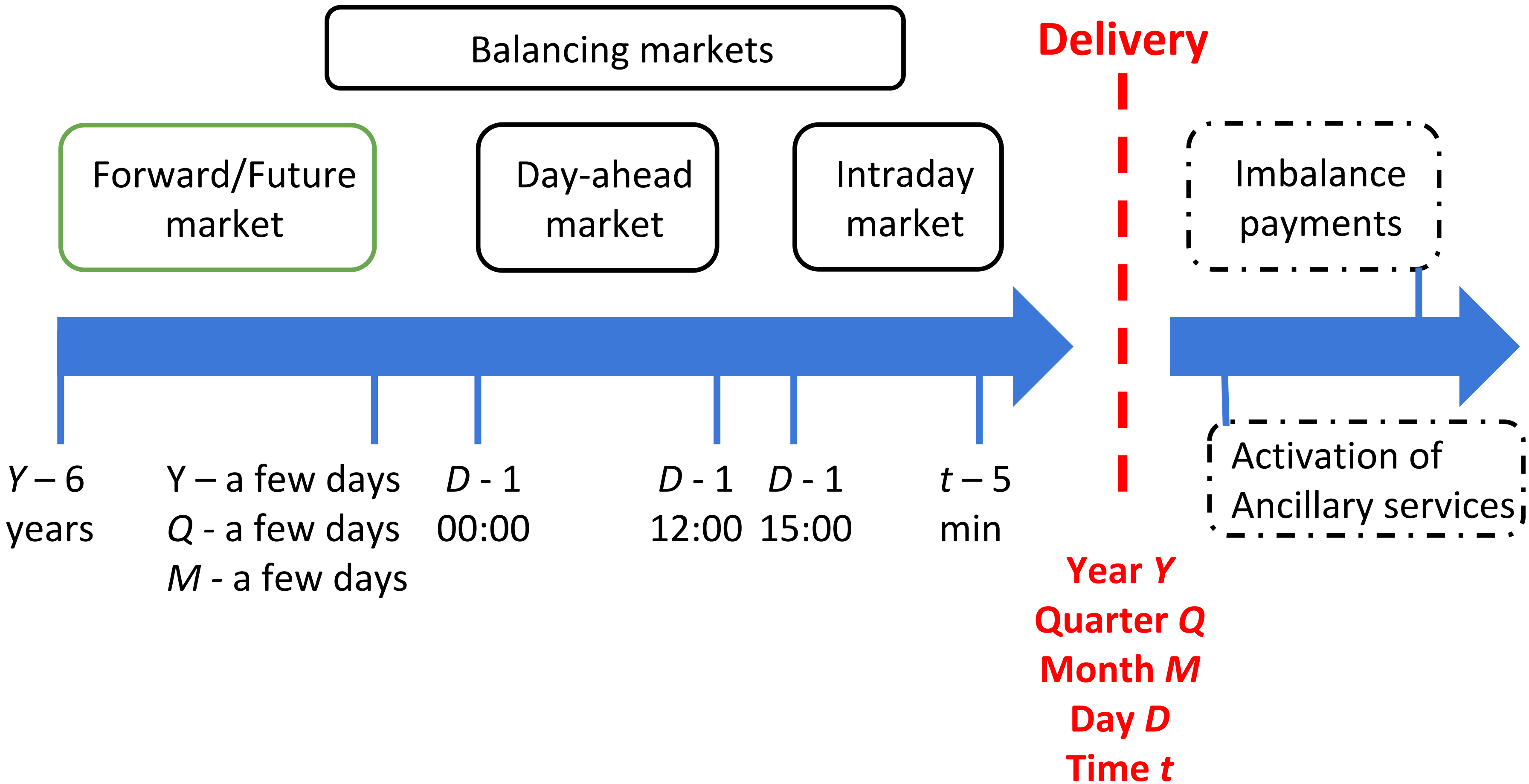
ELEC0080-1 ENERGY NETWORKS
Partim1: Electrical Energy Systems

Lecture 5. Electricity markets (2)

Professor: Damien ERNST
Speaker: Antoine DUBOIS

Table of contents

Chronology of markets

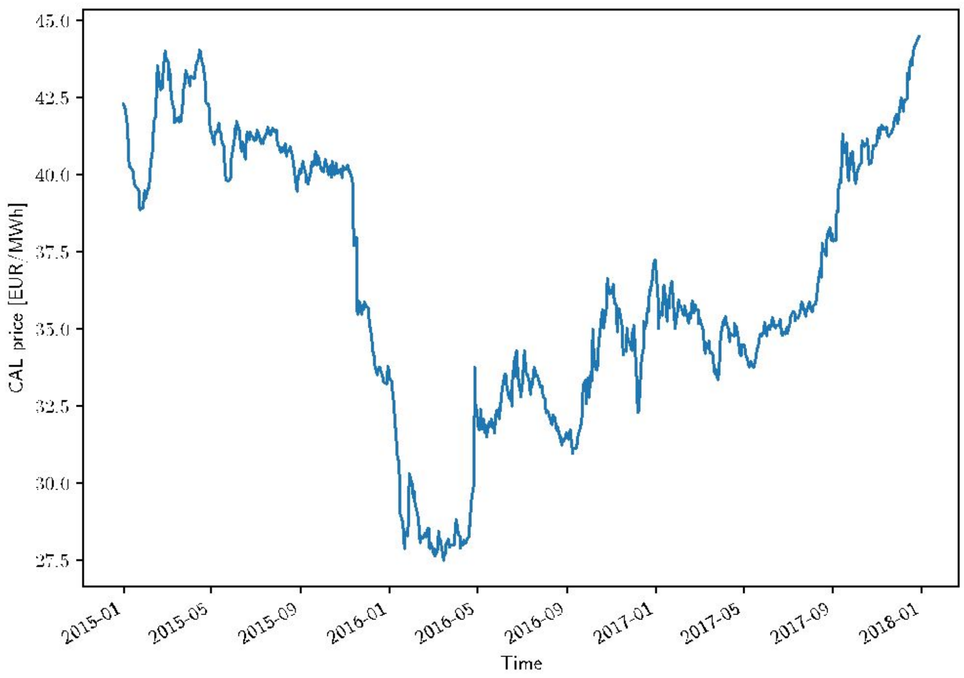


Forward/Future market - Presentation

- Electricity market based on **long-term financial bilateral contracts** between producers and consumers (generally retailers) of electricity.
- Diverse products available: yearly, quarterly or monthly base-load products.
- **Fixed amount** of energy for the given period
- Trading horizon from **6 years up to a few days ahead** of the product first delivery day.
- Opportunity for the market participants to perform price hedging and risk management, to avoid the short-term higher price volatility.
- Market operator: EEX, ICE Endex.

Forward/Future market – Product example

CAL 2018 product

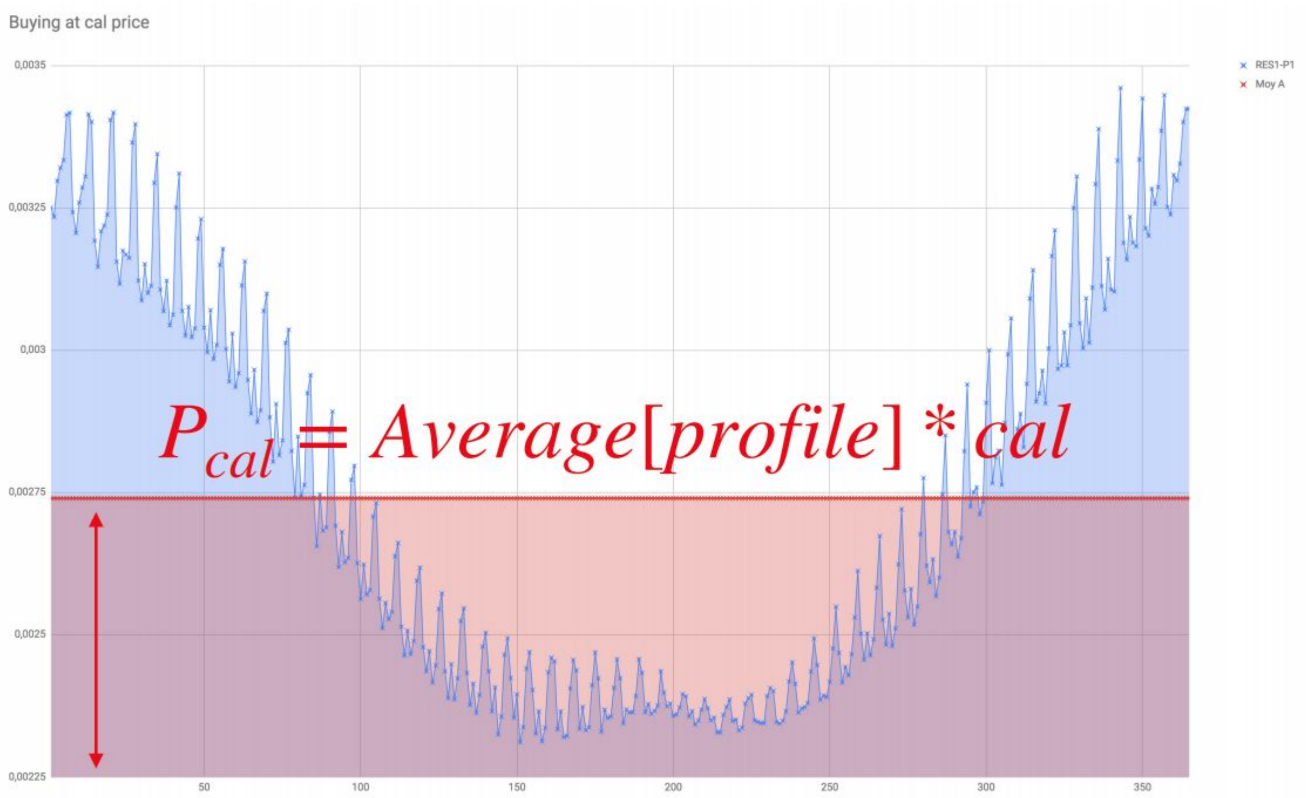


Calendar (CAL) product:

- Yearly base-load product (delivery of constant electric power for the entire year).
- Starting 3 years ahead of the delivery year.
- Ending a few days before the first day of the delivery year.

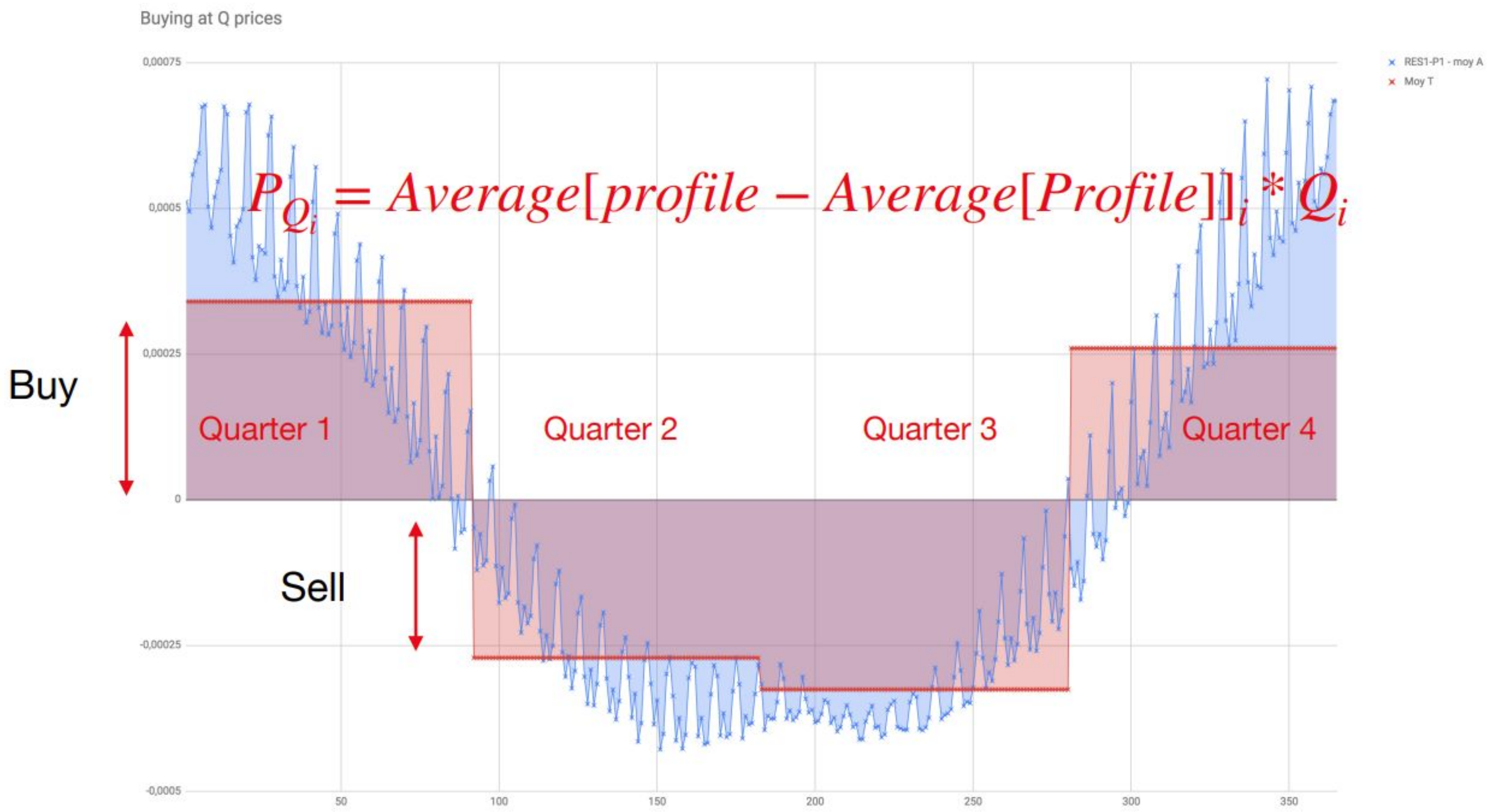
Forward/Future market – Supplier example

- How does a supplier buy energy in advance?



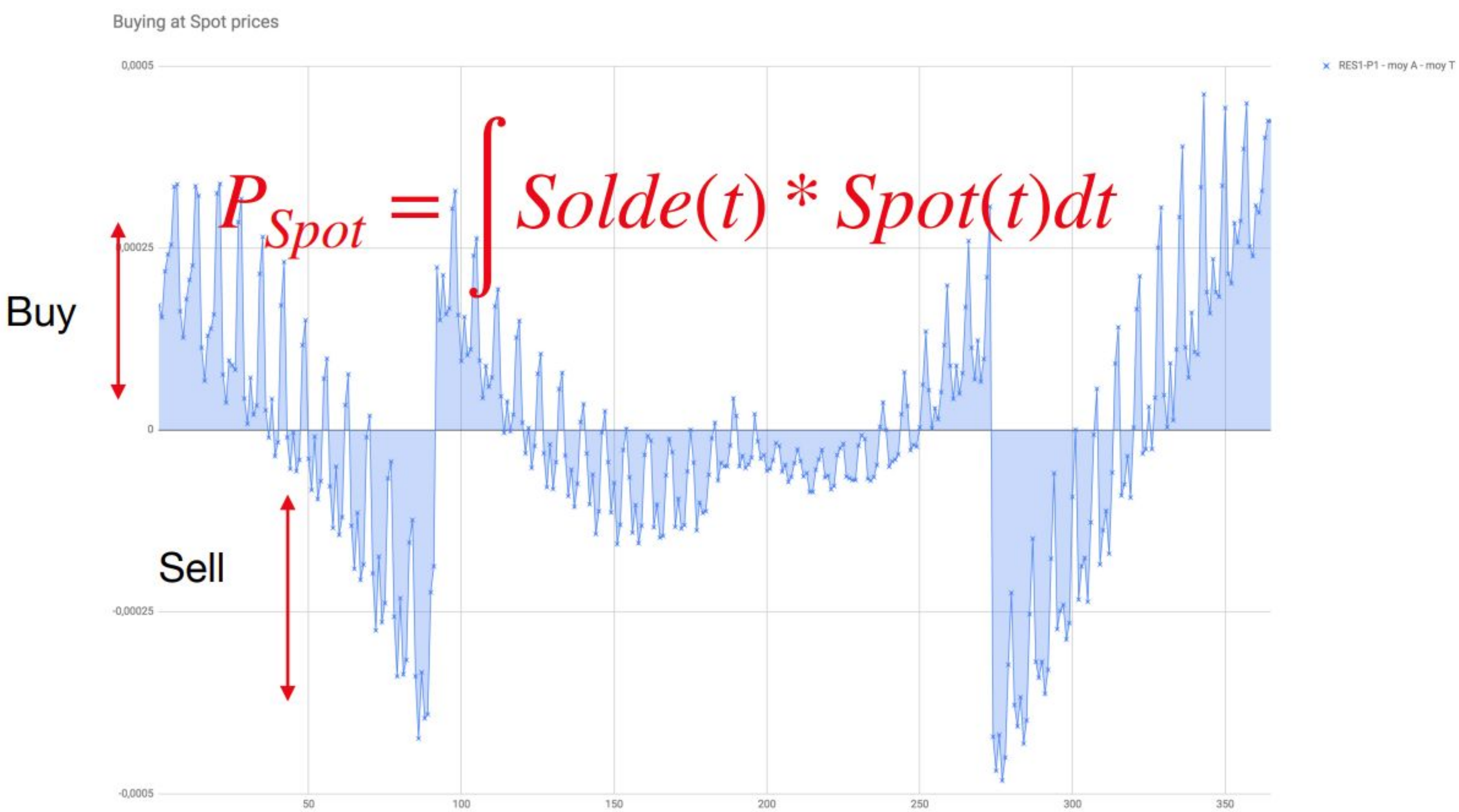
Forward/Future market – Supplier example

- How does a supplier buy energy in advance?

