# Market Code Consultation WS 3

Day Ahead Market Overview

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# There is always a balance to be found…

**Between competitive market with few limitations and a constrained real-time operation of the power system**

## The economist wants:

- Liquid markets
- Large trading area with no/few physical constraints
- Standardised products
- Large number of competing buyers and sellers
- No differentiation between the different buyers and sellers
- Value for money


## The engineers wants:

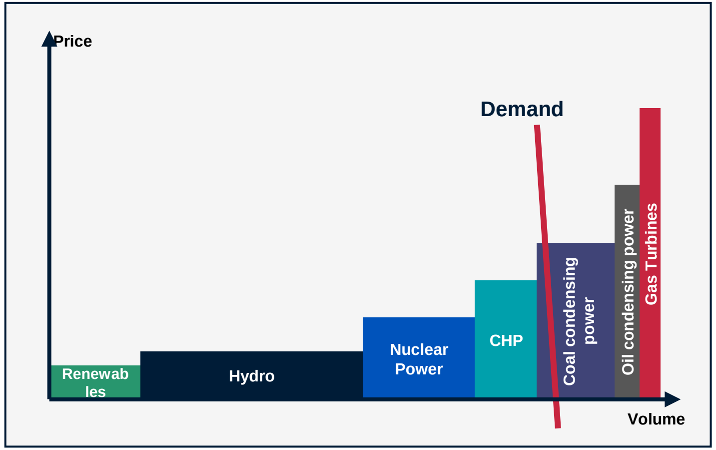
- Market representation of the underlying physical power system
- Representative trading areas with with physical constraints
- Customized products for the physical needs
- Deep knowledge of the sellers and buyers capabilities
- Full compensation for their efforts

**The power market concept needs to take this in account in <u>all</u> market timeframes**

# Bidding principles (1/2)

**Generally two options how to enforce market participants (generators) to bid into the market; cost based bidding versus price based bidding**

- Fully competitive and liberalized electricity markets are usually characterized by **price-based bidding**
  - Pricing principle where generators bid to the market close to their generation unit's short term marginal cost of production
  - Price bidding will result in merit order activation of resources where lowest marginal cost generation units will be most profitable
  - Price bidding / marginal pricing is economic driven and market based
  - Requires shared market power to avoid market abuse situations

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# Bidding principles (2/2)

- **Cost based bidding tries to cover generator's all expenses**
  - Might end up with complex bid structures when all variable and fixed costs are included in the bidding price
  - Usually requires supporting capacity payments to reach the full cost recovery
  - May be more suitable for limited markets with concentrated market power

| Criteria | Cost-based bidding | Bid-based bidding |
|---|---|---|
| Transparency | Fair | Very good |
| Responsiveness of market price signals | Fair (relies on central authorities adjusting cost parameters) | Good |
| Robustness  to non-ideal market conditions | Good | Poor (vulnerable to market power and other distortions) |
| Simplicity and practicality | Fair (requires calculation and monitoring of true costs) | Good |

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# Dispatching models (1/2)

**Dispatching model is essentially an approach to how the generation schedules and consumption schedules for dispatchable Power Generating Facilities or Demand Facilities are determined. Two distinctive models are self-dispatch and central-dispatch.**

- **Self Dispatch** is a dispatch arrangement where resources determine a desired dispatch position for themselves based on their own economic criteria
  - Provides commercial independence within a market
  - Physical dispatch can be either carried out by the resource directly based on the market nominations
  - Or by following dispatch instructions from the TSO which has been determined based on resources' nominations
  - Most of the energy markets in Europe are based on the Self Dispatch principle
  - In Self Dispatch model participants manage their own assets but are also Balance Responsible for any occurring imbalances
  - Generally Self Dispatch supports a fully competitive market-based approach

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# Dispatching models (2/2)

- TSOs operating in **Central Dispatch** systems decide about the dispatch of the majority of units in each time period.

