European Markets 101 and Comparison with US Market Structure

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EPRI ISO/RTO Market Design Tech Webcast Series

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Outline

- The Big Picture
  - Separation of power exchanges and system operators
  - EU timeline
- Balancing
  - EU reserve products
  - Scarcity pricing based on operating reserve demand curves
- Congestion management
  - Zonal versus nodal models
  - ATC-based and flow-based market coupling
  - Interaction of zonal pricing with day-ahead unit commitment
  - DEC game
- Day-ahead market clearing
  - Bidding format in EU day-ahead markets
  - Pricing non-convex bids
  - Future challenges for EUPHEMIA

The Big Picture

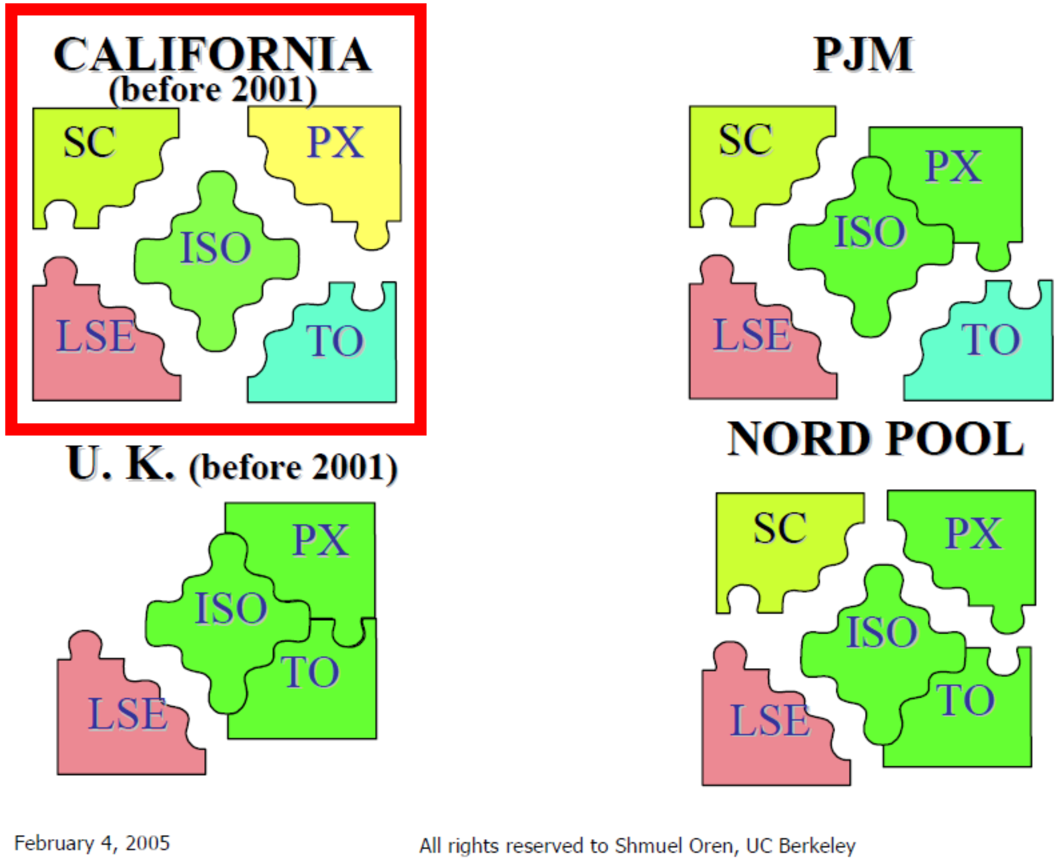
Separation of power exchanges and system operators

Comparison of US and EU DA and RT market timelines

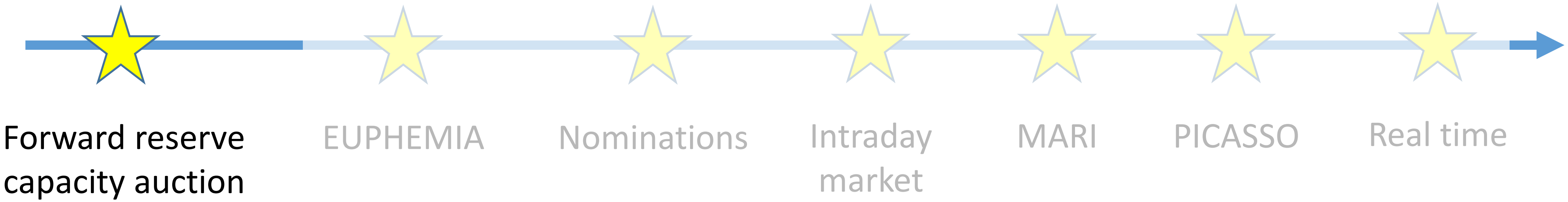
European reserve products

Major Differences Between US and Europe

- European market design resembles, most closely, the pre-2001 California design
- Separation of *power exchange* (PX) and *transmission system operator* (TSO)
- Simplified representation of transmission network via *zonal pricing*
- Diminished role of real-time market:
    - *Balancing responsible parties* (BRPs) encouraged to maintain balance in real time
    - *Balancing service providers* (BSPs) balance the system by activating reserve
- No real-time market for reserve capacity

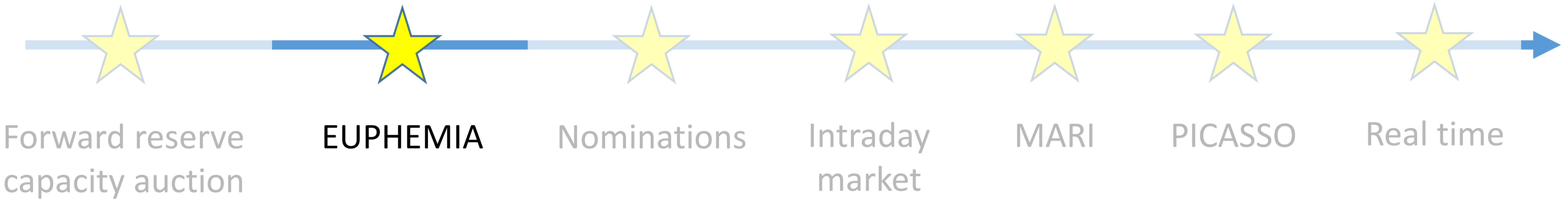


EU Timeline: Forward Reserve Capacity Market



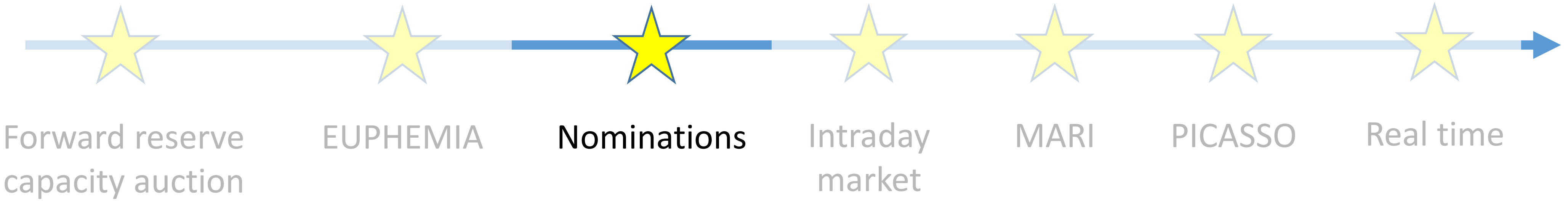
- US analogue: ISP
- Month/week/day-ahead reserve capacity auction
- Typically **not** co-optimized with energy
  - Some markets (e.g. Belgium, Germany): before day-ahead market clearing
  - Other markets (e.g. Italy, Spain): after day-ahead market clearing
  - Yet other markets (e.g. Greece, Cyprus) have ISP
- Individual generators bid in
- Capacity payment due from system operator to generators
- Separated auctioning of different reserve products