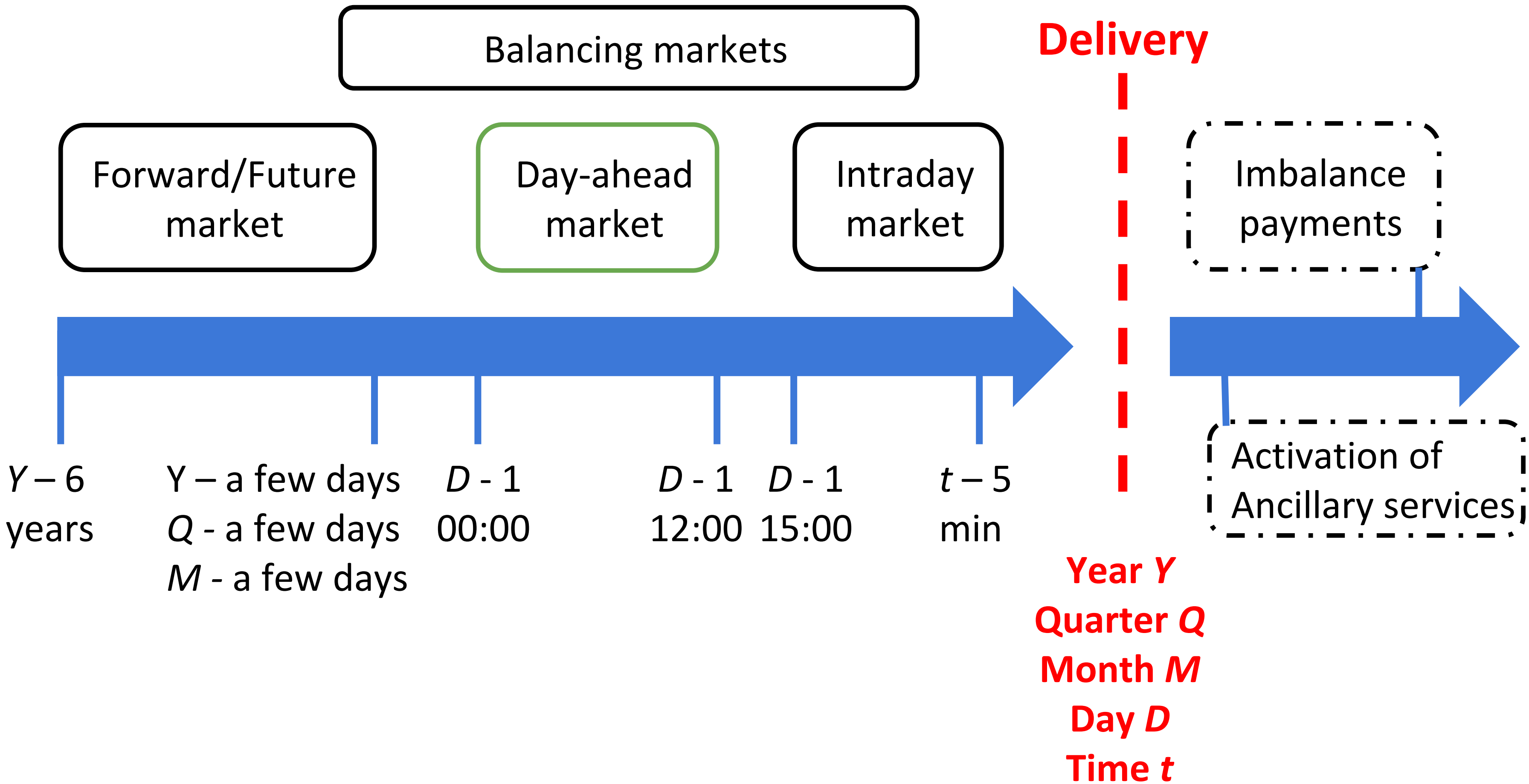


Forward/Future market – Supplier example

- How does a supplier buy energy in advance?



Chronology of markets

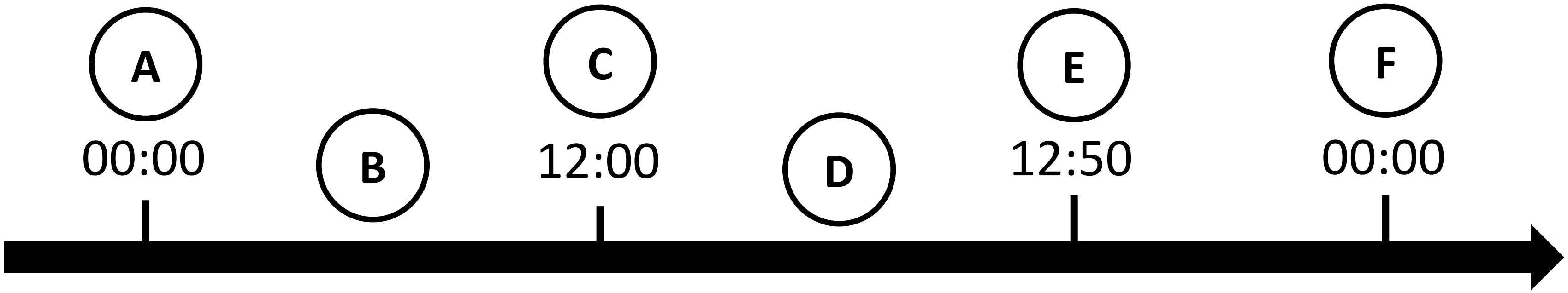


Day-ahead market

⇒ Based on a centralized trading platform cleared by the market operator.

- The day-ahead market is organized as a **pool**.
- This electricity market is operated once a day for all hours of the following day through a **single blind auction** (hourly resolution).
- Market operator: EPEX SPOT

Day-ahead market – Timeline



A. Opening of the day-ahead market for all hours of the following day.
B. Market participants submit their bids and asks to the order book (simple orders, block orders, exclusive orders, curtailable orders, ...).
C. Closing of the day-ahead market for all hours of the following day.
D. Execution of the market clearing algorithm.
E. Notification of the market participants and system operators about the market clearing outcomes.
F. Beginning of the delivery of electricity for the entire day.

Day-ahead market - Price per hour

Price

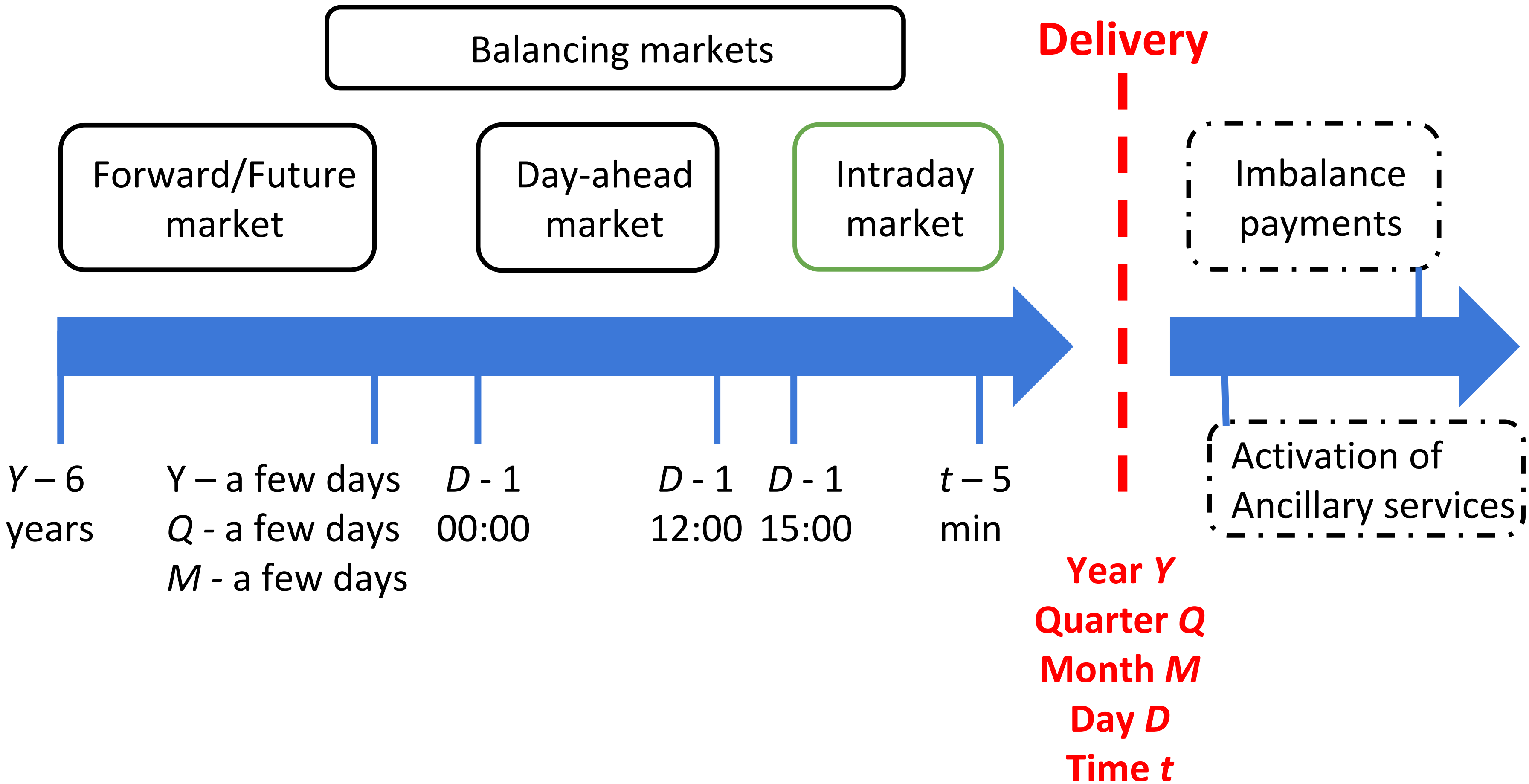
MCV Volume

Day-ahead market – Remarks

1. Why is it taking so long to solve the market clearing algorithm?
   - 24 time periods
   - Offers coming from all over Europe
   - Special orders to be respected:
     - E.g.: Block Orders encompass several hours at the **same price**. A block order is executed at the **same ratio on all its hours**.
   - Transmission constraints or '**cross-border capacities**' set by the TSO **to be respected**
   - EUPHEMIA

2. The day-ahead market is cleared a fairly long time before actual operations (between 12 and 36 hours) ⇒ **risk of imbalances**

Chronology of markets



Intra-day market overview

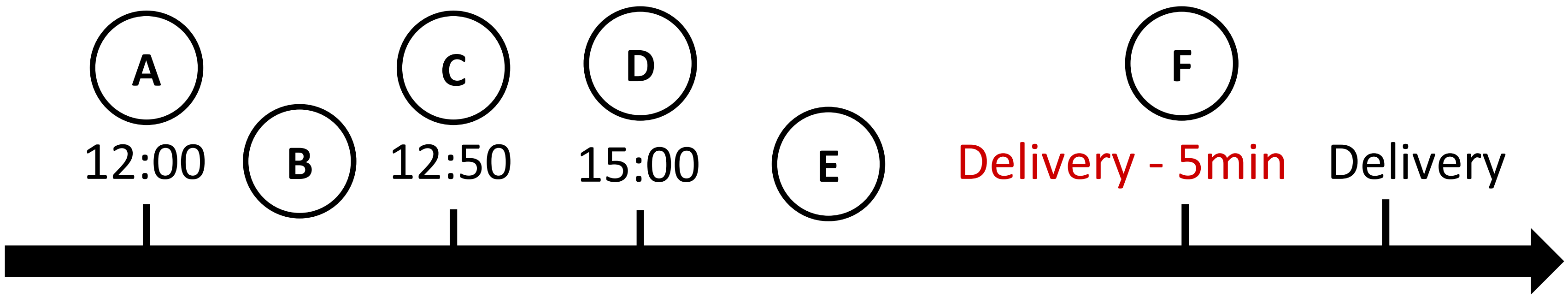
While the day-ahead market is

1. a pool,
2. based on an auction mechanism,

the intraday market is based on bilateral contracts, even though centrally organized (!).

- This electricity market authorizes **continuous trading**, meaning that a trade is executed as soon as two orders match (different constraints have to be met depending on the orders types).
- **Multiple contracts** are available: hourly, half-hourly and quarter-hourly.
- Market operator: EPEX SPOT

Intraday market – Timeline



A. Closing of the day-ahead market for all hours of the following day.
B. Market clearing algorithm execution.
C. Notification of the market participants and system operators about the market clearing outcomes.
D. Opening of the intraday market for the delivery on the following day.
E. Continuous trading on the intraday market.
F. Closing of the intraday market for the delivery period considered.

Intraday market – Fictive example (1)

Context: There is a last minute update in the wind forecast, and the predicted wind power generation associated with the portfolio of a producer is suddenly **decreased by 50 MWh** for the time period 10:00-11:00. This wind power generator intends to adapt its position on the intraday market, whose state is represented hereafter for that specific time period.

Question: Which actions could be performed by this supplier to avoid any imbalance?

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	100	35
G2	Sell	80	40
G3	Sell	50	50
G4	Sell	20	65
C1	Buy	10	55
C2	Buy	20	60
C3	Buy	35	65
C4	Buy	110	70

Curtailable orders (All or None)

Intraday market – Fictive example (2)

1. A first possibility is to buy 50 MWh to G3 and pay 50 x 50 = 2500 €.
2. A second possibility is to buy 80 MWh to G2 and sell respectively 10 MWh and 20 MWh to C1 and C2, thus paying 80 x 40 – 10 x 55 – 20 x 60 = 1450€.
3. Other possibilities?

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	100	35
G2	Sell	80	40
G3	Sell	50	50
G4	Sell	20	65
C1	Buy	10	55
C2	Buy	20	60
C3	Buy	35	65
C4	Buy	110	70

Curtailable orders (All or None)

From financial market to physical operation

Forward/future, day-ahead and intra-day markets are **financial** markets!

1. These are only transactions - No one is “forced” to generate or consume…
2. Both market participants and **system operator** are informed about market clearing outcomes (price and volumes for each market time unit)
3. In the European set-up, the market participants will then self-dispatch, i.e., determine themselves how they will generate or consume depending on volumes and prices

However, **imbalances may still arise** (i.e. amount contracted by a party to buy or sell **different** from the amount that it actually needs or can produce)

From financial market to physical operation

⇒ Managed markets are essential for balancing the load and generation and should **supersede** the open energy market (where most of the trading would occur) as time of delivery approaches.