  - The TSO determines the dispatch instructions based on prices and technical parameters (including the start-up characteristics) provided by the resources, as well as whole network model
  - Balancing, congestion management and reserve procurement are performed simultaneously in an integrated process
  - When Central Dispatch is used there usually is a need to ensure system security and minimize the cost of energy delivery to the end consumer
  - In Central Dispatch model participants have less control on their own units and unit activation may not always follow economic principles

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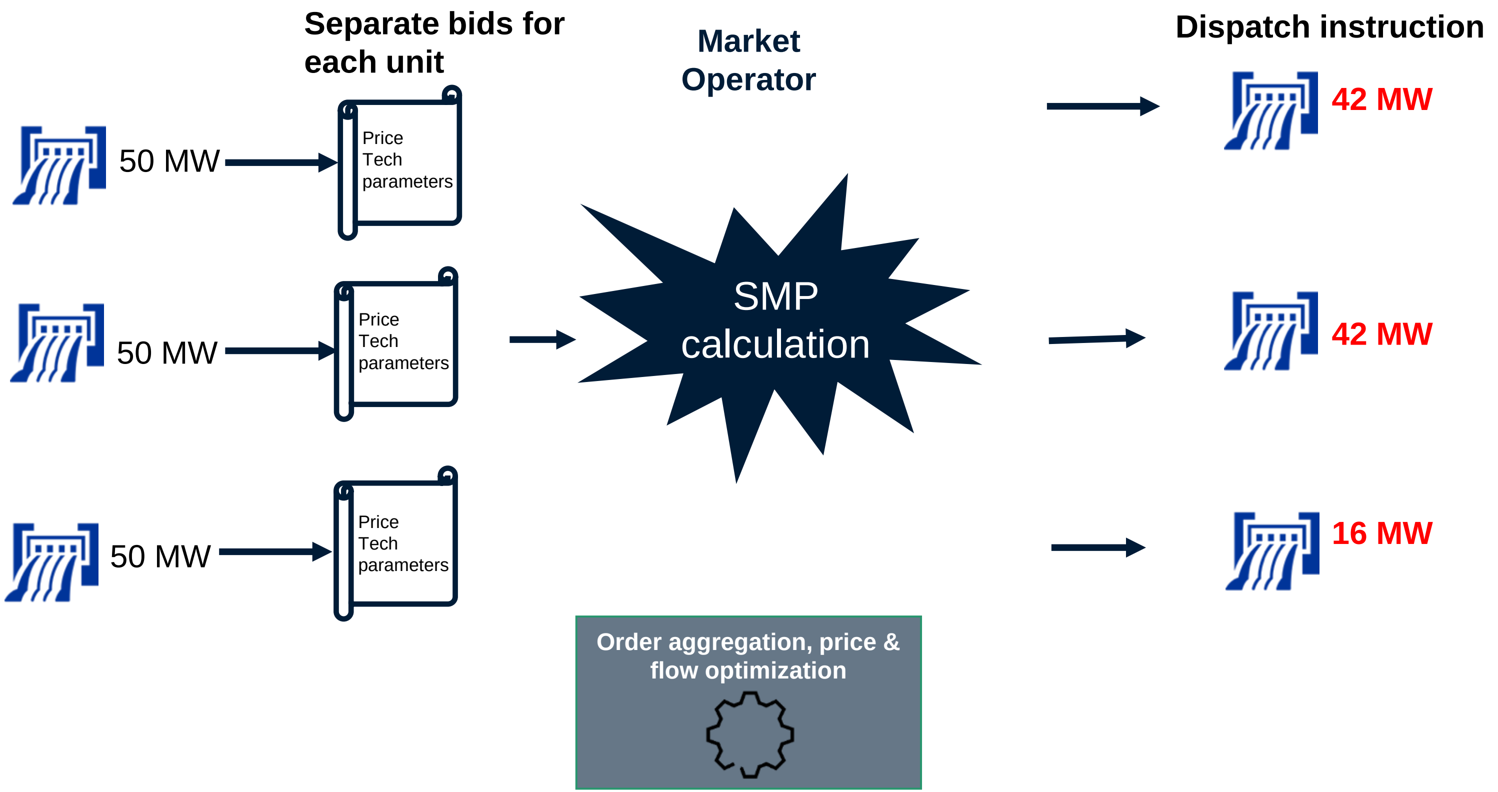
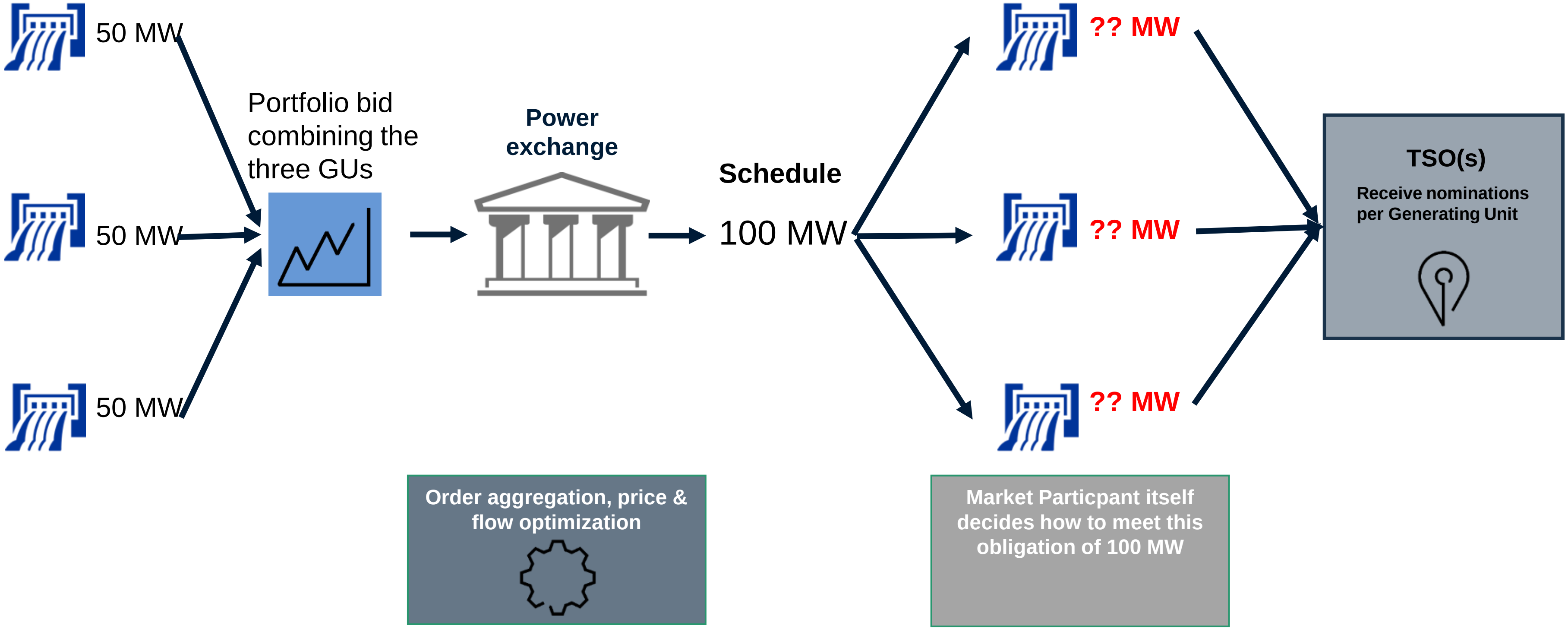
# What does this mean – a central dispatch example

