Efficient price signals in liberalized power markets

KEYNOTE - ENERGY DAYS 2020 - UCL

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Overview

- Impact of prices on adequacy
  - A short story of an adequacy crisis
  - Removal of price caps and its impact on adequacy assessments
- Making power price signals more efficient: what is the focus of CREG?
  - Role of forward markets in risk aversion
  - Scarcity pricing
  - Best forecast of remedial actions
- Conclusion

ROLE OF PRICES

A short story about the adequacy crisis in Belgium at the end of 2018

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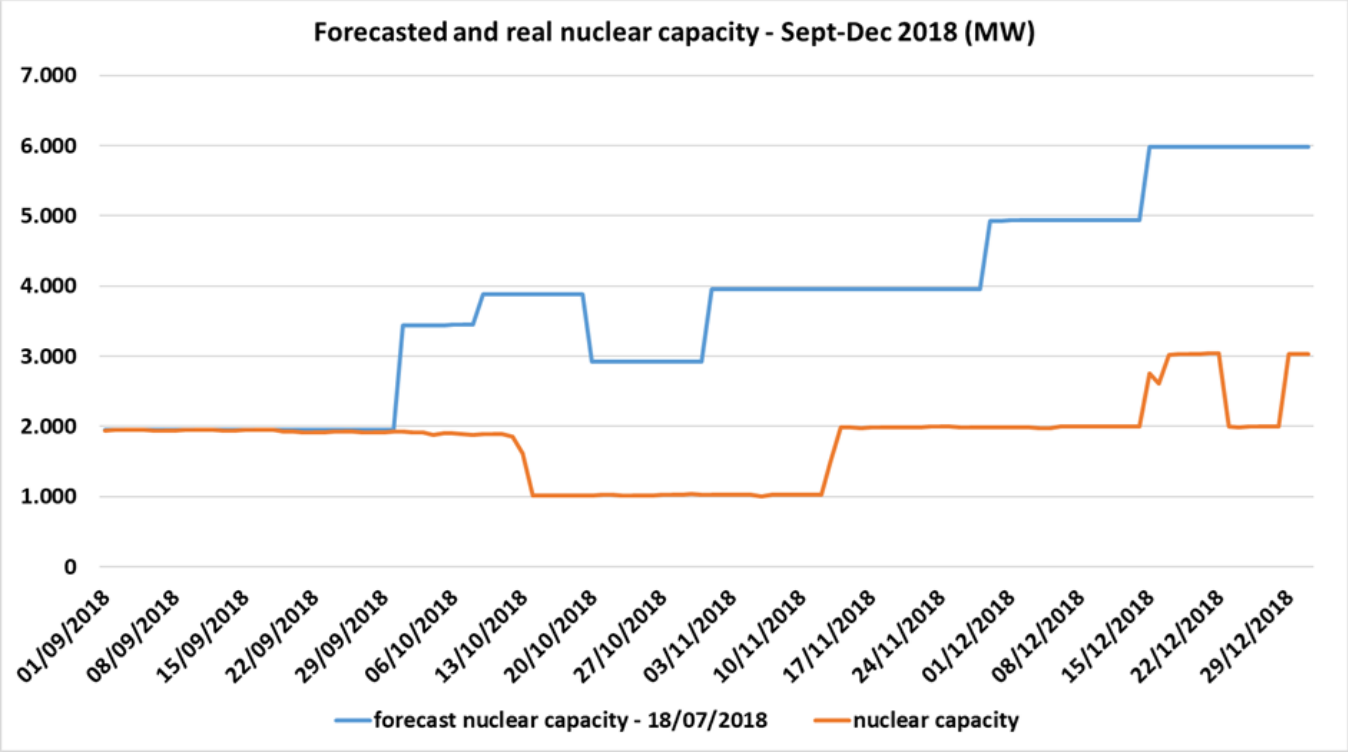
Belgian situation at the end of 2018

- Belgian max peak load: under 13.000 MW
- By the end of September 2018: unexpected loss of 2.000 to 4.000 MW of nuclear capacity, due to safety issues + 1 PST out of order, leading to less import capacity

➔ In October 2018: anticipating a severe adequacy crisis, with <u>the TSO simulating an average of 500 LoLE hours</u> (!) and a shortage of 1600-1700 MW



