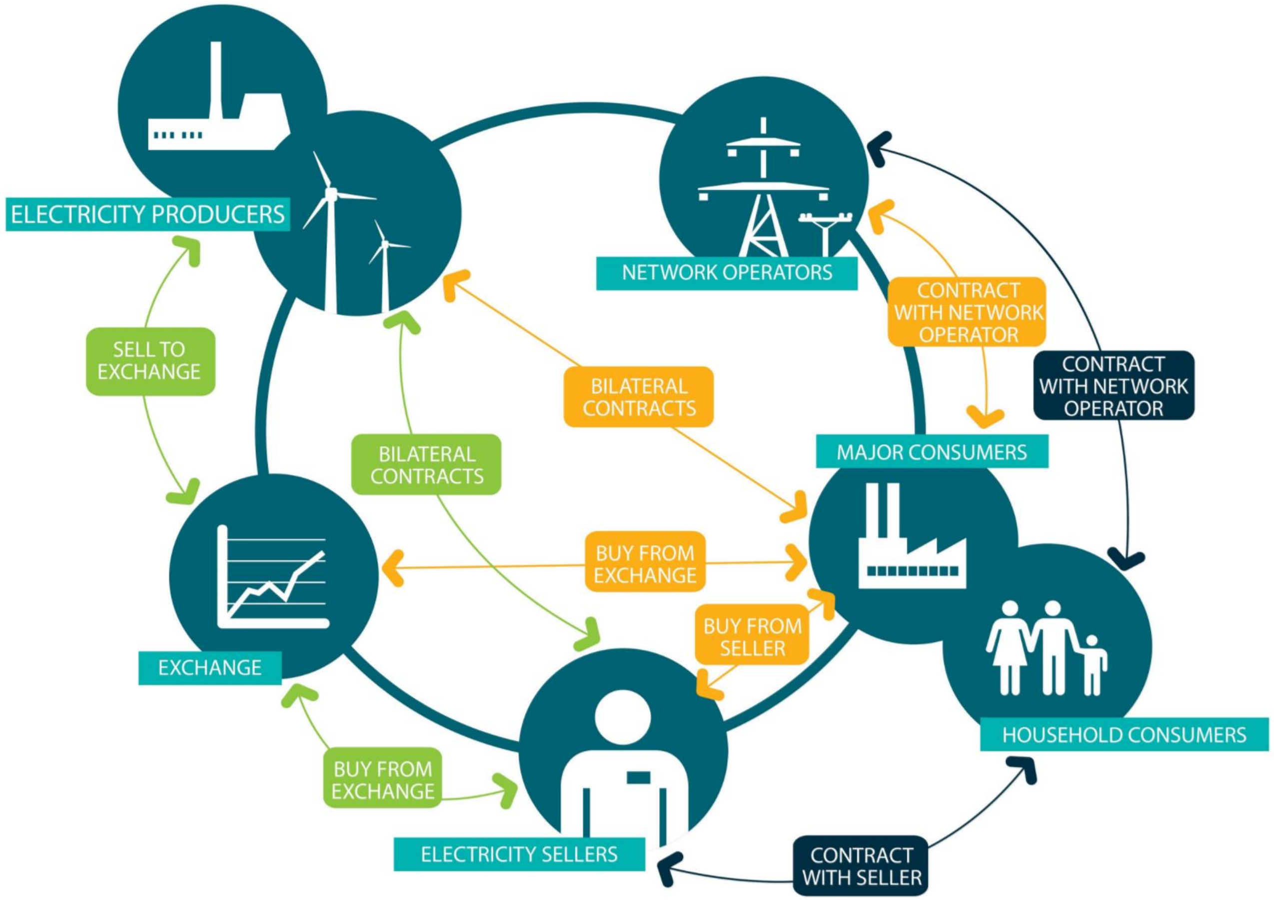
ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)



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Chapter 00 – Organisation of the course

Goals of the course

- Gain a comprehensive understanding of how electricity, gas, oil and carbon prices are determined, including the key factors that influence price fluctuations over time.
- Explore the structure of electricity, gas, oil and carbon markets, including key players (e.g., producers, suppliers, retailers, regulators, consumers), and how these markets have evolved. Be able to critically assess the pros and cons of these schemes.
- Analyse the impact of current political decisions and policies such as renewable energy incentives, carbon pricing, and energy regulations on the future cost and accessibility of electricity.
- Develop an understanding of the economic relationships between electricity and other energy carriers such as gas, oil and renewables, and how shifts in one energy sector can influence pricing and availability in others.
- Equip yourself with the knowledge to predict future trends in the energy sector, taking into account both market and policy changes.

Course guidelines and evaluation criteria

- Attendance in the course is **mandatory**.

- The course will include:
  - Plenary lectures given by Damien Ernst and invited guests,
  - Plenary lectures given by prestigious invited speakers, whose teaching material is available on the class website: https://damien-ernst.be/teaching/elec0018-1-energy-markets/,
  - Weekly reading assignments of scientific papers,
  - Evaluations based on the readings,
  - Group presentations of the readings.

- Grading will be based on the following:
  - Evaluation of the reading assignments (25%),
  - Group presentation of the reading (25%),
  - Oral exam (50%).

- For the second session, grades will be based on a new scientific paper presentation (50%) and an oral exam (50%).

Content of the course

The course is divided into chapters as follows:

Communications and questions

For questions about the organisation or content of the class:

- Preferred option: Discuss with the instructors after class.
- Email: Contact via email at matthias.pirlet@uliege.be.

References (1/3)

The materials (books, lectures, journals, reports) used to develop Chapters 1 to 14, excluding Chapter 11 presented by a guest speaker, are listed below in order from the most recent to the oldest. The sources for the figures and data used in the course are provided in footnotes on the corresponding slides.

Peeters, C. & Elia. (2023). *Elia publishes its adequacy & flexibility study for Belgium for the period 2024-2034*. [Press-release]. https://www.elia.be/-/media/project/elia/shared/documents/pressreleases/2023/20230629_pressrelease_adeqflex_en.pdf

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Dumas, J. (2021). *Energy Markets Retailers*. [Course presentation]. University of Liege. https://github.com/jonathandumas/ELEC0018-1-energy-markets-retailers

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https://bcornelusse.github.io/material/CoursEM20170331.pdf

Hansen, J.-P., Percebois, J. (2017). *Transition(s) électrique(s).* Éditions Odile Jacob.

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Morales, J., Conejo, A., Madsen, H., Pinson, P., Zugn, M. (2014). *Integrating Renewables in Electricity Markets.* Springer.

References (3/3)

Lahaie, S. (2009). *How to take the dual of a linear program*. http://slahaie.net/docs/lpdual.pdf

European Wind Energy Association, Morthorst, P.-E., Awerbuch, S., Krohn, S., Awerbuch, S., Morthorst, P. E., Soren Krohn Consulting, Science and Technology Policy Research, University of Sussex, & Risoe National Laboratory. (2009). *The economics of wind energy*. Krohn, S. Ed. https://www.ewea.org/fileadmin/files/library/publications/reports/Economics_of_Wind_Energy.pdf

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Chapter 01 – Motivation of the course

Introduction to energy markets

Energy plays a key role in economic activities, **making both the availability and cost of energy sources critical factors for economic development and social well-being**. Consequently, governments have established policy objectives to improve the availability, affordability, and sustainability of energy.

The term ‘energy markets’ refers to a complex system in which producers, transport and distribution operators, traders, and consumers interact to achieve their respective objectives. **These markets include electricity, gas, oil, coal, and other energy-related commodities, such as carbon dioxide (CO_2).**

The electricity, gas, oil, and carbon markets are interlinked. Oil and gas are key fuels for electricity generation in many regions, meaning their prices directly influence electricity costs. Additionally, rising CO_2 prices increase the cost of electricity produced from fossil fuels, which can drive greater demand for cleaner energy alternatives.

For these reasons, this course will examine all these markets, with an emphasis on electricity markets.

Why study electricity markets?

Reasons to study electricity markets

There are three main reasons to study electricity markets:

Reason 1:

Electricity will become more and more prominent in our societies.

Reason 2:

The electricity markets have entered a phase where common approaches are challenged.

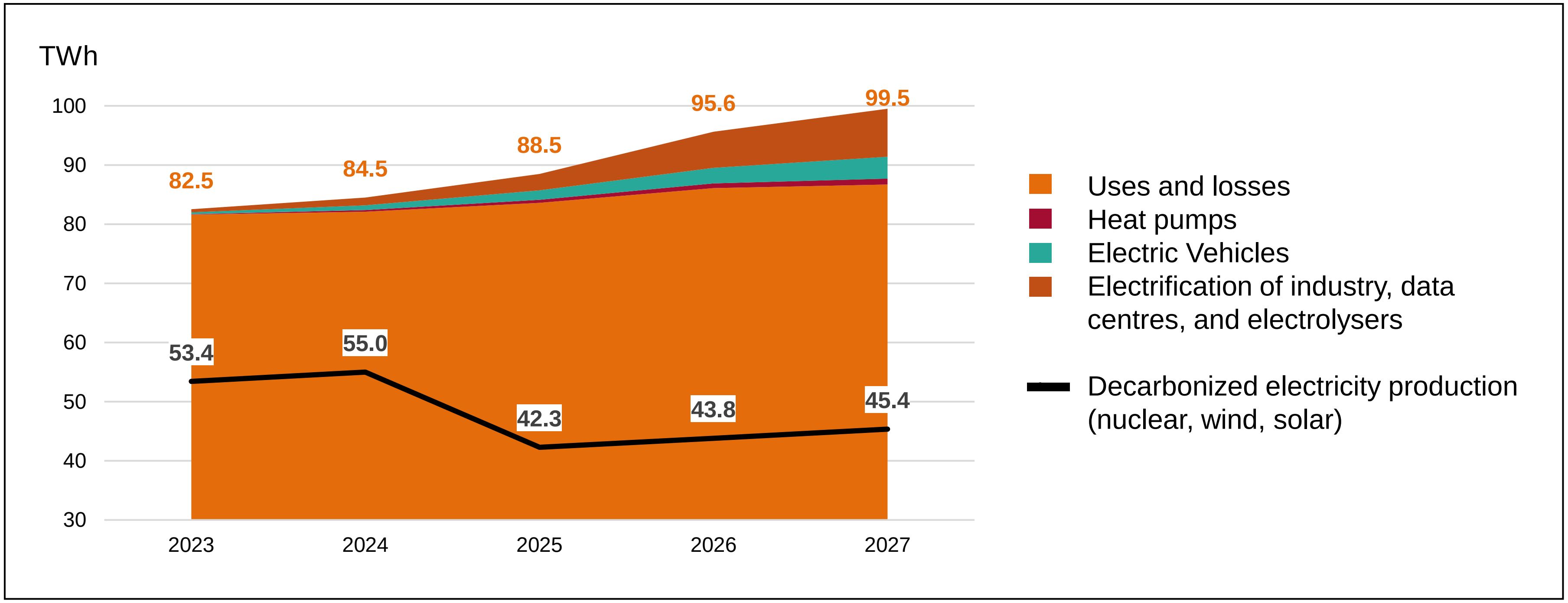
Reason 3:

More and more opportunities to become an active user in electricity markets even if you are a small consumer.

Electricity will become more and more prominent in our societies

Future electricity consumption in Belgium is expected to increase due to rising demand from industries, electrification of transport, and heating systems.

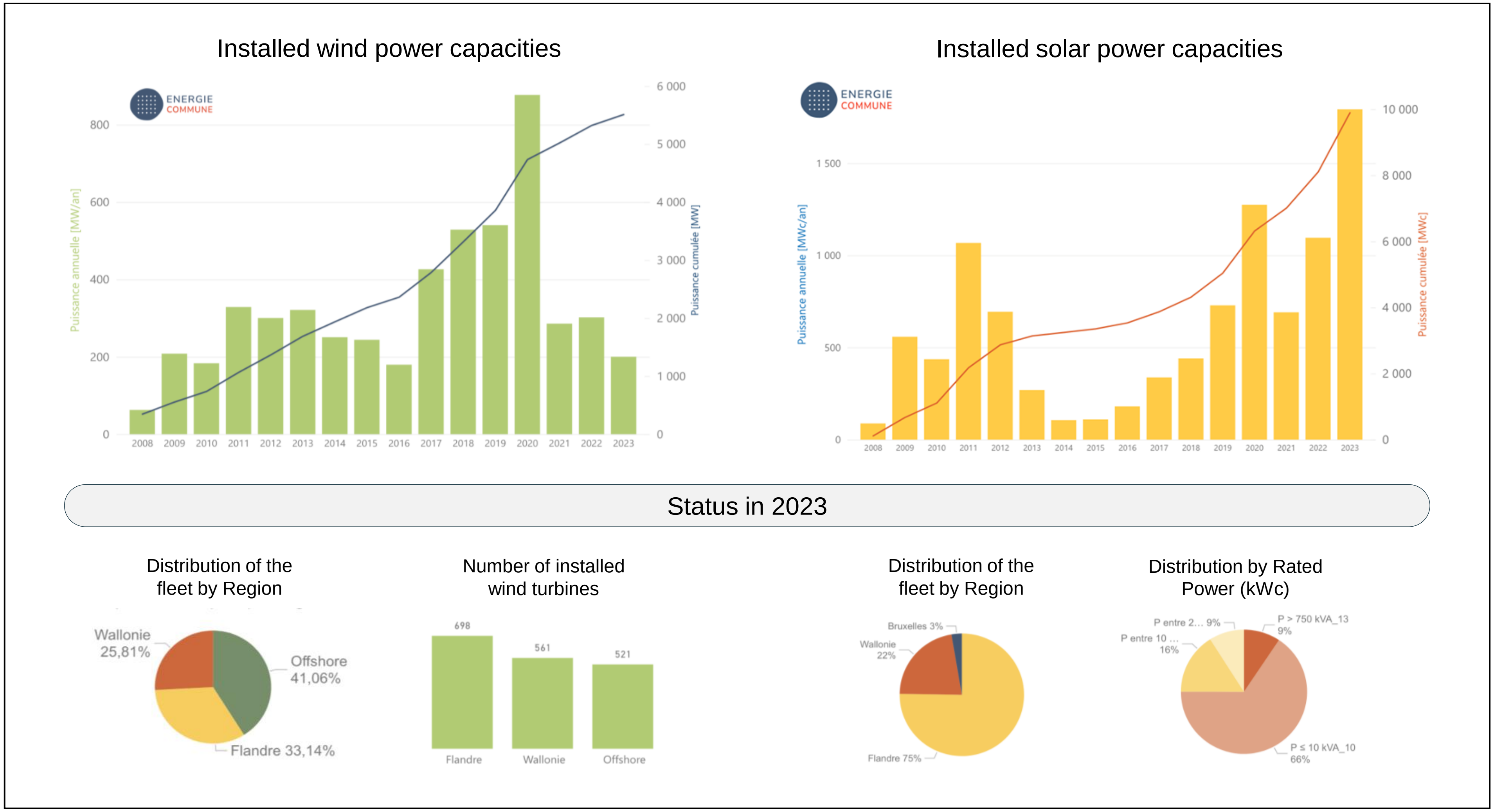
However, consumption trends could vary with advancements in grid flexibility, policy shifts, and energy-saving efforts aimed at balancing this growth. The role of renewables and electrification in sectors like transport will also significantly influence future demand.



Assumed future yearly electricity consumption in Belgium, by Elia (2023). There is a significant gap between decarbonized electricity production and the ever-increasing electricity consumption.[1]

[1]https://www.elia.be/-/media/project/elia/shared/documents/press-releases/2023/20230629_pressrelease_adeqflex_en.pdf

The electricity markets have entered a phase where common approaches are challenged



Evolution of installed wind and solar energy capacities in Belgium + 2023 figures.[1]

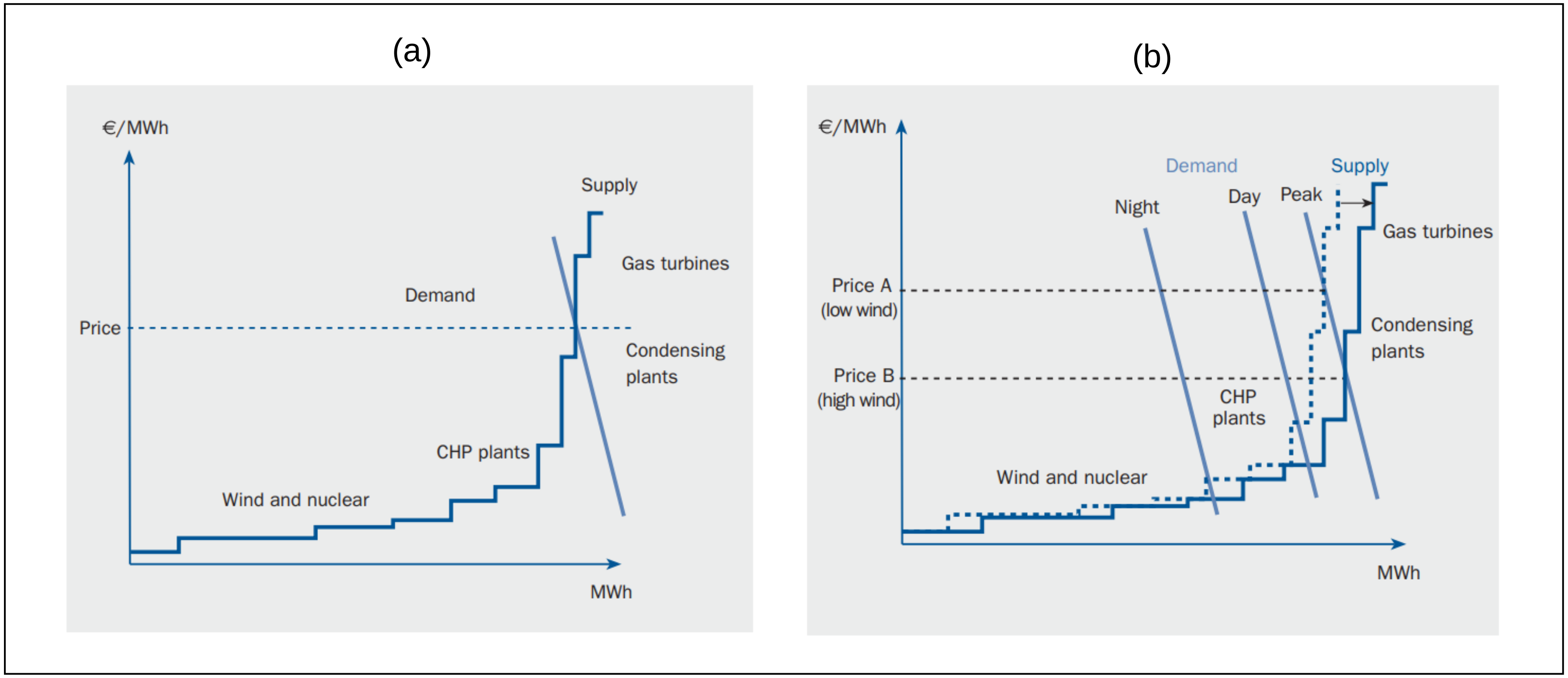
The rise of renewable energy is good news for CO_2 emissions, but the rise of renewables has brought new challenges.

[1]https://www.renouvelle.be/

First challenge: the need for capacity markets

The first challenge is the need to introduce **capacity markets**. As renewables drive prices down, it becomes harder to secure funding for capital expenditures (CAPEX). Electricity prices can even drop to very low levels or become negative.

If we only compensate for energy volumes, no investments would be profitable anymore!



(a) Supply and demand curve for the NordPool Power Exchange and
(b) how wind power influences the power spot price at different times of day.

[1]https://www.ewea.org/fileadmin/files/library/publications/reports/Economics_of_Wind_Energy.pdf

Second challenge: difficulties to balance the system (1/2)

The second challenge is that the deployment of renewable assets creates additional difficulties for Balance Responsible Parties (BRPs) in maintaining the balance between production and consumption. This requires further development of flexibility markets.

Electricity supply, especially from renewable energy sources, is also difficult to predict due to weather conditions:

- **PV with partially cloudy weather**: It is hard to predict when clouds will cover a photovoltaic (PV) installation.

- **Thunderstorms**: Predicting the exact moment when wind farms will reach their cut-off speed is challenging.

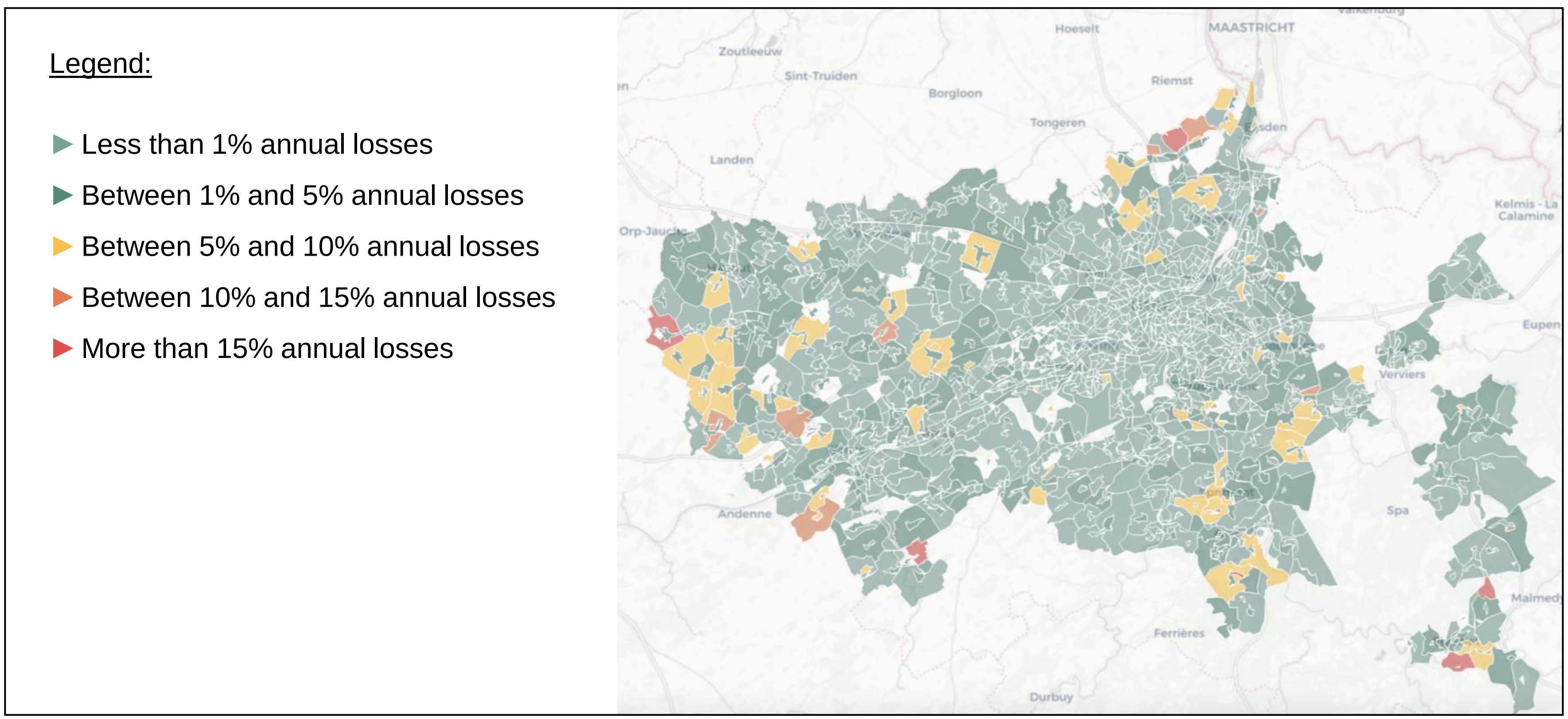
- **Dust storms**: Their impact on PV production is particularly difficult to forecast.

Additionally, congestion can occur in major power lines within a region, potentially leading to generation curtailment.

Third challenge: network issues

The third challenge is that renewables can lead to congestion and voltage issues on transmission and distribution networks. For instance, photovoltaic (PV) generation can cause overvoltage. When overvoltage is detected, PV production may be curtailed to protect the network.

Such issues on the distribution network call the need for new markets or revised market rules specifically designed to address these problems. One example is the development of **local flexibility markets.**



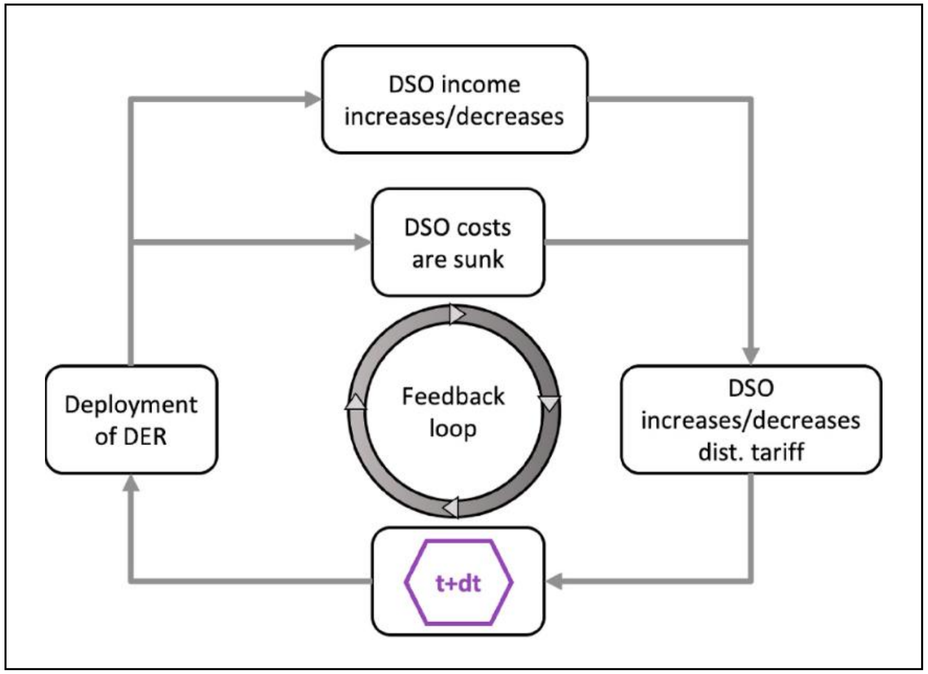
Inverter decoupling in the province of Liège, Belgium.

Fourth challenge: ‘death spiral’ of utilities

The utility grid death spiral refers to a vicious cycle where more consumers adopt distributed energy resources (such as rooftop solar panels), leading to a decline in utility revenues.

As more people generate their own electricity, utilities raise prices to cover the fixed costs of maintaining the grid, which in turn causes even more consumers to leave the grid or reduce their reliance on it.

In Wallonia, a region of Belgium, the introduction of the **prosumer tariff** is linked to this concern, as well as the need to fairly distribute grid maintenance costs.



Multi-agent interaction model with the feedback loop created by the deployment of residential PV panels and by the DSO's remuneration mechanism.[1]

[1]https://doi.org/10.1016/j.enpol.2020.112065

Reason 3: From passive consumer to active participant

To enable a small consumer to actively participate in electricity markets, the first step is transitioning away from fixed electricity pricing.

Prix fixes de l'énergie - 1 an

Redevance fixe [1]		Prix par kWh (€cent/kWh)						Coûts énergie verte [5]
61,48 €/an		Type d'usage	Normal	Bihoraire Heures pleines	Bihoraire Heures creuses	Exclusif Nuit		(€cent/kWh)
	+	Consommation [2]	23,513	24,764	20,247	20,247	+	2,996
	−	Injection [3]	7,802	9,468	3,576			

Coûts de réseaux (distribution et transport) [6]

Gestionnaire du réseau de distribution	Distribution						Transport
	Normal	Bihoraire Heures pleines	Bihoraire Heures creuses	Exclusif Nuit	Activité de mesure Relevé annuel	Tarif prosumer [7]	Transport
	€cent/kWh	€cent/kWh	€cent/kWh	€cent/kWh	€/an	€/kWe/an	€cent/kWh
TECTEO - RESA	9,34	10,37	5,87	5,16	24,90	67,62	2,61

Suppléments

Suppléments (€cent/kWh)	
Cotisation sur l'énergie	0,20417
Redevance raccordement [8]	0,07500

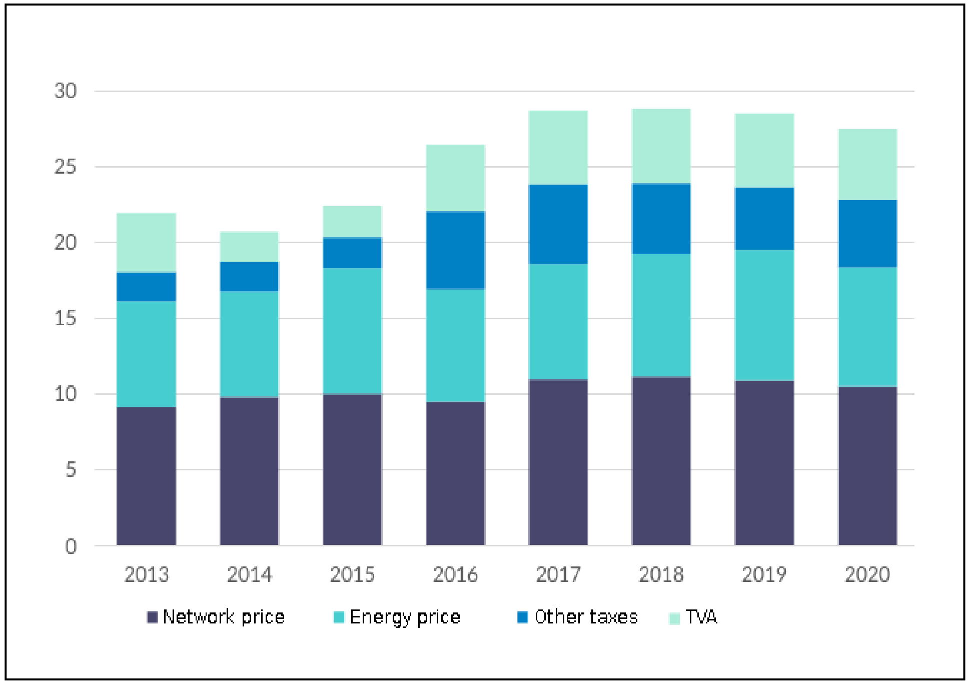
Accise fédérale [11] (€cent/kWh)	
Consommation entre 0 et 3.000 kWh	4,51300
Consommation entre 3.000 et 20.000 kWh	5,03288
Consommation entre 20.000 et 50.000 kWh	4,81876

Data for May 2023 for a residential customer located in the Walloon Region, Belgium, and connected to the RESA network.

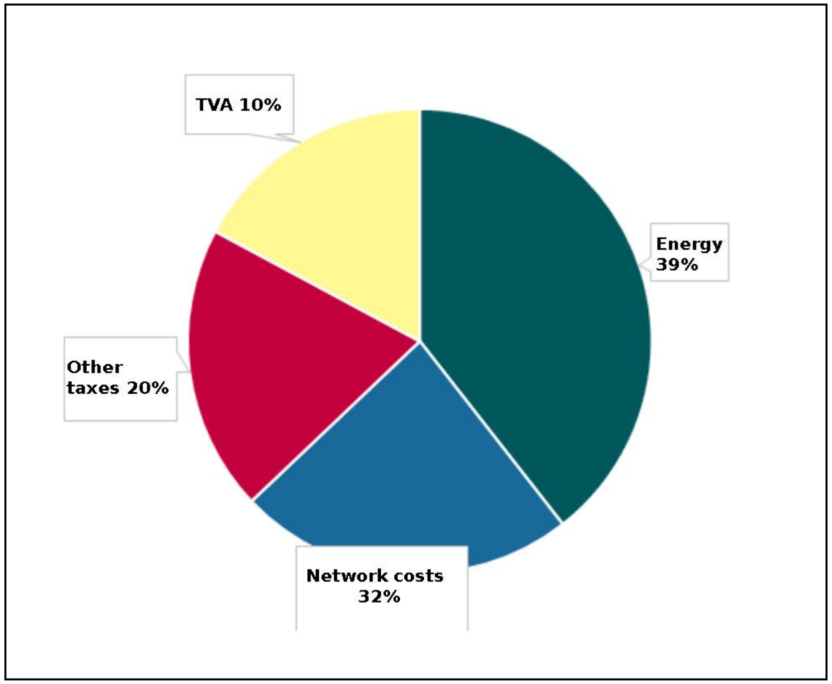
There are few opportunities to reduce your electricity bill

In 2023, the average residential electricity price in Belgium was approximately €0.382/kWh. The average energy consumption per household ranged from 2.5 to 5 MWh per year, resulting in an annual electricity cost of roughly €950 to €1,910.

It is important to note that less than 50% of this price is attributed to the energy itself, and only this portion is influenced by electricity market fluctuations.



Electricity market in 2020: Evolution in eurocents/kWh for consumption band DC (2,500–5,000 kWh/year).[1]



Breakdown of electricity prices in Wallonia, Belgium, October 2021.[2]

[1]https://economie.fgov.be/fr/publications/energy-key-data-fevrier-2022

[2]https://www.creg.be/fr/consommateurs/prix-et-tarifs/comment-est-compose-le-prix-de-lenergie

Now, there are contracts where the price paid for energy varies hourly (contracts indexed to the day-ahead price)

EPEX Spot day-ahead auction status in Belgium on September 13, 2024.[1]

[1]https://www.epexspot.com/en/market-data

And you can start benefiting of short supply chains for energy

Consumers are increasingly concerned about the origin of the electricity they consume, seeking **transparency** regarding its sources and environmental impact.

Additionally, the electricity sector is influenced by the '**short supply chain**' trend, where consumers prefer locally produced electricity from renewable sources. More than just a trend, this short supply chain approach offers several benefits:

- it helps reduce transmission losses,
- it prevents local overvoltage,
- it enhances supply security,
- it supports the local economy.

This has led to the development of **energy communities** and specific types of Power Purchase Agreements (PPA).

Your time to work!

Try to answer the following question:

Why has the electricity bill of consumers risen so dramatically since 2021?

You have 30 minutes to answer this question.

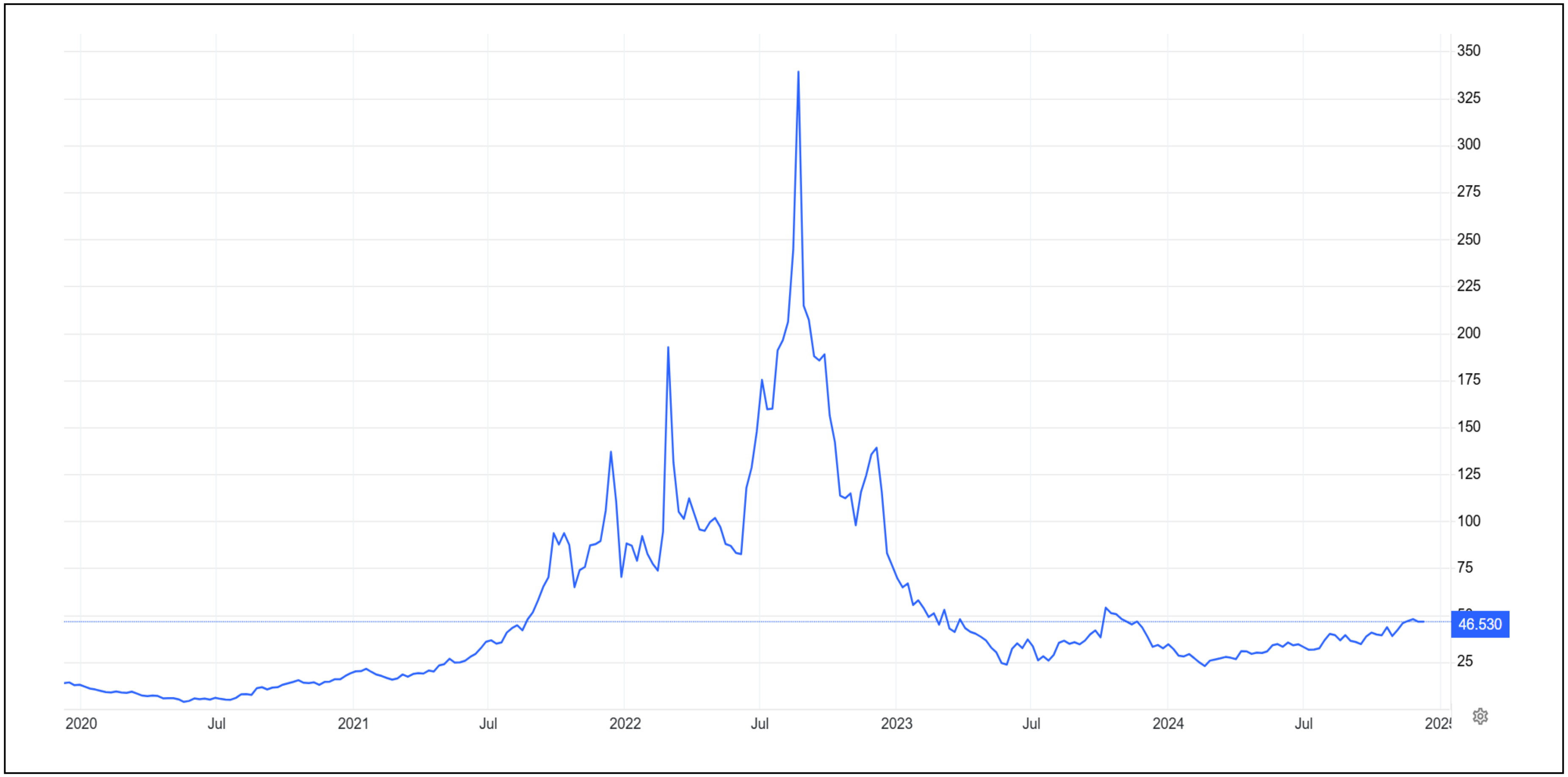
Find at least 3 sources: news articles, videos, scientific articles, etc.

i. Identify which reasons are highlighted in those articles
ii. Identify the main actors of the electricity sector
iii. Note all the terms that you do not understand

After 30 minutes, we will put our findings in common.

Why study gas markets?

A historic peak in natural gas prices in 2022 (1/2)



Natural Gas EU Dutch TTF Pricing in €/MWh.[1]

[1] https://tradingeconomics.com/commodity/eu-natural-gas

A historic peak in natural gas prices in 2022 (2/2)

The most evident answer to the previous question concerns the surge in natural gas prices in Europe, which significantly impacted gas and electricity bills in several European countries and caused an unprecedented energy crisis.

European natural gas prices reached unprecedented highs, exceeding €300/MWh in August 2022 on the **Natural Gas EU Dutch TTF**. The TTF is the main benchmark for natural gas prices in Europe.

A **benchmark** is a reference point. In the context of markets, it represents a commonly accepted price, or index.

Gas-fired power plants as price setters

Gas-fired power plants account for approximately 200 GW of installed capacity in Europe, **representing around 25% of European electricity production**. In comparison, 20% of electricity comes from coal, 13% from nuclear energy, and 18% from renewables.

In European electricity markets, particularly in Germany, gas-fired power plants often act as **‘price setters’**, determining the marginal price. This occurs when demand exceeds the supply that lower-cost energy sources, such as solar or wind, can provide. In such cases, gas-fired plants step in to meet the demand, setting the electricity price because their marginal production cost is the highest among the technologies used to balance the grid.

The marginal cost of gas-fired power plants depends on several factors, including:

- **The price of natural gas**, the primary fuel these plants use.
- **The cost of CO_2 emissions**, as these plants are required to purchase carbon allowances to cover their greenhouse gas emissions under systems like the EU ETS (this will be detailed in Chapter 13, which focuses on carbon markets).