ISO is given the responsibility to maintain the system balance.

Such a setup relies on the crucial concepts of
1. Balance Responsible Parties (BRP)
2. Ancillary services provided by Balance System Providers (BSP)

Balance Responsible Party (BRP)

'Balance Responsible Party' (BRP) in the electricity market is a market participant or its chosen representative **responsible for its imbalances**.

The BRP may be a producer, major customer, energy supplier or trader.

As a result, each BRP is responsible for a portfolio of **access points** and must develop and take all reasonable measures to maintain the balance between injections, offtakes and commercial power trades within their portfolio.

A list of Belgian BRPs is available at:
http://publications.elia.be/upload/List_Arp.html

Source: https://www.elia.be/en/electricity-market-and-system/role-of-brp

BRP - Daily balance schedule

One day before the period in question, the BRP must submit to Elia a daily balance schedule for their portfolio for day D, which consists of:

- Expected injections and offtakes at each access point;
- Commercial power trades, i.e. purchases and sales, with other BRPs and/or related to imports and exports on the borders.

In Belgium, the daily balance schedule must be balanced on a **quarter-hourly basis**: the sum of injections and purchases must equal the sum of offtakes and sales.

To maintain balance at portfolio level, a BRP can use a hub or a power exchange to exchange energy with other BRPs for the following day (day-ahead) or for the same day (intraday).

BRP - Imbalance tariffs

Elia uses the ex-post measurement data of the access points and the commercial trade schedules to verify whether a BRP has remained balanced.

If a BRP incurs an imbalance on a quarter-hourly basis, the BRP is subject to the imbalance tariffs.

The imbalance tariff **incentivises the BRP to keep their portfolio balanced** or, in certain conditions, to help Elia keep the grid secure and reliable.

BSP - Balance Service Providers

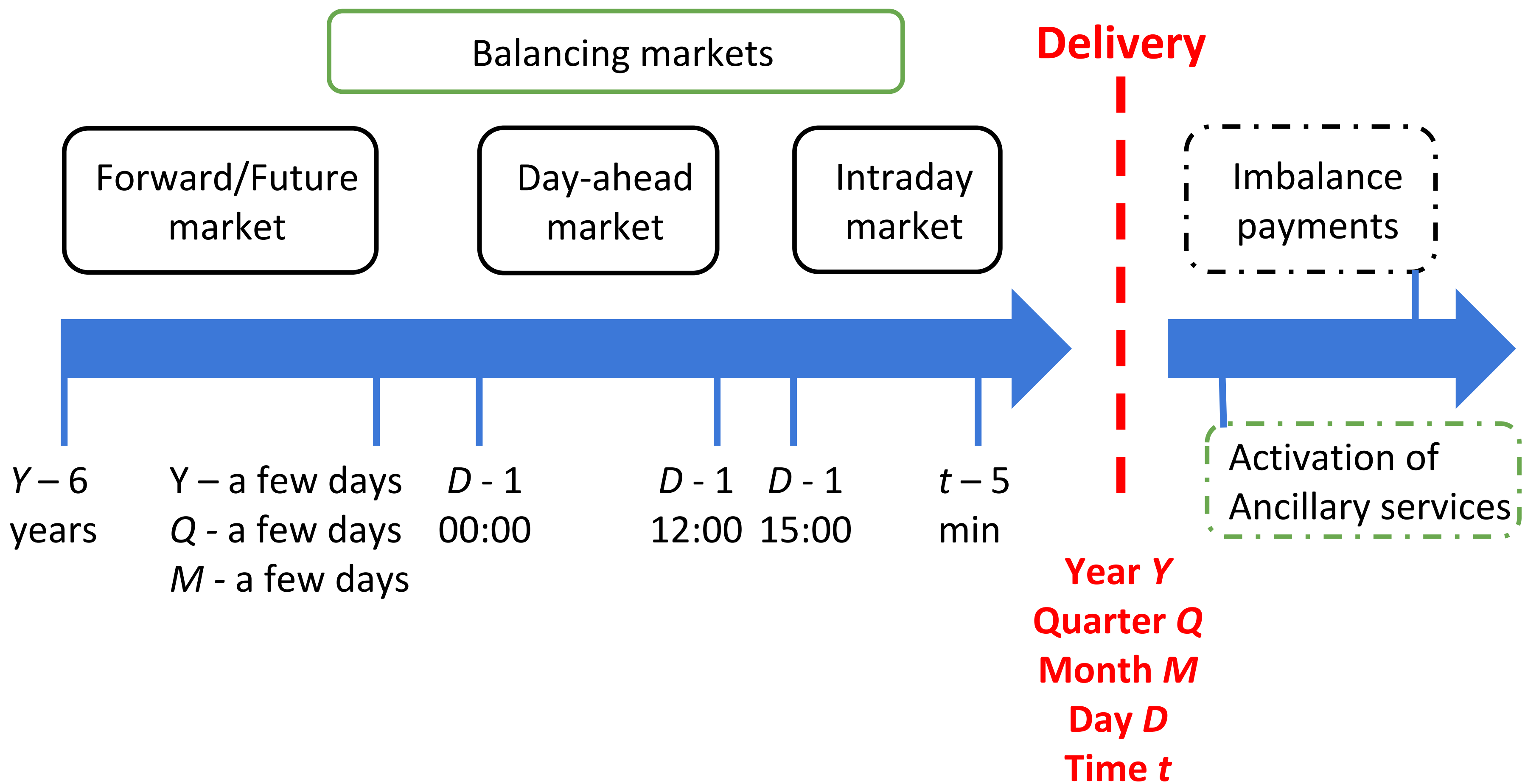
To correct the imbalances created by BRPs

⇒ the ISO organises balancing markets

These markets offer flexibility:

- in the form of **ancillary services**
- provided by **Balance Service Providers** or BSPs

Chronology of markets



Ancillary services

An important aspect of balancing is the approach to procuring ancillary services.

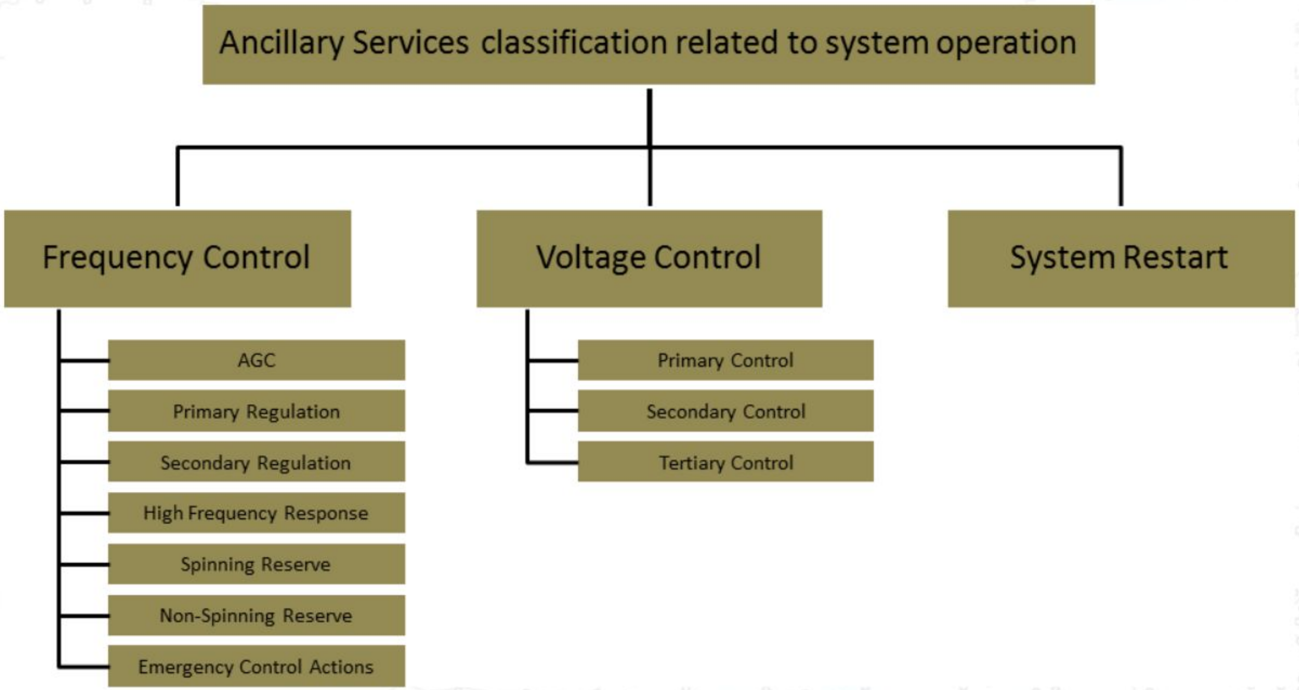
'Ancillary services' refers to a range of functions which ISOs contract so that they can guarantee system security.

These include:

- black start capability (the ability to restart a grid following a blackout);
- frequency response (to maintain system frequency with automatic and very fast responses);
- fast reserve (which can provide additional energy when needed);
- the provision of reactive power
- and various other services.

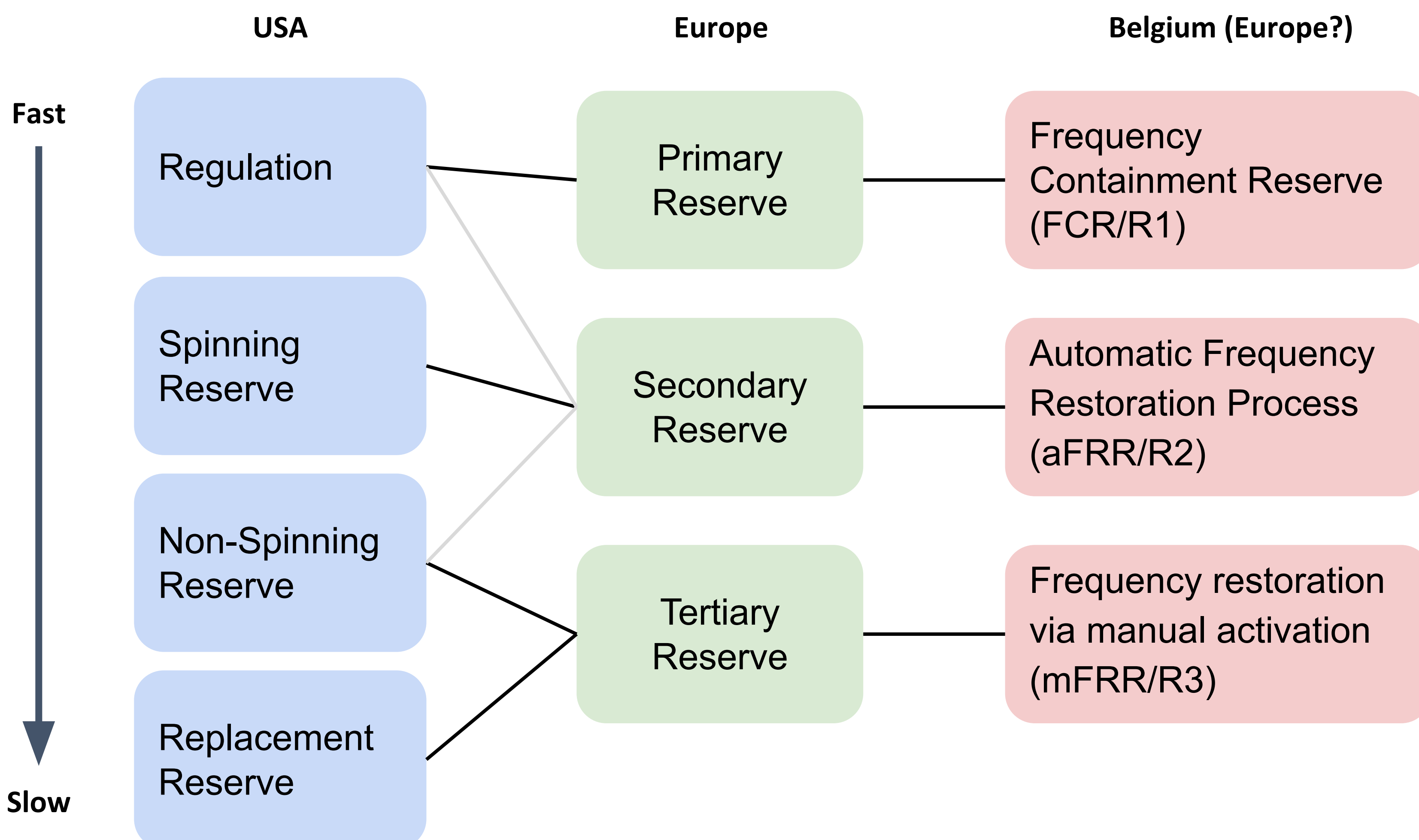
Source: https://docstore.entsoe.eu/about-entso-e/market/balancing-and-ancillary-services-markets/Pages/default.aspx

Various types of ancillary services



We will focus on frequency-related services in the following, as they directly relate to system balance

Reserves - Beware of naming conventions



Ancillary services – Reserves

Primary reserve:

- Automatically activated within 30 seconds
- Goal: stabilizing frequency by equilibrating generation and consumption

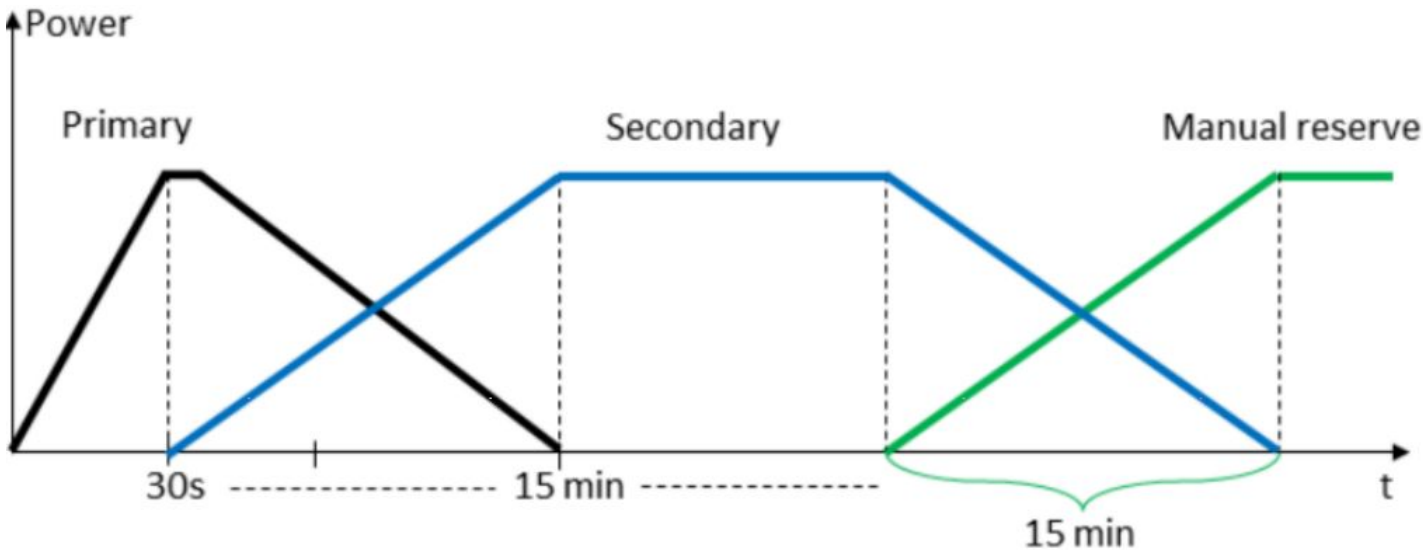
Secondary reserve:

- Automatically activated within 15 minutes
- Goal: get the power grid back to its target frequency

Tertiary reserve:

- Manually activated
- Goal: backup for the secondary reserve

Ancillary services – Reserves



“Renewables in Electricity Markets” course from Pierre Pinson at the Technical University of Denmark (http://pierrepinson.com/index.php/teaching/)

What for and how is the system operator paying ?

Depending on the reserve, the ISO might be paying for:

Capacity and/or energy

For example, primary reserves are ‘energy-neutral services’ in the sense that the BSP are only paid for the capacity they provide.