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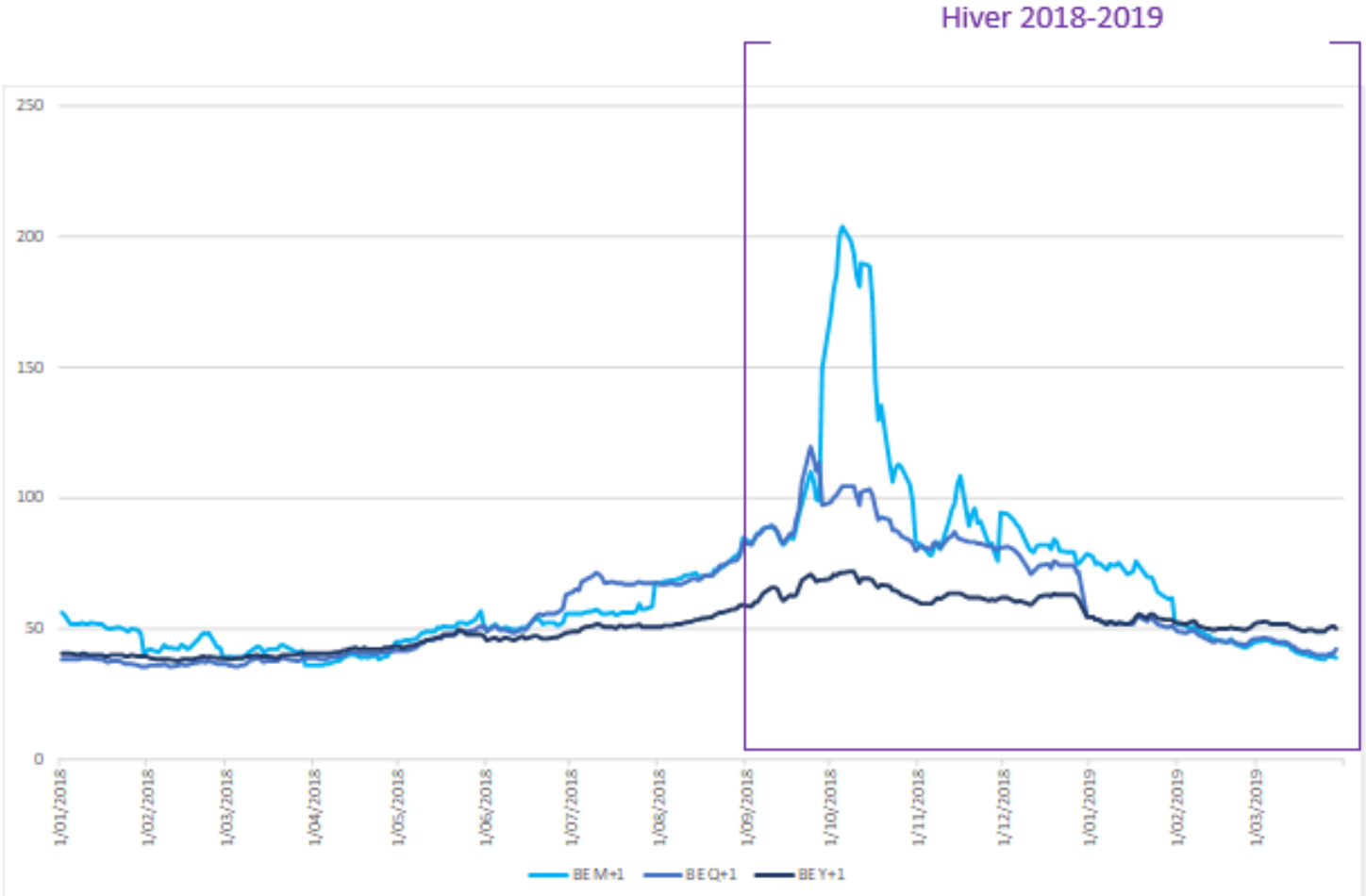
Forward market

By the end of September, an adequacy crisis is clearly expected by the market: month ahead baseload price for November 2018 tops 200 EUR/MWh(!). Also other forward prices (Q+1, Y+1) increased sharply.
➔ Clear market reaction to adequacy risks



Market reaction to high prices

- Prices on the forward market signaling scarcity to all market players

  ➔ Did market actors respond to these price incentives?

  Yes, in total, the Belgian market added more than 1.000 MW of additional capacity within 1-3 months' time

Different types of capacity were added

- Old capacity put back online: 280 MW (2 gas engines, 2 gas turbines, 1 cogen and 1 CCGT)
- Rented emergency generators: 200 MW
- Demand response: 500 MW (300 MW implicit (not offered on day-ahead) 200 MW explicit): all industrial clients
- Slow reserves (mostly former strategic demand reserves): 200 MW (not verified by CREG)

➔ **TOTAL OF 1180 MW OF NEW CAPACITY IN 1-3 MONTHS' TIME**

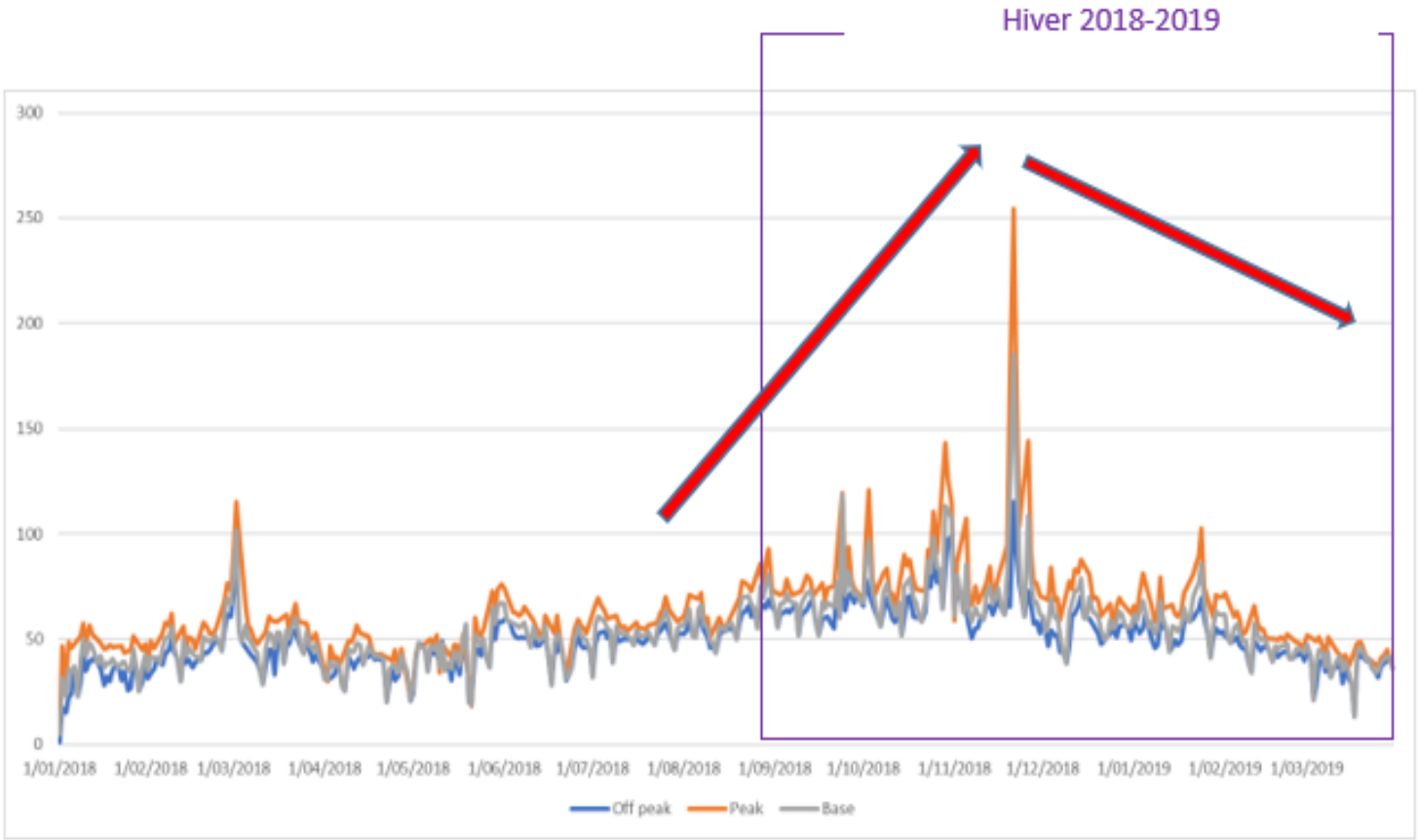
➔ **MARKET CLEARLY RESPONDED TO PRICE SIGNALS**