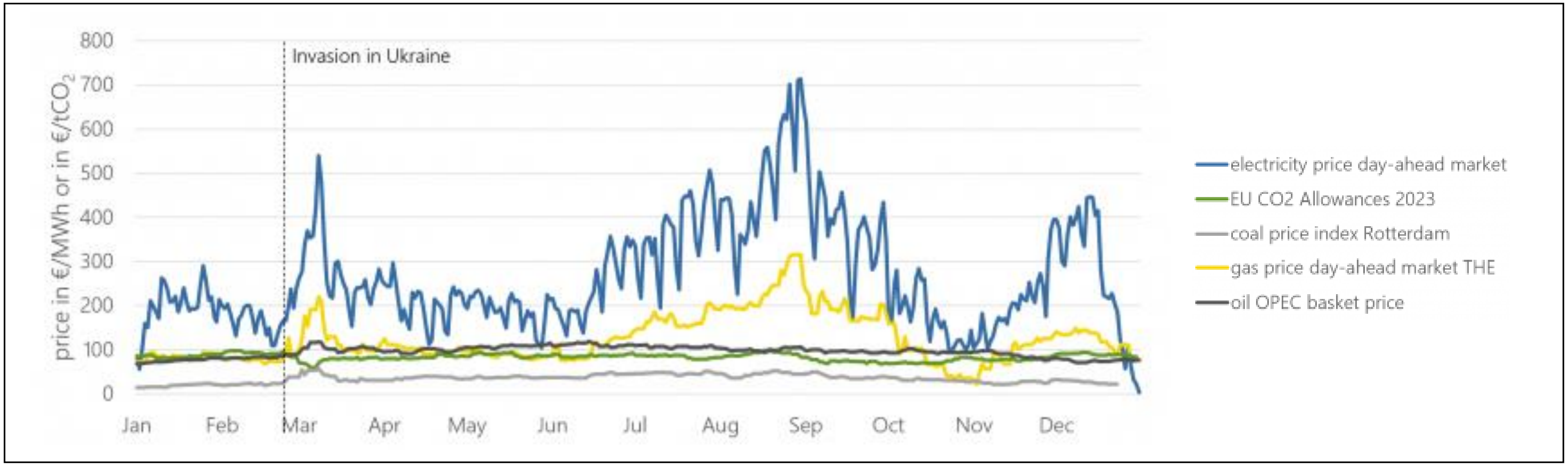
***Marginal cost refers to the additional cost of producing one more unit of electricity.

Example of the price increase in Germany

About 40% of the natural gas used in Europe comes from Russia.

- In 2021, gas prices began to rise due to reduced Russian gas supplies.
- The situation worsened in 2022 following Russia's invasion of Ukraine, leading to further supply restrictions. By March 2022, gas prices peaked at €220/MWh in Germany, nearly ten times the average price of €24/MWh in 2019–2021.
- The Nord Stream pipelines sabotage in September 2022 resulted in another price spike, with gas prices reaching €316/MWh on the day-ahead market.

As shown in the following figure, the fluctuations in electricity prices on the day-ahead market closely follow the trends in gas prices.



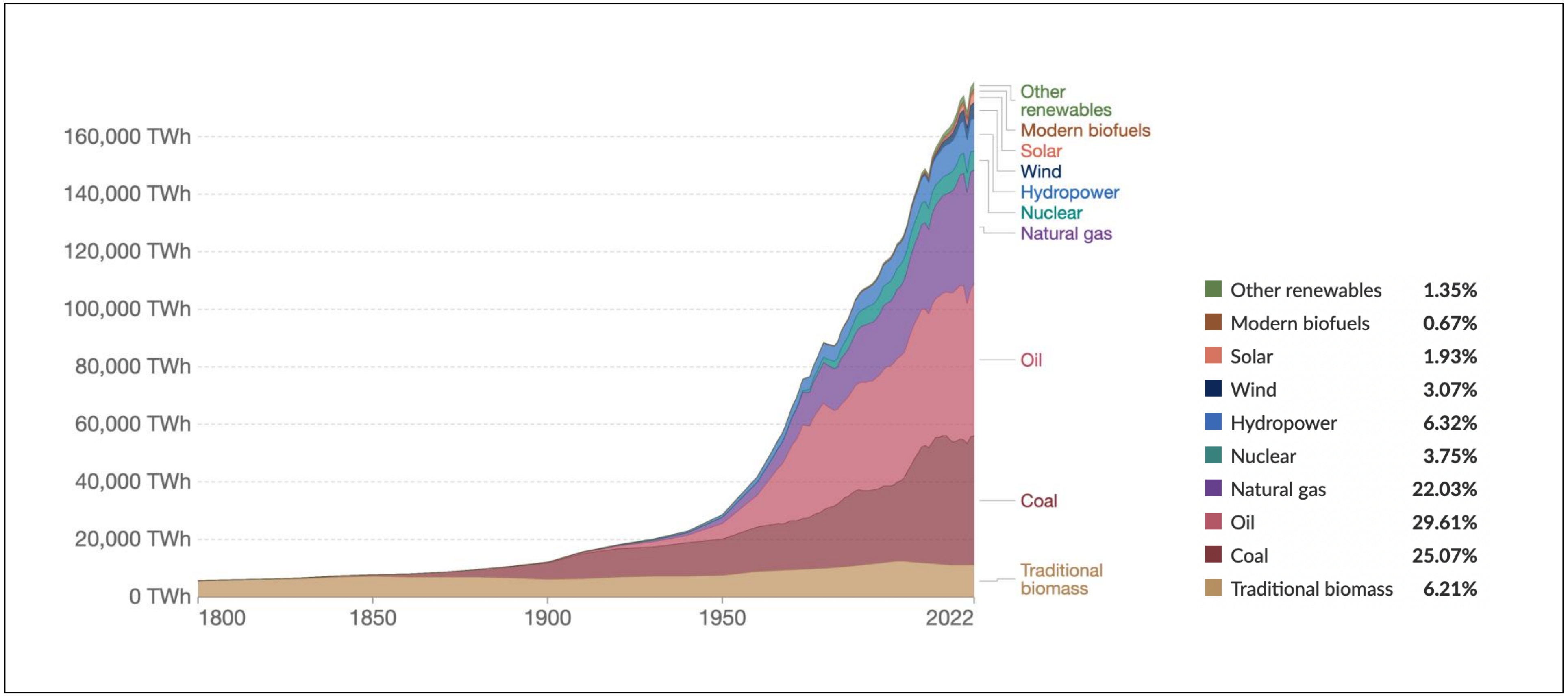
Electricity, fuel and CO_2 prices in Germany in 2022.[1]

[1]https://www.ffe.de/en/publications/german-electricity-prices-on-the-epex-spot-exchange-in-2022/

Why study oil markets?

Oil in global energy consumption

In 2022, oil represented approximately 30% of global primary energy consumption, amounting to 52,970 TWh out of a total of 178,899 TWh.



Global primary energy consumption by source.[1]

Oil markets are highly complex, and governments or organizations often intervene to sustain high prices and/or prevent a collapse, as demonstrated during the 2020 oil crisis.

[1] https://ourworldindata.org/grapher/global-primary-energy

The 2020 oil price crash (1/2)

Daily West Texas Intermediate crude oil futures price in 2020.[1]

[1] https://www.eia.gov/todayinenergy/detail.php?id=46336

The 2020 oil price crash (2/2)

The 2020 oil price crash was triggered by a combination of an unforeseen collapse in demand due to the COVID-19 pandemic and a supply shock caused by a price war between Russia and Saudi Arabia. Storage facilities, especially in Cushing, Oklahoma, the main delivery point for West Texas Intermediate (WTI) future contracts, were approaching full capacity. This oversupply forced producers to pay buyers to take crude oil off their hands. For the first time, **U.S. oil futures prices turned negative**.

On April 20, 2020, WTI futures fell to -$37.63/barrel. The international benchmark, Brent crude, also dropped sharply, hitting $9.12/barrel, a stark contrast to prices exceeding $70 earlier in the year.

The barrel is a unit representing 42 gallons (about 159 liters) in oil trading.

To stabilize the market, an agreement was reached to reduce output by 9.7 million barrels per day, marking the largest coordinated cut in history.

Why study carbon markets?

The trading of carbon allowances (1/3)

Historical price evolution in EUR of European Union Allowances.[1]

[1] https://www.homaio.com/post/what-drives-the-eu-ets-carbon-allowance-price

The trading of carbon allowances (2/3)

Carbon dioxide (CO_2), the primary greenhouse gas driving climate change, is now monitored and traded as a commodity in systems known as carbon markets. These markets place a monetary value on CO_2 emissions, effectively incorporating their environmental and social impacts into economic decision-making.

The **cap-and-trade system** is a widely used market-based mechanism to reduce CO_2 emissions. Under this system, countries or companies are allocated a cap, or maximum limit, on their emissions. This cap represents the **allowable amount of CO_2 they can emit, measured in tons of CO_2 equivalent.**

Entities that emit less than their cap generate surplus allowances—essentially unused emission rights. **These allowances can be traded or sold to other entities that exceed their emission limits**, creating a financial incentive to reduce emissions and allowing the market to determine the most cost-effective reduction measures.

The trading of carbon allowances (3/3)

Power plants burning fossil fuels (coal, natural gas, oil) must purchase carbon allowances for each ton of CO_2 they emit. The price of these allowances directly adds to the cost of electricity generation. Higher carbon prices make fossil-fuel-based electricity more expensive (this is basically their primary goal: encouraging a shift to cleaner energy sources).

However, in practice, gas-fired power plants often set prices on the day-ahead market, especially during times of high demand or low renewable output. As a consequence, the Emissions Trading System (ETS) upward impacts almost directly electricity markets.

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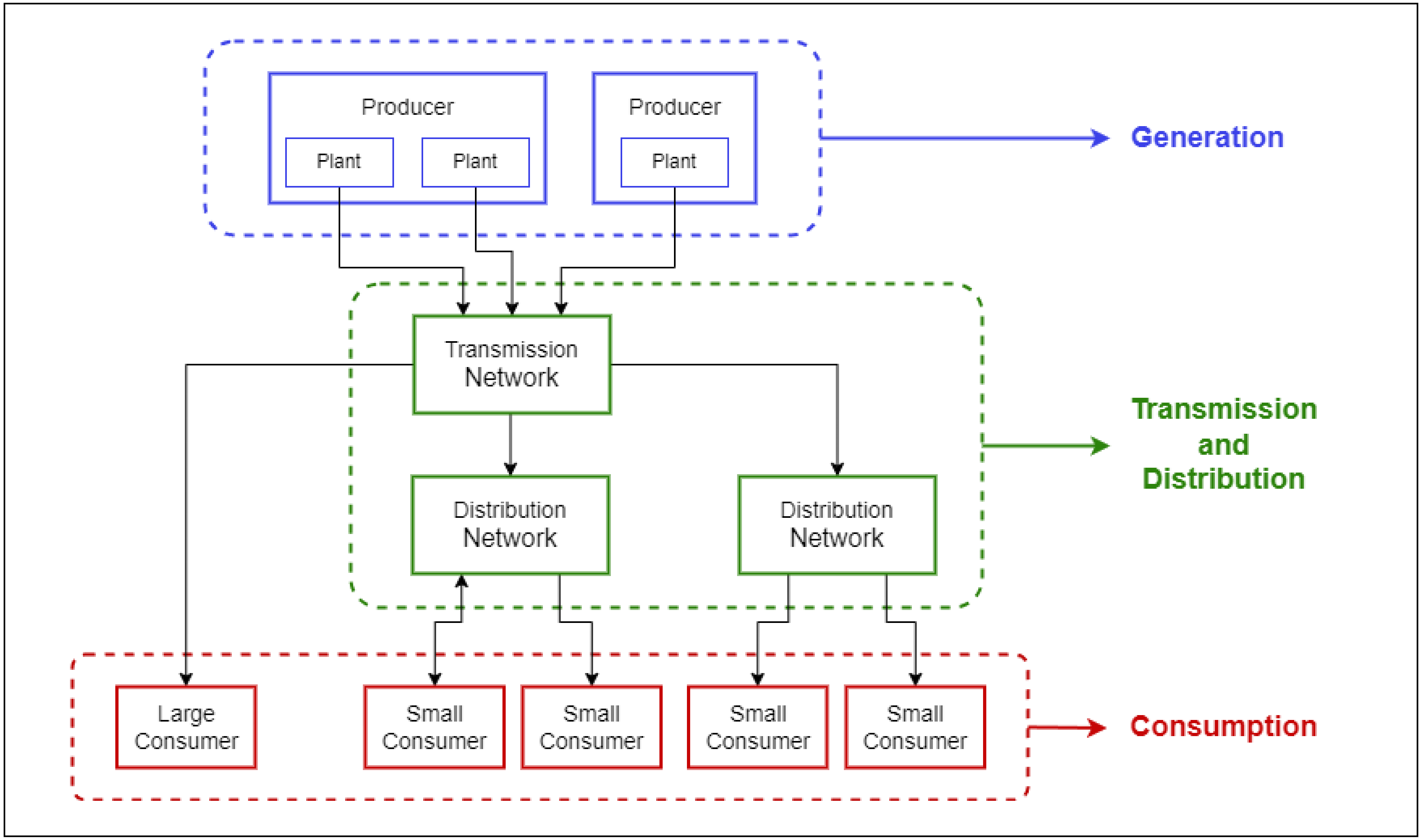
Chapter 02 – Overview of electricity markets

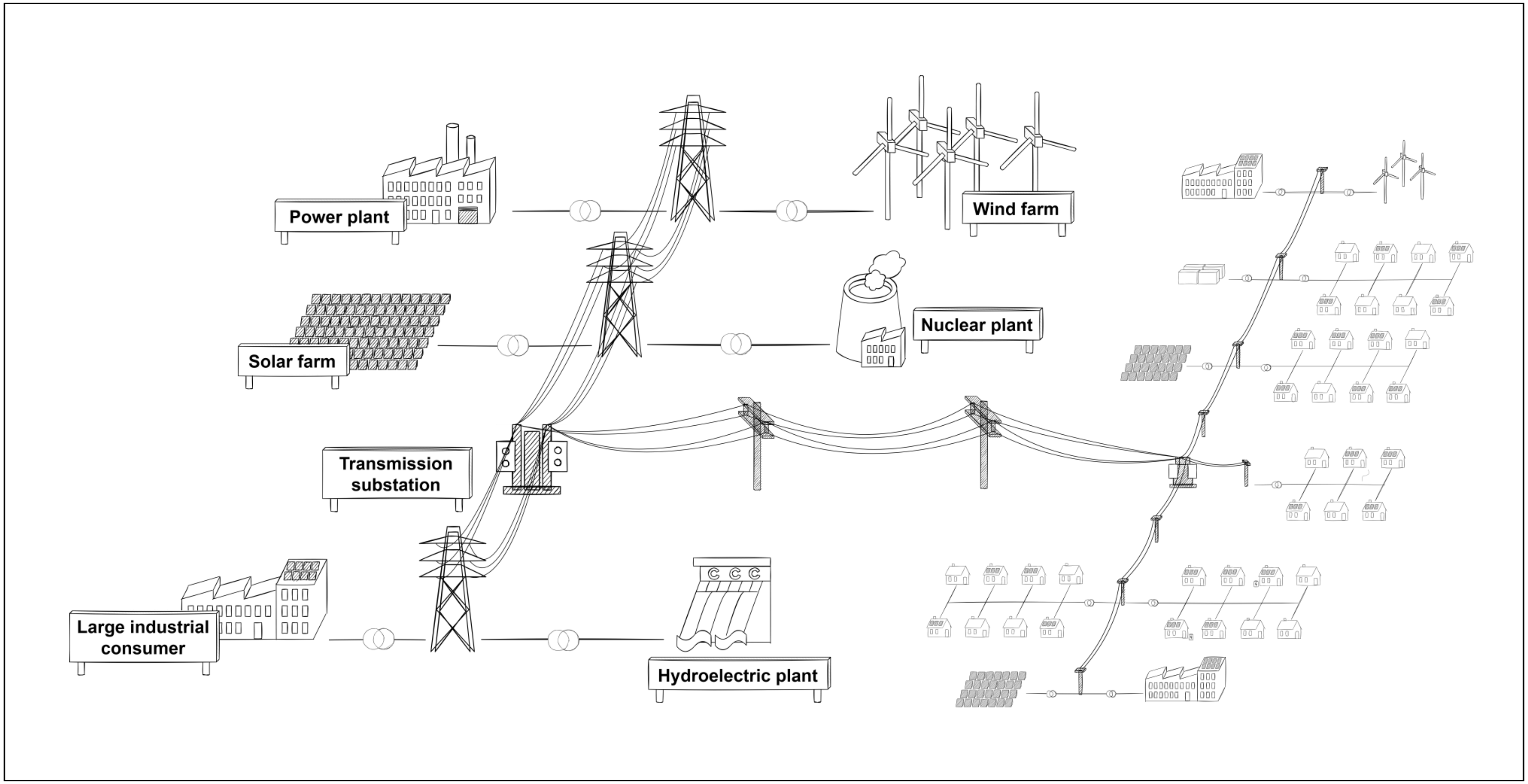
The flow of energy – How electricity reaches consumers (1/2)

The three main components of the electricity grid are:

- Generation
- Transmission and Distribution
- Consumption.



The flow of energy – How electricity reaches consumers (2/2)



Electricity industry – Presentation of the entities

Transmission System Operator (TSO): Operates the high-voltage electricity transmission network. Its role is to ensure the stability and security of the electricity supply.

Distribution System Operator (DSO): Responsible for managing the medium and low-voltage distribution network, delivering electricity to end users.

Producer/Generator: Produces electrical energy and generates sales in the wholesale market.

Retailer: Purchases electricity in the wholesale market for their customers (end consumers).

Supplier: Both procures electricity from the wholesale market and sells it to end consumers.

Consumer: Purchases electricity in the wholesale or retail markets.

Market regulator: Defines market rules and monitors potential abuse of market power.

Market operator: Operates the energy markets (matching, clearing, settlements).

Electricity industry – Main actors in Belgium

Transmission System Operator (TSO):
Elia.

Distribution System Operator (DSO):
ORES, RESA, Sibelga, Fluvius, etc.

Independent System Operator (ISO):
Elia.

Producer/Generator:
Engie Electrabel, EDF Luminus, Lampiris, Eneco, etc.

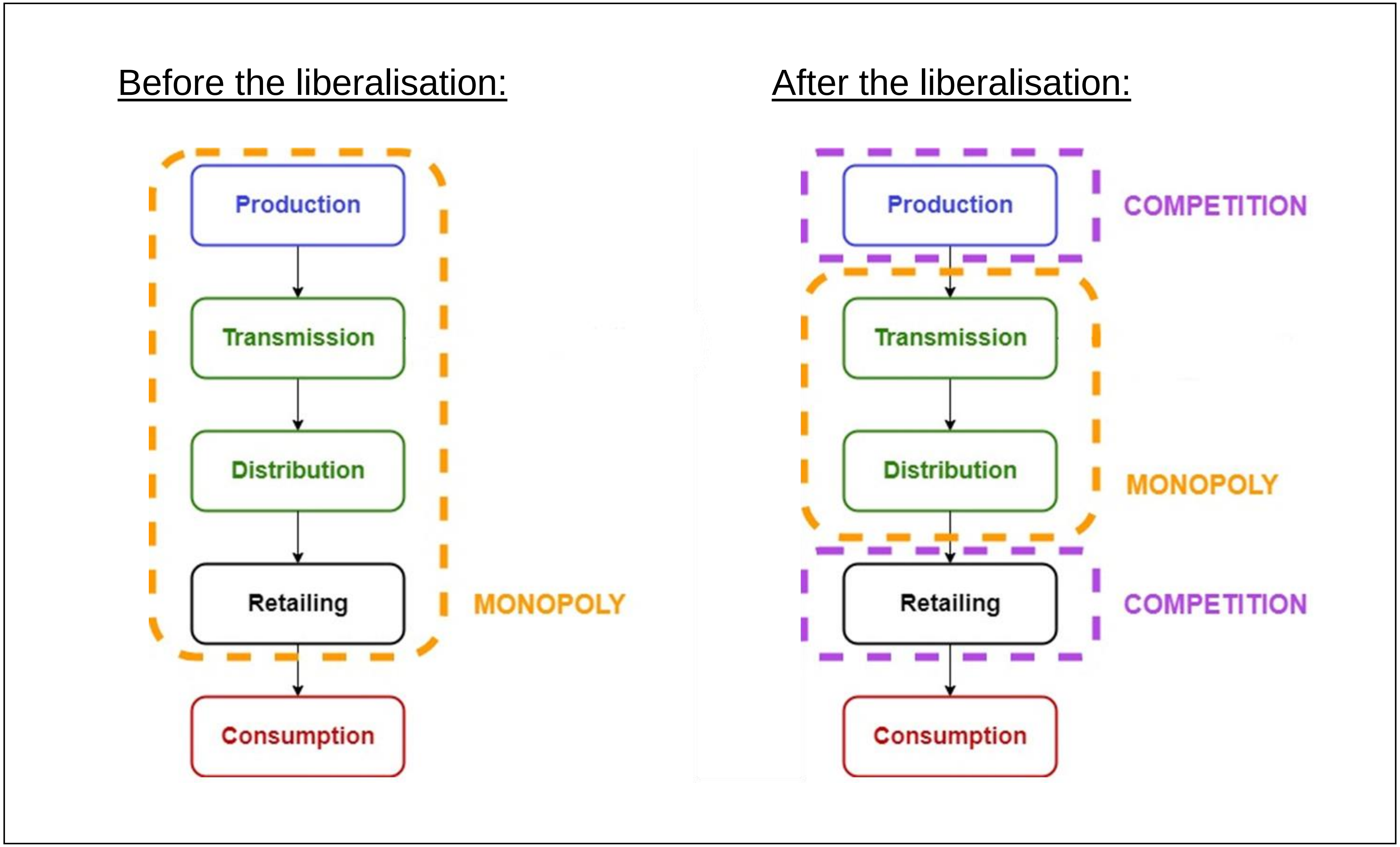
Retailer:
Engie Electrabel, EDF Luminus, Lampiris, Eneco, Mega, etc.

Market regulator:
CREG, CWaPE, BRUGEL, VREG.

Market operator:
EPEX SPOT, EEX, ICE Endex, etc.

Electricity industry – From monopoly to liberalisation

Historically, the electricity industry was organised as a **monopoly** in Belgium. Nowadays, it is significantly **liberalised**:



Electricity Markets – What is traded

The basic unit traded in electricity markets is generally power P over a specific period of time T:

- (Electrical) power is expressed in **Watts (W)**;
- Time is measured as a duration in seconds (s).

A quantity of energy E, expressed in Joules (J), is the product of power and time:

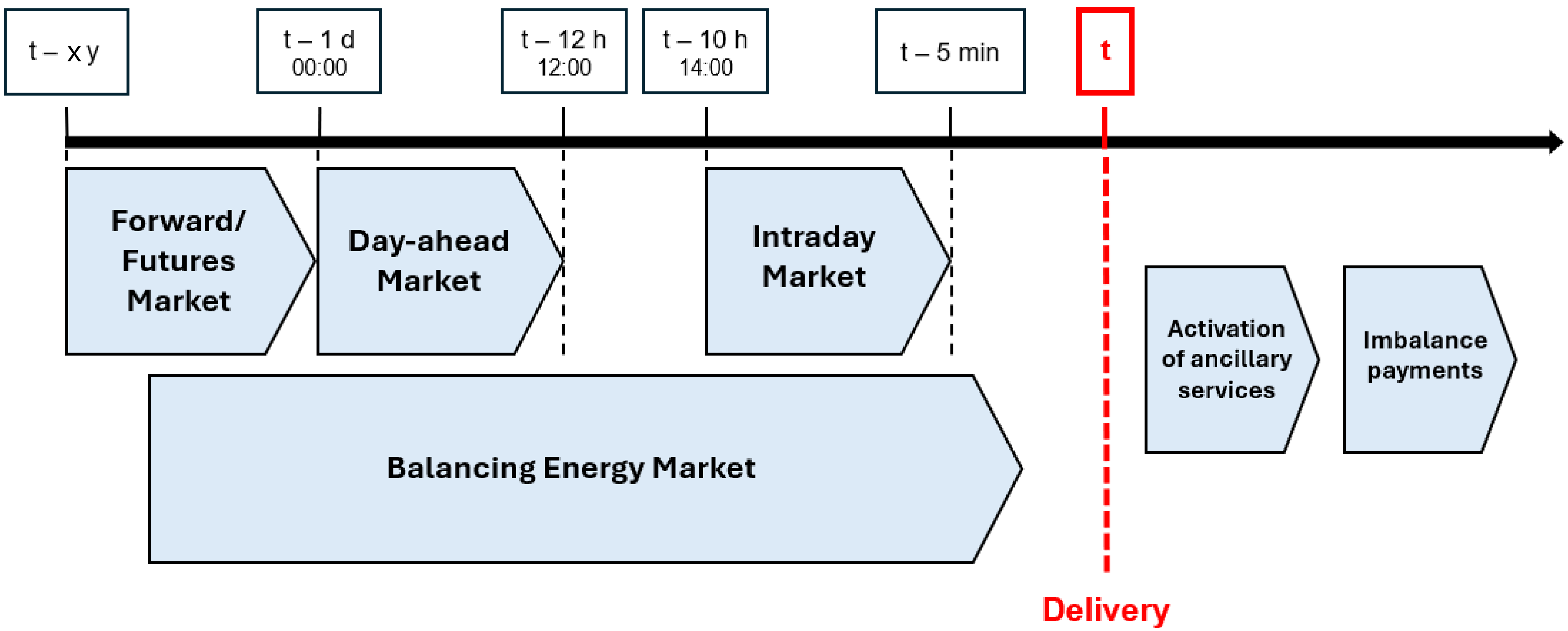
$$\boxed{E\,[\mathrm{J}] = P\,[\mathrm{W}] * T\,[\mathrm{s}]}$$

In electricity markets, **energy volumes are usually expressed in Watt-hours (Wh)** rather than Joules, using prefixes like kilo (k), mega (M), giga (G), or tera (T). MWh is the preferred unit for traders, while kWh is commonly used for domestic consumers (Conversion: 1 kWh = 1,000 W × 3,600 s = 3.6 MJ).

In electricity markets, a **market period** refers to a specific time interval***** during which market participants can buy or sell electricity.

*Typically 15 minutes in the EU, but it may be different in other countries (five-minute intervals in the intraday market in the US).

Electricity Markets – Overview



Presentation of the forward and futures markets

Each participant on these markets can submit an **order**, which is **an instruction to buy (bid) or sell (ask) a certain volume of electricity at a specific price**. The order can be matched with a corresponding order from another participant through a **long-term bilateral contract**.

A bilateral contract is an agreement directly negotiated between two parties, typically between a producer, such as a power plant, and a consumer, which could be a large industrial user, a supplier, or a retailer.

A variety of products are available in long-term contracts, including calendar (yearly), quarterly, or monthly base-load products. **The trading horizon spans from several years until the beginning (or a few days before the beginning) of the market period covered by the contract.**

Difference between the forward and futures markets

Contracts in the futures market are standardised in terms of size, maturity, and specifications (e.g., the volume of electricity, the delivery point). They are traded on organised exchanges like EEX (European Energy Exchange) and ICE Endex.

In contrast, **contracts in the forward market** are negotiated directly between the parties without the involvement of an exchange. They are customised to meet the specific needs of the parties involved.

Both contracts provide market participants with the ability to **lock in a fixed price for a future electricity transaction**, protecting them against unpredictable price fluctuations in the spot or intraday markets (**price hedging**). This helps mitigate the risks associated with the uncertainty of electricity prices.

An example of a product in the forward and futures markets

Let us take the Calendar (CAL) product as an example. This is a yearly baseload product which involves the delivery of constant electric power for the entire year, maintaining the same volume for every market period of the year.

Trading for this product starts three years ahead of the delivery year and ends a few days before the first day of the delivery year.

Historic representation of electricity forward price baseload CAL +1 (08/13/24).
CAL + 1 refers to the delivery of electricity for the entire calendar year following the current one.

Presentation of the day-ahead market

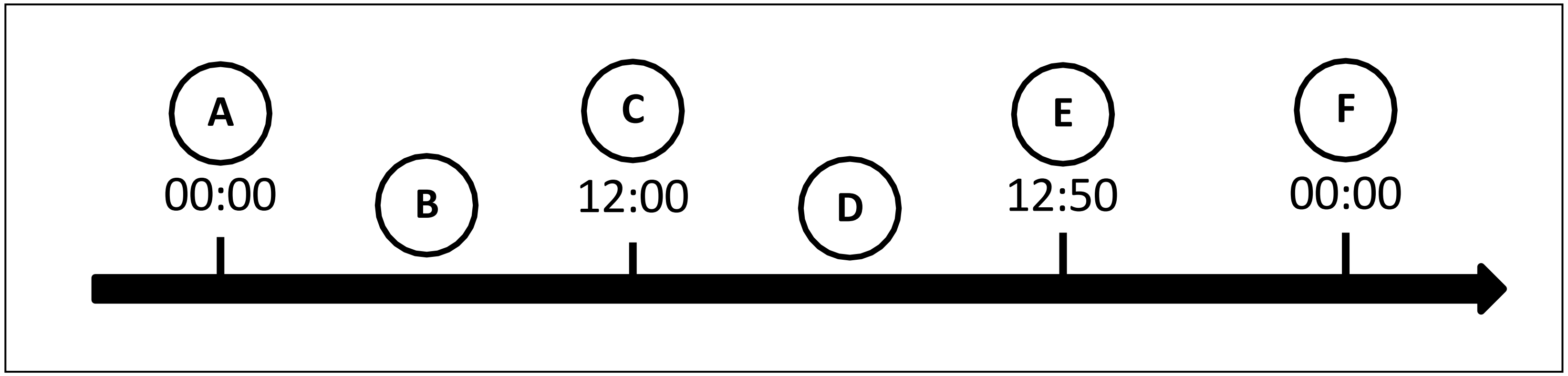
Also known as the electricity **spot market**, the day-ahead market is the central platform of trading for matching electricity supply and demand on a daily basis. This market operates once a day, covering all hours of the following day through a blind auction with hourly resolutions. **In the future, the day-ahead markets are likely to evolve to a quarter-hourly resolution**.

The day-ahead market **operates as a pool where all bids and offers are considered simultaneously** and kept confidential.

A single market-clearing price is determined for each hour in each market zone (a geographical area where electricity prices are uniformly set based on local supply and demand, as well as factors like supply and demand in neighbouring countries and import/export capacities) by the market-clearing algorithm.

The market operator is EPEX SPOT (originally Belpex).

Timeline of the day-ahead market



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.

Types of order

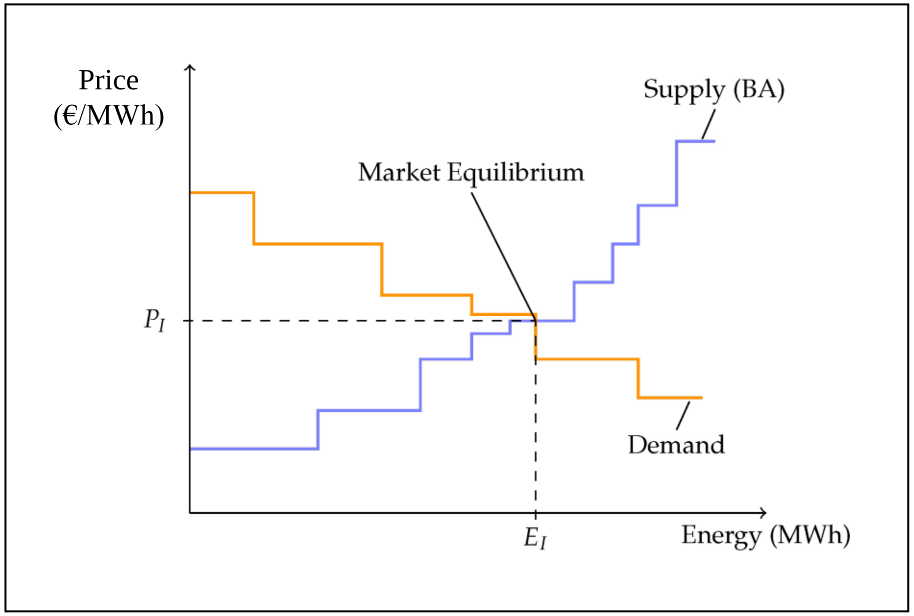
Order type	Time period	Execution condition	Key feature
Simple orders	Single period	Fully executed if market clears at specified price	Independent bids for specific periods
Block orders	Multiple consecutive periods	All or nothing for the entire block of periods	Linked execution across multiple hours
Exclusive orders	Multiple block orders	Only one order from a set can be executed	Provides different block order scenarios
Curtailable orders	Single or multiple periods	Partially executed based on market operator's discretion	Allows for flexibility in execution
…			

The day-ahead market-clearing algorithm (with no congestion)

For each hour of the following day, the clearing algorithm follows these steps:

1) Aggregation of supply: All the asks submitted to the order book are aggregated to form the supply curve, organised from lower to higher costs.

2) Aggregation of demand: All the bids submitted to the order book are aggregated to form the demand curve, organised from higher to lower willingness to pay.



Intersection of the supply (blue) and demand (orange) graph before application (BA) of the algorithm.[1]

3) Determination of equilibrium: The equilibrium point, where the quantity of electricity supplied matches the quantity demanded, is identified at the intersection of the supply and demand curves.

4) Dispatch of orders and price setting: All asks and bids to the left of the equilibrium point are dispatched, meaning these orders are fulfilled. The unique price paid for all energy exchanges, known as the **market-clearing price**, is set at the price at the equilibrium point. This price applies uniformly to all transactions for that hour in the market zone.

[1] https://doi.org/10.3390/en14051255

Managing deviations in the day-ahead market

The problem is that the **clearing of the day-ahead market occurs well before the actual supply and consumption operations**, between 12 and 36 hours in advance. However, actual generation or consumption may deviate from the originally contracted schedule due to factors like changing weather or technical issues.

Market participants have three options:

1. Compensate with other generation or consumption assets within their portfolio

2. Adjust their positions through the intraday market

3. Do nothing and face exposure to the balancing market

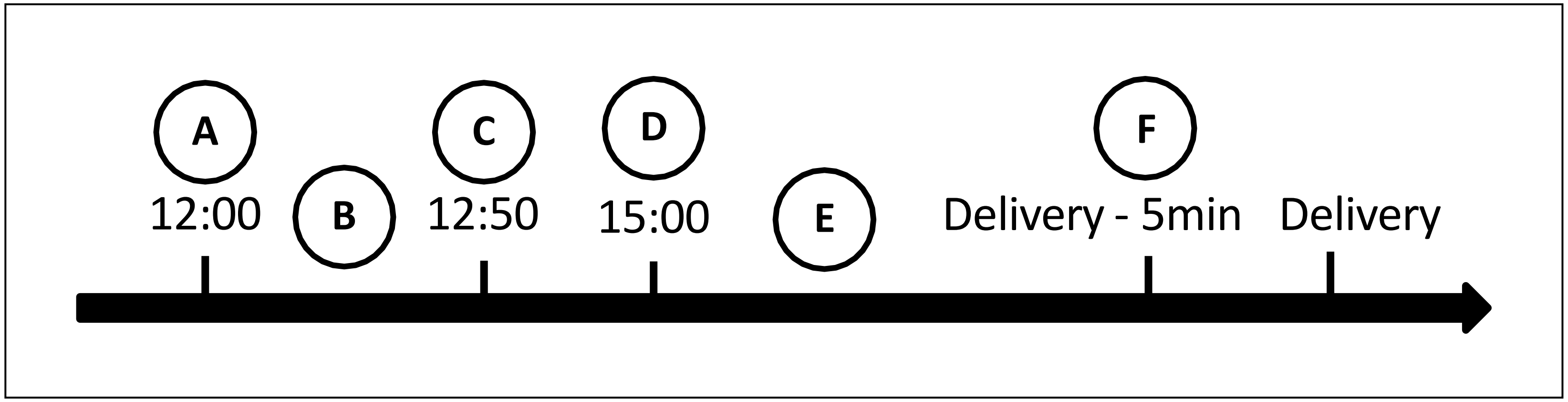
Presentation of the intraday market

The intraday market allows participants to **make last-minute adjustments** and balance their positions closer to real time.

This market supports continuous trading, meaning a trade is executed as soon as two matching orders are found, with different constraints depending on the order types. Hourly, half-hourly, and quarter-hourly contracts are available.

The market operator is EPEX SPOT (originally Belpex).

Timeline of the intraday market



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.

A fictitious example in the intraday market (1/3)

Context: There is a last-minute update in the wind forecast, and the predicted wind power generation in a supplier's portfolio is suddenly reduced by 50 MWh for the market period 10:00-11:00. The wind power generator intends to adjust its position on the intraday market.

Question: What actions could this supplier take to avoid any imbalance?

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

A fictitious example in the intraday market (2/3)

A first possibility is to buy 50 MWh from G3 and pay - **50** × 50 = - €2,500.

A second possibility is to buy 80 MWh from G2 and sell respectively 10 MWh and 20 MWh to C1 and C2, thus paying - **80** × 40 + **10** × 55 + **20** × 60 = - €1,450.

Other possibilities?

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

A fictitious example in the intraday market (3/3)

A third possibility is to buy 100MWh from G1 and 80 MWh from G2, and sell 20 MWh to C2 and 110MWh to C3:

- **100** $\times$ 35 - **80** $\times$ 40 + **110** $\times$ 70 + **20** $\times$ 60 = €2,200

In this third possibility, the supplier even generates additional revenue.

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

Imbalance of the power system

There are several reasons why the power system may become imbalanced:

- **Demand forecasting challenges:** Predicting electricity demand is difficult, and actual consumption may differ significantly from the forecast made during day-ahead market clearing.
- **Supply forecasting challenges:** Predicting electricity supply is particularly challenging for renewable energy sources, which depend on weather conditions. Examples include:
  - Photovoltaic (PV) power with cloudy weather: The timing and impact of clouds over a PV installation can be difficult to predict.
  - Wind power during thunderstorms: It is hard to forecast when wind speeds will reach the cut-off point, causing wind farms to shut down.
  - Dust storms: The effect of dust on PV production is challenging to forecast accurately.*****
- **Technical issues:** Technical problems can affect both electricity generation and the transmission and distribution infrastructure.
- **Transmission congestion:** Congestion on major power lines within a zone can occur, sometimes leading to generation curtailment to avoid overloading the system.

*****See, for instance, https://www.sciencedirect.com/science/article/pii/S2213138824000031

Presentation of the balancing market

The balancing stage, which occurs close to real time (after delivery), is crucial for enabling the TSO to **maintain a balanced power grid (generation ≈ consumption) at any time**.

The complete balancing stage includes:

- The balancing market, where the TSO acquires regulating power from voluntary producers and consumers before the time of delivery;
- Imbalance payments, where market participants cover the costs associated with their contributions to keeping the power system balanced.

The market operator is Elia, in Belgium.

The (negative) flow of money to producers and consumers from the futures, forward, day-ahead, or intraday markets is always based on the volumes committed to in these markets, not the actual volumes delivered.

Imbalances on the balancing market

There exist three possible situations for the power grid balance:

1. Positive imbalance:

Generation > **Consumption** (downward regulation required)

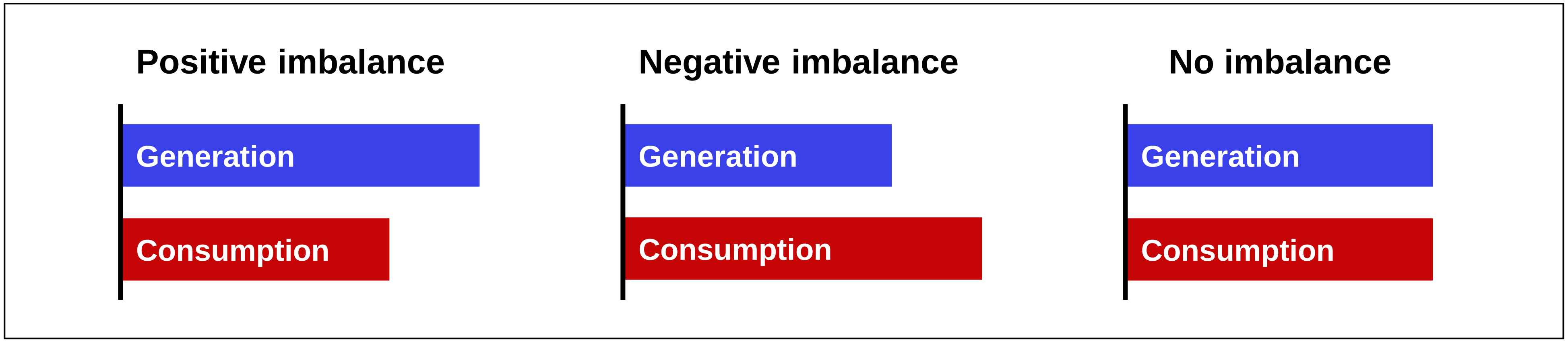
2. Negative imbalance:

Generation < **Consumption** (upward regulation required)

3. 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).