EU Timeline: Day-Ahead Energy Market



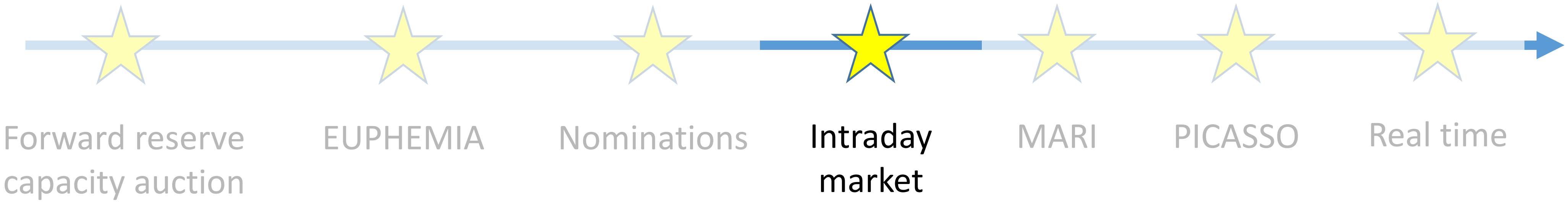
- US analogue: day-ahead energy market
- Gates close @ 12 noon (CET) D-1
- Results published as soon as possible from 12:50pm (CET) D-1
- Single auction for most of Europe
- Portfolio bids
- Zonal network model
- Reserve is **not** auctioned / priced by EUPHEMIA
- Payments for day-ahead energy due from power exchange to suppliers, and from consumers to power exchange

EU Timeline: Nominations



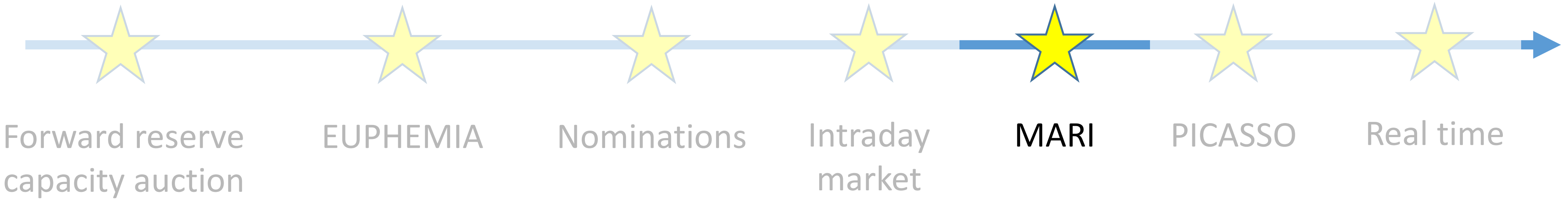
- No US analogue
- *Nominations*: day-ahead production schedules submitted by utilities to TSOs for individual generators, according to
  - day-ahead cleared trades
  - reserve commitments
- Nominations (in Belgium, at least) submitted by 2pm (CET) D-1
- Nominations (in Belgium, at least) may be rejected by TSO if expected to violate transmission constraints, notification is sent by 6pm (CET) D-1

EU Timeline: Intraday Market



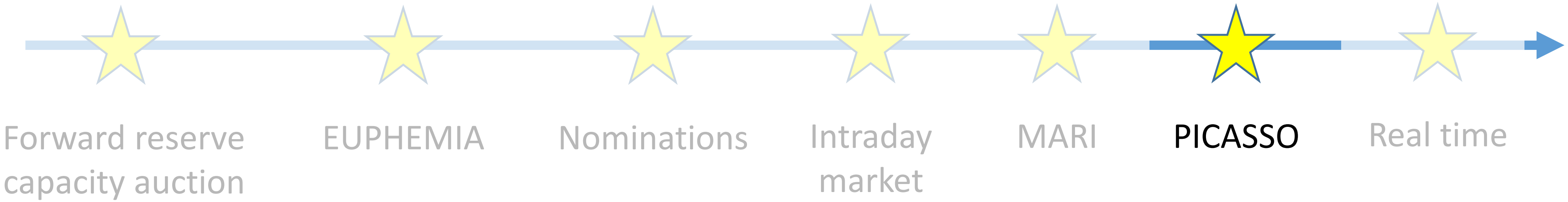
- No exact US analogue
- Intraday auction at 3pm D-1
  - Payments due from ID exchange to suppliers, and from consumers to ID exchange
- Continuous intraday market opening at 4pm D-1 and running until 30 minutes before delivery time
  - Bilateral trades
- Zonal model

EU Timeline: MARI



- US analogue: security-constrained economic dispatch
- What is traded is **tertiary** balancing energy
  - Demand for balancing energy: transmission system operators
  - Supply for balancing energy: balancing service providers
- Zonal model
- Reserve capacity is **not** part of this platform
- Integrated platform for big part of Europe
- Resources that have been in forward tertiary reserve markets are **obliged** to bid **at least** their forward capacity to MARI
- Run 10 minutes before real time, run every 15 minutes
- Target go-live: December 2021

EU Timeline: PICASSO



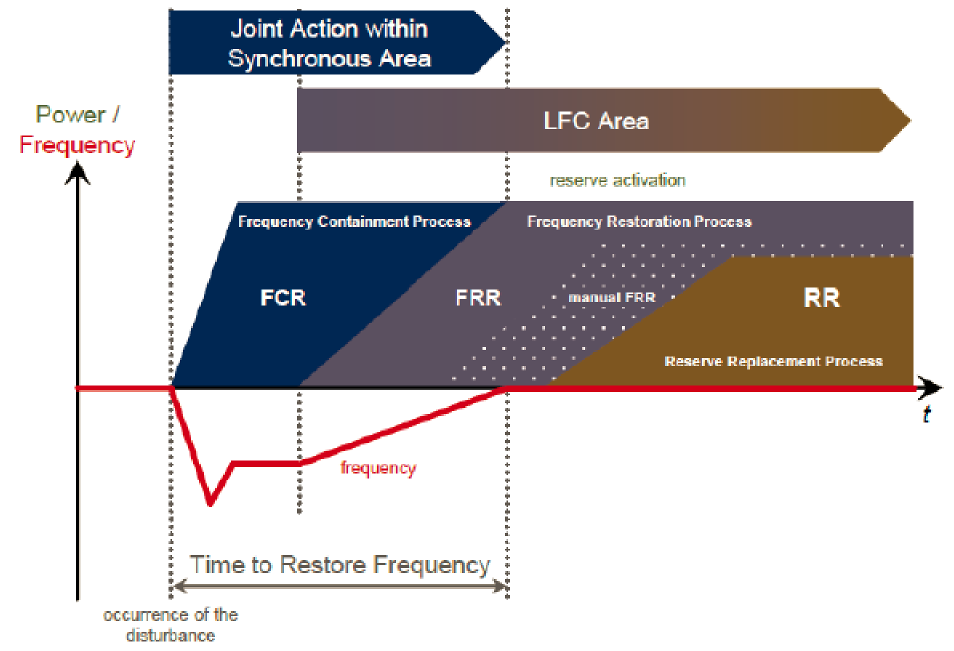
- US analogue: automatic generation control
- What is traded is **secondary** balancing energy
- Zonal model
- Reserve capacity is **not** part of this platform
- Integrated platform for big part of Europe
- Resources that have been in forward secondary reserve markets are **obliged** to bid **at least** their forward capacity to PICASSO
- Run every 4 seconds
- Target go-live: December 2021

Balancing

EU reserve products

Scarcity pricing using operating reserve demand curves

Frequency Control and Restoration



Primary Reserve

Primary reserve (a.k.a. primary control, frequency containment reserve) is the first line of defense