One market participant with three generators – all with 50 MW potential generation for the given hour that is offered to the market



# What does this mean? A simplified example

## Self-dispatch



# Market pricing (1/3)

**Generally, three distinguished spot market pricing methodologies are used; Single Price, Zonal Price and Nodal price**

- **Zonal Pricing** simulates the bottlenecks in the transmission system and divides the market area in specific price areas which all may have distinctive price reflecting the grid congestion.
  - Zonal Pricing does not require inclusion of possible transmission network parameters into the modelling and price calculation
  - Zonal Pricing requires TSO to identify possible bottlenecks in the system and creation of the price areas to simulate the congested market situation
  - Usually the amount of price areas is quite limited inside one country providing smaller number electricity prices within one region
- **Single Pricing** can be seen as a special case of **Zonal Pricing** when there is only one identified price zone
  - Only valid when the transmission system has no transmission constraints
  - In case the transmission system has bottlenecks then Singe Pricing may lead to additional costs to balance prices not matching the underlying physical system

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# Market pricing (2/3)

## Adjustments for Zonal Pricing to tackle the physical transmission constraint issue

**Price area model:**

Between the bidding areas.

- The power exchange is handling the capacities and flows between the bidding areas implicit in the Day-Ahead price calculation
- Costs of grid congestions are spread out on buyers and sellers in the market settlement through the different area prices

**Countertrade:**

Within the bidding areas

- TSO's perform counter purchase on each side of the bottleneck to balance the market.
- Costs are covered through the grid tariffs.