Price signals in the balance markets (1/2)

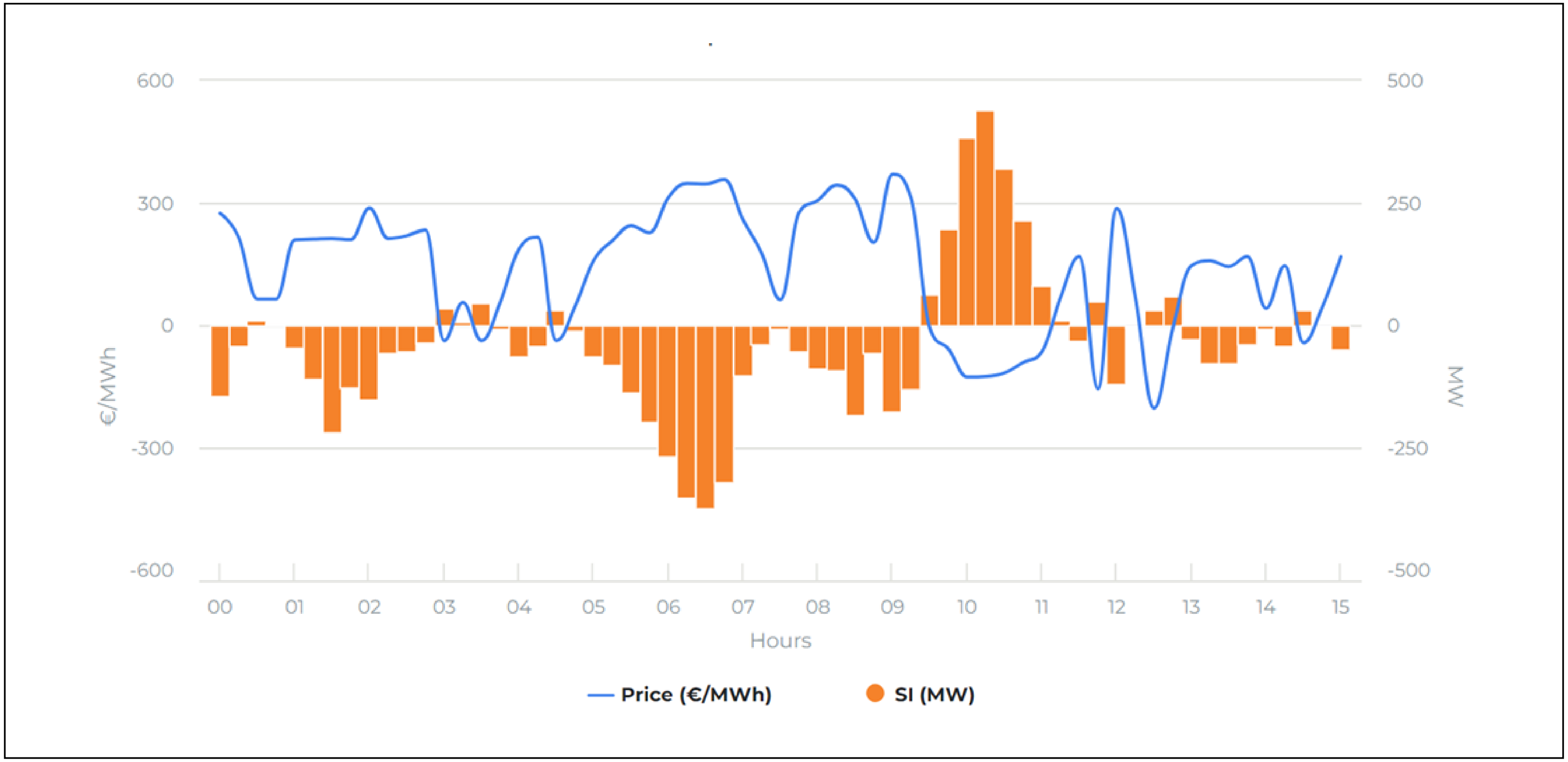
The imbalance market operates with imbalance prices. This pricing incentivises producers and consumers to be as accurate as possible in their scheduling to avoid costly imbalances.

These prices are designed to reflect the costs the TSO incurs to maintain grid stability, such as:

- **Upward reserves:** In cases of a shortfall (generation < consumption), the TSO purchases additional electricity from producers or storage systems capable of quickly increasing production.

- **Downward reserves:** In cases of oversupply (generation > consumption), the TSO either asks producers to reduce production or pays flexible consumers to increase their demand.

Price signals in the balance markets (2/2)



Imbalance prices on 17/09/2024.

Market participants (producers or major consumers) who deviate from their schedules must pay or receive compensation based on these imbalance prices.

Exercise 1:

A wind producer has sold 100 MWh of electricity at a price of €45/MWh on the day-ahead market for the period 10:00-11:00. Due to inaccurate wind forecasts at the time of market clearing (day-ahead market), the actual production deviates from the original schedule. The imbalance price for this market period***** is set at €50/MWh.

1. What is the revenue of this producer if its actual production is 80 MWh?

2. What is the revenue of this producer if its forecast is correct?

3. What is the revenue of this producer if its actual production is 120 MWh?

*On the day-ahead market, a period is 1 hour. In some EU markets, electricity delivery is expected to be balanced over intervals of 15 minutes. This introduces what is called a quarter-hourly (15-minute) granularity in terms of production and consumption obligations.

Solution:

Part 1:

Day-ahead market revenue: 100×45 = €4,500.
Imbalance market revenue: - 20×50 = - €1,000.
Eventually, the producer's revenue is equal to €3,500 (€43.75/MWh).

Part 2:

Day-ahead market revenue: 100×45 = €4,500.
Imbalance market revenue: 0×50 = €0.
Eventually, the producer's revenue is equal to €4,500 (€45/MWh).

Part 3:

Day-ahead market revenue: 100×45 = €4,500.
Imbalance market revenue: 20×50 = €1,000.
Eventually, the producer's revenue is equal to €5,500 (€45.83/MWh).

The balancing market – Two-price imbalance settlement

In the third part of the previous exercise, the producer's positive imbalance (excess production) partially offsets the negative imbalance of the entire power system, resulting in a revenue surplus. **This can encourage speculative behaviour in the imbalance market, which is undesirable as it could lead to significant instabilities in the power system.**

To address this, **a two-price imbalance settlement is used** instead of a one-price imbalance settlement:

- Actors contributing to the power system imbalance are penalised based on the imbalance price;
- Actors unintentionally offsetting the power system imbalance do not receive additional rewards beyond the day-ahead market clearing price.

Considering a two-price imbalance settlement policy in the third part, the producer's revenue would be:

Day-ahead market revenue: 100 x 45 = €4,500.
Imbalance market revenue: 20 x 45 = €900.
Eventually, the producer's revenue is equal to €5,400 (€45/MWh).

Presentation of the ancillary services market

The ancillary services market provide essential support services that maintain grid stability, reliability, and efficiency. It operates alongside primary electricity markets like the day-ahead and intraday markets.

The ancillary services market relies on a combination of market-based mechanisms and regulatory requirements. TSOs and DSOs procure ancillary services from market participants, including power plants, demand response providers, and other entities capable of delivering these services.

There are multiple types of ancillary services, including:

- **Frequency control:** Primary, secondary, and tertiary reserves
- **Voltage control:** Primary, secondary, and tertiary controls
- **System restart**: Black start capability

The market operator is also Elia, in Belgium.

Ancillary services classification

Ancillary services classification related to system operation

Frequency control

- Automatic Generation Control (AGC)
- Primary regulation
- Secondary regulation
- High-frequency response
- Spinning reserve
- Non-spinning reserve
- Emergency control actions

Voltage control

- Primary control
- Secondary control
- Tertiary control

System restart

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 03 – From monopolies to liberalisation in electricity markets

The amazing evolution of the structure of the electricity markets

Some facts:

- For several decades, the amount of energy delivered by the electricity network **has doubled about every 8 years**.
- In most parts of the world, the average consumer is deprived of electricity **for less than two minutes per year**.

How did the structure of the electricity markets we know today develop?

Let us look at the history of the energy (electricity) industry, from monopoly to the emergence of liberalisation.

Responding crisis and war with market transformation

Context in the U.S.:

- In 1929, the Great Depression hit the United States.
- Capitalism and the market economy – dominant at this time – were pointed to as one of the main culprits of this crisis.
- Franklin D. Roosevelt, who was elected in 1933, spoke about ‘a cynical and egoistic market economy’.
- He implemented a series of measures to decrease the power of private entities and increase the power of the state.

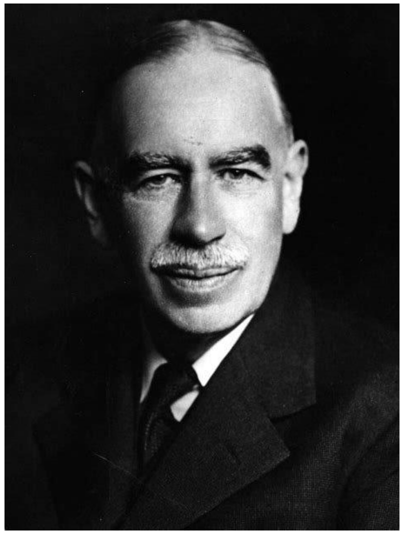
Context in Europe:

- In the 1950s, Europeans had emerged from two wars (1914-1918 & 1939-1945) and an economic crisis (1920s).
- There was a similar anti-capitalist sentiment.
- Strong labour unions and governments pushed for nationalization.

Keynesian economics: shaping markets through public policy

Supported by the theories of a renowned economist of the time, **John Maynard Keynes (1883-1946)**:

- did not believe that a constant equilibrium exists between demand and supply;
- saw the economy as being in constant imbalance rather than a succession of balanced states;
- promoted a political economy where demand is supported by large infrastructure projects (as done in the US), or public spending (e.g., social security implemented in Europe).



'The ideas of economists and political philosophers, both when they are right and when they are wrong are more powerful than is commonly understood. Indeed, the world is ruled by little else.

Practical men, who believe themselves to be quite exempt from any intellectual influences, are usually slaves of some defunct economist.'

John Maynard Keynes

Economies of scale in electricity production

These political and economic views were to be applied to the electricity sector. They were also supported by technological advances.

Evolution of production unit size:

- Start of the century: ~25 MW
- From 1945 to 1965: an increase from 50 MW to 300 MW
- 1970s: nuclear power plants of ~1000 MW

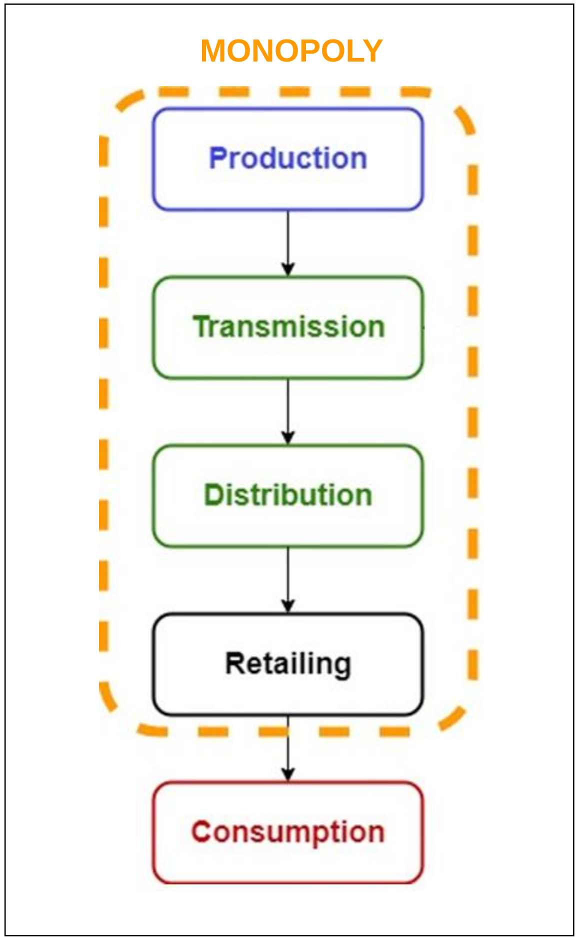
It became possible to build bigger, better, and less expensive units. **The unit cost of production was divided by 4 or 5 between 1950 and 1980**. However, the total cost of one unit increased as the units became larger.

Consolidation and monopoly

Until the 1980s, electricity consumers had no choice in selecting their supplier, as electricity providers operated as regional monopolies. These suppliers were vertically integrated, meaning a single company controlled production, transmission, and distribution within a specific area.

Consumers were bound to their local supplier and subject to **a uniform, imposed price for electricity**, with no competitive alternatives available.

By the end of the 1980s, most developed economies had fully embraced this monopolistic model in the electricity sector. Consolidation efforts had further reduced the number of suppliers, exemplified by Belgium, where over a dozen companies in 1950 merged into only a few by 1990.



Advantages of monopoly structures in electricity markets

- Monopoly structures supported **large-scale and coordinated electrification projects**, driving economic development and enhancing living standards. These achievements may not have been feasible in a fragmented, competitive market during the early stages of electricity distribution.

- Centralized control allowed for **consistent growth of electricity networks**, meeting the needs of a rapidly modernizing society. Over several decades, electricity demand doubled approximately every eight years, showcasing the scalability of this approach.

- Monopoly structures ensured **continuity of service**, with reliability metrics showing significant improvements. For example, by 2004, the average consumer experienced less than two minutes of power outages annually.

Drawbacks of monopoly structures in electricity markets

- **Economic inefficiency**

  Monopolies were not inherently cost-effective, often lacking incentives to optimize operations and reduce costs.

- **Inefficiency in operations**

  The absence of competitive pressure discouraged efficient practices, leading to operational complacency.

- **Unnecessary investments**

  Monopolistic structures sometimes led to overinvestment in infrastructure or projects that did not align with actual demand.

- **Government influence**

  Public entities operating within monopolistic frameworks were prone to excessive government interference, which could detract from operational independence.

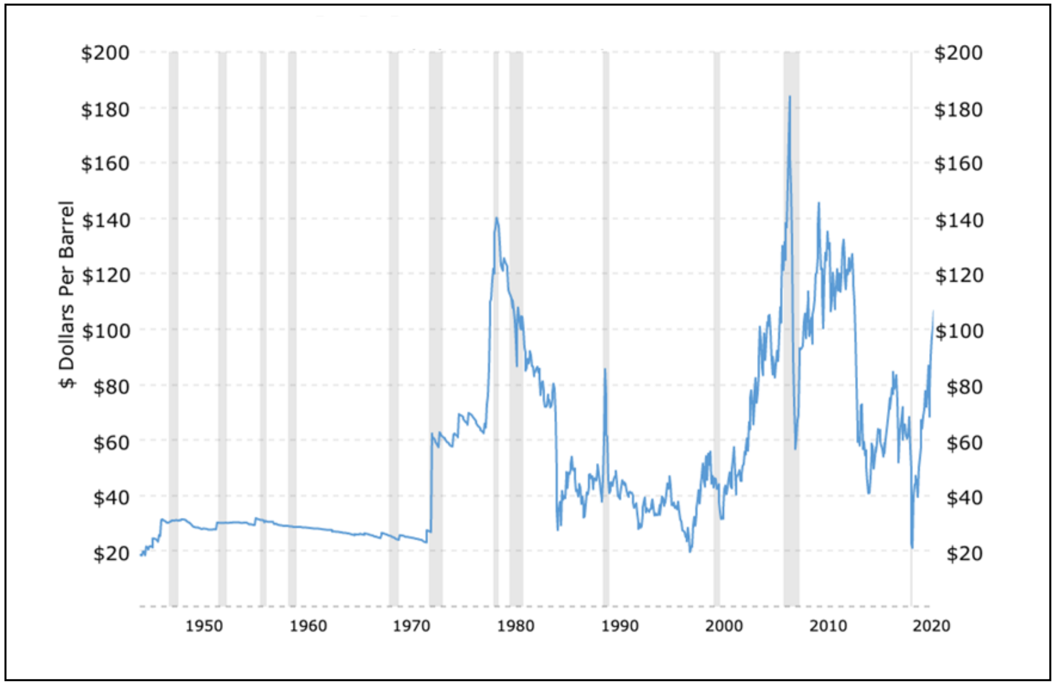
- **Higher costs for consumers**

  The lack of competition often resulted in higher electricity prices compared to what could be achieved in a competitive market.

The rise of liberalisation (1/3)

In 1973, the first oil crisis led to oil prices quadrupling, followed by a doubling in 1979. Electricity prices, which had been declining for decades, suddenly surged.

This resulted in a loss of public trust in institutions across Europe due to the perceived poor handling of the crisis.



West Texas Intermediate oil price (adjusted for inflation) history 1946–2022.[1]

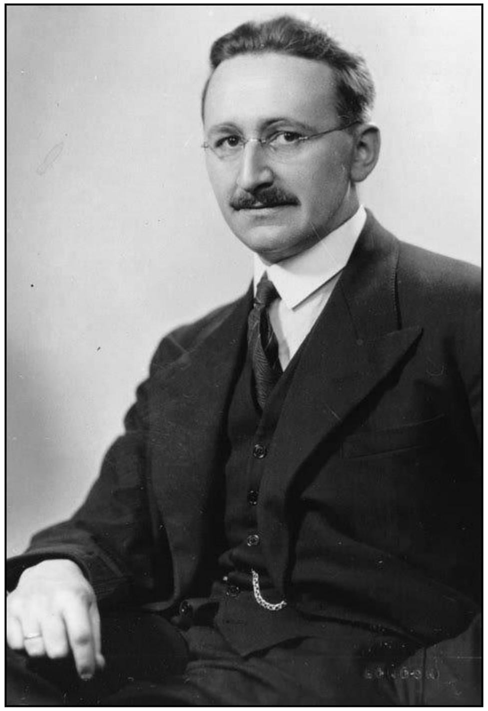
The crisis led to the election of Margaret Thatcher, who initiated a significant wave of privatisations. In response, Europe advocated for the creation of the 'Single Market' and **promoted competition as a strategy to revitalise the continent**.

[1]https://www.macrotrends.net/1369/crude-oil-price-history-chart

The rise of liberalisation (2/3)

The new UK prime minister was inspired and supported by **Friedrich Hayek** (1899–1992).

- He proposed an alternative way of managing the economy through liberalism, a view shared by people like Milton Friedman and the Chicago Boys (Chile).
- He believed that the state should not intervene in economic life and saw the market as a tool to oppose governmental planning or control.
- His influence has been rising since the 1930s.

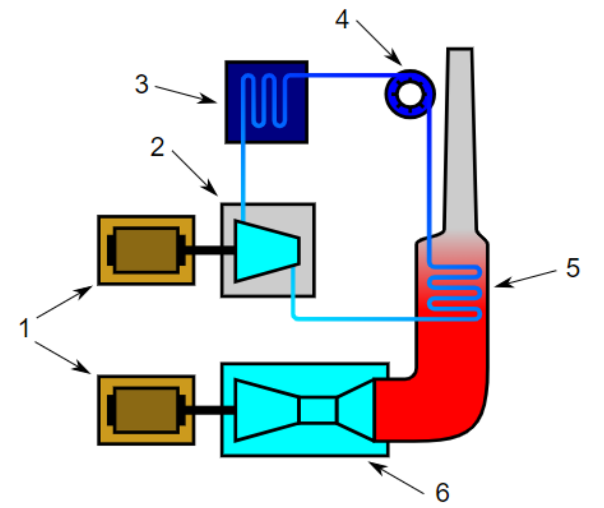


The rise of liberalisation (3/3)

As for the wave of nationalization, liberalisation was supported by technological changes. In the 1980s, a new production technology emerged: **the combined cycle gas turbine (CCGT)**.

These units could use both gas and steam to run turbines that produced electricity, achieving efficiencies comparable to those of large production units, but at much smaller sizes (300 MW, or even 50 MW).

Their size made them easy to deploy, removing barriers to entry that protected monopolies while diminishing some of their added value.



Legend:
1-Electric generators, 2-Steam turbine,
3-Condenser, 4-Pump,
5-Boiler/heat exchanger, 6-Gas turbine

Working principle of a combined cycle power plant.[1]

A few years later, they were joined by new renewable energy sources that also enjoyed the same modularity.

[1]https://wiki.openstreetmap.org/wiki/Tag:plant:type%3Dcombined_cycle

The liberalisation of the electricity sector in 6 steps (1/2)

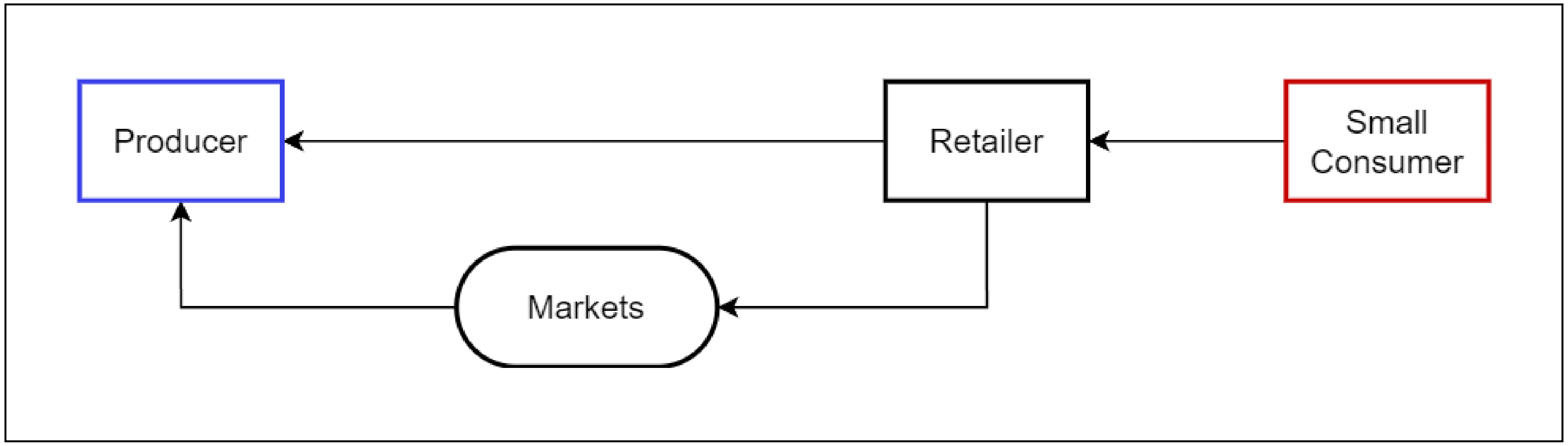
Step 1: Open production to competition

Step 2: Introduce a new actor, **the retailer** (or provider):

- Serve as an intermediary between producers and small consumers
- Protect small consumers from price fluctuations

Step 3: Retailers buy electricity from producers:

- Bilateral contracts
- Centralized market operated by a market operator



Flow of money in liberalised electricity markets.

The liberalisation of the electricity sector in 6 steps (2/2)

Step 4: Electricity transport is a natural monopoly

- At the national level:
  Transmission network operated by a **Transmission System Operator (TSO)** or several TSOs, each having the monopoly on its own geographic territory
- At the regional level:
  Distribution network operated by the **Distribution System Operators (DSOs)**

Step 5: Introduce the ISO (Independent System Operator)

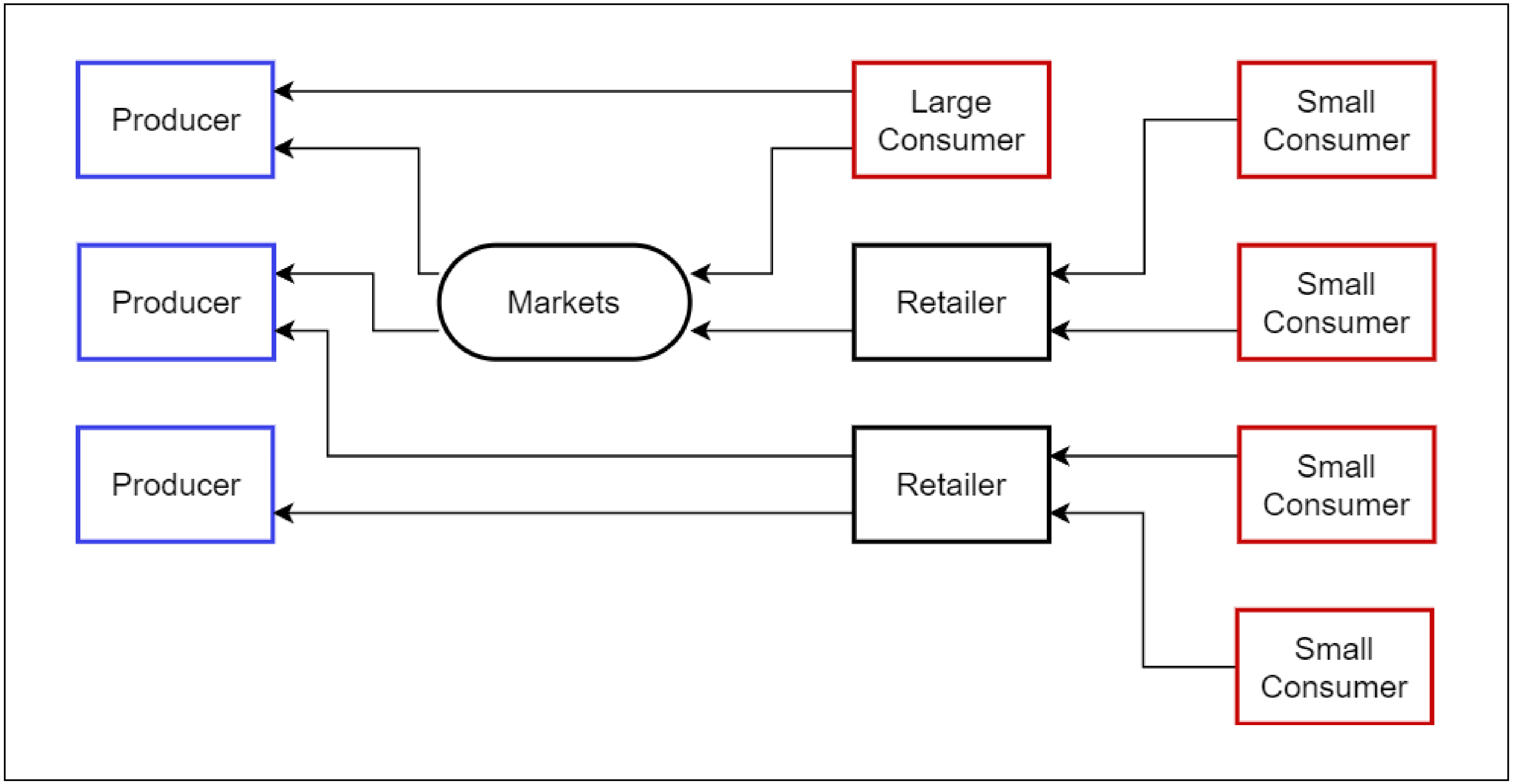
- Responsible for **maintaining the security** of power system operation
- Can be managed by the TSO (as it is the case in Belgium)

Step 6: Introduce the regulator:

- Determines or approves the electricity **market rules**
- Investigates the suspected cases of abuse (market power)
- Sets or controls the prices of products and services in the case of monopolies (e.g. distribution network fees)

Flow of money (1/2)

Retailers can buy directly from producers, from the market, or a mix of both.



Flow of money in liberalised electricity markets.

Flow of money (2/2)

Note that this is still a very simplified view of money flows. Among other things, this does not show:

- Payment of taxes and network fees, which are included in the price paid by small consumers to retailers, who then pay those taxes and fees.
- Buying from producers/selling by retailers. Sometimes, as we will see later, producers (or retailers) can be incentivized to buy (or sell) energy instead of selling (or buying) it.
- Balancing fees.
- Payments for capacity mechanisms.
- Guarantees of origin.

Open questions about liberalisation

Challenges following the end of the monopoly utility model:

Previously, the operation and development of the power system were managed by a single organisation, which was one of the key advantages of the monopoly model. However, with liberalisation, this centralised control has been replaced by multiple entities.

This raises several important questions:

- Can these entities be coordinated to achieve least-cost operations (e.g., joint maintenance of the transmission system and operational lines, coordination of long-term development in generation and transmission)?
- Will free markets ensure that generation will always meet demand?
- How can future investments be optimised?

Remarks about liberalisation

- Most economic laws supporting the push for liberalisation assume a market with perfect competition. However, this is far from the case in electricity markets.
- Typically, in France, EDF – the former national monopoly – still owns most of the production assets.
- To ensure fair competition, Europe has imposed corrective mechanisms such as ARENH (Accès Régulé à l’Électricité Nucléaire Historique), which requires EDF to sell part of its production to its competitors at a regulated price.

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Energy market and regulation

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Chapter 04 – Participants in the electricity markets

Recap of actors in Belgium (1/6)

Generating Companies/Producers:

- Own one or more power plants
- Sell the electrical energy produced by these plants
- May also compete to sell ancillary services

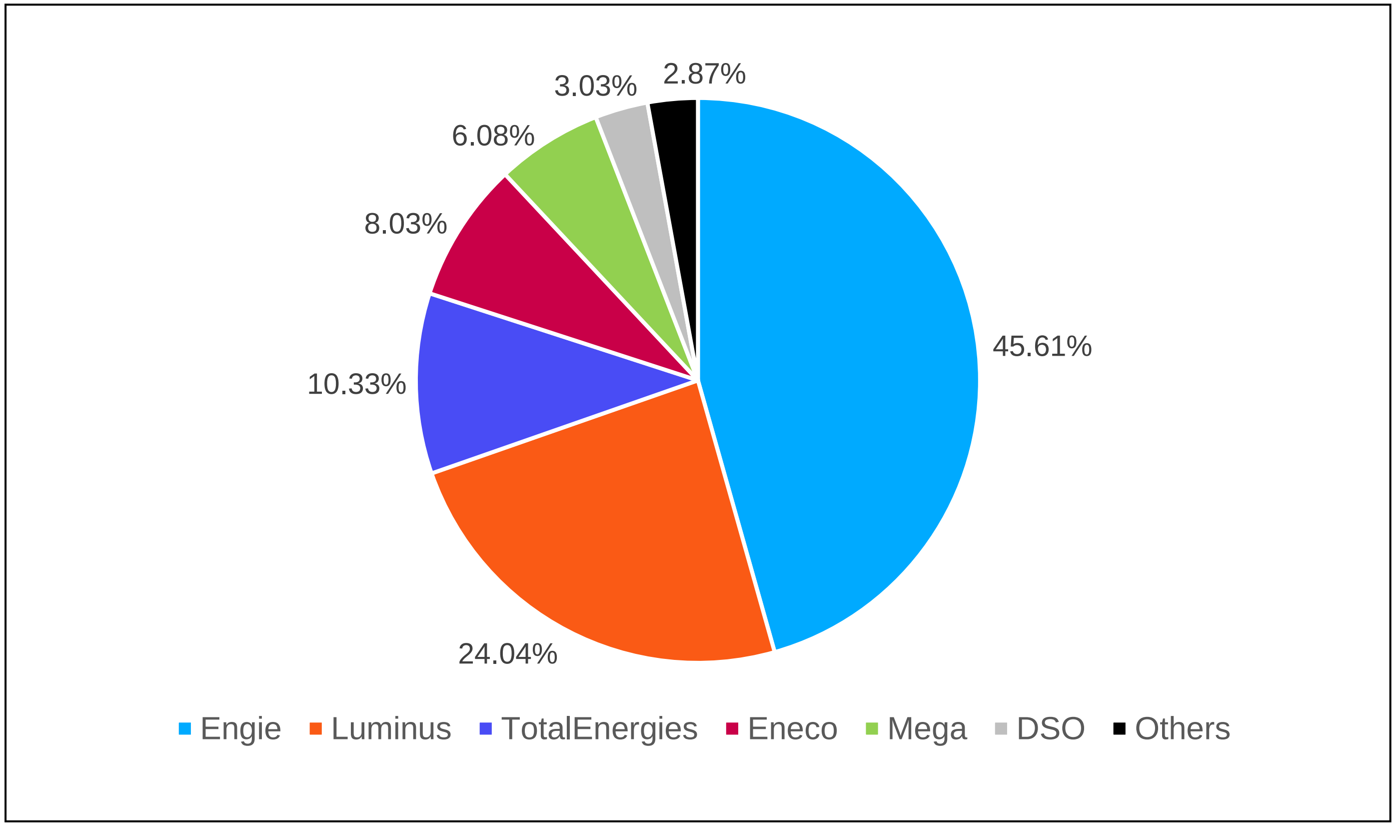
Generation Companies with assets in Belgium:

- Engie Electrabel
- EDF Luminus
- Eneco
- TotalEnergies
- ...

Recap of actors in Belgium (2/6)

Retailer:

- Sells electricity to small consumers through the retail market
- Buys electricity from producers on the wholesale market (or directly from producers)
- A generation company can also operate as a retailer.



Market share of retailers in Wallonia (Belgium).[1]

[1] https://www.creg.be/fr/consommateurs/le-marche-de-lenergie/parts-de-marche-des-fournisseurs-denergie

Recap of actors in Belgium (3/6)

The **TSO** manages the transmission network and the **ISO** maintains the security of the network. In Belgium, TSO = ISO → Elia.

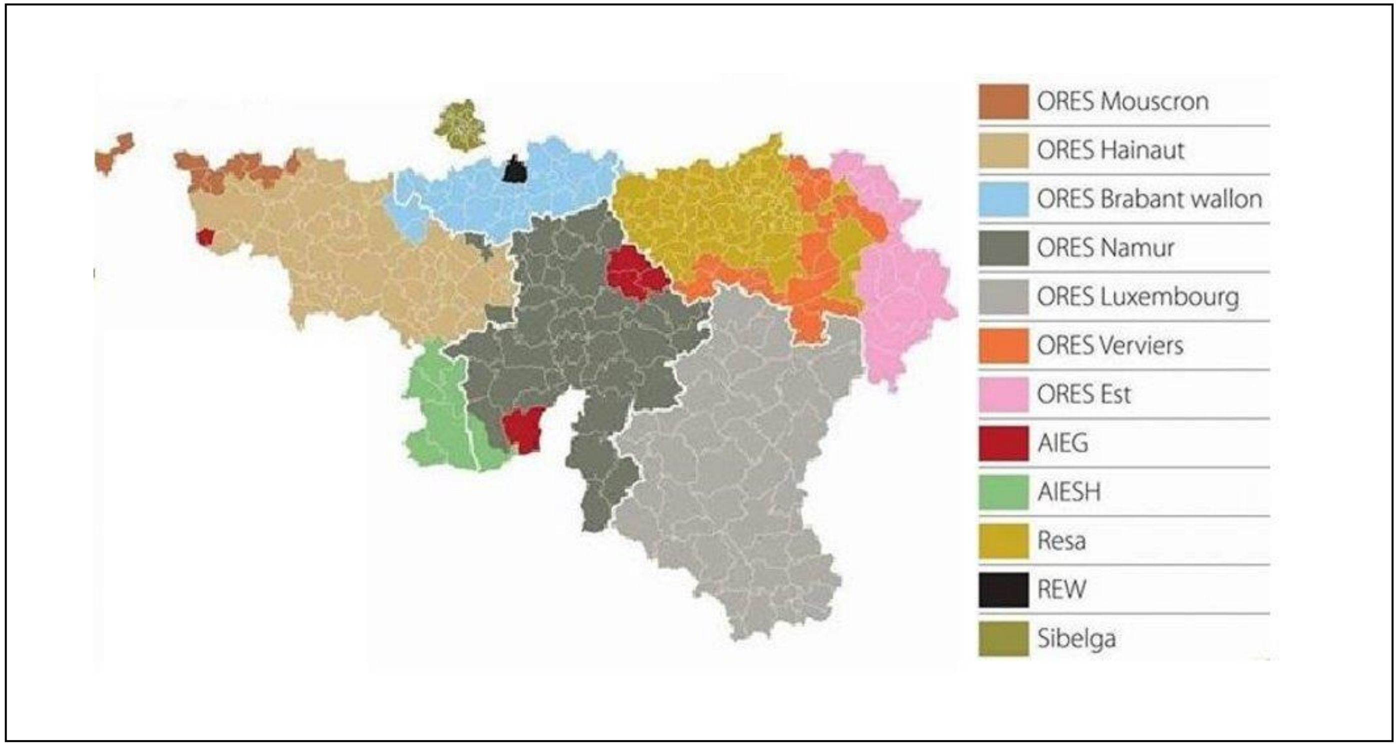
At the European level:

ENTSO-E – European network of transmission system operators for electricity.

Recap of actors in Belgium (4/6)

Several DSOs for the three Belgian regions:

- Wallonia: Ores, Resa, Régie de Wavre, AIESH, AIEG;
- Brussels-Capital region: Sibelga;
- Flanders: Fluvius.



Distribution of DSOs across Belgian territory.

Recap of actors in Belgium (5/6)

1 country, 4 regulators:

- National: CREG – Commission de Régulation de l’Electricité et du Gaz;
- Wallonia: CWAPE – Commission Wallonne Pour l’Energie;
- Brussels-Capital: BRUGEL – Brussels Gaz and Electricity;
- Flanders: VREG – Vlaamse Regulator van de Elektriciteits- en Gasmarkt.

Recap of actors in Belgium (6/6)

Market Operator:

- Matches generating bids (from sellers) with consumption offers (from buyers);
- Manages the settlement of accepted bids and offers.

The market operator varies depending on the type of market.

Moreover, most European markets have been integrated.

Typical market operators include EPEX SPOT, EEX, and ICE Endex.

A simplified view of the producer (1/2)

Now, let us take a closer look at two specific actors: the **producer (generator)** and the **retailer (provider)**. Let us start with the producer.

The goal of the producer is to maximize profit, which is calculated as revenue minus costs. Revenue is simply the quantity of energy sold multiplied by the price at which it is sold.

Costs are generally divided into two categories:

Long-term costs: investments and maintenance costs.

Short-term costs: operational and fuel costs, etc.

Another important cost is the marginal cost of production, which is the cost of producing the last unit of energy.

A simplified view of the producer (2/2)

Let us consider a generating company that tries to maximise the profits Ω_i it derives from a single generating unit called unit i.

Mathematically, this resolves to solving the problem:

$$\boxed{\max(\Omega_i) = \max(\pi P_i - C_i(P_i))}$$

where P_i is the power produced, π is the price at which this production is sold, and $C_i(P_i)$ is the cost of producing this power.

Optimality occurs when $\frac{d\Omega_i}{dP_i} = \frac{d(\pi P_i) - d(C_i(P_i))}{dP_i} = 0$.

- The first term is the **marginal revenue** of unit i, which is equal to the price π.
- The second term is the **marginal cost** of production of unit i.

For optimality, production must be increased until the marginal cost is equal to the market price.

Exercise 1:

Consider the unit with the inverse production function (quantity of fuel needed to generate P_1):

$$H_1(P_1) = 110 + 8.2P_1 + 0.002P_1^2 \text{ MJ/h}$$

with a minimum stable generation of 100 MW and a maximum output of 500 MW. The cost of fuel F = €1.3/MJ.

