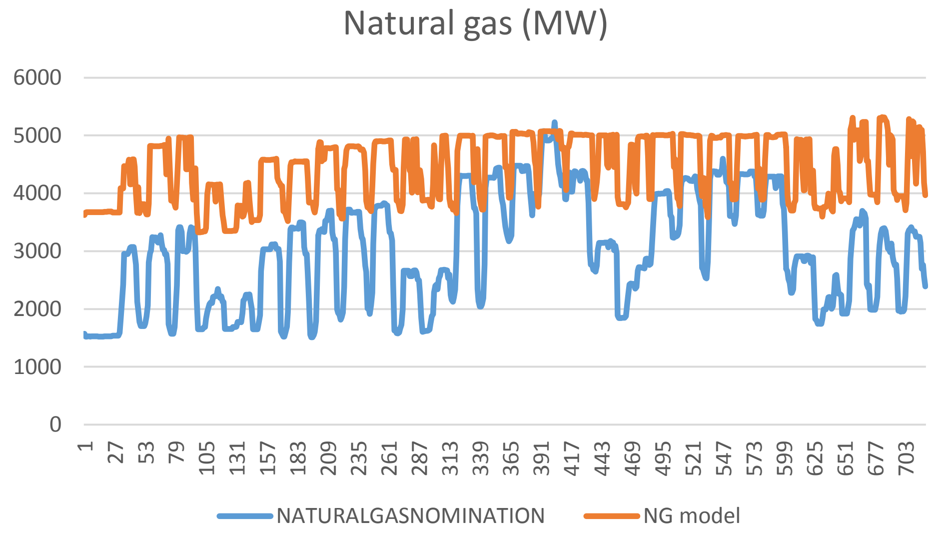


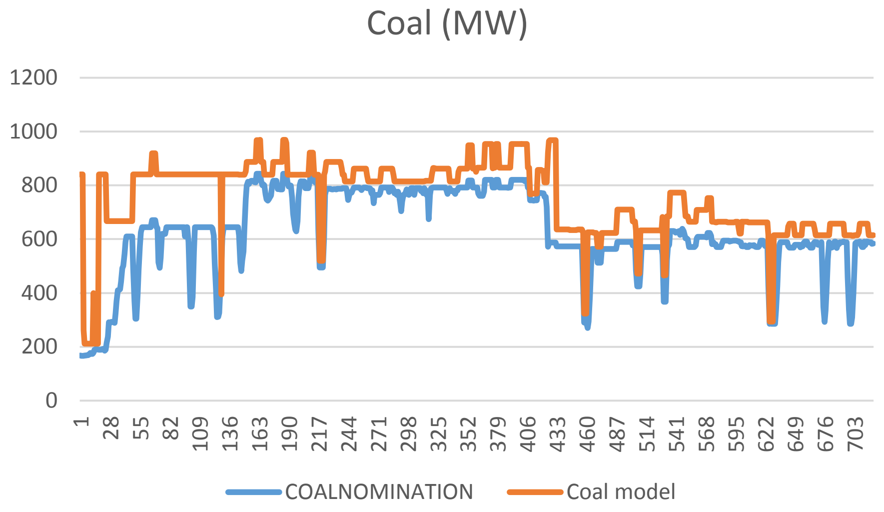


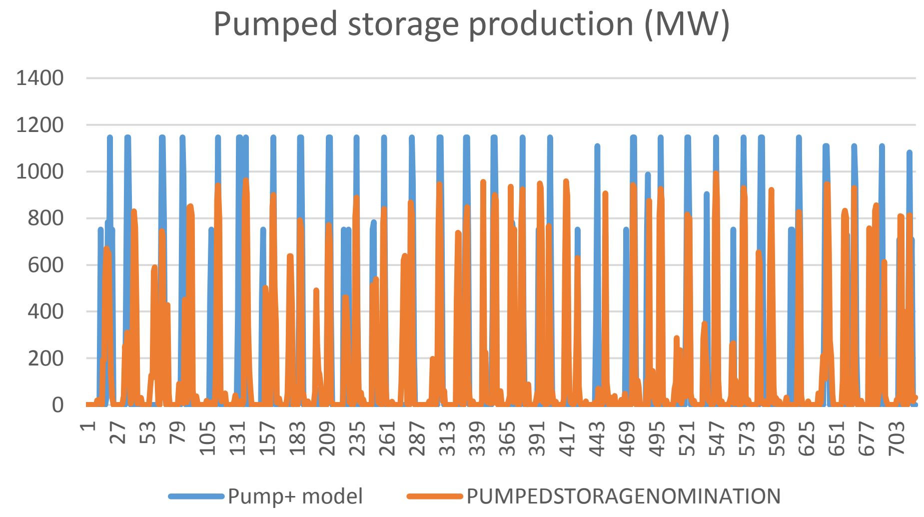


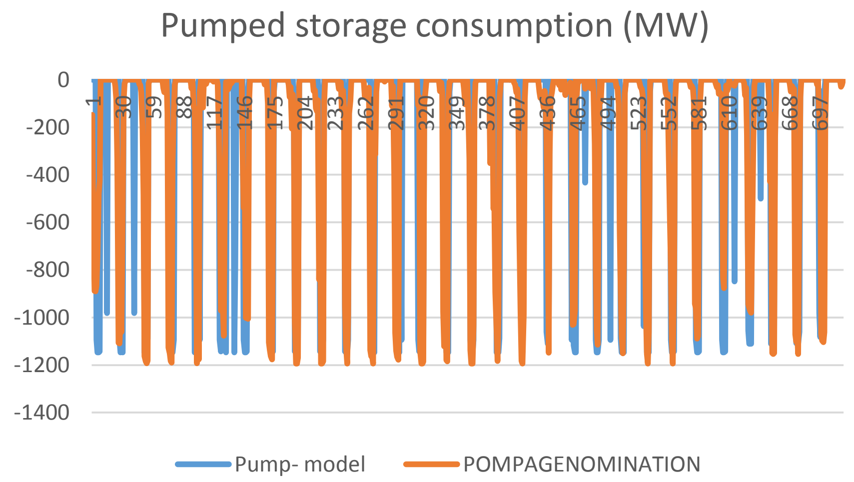


Dispatching Against Price, January 2013







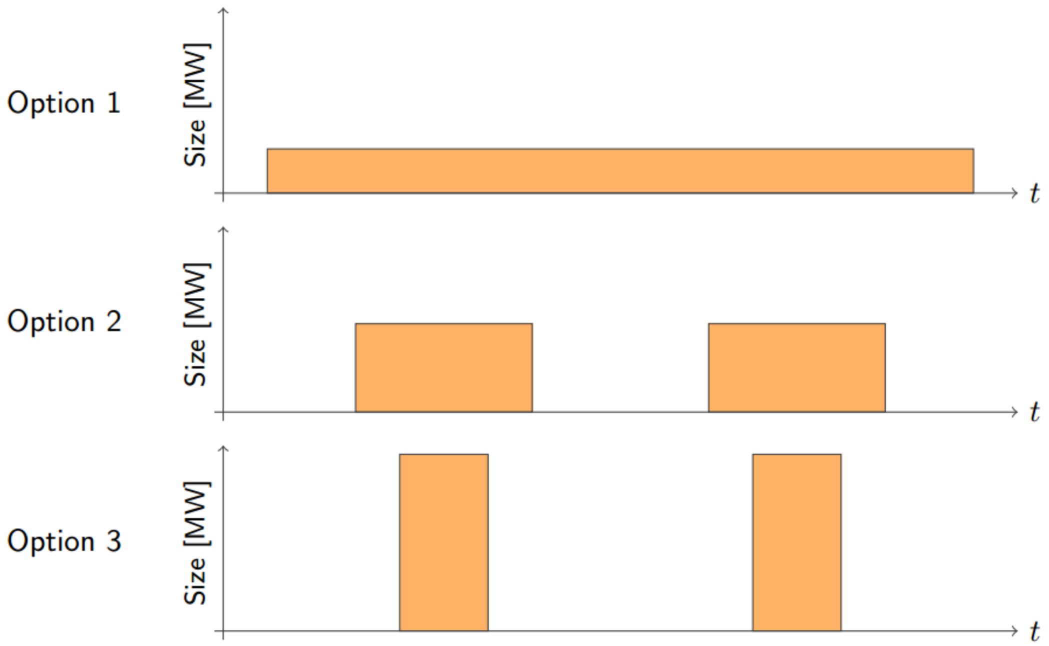


Remarks

- Model tracks production by fuel fairly accurately in months of high demand
- Model overestimates production of CCGT in months of low demand
  - One source of inaccuracy is the fact that we do not have access to data of CCGT units that were decommissioned after October 2014
  - Since price adders kick in during tight conditions, this inaccuracy should have minor effects on our results
- Centralized unit commitment dramatically outperforms alternative of dispatching units against price
- EUPHEMIA primal (commitment and dispatch) decisions appear to be efficient if our estimated model parameters are accepted as accurate

Understanding Prices

- CWE energy market is cleared by EUPHEMIA, an algorithm that seeks market clearing prices for continuous and discrete bids
- We have tested two models that approximate this behavior
  - Solving the dispatch problem with unit commitment fixed, and computing dual multipliers of power balance constraint
  - Solving an approximation of prices that attempts to minimize surplus losses of CCGTs, given their dispatch schedule
- Motivation for second approach: if we trust that our dispatch decisions are close to reality, let us find a price that minimizes deviation from what EUPHEMIA is supposed to do



Mutually exclusive block orders

A Model for Approximating EUPHEMIA

$$\min \sum_{g} surplusShortage_g$$

$$prod_t = prod_t^*$$

$$0 \leq prod_{gt} \perp MC_g(p_{gt}) - \lambda_t + scarcityRent_{gt} \geq 0$$

$$0 \leq scarcityRent_{gt} \perp ProdMax_g(p_{gt}) - prod_{gt}^* - FCRU_g^* - aFRRU_g^* - mFRRU_g^* \geq 0$$