➔ **CONSEQUENTLY, FORWARD PRICES DECLINED SHARPLY**

Ex-post: no adequacy problems

Ex-post, it was clear there was no adequacy issue. Max hourly price on day ahead was 499 €/MWh, well below the market price cap. CREG calculated there was <u>always a margin left of at least 3.7 GW before curtailment</u>

➔ Clear overestimation of adequacy risk by TSO and/or underestimation of the market reaction



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Adequacy risk and increase of capacity

- How is it possible that adequacy problems were so overestimated?
  - TSO is risk averse
  - Information asymmetry: having correct and complete information on all actors relevant to energy is just impossible => a very quick and strong reaction from market parties that was unexpected by TSO, ministry, NRA
- Numerous other examples possible regarding market reactions that we did not anticipate, because this is distributed information, not directly available to NRAs and TSOs.
- This information asymmetry is an important reason to liberalise markets and to avoid central planning by bureaucratic institutions, like NRAs and Ministries.
- Regulation 2019/943, especially chapter IV and article 10, is a further step in this liberalisation process.

The importance of price signals

- Prices are key in markets:
  - They aggregate the distributed information on the state of the system
  - They signal to the (distributed) market actors what the state of the system is
  - All market actors can act on this price signal, changing the state of the system

➔ In liberalized markets, efficient price signals are essential for the good functioning of the market

ROLE OF PRICES

Removal of price caps and its impact on adequacy assessments

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No price cap

- Article 10 of Regulation 2019/943: “no maximum limit to the wholesale electricity price”
- There can be a **technical bidding limit**. Currently, this is 3000 €/MWh on day ahead
- <u>Bidding limit in EU increases by 1000 €/MWh every time the market price reaches at least 60% of the bidding limit</u>

⇒ When there is (near) scarcity, the bidding limit increases by 1000 €/MWh

⇒ As long as LoLE is not zero in a control zone in the EU, the bidding limit is expected to increase

ERAA / Reliability Standard

- ACER (+ NRAs) have approved the methodology to calculate the Reliability Standard
- **Reliability Standard** is a LoLE-target, with the social optimal:

$$LOLE_{\mathrm{RT}} = \frac{CONE_{fixed}}{VOLL_{RS} - CONE_{var}}$$

- LoLE_RT =Loss of Load Expectation of a reference technology (<u>expected</u> number of hours per year)
- CoNE_fixed = fixed Cost of New Entry (yearly annuity, €/MW)
- VoLL_rs = Value of Lost Load of consumers likely to be impacted by emergency load shedding
- (we will assume CoNE_var <<)

Reliability Standard and CoNE

- If the yearly expected revenue of a capacity is higher than its cost (CoNE), then the capacity will come to the market
- During LoLE-hours, when supply cannot meet demand, the market price needs to go to the bidding limit
  ➔ yearly expected revenue during scarcity = LoLE * biddingLimit * MW

- If biddingLimit > VoLL_rs, then yearly expected revenue during scarcity is higher than CoNE, because CoNE = LoLE * VoLL_rs
  ➔ revenue during scarcity hours is already sufficient for new capacity to come to the market
  ➔ <u>no adequacy concern if biddingLimit > VoLL_rs</u>

biddingLimit > VoLL_rs

- One could argue that a biddingLimit that is higher than VoLL_rs could be politically unstable
- However, this is not regulated by politicians, but by ACER (the European Agency and 27 NRAs), confirmed by the Regulation which was introduced by the Member States
- In addition, VoLL_rs does not need to be that high. It is the VoLL that reflects the willingness to pay to avoid a forced load shedding during an emergency plan. This emergency plan needs to be cost-efficient, according to European legislation => <u>VoLL_rs needs to be as low as possible</u>

[For Belgium, consumers in the emergency plan are mostly households in rural areas with an estimated VoLL of about 2000-5000 €/MWh, while the current price cap for real time prices in Belgium is already 13500 €/MWh]

Higher CoNE and reliability standard

- The automatic adjustment of the biddingLimit will make the limit as high as needed to ensure market entry (i.e. will eventually increase to cover the costs + risk premium)
- If the cost of new capacity (CoNE) would increase due to whatever reason (e.g. increased cost or price risk), this also relaxes the reliability standard through a higher LoLE-target, because LoLE = CoNE / VoLL

Conclusion

- With no price caps and LoLE-target = CoNE / VoLL, the conclusion should be that if prices can reach the biddingLimit, no adequacy problem can be assessed

→ Without adequacy problems, no capacity mechanism can be introduced (Regulation 2019/943)

→ Making price signals more efficient is not about solving adequacy issues (because this has already been solved) but about increasing the system efficiency, e.g. by lowering the risk premium

→ Lower risk premium will lead to lower CoNE

→ Lower CoNE will lower LoLE-target and thus lower LoLE which is beneficial to society

IMPROVEMENTS: MAKING PRICE SIGNALS MORE EFFICIENT

FORWARD MARKETS AND RISK AVERSION

What is risk aversion: the coin flip

- Simple experiment: you have the following choice
  - Receive 450€
  - Flip a coin => when it is head you win 1100€, when it is tails you lose 100€

  What do you choose?