Questions:

1. What is the power that should be generated by the unit to maximize profit if electricity can be sold at €12/MWh?

2. At which electricity prices should the unit operate at maximum output?

3. What is the electricity price below which the unit cannot make any profit?

Solution:

Part 1:

Define the profit function: $Prof(P_1, \pi) = P_1 \times \pi - F \times H_1(P_1)$

Freeze the price to €12/MWh, and compute the derivative of the profit function with respect to the power:

$$\frac{dProf(P_1, 12)}{dP_1} = 1.34 - 0.0052 \times P_1$$

$$\frac{dProf(P_1, 12)}{dP_1} = 0 \iff P_1 = 257.69 \text{ MW}$$

Part 2:

The partial derivative of the profit function with respect to the power variable allows to determine a relationship between any power and its associated optimal price :

$$\frac{\partial Prof(P_1, \pi)}{\partial P_1} = -0.0052 \times P_1 + \pi - 10.66$$

$$\frac{\partial Prof(P_1, \pi)}{\partial P_1} = 0 \iff \pi = 10.66 + 0.0052 \times P_1$$

We then compute the optimal price associated with a power of 500MW:

$$\pi^*(P_1) = 10.66 + 0.0052 \times P_1$$

$$\pi^*(500) = 13.26 \text{ EUR}$$

Part 3:

First approach: solve the following optimization problem:

$$\begin{aligned} &\min_{\pi, P_1} \pi \\ &\text{subject to } \pi \times P_1 - F \times H_1(P_1) \geq 0 \\ &\qquad 100 \leq P_1 \leq 500 \end{aligned}$$

Alternative approach: getting a zero profit provides a mathematical relationship that returns, for any power, the minimum price:

$$\pi_{\text{min}}(P_1) = \frac{143}{P_1} + 10.66 + 0.0026 \times P_1$$

$$Prof(P_1, \pi) = 0 \iff \pi = \frac{143}{P_1} + 10.66 + 0.0026 \times P_1$$

By minimizing the previous mapping through differentiation, we can compute a power for which the associated minimal price is the smallest among all minimum prices:

$$\frac{d\pi_{\text{min}}(P_1)}{dP_1} = 0.0026 - \frac{143}{P_1^2} \qquad \frac{d\pi_{\text{min}}(P_1)}{dP_1} = 0 \iff P_1 \in \{-234.52, 234.52\}$$

We finally get the electricity price by computing the minimum price associated with the power :

$$\pi_0 = \pi_{\text{min}}(234.52) = 11.88 \text{ EUR}$$

A more realistic scheduling

The production profile needs to be optimized over several market periods rather than just one due to the following factors:

- **Start-up costs**: These are the costs associated with starting units. Diesel generators and open cycle gas turbines have low start-up costs, while large thermal units require a significant amount of heat energy before the steam reaches the temperature and pressure sufficient to sustain the generation of electric power, resulting in high start-up costs.

- **Dynamic constraints**: Limits are placed on the variation of production of a generator to avoid mechanical stress (mainly on the prime mover) and the problems related to temperature gradients.

- **Environmental constraints**: For example, the rate at which certain pollutants are released into the atmosphere is limited (or restricted over a year), and there are constraints on the use of water for hydro plants.

How can we measure the cost to produce electricity?

The **Levelized Cost of Electricity (LCOE)**, or Levelized Energy Cost (LEC), is often used as a measure to define the cost of electrical energy.

It represents the **net present value of the unit cost of electricity**.

LCOE is commonly considered as a proxy for the average price that the generating asset must receive in the market to break even over its lifetime.

It provides a first-order economic assessment of the cost competitiveness of an electricity-generating system, incorporating all costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital.

LCOE – Mathematical formulation

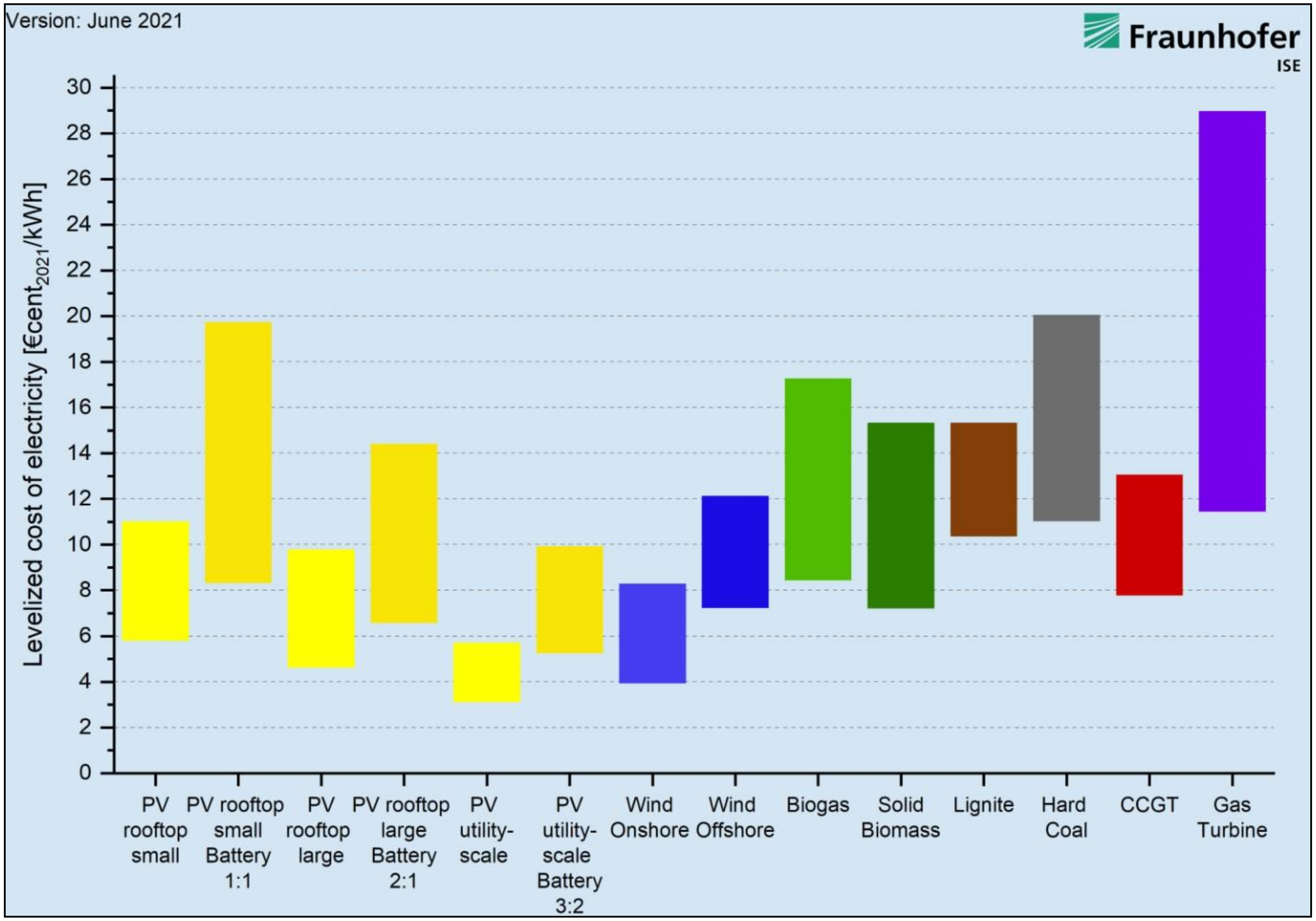
Mathematically, LCOE is computed as:

$$LCOE = \frac{cost}{electricity} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where:

- I_t = Investment expenditures in the year t;
- M_t = Operations and maintenance expenditures in the year t;
- F_t = Fuel expenditures in the year t;
- E_t = Electricity generation in the year t;
- r = Discount rate;
- n = Life of the system

LCOE – Example



LCOE of renewable energy technologies and conventional power plants at locations in Germany in 2021.[1]

[1] https://www.ise.fraunhofer.de/en/press-media/press-releases/2021/levelized-cost-of-electricity-renewables-clearly-superior-to-conventional-power-plants-due-to-rising-co2-prices.html

The net present value

To evaluate the profitability of a project, producers can use the **net present value (NPV)**. The NPV of a project for electricity generation is defined as:

$$NPV = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t}$$

$$C_t = R_t - M_t - F_t - I_t$$

where C_t is the cash-flow during year t and R_t are the revenues generated by the power plant during year t.

The **internal rate of return (IRR)** of a project is the value of r that leads to an NPV equal to 0.

The **payback period** is the time required to recoup the funds expended in an investment.

Exercise 2:

Mister X has installed at home 4 kWp of PV panels at a price of €6,000. His panels have a lifetime of 20 years. This installation generates 3,500 kWh of electricity per year.

1. Compute the LCOE given a discount rate of 0% and 5%.

2. Assume a retail price for electricity of €c23/kWh, compute the payback period of the installation.

3. Given the same retail price for electricity, compute the internal rate of return of the project.

Reminder: $\sum_{k=a}^{b} q^k = \frac{q^a - q^{b+1}}{1-q}$ where $a, b \in \mathbb{N}$ and $q \neq 1$.

Solution:

Part 1:

Apply the LCOE formula, taking into account the following assumptions:

$$n = 20$$

$$I_1 = 6000, I_t = 0, \forall t \in \{2, \ldots, n\}$$

$$M_t = 0, \forall t \in \{1, \ldots, n\}$$

$$F_t = 0, \forall t \in \{1, \ldots, n\}$$

$$E_t = 3500, \forall t \in \{1, \ldots, n\}$$

LCOE values for discount factors of 0% and 5% are €c9/kWh and €c14/kWh, respectively.

Part 2:

Consider the simple payback time. Each year, an economy of 3,500 × 0.23 euros is made. Thus, payback time is :

$$\Delta = \frac{6000}{0.23 \times 3500} = 7.45 \text{ years.}$$

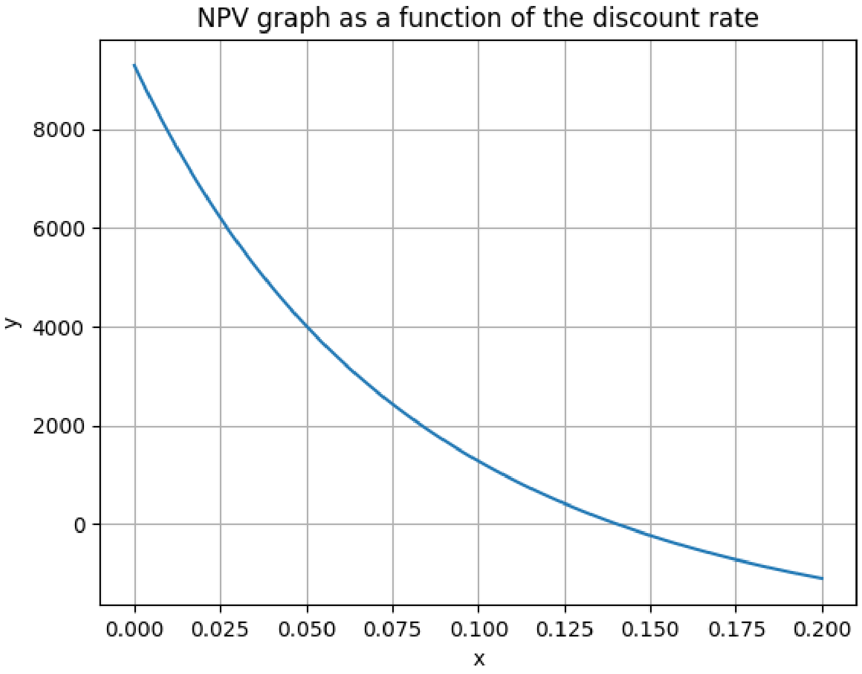
Part 3:

IRR can be obtained by studying the NPV as a function of the discount rate:

$$NPV(r) = \frac{0.23 \times 3500 - 6000}{1+r} + \sum_{t=2}^{20} \frac{0.23 \times 3500}{(1+r)^t}$$

The internal interest rate can be found by searching numerically for a zero of the NPV function, for instance using Newton-Raphson scheme:

$$\text{IRR} \ \sim 0.14$$



Fixed price contracts from retailers

The role of retailers is to buy electricity from producers and sell it to consumers. Retailers may offer their customers various types of contracts, which generally fall into two categories: **fixed price contracts or variable price contracts**, depending on the customers risk aversion.

In the so-called fixed price contract, you pay a monthly fee equal to:

A + B x **Consumption**

with **A** is expressed in EUR, **B** in EUR/kWh and where **Consumption** is the monthly consumption in kWh. The terms **A** and **B** do not change over the duration of the contract.

Variable price contracts from retailers

For a typical variable energy price contract, you pay per month a fee equal to:

A + (Index x **B + C)** x **Consumption**

where **A** is expressed in EUR, **C** in EUR/kWh and **B** is dimensionless. These three terms remain constant over the duration of the contract. **Index** is expressed in EUR/kWh and varies from month to month. It is related to the average of the prices observed on the spot market.

In Belgium, 60% of contracts were fixed price contracts before the 2022 energy crisis. Now retailers prefer very much to offer variable price contracts.

Challenges in energy retailing and pricing

- To buy energy at a variable price on the wholesale market and sell it at another price, sometimes a fixed one, at the retail level.

- The quantity-weighted average price at which a retailer purchases energy should be lower than the rate it charges its customers.

- Retailers must accurately forecast the consumption of their customers to reduce their exposure to spot market prices (accuracy is usually good when serving a large group of customers).

- Retailers may offer more competitive tariffs to customers who record the energy consumed during each time period.

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 05 – Chronology of electricity markets and the forward/futures markets

Explanation of the terminology

The first option to build an offer is to buy directly from the producer. They can also buy electricity through a market.

But what are exactly electricity markets?

According to Investopedia, a market is a place where two parties can gather to facilitate the exchange of goods and services. The parties involved are usually buyers and sellers. The market may be physical like a retail outlet, where people meet face-to-face, or virtual like an online market, where there is no direct physical contact between buyers and sellers.

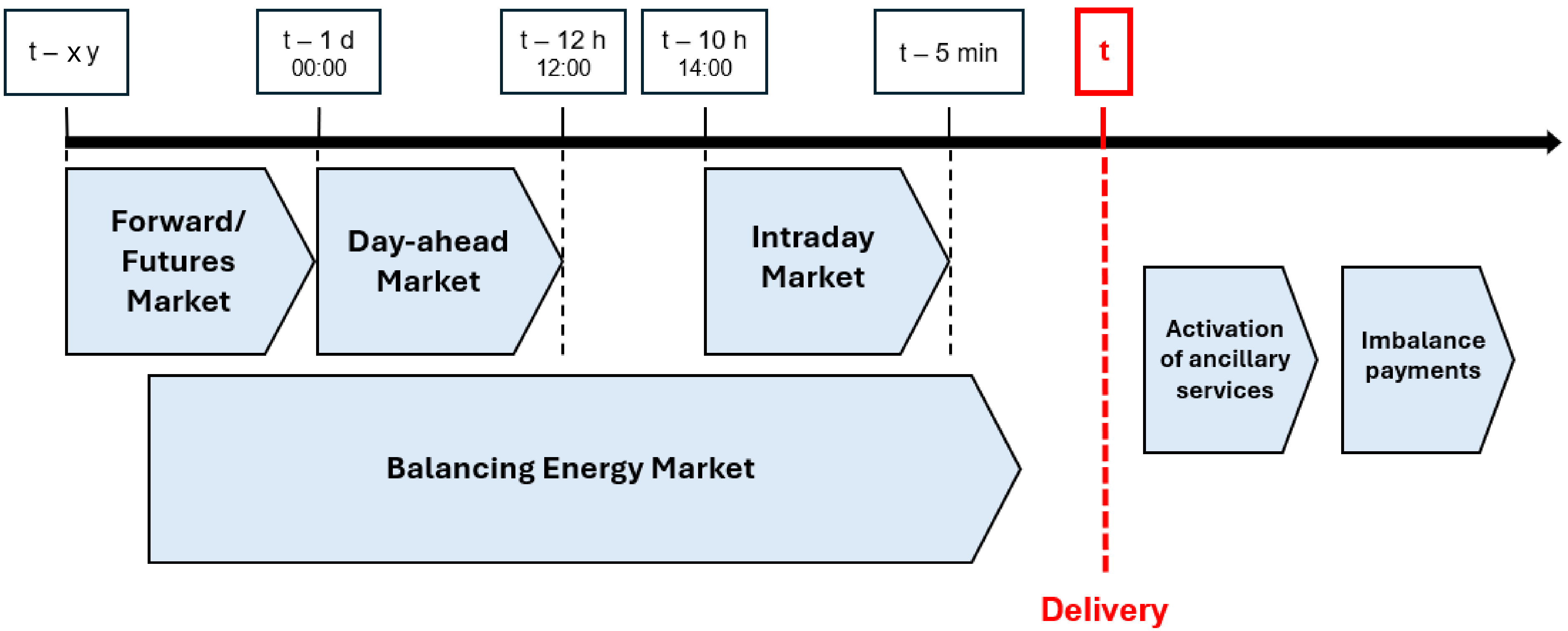
What is an electricity market?

- product → electricity (both energy and power)
- buyers → retailers & sellers → producers
- mostly virtual

Why an '*s*' in markets?

Electricity has some special properties → several ways to exchange it.

Chronology of markets



Bilateral contracts

There are two main categories of markets, bilateral markets and electricity pools.

In **bilateral trading**, energy is exchanged directly between two parties: a buyer and a seller. Several forms of bilateral trading exist, depending on the volume of energy involved and the time available for delivery:

- **Customized long-term contracts**:

  These contracts are negotiated privately and typically involve large volumes of energy. Due to the scale of the transaction, they tend to incur higher transaction costs.

- **Over-the-counter (OTC) trading**:

  This form involves smaller amounts of energy and typically uses a standard delivery profile that specifies energy amounts for different times of the day or week. OTC trading generally has lower transaction costs and is often used for adjusting or refining positions.

Electronic trading

Electronic trading: Offers to buy energy or bids to sell energy are traded. Bids and offers are visible to everyone but remain anonymous.

When a party enters a new bid, the system checks if it matches an existing offer (i.e., an offer with a price greater than or equal to the bid). If a match is found, a deal is struck. Otherwise, the bid is added to the list of bids. A similar procedure applies to offers.

Remarks: Electronic trading is fast and cost-effective, often used to refine positions in the minutes before the market closes.

Electricity pools

Electricity naturally pools as it flows from generators to loads, leading to the concept that trading could be **centralized through electricity pools**.

In this system, there are no repeated interactions between buyers and sellers to achieve market equilibrium. Instead, **a pool provides a systematic mechanism for determining this equilibrium**.

The trading process in a pool is centralized, simplifying the matching of supply and demand at an aggregated level, and ensuring that prices reflect the overall balance between generation and consumption.

Electricity pools – how they work

Producers submit **bids** for the period under consideration.

Bids represent the amount of electrical energy at a certain price. These bids are ranked in order of increasing price, and a **supply curve** for the market is created.

Consumers submit **offers** (the amount of energy they are willing to buy at a certain price), forming a **demand curve**.

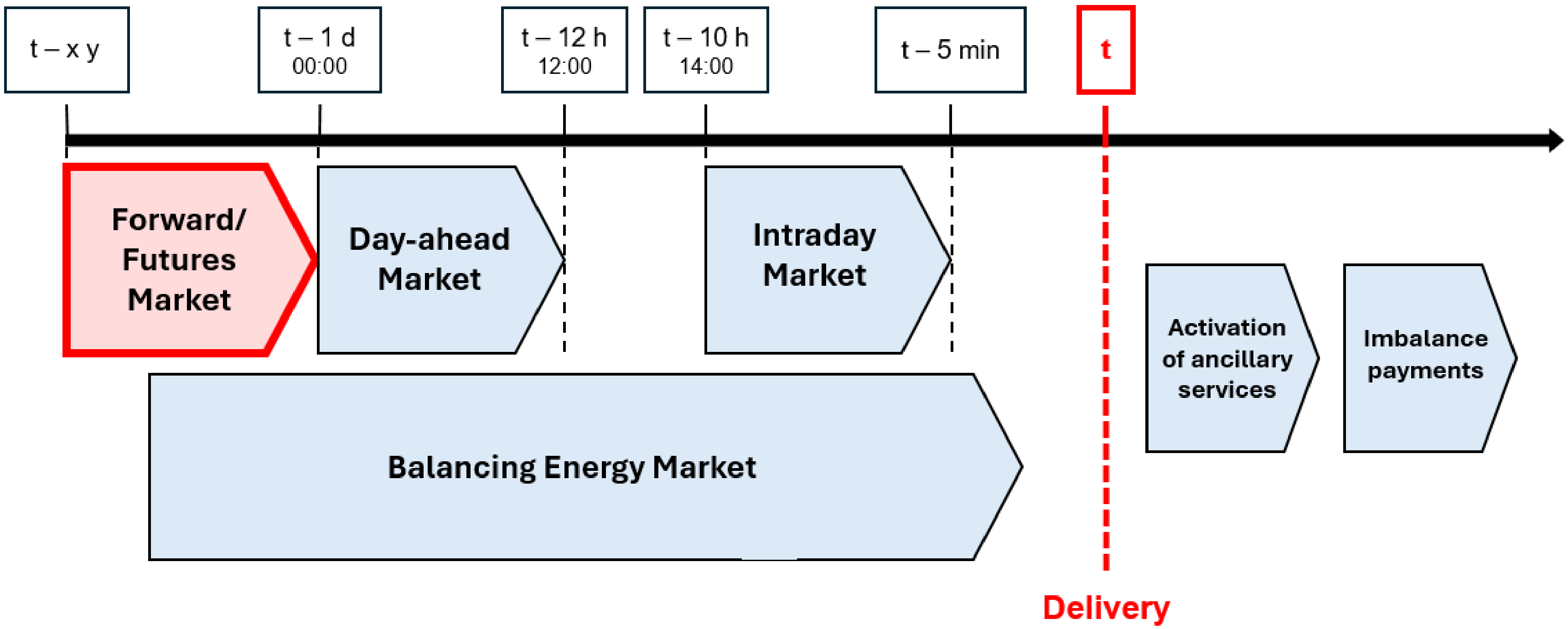
⇒ These two curves define the **merit order**.

The intersection of the demand and supply curves represents the market equilibrium price (also called the **System Marginal Price, SMP**).

Bids below the market equilibrium price and offers above it are accepted.

More information on this subject will be covered in the Chapter 06.

Let us focus on the first market



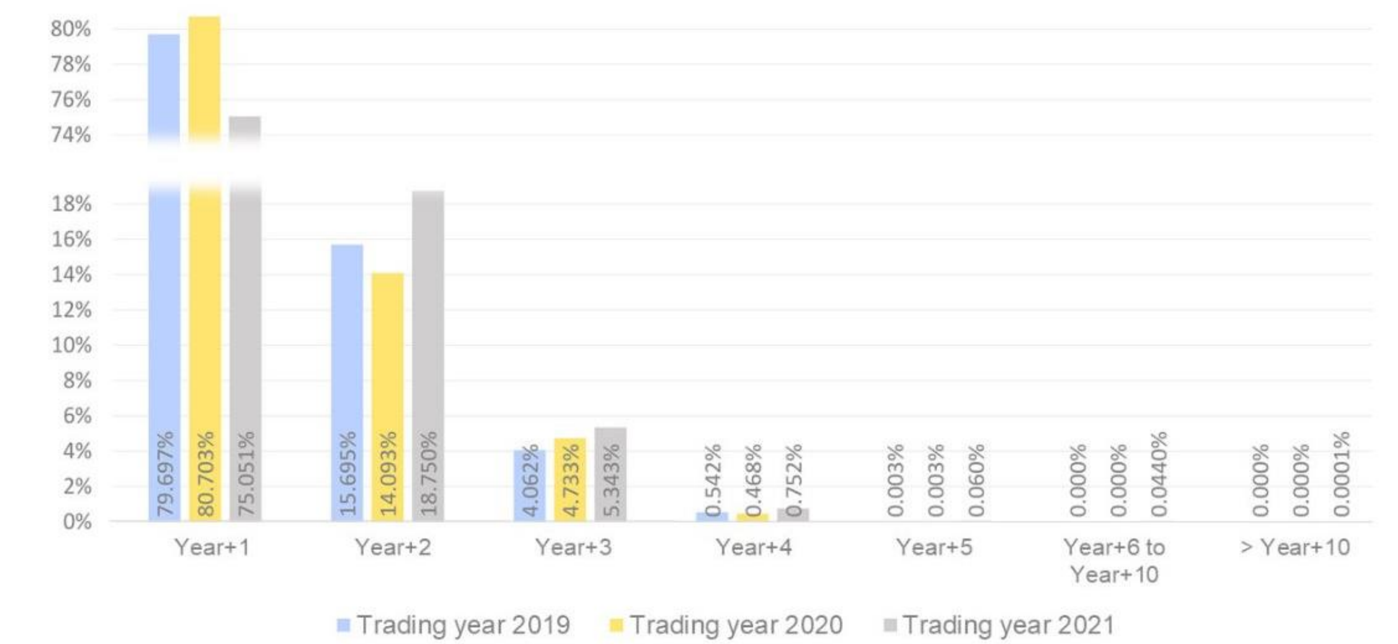
The forward market is the most prominent electricity market when it comes to the number of transactions (88% of transactions), followed by spot markets covering day-ahead (11%) and intraday (1%) timeframes.

Forward/future market – Reminder

A variety of products are available, including yearly, quarterly, or monthly base-load products. These products provide a fixed amount of energy for the given period.

The trading horizon ranges from several years up to a few days before the product's first delivery day.

Market operators include EEX and ICE Endex.



Source: ACER data.

Note: The blue, yellow and grey bars respectively sum up to 100% (over all timeframes). For 2020 (respectively 2021), Year +1 means products for delivery in 2021 (respectively 2022).

Relative shares of trading volume per year in the future of Germany (2019-2021)[1].

[1] https://www.acer.europa.eu/sites/default/files/documents/Publications/Progress_report_European_wholesale_electricity_21.pdf

Hedging (1/3)

The forward/futures market brings together producers and consumers interested in trading through forward/futures contracts to **reduce exposure to the volatility** of the spot market, a practice known as **hedging**.

The forward/futures price should reflect **the consensus expectation of the spot price.**

<u>Examples of hedging:</u>

A generator is interested in hedging its revenues from producing electricity. It sells 100 MWh of electricity every hour of a year at €50/MWh in a forward market:

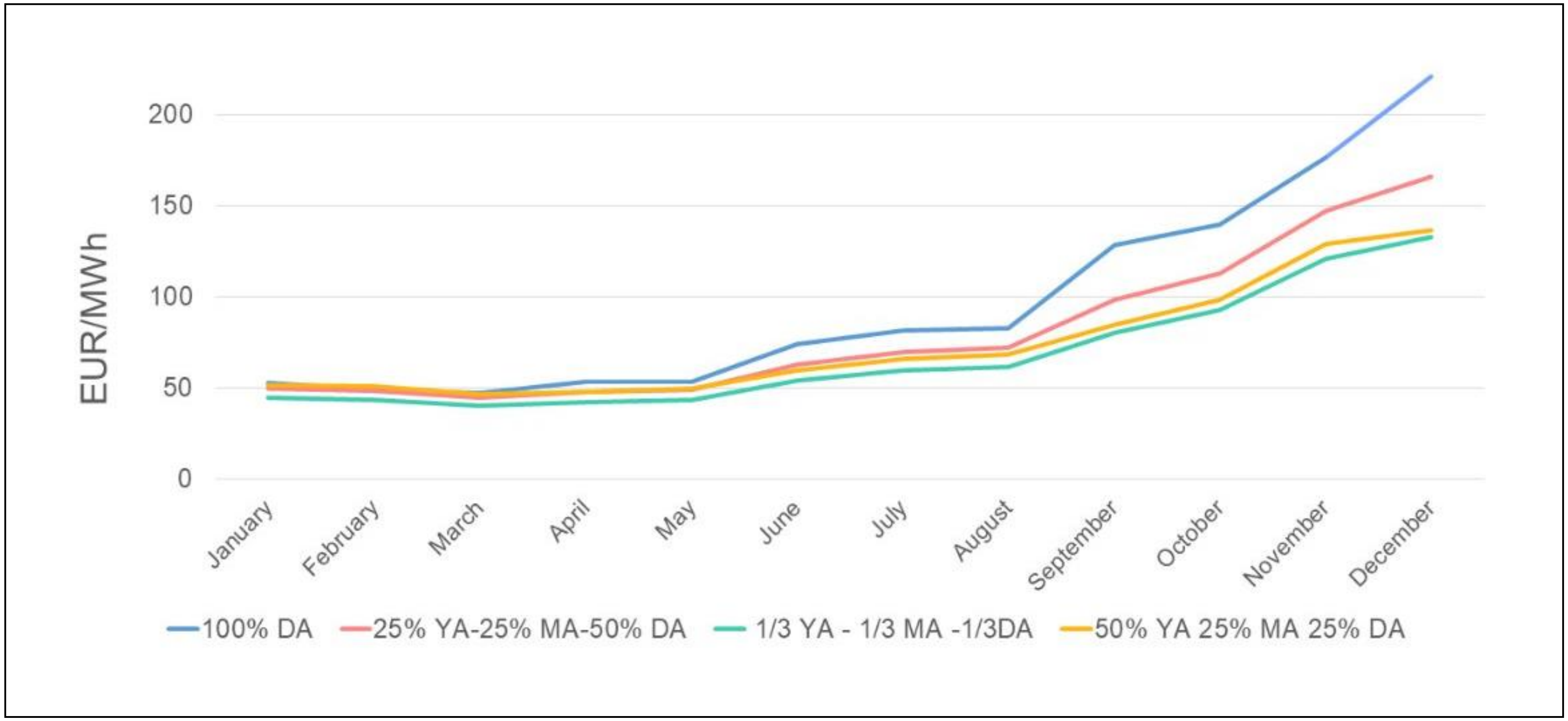
- (+): it **hedges against the risk** of prices (and revenues) dropping below €50/MWh (e.g.: €30/MWh).
- (-): it gives up potential additional revenues if prices increase to €100/MWh.

An electricity-intensive consumer will also wish to hedge its costs. If the consumer buys that annual 100 MWh contract for €50/MWh:

- (+): it **avoids the risks** of losing money if prices increase above €50/MWh (e.g.: €100/MWh).
- (-): it gives up on the potential lower cost (e.g.: €30/MWh).

Hedging (2/3)

Using proper hedging strategies allows to reduce the cost of energy. The following graph illustrates that hedging the procurement smoothens the impact of high prices.



Unit procurement costs in €/MWh of a retailer using different hedging strategies in the German electricity market in 2021.[1]

[1] https://www.acer.europa.eu/sites/default/files/documents/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf

Hedging (3/3)

The previous figure shows different procurement strategies a retailer could have adopted in the German electricity market in 2021. These strategies range from fully sourcing electricity in day-ahead markets to using various shares of month- or year-ahead contracts. The example demonstrates that hedging procurement smooths the impact of high prices, which began in September 2021. The longer the hedge, the more gradual the price increase experienced by the retailer and its customers.

Price volatility does not necessarily increase the average cost paid by consumers over time. Likewise, **long-term procurement does not completely shield consumers from rising prices but spreads the impact over a longer period**, reducing the immediate shock of price spikes.

Forward contracting

Forward contracts are over-the-counter (OTC) bilateral agreements that allow for customizable terms based on the specific needs of the parties involved.

These terms include:

- The quantity and quality of the product to be delivered;
- The delivery date;
- The payment date following delivery;
- The penalties for either party failing to meet their commitments;
- The price to be paid.

Forward contracting facilitates planning by minimizing the risk of unexpected price fluctuations. It enables businesses to set prices with confidence in their cost structure and allows consumers to better manage their budgets.

Since these are bilateral contracts, there is a **counterparty risk** (i.e., the risk that one party will default on its obligations). There is no third-party institution that guarantees the transaction between the two parties.

Futures contracting

Futures contracts are traded on regulated markets, such as the EEX. Because of this, **futures contracts tend to be more liquid than OTC forward contracts**. This increased liquidity means that there are many market participants, making it easier to buy and sell these contracts; traders can easily enter and exit positions without causing significant price fluctuations.

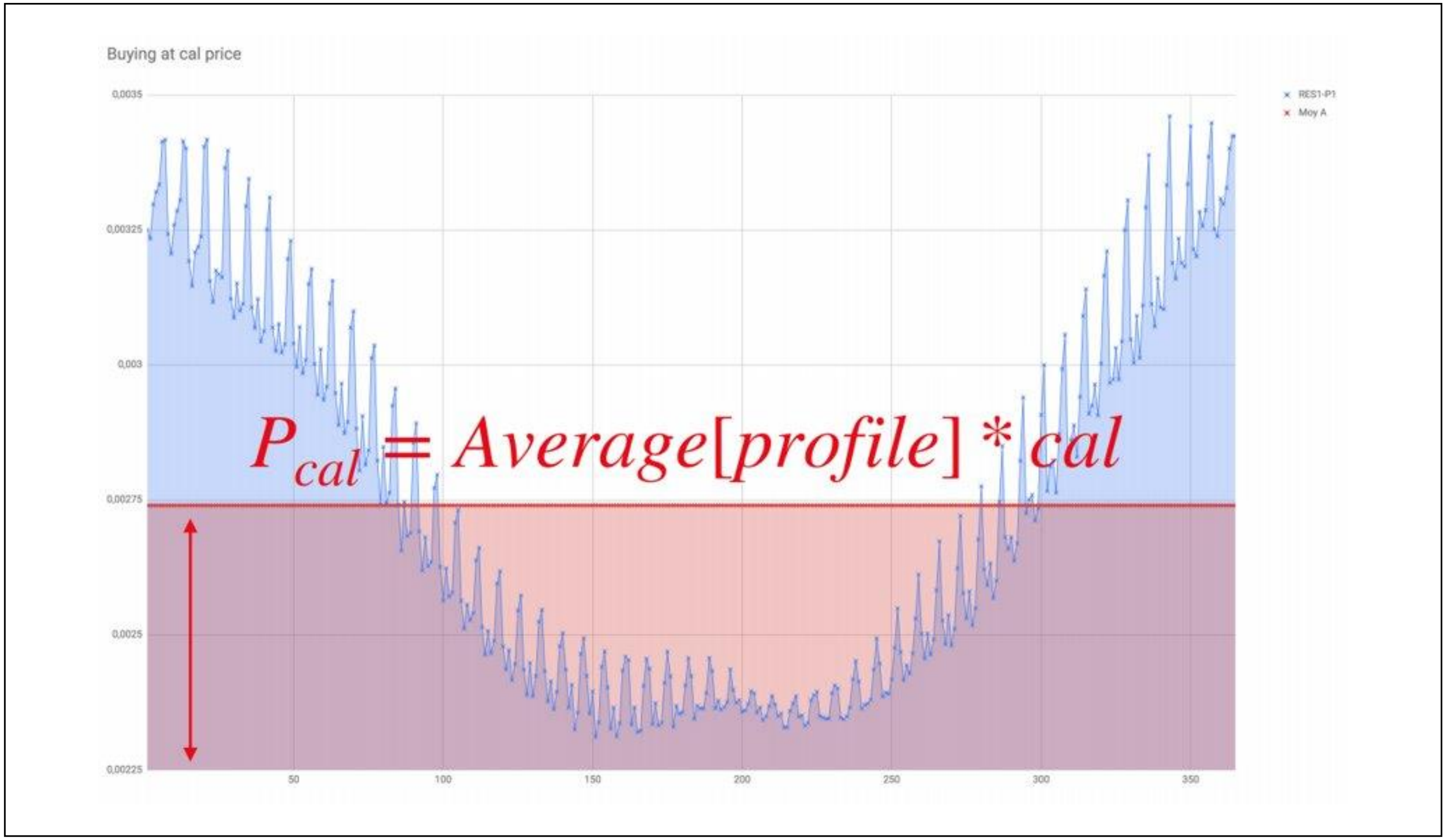
In the context of futures contracts, a clearinghouse acts as an intermediary. It ensures that transactions are executed properly, thereby **reducing counterparty risk for participants**. If one party defaults, the clearinghouse takes on the obligations, protecting the other participants.