1. Change of inertia in generator rotors: immediate
2. Frequency-responsive governors (automatic controllers): reaction is immediate, may take a few seconds reach target

Secondary Reserve

Secondary reserve (a.k.a. automatic frequency restoration reserve, secondary control, automatic generation control): second line of defense

- Reaction in a few seconds, full activation time (PICASSO): 7.5 minutes
- Setpoint updated every four seconds
- Requirements dictated by reliability targets of system operator
- AGC signal translates to TSO demand in PICASSO platform

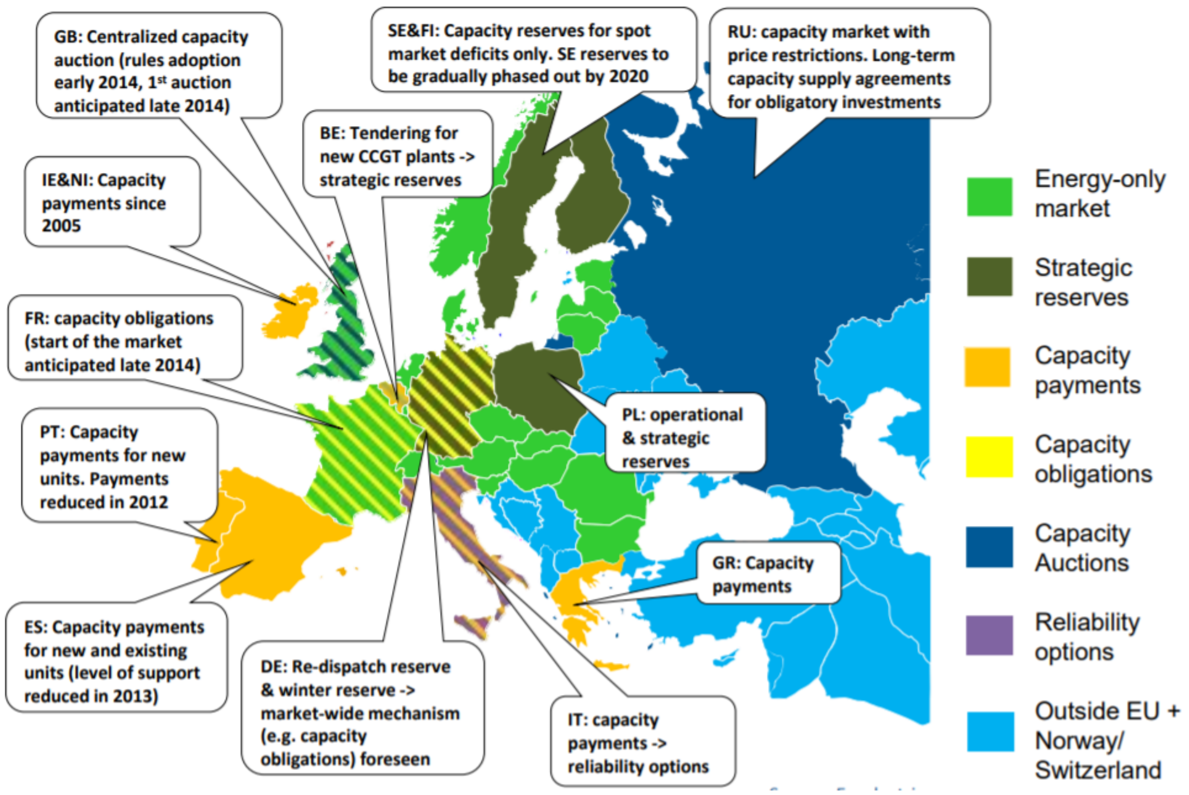
Tertiary Reserve

Tertiary reserve (a.k.a. manual frequency restoration services, tertiary control, tertiary reserve, replacement reserve): third line of defense

- Full activation time (MARI): 15 minutes
- Requirements dictated by reliability targets of system operator

Balkanization of European Electricity Market

- Diverse approaches towards remuneration of (flexible) capacity in Europe
- Some of these measures draw scrutiny as possibly constituting anti-competitive *state aid*
- European Commission not in favor of balkanization of member-state market rules
- Two *legal documents* of the European Commission indicate favorable view towards ORDC:
  - Electricity balancing guideline
  - Clean energy package



Source: Eurelectric

European Commission Electricity Balancing Guideline, Article 44(3)

Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity pursuant to Chapter 5 of this Title, administrative costs and other costs related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a **shortage pricing function**. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority.

Official Journal of the European Union

COMMISSION REGULATION (EU) 2017/2195

of 23 November 2017

establishing a guideline on electricity balancing

Clean Energy Package, Article 20(3)

Member States *with identified resource adequacy concerns* shall develop and publish *an implementation plan with* a timeline for adopting measures to eliminate any identified regulatory distortions *or market failures as a part of the State aid process*. When addressing resource adequacy concerns*, the* Member States shall in particular *take into account the principles set out in Article 3 and shall consider:*

...

*(c) introducing a **shortage** **pricing** **function** for balancing energy as referred to in Article 44(3) of Regulation 2017/2195;*

...

European Parliament
2014-2019

TEXTS ADOPTED
Provisional edition

P8_TA-PROV(2019)0227

Internal market for electricity ***I

European Parliament legislative resolution of 26 March 2019 on the proposal for a regulation of the European Parliament and of the Council on the internal market for electricity (recast) (COM(2016)0861 – C8-0492/2016 – 2016/0379(COD))

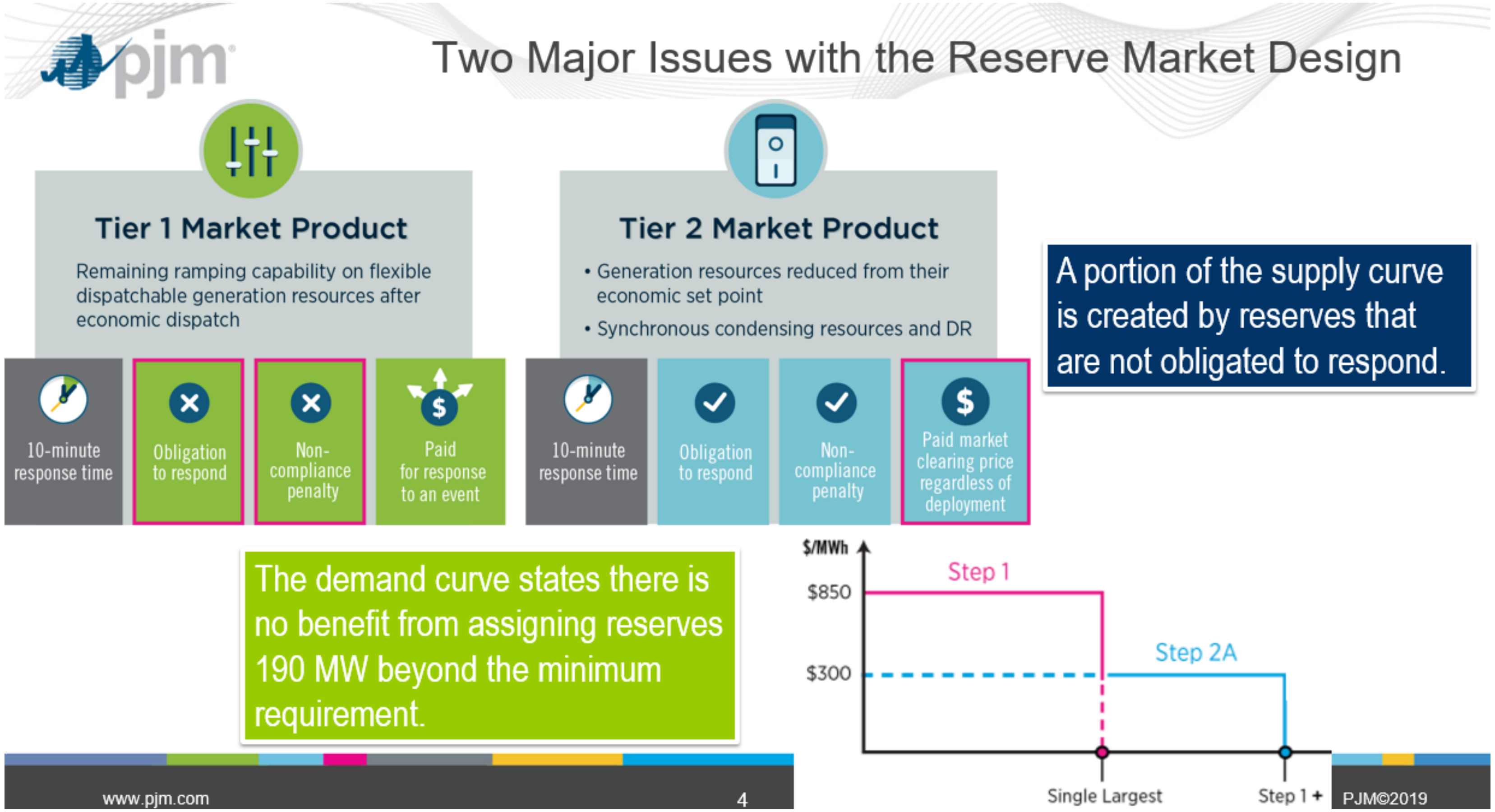
(Ordinary legislative procedure – recast)