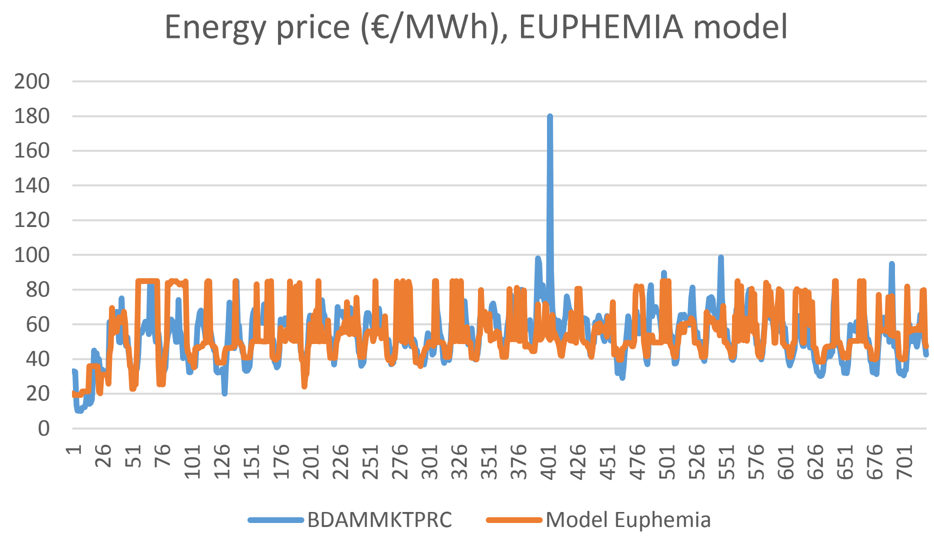
Dispatched resources (including coal)

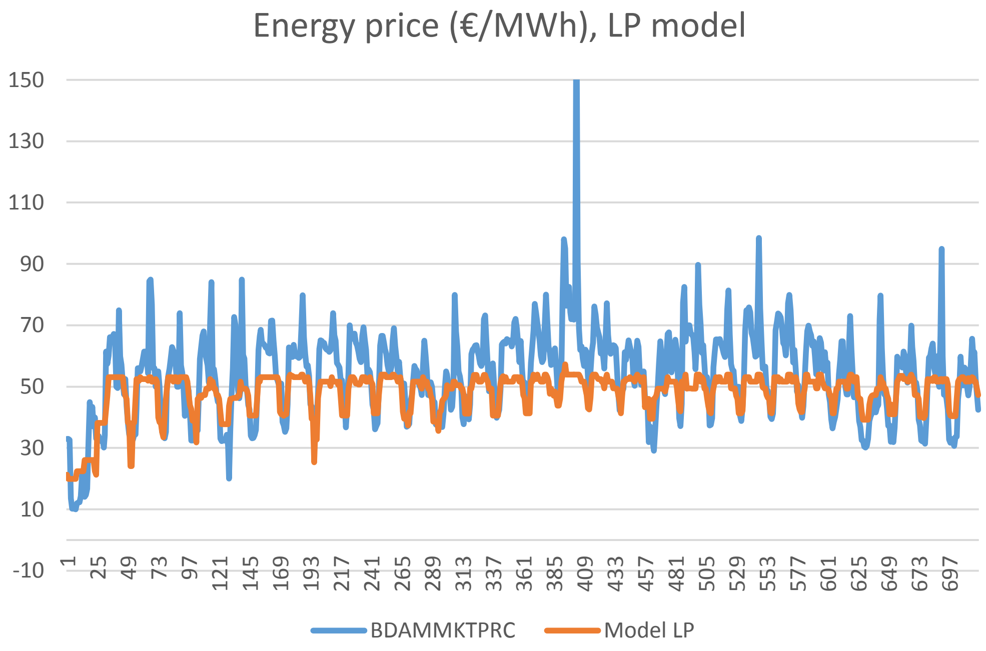
$$dailySurplus_g = \sum_{gt} \lambda_t \cdot p_{gt}^* - TotalCost_g(u_g^*, prod_g^*) + {\color{red}surplusShortage_g}$$