Forward vs Futures – summary of differences

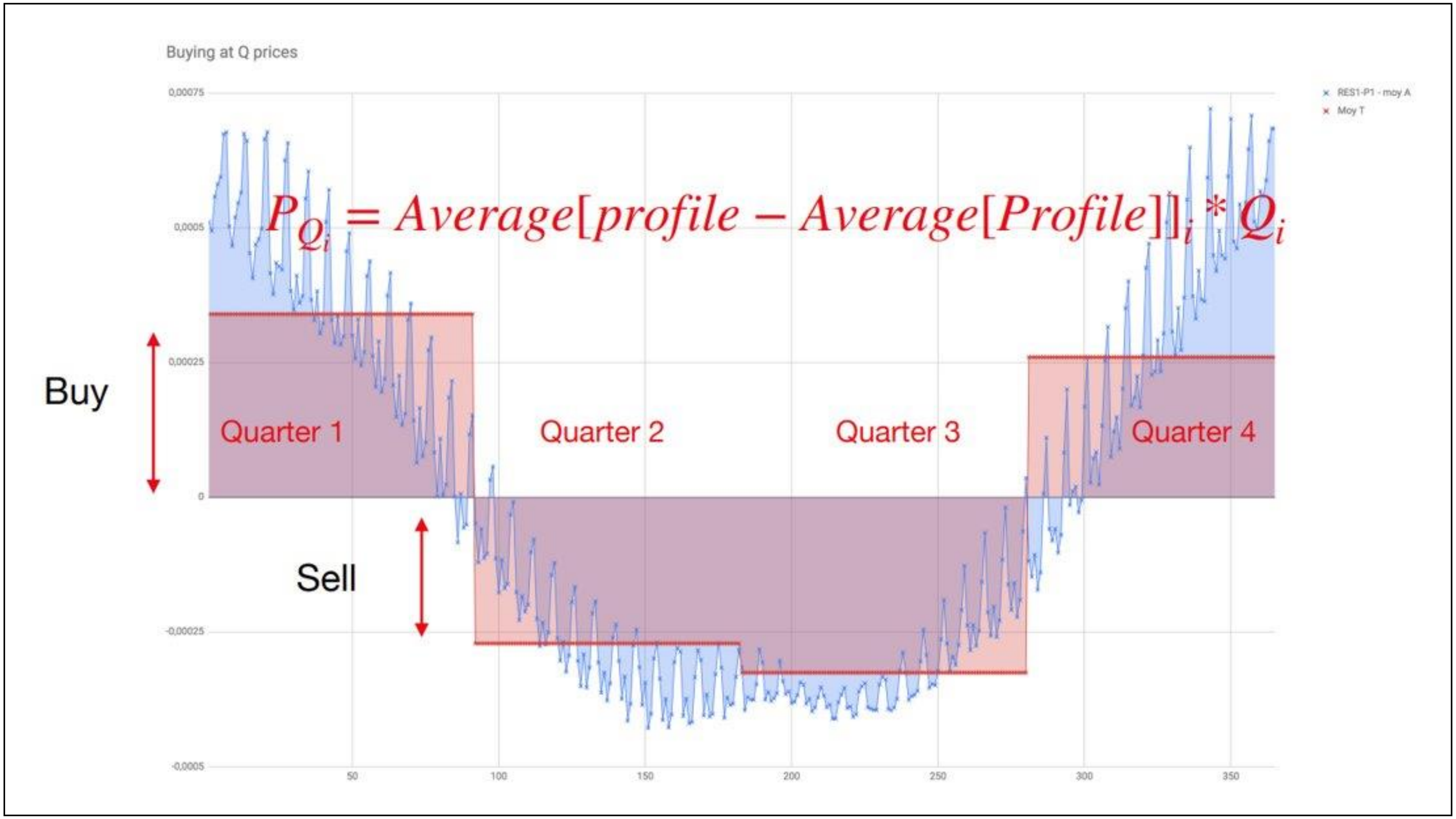
Aspect	Forward Market	Futures Market
Trading platform	OTC (private negotiation)	Organized exchange (standardised)
Regulation	Less regulated (higher counterparty risk)	Highly regulated (lower counterparty risk)
Customisation	Fully customisable	Standardised contracts
Settlement	Mainly physical (can be financial)	Mainly financial (can be physical)
Liquidity	Lower liquidity	Higher liquidity
Price transparency	Less transparent	Highly transparent
Counterparty risk	Higher (no clearinghouse)	Lower (clearinghouse guarantees)

What is a good strategic practice for a supplier to effectively use forward markets for hedging? (1/3)

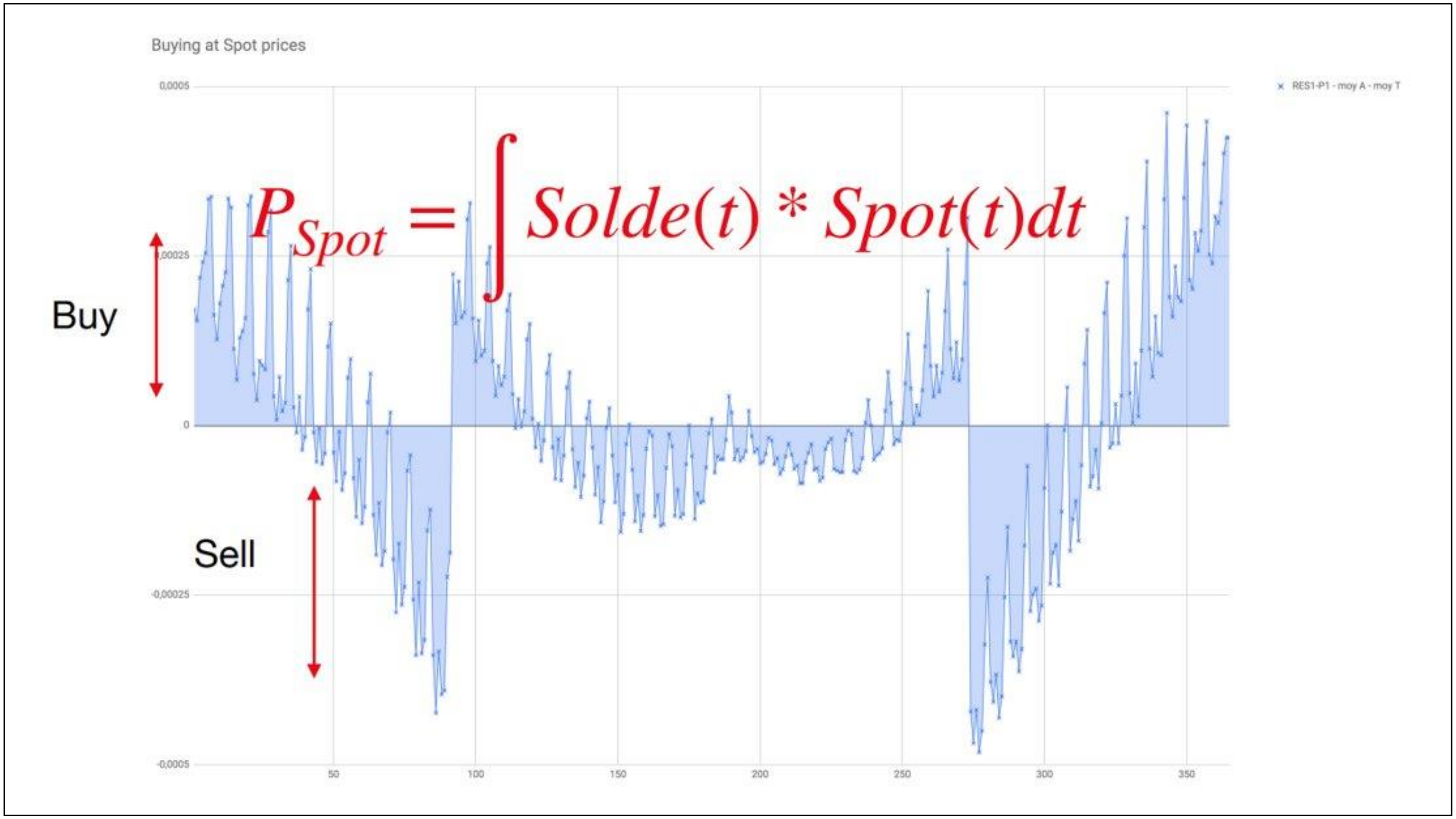
A supplier cannot only purchase standardized products to cover a long period. In this context, how can it effectively hedge itself?



What is a good strategic practice for a supplier to effectively use forward markets for hedging? (2/3)



What is a good strategic practice for a supplier to effectively use forward markets for hedging? (3/3)



Options (1/2)

Futures and forward contracts are firm contracts, meaning delivery is unconditional. If the seller is unable to deliver the agreed quantity, or the buyer cannot take full delivery, they must buy or sell it via another market (e.g., day-ahead).

Options are contracts with conditional delivery; they are only exercised if the holder chooses to do so.

- **Call option:** gives the holder the right to buy a specified amount of a commodity at a price called the exercise price.

- **Put option:** gives the holder the right to sell a specified amount of a commodity at the exercise price.

Options (2/2)

Contracts for difference (or swaps) work as follows:

The two parties agree on a strike price and an amount of the commodity for a given period of time. The contract is settled by paying the difference between the strike price and the spot market price for that period, multiplied by the agreed amount, to the buyer or seller.

For instance, if the spot price is €100/MWh, the swap price is €75/MWh, and the amount is 20 MWh, the buyer pays €25 $\times$ 20 to the seller at the agreed date and time. If the spot price falls below €75/MWh, the seller owes money to the buyer.

Contracts for difference are often grouped across several time periods. For example, peak swaps cover multiple peak load hours. More complex forms of swaps exist, such as caps, floors, and collars (see [Biggar]).

Power Purchase Agreement

A **Power Purchase Agreement (PPA)** is a long-term (10-20 years) contractual agreement between an energy buyer and seller.

The buyer agrees to purchase a portion of the production from a generation asset at a fixed price per MWh for the duration of the contract.

PPAs can provide a reliable source of financing for project developers while offering protection to investors.

Although this type of contract can be used for any generation asset, renewable project developers have increasingly turned to PPAs for financing as government subsidies for renewable energy projects have decreased.

Collateral

Collateral refers to **money set aside as a guarantee** by the buyer and seller of long-term products. This guarantee covers the risk of default by one of the counterparties.

Hedging through trading in **forward and futures markets requires collateral**.

When prices spike and volatility increases, collateral requirements also rise significantly, increasing the financial guarantees that market participants need to hedge for future years.

An increase in collateral requirements – also called **margin call** - often leads to increased debt, which may put some market participants at risk of bankruptcy.

Collateral – example (1/2)

1. Initial Contract:

Party A buys a calendar product for **2,000 MWh** to be delivered in Year Y+2 at **€100/MWh**. The total contract value is: $2{,}000 \times 100 = €200{,}000$.

2. Market price drop in year Y+1:

During year Y+1, the market price for the same product drops to **€80/MWh**.

If Party A defaults (e.g., becomes bankrupt or decides not to honor the contract to buy electricity from a cheaper source), they will fail to fulfill their obligation to purchase at the agreed-upon price of €100/MWh.

Collateral – example (2/2)

3. Seller's risk:

The seller is now in a position where they would have to sell the **2,000 MWh** in the open market at the lower market price of **€80/MWh** instead of the agreed price of **€100/MWh**.

This results in a **€20/MWh** loss for the seller. For **2000 MWh**, this amounts to a total potential loss of **2,000 MWh** × **€20/MWh** = **€40,000.**

4. Margin Call:

To **protect** the *seller* from this **potential loss**, a margin call of **€20/MWh** is applied to the **2,000 MWh** that Party A has contracted to buy.

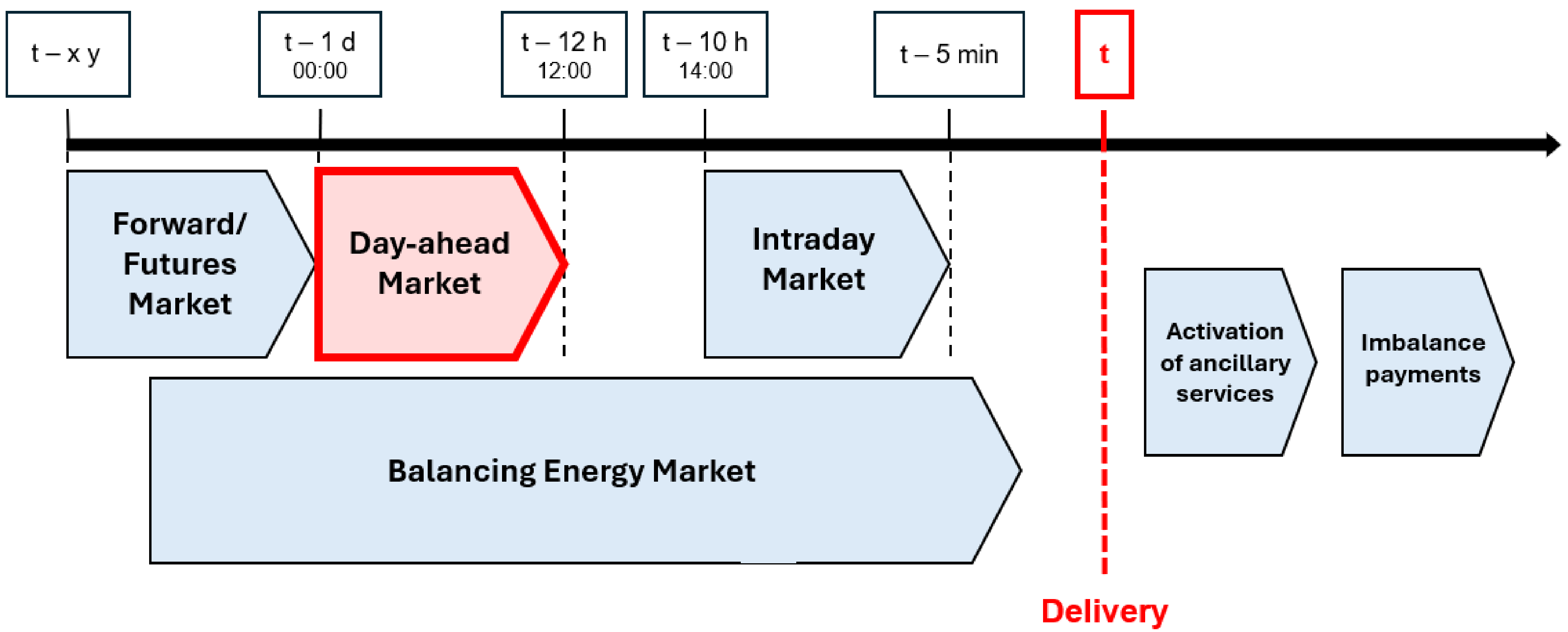
This means that Party A (buyer) is required to deposit the potential loss of **€40,000** as collateral to cover the risk of default.

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 06 – The day-ahead market and its optimization problem

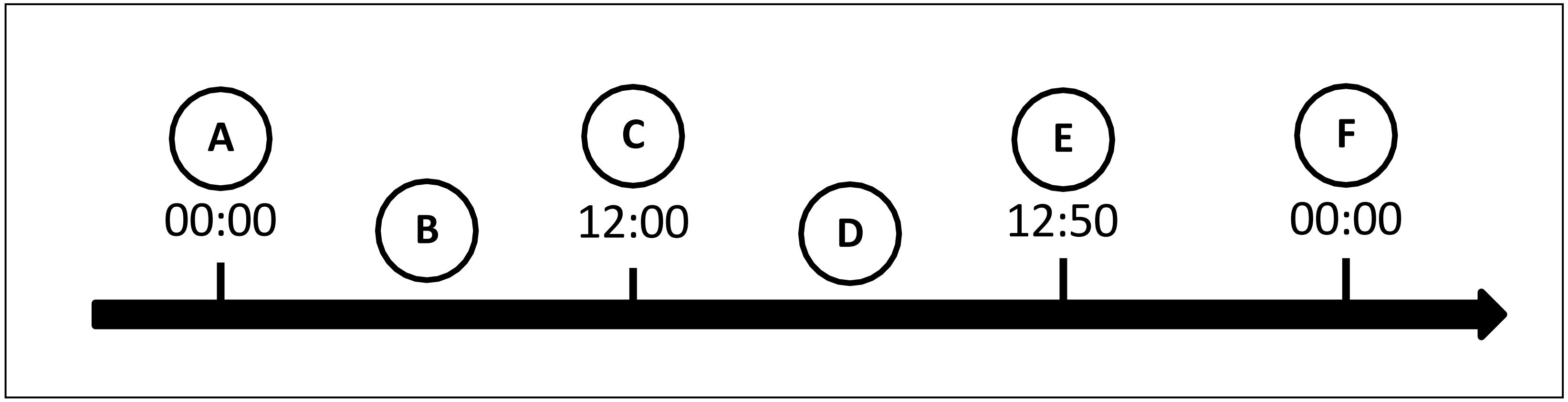
Chronology of markets



Elements of context of the day-ahead market

- One day before delivery time, the day-ahead market, also referred to as the electricity spot market, allows participants to **adjust their position for the 24 hours of the following day**.
- Hourly products allow participants to buy or sell electricity for each hour of the next day.
- The market operator is **EPEX SPOT**.
- Producers aim to:
  - sell energy if they expect to make a profit (referred to as being ‘in the market’) or,
  - purchase energy to meet their delivery obligations if it is cheaper than producing it themselves. (referred to as being ‘out of the market’)
- Retailers buy energy for their consumers and adjust their positions based on their expectations of a surplus or shortage, depending on their forward contracts.

Timeline of the day-ahead market



A. Opening of the day-ahead market for all hours of the following day.

B. Market participants submit their bids and offers to the order book.

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.

Exercise 1:

According to the buying and selling instructions given in the table:

1. What minimum price should a consumer pay for buying 20 MWh? What is the cost of the last unit of energy?

2. What maximum revenue will a producer receive for selling 20 MWh? What is the revenue of the last unit of energy?

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	50	20
G2	Sell	100	10
G3	Sell	20	30
G4	Sell	200	5
G5	Sell	10	0
C1	Buy	50	1
C2	Buy	100	15
C3	Buy	200	20
C4	Buy	50	30

Solution:

Part 1:

- What minimum price should a consumer pay for buying 20 MWh?

  10 MWh × €0/MWh + 10 MWh × €5/MWh = €50

- What is the cost of the last unit of energy?

  €5 – the marginal cost for a consumer

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	50	20
G2	Sell	100	10
G3	Sell	20	30
G4	Sell	200	5
G5	Sell	10	0
C1	Buy	50	1
C2	Buy	100	15
C3	Buy	200	20
C4	Buy	50	30

Part 2:

- What maximum revenue should a producer receive for selling 20 MWh?

  20 MWh × €30/MWh = €600

- What is the revenue of the last unit of energy?

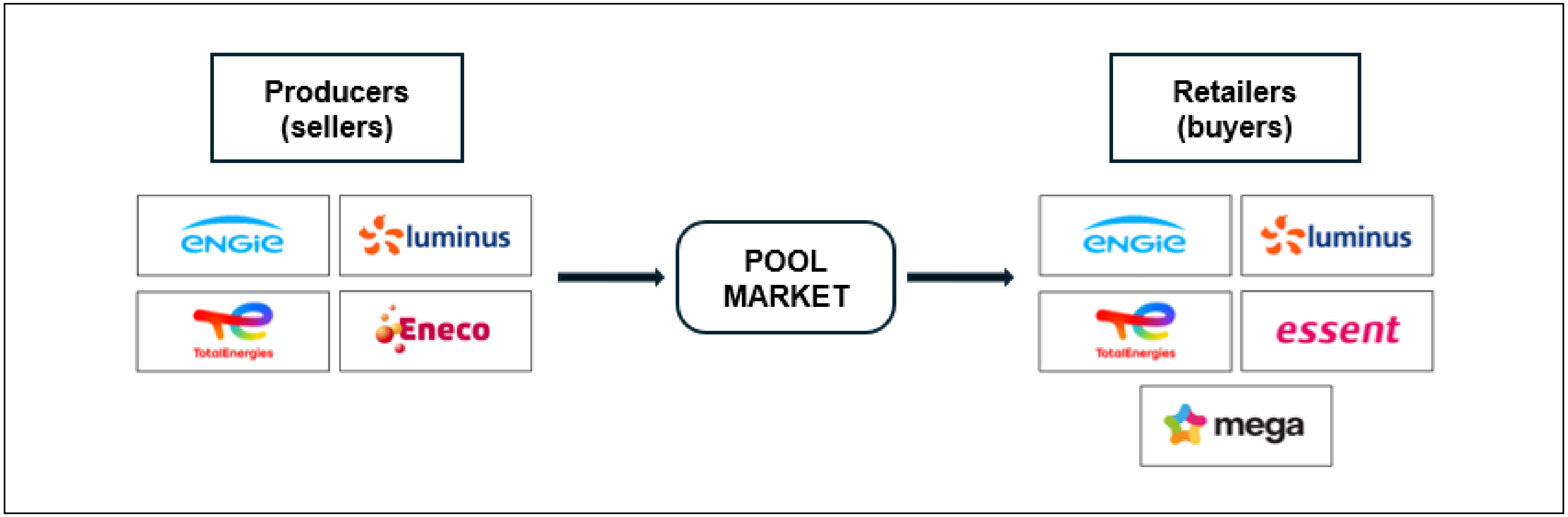
  €30 – the marginal revenue for the producer

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	50	20
G2	Sell	100	10
G3	Sell	20	30
G4	Sell	200	5
G5	Sell	10	0
C1	Buy	50	1
C2	Buy	100	15
C3	Buy	200	20
C4	Buy	50	30

Key terms in electricity markets – Pool market

Participants in the pool market can submit requests to buy or sell energy, which are referred to as 'orders', 'offers', or 'bids'.

The expression 'pool market' refers to a centralized marketplace where electricity is traded between sellers (producers/generators) and buyers (i.e., retailers, suppliers, large consumers).



Sellers and buyers **do not interact outside of the pool market**, even if they belong to the same firm. All bidding decisions must be based only on public information.

Key terms in electricity markets – Orders

An **order** is a general term that applies to both the buying and selling of quantities or volumes of electrical power at a specified price for a given period. Orders are anonymous in the pool market.

- An **ask order** represents the price a seller is willing to accept; this is an offer.
- A **buy order** represents the price a buyer is willing to pay.

Producers submit ask orders to supply a specific amount of electrical power at a designated time for the relevant period. Retailers submit orders specifying the quantity they need and the price they are willing to pay.

<u>Note:</u> In the context of electricity markets, the term ‘bidding’ is often used to encompass both the process by which producers and retailers submit offers to supply or purchase electricity. Therefore, the term ‘bid’ can refer to both an ask order and a buy order.

Key terms in electricity markets – Marginal cost

The marginal cost is the change in total production cost that results from producing one additional unit. In the context of electricity generation, **this means the cost for a producer to generate an additional MWh**.

In the electricity market, **producers typically submit their marginal costs as bid prices**; they aim to sell their electricity at a price that covers the cost of producing that last unit. It also reflects their incentive to avoid underestimating or overestimating their costs. If a producer submits a bid price that is too low, they may not cover their costs. Conversely, a price that is too high could make them uncompetitive compared to other producers.

Key terms in electricity markets – Merit order

In the day-ahead market, producers submit their offers for each hour of the upcoming day. **The merit order organizes these offers based on their marginal costs**, ranking them from lowest to highest. This systematic arrangement determines which producers will supply electricity to meet demand.

To address this demand, the market operator (EPEX SPOT) looks at the total electricity requirement for each hour of the day and starts accepting offers according to the merit order. The least expensive production units are activated first, meaning that offers from producers with the lowest marginal costs are accepted until the total demand is satisfied. **The last accepted offer that meets the total demand sets the clearing price for that hour**.

Key terms in electricity markets – Social welfare

Social Welfare is a measure of the overall economic efficiency of the electricity market, representing the combined benefit to both consumers and producers. **Social welfare is maximized when the margin between the value consumers get from using electricity and the cost of producing it is as large as possible**. This happens when:

- Consumers benefit by paying a price (clearing price) lower than what they are willing to pay, generating the **consumer surplus**.

- Producers benefit by receiving a price (clearing price) higher than their marginal cost of production, generating the **producer surplus**.

The clearing price is a key factor in determining social welfare. If it is too low, producers may not cover their costs, leading to inefficient production or supply shortages. If it is too high, consumers may pay more than necessary, reducing consumer surplus. The optimal clearing price, therefore, is one that reflects the true marginal cost of production while satisfying demand.

Exercise 2:

Let us revisit the buying and selling instructions from Exercise 1.

1. What is the marginal cost for *x* MWh?

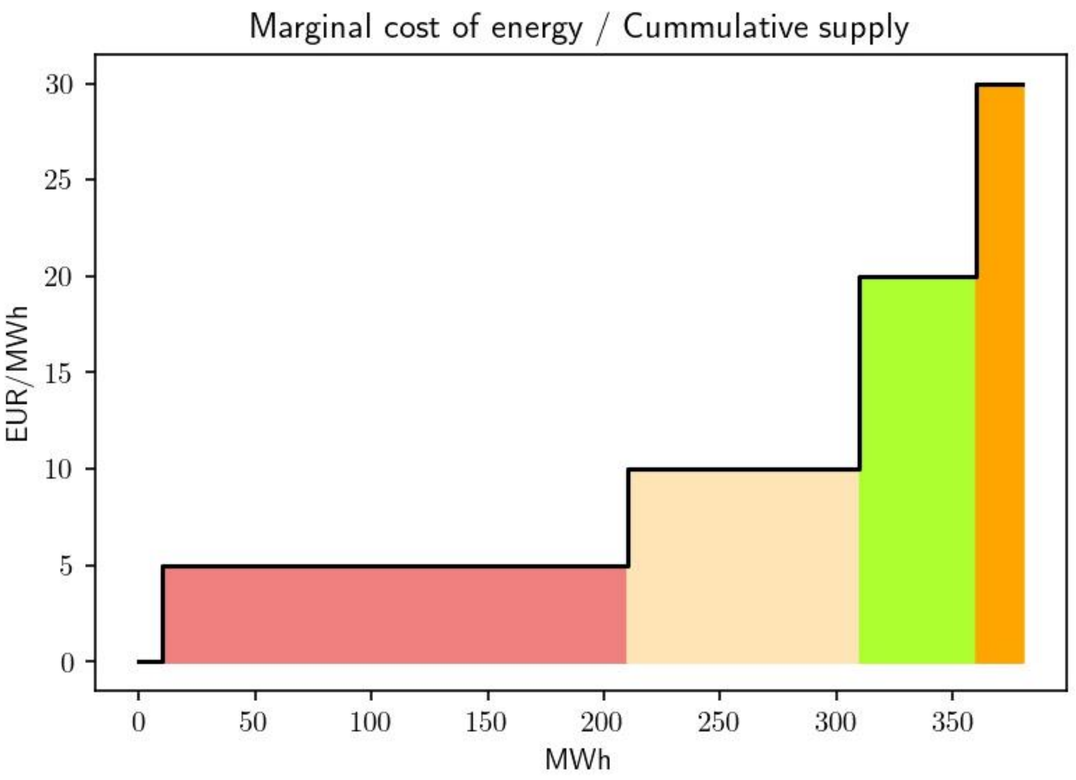
2. What is the marginal revenue for *x* MWh?

ID	Side	Quantity (MWh)	Price (€/MWh)
G1	Sell	50	20
G2	Sell	100	10
G3	Sell	20	30
G4	Sell	200	5
G5	Sell	10	0
C1	Buy	50	1
C2	Buy	100	15
C3	Buy	200	20
C4	Buy	50	30

Solution:

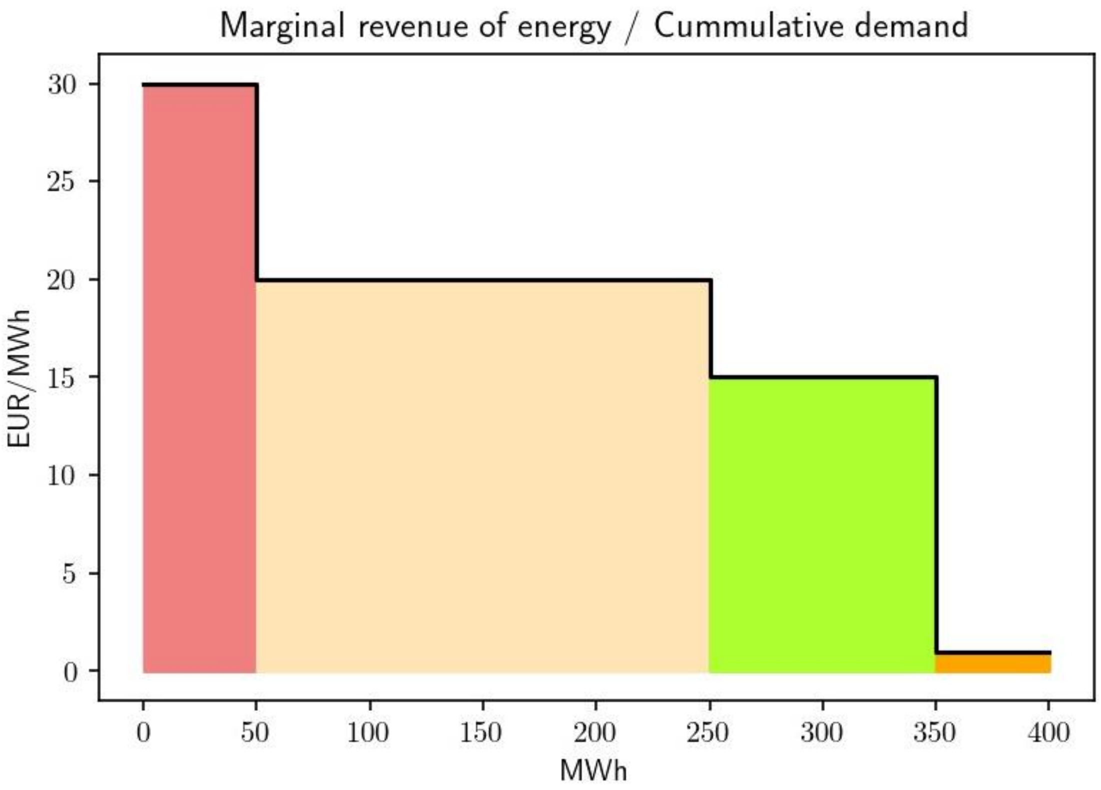
Part 1:

ID	Side	Quantity (MWh)	Price (€/MWh)
G5	Sell	10	0
G4	Sell	200	5
G2	Sell	100	10
G1	Sell	50	20
G3	Sell	20	30



Part 2:

ID	Side	Quantity (MWh)	Price (€/MWh)
C4	Buy	50	30
C3	Buy	200	20
C2	Buy	100	15
C1	Buy	50	1



Key terms illustrated through supply and demand curves (1/2)

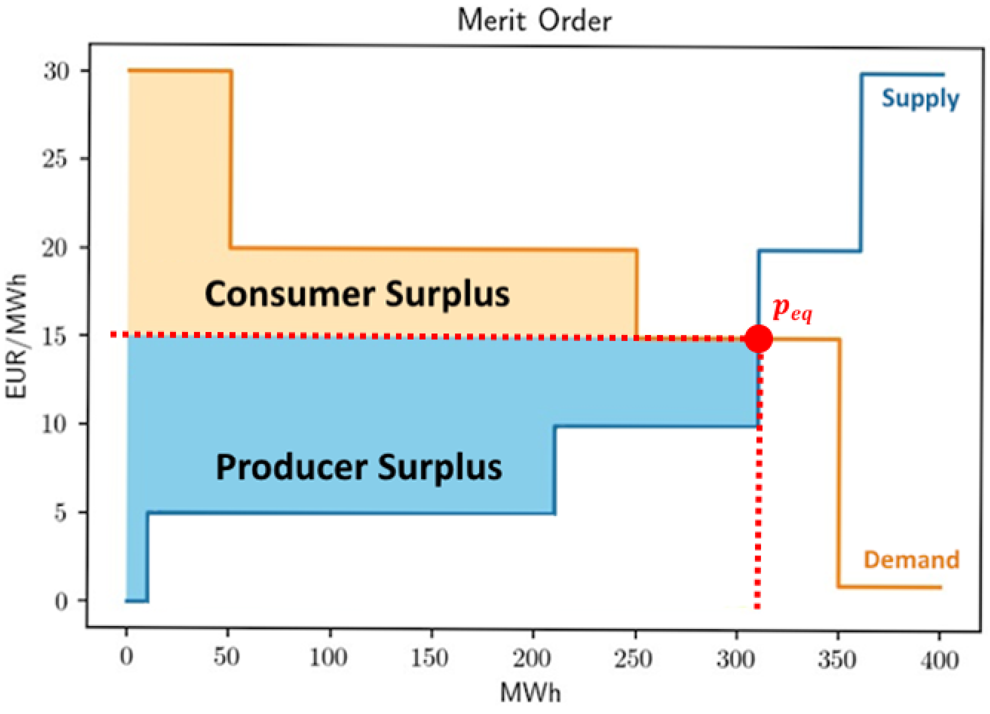
- The merit order refers to the arrangement of bids/offers in order of cost-efficiency.

- The marginal cost represents the cumulative supply curve, while the marginal revenue reflects the cumulative demand.

- The clearing price is the **equilibrium price p_{eq}** where supply and demand intersect.

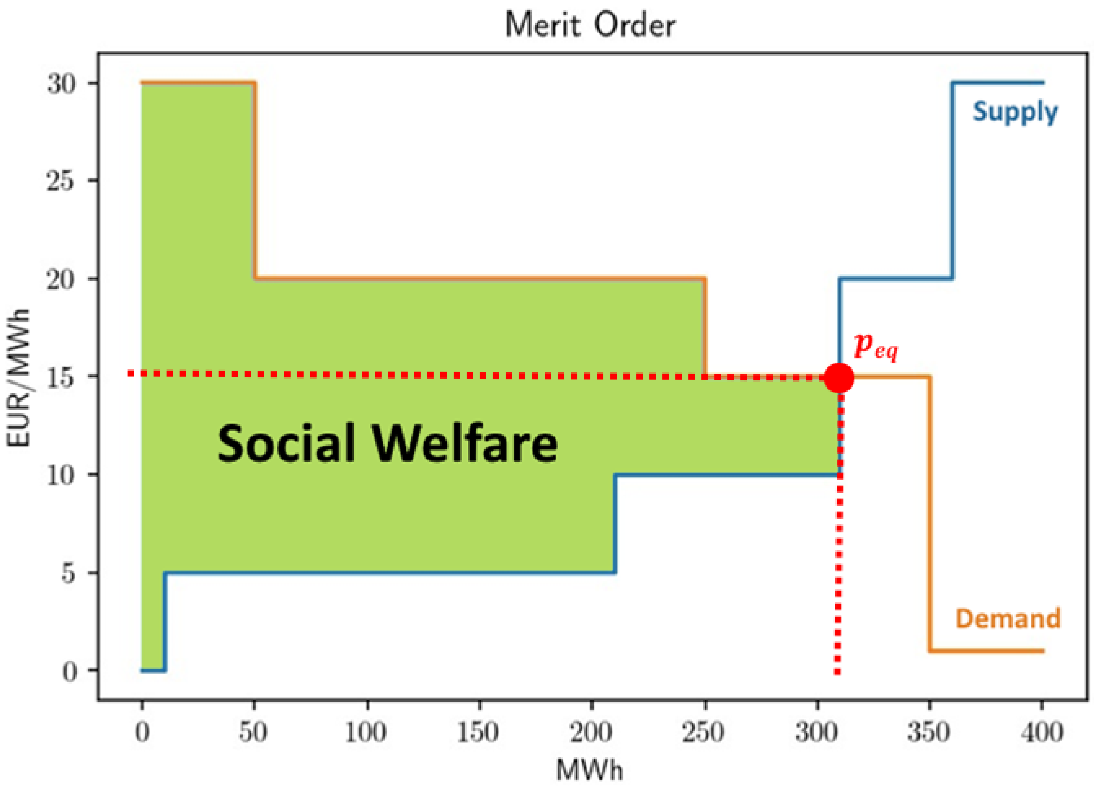
- The **consumer surplus** is the benefit for consumers when the price they are willing to pay is higher than the clearing price.

- The **producer surplus** is the benefit for producers when their marginal cost of production is lower than the clearing price.



Key terms illustrated through supply and demand curves (2/2)

- The **social welfare** is the area between the supply and demand curves, corresponding to the total of consumer and producer surpluses. It can be seen as the benefit of clearing the market at the equilibrium price



The settlement of the market clearing

What is the final cost of electricity?

There are two payment mechanisms:

- **Pay-as-clear** (or uniform pricing): a single price is set as the clearing price.
- **Pay-as-bid**: each participant receives the amount they bid.

In the EPEX market, the pay-as-clear mechanism is used, with pricing based on the equilibrium price. Under the pay-as-clear system, agents are incentivized to bid at their marginal cost.

Question:

In the previous exercise, which payment mechanism has been implemented?

Pay-as-bid vs Pay-as-clear

In a **pay-as-clear market**, all participants receive the same clearing price for their electricity, which is determined by the marginal cost of the last unit needed to meet demand. This mechanism encourages producers to bid at their true cost of production (marginal cost), as they know they will be paid the market-clearing price regardless of their bid.

In a **pay-as-bid market**, participants are paid the price they bid. This encourages producers to strategically inflate their bids to match what they anticipate the clearing price will be, rather than bidding based on their actual costs. As a result, the system could become **inefficient**, with less accepted demand, **unreliable price discovery**, and **higher overall market prices** due to ‘gaming’ behavior.

In conclusion, **a pay-as-bid market would introduce additional complexity in forecasting and potentially lead to inefficiencies**, as some producers might misestimate the price. This could result in financial losses, price spikes, and a reduction in accepted demand.

Pay-as-bid vs Pay-as-clear – Example (1/3)

Let us assume there are four producers—A, B, C, and D—bidding to supply electricity to meet a total demand of 100 MWh.

- Producer A bids 30 MWh at €50/MWh;
- Producer B bids 20 MWh at €60/MWh;
- Producer C bids 70 MWh at €80/MWh;
- Producer D bids 40 MWh at €100/MWh.

We will examine the profit differences between both payment mechanisms: pay-as-clear and pay-as-bid.

Pay-as-bid vs Pay-as-clear – Example (2/3)

In a pay-as-clear market, the price paid to all producers is determined by the highest accepted bid. Since producer C's bid of €80/MWh is the highest bid needed to meet demand, producers A, B, and C receive €80/MWh for their electricity.

- Producer A bids €50/MWh, produces 30 MWh, and is paid €80/MWh. Its profit is therefore (€80/MWh – €50/MWh) × 30 MWh = **€900**.
- Producer B bids €60/MWh, produces 20 MWh, and is paid €80/MWh. Its profit is therefore (€80/MWh – €60/MWh) × 20 MWh = **€400**.
- Producer C bids €80/MWh, produces 50 MWh, and is paid €80/MWh. Its profit is therefore (€80/MWh – €80/MWh) × 50 MWh = **€0**. Producer C breaks even, but all producers are incentivized to bid their true costs, as the clearing price is set by the marginal producer (C).

Pay-as-bid vs Pay-as-clear – Example (3/3)

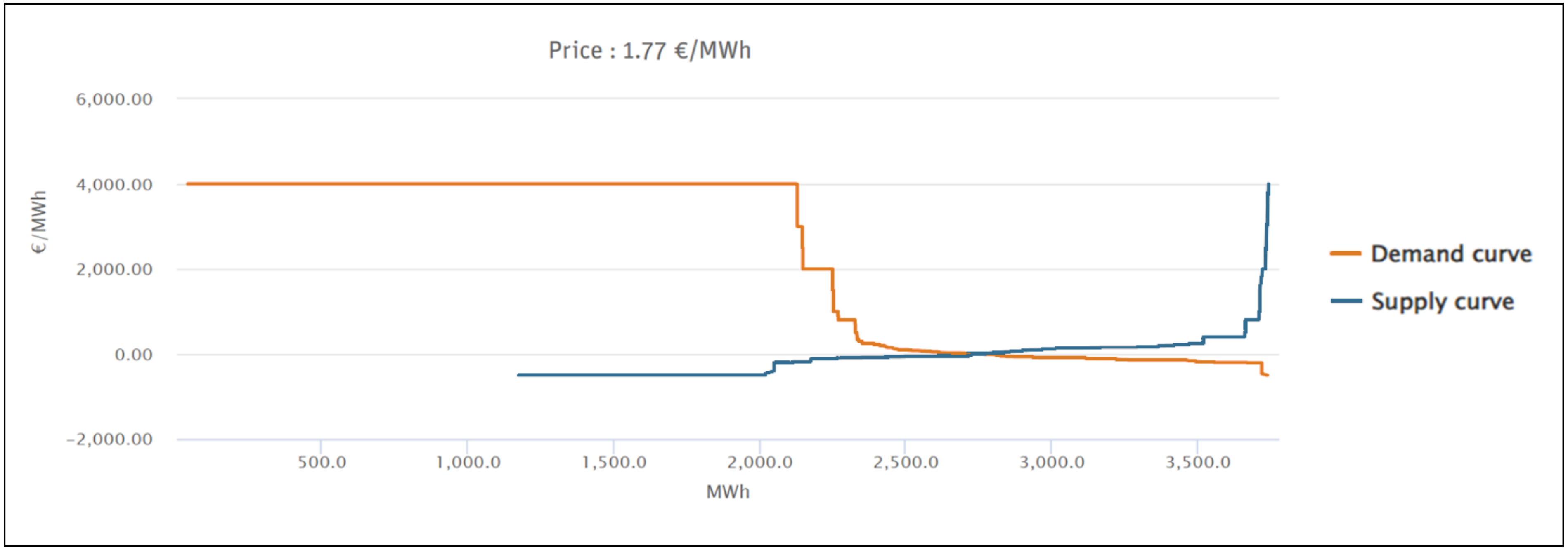
In a pay-as-bid market, each producer is paid based on the price they offer, rather than a uniform clearing price. If they bid at their marginal cost:

- Producer A is paid €50/MWh for its 30 MWh.
- Producer B is paid €60/MWh for its 20 MWh.
- Producer C is paid €80/MWh for its 50 MWh.

In this case, none of the producers makes a profit, as they receive exactly their marginal cost. Observing this, in future auctions, producers A and B might bid higher—possibly closer to producer C’s price (€80/MWh)—to increase their profit.

This kind of strategic offering could lead to inefficiencies, as producers focus on predicting the market price rather than offering based on their true costs.

Example – EPEX auction



*Displayed are the aggregated curves, including all orders submitted between 00:00 and 01:00 on September 28th, 2024, to the operating NEMOs (*Nominated Electricity Market Operators*) for the respective SDAC (*Single Day-Ahead Coupling*) auction in the concerned bidding zone. The displayed "Price" information reflects the EPEX SPOT market clearing price of the corresponding EPEX SPOT auction.*

Displayed prices correspond to the EPEX SPOT market clearing prices of the respective SDAC auction.

Overview of the optimization problem of the day-ahead market

Objective:

- Maximize social welfare.

Assumptions:

- A set of bids is provided for a specific hour of the day.
- A bid can be partially cleared, meaning a portion of the quantity can be purchased.
- Pay-as-clear mechanism is used at the equilibrium price p_{eq}.

Main constraint:

- Demand and supply must be balanced at each hour.

Parameters and variables of the optimization problem

Buy orders submit by the retailers (Demand)**:**

- Set of orders $L_D = \{D_i | i = 1, \cdots, N_D\}$;
- Maximum quantity for order D_i: P_i^D;
- Willingness to pay for order D_i: λ_i^D.