- Most people would take the 450 euro, even though the <u>expected</u> profit of the coin flip is higher (500€). People feel uncomfortable with uncertainty, they prefer certainty.

➔ the amount you are willing to forgoe compared to the expected value is a measure for your risk aversion given the uncertainty

➔ If there would exist an option where you can earn the expected value (500) without running the risk of the coin flip, people would of course prefer that

The role of forward markets

- Forward markets provide just that: trading against the expected value
- In power markets, profits depend on unexpected events
- Assume a producer who has a CCGT. In the next quarter (2021 Q1) assume only two possible scenario's:
  - Scenario A: in 2021 Q1 there will occur a cold spell and low wind, with consequently very high prices and a high profit for the producer (spot price = 100, profit = 5M). This scenario has a probability of 50%.
  - Scenario B: 2021 Q1 will have normal temperature and a lot of wind, with consequently low prices and a small loss for the producer (spot price = 40, profit = -1M). This scenario has a probability of 50%.
- The expected spot price is 50%*100+50%*40 = 70. The expected profit is 50%*5M+50%*(-1M) = 2M

The role of forward markets

- The forward price is equal to the expected value of the spot price (+ a risk premium)

➔ The producer can sell electricity on the forward market against the expected spot price (70) and earn a certain profit (2M) instead of running the risk of the coin flip

➔ Forward markets take away the risk of uncertain events: <u>on forward markets you can trade against the **expected** value</u> without running the risk of the coin flip

2 types of variables / uncertainties

- Certain variables (temperature, wind, outages,…) are unknown when the investor takes an investment decision, and they stay unknown when the investor hedges the output on the forward market
  - Whether a cold spell will occur in 2030 is unknown now, but also unknown 1 year ahead

➔ These variables do not lead to increased price risk (class B)

- Other variables (fuel and CO2 prices) are unknown when the investor takes an investment decision, but become known when the investor hedges the output on the forward market
  - What the CO2 price will be in 2030 is unknown now, but will be known 1 year ahead (there will be a price on the forward market)

➔ These variables increase the price risk (class A)

2 types of variables / uncertainties

- The distinction between these two classes of variables is important when assessing the risk aversion of an investor
- Climate conditions (cold spells, wind output) and unexpected outages can have a dramatic impact on prices/profits but an investor can hedge them, so there is no (significant) increase of risk
- Fuel prices also have a (smaller) impact on prices, but an investor cannot hedge them (at least not over the total lifetime of the asset), so there is an increase of the risk

➔ forward markets can take out a large part of the risk (but not all)

Forward markets decrease risk

- Depending on different outcomes for the different variables we can have the following outcome for a CCGT in 2030
- An investor knows she will always be able to trade against the expected value of the class B variables (last column), but not against the expected value of the class A variables (last row: not available (NA))

		Class B variables							
	profit of CCGT according to scenario in real time	**Low T, low wind, many outages**	**Low T, low wind**	**low T**	**high T**	**high T, high wind**	**high T, high wind, no outages**		***expected profit***
Class A variables	**low gas price, low CO2, high coal price**	100	80	60	40	20	0		***50***
	low gas price, low CO2	90	70	50	30	10	-10		***40***
	low gas price	80	60	40	20	0	-20		***30***
	high gas price	70	50	30	10	-10	-30		***20***
	high gas price, high CO2	60	40	20	0	-20	-40		***10***
	high gas price, high CO2, low coal price	50	30	10	-10	-30	-50		***0***
	expected profit	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**		**NA**

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Forward markets decrease CoNE

- The expected profit with and without forward markets is the same (25), but the risk profile is quite different
- When ignoring forward markets, the example shows 36 possible profits ranging from -50 to +100, with 9 negative profits (9 out of 36 = 25%)
- With forward markets, the example shows 6 possible profits, ranging from 0 to 50 (so no negative profits)
- It is important to know that EntsoE has (until now) only simulated prices without taking into account forward markets. The resulting profits would imply higher risk than in reality
- Without taking forward markets into account, one would incorrectly conclude a higher risk compensation is needed, resulting in a higher (equivalent) WACC and thus incorrectly would lead to a higher CoNE than in reality

Proposal

- A good estimation of risk compensation should be based on the true distribution of revenues for a certain asset

  ➔ forward markets need to be taken into account

- The CREG proposes the following:
  - Take 15 (or more) different realistic combinations of CO2 and fuel prices (class A variables)
  - Take 20 historical climate years and outage patterns (class B variables).
  - Simulate the resulting 300 (or more) market revenues, which are averaged into 15 (or more) market revenues (an average over the class B variables per combination of class A variables)
  - Take random draws from these 15 (or more) market revenues to get a distribution of market revenues for a given asset
  - Based on this distribution of market revenues, calculate a hurdle rate (or other measure for risk aversion) for a given asset

Market completeness

- Need for more forward products that can be easily traded
- Baseload and peakload forward markets exist
- Forward markets for “super-peak” capacity (like demand response and emergency generators) are underdeveloped