$$dailySurplus_g \geq 0$$

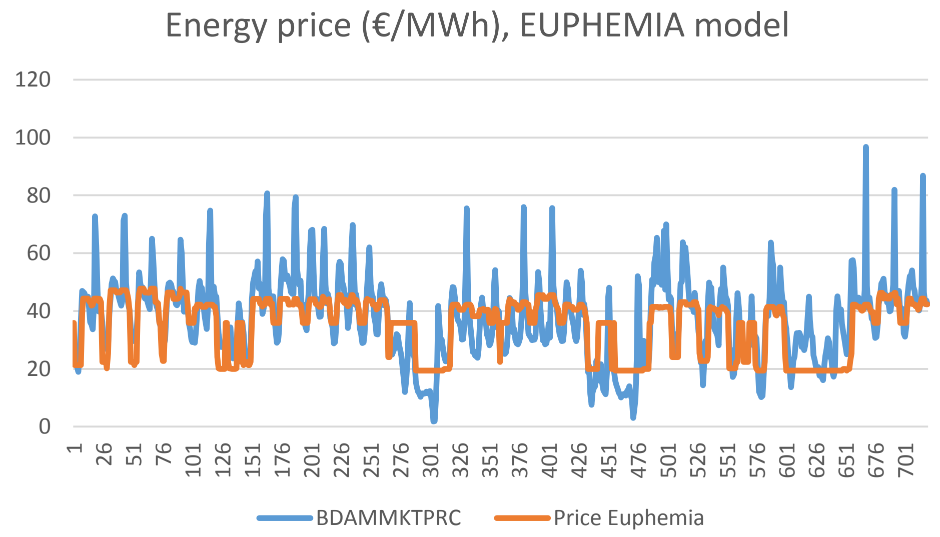
CCGT

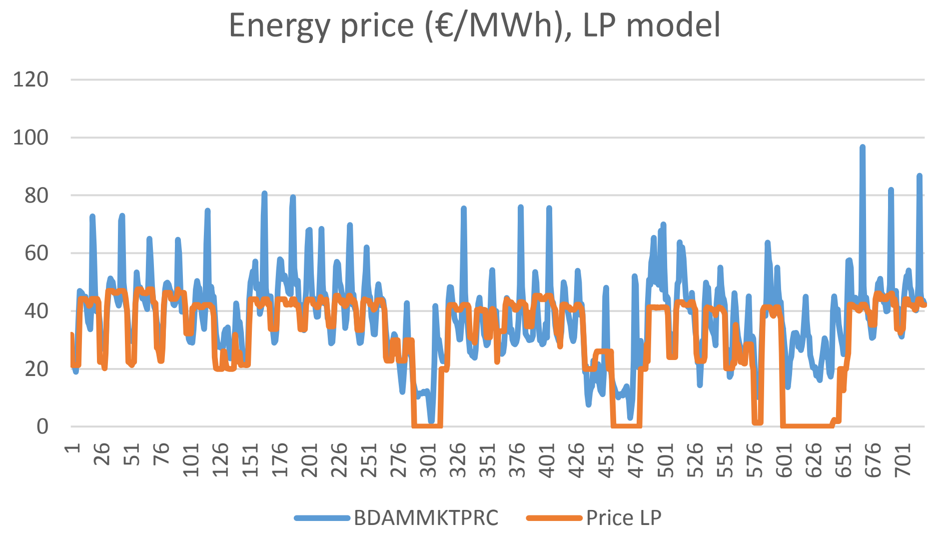
Price Fit, January 2013





Price Fit, March 2014



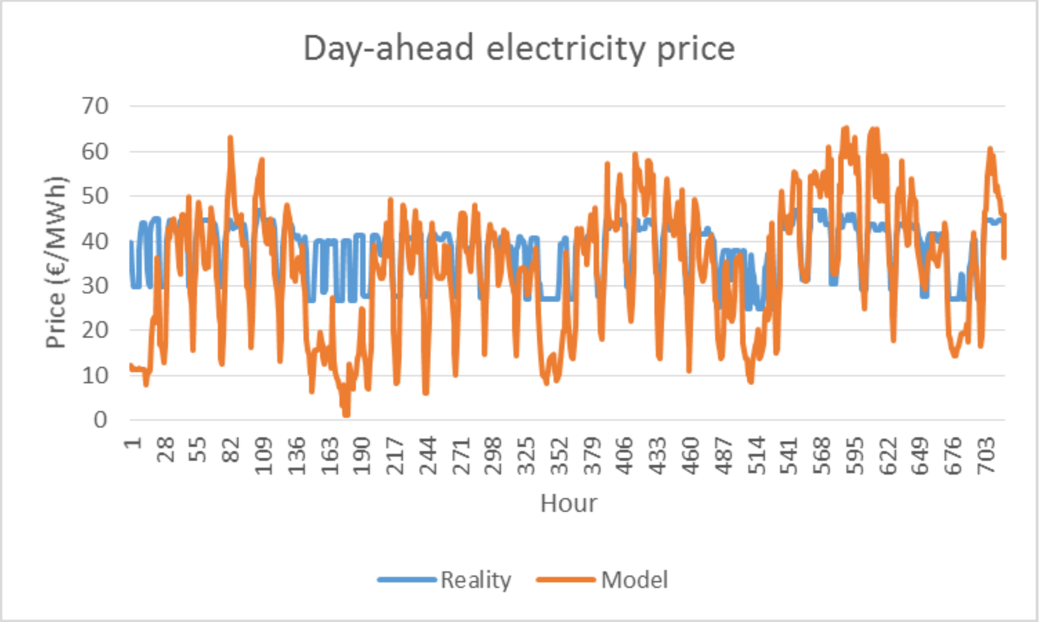


Remarks

- EUPHEMIA approximation outperforms LP
- Price model captures some of the variability of prices
  - Price dips during the night due to coal
  - Price jumps during the day due to CCGT unit commitment costs
- Price jumps during the day cannot be explained by unit commitment costs alone

Energy Price, July 2013

- July 2013 exhibited large variations in energy prices which were impossible to model using a convex model of agent behavior
- Reserve requirements keep CCGT units online at their technical minima
- Coal units set the price in the night, at a price below the marginal cost of online CCGT units



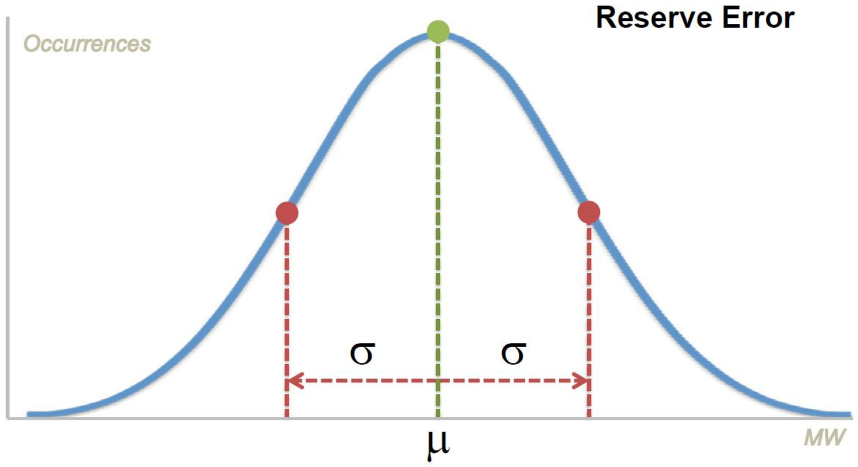
Results

First study (January 2013 – September 2014)