Ask orders submit by the producers (Generation)**:**

- Set of orders $L_G = \{G_j | j = 1, \cdots, N_G\}$;
- Maximum generation capacity for order G_j: P_j^G;
- Price for order G_j: λ_j^G.

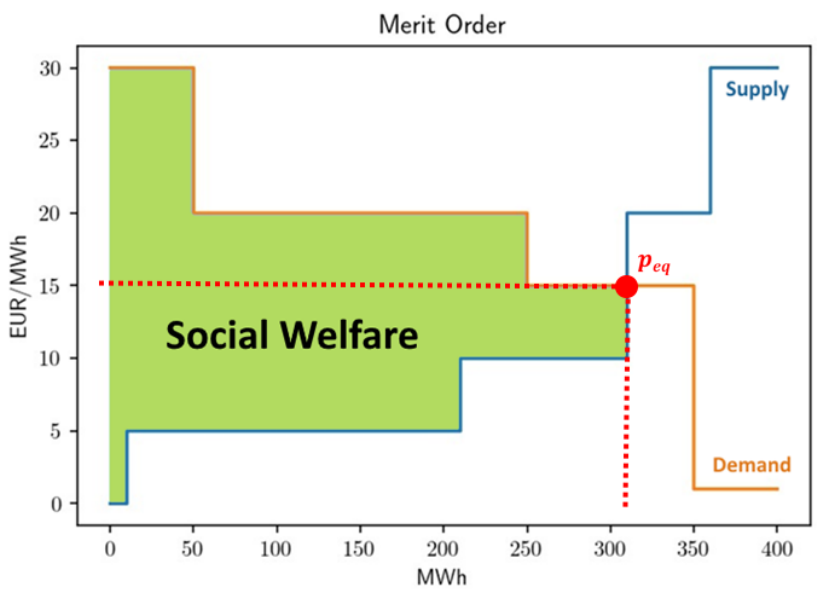
Decision variables:

- Consumption schedule $y^D = \left[y_1^D, \ldots, y_{N_D}^D\right], 0 \leq y_i^D \leq P_i^D$,
- Generation schedule $y^G = \left[y_1^G, \ldots, y_{N_G}^G\right], 0 \leq y_j^G \leq P_j^G$.

Optimizing the social welfare

The objective is to find the schedules y^D and y^G that maximize social welfare, which corresponds to the area between the cleared supply and demand bids.

$$\max_{y^D, y^G} \sum_{i=1}^{N_D} \lambda_i^D y_i^D - \sum_{j=1}^{N_G} \lambda_j^G y_j^G$$



Demand (consumption) and supply (generation) must be equal:

$$\sum_{i=1}^{N_D} y_i^D - \sum_{j=1}^{N_G} y_j^G = 0$$

Generation / Demand constraints:

$$0 \leq y_i^D \leq P_i^D, \qquad \forall\, i = 1, \cdots, N_D$$
$$0 \leq y_j^G \leq P_j^G, \qquad \forall\, j = 1, \cdots, N_G$$

In the following, we consider the equivalent minimization problem obtained by minimizing the negative of the objective function while keeping all constraints unchanged.

A simple 2S-2C example of social welfare optimization

Let us consider two producers and two retailers.

$$\max_{y_1^G, y_2^G, y_1^D, y_2^D} \quad \lambda_1^D y_1^D + \lambda_2^D y_2^D - \lambda_1^G y_1^G - \lambda_2^G y_2^G$$

- Demand (consumption) and supply (generation) must be equal:

  $$y_1^G + y_2^G - y_1^D - y_2^D = 0$$

- Generation / consumption constraints:

  $$0 \le y_1^G \le P_1^G, \; 0 \le y_2^G \le P_2^G,$$
  $$0 \le y_1^D \le P_1^D, \; 0 \le y_2^D \le P_2^D.$$

The equivalent minimization objective is:

$$\min_{y_1^G, y_2^G, y_1^D, y_2^D} \quad -\left(\lambda_1^D y_1^D + \lambda_2^D y_2^D - \lambda_1^G y_1^G - \lambda_2^G y_2^G \right)$$

Optimizing social welfare involves solving a linear program

Linear Programming (LP) is usually expressed in a standardised form called the 'compact form':

$$\min_{\mathbf{y}} \ \mathbf{c}^{\mathrm{T}}\mathbf{y}$$

subject to

$$\mathbf{A_{eq}}\,\mathbf{y} = \mathbf{b_{eq}}$$
$$\mathbf{A}\,\mathbf{y} \leq \mathbf{b}$$
$$\mathbf{y} \geq 0$$

The compact form allows to easily encode the problem in a classical solver. **Solving this problem, called the primal, provides the demand and generation schedules**.

In the case of the 2P-2R example, this leads to…

$$\min_{\mathbf{y}} \ \mathbf{c}^{\mathbf{T}}\mathbf{y}$$

subject to

$$\mathbf{A_{eq}}\,\mathbf{y} = \mathbf{b_{eq}}$$
$$\mathbf{A}\,\mathbf{y} \leq \mathbf{b}$$
$$\mathbf{y} \geq 0$$

where:

$$\mathbf{y} = \begin{bmatrix} y_1^G \\ y_2^G \\ y_1^D \\ y_2^D \end{bmatrix} \qquad \mathbf{c} = \begin{bmatrix} \lambda_1^G \\ \lambda_2^G \\ -\lambda_1^D \\ -\lambda_2^D \end{bmatrix} \qquad \mathbf{b} = \begin{bmatrix} P_1^G \\ P_2^G \\ P_1^D \\ P_2^D \end{bmatrix} \qquad \mathbf{A} = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix}$$

$$\mathbf{A_{eq}} = \begin{bmatrix} 1 & 1 & -1 & -1 \end{bmatrix} \qquad \mathbf{b_{eq}} = 0$$

The dual LP to get the clearing price

If we want to obtain the clearing price, **we need to solve the dual of the previous LP, which is also a LP**:

$$\max_{\mathbf{y},\boldsymbol{\nu}} \; -\mathbf{b}^{\mathrm{T}}\boldsymbol{\nu}$$

subject to

$$\mathbf{A}_{\mathbf{eq}}^{\mathbf{T}}\boldsymbol{\lambda} - \mathbf{A}^{\mathrm{T}}\boldsymbol{\nu} \leq \mathbf{c}$$
$$\boldsymbol{\nu} \geq 0$$

λ and ν are dual variables, also known as Lagrange multipliers, associated with the equalities and inequalities from the primal problem;

- λ corresponds to the (unique) equality constraint which links generation and demand. Solving for λ provides the clearing price λ* (the equilibrium price p_{eq});
- ν is associated with the inequality constraint. Solving for ν provides the consumer surplus and producer surplus;

In practice, there is no need to formulate the dual problem, as most solvers directly provide the solution when solving the primal problem.[1]

In the case of the 2P-2R example, this leads to…

$$\max_{\mathbf{y},\boldsymbol{\nu}} \; -\mathbf{b}^{\mathrm{T}}\boldsymbol{\nu}$$

subject to

$$\mathbf{A}_{\mathbf{eq}}^{\mathrm{T}}\boldsymbol{\lambda} - \mathbf{A}^{\mathrm{T}}\boldsymbol{\nu} \leq \mathbf{c}$$
$$\boldsymbol{\nu} \geq 0$$

where:

$$\lambda = \lambda^S \qquad \nu = \begin{bmatrix} \nu_1^G & \nu_2^G & \nu_1^D & \nu_2^D \end{bmatrix}$$

And, more concretely,

$$\max_{\lambda^s,\nu_1^G,\nu_2^G,\nu_1^D,\nu_2^D} \; -\nu_1^G P_1^G - \nu_2^G P_2^G - \nu_1^D P_1^D - \nu_2^D P_2^D$$

subject to:

$$\lambda^S - \nu_1^G \leq \lambda_1^G \qquad -\lambda^S - \nu_1^D \leq -\lambda_1^D$$
$$\lambda^S - \nu_2^G \leq \lambda_2^G \qquad -\lambda^S - \nu_2^D \leq -\lambda_2^D$$
$$\nu_1^G \geq 0, \nu_2^G \geq 0, \nu_1^D \geq 0, \nu_2^D \geq 0.$$

A closer look at the constraints

$$\max_{\lambda^s, \nu_1^G, \nu_2^G, \nu_1^D, \nu_2^D} \quad - \nu_1^G P_1^G - \nu_2^G P_2^G - \nu_1^D P_1^D - \nu_2^D P_2^D$$

subject to:

$$\begin{aligned}
\lambda^S - \nu_1^G \leq \lambda_1^G &\iff \lambda^S - \lambda_1^G \leq \nu_1^G \\
\lambda^S - \nu_2^G \leq \lambda_2^G &\iff \lambda^S - \lambda_2^G \leq \nu_2^G \\
-\lambda^S - \nu_1^D \leq -\lambda_1^D &\iff \lambda_1^D - \lambda^S \leq \nu_1^D \\
-\lambda^S - \nu_2^D \leq -\lambda_2^D &\iff \lambda_2^D - \lambda^S \leq \nu_2^D
\end{aligned}$$

Controlling the gap between equilibrium price and pre-specified suppliers and consumer prices.

$$\nu_1^G \geq 0, \nu_2^G \geq 0, \nu_1^D \geq 0, \nu_2^D \geq 0.$$

Overview of the inelastic demand

What if there is a demand D that **must be delivered** regardless of the price?

The social welfare is infinite, as the consumer is willing to pay an infinite price in the worst-case scenario. It is infinite only because the **net consumer surplus is infinite**.

In this context, maximising social welfare corresponds to maximising the net producer surplus. Equivalently, the optimal dispatch is the one that maximises the area under the cleared generation bids. This area is referred to as the **opportunity cost**.

$$\min_{\{y_j^G\}} \sum_{j=1}^{N_G} p_j^G y_j^G$$

subject to

$$\sum_{j=1}^{N_G} y_j^G = D$$

$$0 \le y_j^G \le P_j^G, \qquad \forall j = 1, \cdots, N_G$$

The inelastic demand in practice

In practice, it might happen that the total supply does not cover the demand. In this case, the previous optimization problem has no solution.

To address this, we can add to the objective function the cost p_{shed} for the portion of the demand ΔD that is not supplied. This price corresponds to the **Value Of Lost Load (VOLL)** and is typically set to $p_{shed} = €1{,}000/\text{MWh}$.

$$\min_{\{y_j^G\},\Delta D} \quad \sum_{j=1}^{N_G} p_j^G y_j^G + p_{shed}\Delta D$$

subject to

$$\sum_{j=1}^{N_G} y_j^G + \Delta D = D$$

$$0 \ \leq \Delta D \leq D$$

$$0 \ \leq y_j^G \leq P_j^G, \qquad \forall j = 1, \cdots, N_G$$

Overview of the shifting demand

Shifting demand: Rather than reducing their demand, consumers may choose to delay their demand until prices are lower. This concept has existed for a long time, exemplified by night and day tariffs.

There are many opportunities for shifting demand that can still be exploited, even for small customers (e.g., turning off the fridge for half an hour or delaying laundry).

Investments in systems to take advantage of these demand-shifting opportunities are crucial in a landscape where more and more electricity is generated from renewables.

Investments: Recording consumers' consumption for every market period (which is essential to avoid purchasing electricity based on a fixed tariff), installing automatic devices in homes to shift loads, etc.

Negative prices may happen (1/2)

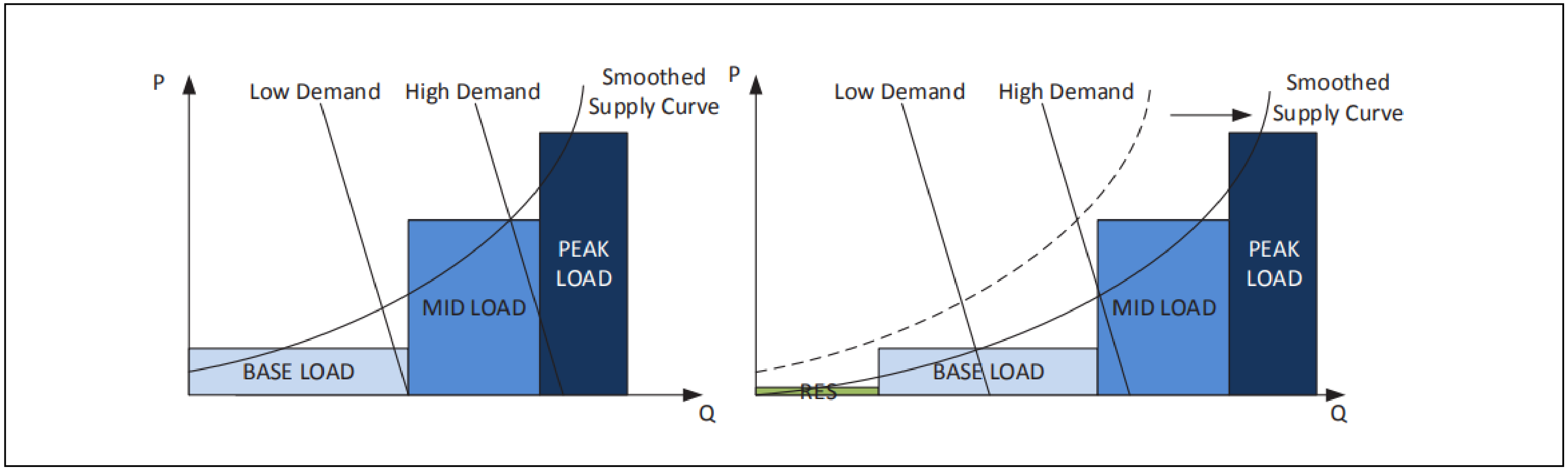
A negative clearing price in the day-ahead market is the consequence of an oversupply of electricity. Typically, this oversupply is the consequence of the association of a **low demand** and **inflexible and/or abundant generation**.

Some producers may submit offers at negative prices: nuclear, run-of-the-river hydro, trash burning, and other generators that have to run. Submitting these orders at negative prices is a strategy to be sure that these units are included in the production schedule, no matter the price.

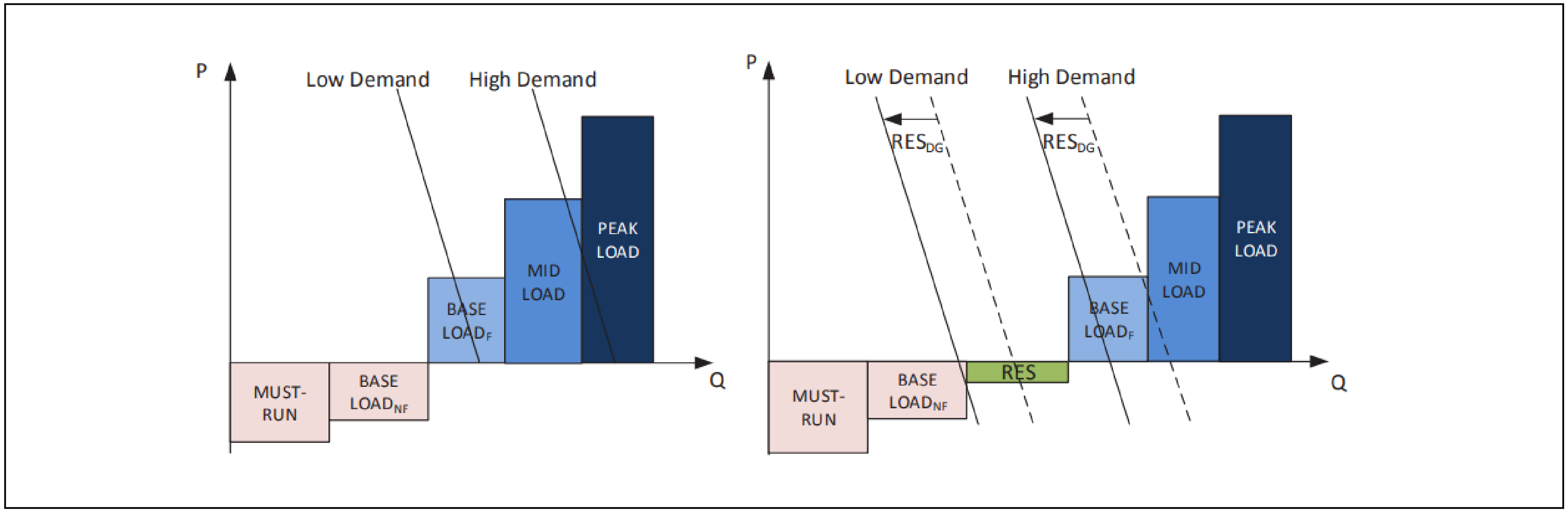
Other negative offers might come from renewable generators who receive production subsidies and can thus remain profitable even if the price is negative.

In addition, negative prices can occur in regions where there is limited transmission capacity to export surplus electricity. In such cases, the local electricity supply exceeds local demand, causing prices to fall to negative levels in that region, even though other areas might need the electricity.

Negative prices may happen (2/2)



Theorical merit order without (left) and with RES (right).[1]



Practical merit order without (left) and with RES (right);
$RES_{(X)}$ expected renewable generation production of distributed nature; F flexible; NF non-flexible.[1]

[1] https://doi.org/10.1016/j.tej.2015.04.001

ELEC0018-1
Energy market and regulation

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Chapter 07 – The day-ahead market and the problem with transmission networks

The optimization problem – Reminder (1/2)

Buy orders submit by the retailers (Demand)**:**

- Set of orders $L_D = \{D_i | i = 1, \cdots, N_D\}$;
- Maximum quantity for order D_i: P_i^D;
- Willingness to pay for order D_i: λ_i^D.

Ask orders submit by the producers (Generation)**:**

- Set of orders $L_G = \{G_j | j = 1, \cdots, N_G\}$;
- Maximum generation capacity for order G_j: P_j^G;
- Price for order G_j: λ_j^G.

Decision variables:

- Consumption schedule $y^D = \left[y_1^D, \ldots, y_{N_D}^D\right], 0 \leq y_i^D \leq P_i^D$,
- Generation schedule $y^G = \left[y_1^G, \ldots, y_{N_G}^G\right], 0 \leq y_j^G \leq P_j^G$.

The optimization problem – Reminder (2/2)

The goal is to find an optimal dispatch (or schedule) for the market participants in order to maximize social welfare.

This can be achieved by solving the so-called **primal optimization problem**, which is formulated by writing the social welfare objective, the supply-demand balance equality constraint, and the inequality constraints related to generation and consumption.

$$\min_{\mathbf{y}} \ \mathbf{c}^{\mathrm{T}}\mathbf{y}$$

subject to

$$\mathbf{A_{eq}}\,\mathbf{y} = \mathbf{b_{eq}}$$
$$\mathbf{A}\,\mathbf{y} \leq \mathbf{b}$$
$$\mathbf{y} \geq 0$$

By solving the **dual problem**, we can also determine the clearing price, also known as the equilibrium price or system price.

$$\max_{\mathbf{y},\boldsymbol{\nu}} \ -\mathbf{b}^{\mathrm{T}}\boldsymbol{\nu}$$

subject to

$$\mathbf{A}_{\mathbf{eq}}^{\mathbf{T}}\boldsymbol{\lambda} - \mathbf{A}^{\mathrm{T}}\boldsymbol{\nu} \leq \mathbf{c}$$
$$\boldsymbol{\nu} \geq 0$$

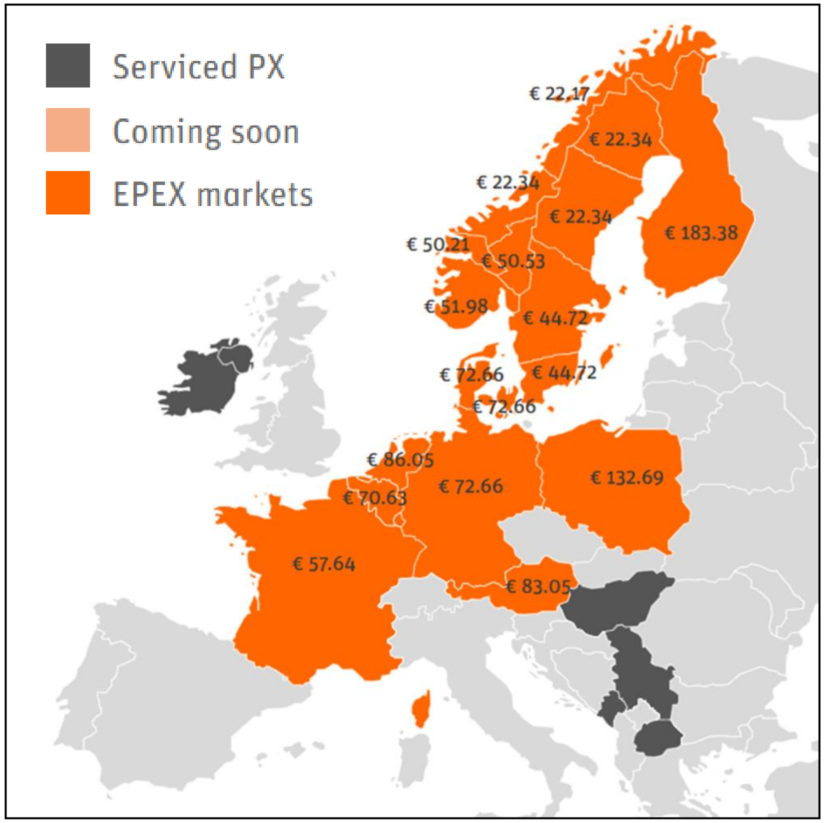
The problem with transmission networks (1/2)

Many European countries can participate in bidding in a day-ahead electricity market. **Bidding zones** are specific geographic areas where market participants can submit their bids and offers for electricity. Each **bidding zone** (or bidding area) has its own Power eXchange (PX) which collects participants orders.

A bidding zone can contain multiple **nodes**, each representing a specific location in the electricity grid where electricity is generated, consumed, or transferred.

These nodes are interconnected through transmission lines, which allow for the transfer of energy between them. The price within a bidding zone is uniform, meaning that all nodes within that zone receive the same price for electricity.

However, there is a limit to the amount of power that can be transmitted due to capacity constraints on these lines.

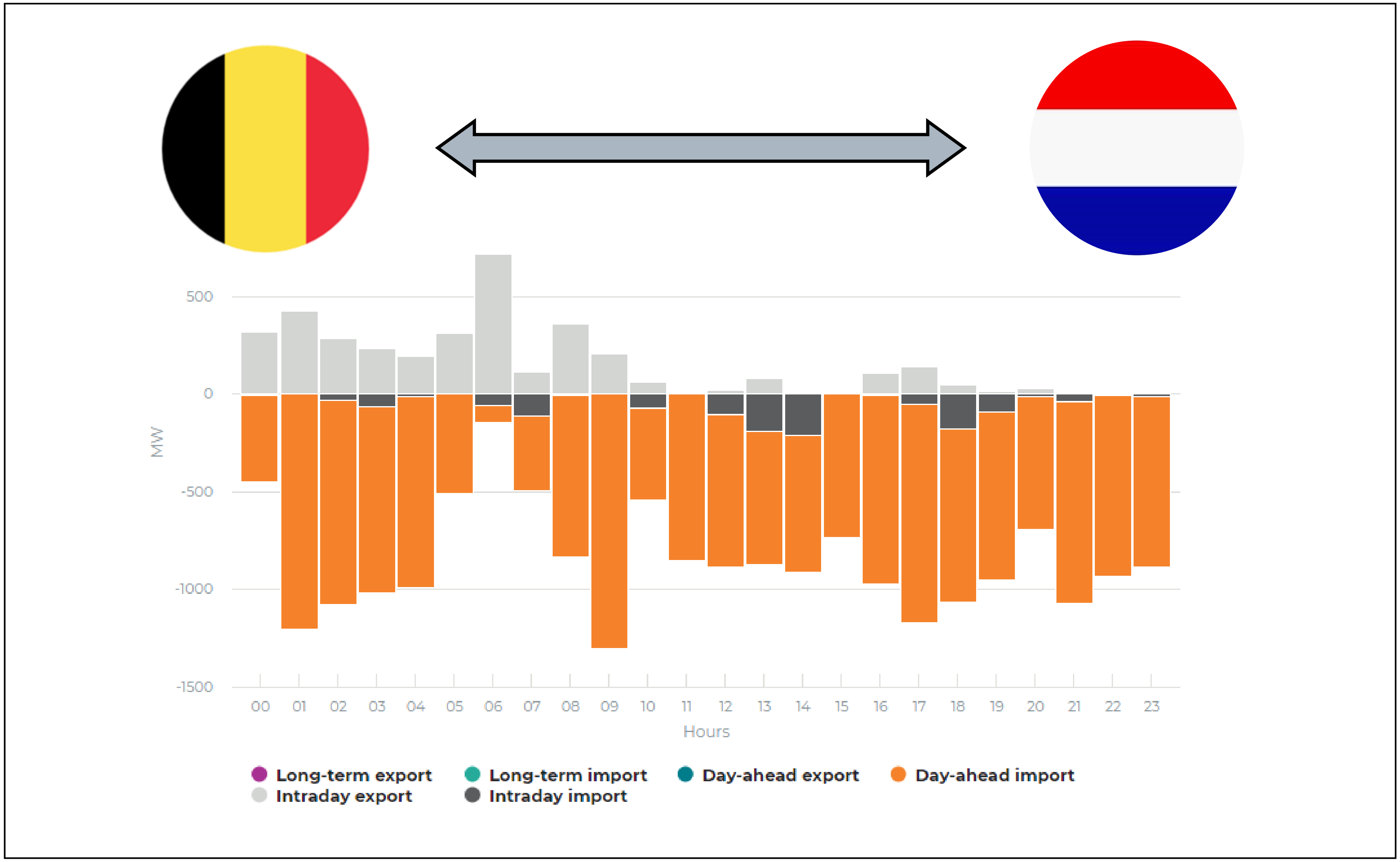


EPEX auction status (October 3, 2024).

How can this constraint be considered in the day-ahead auction?

The problem with transmission networks 2/2

The objective remains identical: maximizing the total social welfare across the different nodes. The energy exchanged between two nodes is constrained by **the maximum capacity of the transmission line(s) connecting them**.



History, vocabulary and acronyms – the EU context (1/3)

Before the introduction of Market Coupling, cross-border capacity and electricity had to be purchased separately: a trading member had to reserve cross-border capacity before using this capacity to transport the purchased electricity.

Market Coupling utilizes implicit auctions, where market participants bid for the electricity on the Power Exchange without individually receiving cross-border capacity allocations.

Power Exchanges then take into account available cross-border capacities in the price calculation process to minimize the price differences across market areas.

The mechanism for coupling markets is called “**Single Day-Ahead Coupling**” **(SDAC).** Its goal is to create a single pan-European cross-zonal day-ahead electricity market.

In practice, the SDAC mechanism allows cross-border transmission capacities to be allocated in “the most efficient way” by coupling wholesale electricity markets using a common algorithm: EUPHEMIA (the acronym comes from Pan-European Hybrid Electricity Market Integration Algorithm).

History, vocabulary and acronyms – the EU context (2/3)

2006: Tri-lateral Market Coupling between the French, Belgian and Dutch day-ahead markets.
2010: Market coupling in Central West Europe (CWE) – Benelux, France and Germany.
2014: Price coupling in North-Western Europe (NEW) using the Price Coupling of Regions (PCR) solution. At the same time, a similar solution is implemented in South-Western Europe (SWE). Full coupling of both NEW and SWE is achieved through Multi-Regional Coupling (MRC). This includes Belgium, Denmark, Estonia, Finland, France, Germany+Austria, Great Britain (GB), Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Sweden, Portugal and Spain.
Later in 2014: 4M MC coupling between the Czech Republic, Hungary, Romania and Slovakia using the PCR solution.
2015: Italy and Slovenia coupled with MRC.
2016: Bulgaria and Croatia join MRC (in isolated mode).
2018: Croatia and the island of Ireland coupled with MRC; Germany and Austria split into two bidding zones.
2020: Greece coupled with MRC through SDAC.
2021: EU-GB interconnectors and GB bidding zones exit SDAC; Bulgaria coupled with SDAC; 4M MC and MRC coupling; inclusion of Bulgaria-Romania border in SDAC coupling.
2022: Croatian-Hungarian border included in SDAC coupling.

History, vocabulary and acronyms – the EU context (3/3)

- **SDAC** represents the current and most extensive phase of European market coupling for day-ahead electricity markets.
- **PCR** was a precursor initiative aimed at developing the price coupling mechanism across regional markets, which eventually evolved into SDAC.
- **MRC** was a regional coupling effort focused on establishing a common price reference in specific regions, paving the way for the broader coupling mechanism seen in SDAC.

Involved parties

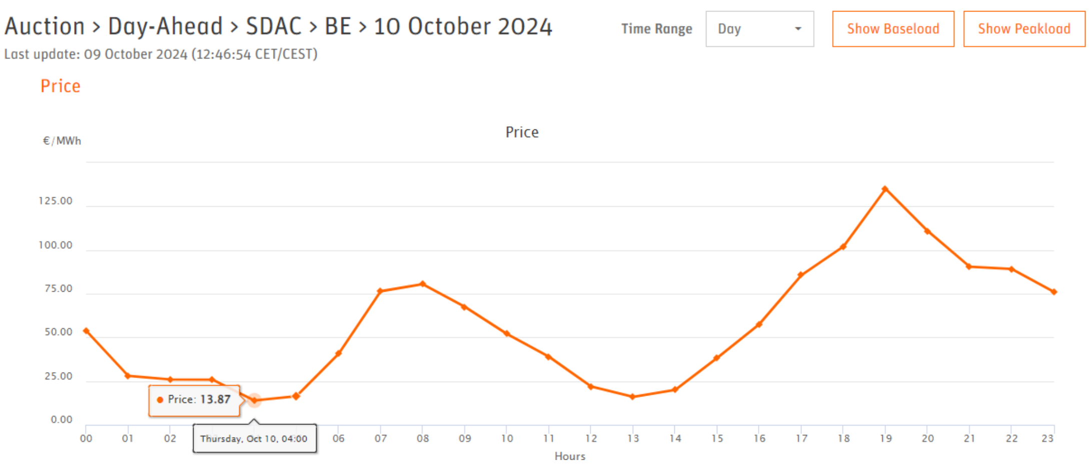
Transmission System Operators (TSOs):

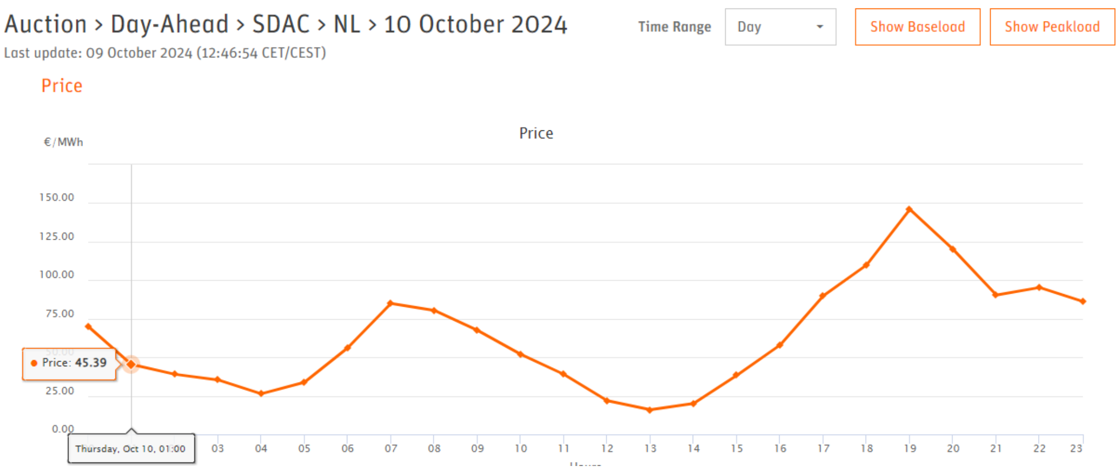
50Hertz Transmission, ADMIE, Amprion, APG, AST, ČEPS, Creos, EirGrid, Elering, ELES, ELIA, Energinet, ESO, Fingrid, HOPS, Litgrid, MAVIR, PSE, REE, REN, RTE, SEPS, SONI, Statnett, Svenska Kraftnät, TenneT DE, TenneT NL, Terna, Transelectrica, and TransnetBW.

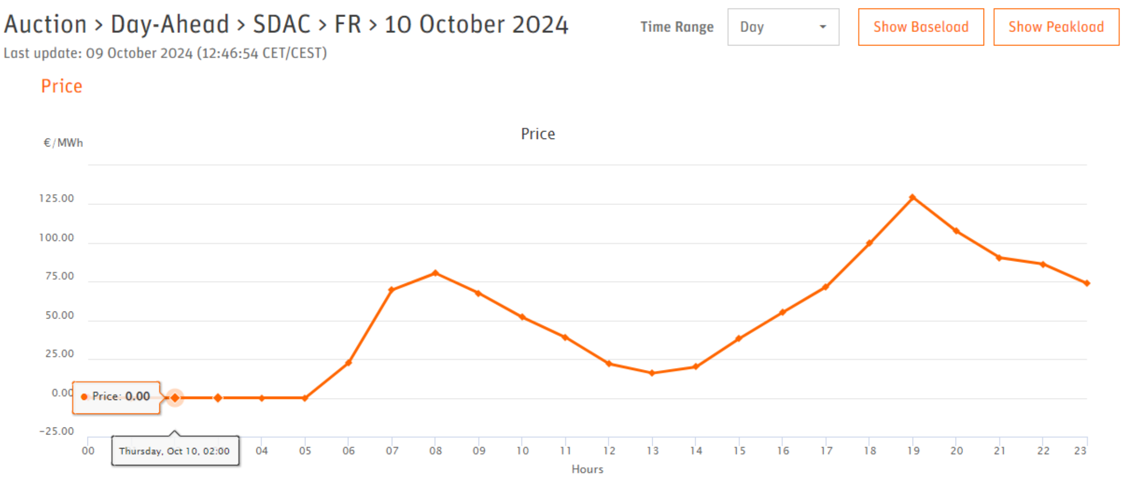
Nominated Electricity Market Operators (NEMOs):

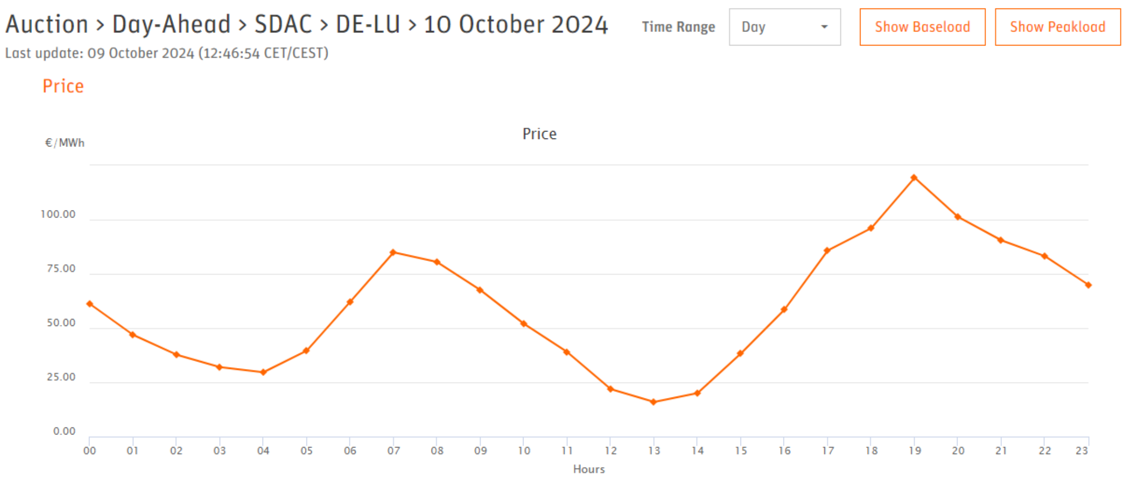
BSP, CROPEX, SEMOpx (EirGrid and SONI), EPEX, EXAA, GME, HEnEx, HUPX, IBEX, Nord Pool, OMIE, OKTE, OPCOM, OTE, and TGE.

Day-ahead market, 10/10/24 – BE-NL-FR-DE-LU



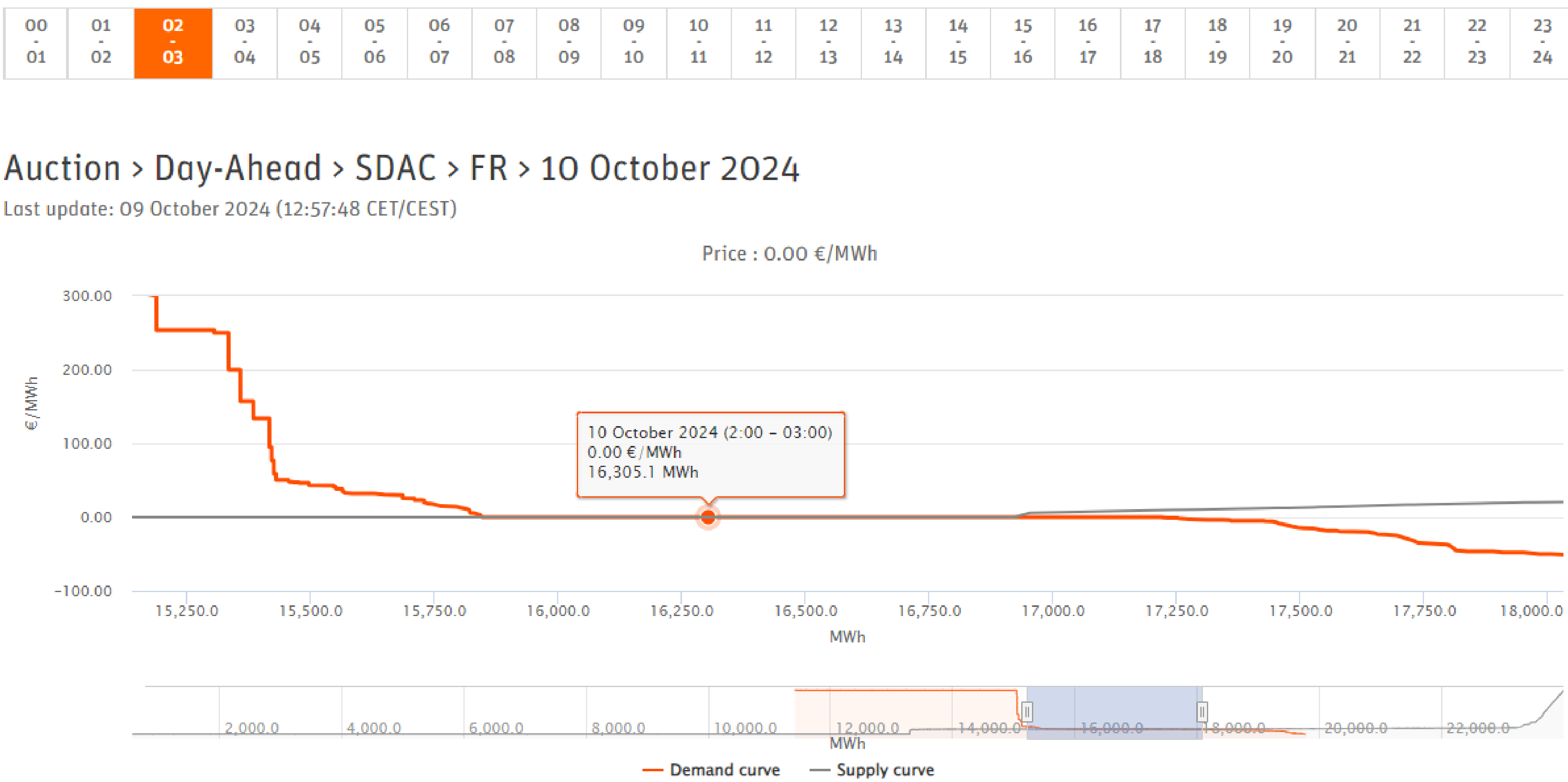






Source: https://www.epexspot.com/en/market-data

0 euro clearing price in FR between 2am and 3am on 10/10/24



Source: https://www.epexspot.com/en/market-data

Parameters and variables of the optimization problem considering nodes

Each order is now associated with a node $n = 1, \cdots, N$.