Based on the acquired reserves, the ISO will set an **imbalance price** or **imbalance tariff**.

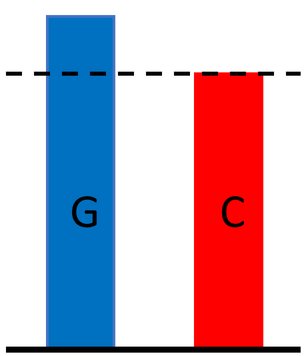
⇒ BRP in imbalance need to pay their imbalance times this tariff.

System vs participant imbalance

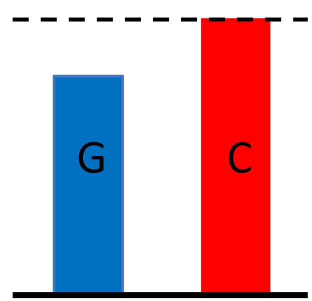
There exist 3 possible situations for the system as a whole:

- **Positive imbalance**: Generation > Consumption (downward regulation required).
- **Negative imbalance**: Generation < Consumption (upward regulation required).
- **No imbalance**: Generation ~ Consumption (no regulation required).

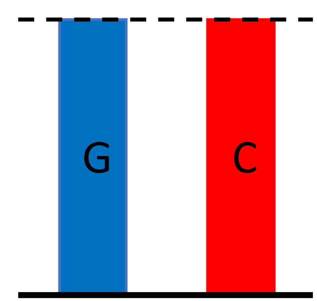
The same reasoning is also valid for a producer/consumer considered individually (contracted production/consumption vs actual production/consumption).



Positive imbalance



Negative imbalance



No imbalance

Imbalance payment – Simple example (1)

Context:
- A generator is scheduled to produce 100 MWh for 40€/MWh of electricity with wind turbines during the time period 10:00-11:00.
- Inaccurate wind forecasts at the time of delivery ⇒ deviation of the actual production from its original schedule.
- The whole system also in *negative imbalance* (G < C) and the ISO activates reserves for 50€/MWh.

Questions:

1. What is the revenue of this generator if its actual production is 80 MWh? (*negative imbalance*)
2. What is the revenue of this generator if its forecast was correct?
3. What is the revenue of this generator if its actual production is 120 MWh? (*positive imbalance*)

Imbalance payment – Simple example (2)

Answers:

1. Day-ahead market revenue: 100 x 40 = 4000€.
   Imbalance revenue: -20 x 50 = -1000€.
   Eventually, the generator's revenue is equal to 3000€.

2. Day-ahead market revenue: 100 x 40 = 4000€.
   Imbalance revenue: 0 x 50 = 0€.
   Eventually, the generator's revenue is equal to 4000€.

3. Day-ahead market revenue: 100 x 40 = 4000€.
   Imbalance revenue: 20 x 50 = 1000€.
   Eventually, the generator's revenue is equal to 5000€.

Imbalance payment – Simple example (3)

Remarks:

In the 3rd situation, the positive imbalance of the producer (partially) counters the negative imbalance of the entire power system, resulting in a revenue surplus.

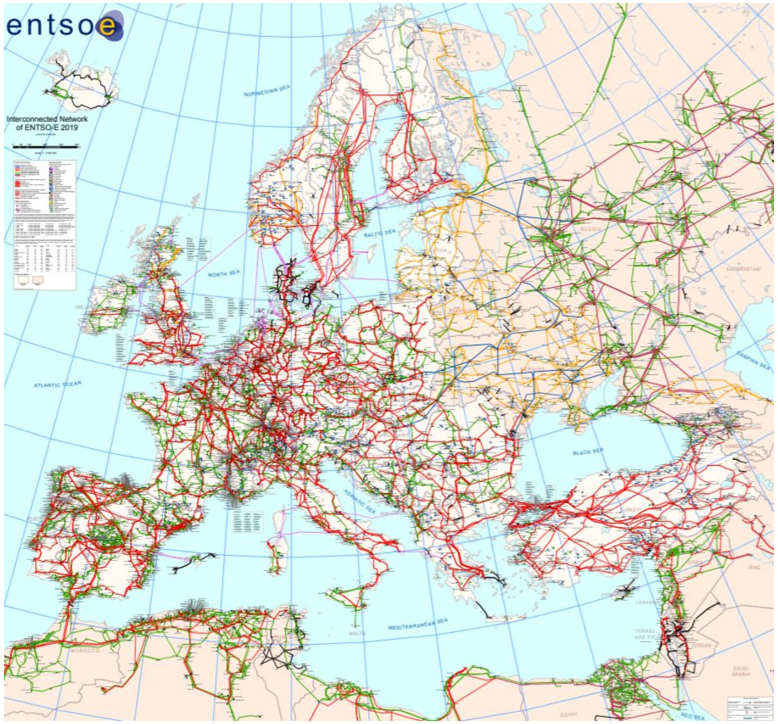
⇒ This may lead to speculation on the imbalance side, which is undesired for the sake of safety.

One price settlement VS **two prices** settlement

Part 4. Including the transmission network limits

Transmission networks

- So far, in our market discussion, we have not talked much about physical limits.
- To illustrate, we will briefly introduce the impact of transmission capacity on the day-ahead market.



Transmission networks

- The **network** is divided into **nodes**. The nodes are interconnected with **transmission lines**. It is possible to transmit a **limited amount of power** from one node to the other through these lines.
- How to take these constraints into account in the day-ahead auction?

Let's exemplify

- *Deadline for offers*: 29th of January, 12:00 - *Delivery period*: 30th of January, 11:00-12:00
- Supply and demand offers include:

Demand: (for a total of 1065 MWh)

Company	Supply/Demand	id	Amount (MWh)	Price (€/MWh)
CleanRetail	Demand	D_1	250	200
El4You	Demand	D_2	300	110
EVcharge	Demand	D_3	120	100
QualiWatt	Demand	D_4	80	90
IntelliWatt	Demand	D_5	40	85
El4You	Demand	D_6	70	75
CleanRetail	Demand	D_7	60	65
IntelliWatt	Demand	D_8	45	40
QualiWatt	Demand	D_9	30	38
IntelliWatt	Demand	D_{10}	35	31
CleanRetail	Demand	D_{11}	25	24
El4You	Demand	D_{12}	10	16

And supply...

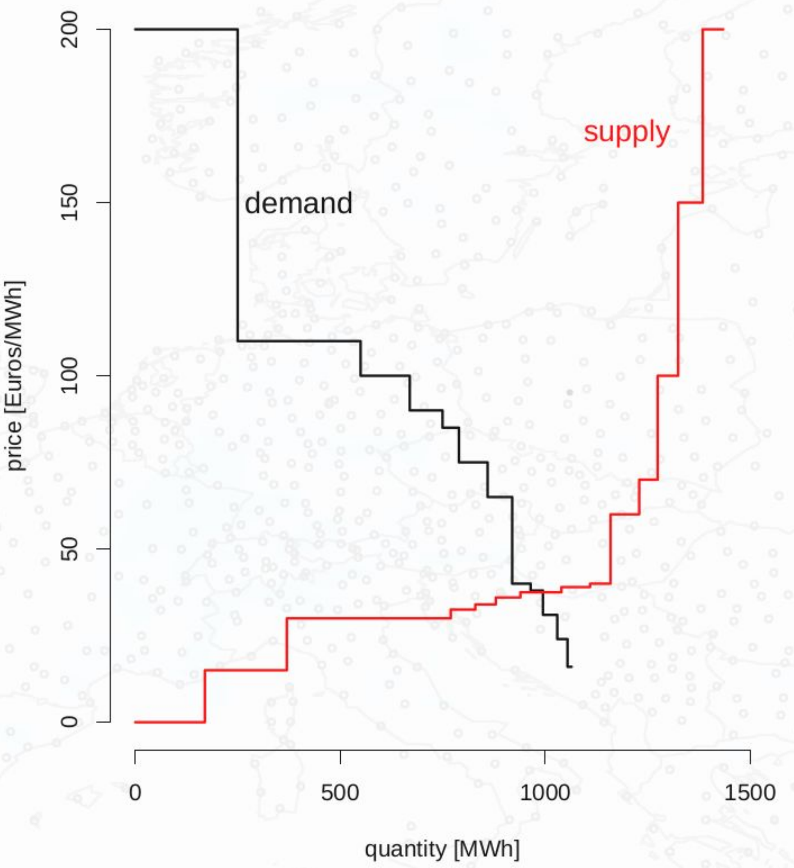
Supply: (for a total of 1435 MWh)

Company	Supply/Demand	id	Amount (MWh)	Price (€/MWh)
RT®	Supply	G_1	120	0
WeTrustInWind	Supply	G_2	50	0
BlueHydro	Supply	G_3	200	15
RT®	Supply	G_4	400	30
KøbenhavnCHP	Supply	G_5	60	32.5
KøbenhavnCHP	Supply	G_6	50	34
KøbenhavnCHP	Supply	G_7	60	36
DirtyPower	Supply	G_8	100	37.5
DirtyPower	Supply	G_9	70	39
DirtyPower	Supply	G_{10}	50	40
RT®	Supply	G_{11}	70	60
RT®	Supply	G_{12}	45	70
SafePeak	Supply	G_{13}	50	100
SafePeak	Supply	G_{14}	60	150
SafePeak	Supply	G_{15}	50	200

That is a lot of offers to match... but how?

Merit-order

- Consumption offers are ranked in *decreasing price order*
- Supply offers are ranked in *increasing price order*
- This defines the **merit order**
- A "magic" point appears: the equilibrium point between supply and demand...



Market-clearing results

1. Total energy: 995 MWh

2. Supply side - accepted: {G1 , . . . , G8} (but only 55 MWh for G8)
3. Supply side - rejected: {G9 , . . . , G15}

4. Demand side - accepted: {D1 , . . . , D9}
5. Demand side - rejected: {D10 , . . . , D12}

6. System price: 37.5 €/MWh

From system to area prices

Let's now split the system into two areas DTU-West and DTU-East with a transmission **capacity of 40 MW.**

Demand: (for a total of 1065 MWh)

Company	id	Amount (MWh)	Price (€/MWh)	Area
CleanRetail	D_1	250	200	DTU-West
El4You	D_2	300	110	DTU-East
EVcharge	D_3	120	100	DTU-West
QualiWatt	D_4	80	90	DTU-East
IntelliWatt	D_5	40	85	DTU-West
El4You	D_6	70	75	DTU-West
CleanRetail	D_7	60	65	DTU-East
IntelliWatt	D_8	45	40	DTU-West
QualiWatt	D_9	30	38	DTU-West
IntelliWatt	D_{10}	35	31	DTU-East
CleanRetail	D_{11}	25	24	DTU-East
El4You	D_{12}	10	16	DTU-East

And supply...

Supply: (for a total of 1435 MWh)

Company	id	Amount (MWh)	Price (€/MWh)	Area
RT®	G_1	120	0	DTU-West
WeTrustInWind	G_2	50	0	DTU-East
BlueHydro	G_3	200	15	DTU-West
RT®	G_4	400	30	DTU-East
KøbenhavnCHP	G_5	60	32.5	DTU-West
KøbenhavnCHP	G_6	50	34	DTU-East
KøbenhavnCHP	G_7	60	36	DTU-West
DirtyPower	G_8	100	37.5	DTU-West
DirtyPower	G_9	70	39	DTU-West
DirtyPower	G_{10}	50	40	DTU-West
RT®	G_{11}	70	60	DTU-East
RT®	G_{12}	45	70	DTU-West
SafePeak	G_{13}	50	100	DTU-East
SafePeak	G_{14}	60	150	DTU-East
SafePeak	G_{15}	50	200	DTU-East

Localizing the previous market results

- Following previous market clearing results, one obtains
  - DTU-West:
    - Supply side: $\{G_1, G_3, G_5, G_7, G_8\}$ (but only 55 MWh for G_8) - Total: 495 MWh
    - Demand side: $\{D_1, D_3, D_5, D_6, D_8, D_9\}$ - Total: 555 MWh

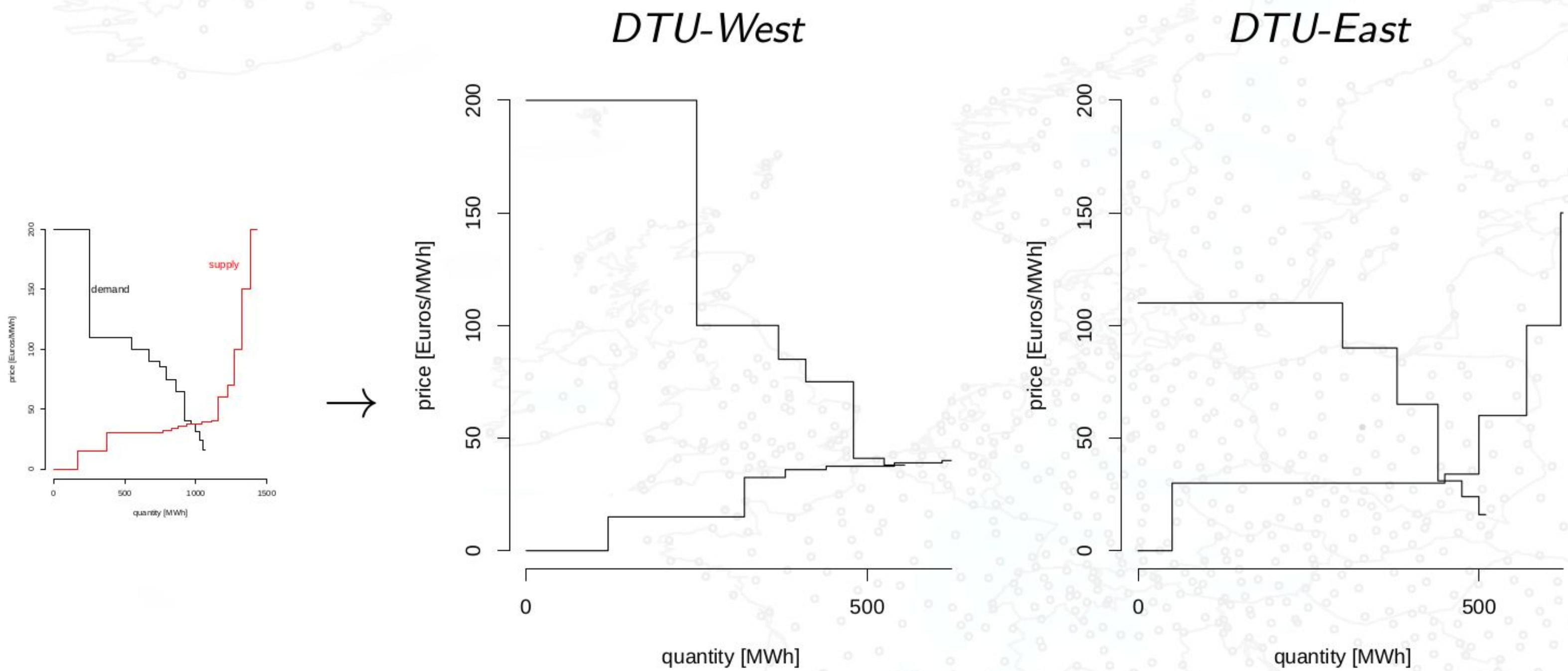
    $\rightarrow$ Deficit of 60 MWh
  - DTU-East:
    - Supply side: $\{G_2, G_4, G_6\}$ - Total: 500 MWh
    - Demand side: $\{D_2, D_4, D_7\}$ - Total: 440 MWh

    $\rightarrow$ Surplus of 60 MWh

BUT, only 40 MWh can flow through the interconnection!