Scarcity Pricing Developments in PJM

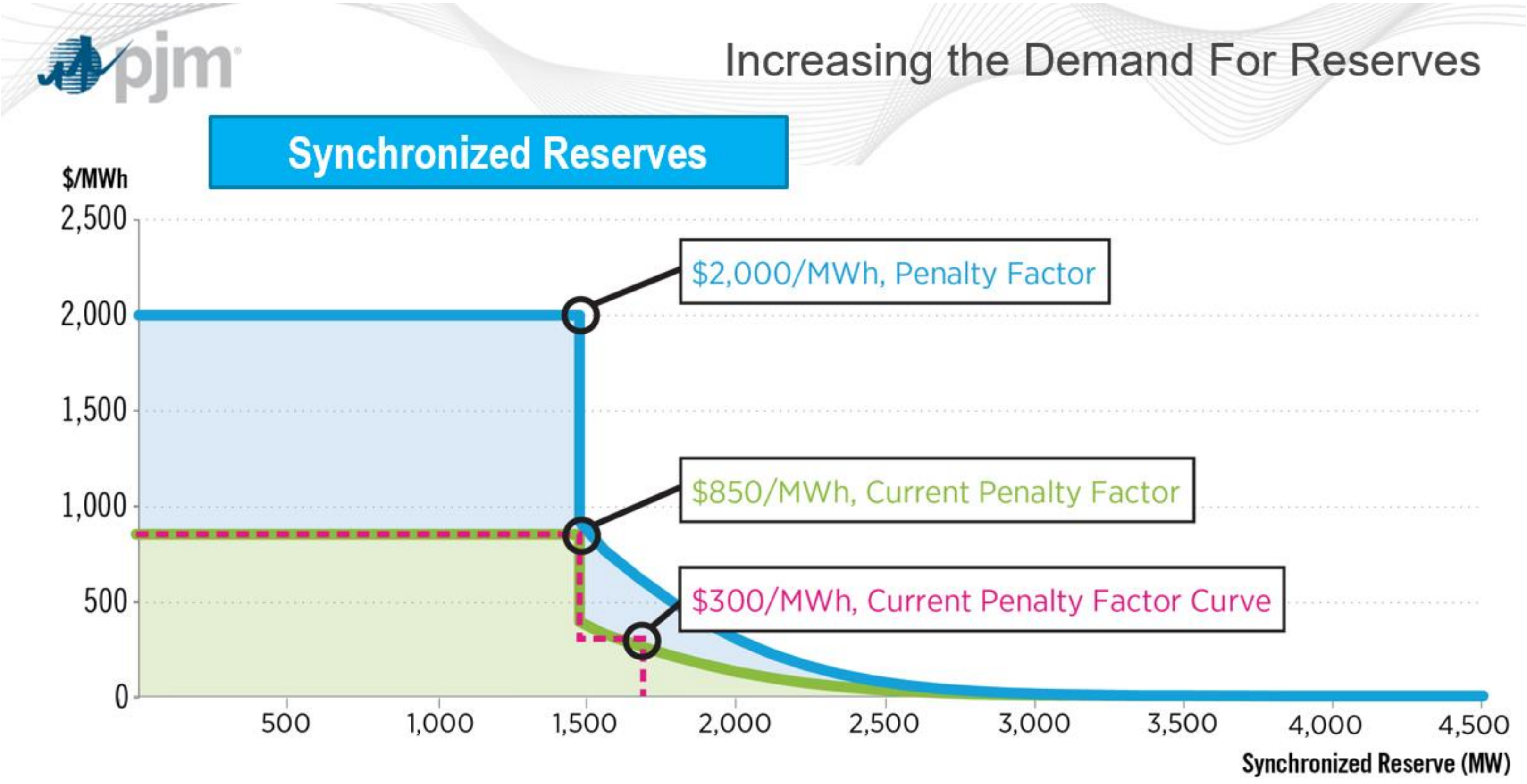
- Synchronized Reserves are a 10-minute, online, reserve product
- Average requirement is about 1640 MW
- 2018 Market Revenues 44 million

- Price performance is poor
  - $24 million settled through clearing price
  - $20 million settled through uplift payments
- Revenues paid through the market clearing price only cover about 78% of the total cost to procure reserves

Scarcity Pricing Developments in PJM



Scarcity Pricing Developments in PJM

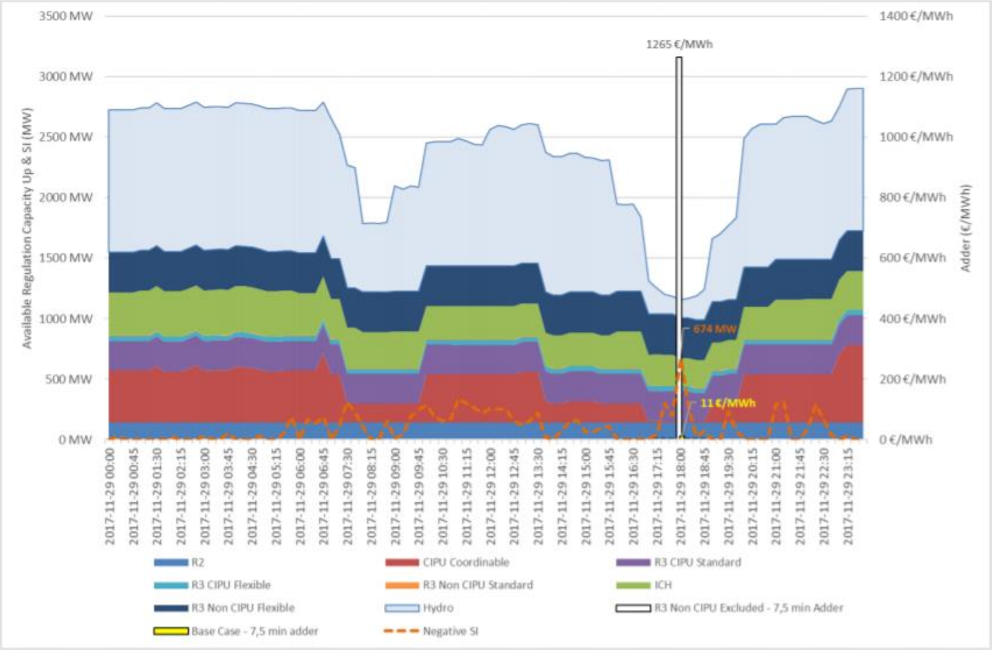


The Belgian ORDC Studies

- **First study (2015)** [1]: How would electricity prices change if we introduce ORDC in the Belgian market?
  - **Finding**: it could enable the majority of combined cycle gas turbines, which are currently operating at a loss, to *recover their investment costs*
- **Second study (2016)** [2]: How does scarcity pricing depend on
  - strategic reserve
  - value of lost load
  - restoration of nuclear capacity
  - day-ahead (instead of month-ahead) clearing of reserves
- **Third study (2017)** [3]: can we take a US-inspired design and plug it into the existing European market?
  - **Finding**: the energy adder in itself will not suffice, the first step is to put in place a *real-time market for reserve capacity*