Second study (September 2015 – March 2016)

LOLP Computation

- 15-minute uncertainty is estimated based on reserve energy activation (data available)
- Following Hogan and ERCOT practice, we fit a Gaussian for each different season and 6 intervals within the day



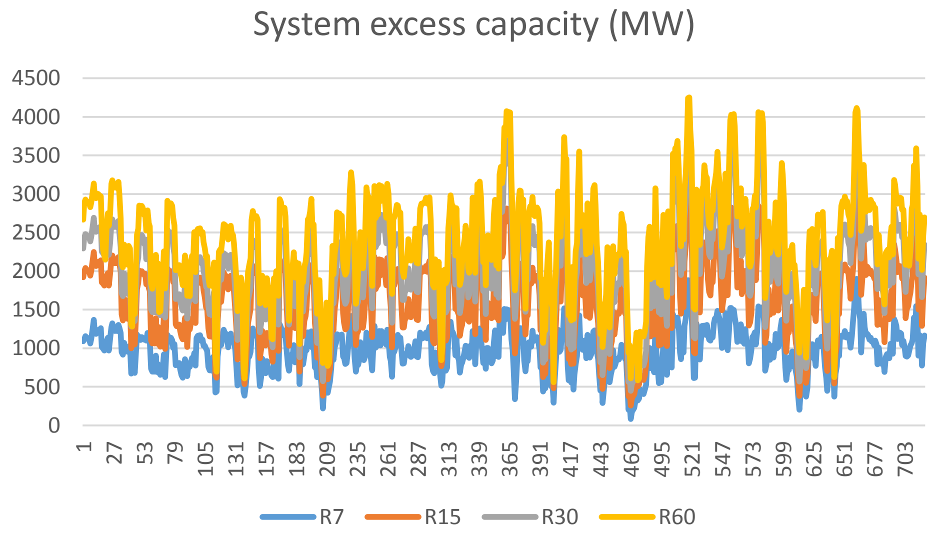
Seasons	Hours	Mean (€/MWh)	St dev (€/MWh)
Winter (month 12, 1, 2)	1, 2, 23, 24	-31.18	96.42
	3-6	-34.88	83.51
	7-10	8.20	103.47
	11-14	-26.39	185.15
	15-18	-19.74	136.75
	19-22	7.58	102.46
Spring (month 3, 4, 5)	1, 2, 23, 24	9.14	97.69
	3-6	-0.45	77.12
	7-10	14.39	103.85
	11-14	-17.89	168.62
	15-18	-58.75	175.45
	19-22	12.80	105.87
Summer (month 6, 7, 8)	1, 2, 23, 24	7.52	89.68
	3-6	-3.63	79.13
	7-10	3.03	92.52
	11-14	6.51	135.41
	15-18	0.50	127.57
	19-22	11.40	98.22
Fall (month 9, 10, 11)	1, 2, 23, 24	-27.84	86.06
	3-6	-24.24	73.11
	7-10	19.45	97.07
	11-14	-23.08	129.76
	15-18	-8.92	116.73
	19-22	6.57	94.19

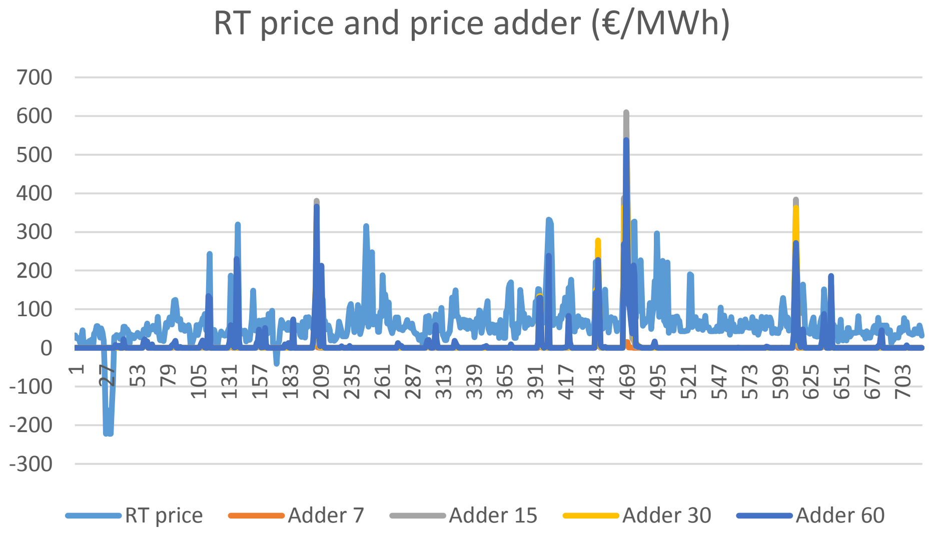
CCGT Profits and Adder Benefits: January 2013 – September 2014