  => if we could develop these markets, this will decrease risk regarding investments in super-peak capacities

[side remark: liquid super-peak forward markets are (much) less important than for e.g. CCGTs because super-peak capacities often have (much) lower lead times and (much) lower capex => see e.g. the adequacy crisis in Belgium at the end of 2018]

IMPROVEMENTS: MAKING PRICE SIGNALS MORE EFFICIENT

Scarcity pricing

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Scarcity pricing

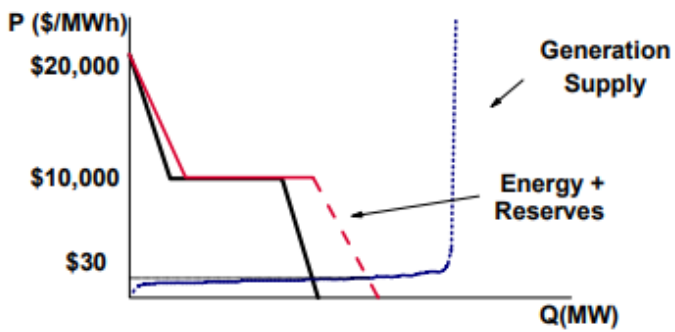
- A power system needs energy and reserves
- Reserves are needed to ensure the reliability of the system
- Now reserves are procured by the TSO in a separated market, paying a capacity fee for standing by
- If you want prices to efficiently reflect the true system need for capacity (and the risk of curtailment), the price needs to adequately reflect the need for energy and reserves
- Scarcity pricing provides this price signal

Principle of the mechanism: augment the demand curve by reserves requirements

ELECTRICITY MARKET **Connecting Reliability and Market Design**

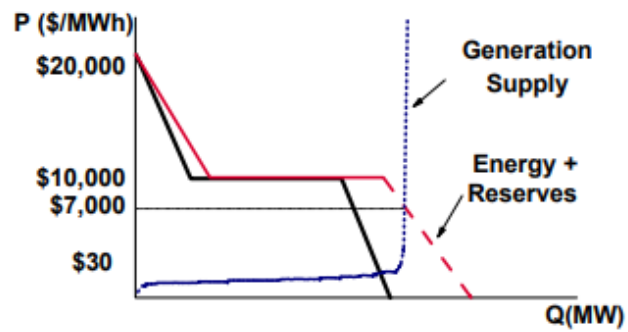
Simultaneous market clearing provides incentives to provide both energy and operating reserves. Prices for reserves and energy that reflected real scarcity conditions would provide stronger incentives to support both reliable operations and adequate investment.

Normal "Energy Only" Market Clearing



When demand is low and capacity available, reserves hit nominal targets at a low price.

Scarcity "Energy Only" Market Clearing



When demand is high and reserve reductions apply, there is a high price.

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Reference: William Hogan, March 2006, RELIABILITY AND SCARCITY PRICING: OPERATING RESERVE DEMAND CURVES

ORDC mechanism

BASED ON THE COMPUTATION OF A PRICE ADDER TO THE BALANCING PRICE REFLECTING SCARCITY

PRINCIPLE

1. If the volume of fast reserves is equal to a minimum level and that any (real-time) load increase leads to curtailment,
2. Then the value of reserves is equal to the VoLL
3. For any amount of reserves above that minimum level, the value of reserves is equal to the probability of curtailment (the Loss of Load Probability - LOLP) multiplied by the VOLL

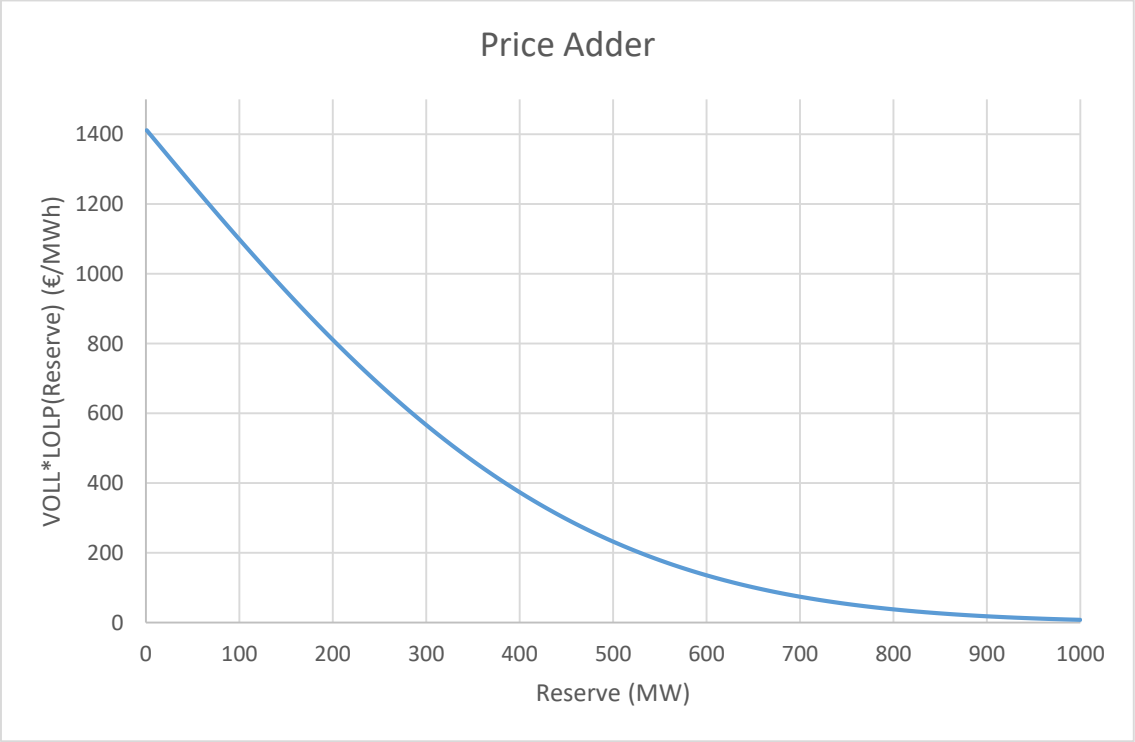
REQUIREMENTS

1. Mainly an estimation of the VOLL, and the determination of the LOLP in function of the expected volume of reserves that can be activated in a given time period