ELIA Ex-Post Simulation of Scarcity Prices

- **ELIA ex-post simulation (2018)** [4]: ELIA (Belgian TSO) releases report on the simulation of scarcity prices in the Belgian market for 2017
  - **Finding**: comfortable year, infrequent occurrence of adders



ORDC adder on November 29, 2017
Source: ELIA [4]

Publication of Scarcity Prices by ELIA

- **ELIA D+1 publication of adders (2019)**: Effective October 2019, ELIA is publishing adders in D+1

D+1 publication of the different scarcity price-adders

The scarcity price-adders shown here are calculated according to the model conceptualized in the CREG/UCL study (cf. chapter 7. Implementation) that - under specific assumptions - assesses the risk of scarcity and assigns a value to these moments that is linked to the loss of load probability and the value of lost load. The relevant concepts from the CREG/UCL study linked to this publication are described below. How such scarcity price-adders might link further to the prevailing market design and remuneration flows goes beyond this price-adder publication and is reflected upon in other parts of the CREG/UCL study.

Which scarcity price-adders are shown? (cf. section 7.1 The Three Adders in CREG/UCL study)

How are the scarcity price-adders calculated? (cf. section 7.3 Constructing the Price Adders in CREG/UCL study)

21/10/2019

Quarter	Adder 7.5 min. (€/MWh)	Adder 15 min. (€/MWh)	Adder Energy (€/MWh)
00:00 > 00:15	0,00	0,00	0,00
00:15 > 00:30	0,00	0,00	0,00
00:30 > 00:45	0,00	0,00	0,00
00:45 > 01:00	0,00	0,00	0,00
01:00 > 01:15	0,00	0,00	0,00
01:15 > 01:30	0,00	0,00	0,00
01:30 > 01:45	0,00	0,00	0,00
01:45 > 02:00	0,00	0,00	0,00

Source: ELIA https://www.elia.be/en/electricity-marketand-system/adequacy/scarcity-pricing-simulation

Example: Settlement without Adder

Settlement type	Formula	Price [€/MWh]	Quantity [MW]	Cash flow [€/h]
Day-ahead energy	$\lambda PF_t \cdot pF_{gt}$	λPF_t =20 €/MWh	pF_{gt} = 0 MW	0
Day-ahead reserve	$\tilde{\lambda} RF_t \cdot rF_{gt}$	rF_{gt} = 65 MW	rF_{gt} = 25 MW	1,625
Real-time energy	$\lambda PRT_t \cdot (pRT_{gt} - pF_{gt})$	λPRT_t = 300.0 €/MWh	$pRT_{gt} - pF_{gt}$ = 125 MW	37,500
Total				39,125

Example: Settlement with Adder

Settlement type	Formula	Price [€/MWh]	Quantity [MW]	Cash flow [€/h]
Day-ahead energy	$\lambda PF_t \cdot pF_{gt}$	λPF_t =20 €/MWh	pF_{gt} = 0 MW	0
Day-ahead reserve	$\tilde{\lambda} RF_t \cdot rF_{gt}$	rF_{gt} = 65 MW	rF_{gt} = 25 MW	1,625
Real-time energy	$\lambda PRT_t \cdot (pRT_{gt} - pF_{gt})$	λPRT_t = 1,529.2 €/MWh	$pRT_{gt} - pF_{gt}$ = 125 MW	191,150
Real-time reserve	$\tilde{\lambda} RRT_t \cdot (rRT_{gt} - rF_{gt})$	$\tilde{\lambda} RRT_t$ = 1,229.2 €/MWh	$rRT_{gt} - rF_{gt}$ = -25 MW	-30,730
Total				162,045

Congestion Management

Zonal versus nodal models

ATC-based and flow-based market coupling

Interaction of zonal pricing with day-ahead unit commitment

DEC game

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Zonal Electricity Markets in Europe

- European electricity market organized as a zonal market, EC 714/2009
- Two types of export/import limits:
  - Limits on the bilateral exchange between neighboring zones, Available-Transfer-Capacity Market Coupling (**ATCMC**)
  - Limits on the net position configuration of zones, Flow-Based Market Coupling (**FBMC**)
- Both methodologies should be N-1 robust (*critical branches / critical outages*), Amprion (2017)
- FBMC used to clear day-ahead electricity market at the Central Western European system since May 2015
- Other markets might implement FBMC in the near future (e.g. Nord Pool, Energinet (2017))

Available Transfer Capacity Model

Available transfer capacity market coupling

- Transportation model
- Basic decision variables: zone-to-zone power transfers
- Discretionary parameters decided by TSOs: zone-to-zone capacities

Flow-based market coupling

- More general than transportation model, less general than nodal model
- Basic decision variables: zonal net injections
- Discretionary parameters decided by TSOs:
  - Zone-to-zone capacities
  - Generation shift keys

Motivation for Flow-Based Market Coupling

- Preferred methodology for electricity market operations of the EC, EU 2015/1222: "*... a method that takes into account that electricity can **flow via different paths** and optimizes the available capacity in **highly interdependent grids** ...* "
- Increases in day-ahead market welfare of 95M €/year with respect to ATCMC, Amprion (2013)
- Congestion management and balancing costs not included in studies; they amounted to 945M€ in 2015, ENTSO-E (2015)

Flow-Based Domain

- Select a base case (net positions, flows on branches)
- Compute zone-to-line Power Transfer Distribution Factors
- Zone-to-line PTDFs are used to define a flow-based domain, which is the set of “acceptable” **zonal** net injection
- $\mathcal{P}$ should include all feasible cross-border trades, EC 714/2009, Annex I, Art. 1.1
- $\mathcal{P}$ should not include configurations that can harm security, EC 714/2009, Annex I, Art. 1.7

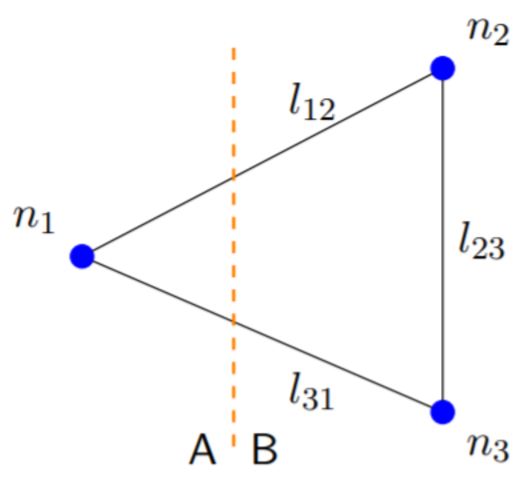
ATC model of a Three-Node Network

Physics:

$$r_1 + r_2 + r_3 = 0$$
$$-100 \leq r_1 \leq 100$$
$$-100 \leq r_2 \leq 100$$
$$-100 \leq r_3 \leq -50$$
$$-25 \leq f_{12} = 1/3\, r_1 - 1/3\, r_2 \leq 25$$