	Profit (€/MWh), no adder	Profit (€/MWh), with adder	Adder benefit (€/MWh)
CCGT1	**3.6**	10.6	8.5
CCGT2	**1.3**	**3.6**	11.6
CCGT3	**1.1**	10.0	7.7
CCGT4	**3.8**	11.1	10.0
CCGT5	**0.9**	6.4	7.5
CCGT6	**3.9**	8.3	6.8
CCGT7	**1.0**	**3.2**	6.8
CCGT8	**1.1**	8.0	8.0
CCGT9	**2.3**	11.1	10.1
CCGT10	**1.7**	7.4	14.9
CCGT11	**1.7**	**4.3**	8.6

Price Adders, January 2013

- A deeper time horizon implies more reserves are available…
- … but conditions are also more uncertain





Remarks

- CCGT seems not to be viable given the market prices of the study (confirming what we have already heard in the policy debate)
- Adders, as computed in the study, could potentially change this for the majority of CCGT units (although there are still three CCGTs that are not profitable after the intro of the adders)
- The average adder for the duration of the study is 6.06 €/MWh, but the adder is effectively much higher for CCGT units (e.g. up to 20 €/MWh for some months)
  - ORDC mechanism rewards flexibility
  - Result of positive correlation of CCGT production with adders/conditions of scarcity

CCGT Profits and Adder Benefits with Restored Nuclear: September 2015 – March 2016

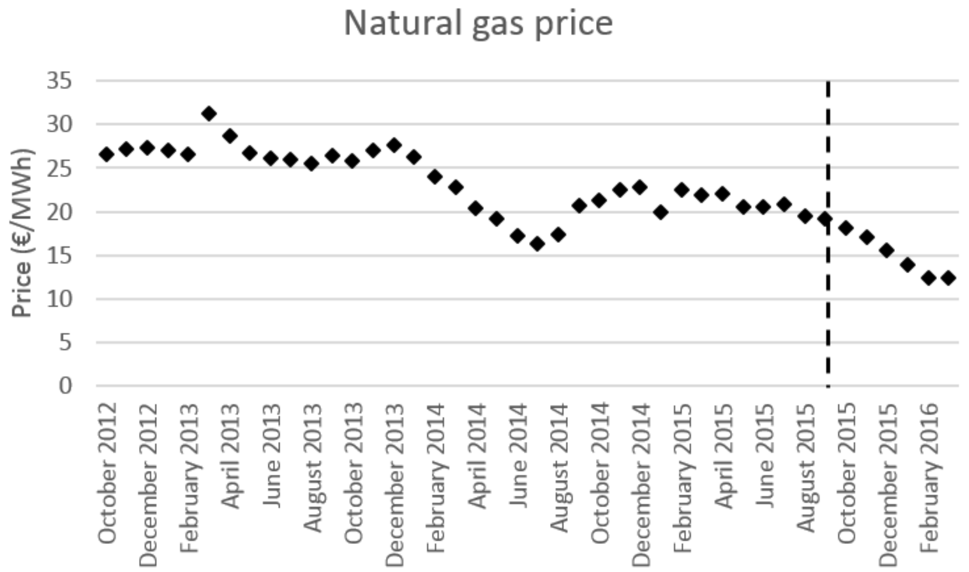
	Profit (€/MWh), no adder	Profit (€/MWh) with adder – no back-propagation	Profit (€/MWh) with adder – full back-propagation
CCGT1	10.6	10.6	10.8
CCGT2	9.2	9.3	9.4
CCGT3	9.8	9.8	10.1
CCGT5	9.5	9.5	9.8
CCGT6	9.2	9.2	9.4
CCGT8	9.4	9.4	9.7
CCGT9	11.0	11.0	11.3
CCGT11	9.2	9.2	9.4

Remarks

- *All* CCGT units are comfortably profitable
  - Significant drop in natural gas prices
  - Less competition among surviving CCGTs due to retirement of three CCGT units since first study
- Low ORDC adder, 0.3 €/MWh, due to restoration of nuclear capacity => scarcity adders are *adaptive*

Drop in Natural Gas Prices

- Dashed line indicates beginning of study interval
- Price of natural gas in interval of second study is at its lowest value since October 2012



Source: SpotZTP

Drop in Competitive Pressure

- Average CCGT capacity has dropped from 6506 MW in the first study to 4367 MW in the second study
- This relieves competitive pressure on surviving CCGTs due to increased market share
- All units increase utilization rates, some (CCGT2, CCGT11) by 3x

	First study utilization rate (%)	Second study utilization rate (%)
CCGT1	55.2	58.3
CCGT2	14.0	48.5
CCGT3	71.1	73.2
CCGT5	52.1	58.2
CCGT6	31.7	46.6
CCGT8	46.1	55.7
CCGT9	69.1	69.5
CCGT11	18.7	62.3