Buy orders submit by the retailers (Demand)**:**

- Node for order D_i^n: n.
- Set of orders L_D for N_D demand bids $= \{D_i^n | i = 1, \cdots, N_D; n = 1, \cdots, N\}$;
- Set of indices of demand bids in node n: $I_n = \{i | D_i^{n'} \in L_D;\ n' = n\}$;
- Maximum quantity for order D_i^n: P_i^D;
- Willingness to pay for order D_i^n: λ_i^D;

Ask orders submit by the producers (Generation)**:**

- Node for order G_j^n: n.
- Set of orders L_G for N_G generation bids $= \left\{G_j^n \middle| j = 1, \cdots, N_G; n = 1, \cdots, N\right\}$;
- Set of indices of generation bids in node n: $J_n = \{j | G_j^{n'} \in L_G;\ n' = n\}$;
- Maximum quantity for order G_j^n: P_j^G;
- Willingness to pay for order G_j^n: λ_j^G;

Decision variables:

- Consumption schedule $y^D = \left[y_1^D, \ldots, y_{N_D}^D\right], 0 \le y_i^D \le P_i^D$,
- Generation schedule $y^G = \left[y_1^G, \ldots, y_{N_G}^G\right], 0 \le y_j^G \le P_j^G$.

Constraints of the optimization problem considering nodes

Let us introduce:

- The maximum capacity $C_{n,n'}$ of the interconnections between two nodes n and n';
- The power exchanged $q_{n,n'}$ between two nodes n and n'.

The exchanged power $q_{n,n'}$ between two nodes is bounded by the maximum capacity of the line. However, power can flow in both directions:

$$-C_{n,n'} \leq q_{n,n'} \leq C_{n,n'}, \qquad \forall n, n' = 1, \cdots, N$$

The power flowing from node n to node n' is the opposite of the power flowing from node n' to node n:

$$q_{n,n'} = -q_{n',n}, \qquad \forall n, n' = 1, \cdots, N$$

Formulation of the optimization problem considering nodes

The objective is still to maximise social welfare:

$$\boxed{\max_{y^D, y^G} \sum_{i=1}^{N_D} \lambda_i^D y_i^D - \sum_{j=1}^{N_G} \lambda_j^G y_j^G}$$

Each bid can still be partially accepted but is bounded by the quantity offered at that price:

$$0 \leq y_i^D \leq P_i^D, \qquad \forall\, i = 1, \cdots, N_D$$
$$0 \leq y_j^G \leq P_j^G, \qquad \forall\, j = 1, \cdots, N_G$$

At each node, the difference between consumption and production equals the total power exchanged by that node with the other nodes:

$$\sum_{i \in I_n} y_i^D - \sum_{j \in J_n} y_j^G = \sum_{n'=1}^{N} q_{n',n}$$

Solution of the optimization problem considering nodes

The solution to the problem is the **optimal dispatch** subject to the transmission constraints:

$$\max_{\{y_i^D\},\{y_j^G\}} \sum_{i=1}^{N_D} p_i^D y_i^D - \sum_{j=1}^{N_G} p_j^G y_j^G$$

subject to

$$\sum_{i \in I_n} y_i^D - \sum_{j \in J_n} y_j^G = \sum_{n'=1}^{N} q_{n',n}\,, \qquad \forall n = 1, \cdots, N$$

$$0 \le y_i^D \le P_i^D, \qquad \forall i = 1, \cdots, N_D$$
$$0 \le y_j^G \le P_j^G, \qquad \forall j = 1, \cdots, N_G$$

$$-C_{n,n'} \le q_{n,n'} \le C_{n,n'}, \qquad \forall n, n' = 1, \cdots, N$$
$$q_{n,n'} = -q_{n',n}\,, \qquad \forall n, n' = 1, \cdots, N$$

Discussion about the optimal dispatch

The power transmitted on a line $q_{n,n'}$ can be expressed as a function of the susceptance of the line, $B_{n,n'}$, and of the phase difference between the voltages at the nodes, $\delta_{n,n'}$:

$$q_{n,n'} = B_{n,n'}\delta_{n,n'}$$

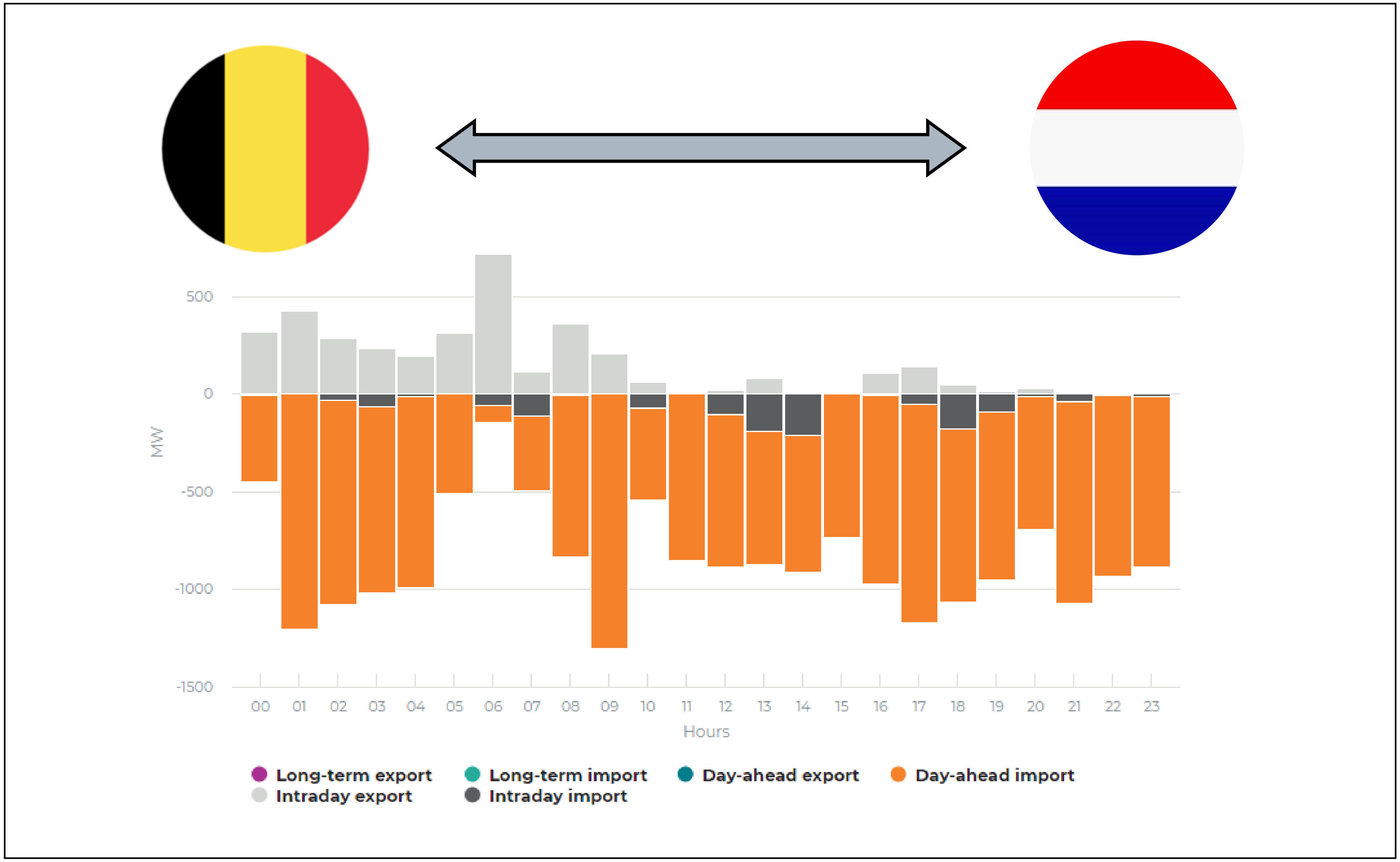
In a two-node system, power flows from the node with the lower price (if cleared independently) to the node with the higher price.

However, this does not hold true not when there are more than two nodes, as the power flow becomes more complex due to interactions between multiple nodes.

Exercise 1:

Simplify the previous model to a two-node system.

- Consider a transmission line with capacity C.
- Let q be the power exchanged between the two nodes.



Solution:

$$\max_{\{y_i^D\},\{y_j^G\}} \sum_{i=1}^{N_D} p_i^D y_i^D - \sum_{j=1}^{N_G} p_j^G y_j^G$$

subject to

$$\sum_{i \in I_1} y_i^D - \sum_{j \in J_1} y_j^G = q$$

$$\sum_{i \in I_2} y_i^D - \sum_{j \in J_2} y_j^G = -q$$

$$0 \le y_i^D \le P_i^D, \qquad \forall i = 1, \cdots, N_D$$
$$0 \le y_j^G \le P_j^G, \qquad \forall j = 1, \cdots, N_G$$

$$-C \le q \le C$$

Exercise 2:

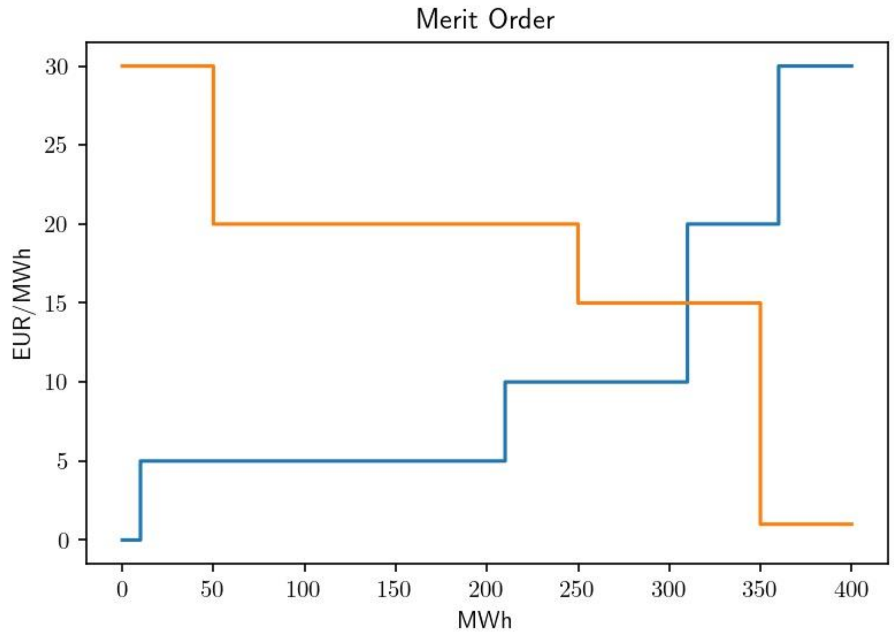
1. Build the merit orders for both nodes, first assuming they are not interconnected.

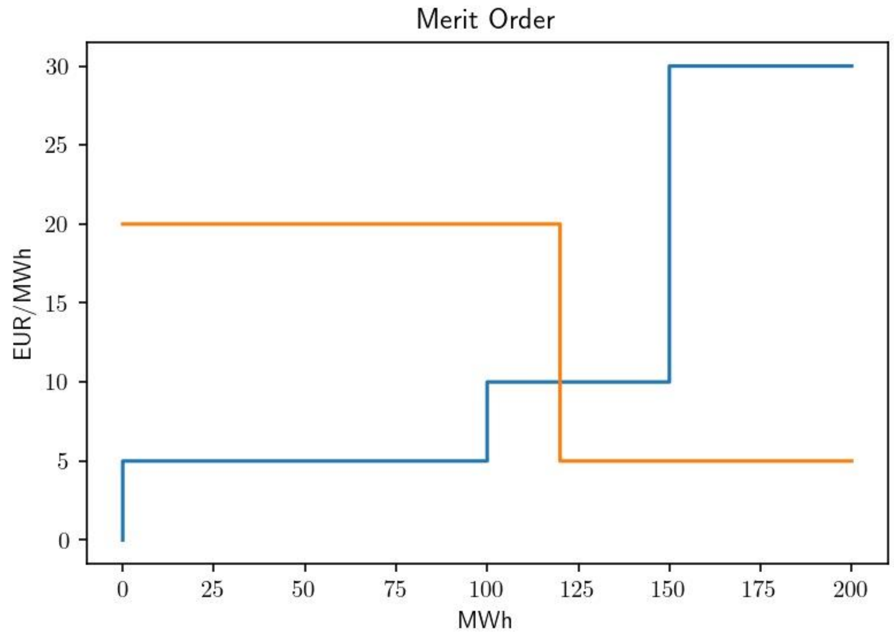
2. Now, assuming a transfer of 10 MWh from node 1 to node 2 is possible, is it profitable to trade between the two nodes based on their independent merit orders?

ID	Side	Node	Quantity (MWh)	Price (€/MWh)
G1	Sell	1	50	20
G2	Sell	1	100	10
G3	Sell	1	20	30
G4	Sell	1	200	5
G5	Sell	1	10	0
G6	Sell	2	100	30
G7	Sell	2	50	10
G8	Sell	2	100	5
C1	Buy	1	50	1
C2	Buy	1	100	15
C3	Buy	1	200	20
C4	Buy	1	50	30
C5	Buy	2	100	5
C6	Buy	2	120	20

Solution:

Part 1:

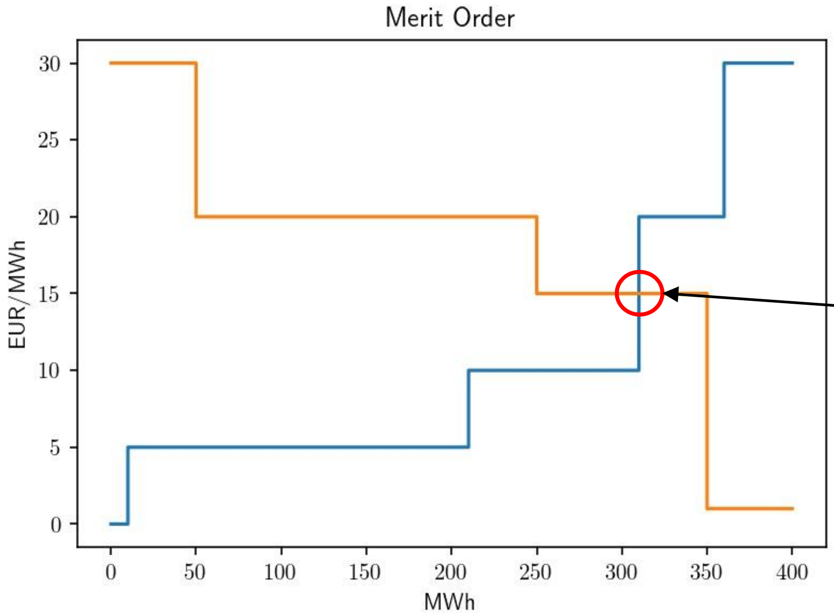


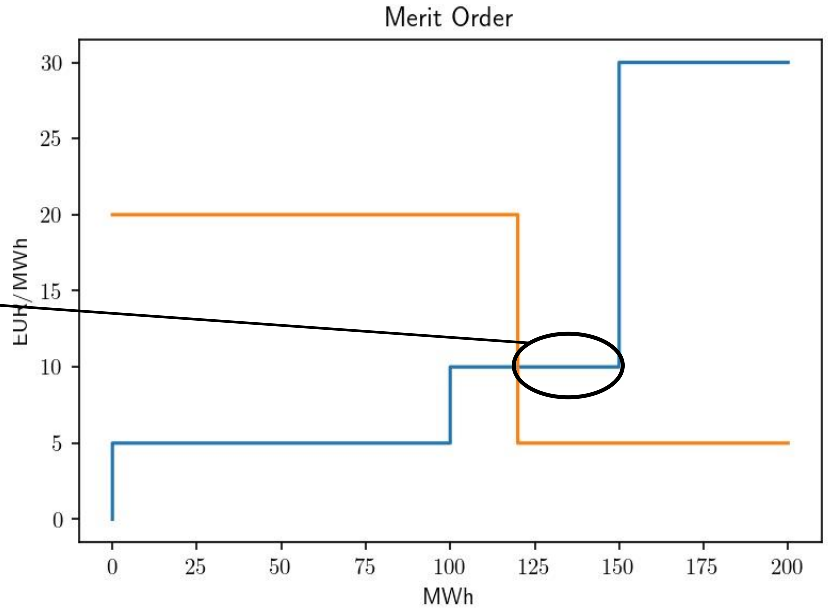


Want to draw the graph by yourself? Check [that link]() (Google Colab).

Part 2:

The 30 MWh available at the second node are less expensive than the clearing price at the first node. Therefore, it will be profitable to transfer an additional 10 MWh from node two to node one. In this example, the equilibrium prices remain unchanged, but the merit order at node one shifts by 10 MWh.





Part 2: alternative approach

Let us write down the optimization problem.

To do so, we will not use the “compact form” as described in the previous lesson, but we will directly write down the equations using the GBOML language.

Let us explore the code together.

Settlement of the clearing price

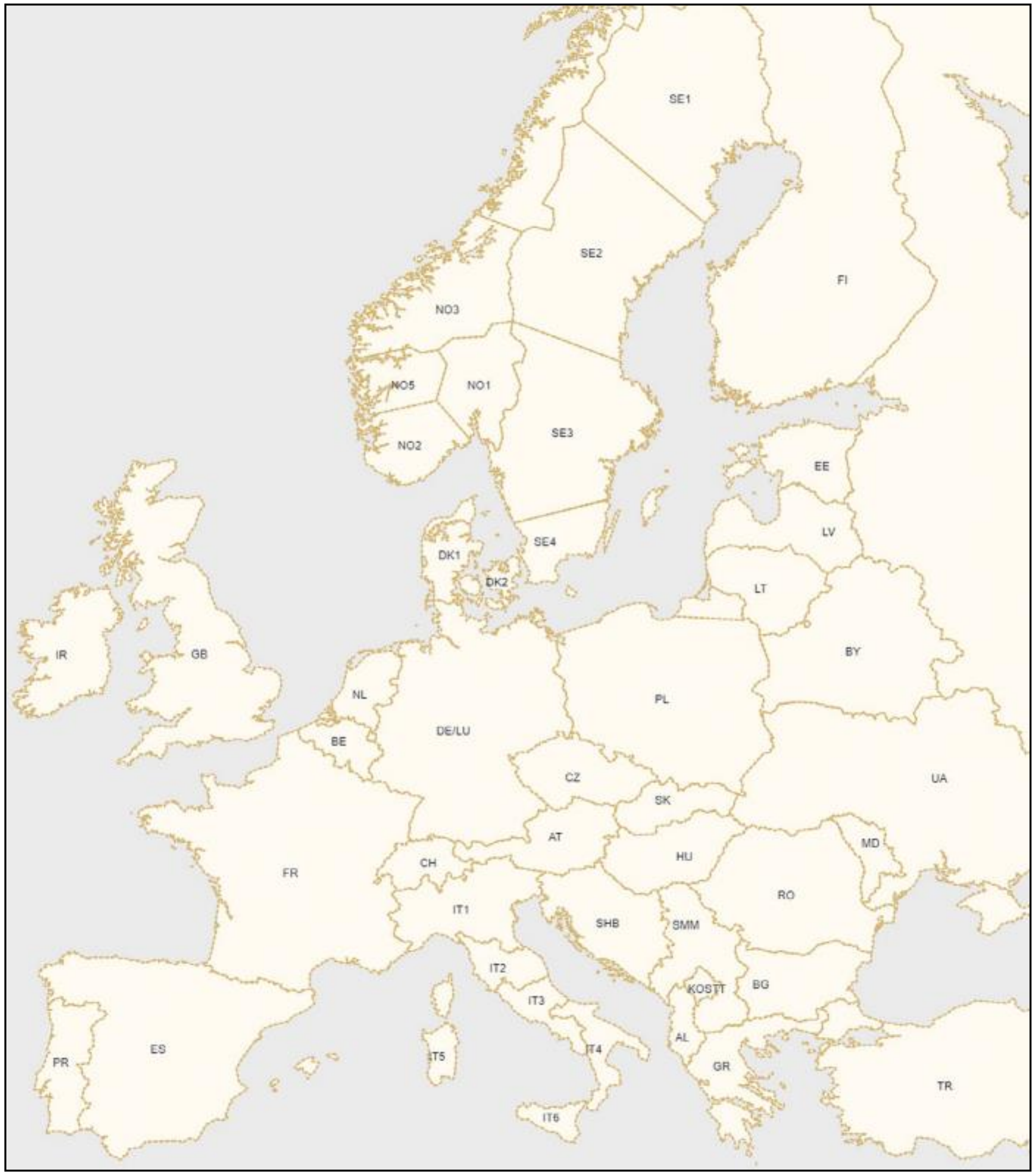
The merit price at which electricity is bought and sold at a specific node in the network is the **nodal price**. When transmission lines are congested, they cannot carry all the electricity that producers want to send to the market. This limitation means that **some nodes may experience different prices due to their capacity to receive electricity**.

In Europe, the market is divided into bidding zones that aggregate multiple nodes. Each zone has a uniform **zonal price**, meaning that all nodes within that zone share the same price for electricity transactions. Each participant pays or is paid at its zonal price.

Since the zonal price does not reflect all individual nodal prices, it might miss some local congestion issues. For example, if one node in a zone is congested while another is not, both nodes will still have the same zonal price. Consequently, **the zonal price fails to accurately represent the true supply and demand conditions at each node**.

This situation may result in a **congestion surplus**, which is the difference between the payments made by the loads and the revenues received by the producer.

Bidding zones in Europe



Bidding zone configuration from ENTSO-E technical report 2021.[1]

[1] https://eepublicdownloads.azureedge.net/clean-documents/mc-documents/211209_ENTSO-E%20Bidding%20Zone%20Configuration%20Technical%20Report%202021.pdf

In reality, things are even more complex

- Extending the market clearing process to include block orders is not straightforward. Some orders may also be partially cleared (prices may even depend on quantities);
- The social welfare must take into accound potential costs associated with transmission contraints;
- In practice, the social welfare objective is not linear, but quadratic;
- There are also integer decision variables;
- There are some operational constraints, in particular ramping constraints, so all 24-hourly products must be considered together;
- …

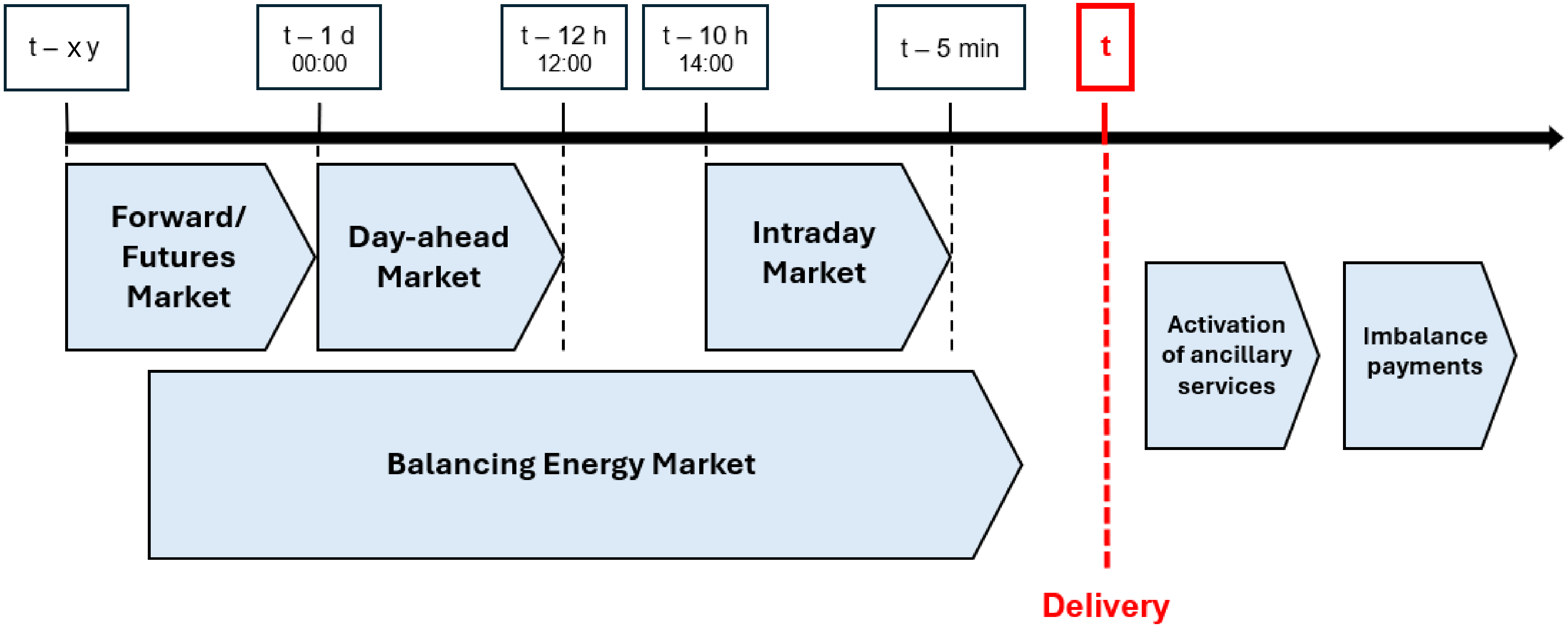
The EUPHEMIA solution to perform Market Coupling approximates the overal problem with a Mixed Integer Quadratic Program (MIQP). The output solution needs to be checked afterwards for its compliance with the original problem.

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 08 – Balancing and securing the electricity power system

Overview of electricity markets – Reminder



From transactions to potential imbalances

Forward/futures, day-ahead, and intraday markets are **financial markets**:

- These are only transactions; **no one is ‘forced’** to generate or consume;
- After market clearing, which determines the prices and volumes for each market time unit, **market participants are informed of the outcomes**;
- In the European setup, participants then proceed with **self-dispatch,** meaning they decide independently how to generate or consume electricity based on the agreed-upon volumes and prices.

However, **imbalances can still occur** when the amount a party has contracted to buy or sell differs from what it actually needs or can produce.

Balancing and securing the power system

To ensure that the power system operates smoothly, **managed markets** play a crucial role in balancing supply and demand.

They refer to **any controlled or regulated market** mechanism, typically under the oversight of the Independent System Operator (ISO), that ensures the **safe, secure, and efficient operation of the power system**.

The managed market framework **takes priority over the open energy market**.

Beyond real-time balancing, there are additional considerations to ensure that electricity demand is always met. These include:

I. **managing network security problems**,

II. **ensuring the availability of ancillary services**,

III. **maintaining future system security**.

We will examine each of these three aspects in detail in their respective parts.

Part I:

Network security problems

What kind of security problems are we speaking of?

Needs are classified according to **three different issues**:

1) **Balancing issues**: This category includes the challenges associated with maintaining a balance in the electrical grid, such as the real-time adjustments needed to ensure that the supply of electricity matches the demand, preventing frequency deviations.

2) **Network issues**: This refers to challenges related to the physical infrastructure of the electrical grid, such as the transmission and distribution network. This involves issues related to network capacity and voltage control.

3) **System restoration**: This involves the procedures and actions taken to restore the electrical grid to normal operation after a significant disruption, such as a blackout or a natural disaster. This includes bringing substations, power lines, and generation sources back online in a coordinated manner.

Note: This classification is not perfect, as there are interactions, for example, between balancing and network issues.

Addressing these issues with ancillary services

Ancillary services are support services that help maintain the reliability and stability of the power system. **These services can include frequency control, voltage control and system restart**; they are essential for addressing each of these issues.

They are typically provided by both producers (such as power plants and other sources of electricity) **and loads** (consumers). For example, in the context of frequency control:

- Producers can offer services such as reserve capacity or regulation by adjusting their output as needed.
- Certain loads may have demand response capabilities, allowing them to reduce their consumption during peak periods.

We will examine the three types of issues one by one,
looking at how they manifest and how to address them.

1) Balancing issues – Understanding frequency stability

<u>Assumption:</u>

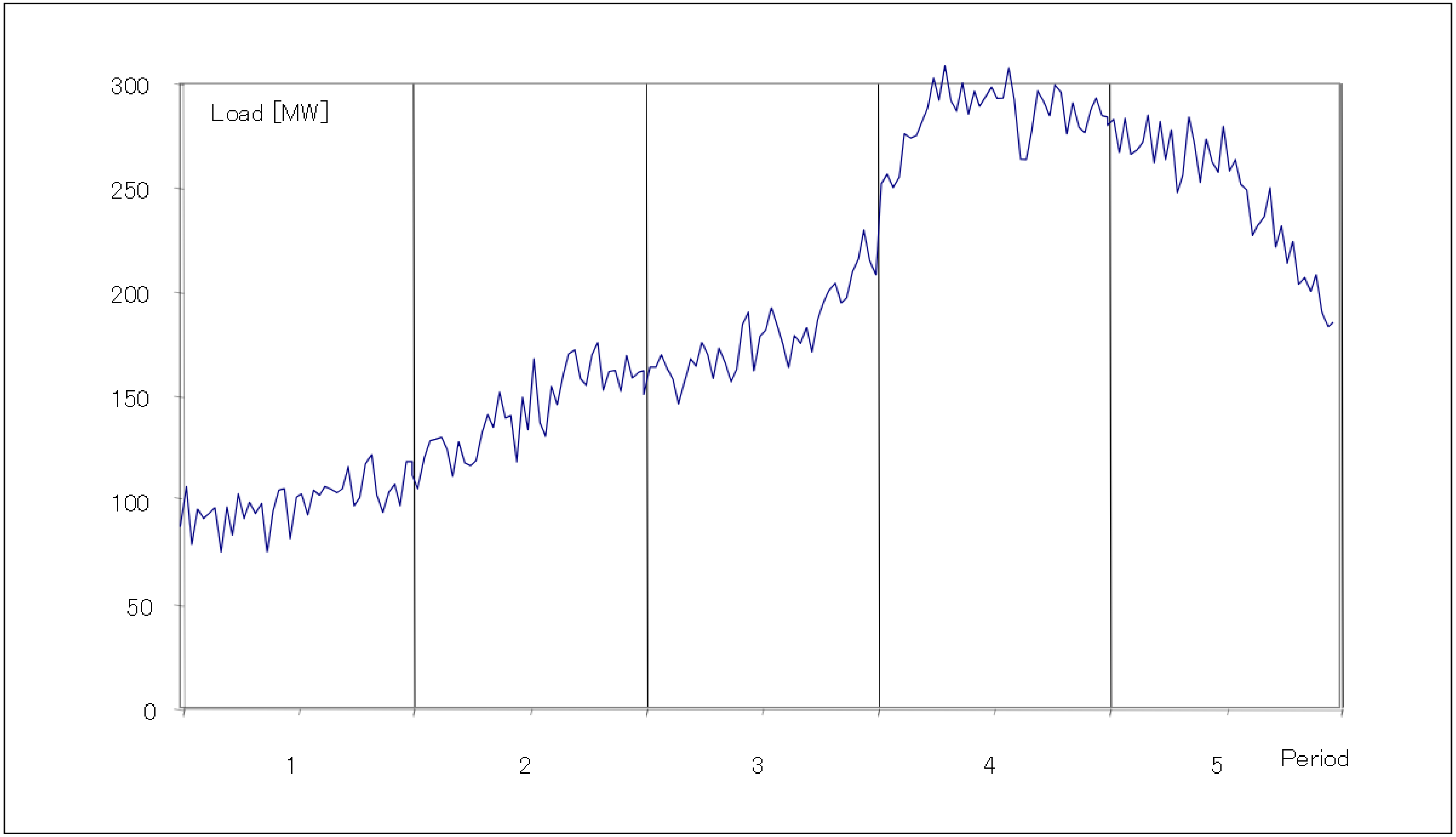
- All loads and generators are connected to the same bus bar.
- If there is **too much generation**, excess energy is stored by the generators in the form of kinetic energy, which leads to an **increase in frequency**.
- If there is **too little generation**, generators release kinetic energy, resulting in a **decrease in frequency**.

Systems with low inertia are more vulnerable to large frequency deviations because they lack the rotational momentum to stabilize frequency changes. **Large frequency deviations can activate the overspeed or underspeed protection systems of generators**. This can further destabilize the system by causing **shutdowns** or reduced generation capacity, leading to a **chain reaction** of instability that can result in a **system collapse**.

This chain reaction occurs when imbalances in generation and demand trigger successive negative effects on the stability of the system.

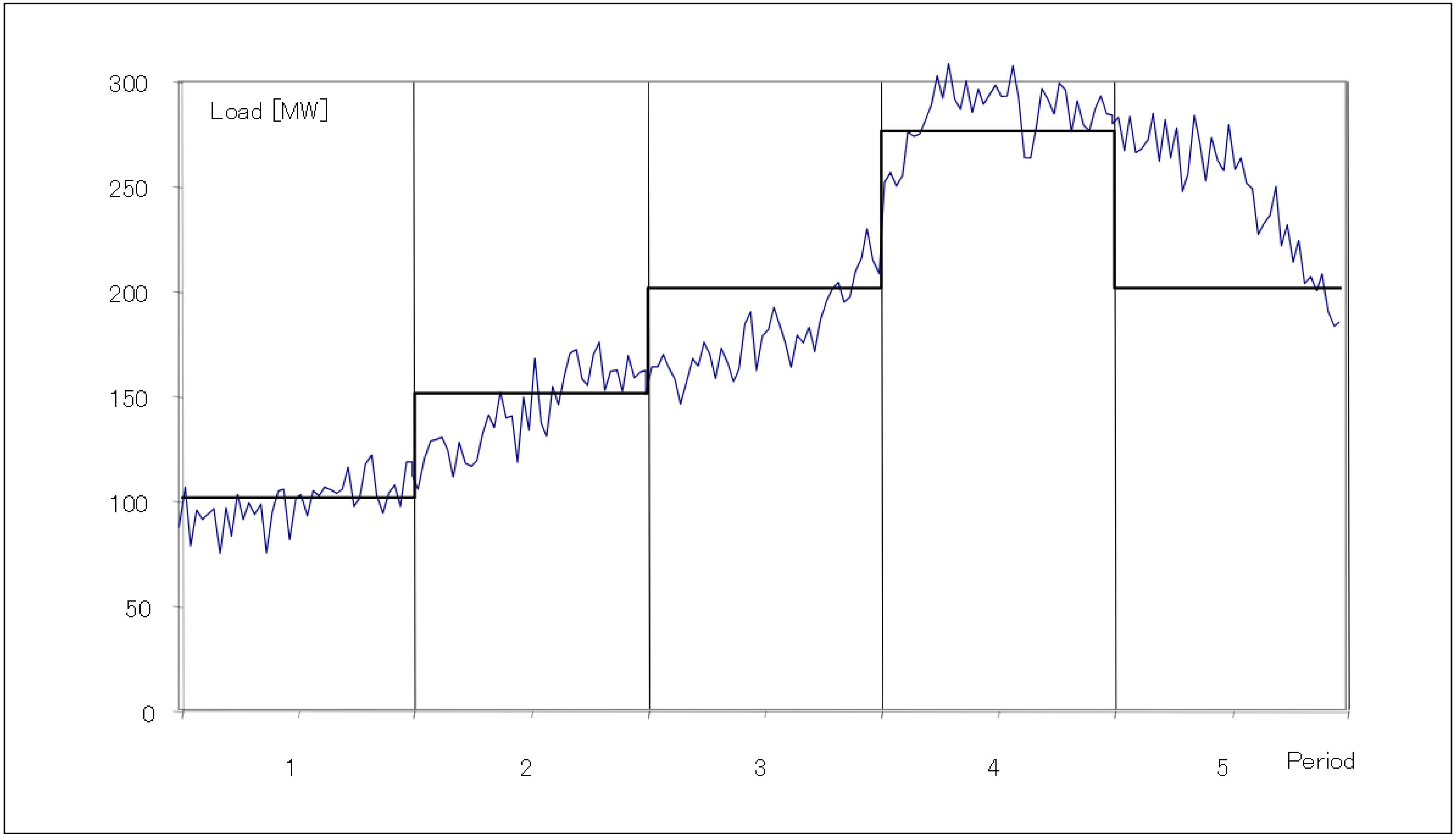
The general philosophy for handling balancing issues is to **always try to keep the frequency as close as possible to its nominal value**.

1) Balancing issues – An example of imbalances (1/6)



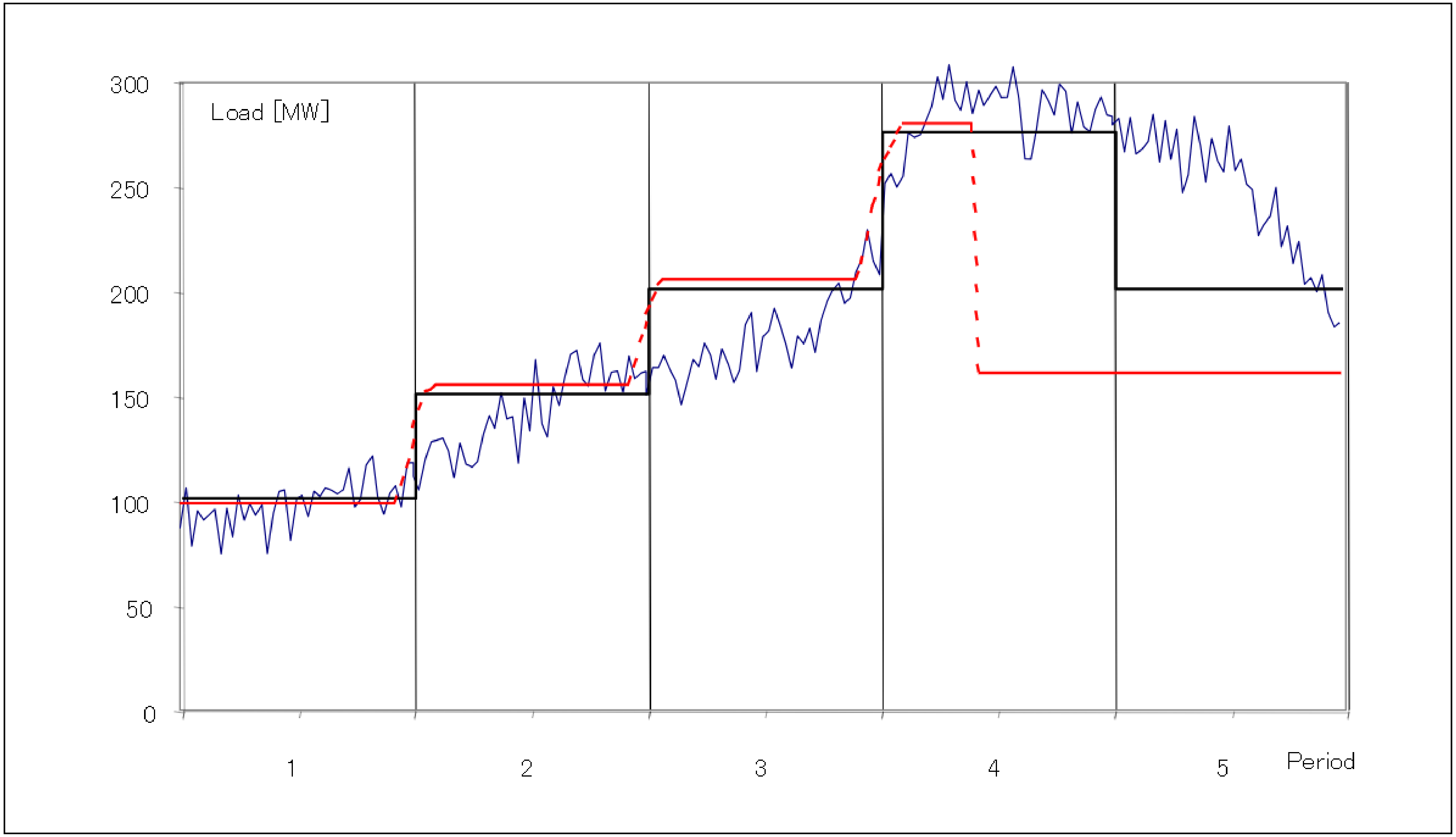
Load over 5 periods.