Zonal net positions:

$$p_A = r_1$$
$$p_B = r_2 + r_3$$



$$G = \{1, 2, 3\}$$
$$Q_1 = 200,\ Q_2 = 200,\ Q_3 = 50$$
$$N = \{n_1, n_2, n_3\}$$
$$L = \{l_{12}, l_{23}, l_{31}\},\ F_{12} = 25$$

100MW demand per node

ATC model uses zone-to-zone transfers as decision variables

$$e = p_A$$
$$ATC^- \leq e \leq ATC^+$$

But deciding on ATC capacities is complicated, non-transparent, contentious

Too large ATCs => infeasible dispatch

Too small ATCs => economic inefficiency

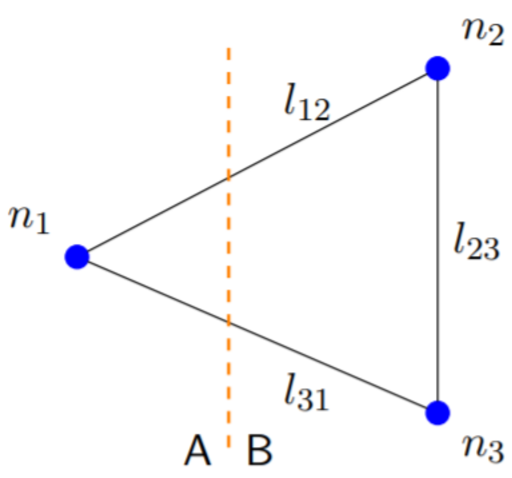
FBMC model of a Three-Node Network

Physics:

$$r_1 + r_2 + r_3 = 0$$
$$-100 \leq r_1 \leq 100$$
$$-100 \leq r_2 \leq 100$$
$$-100 \leq r_3 \leq -50$$
$$-25 \leq f_{12} = 1/3\, r_1 - 1/3\, r_2 \leq 25$$

Zonal net positions:

$$\begin{aligned} p_A &= r_1 \\ p_B &= r_2 + r_3 \end{aligned}$$



$$G = \{1, 2, 3\}$$
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$$L = \{l_{12}, l_{23}, l_{31}\},\ F_{12} = 25$$

100MW demand per node

FBMC defines linear inequalities for every critical network element

But how much does injection in each zone affect flow on critical network element?

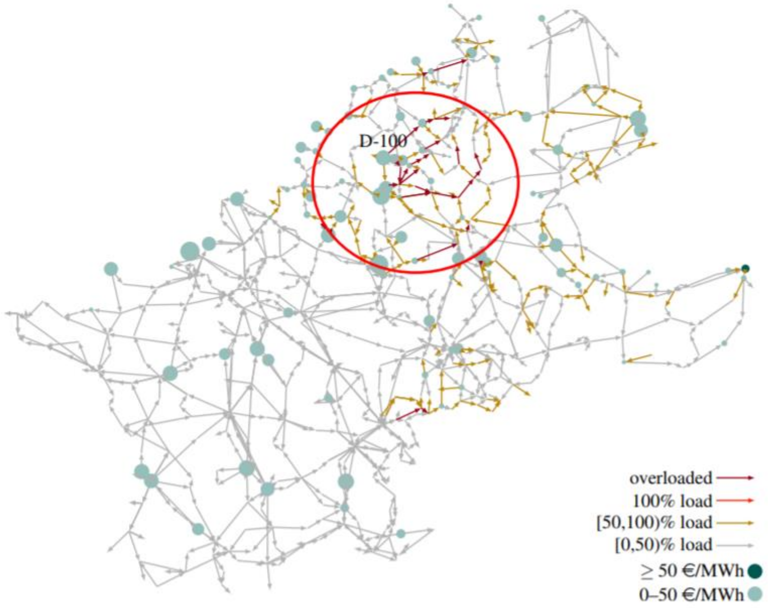
$$GSK_{A,A-B} \cdot p_A + GSK_{B,A-B} \cdot p_B \leq T_{A-B}$$

How much should the capacity of the link from zone A to zone B be?

Correct Pricing *Matters*

- Zonal models can result in **infeasible** power flows (e.g. starting up cheap coal)
- Power flows can be made feasible in real time, but it is costly, e.g.
  - reduce production of coal
  - start up combined cycle gas turbines

=> **operating costs that could be avoided**



Source: [Aravena, 2017]

Estimate of Day-Ahead Inefficiencies in Central Western Europe

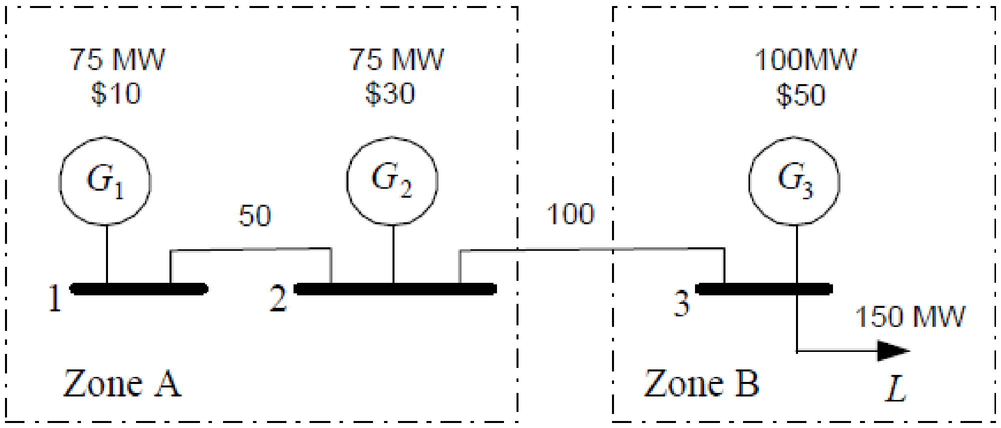
Policy	Day ahead (M€/year)	Real time (M€/year)	Total (M€/year)	Efficiency losses
Nodal	11,248	534	11,818	-
Flow-based zonal	10,458	1,963	12,420	**602 M€/year**
ATC-based zonal	10,470	1,949	12,419	**601 M€/year**

Source: [Aravena, 2019]

Conclusions:

- *Day-ahead* generator on/off decisions have significant *real-time* economic implications
  - Transition to FBMC not necessarily resulting in increasing operational efficiency

A Dec-Game Example (Alaywan, 2004)



- Day-ahead zonal auction
  - G1: 75 MW, G2: 75 MW
  - Intra-zonal congestion on line 1-2
  - Inter-zonal congestion on line 2-3
- Re-dispatch bid of G1: -250 $/MWh
- For the 25 MW that G1 over-schedules, it gets paid