Impact of Strategic Reserve

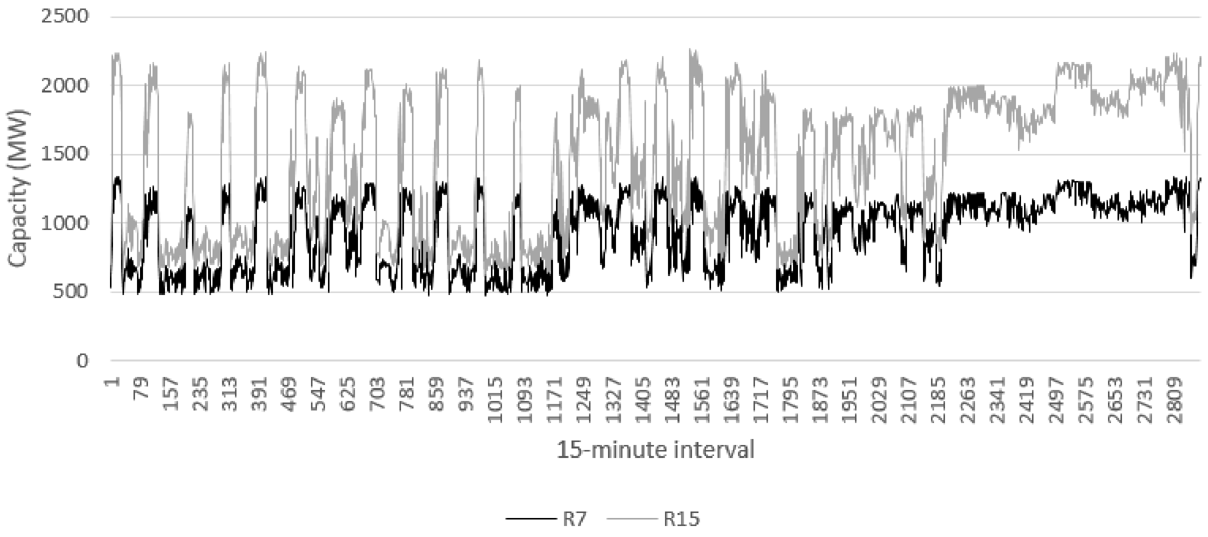
- Strategic reserve is standby emergency capacity (akin to reliability must run capacity in ERCOT) which was mobilized by the Belgian system operator in order to deal with scarcity
  - Total strategic reserve capacity in 2015: 1535.5 MW (demand response: 358.4 MW, CCGTs: 1177.1 MW)
- How we model strategic reserve: constant shift to reserve capacity R in adder formula (see slide 6)

CCGT Profits and Adder Benefits – No Strategic Reserve

	Profit (€/MWh), no adder	Profit (€/MWh) with adder – no back-propagation	Profit (€/MWh) with adder – full back-propagation
CCGT1	10.6	10.6	15.2
CCGT2	9.2	9.3	12.6
CCGT3	9.8	9.8	14.6
CCGT5	9.5	9.5	14.1
CCGT6	9.2	9.3	12.8
CCGT8	9.4	9.4	13.9
CCGT9	11.0	11.0	15.8
CCGT11	9.2	9.2	13.2

Remarks – No Strategic Reserve

- Removal of strategic reserve lifts ORDC adder from 0.3 €/MWh to 4.4 €/MWh
- Without back-propagation of scarcity signal to forward markets, adder has negligble impact



Available capacity for December 2015 for the case without strategic reserve

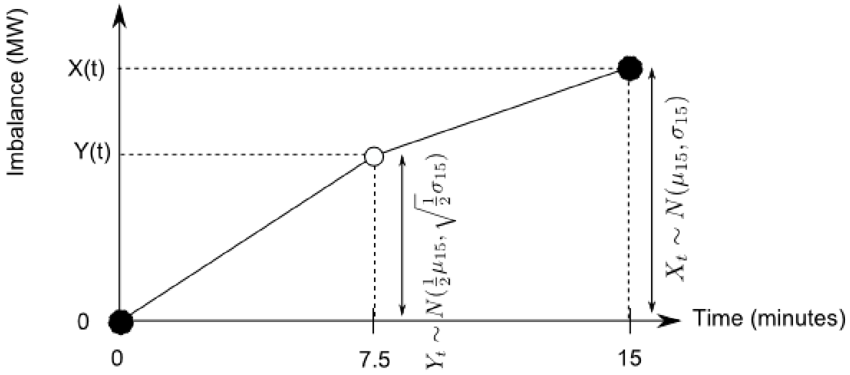
Imbalance Correlations

- When considering the adder formula over multiple time scales, we have two contributions to ORDC adder:
  - Secondary reserve capacity scarcity (response time: Δ_1=7.5 minutes): $\frac{T_1}{T_1+T_2}(VOLL - \widehat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_1}(R_{\Delta_1})$
  - Tertiary reserve capacity scarcity (response time: Δ_2=15 minutes): $\frac{T_2}{T_1+T_2}(VOLL - \widehat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_2}(R_{\Delta_2})$
- Imbalances in 7.5-minute and 15-minute horizon may be correlated => this influences the computation of the adder because it influences the function $LOLP_{\Delta_i}$

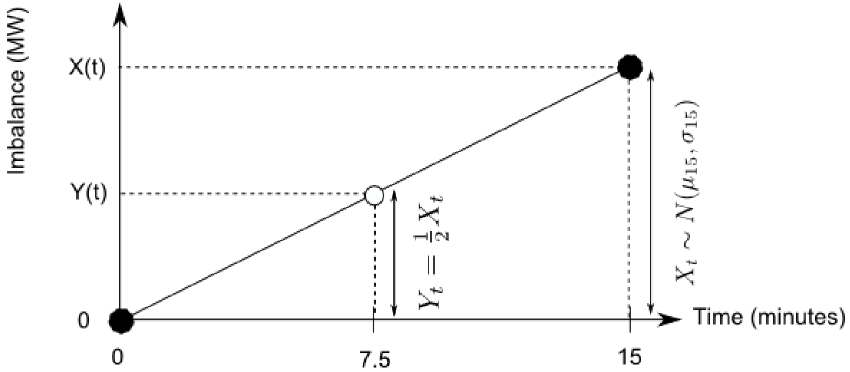
Imbalance Correlations

- Suppose that imbalance in 15-minute horizon is normally distributed with mean μ_{15} and standard deviation σ_{15}
- Infer distribution of imbalance in 7-minute horizon for three cases:
  - One extreme: increments of imbalance are independent
  - Other extreme: increments of imbalance are fully correlated
  - Intermediate: increments of imbalance are partially correlated