Market split: Import-Export approach

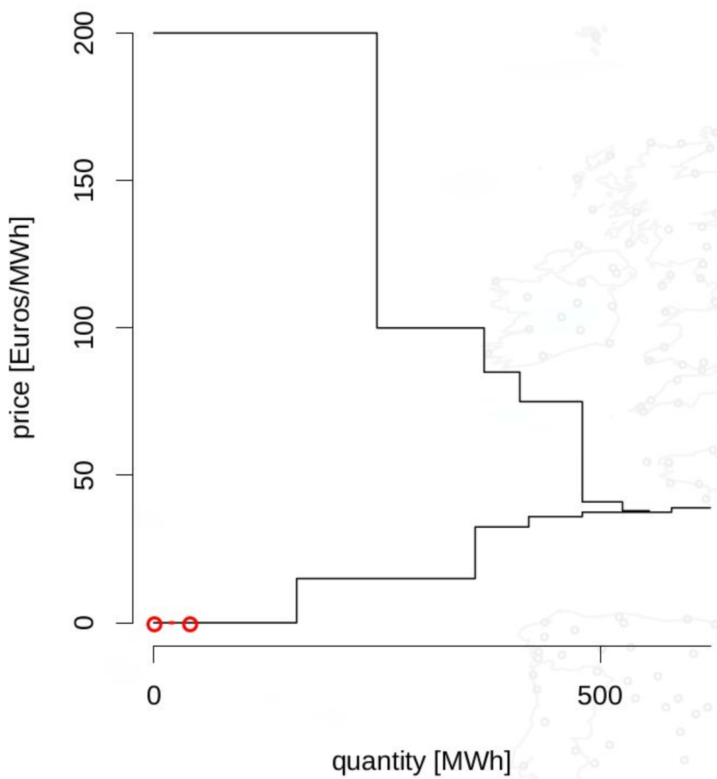
- Due to transmission constraints, the market has to split and becomes two markets

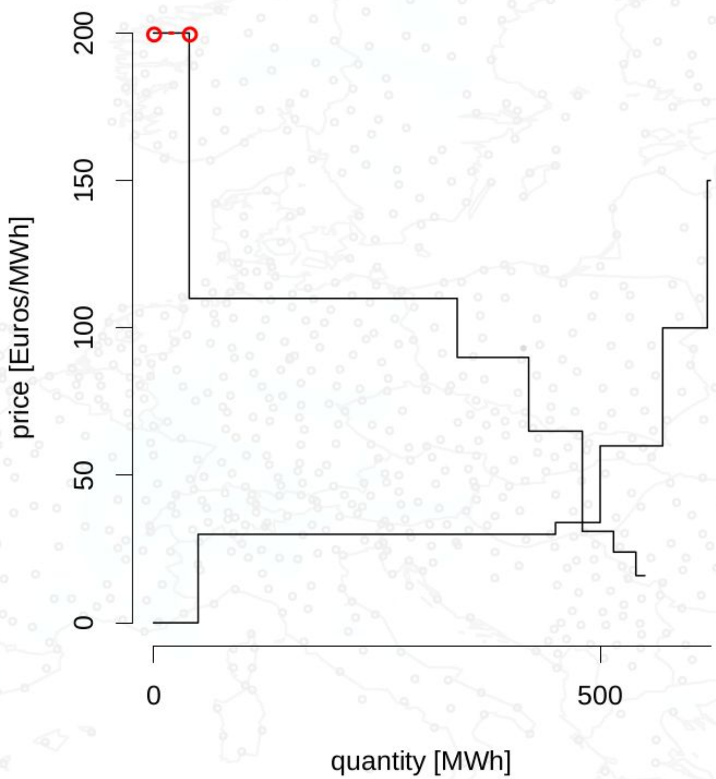


- In practice:
  - 2 market zones with their own supply-demand equilibrium
  - extra (price-independent) consumption/generation offers representing the transmission from one zone to the next to be added

Adding transmission-related offers

- Extra supply in the high price area (40 MWh coming from DTU-East)
- Extra consumption in the low price area (40 MWh for DTU-West)





- Power ought to flow from a low price area to a high price area

Results for each zone

- That eventually yields
  - DTU-West:
    - Supply side: $\{G_1, G_3, G_5, G_7, G_8\}$ (but only 75 MWh for G_8) - Total: 515 MWh
    - Demand side: $\{D_1, D_3, D_5, D_6, D_8, D_9\}$ - Total: 555 MWh

    $\rightarrow$ Zonal price: 37.5 €
  - DTU-East:
    - Supply side: $\{G_2, G_4, G_6\}$ (but only 30 MWh for G_6) - Total: 480 MWh
    - Demand side: $\{D_2, D_4, D_7\}$ - Total: 440 MWh

    $\rightarrow$ Zonal price: 34 €

A few questions at this stage:

- What is the impact on the settlement?
- Do you think it would generalize well for more than 2 zones?

Settlement - Congestion surplus

- If we subtract consumer payments from producer revenues, it is not 0:

  ⇒ 37.5*555 + 34*440 - (515*37.5 + 480*34) = 140 €

- **Congestion surplus** : difference between the payments made by the loads and the revenues of the generator.

- Congestion surplus only arises when the transmission line is saturated/congested.

Approaches to representing network constraints

- There are basically two philosophies, developed on both sides of the Atlantic:
  - US
  - Europe

	Europe	US
System Operator	TSO	ISO
Market Operator	Ind. Market Operator	ISO
Offers	Market products	Unit capabilities
Clearing	Supply-demand equilibrium	UCED problem
Prices	Zonal	Nodal

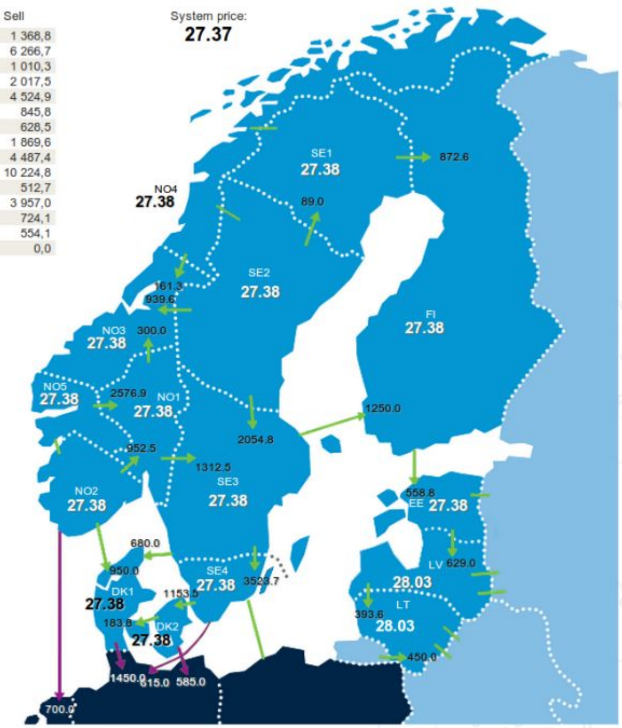
TSO: Transmission System Operator
ISO: Independent System Operator
UCED: Unit Commitment and Economic Dispatch

Illustration of zonal and nodal pricing

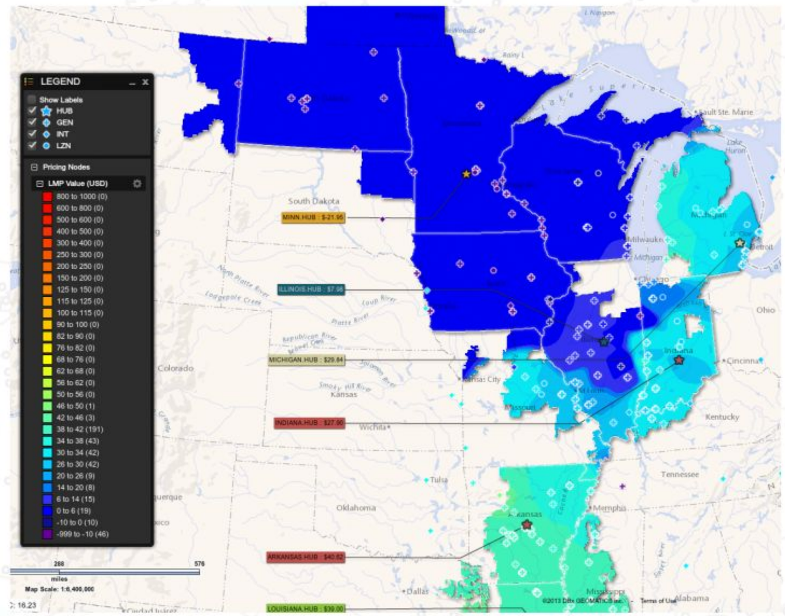
Scandinavia (Zonal):

Elspot volumes

	Buy	Sell
NO1	3 285,7	1 368,8
NO2	4 364,2	6 266,7
NO3	2 411,2	1 010,3
NO4	1 856,2	2 017,5
NO5	1 948,0	4 524,9
DK1	2 659,6	845,8
DK2	1 598,2	628,5
SE1	1 086,0	1 869,6
SE2	1 404,0	4 487,4
SE3	8 138,4	10 224,8
SE4	2 882,9	512,7
FI	5 520,8	3 957,0
EE	653,9	724,1
LT	947,7	554,1
LV	235,4	0,0



Midwest US (Nodal):



Go visit: `http://nordpoolgroup.com` (market data, map)

Go visit: https://www.misoenergy.org

A word about losses in transmission networks

Losses occur in electricity networks (e.g. copper losses, eddy currents, …)

Since one or more generators must produce this lost energy and since these generators expect to be paid for all the energy they produce, a mechanism must be devised to take losses and their cost into account in electricity networks.

Allocating the losses or their costs between all the market participants is a problem that does not have a rigorous solution.

A fair mechanism is one in which the participants that contribute more to losses pay a larger share than the others.

Part 5. Influence of renewable integration

Regulation in the electricity system

- Until the 1980s, the electricity system was mainly treated as a physical infrastructure system. It should primarily supply the required services.
- In the 1980's and 1990's, energy was treated more and more as a commodity, which could be left to market forces.
- The electricity system was divided into:
  - a natural monopoly part (--> regulated industry)
  - a commercial part (--> market competition)
- Until 2000, most European countries had newly established commercial markets for the electricity system.
- In the view of many economists, the liberalised supply and trade area should operate in an efficient way when left alone.
- From the 2000s, the view on the markets became more pluralistic: New objectives started to become more important and regulation became more important again.

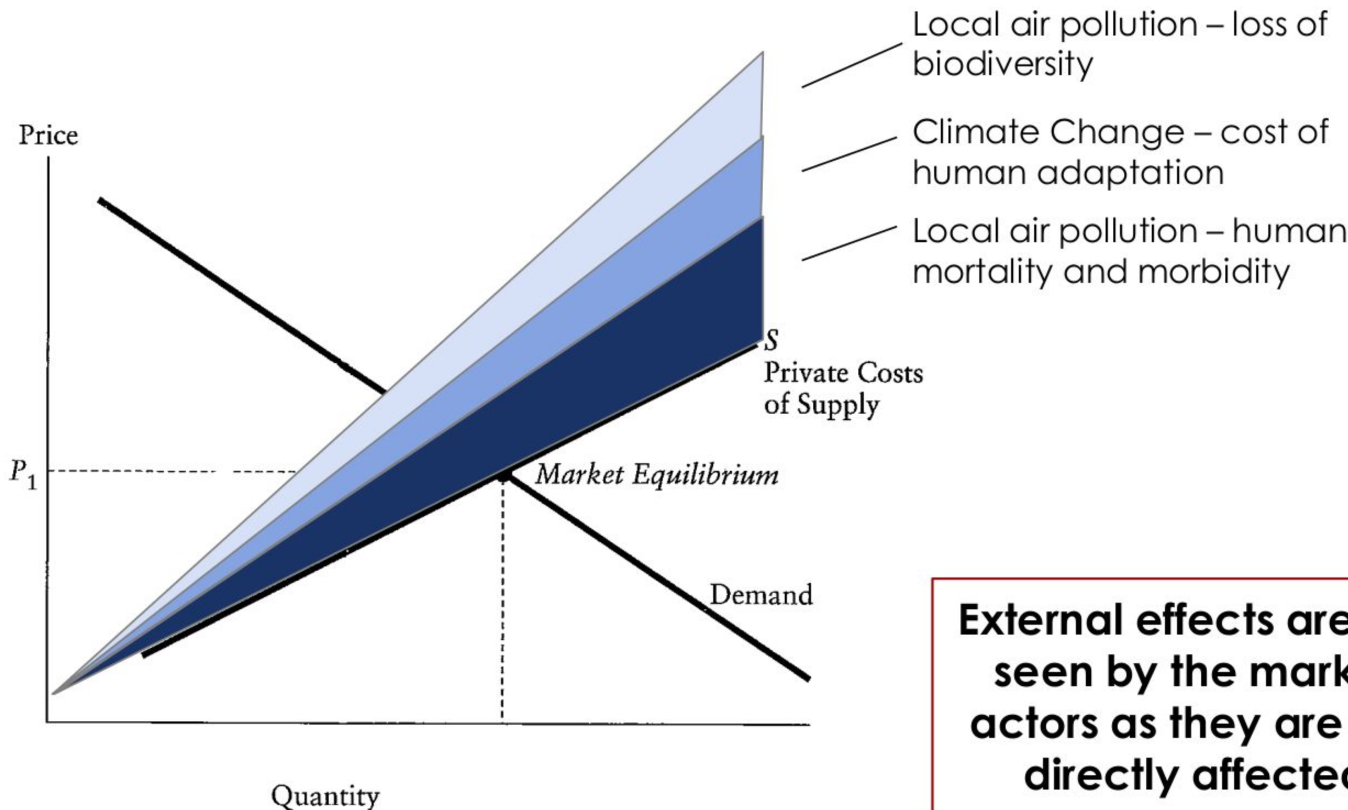
Different approaches: Consumer cooperatives and state-owned monopolies (Denmark) or private-owned monopolies (USA), or a mixture of both (Germany).

New objectives:

1. Security of supply (independence from fossil fuels)
2. Climate change

Sources: Helm 2007

Efficient Markets: Marginal cost and benefits



External effects are not seen by the market actors as they are not directly affected

Market failures and need for regulation

1. **Complementarity** to the rest of the economy
   → societal costs of scarcity (excess demand) are higher than those of excess supply
2. **Just-in-time** requirements: Storage options are extremely limited
   → supply and demand must be kept balanced at all times for technical reasons, economic cycles to adjust demand/supply may become problematic
3. **Natural monopoly** in the network/grid segment
   → shared pool, i.e. a public good to the system as a whole – undersupplied by markets
4. **Positive externalities**, such as innovation processes, job creation, security of supply, social and equity issues,…)
5. **Negative environmental externalities** (emissions from fossil fuels)
   → if not adequately internalised, they cause wrong incentives

Regulation is needed to govern sufficient, stable supply in the interest of society and to internalise externalities

Setting the right incentives

- So, regulation is necessary. How to do it?

Chooses the desired targets

Principal

Policy maker

influences

SETTING INCENTIVES

Agents

Households

Firms

Act according to their self-interest (maximise utility / profits)

- How to deal with external cost?