$$25 \cdot (zonal\ price\ +\ 250)$$

- German approach towards dealing with DEC game: **cost-based re-dispatch**

Day-Ahead Market Clearing

Bidding format in EU day-ahead markets

Pricing non-convex bids

Future challenges for EUPHEMIA

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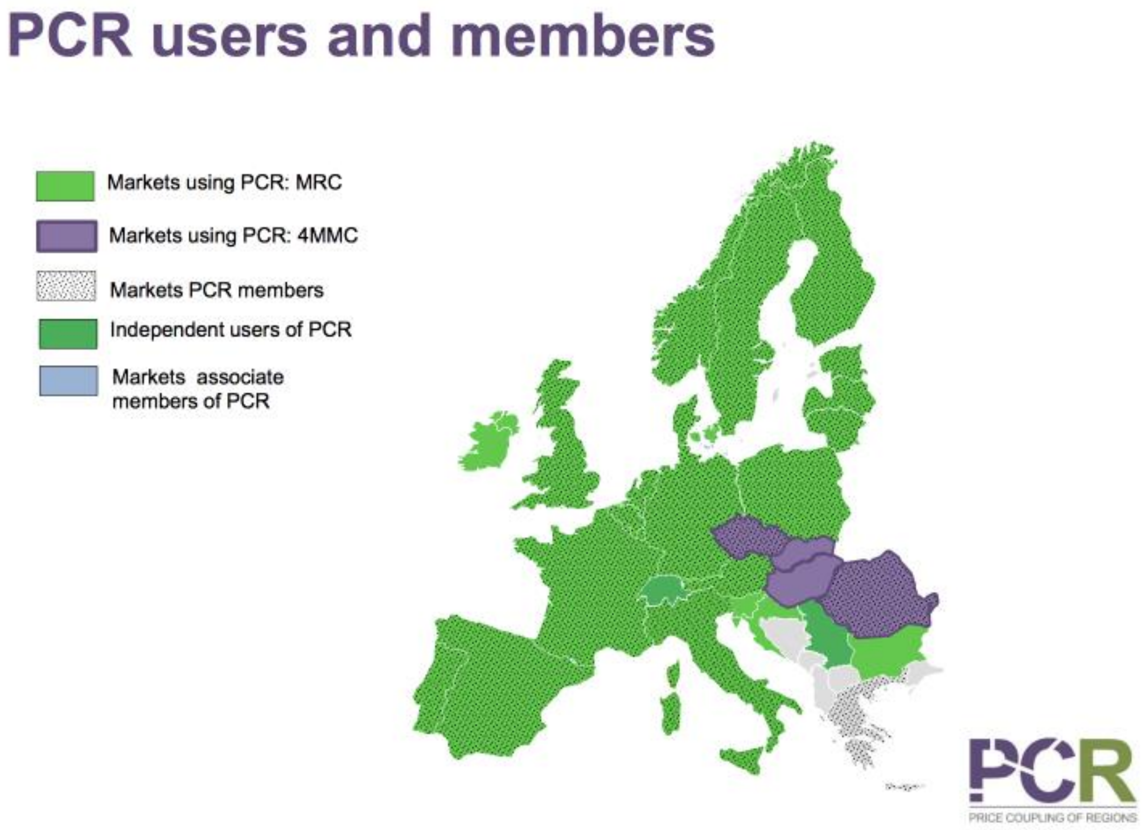
The Day-Ahead Market

- **Price Coupling of Regions (PCR)**: project of European power exchanges to create a single day-ahead price coupling solution
- **EUPHEMIA**: the algorithm developed by *N-SIDE* (*UCLouvain* spin-off) for computing day-ahead price



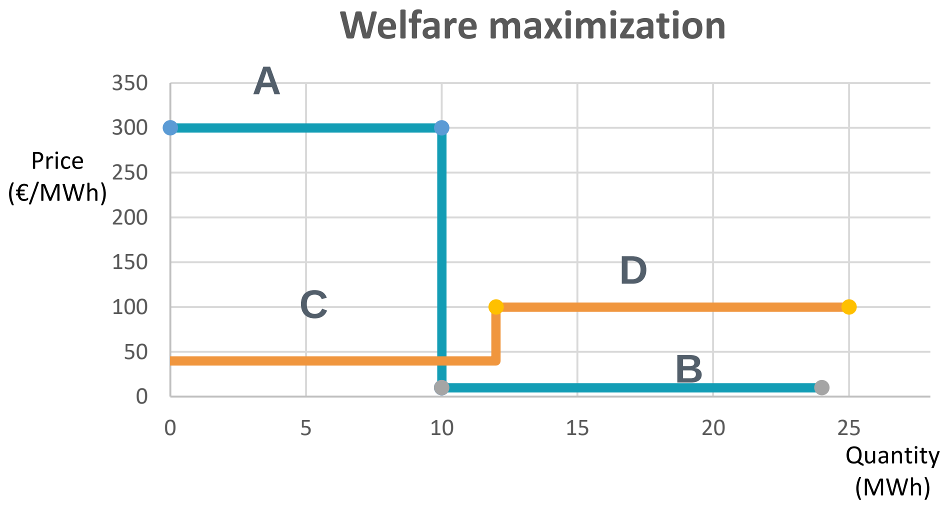
Unit Commitment in US markets

- Scheduling of units in day-ahead time frame
  - Performed 24-36 hours in advance
  - Necessary because of delays in starting / moving units
  - Based on forecasts (of demand, renewable energy , system state)
- Economic factors
  - Startup cost
  - Min load cost
  - Variable fuel cost
- Technical constraints
  - Min up/down times
  - Temperature-dependent startups
  - Startup/shutdown profiles
  - Ramp/rates

Bidding Format in EUPHEMIA

- Bids correspond to portfolios, not individual resources
- Bids internalize fixed costs and constraints of aggregate resources
- Example: consider bidding the following generator in a **single-period** day-ahead unit commitment auction
    - Capacity: 200 MW
    - Startup cost: 1000 €
    - Marginal cost: 5 €/MWh
- EU bid: a take-it-or-leave-it <u>block bid</u> for 200 MW @ **at least** 10 €/MWh
- Main day-ahead EU bidding products
    - Classic bid curves
    - Block orders
    - Complex orders with minimum income condition
    - PUN orders

Markets with Continuous (convex) Orders: Uniform Clearing Prices **Always** Exist



Bid	Quantity (MWh)	Price (€/MWh)
A (buy)	10	300
B (buy)	14	10
C (sell)	12	40
D (sell)	13	100

Uniform Clearing Price

1. Definition:

- **Profit maximization**: Given the price, orders are executed in a way that maximizes profit
- **Market clearing**: Supply = Demand

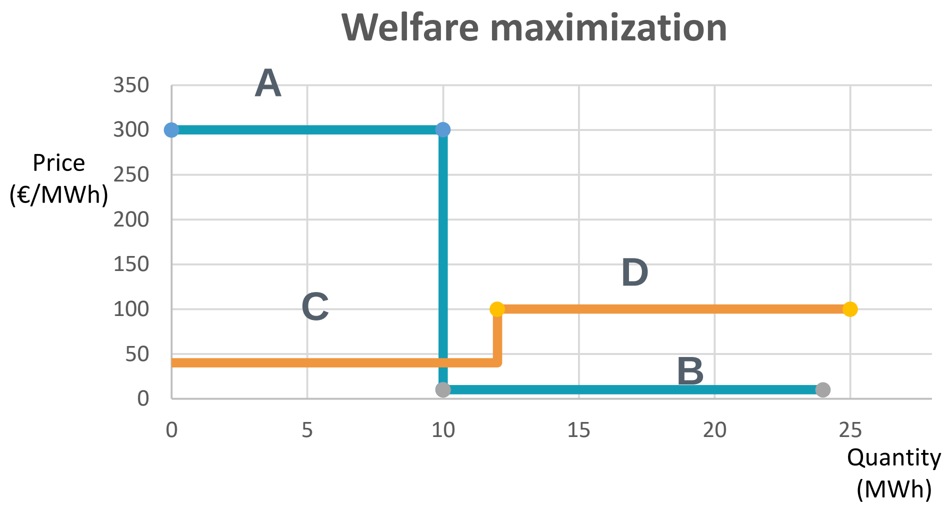
2. For this example:

- *unique* clearing price is 40 €/MWh

3. Existence can be proved mathematically in such settings

4. Corresponds to a welfare maximizing solution

Markets with "Complicated" Orders: Uniform Clearing Prices Might **Not** Exist



Bid	Quantity (MWh)	Price (€/MWh)	Min. acceptance (MWh)
A (buy)	10	300	0
B (buy)	14	10	0
C (sell)	12	40	11
D (sell)	13	100	0

"Complicated orders"