ORDC: Probabilistic approach

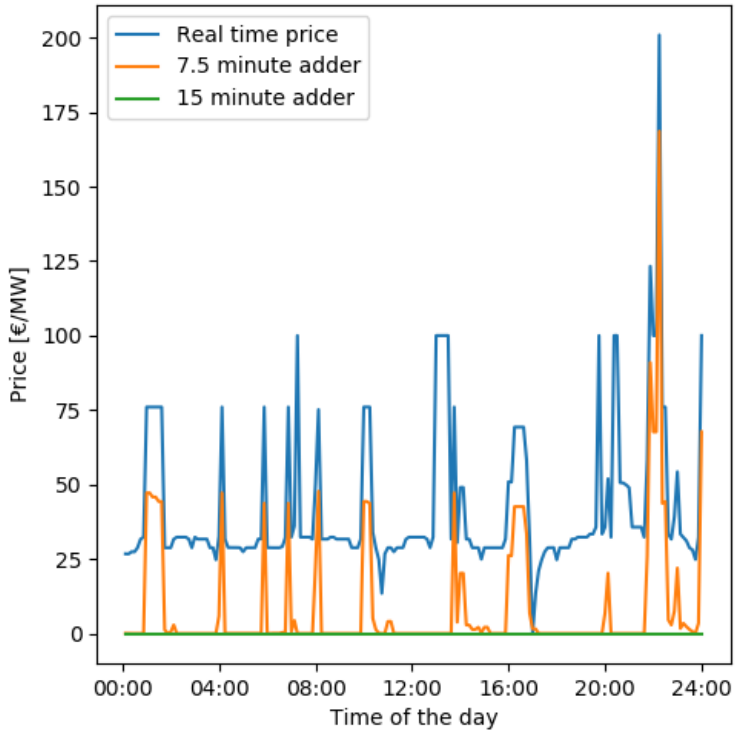
1. Price adder (to the ~= VOLL x LOLP(r) where r is the volume of available fast reacting reserves

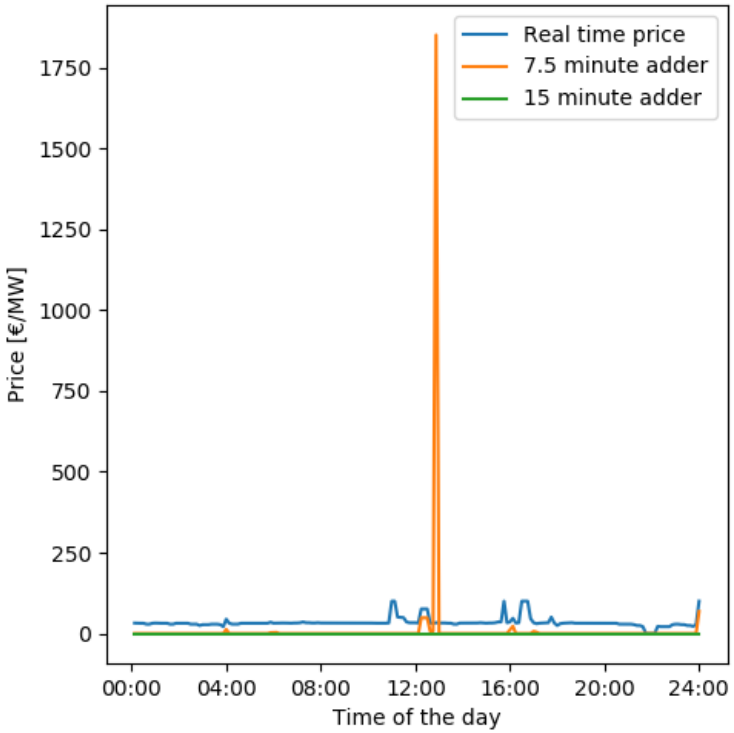
- Replace a few very high prices spikes by more frequent spikes of lower magnitude through an adder to the electricity price that reflects scarcity



Scarcity pricing

- With the price adder, the price level will increase if there is (near) scarcity
- With scarcity pricing, the distribution of the price can change (figures from UCL) decreasing the risk for an investor





Scarcity mechanism (ORDC) properties

1. Provides an **“all inclusive” remuneration** through an improved electricity price
2. With a focus on the valuation made by consumers for electricity or for not being curtailed (i.e. the preference of consumers for reliability), avoiding to pay too much for a specific technology – **technology neutral**
3. Facilitates the **energy transition** towards more renewable integration
4. **Remunerates flexibility**, or units present in the market with reserves able to react very quickly
5. With the price adder, it solves (at least a part) of the missing money problem
6. Depending on the design, ORDC makes investing in peak capacity **less risky**