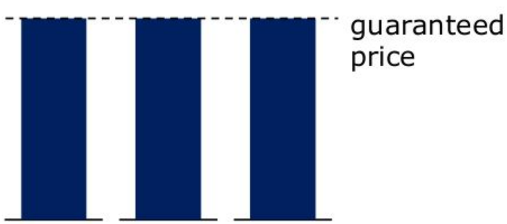
1. Collect fees from the polluters (Tax, Emissions trading,…)
2. Pay subsidy to alternative (non-polluting) technologies

Generation-based RES support

EXERCISE Part 1

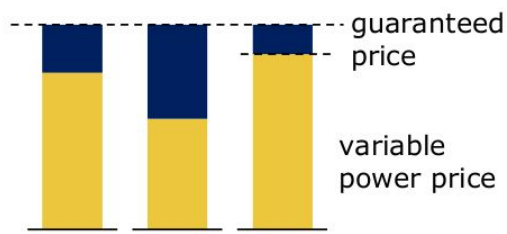
(1) Price-based

'Traditional' Feed-in Tariff (FIT)

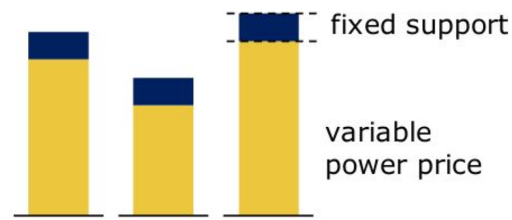


'Modern' Feed-in Tariff (FIT)

Sliding Premium / Contract for Difference (CfD)

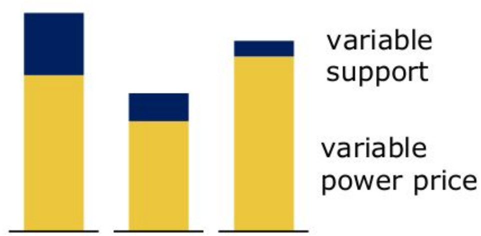


Fixed Feed-in Premium (FIP)



(2) Quantity-based

Tradable Green Certificates Scheme (TGC) / Quota Obligation

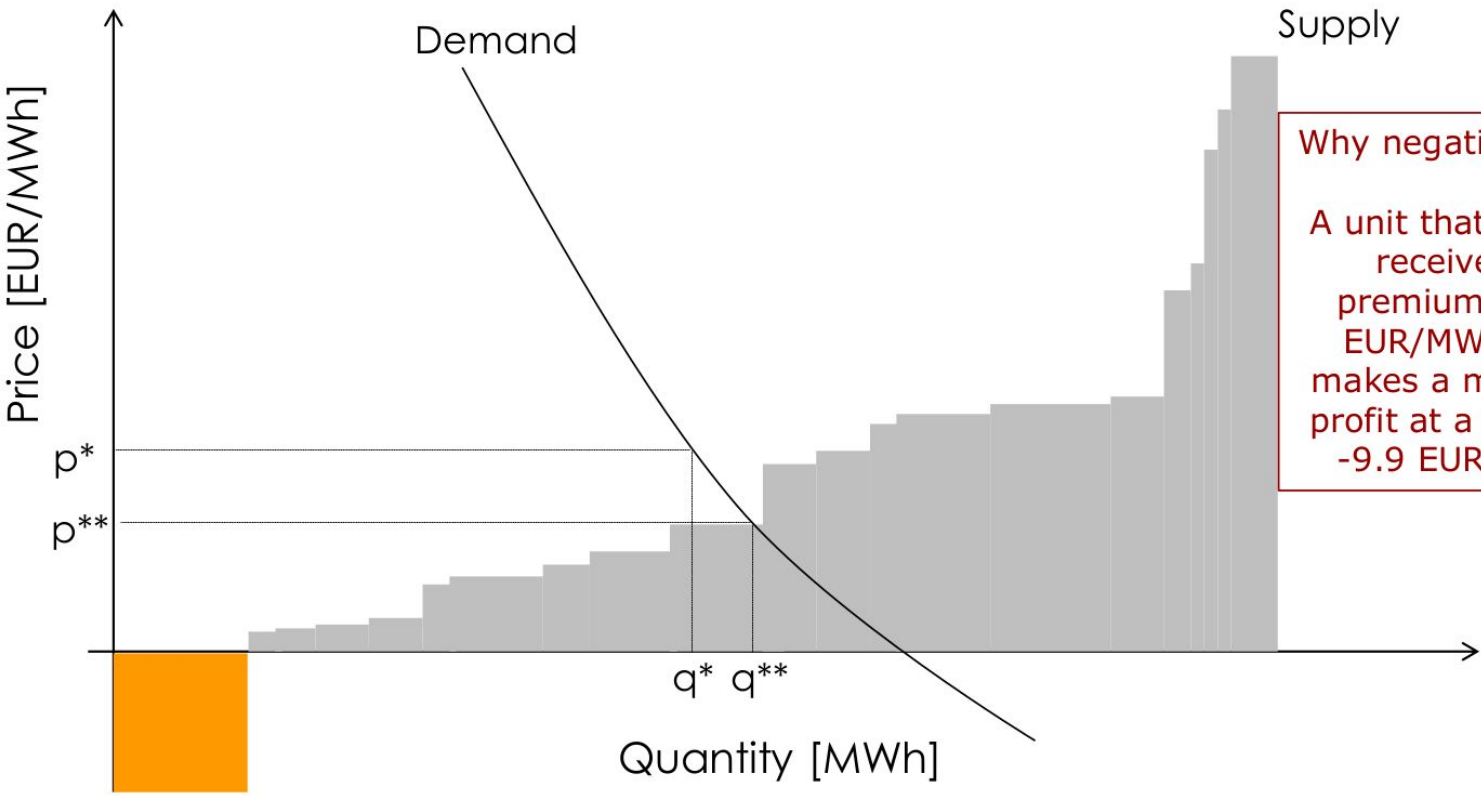


How would a supported wind park bid into the spot market – and what is the effect on market price?

'Traditional' Feed-in tariff: *No bidding – production at all prices*

'Fixed' Feed-in premium: *Bidding at minus the premium*

'Sliding premium' Feed-in tariff: *Bidding at minus the tariff (strike price)**



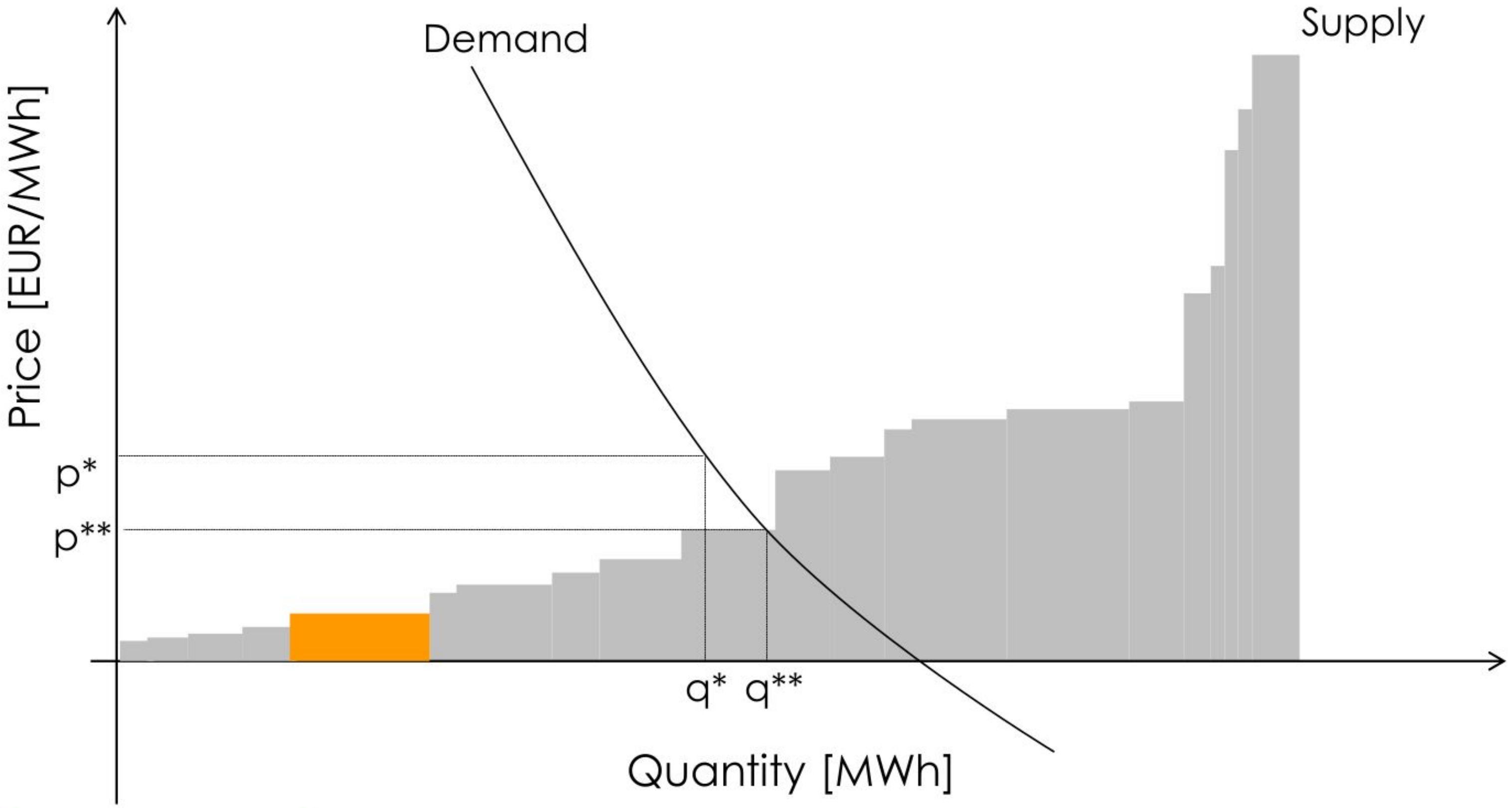
Why negative bids?

A unit that always receives a premium of 10 EUR/MWh still makes a marginal profit at a price of -9.9 EUR/MWh

*in schemes where the units are hourly settled and support is limited to max. the strike price

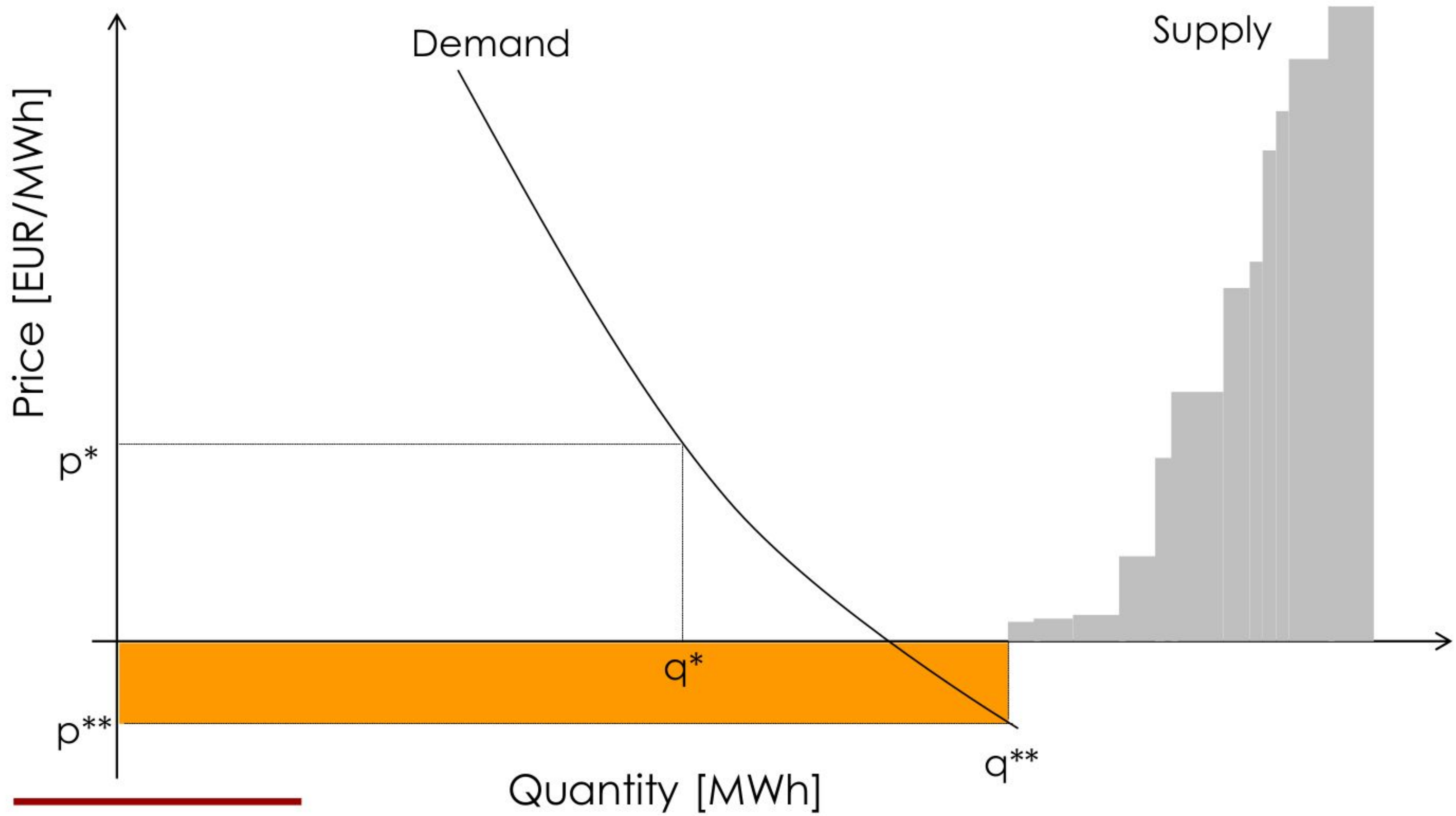
And what is the effect on market price if the park bid at marginal cost?

The negative bidding incentives are not problematic when supported units are pure price takers (= at low market shares)



How would a supported wind park bid into the spot market – and what is the effect on market price?

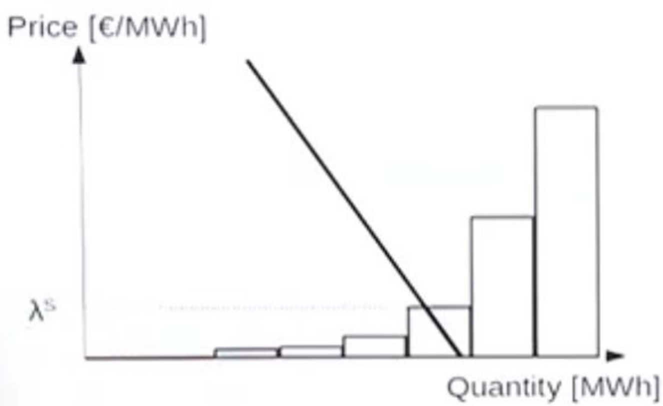
As soon as supported units become price setters (= at high market shares), we need adjustments of support scheme design



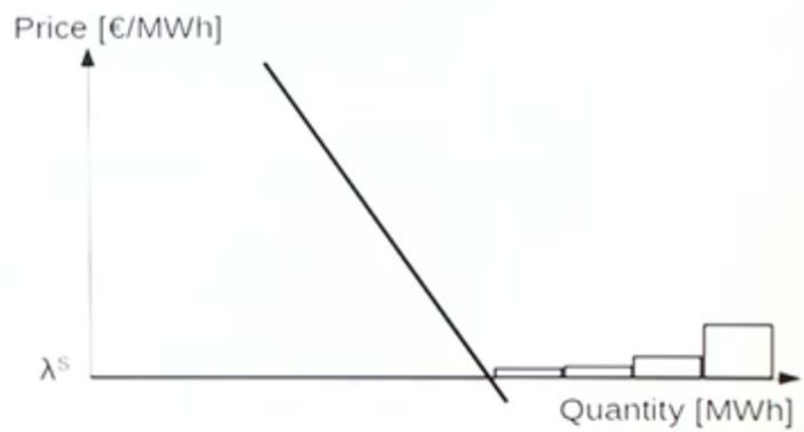
How to deal with negative prices?