Imbalance Correlations

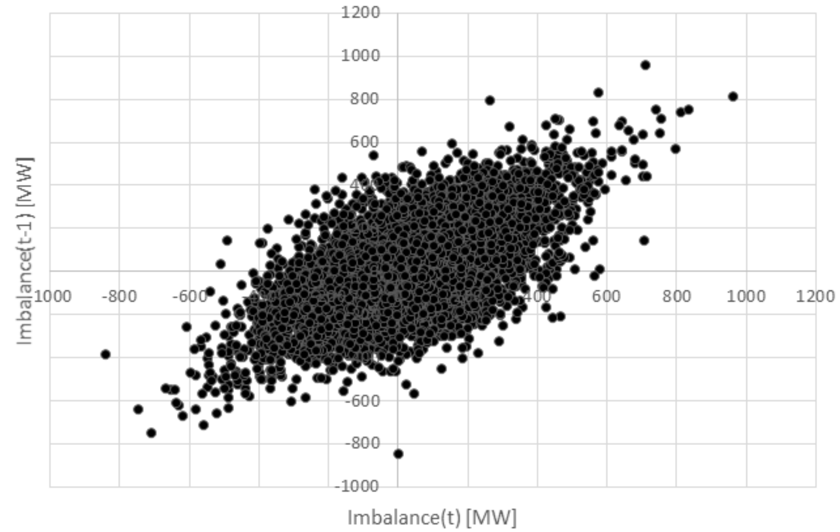


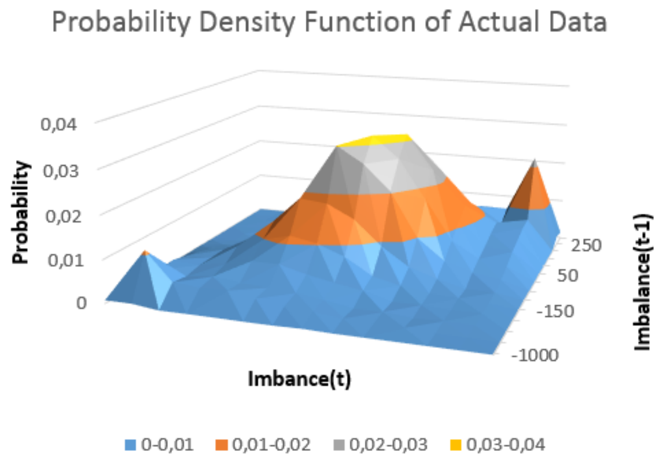
Independent imbalance increments



Fully correlated imbalance increments

Do Correlations Exist?





Strong positive correlation of imbalances

Impact of Correlations on Adder

	Independent increments (€/MWh)	Fully correlated increments (€/MWh)	Partially correlated increments (€/MWh)	Contribution of 15-minute term
Reference	0.47	0.26	0.26	0.25
No strategic reserve	3.18	1.88	1.89	1.84
VOLL=8300 €/MWh	1.35	0.74	0.75	0.72

Conclusions and Perspectives

Conclusions and Perspectives

- Conclusions of first study
  - CCGT units can cover short-term operating costs, but seem unable to recover long-run investment costs
  - Introduction of scarcity pricing appears to restore long-run viability of CCGT units
- Conclusions of second study
  - Scarcity pricing almost vanishes when restoring nuclear capacity in Belgium
  - Scarcity pricing is muted by strategic reserve
  - Assumptions on correlation of imbalances have non-negligible influence on adder, perfect correlations assumption presents reasonable trade-off between simplicity and accuracy
- Perspectives of third study
  - Can US-style scarcity be plugged into European market design?
  - Our methodology will be based on (i) areview of scarcity pricing best practices / lessons learned in ERCOT (and possibly other US markets), and (ii) an equilibrium model of DA-RT settlement

Back-Propagation of Scarcity Signal

- The ORDC adder is best suited to a US-style pool with a two-settlement system:
  - **Real-time** trading of reserve capacity and energy
  - **Simultaneous** clearing of reserve capacity and energy
- Certain European systems (such as Belgium) apply a rough form of scarcity pricing
- Two major divergences of European market design from ORDC theory
  - No co-optimization of reserve capacity and energy: this can be dealt with in practice, see e.g. ERCOT
  - It is not clear if power is traded in real time: this affects **back-propagation** of the adder signal

Back-Propagation of Scarcity Signal (II)

- In an ideal implementation of ORDC, the real-time value of capacity back-propagates to forward prices
- This cannot be ensured in certain European market designs due to:
  - the fact that real-time deviations that help the system are not necessarily encouraged
  - the fact that opportunity cost bids are not necessarily allowed in forward (e.g. day-ahead) markets
- We therefore examine two limit cases:
  - No back-propagation of adder: the adder is only applied to real-time *changes* of output
  - Full back-propagation of adder: the adder is applied to the *entire* real-time output of a generator

Thank you

For more information

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