"Complicated" in theory: non-convex

"Complicated" in practice:
- Block orders or min acceptance ratios
- MICs
- PUNs

UNIFORM PRICING does not exist for this example

- At 40 €/MWh, **Supply < > Demand** *because of min acceptance*

C produces either 0 or > 11MWh and A buys 10MWh, all other bids are rejected

- Below 40 €/MWh, **Supply < Demand**
- Above 40 €/MWh, **Supply > Demand**

Two Solutions to the Existence Problem

Uniform Pricing &
Paradoxically rejected bids

Same price in a bidding area for everybody, *but allow some paradoxically rejected orders*

Rationale:

- Paradoxically rejected in-the-money orders (PRB): no losses incurred, more tolerable, no need for side payments
- Paradoxically accepted out-of-the-money orders (PAB): losses are incurred, not acceptable (without compensations)

Mathematically:

- **maximize welfare, *subject to extra constraints (no PAB but allow PRBs for block and mic orders)***
- **extra constraints: less welfare**

Practice in EUPHEMIA

Very complex problem: **not solved to optimality**

Uplifts / side payments

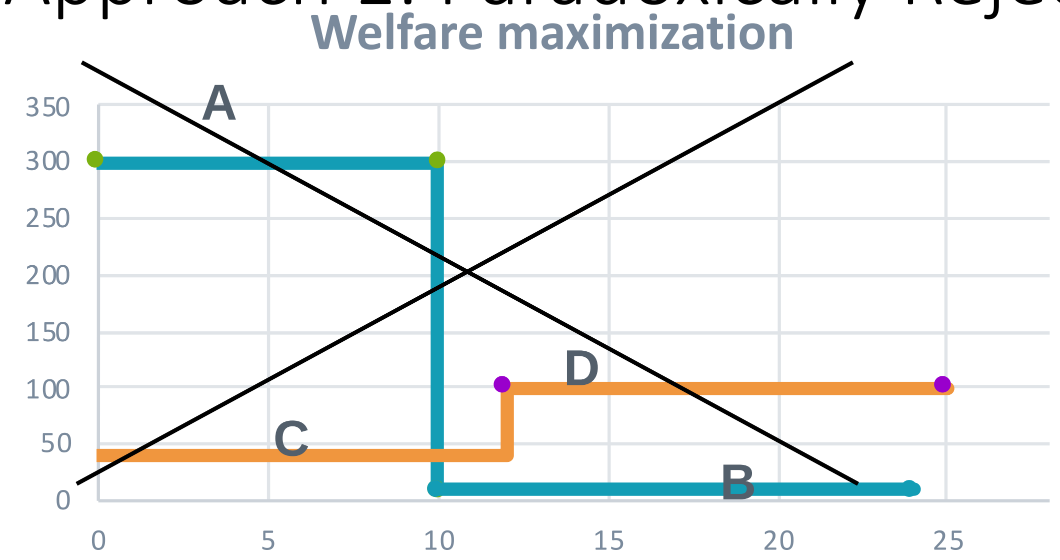
Rationale: send welfare-maximizing instructions to all bids, use side/uplift payments as needed to "make everybody happy"

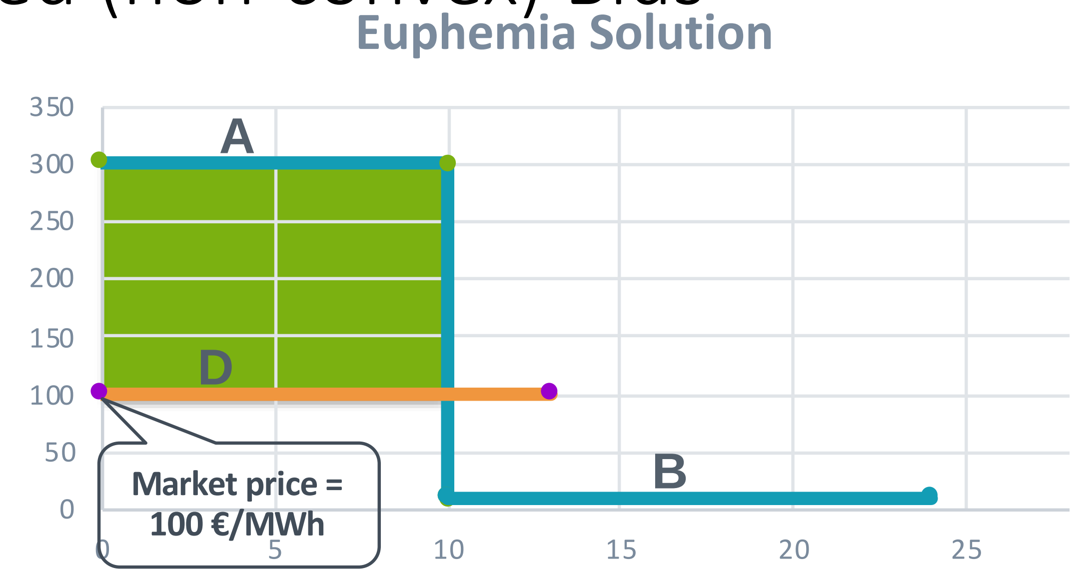
Mathematically:

- **Solve for optimal selection of orders**
- **Solve for price**
- **Compute uplifts separately**

Practice in the USA

Approach 1: Paradoxically Rejected (non-convex) Bids

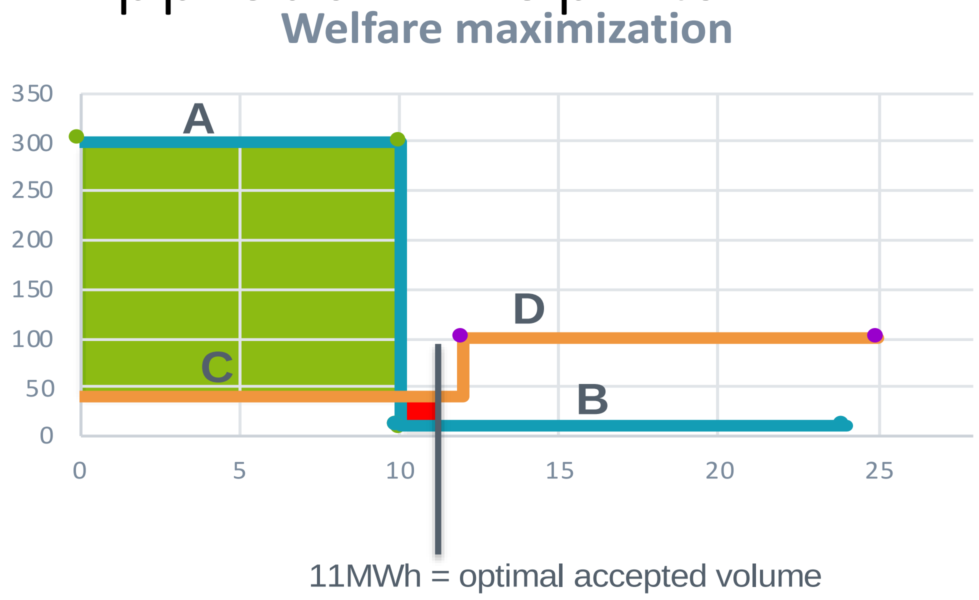




Bid	Quantity (MWh)	Price (€/MWh)	Min. acceptance (MWh)
A (buy)	10	300	0
B (buy)	14	10	0
~~C (sell)~~	~~12~~	~~40~~	~~11~~
D (sell)	13	100	0

- For this example, we showed we cannot accept C
- So if we reject C, price becomes 100 €/MWh
- Welfare = 2000 €

Approach 2: Uplifts



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D (sell)	13	100	0

- Step 1: fix the optimal *quantities* (***maximize welfare***)
  - Order A: 10 MWh
  - Order B: **1 MWh**
  - Order C: 11 MWh
  - Order D: 0 MWh
- Step 2: figure out a uniform price; let's try 40 €/MWh
- Step 3: pay uplifts, if needed
  - Order A, C, D: 0 €, no uplifts
  - Order B: 30 €

Thank you

For more information

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