- The regulator states that if clearing prices are negative, market participants lose their support (CfD and FIP)
- For both support scheme, the optimal strategy is then to offer at 0 €/MWh

- Only a few of them



- Quite many more



- Clearing prices still decrease, but they never become negative

Effects of renewable introduction

Increase introduction of renewables:

$\longrightarrow$ reduce prices on energy markets
$\longrightarrow$ increase system cost

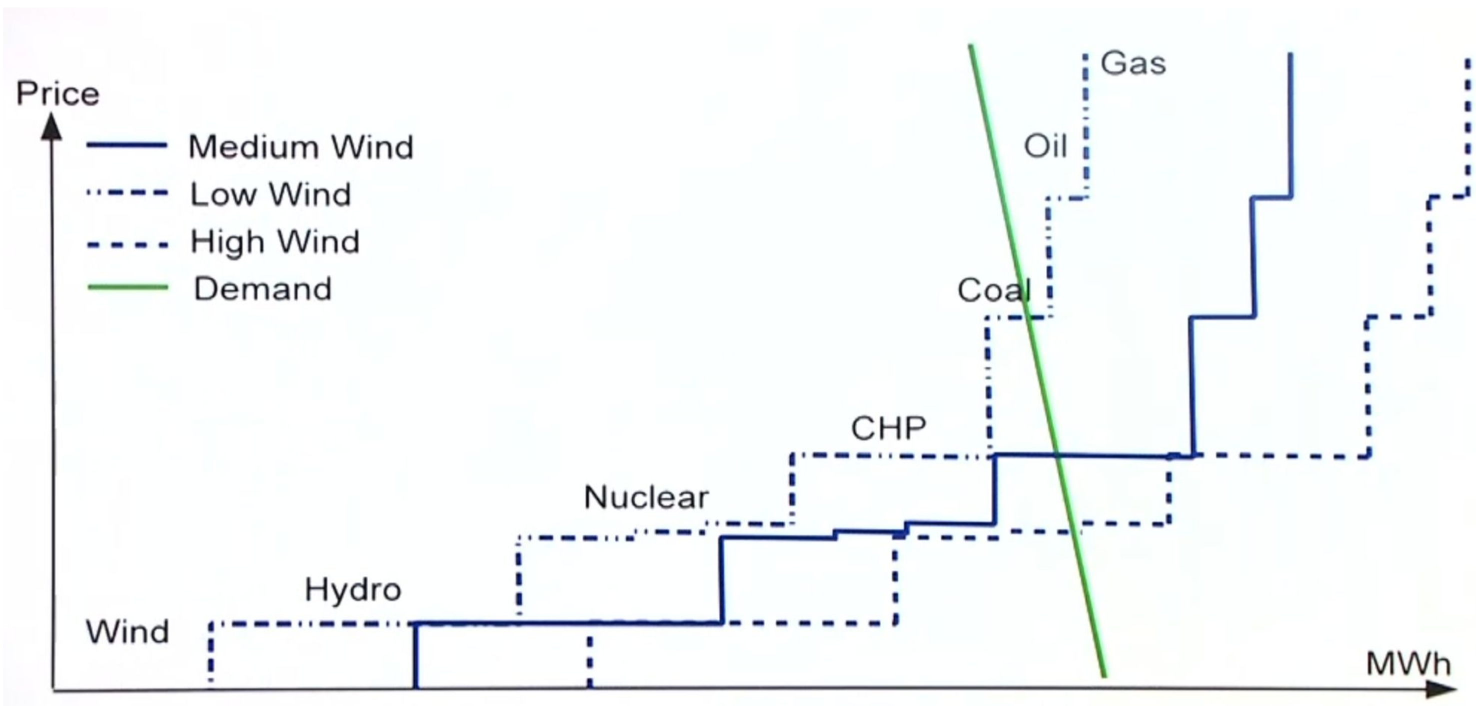
Let’s analyze that for two different kinds of renewable generation:

$\longrightarrow$ industrial production level
$\longrightarrow$ prosumer level

Industrial level

Renewable energy generally bid at 0.

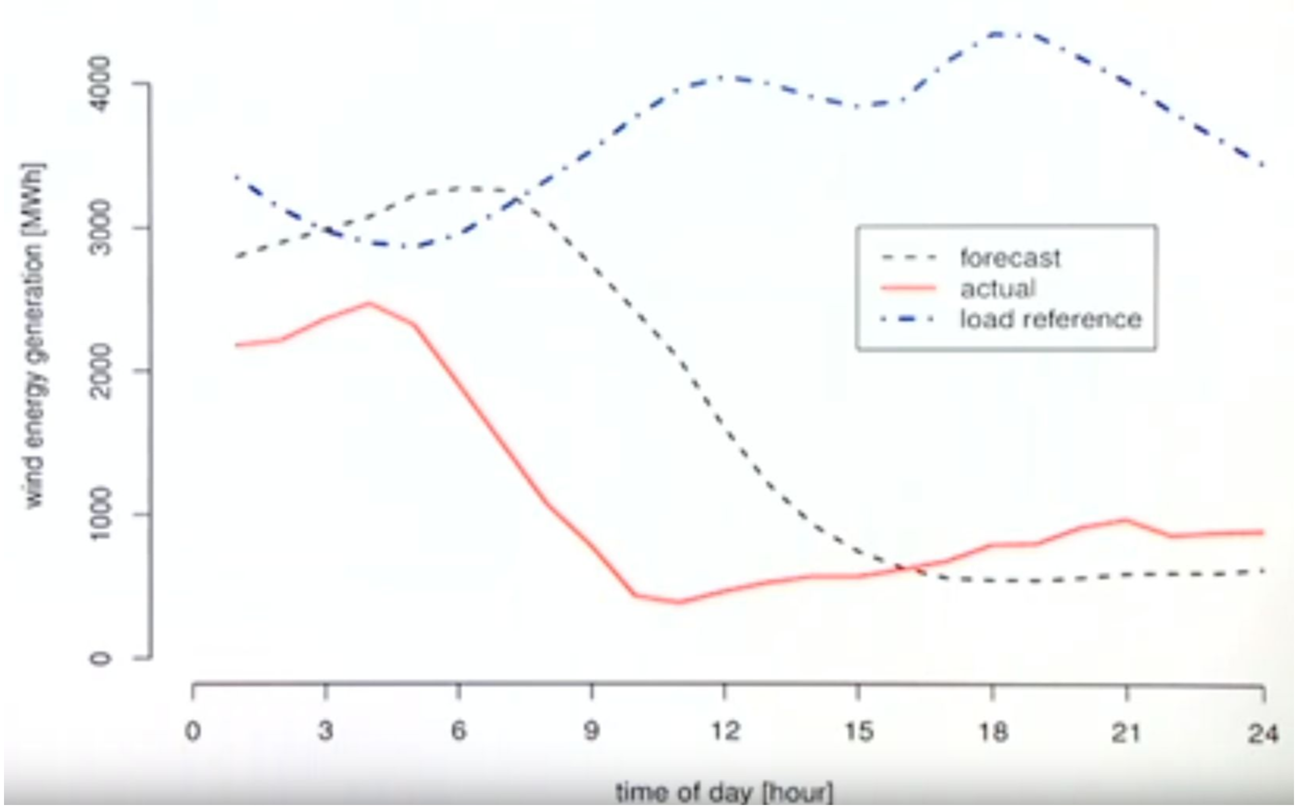
Impact on the merit-order curve:
1. High renewable generation → low prices
2. Low renewable generation → high prices



A rising need for reserve

Fluctuations of renewables and forecast errors lead to:

1. increase need for balancing reserves
2. impacts the system costs



Prosumer level

Typically, company or households possessing solar panels

→ Initial investment but reduce the electricity bill

→ Can generate overtensions on the network and damage it

Currently, PV owners do not pay for the service of the network.

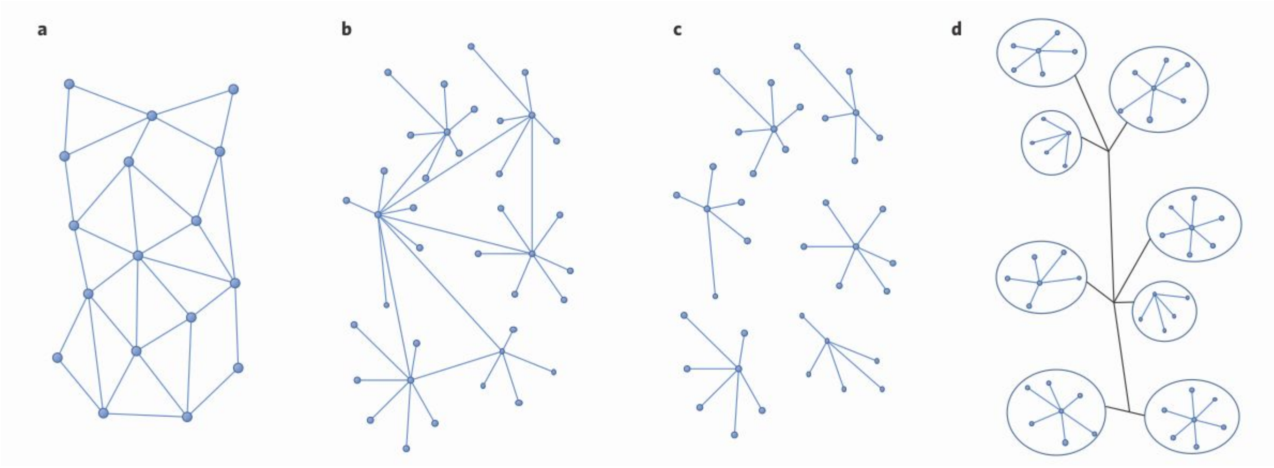
→ Might change rapidly in the future e.g. tax on capacity installed

Source: https://pangea.stanford.edu/news/stanford-engineers-create-low-cost-battery-storing-renewable-energy

Impacts on the markets

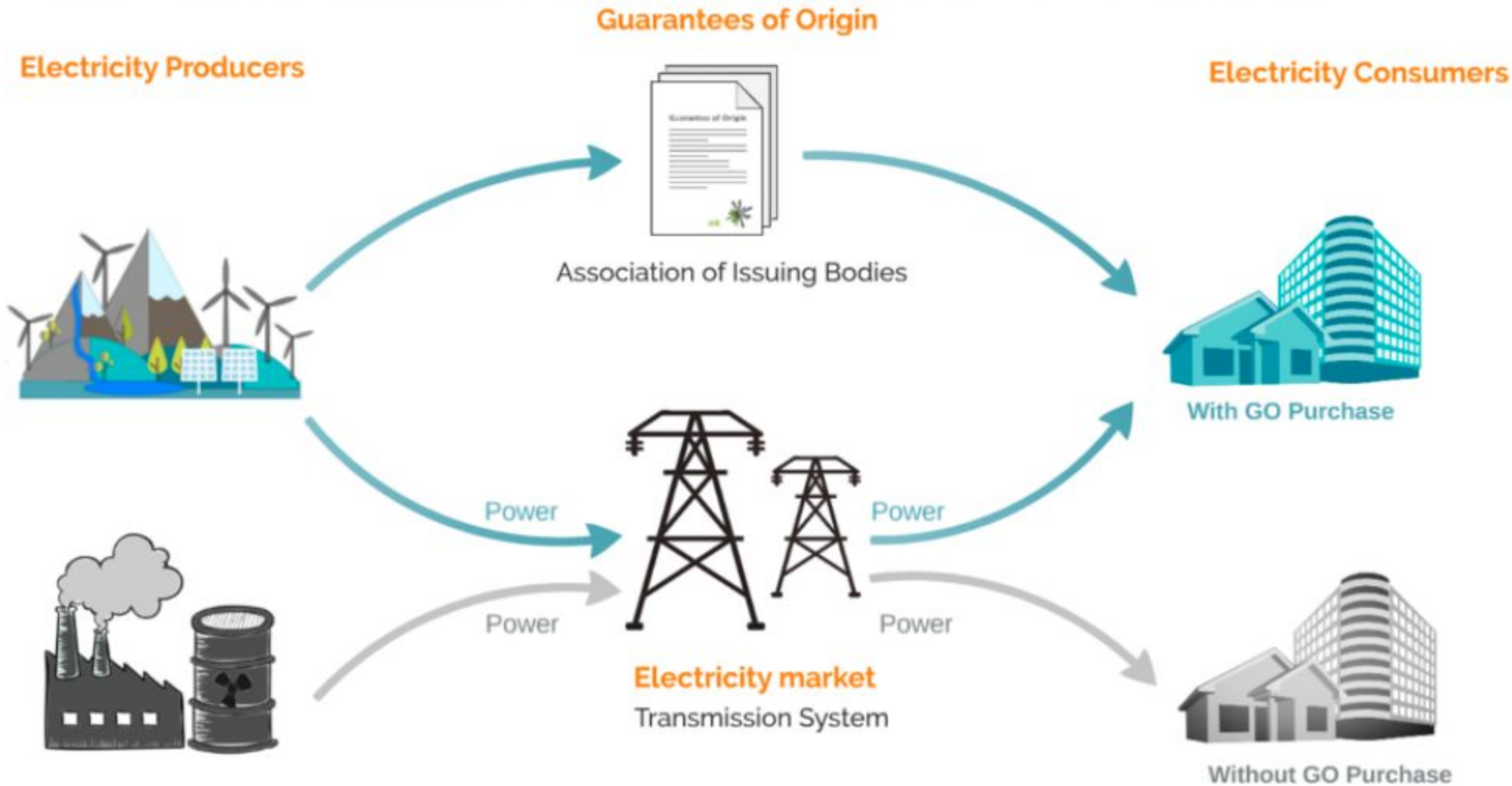
We are seeing the increase of new alternative markets:

Read *“Electricity market design for the prosumer era”*



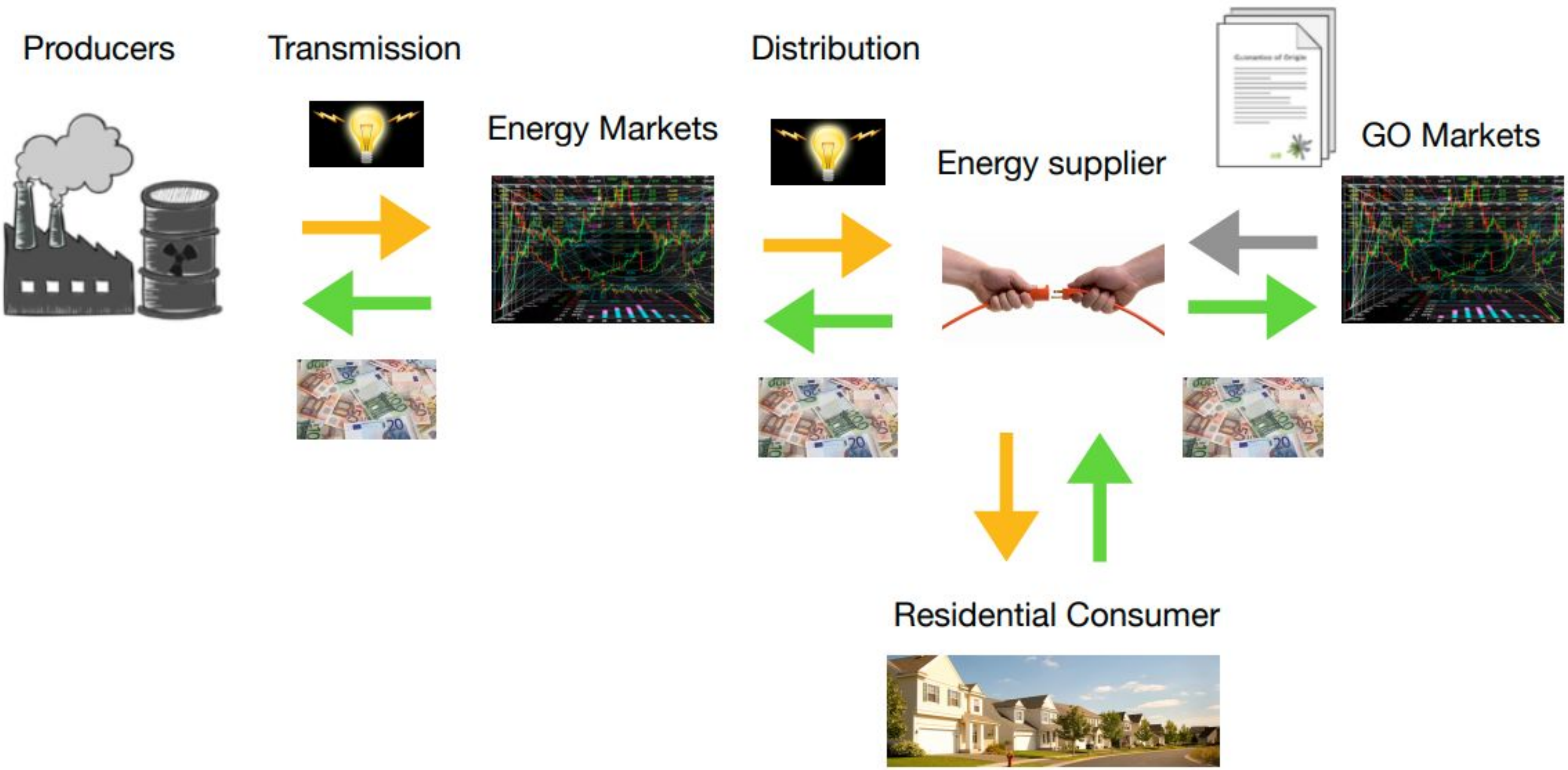
« Green » energy ? -> Guarantees of Origin (GO)

A Guarantee of Origin (GO or GoO) is a **tracking instrument** defined in article 15 of the **European Directive 2009/28/EC**
Source: https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0028