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# Market pricing (3/3)

- **Nodal Pricing** determines distinctive price for each network node. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads.

  - Nodal prices are calculated automatically with most security constrained dispatch optimizations. Therefore, Nodal Price calculation requires comprehensive model of the transmission system
  - Since system constraints are taken into account in the price calculation, inter-zone adjustments are less frequently needed to match the physical transmission system
  - Since nodal pricing creates one price for each node there might be multiple different prices within one country or region
  - Usually Nodal Pricing requires complementary risk management tools such as Financial Transmission Rights to cover market participants from price risk

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# Gross pools vs Net pools

## Gross pool

- Producer offers entire capacity
- Pool sets production schedule

- *„Classic pool"*

## Net pool

- Producer
    - Nominates initial schedule
    - Offers entire capacity
- Pool sets production schedule
- *Modification to allow for inclusion of bilateral contracts (at costs of additional complexity!)*
- *Note: Same principle commonly used in many (but not all!) balancing mechanisms in bilateral markets*

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# So, what has influenced the SAWEM?

The market code depicts what many have called a ***hybrid market model***. What is this based on:

- Net pool (allowing bilateral agreements between parties)
- Self-scheduling of bilateral agreements, but ultimately Central Dispatch
- A (single) zonal setup
- Unconstrained market prices, but constrained dispatch
- is the best option for the initial stages of the VWEM because the current generation structure, particularly with some form of locational pricing, does not guarantee sufficient competition in all generation segments (baseload, intermediate and peak) and locations to be reasonably assured that generators would offer nearly all of their capacity most of the time at marginal cost.
- Price-based bidding except for Eskom GX

Why?

- Not sufficient competition – Eskom has market power on both sides
- Simplified to start with, might move to more zones and more self-dispatch in the future
- Inspired by implementations in the old Single Electricity Market in IrelandYNothern Ireland as well as Vietnam.

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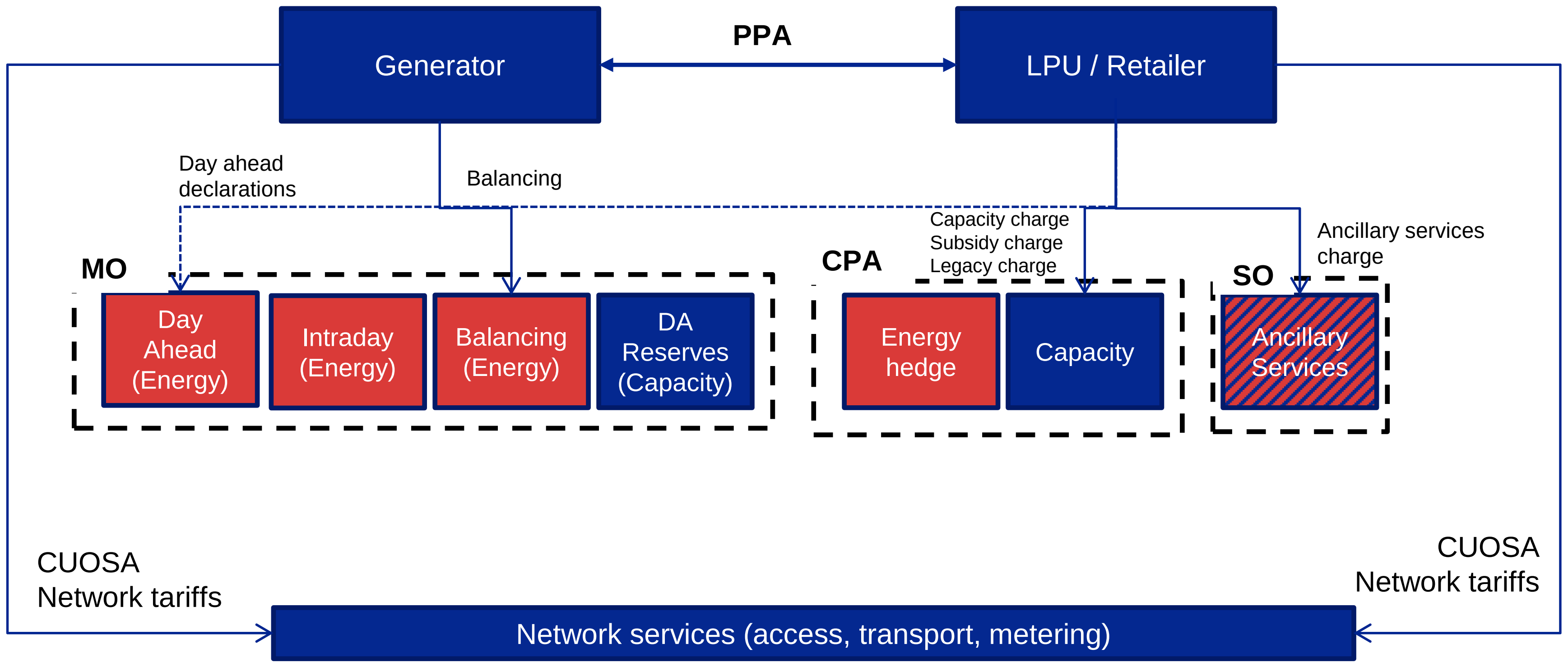