➔ **Final studies for CREG by UCL on this topic**

IMPROVEMENTS: MAKING PRICE SIGNALS MORE EFFICIENT

Best forecast of re-dispatching

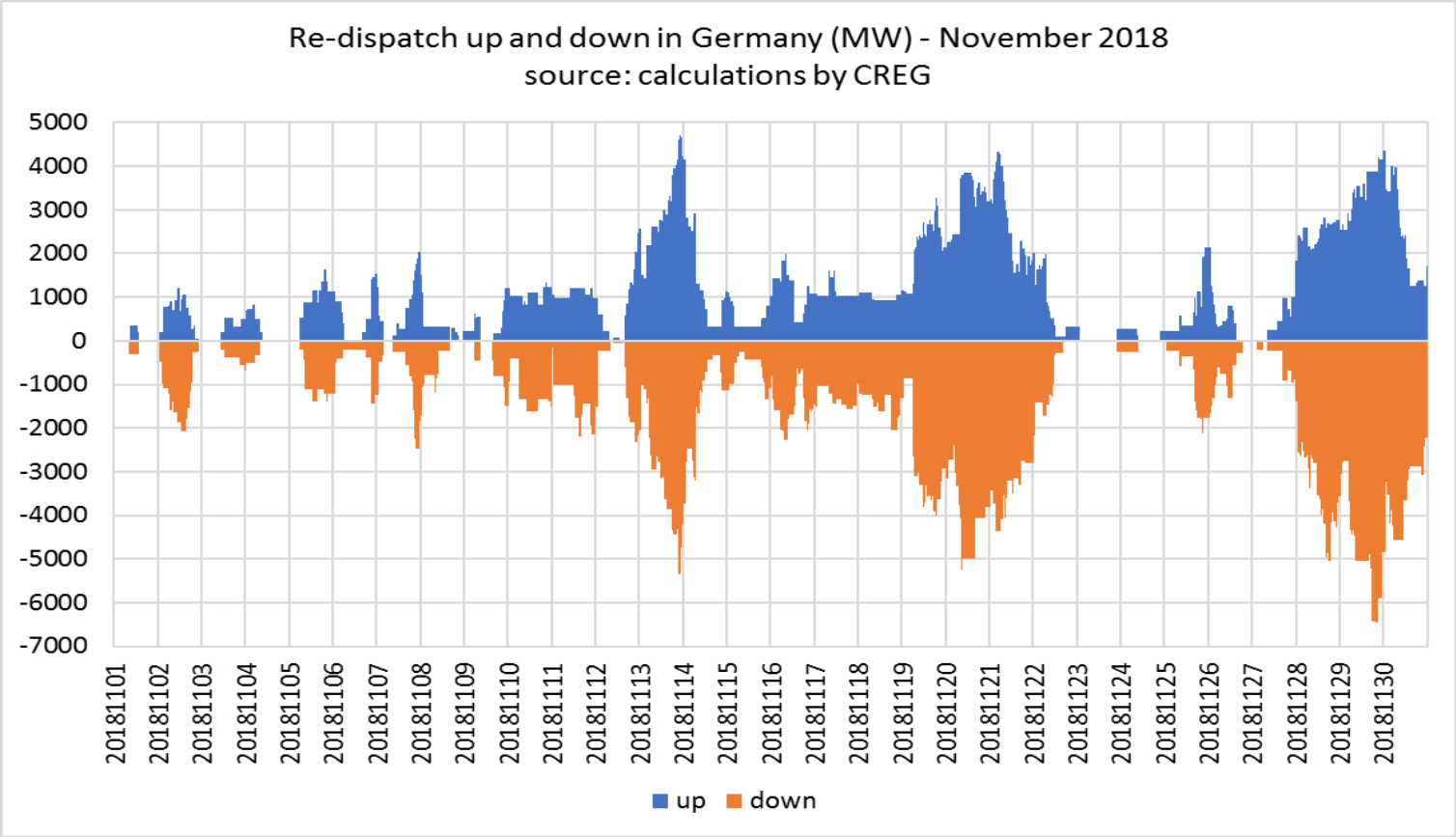
Re-dispatching distorts price signal

- In a power system you need generation and transmission capacity
- Prices should reflect the actual available generation and transmission capacity
- When congestion occurs, re-dispatching generation is necessary to maintain the system
- Re-dispatching always distorts the price signal
- When congestion and re-dispatching occur frequently, this can be predicted pretty accurately ("best forecast")

  ➔ preventive re-dispatch becomes possible: units to be re-dispatched down cannot bid in the day ahead or intraday market (but still may receive compensation)

- [A first best solution is to have adequate locational price signals: smaller zones or nodal pricing]

Volume of Re-dispatching in Germany



These data have been used to calculate the impact of re-dispatching on the zonal price

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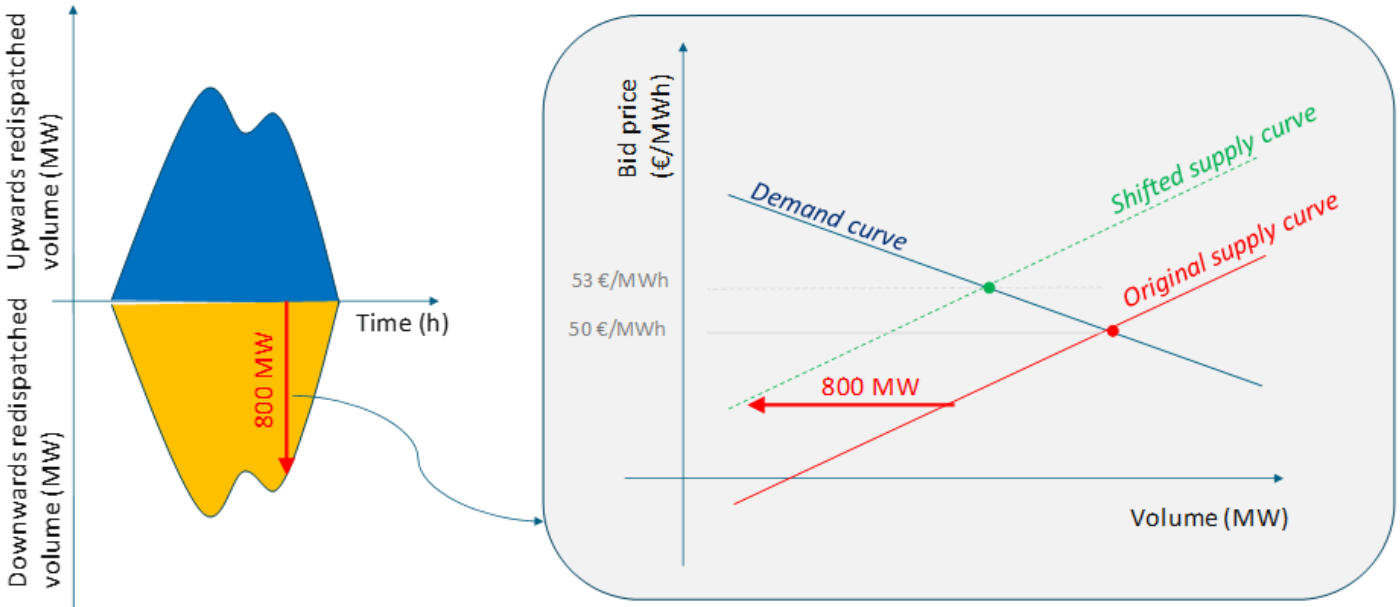
Estimation of the impact on the price signal