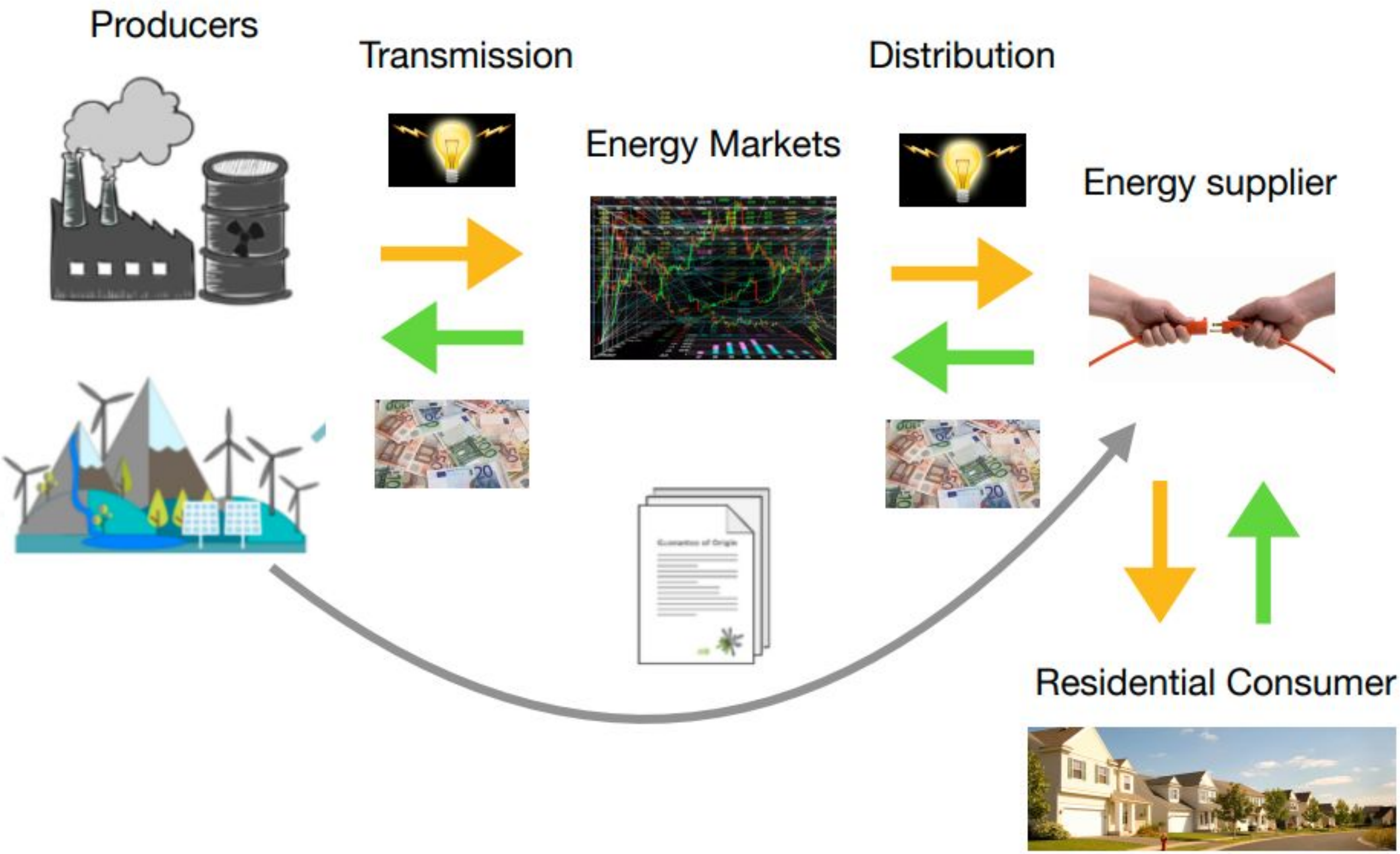


Source of following slides: Jonathan Dumas

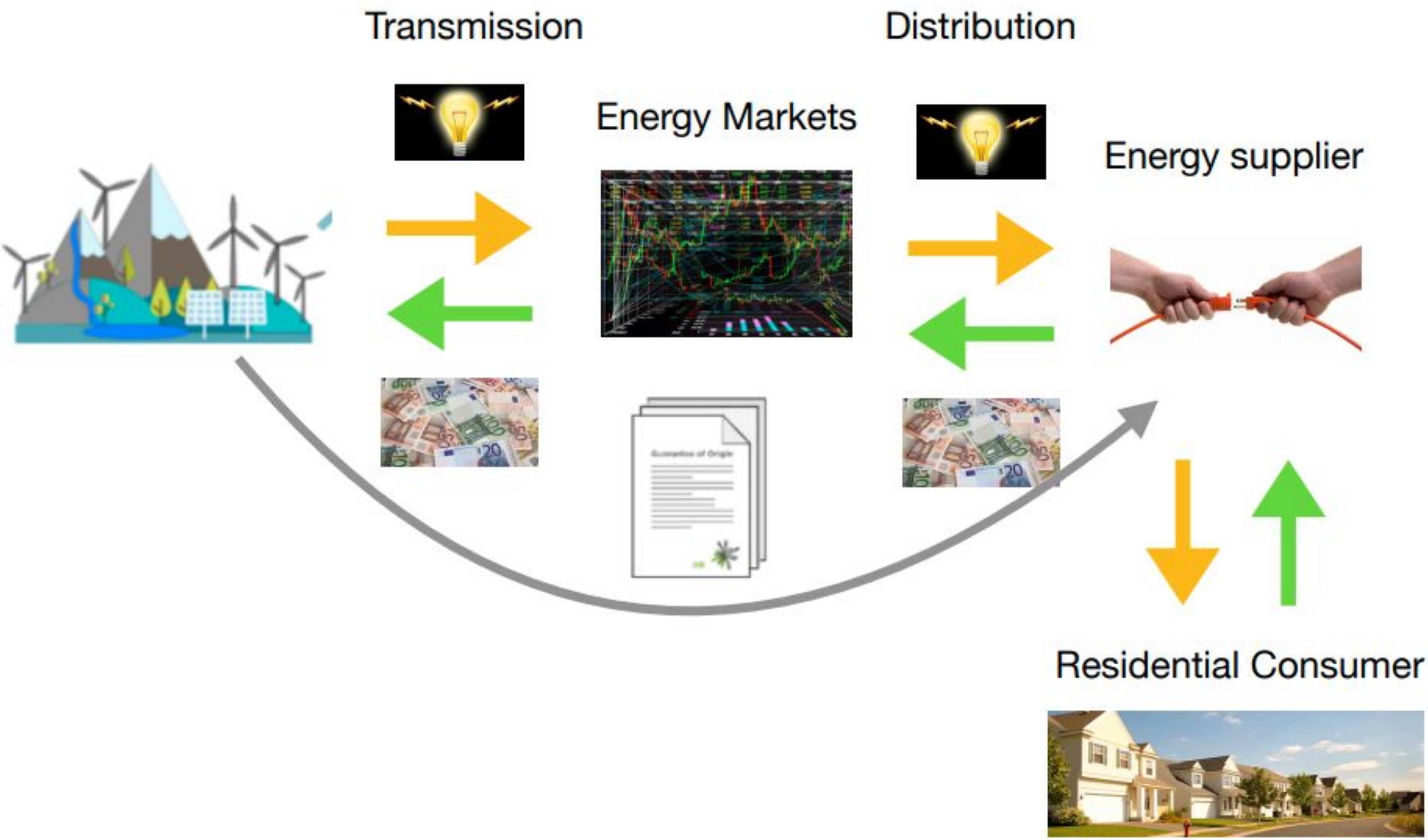
Non-« green » to « green » market offer



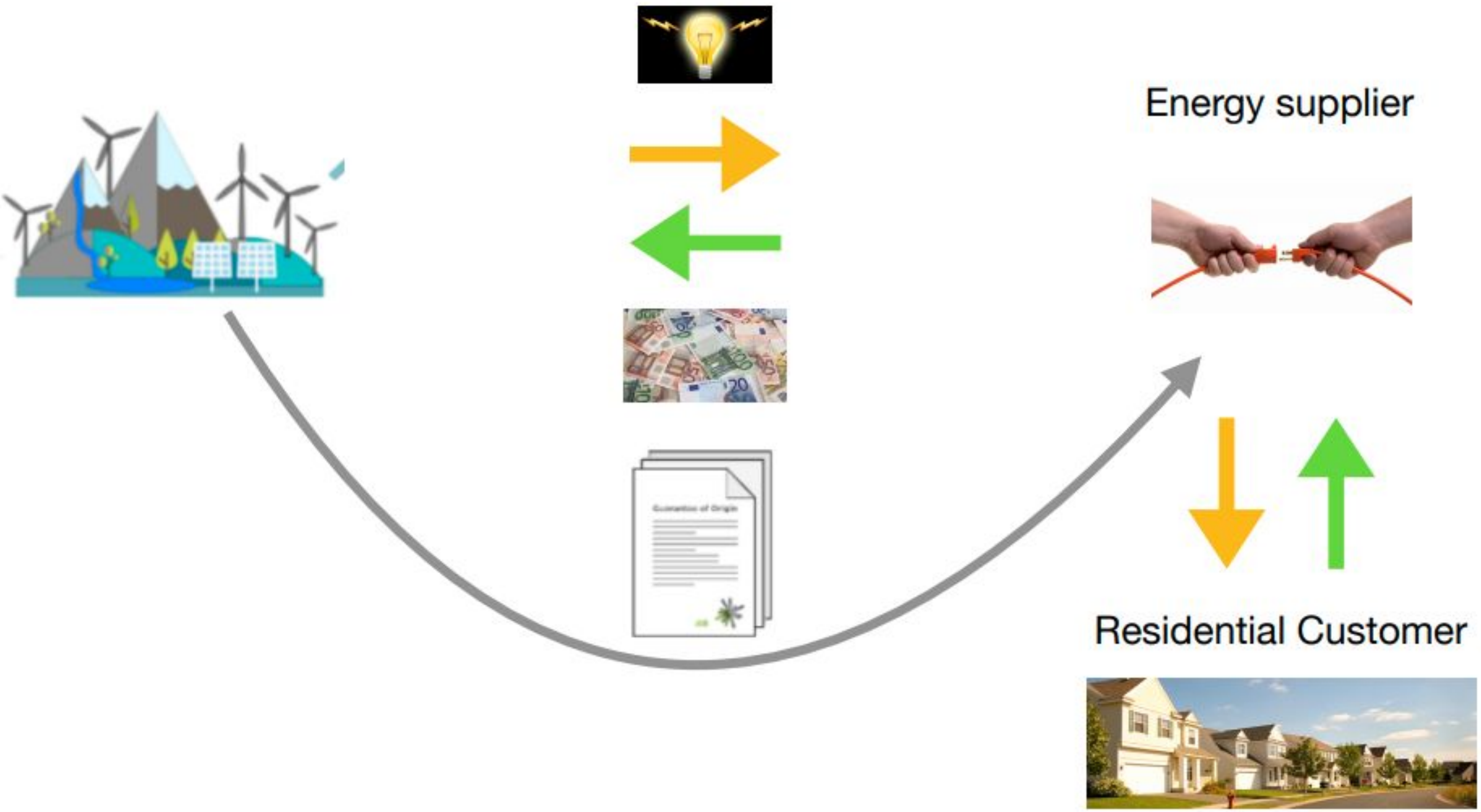
Mix « green » to « green » market offer



« Green » market offer



Direct « green » offer



Small recap

How an **energy supplier** **builds** a **residential electricity offer** ?

- **direct** to the producer -> money into the pockets of the producer
- **market** based offer -> money to a lot of market players
- **mix** **direct** - **market** based offer

What is a « **green »** energy offer ?

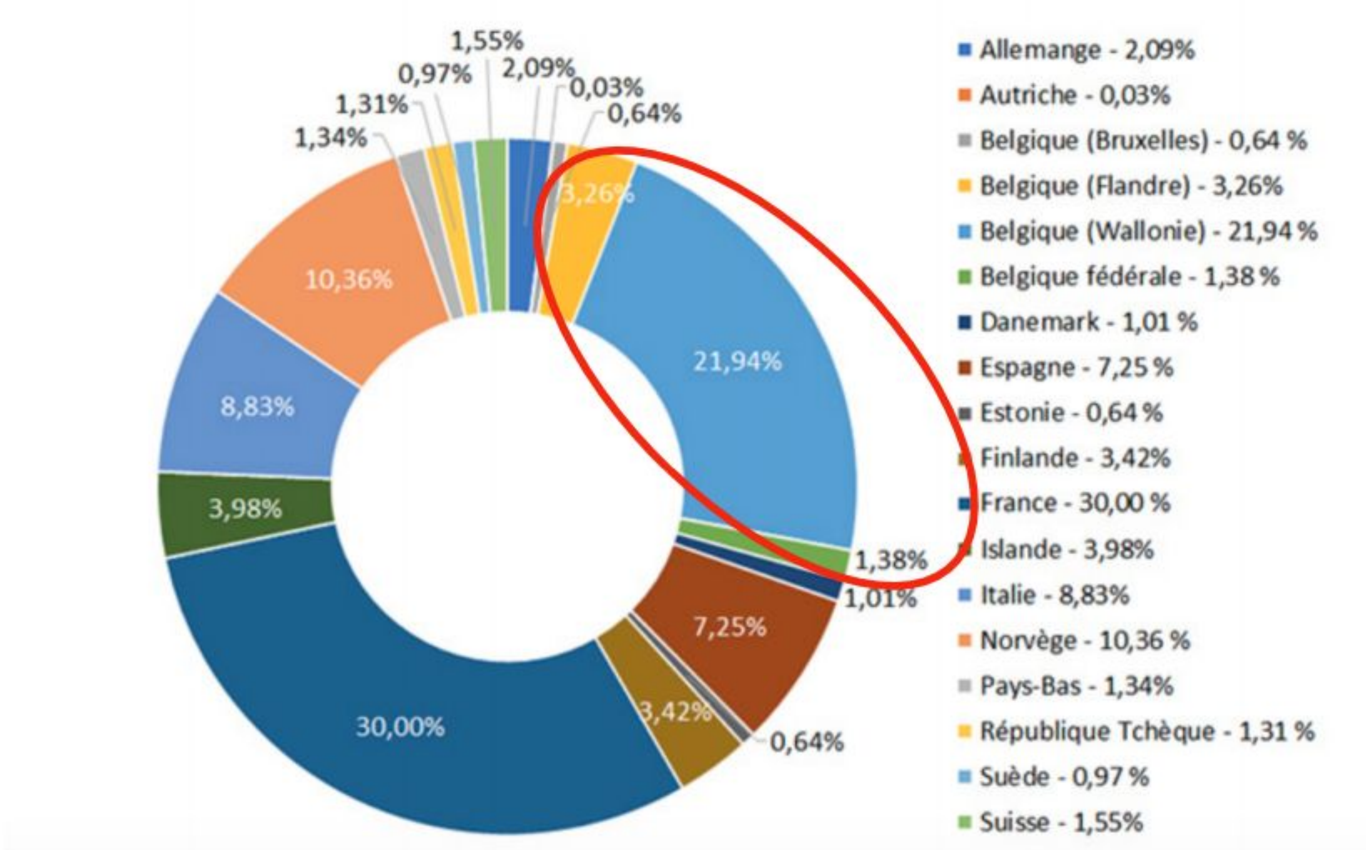
- **Guarantees of Origin** (GO)

« green » does not mean low carbon footprint !!!

Residential energy supplier

Walloon 2019 GO distribution per country

30% GO from Belgium



Source: https://www.cwape.be/?dir=4.12.1

Conclusion

It is impossible to compare energy suppliers on GOs ...

Some possible criteria:

- energy mix
- **carbon footprint** of the energy mix
- financial **transparency**
- **Belgian GO** vs GO from other countries, etc
- direct, market-based offer ?
- Etc

« green » does not mean low carbon footprint !!!

Conclusion

- Electricity is special commodity.

- A plethora of markets and financial security mechanisms have been created to ensure that production always equals demand.

- These markets are evolving rapidly as our society tend towards a more decarbonate future.