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# Unconstrained and Constrained pricing

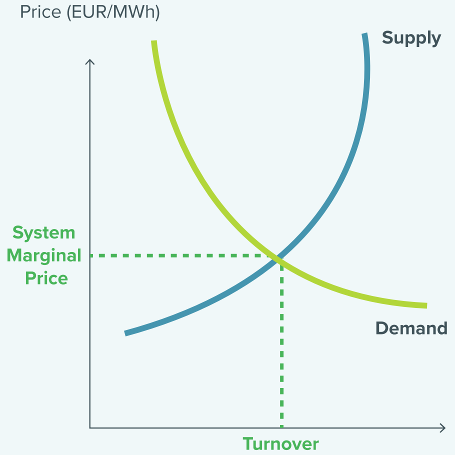


Figure 3. System Marginal Price and power volumes for both supply and demand curves

a) A generator offers a generating unit at a price of R500 for a given hour.

b) The unconstrained market result is that this generator should produce 50 MWh at a SMP of R700.

c) However, due to network constraints, its production schedule is reduced to 45 MWh.

The generator's financial settlement for that specific hour would then be:

Total payment = production payment + lost opportunity payment

= (electricity produced  SMP) + (lost opportunity  generator offer price)

Total payment = (45 MWh  R700) + [(50MWh – 45MWh)  (R700 – R500)]

= R31 500 + R1 000

= R32 500

# Eskom – Co-optimisation



This is a simplified example based on one inflexible demand-side requirement of 600 MW and one reserve requirement (in reality, there will be three) from the System Operator of 150 MW. There are no network constraints in this example.

Three generating units (GU) with the following (simplified) parameters are offered to the market:

GU1 (1) 300 MW, priced at R400/MW, non-flexible

(2) 100 MW, priced at R500/MW, flexible

GU2 (1) 100 MW, priced at R600/MW, flexible

GU3 (1) 200 MW, priced at R550/MW, non-flexible

(2) 100 MW, priced at R700/MW, flexible

If you do a pure energy market calculation, the result would be:

GU 1: All its output would be taken (400 MW),

GU 2: None of its output would be taken,

GU 3: 200 MW would be taken (Order 1),

and the SMP would be R550 (the price of the last unit used in a merit-order selection).

However, the co-optimisation will also need to consider the reserve requirement from the SO.

Based on the orders on the previous page, the selection process would therefore be:

**Reserves (this requires flexible generation):**

GU 1: 100 MW from Order (2)

GU 2: 50 MW from Order (1)

**Energy (both flexible and non-flexible generation can be used):**

GU 1: 300 MW from Order (1)

GU 2: 50 MW of its Order (1) (remaining after reserve selection)

GU 3: 200 MW of its Order (1) and 50 MW of Order (2)

Resulting in a SMP for energy of **R700/MW** (the price of the last unit used in a merit-order selection) and a SMP for reserves of **R300/MW** (based on the lost opportunity cost from being kept outside the energy market calculated as the difference between the lowest cost offered – R400 for order 1 for GU 1 and the SMP – calculated at R700/MW).

**Payments would then end up as:**

GU1 Energy 300 MW * R700 = R210.000

Reserve 100 MW * R400 = R40 000

GU2 Energy 50 MW * R700 = R35 000

Reserve 50 MW * R400 = R20 000

GU3 Energy 250 MW * R700 = R175 000

No reserve payment

THANK YOU

FOR YOUR ATTENTION!

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