Calculate the new market clearing price for this hour by removing the hourly downwards redispatched volume from the original supply curve.

1. By removing the units re-dispatch down, we shift the German supply curve to the left and increase the zonal clearing price
2. Applied to the months of October 2018 till end February 2019, this gives an average of 6,2 €/MWh, and 7,8 €/MWh only for the hours with re-dispatching

CONCLUSION

Conclusion

- Adequacy:
  - Removal of price caps
  - Definition of reliability standard as LoLE = CoNE / VoLL

  ➔problem of adequacy should be considered as solved
- Focus on efficiency => better price signal:
  - More forward products and more efficient forward markets will decrease the risk premium (and CoNE) and thus lower curtailment
  - Risk aversion should be simulated correctly, with a distinction between uncertainties (“hedgeable” or not)
  - Scarcity pricing efficiently reflects the true system need for capacity
  - Transmission capacity is essential in power markets: if best forecast is no transmission capacity => no supply possible => no part in price formation

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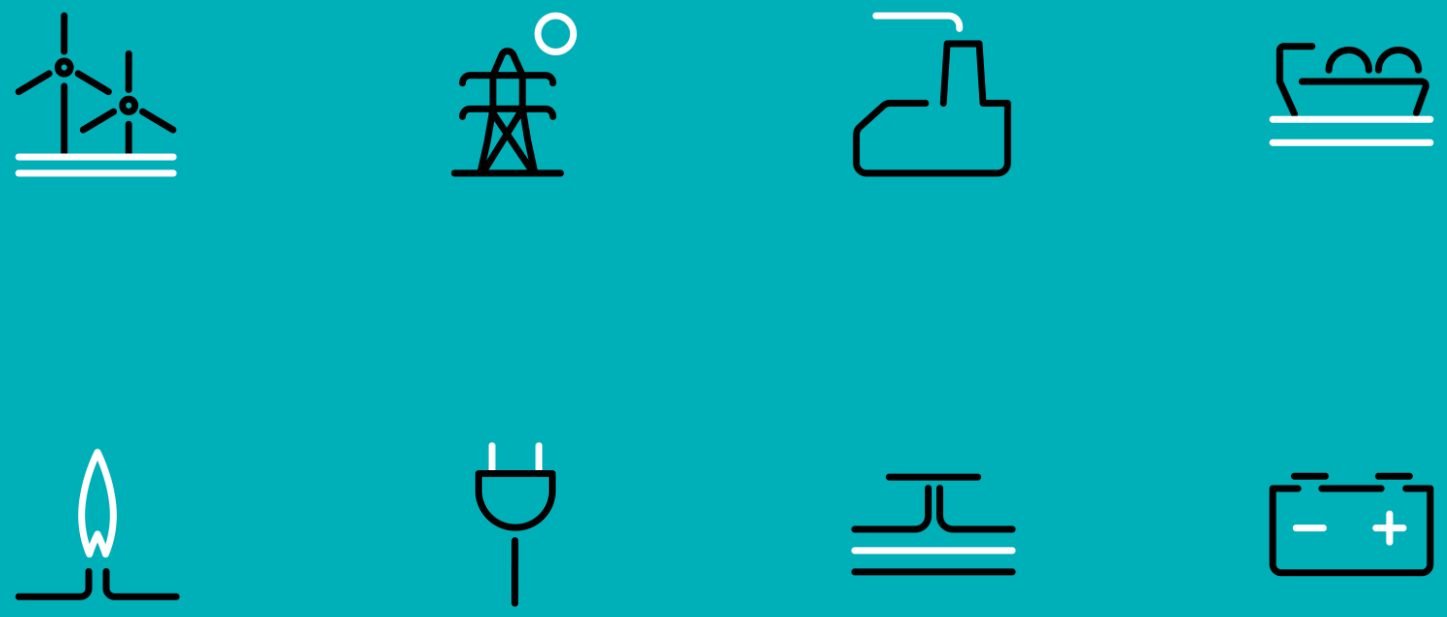

Commission for Electricity and Gas Regulation

ADDITIONAL SLIDES

LoLE > 0

- LoLE-target = CoNE / VoLL => non-zero target
- As long as there are LoLE hours, the price cap will continue to increase (see Acer decision)
- This will attract new capacity, since revenue during LoLE will increase
- This will only stop when there is sufficient capacity to have no LoLE hours
- This implies an overinvestment, because real LoLE < LoLE-target = CoNE/VoLL (which is considered as the social optimal LoLE)

Following this reasoning, one should conclude that avoiding overinvestment in the EOM while meeting the adequacy standard comes down to setting an appropriate level of the market price cap

➔ solving the adequacy concern in the EOM translates in setting an optimal market price cap