1) Balancing issues – An example of imbalances (2/6)



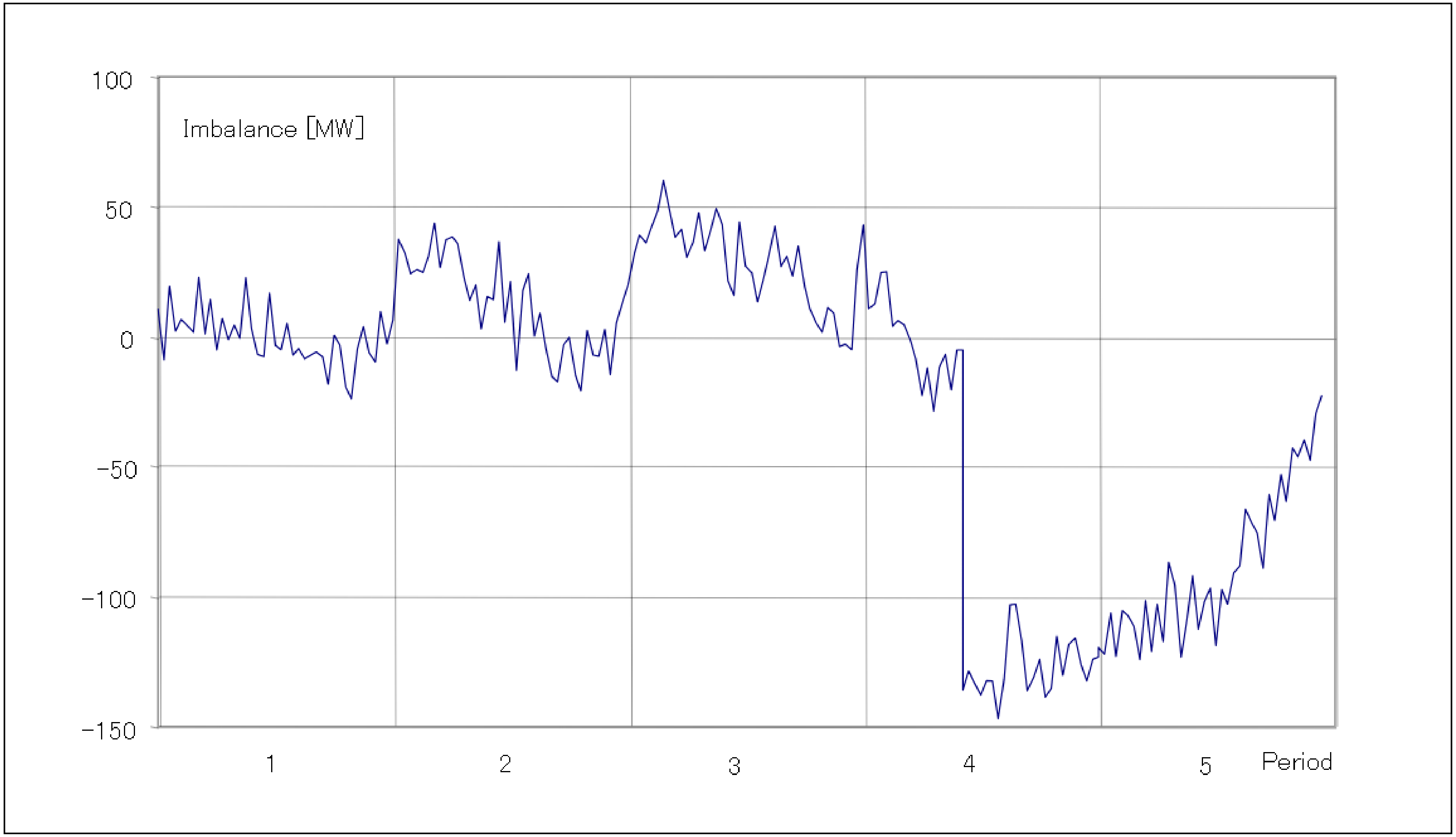
Energy traded based on forecast.

1) Balancing issues – An example of imbalances (3/6)



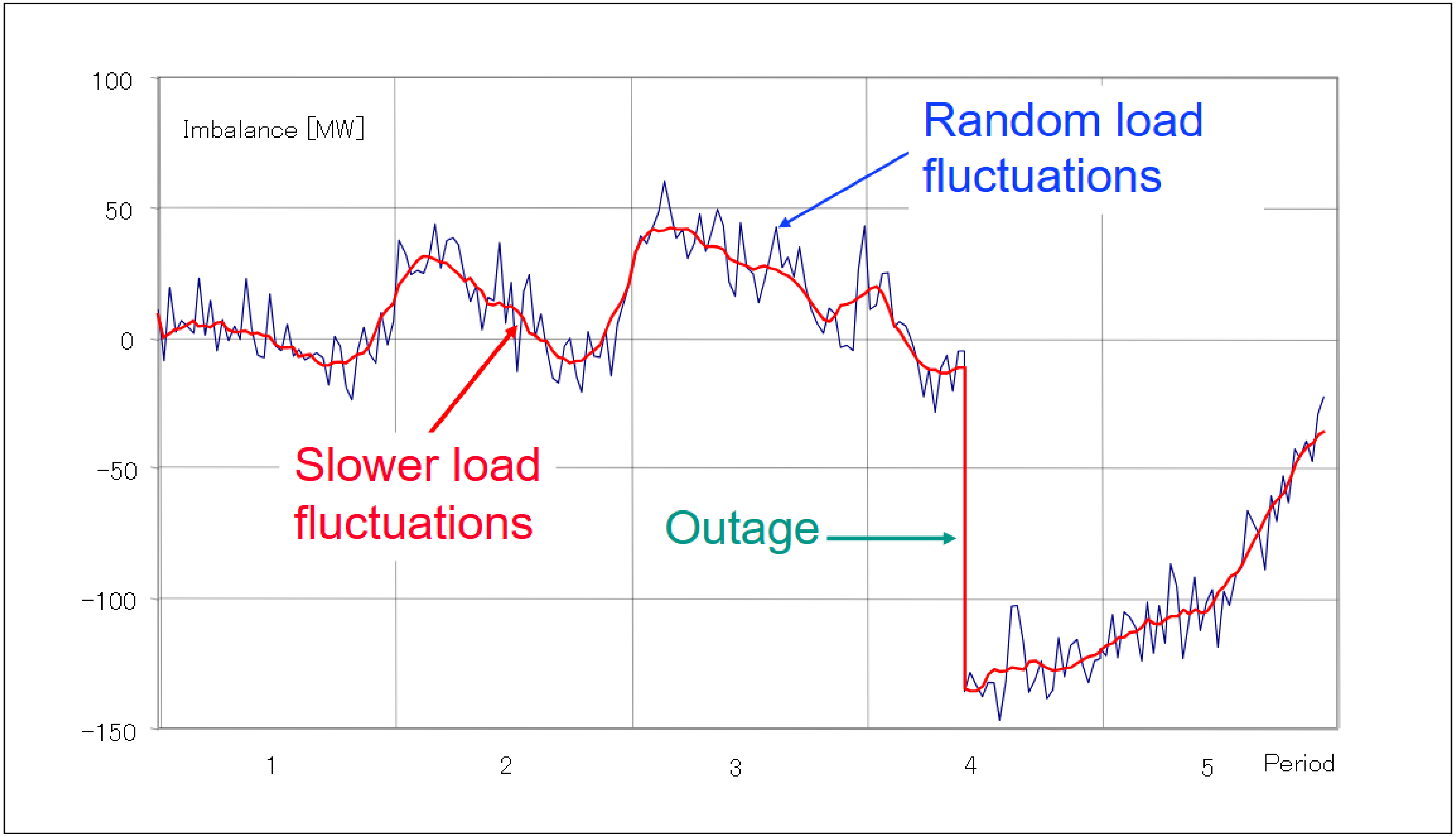
Energy produced versus energy traded.

1) Balancing issues – An example of imbalances (4/6)



Imbalances.

1) Balancing issues – An example of imbalances (5/6)



Components of the imbalances.

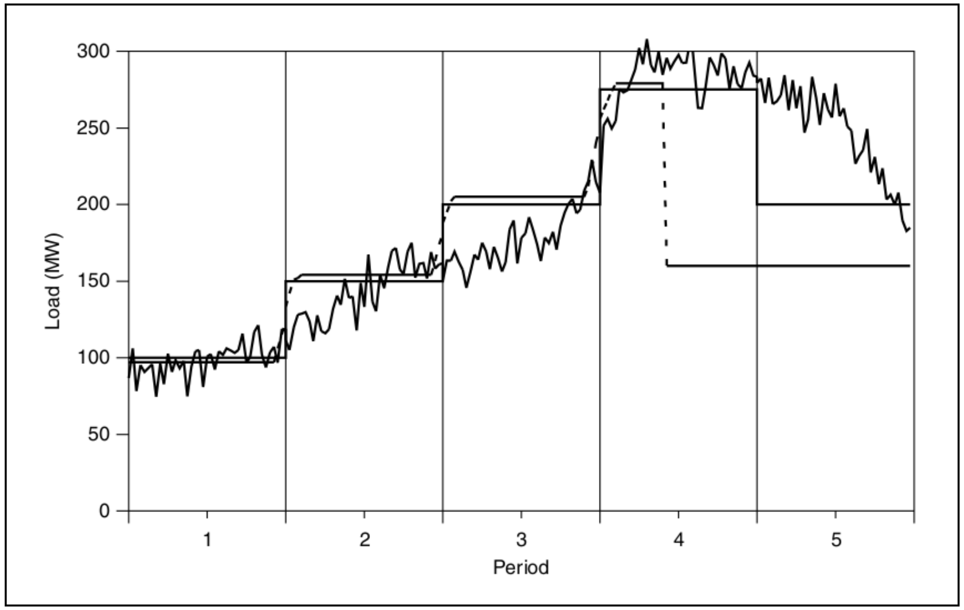
1) Balancing issues – An example of imbalances (6/6)

Differences between load and energy traded:

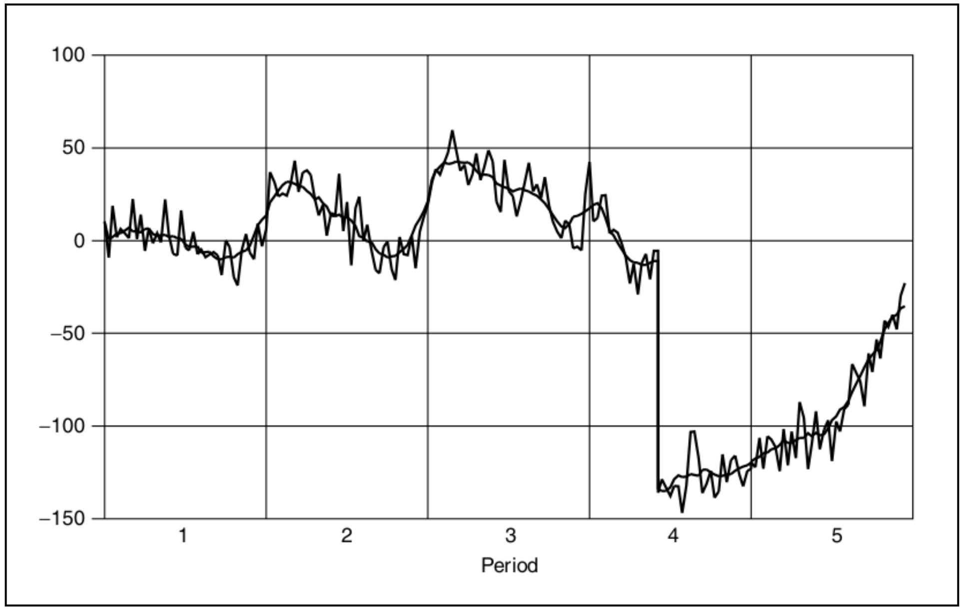
- Trades do not account for rapid load fluctuations;
- The market assumes load is constant throughout the trading period;
- Forecasting errors lead to discrepancies.

Differences between the energy traded and the energy produced:

- Minor control errors can occur;
- Finite ramp rates at the start and end of trading periods cause imbalances;
- Unit outages create significant imbalances.



Load and generation fluctuations.



Resulting imbalances.

1) Balancing issues – Types of imbalances

Imbalances between load and generation have **three different components** with distinct time signatures:

- **Rapid random fluctuations**: Sudden and unpredictable changes in load or generation that occur on a short timescale, making them hard to predict (e.g., the start or stop of equipment).

- **Slower cyclical fluctuations**: More predictable changes that occur over a longer period, such as daily or seasonal variations in consumption (e.g., higher demand in the evening or during winter).

- **Occasional large deficits**: Rare but significant imbalances that can result from the failure of large power plants.

1) Balancing issues – Tailored ancillary services

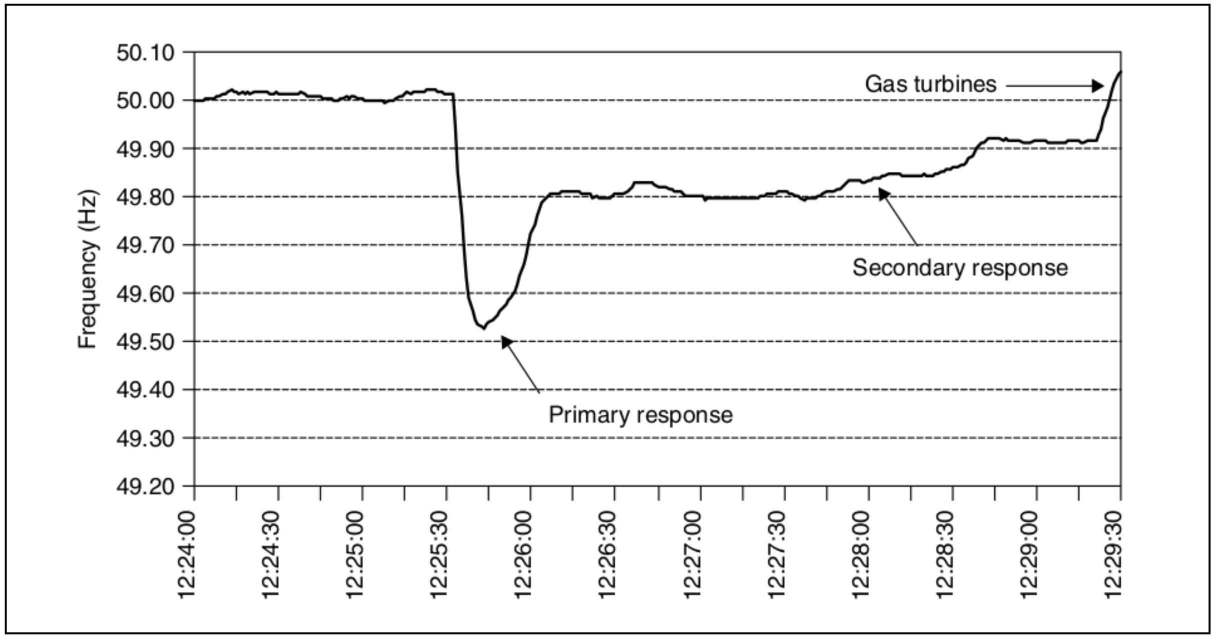
The ISO can treat the previous components separately and tailor the different ancillary services needed to cope with each specific component of the total imbalance.

- **Regulation service**: It is designed to handle rapid fluctuations in load and small unintended changes in generation. It helps the system frequency remain closer to its nominal value and is provided by units that can rapidly increase or decrease their output.

- **Load-following service**: It addresses slower fluctuations, particularly those that are predictable but not considered by the market, such as intra-period changes.

- **Reserve services**: They are designed to help with large and unpredictable power deficits. However, obtaining reserve services is a preventive security action, ensuring that reserve capacity is available to take proactive measures.

1) Balancing issues – An example of response sequence



A 1,220 MW generation loss occurs in Great Britain, which has a total installed capacity of 65 GW;

Sequence of events:

1) The **primary response**, fully activated within 10 seconds and sustained for an additional 20 seconds, successfully stops the frequency drop;
2) Following this, the **secondary response** kicks in, becoming fully available 30 seconds after the incident and lasting for another 30 minutes to bring the system closer to its nominal frequency;
3) Finally, **gas turbines** come online, producing the last increase in frequency to stabilize the system.

2) Network issues – Avoiding system destabilization

As load and generation vary, the flows through the network and the voltages at different points fluctuate. The operator is responsible for maintaining a safe balance by adjusting the flows and keeping the system stable.

Every component of the power system (such as transformers, cables, and generators) has a maximum capacity it can handle safely. To prevent damage or failure, the ISO must **ensure that none of the equipment is overloaded**.

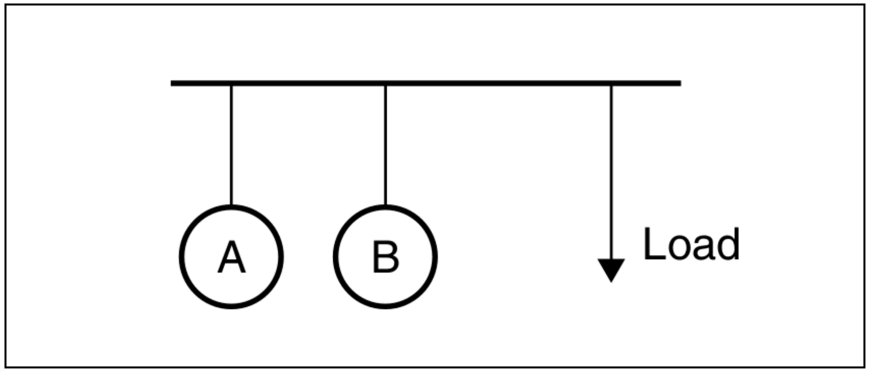
An **N-1 contingency analysis** must also be carried out to ensure that the system remains stable even if one key component fails.

Destabilization can take various forms, such as:

- **cascading failures**, where one failure triggers others like a domino effect;
- **voltage collapse**, where node voltages drop significantly, potentially leading to a blackout;
- **loss of synchronism**, resulting in discrepancies in voltage, phase, current, or frequency;
- **large undamped oscillations** that may trigger protection relays.

2) Network issues – N-1 security criterion

A system has two generators, A and B, each with a capacity of 100 MW, connected to a load.



However, **the maximum load that can be handled securely is not 200 MW, but 100 MW!** This is because the operational limit is determined by the N-1 security criterion, which requires that the system must remain stable even if one generator fails.

Therefore, **the maximum secure load of the system is the minimum load that can be supported under these conditions**.

2) Network issues – The operating cost of reliability

Electricity buyers and sellers need a reliable power network. Reliability has a value: improving reliability should be measured in terms of reduction in the expected cost of outages, which is not trivial.

Alternative:

For estimating the cost of an outage, one can rely on the estimation of a quantity called the **Value of Lost Load (VoLL)** which is defined as the amount of money that an average customer would be willing to pay for not being deprived of a MWh of electrical energy without sufficient advance notice.

Country / Region	VoLL ($/MWh)
UK	22,000
EU	12,290 – 29,050
US	7,500
New Zealand	41,269
Australia	45,708
Ireland	9,538
Northeast USA	9,283 – 13,925

Sources: *Fundamentals of Power System Economics – D.K. & G.S., London Economics & Brattle Group.*

2) Network issues – Actions for reliability

However, reliability also has a cost. The operating cost of reliability emanate from two types of activities that the system operator engages in:

- **Preventive measures**: Designed to put the system in a state where the occurrence of a credible disturbance does not cause instability.

- **Corrective measures**: Taken after a disturbance to "save" the system from further instability.

In the previous illustration of two generators, each with a capacity of 100 MW, connected to a load, both preventive and corrective actions are employed.

Preventively, the maximum load that can be served is limited. However, in the event of a generator outage, corrective adjustments may be made to the generating power of the remaining generator.

2) Network issues – Preventive actions

When the state of the system indicates that a credible contingency could trigger instability, operators must take preventive actions.

- **Low or negligible cost preventive actions include:**
  - Transformers have multiple taps that allow to change voltage levels;
  - Changing the configuration of the network, including opening or closing specific transmission lines, transformers, or other components;
  - Generators can have their voltage set points adjusted;
  - Phase-shifting transformers allow control over power flow by adjusting the phase angle of voltage.

- **High-cost preventive actions arise as system loading increases.**

  At a certain point, security can only be ensured by imposing limitations on generation patterns, which come with significant costs.

Extensive computations are required to select the most effective actions, especially when complex instability phenomena are considered.

2) Network issues – Reactive power support services

In a power system, managing voltage levels is crucial for ensuring the reliable operation of the grid. Several reactive resources and voltage control devices (such as capacitors, reactors, and tap-changing transformers) can be controlled directly by the ISO to help maintain voltage stability. **Generating units provide reactive power support which is the most effective means of controlling voltage**.

Therefore, a voltage control service needs to be defined to specify the conditions under which the system operator can utilize the reactive power resources provided by generating companies. Defining the conditions can be challenging; it requires **consideration of both normal grid operation and unexpected events**, such as equipment failures or outages.

2) Network issues – Services from producers

System operators may also need to obtain additional network services from producers, such as:

- **Inter-trip schemes**: These automatically disconnect some generation and/or load in the event of a fault to maintain system stability. These schemes have no effect on the current state of the power system, but in the event of a fault, the automatically disconnect some generation and/or lad to maintain stability.

- **Power system stabilizers**: These devices adjust the output of generators to dampen oscillations that may develop in the network. They can also increase the amount of power that can be transmitted through a line.

3) System restoration

Disturbances may spiral out of control, leading to a complete collapse of the power system. The system operator is responsible for restoring the system as quickly as possible. However, **restarting large thermal plants requires a significant amount of power, which may not be available if the entire system has collapsed**.

Some generators, such as hydro plants and diesel generators, can restart autonomously. The system operator must ensure that sufficient restoration resources are available. This ancillary service is commonly referred to as **black-start capability**.

Part II:

Ancillary services

Overview of ancillary services

Power system operators require various resources to maintain the security and reliability of the electrical grid, and some of these resources must be obtained from other industry participants in the form of ancillary services.

These include:

- **Black start capability**: The ability to restart a grid following a complete blackout, ensuring that it can be brought back online in a controlled and systematic manner.
- **Frequency response**: Designed to maintain system frequency within a very narrow and stable range, these services involve automatic and very fast responses to changes in power supply and demand. Frequency response helps prevent frequency deviations that could lead to instability.
- **Fast reserve**: Provides additional energy or capacity on short notice when needed. These resources can be rapidly deployed to address unexpected imbalances between power supply and demand.
- **Reactive power support**: Another critical ancillary service to control voltage levels. Devices such as capacitors, reactors, and generators can provide reactive power as needed.
- etc.

Ancillary services classification

Ancillary services classification related to system operation

Frequency control

- Automatic Generation Control (AGC);
- Primary regulation;
- Secondary regulation;
- High frequency response;
- Spinning reserve;
- Non-spinning reserve;
- Emergency control actions.

Voltage control

- Primary control;
- Secondary control;
- Tertiary control.

System restart

We will focus more on frequency control, as it is the key mechanism that maintains the balance of the system.

Types of reserves used in power grid frequency control

Primary:

Generators are equipped with automatic voltage control systems that continuously adjust their output to maintain the grid frequency around the nominal frequency (**e.g., 50 Hz in Europe**). This control mechanism helps prevent frequency deviations at the source and ensures that the generator's output remains within an acceptable range.

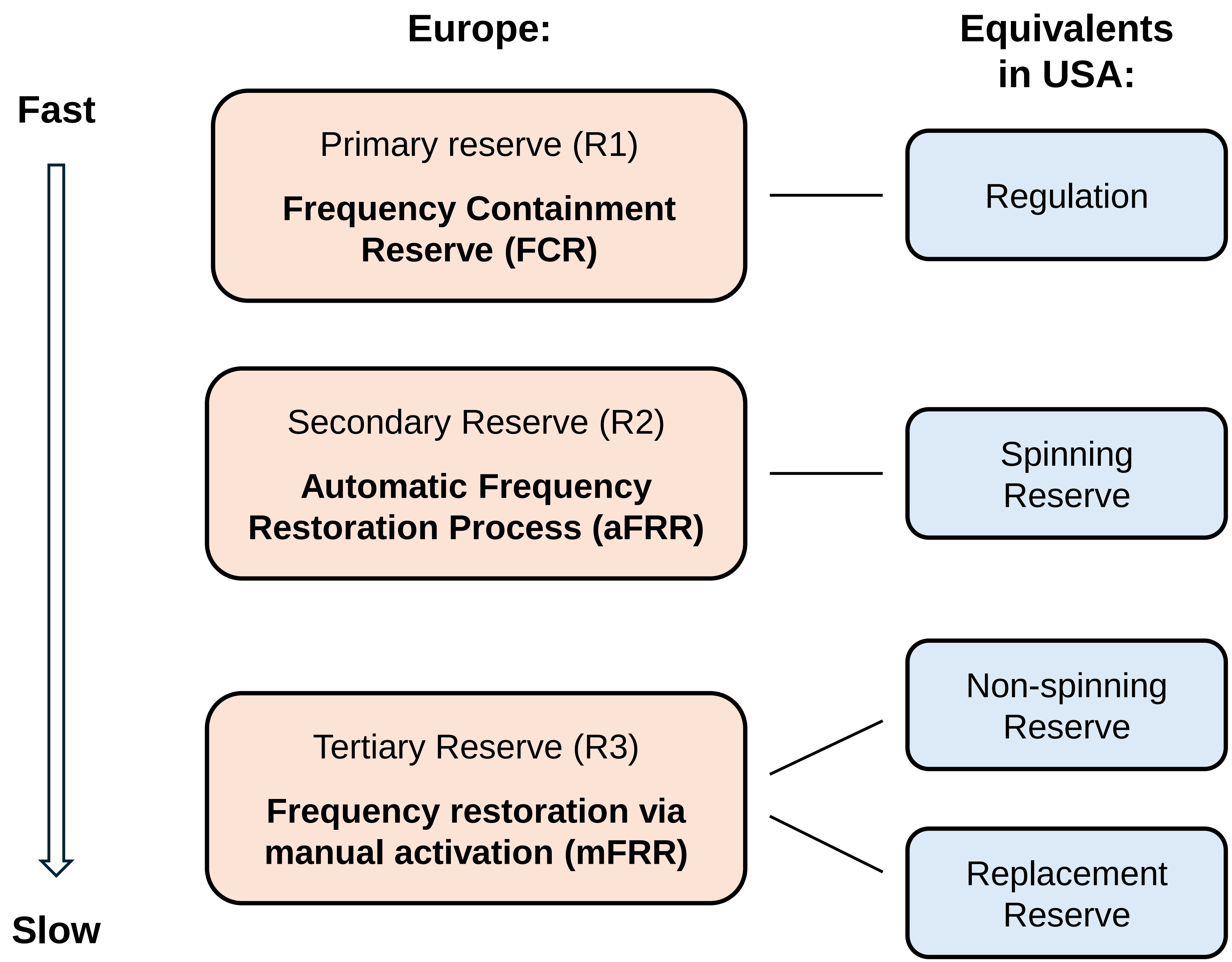
Secondary:

This level of control coordinates the settings and operation of various devices and equipment to provide automatic and rapid responses to frequency deviations. It plays a key role in restoring the frequency of the grid to its nominal value after significant disturbances.

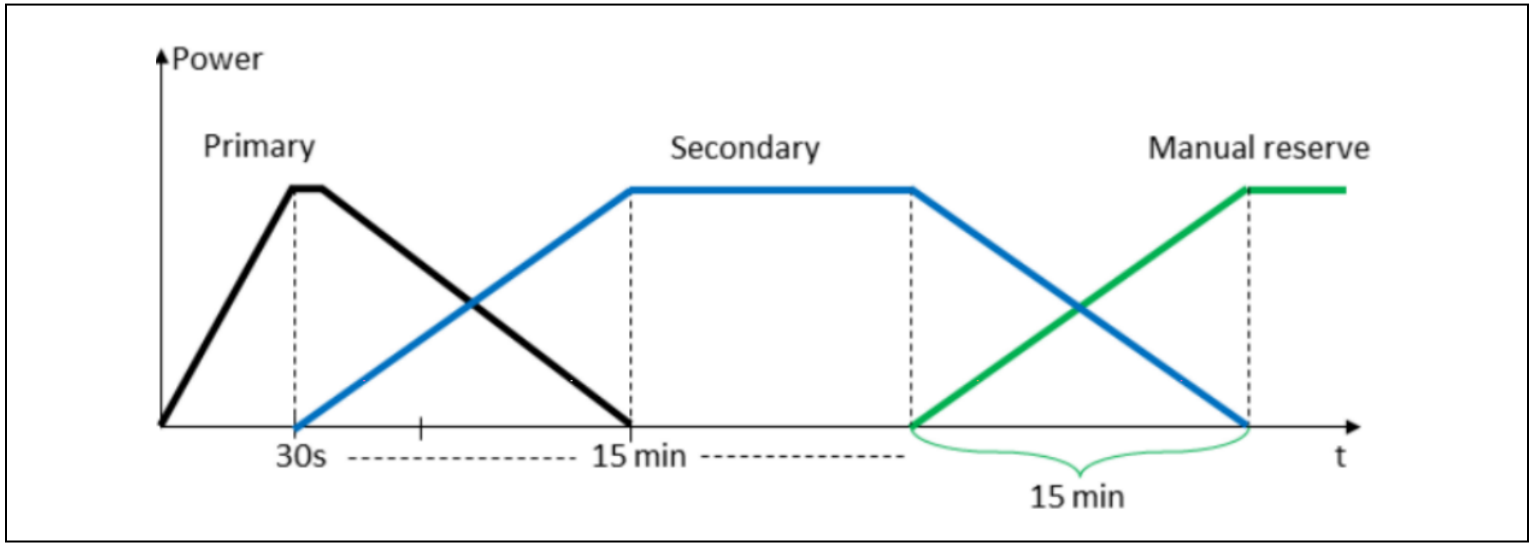
Tertiary:

Tertiary control strategies are typically used in situations where automatic reserves are insufficient to stabilize the grid frequency. They may involve additional resources that can be brought online under the control of grid operators.

Naming conventions in power grid frequency control



Activation timeline of frequency control reserves



- **FCR: stabilizing the frequency.**

  Automatically fully available within 10 seconds and sustainable for an additional 20 seconds.

- **aFRR: return the power grid to its target frequency.**

  Automatically fully available within 30 seconds of an incident and sustainable for an additional 30 minutes.

- **mFRR: providing backup for the secondary reserve.**

  Manually activated.

Obtaining ancillary services (1/2)

Let us examine two mechanisms for obtaining ancillary services

1) Compulsory provision of ancillary services:

In this approach, the regulator or system operator mandates some participants, such as producers or grid operators, to provide specific ancillary services as a condition of participating in the power market. These requirements are typically outlined in regulations, contracts, or service agreements.

This method is often suitable for critical services necessary for grid stability and reliability, particularly those with strong public interest. **Services like black start capability, frequency response, and fast reserve typically fall under compulsory provision**.

The compulsory provision ensures that **essential services are always available, even in the absence of market incentives**. This approach helps avoid situations where a lack of these services could compromise the security of the power system.

Obtaining ancillary services (2/2)

2) Market-based mechanism for ancillary services:

Ancillary services are procured through competitive markets where market participants, including generators and demand response providers, offer their services in response to market signals such as prices or requests for proposals. These markets are designed to promote efficient resource allocation and price discovery.

Market-based mechanisms are well-suited for services that can be provided by various sources and are not immediately critical to grid stability. **Examples include regulation services, load-following, and some reserve services.**

This approach encourages competition, innovation, and cost-effectiveness in delivering ancillary services. They **allow participants to respond flexibly to changing grid conditions and price signals, potentially resulting in more efficient service delivery**.

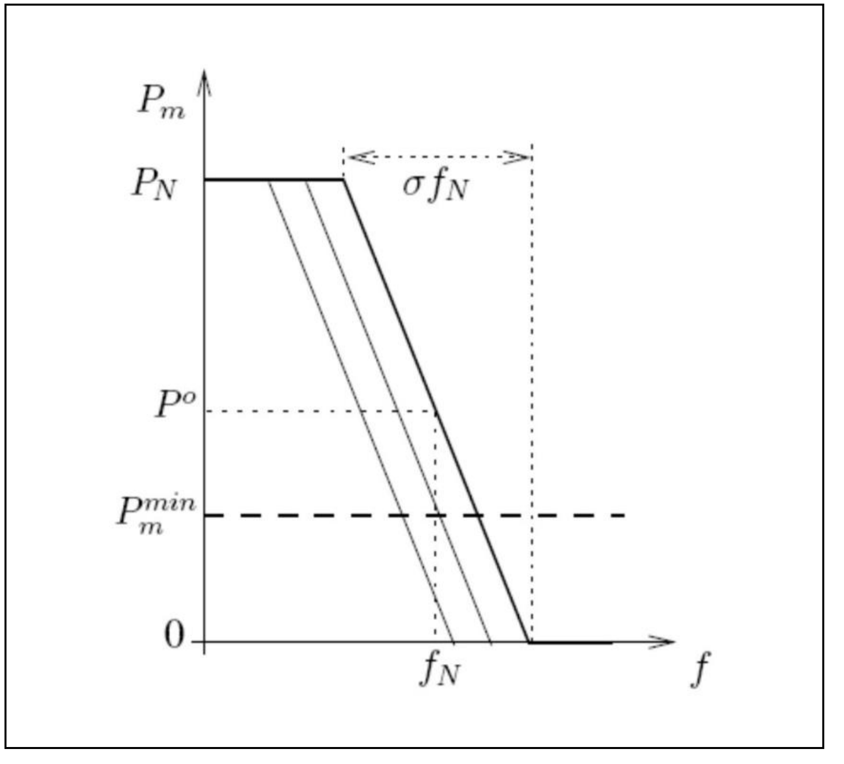
The choice between compulsory provision and market-based mechanisms is influenced by the type of ancillary service, the nature of the power system, and historical circumstances.

Compulsory provision of ancillary services

As a condition for connection, a category of industry participants can be required to provide a specific type of ancillary service.

For example, generating units may be required to be equipped with a 4% droop coefficient (σ) to ensure that all units contribute equally to frequency regulation. **The droop coefficient defines the relationship between a generator's output and the grid frequency**. A 4% droop coefficient means that the generator will adjust its output by 4% for every 1 Hz change in grid frequency.

Generating units may also be required to operate with a power factor ranging from 0.85 leading to 0.9 lagging and be equipped with voltage regulators. **The power factor measures the ratio of active power to apparent power in an alternating current circuit**. A power factor range of 0.85 leading to 0.9 lagging indicates that the generators must provide a mix of reactive power (leading or lagging) to help control and stabilize voltage levels.



The disadvantages of compulsory provision

- **Unnecessary investments**: Not all generating units need to participate in frequency control, and not all units require power system stabilizers.
- **Limited room for innovation**: This approach does not allow for technological advancements or commercial innovation.
- **Unpopularity**: Providers may feel compelled to supply services for which they are not compensated (e.g., producing reactive reserves increases losses and limits the maximum amount of active power that can be produced).
- **Inability to provide services**: Some participants may be unable to provide required services (e.g., nuclear units cannot rapidly adjust their power output). Therefore, compulsion may not be suitable for certain services.
- **Inefficient resource use**: Efficient units should not be forced to operate at partial load to provide reserves.

Market-based mechanism for ancillary services

Instead of making the provision compulsory, the ISO can organize markets where it will buy ancillary services from other market participants.

Long-term contracts are preferred for services in which the amount needed does not change (or changes very little) over time, such as **black-start capability, inter-trip schemes, power-system stabilizers, and frequency regulation**.

Spot markets are needed for services where the needs vary substantially over the course of the day and offers change due to interactions with the energy market. The last part of the necessary reserve is often provided through short-term market mechanisms.

In Europe, these markets are structured around two types of actors:

- **Balance Responsible Parties (BRPs)**: These are market participants responsible for ensuring that their own energy consumption and/or production matches their contracted positions. BRPs may be producers, suppliers, large consumers, or traders.
- **Balance System Providers (BSPs)**: They provide balancing services to the grid operator. They may include producers, demand response providers, or other entities capable of supplying ancillary services to maintain grid balance.

The Balance Responsible Party (BRP)

A BRP is a market participant, or its designated representative, responsible for managing its imbalances. BRPs are required to take all reasonable measures to maintain balance. This may involve adjusting generation, trading in the electricity market, or implementing demand response measures to align supply and demand.

Each BRP is responsible for a portfolio of **access points** and must take all necessary actions to maintain 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

Day balance schedule by BRPs in Belgium

The day before the operating period, BRPs must submit a **daily balance schedule** to Elia for their portfolio. This schedule includes:

- The expected injections (electricity generation) and offtakes (electricity consumption) at each access point.

- Commercial power trades, such as purchases and sales, with other BRPs or those related to cross-border transactions (imports and exports). These transactions can be day-ahead or intraday, depending on market conditions.

In Belgium, the daily balance schedule must be balanced on a **quarter-hourly basis**, meaning the sum of injections and purchases must equal the sum of offtakes and sales for every 15-minute interval.

Imbalance tariffs by BRPs in Belgium

Elia uses ex-post measurement data from the access points and the commercial trade schedules to **verify whether a BRP has maintained balance**.

If a BRP incurs an imbalance on a quarter-hourly basis, they are subject to **imbalance tariffs** which are financial penalties. The imbalance tariffs **incentivize the BRP to keep their portfolio balanced** or, under certain conditions, to assist Elia in maintaining grid security and reliability.

To correct the imbalances created by BRPs, the ISO organizes balancing markets. These markets offer flexibility in the form of ancillary services provided by **Balance Service Providers (BSPs)**.

Note about demand-side provision of ancillary services

Historically, generating units provided all ancillary services. In a competitive environment, the demand side should also be able to offer these services.

In principle, all balancing issues could be addressed by the demand side. Additionally, the demand side could help tackle other instability issues, such as voltage instability, loss of synchronism, and damping of oscillations.

Demand response programs enable consumers to reduce or shift their electricity consumption during peak periods, which can help alleviate supply-demand imbalances and manage frequency fluctuations.

This presents huge opportunities for new businesses, but things may quickly evolve (e.g., cheap batteries appearing on the market).

Buying ancillary services

The ISO is responsible for purchasing ancillary services on behalf of the users of the system through a market mechanism. He pays the providers of these services and recovers costs from the users. It is essential for the ISO to buy the **optimal amount** of services and pay the appropriate price for them.

Depending on the type of reserve, the ISO may pay for **capacity and/or energy**. For example, primary reserves are considered “energy-neutral services”, meaning that the BSPs are only compensated for the capacity they provide.

Fair cost allocation is essential in this context. Users need to pay a **fair share of the costs associated with procuring ancillary services**. The allocation methods aim to distribute these costs equitably among the various users based on their usage and the benefits they receive from reliable grid operations.

Quantifying the needs of ancillary services

Marginal cost of security: This refers to the cost associated with increasing the reliability and stability of the electricity system. It can be defined using probabilistic models that estimate the amount of load that cannot be served during one year for a given level of security.

Marginal value of security: This represents the additional value that increased security provides to customers, which can be more challenging to compute.

Cost/benefit analysis: This is used to determine the point at which the level of needs for ancillary services is economically optimized. It identifies the point where the marginal cost of providing additional security equals the marginal value of that security.

Allocating the cost of ancillary services

Not all consumers value system security equally. For example, the cost of service interruption is greater for a semiconductor factory than for a residential customer. Therefore, customers should be able to pay for a desirable level of reliability. However, selling customized reliability is often too difficult to achieve in practice.

The requirement for load-following and regulation services depends on the type of customers. Typically, industrial customers need more regulation, so costs should be allocated according to the type of load to avoid creating a situation where a cluster of customers subsidizes others.

In practice, since all users receive the same level of security, the cost of ancillary services is shared among all users based on some measure of their use of the system, typically the energy consumed or produced.

Part III:

Future system security

Preparing for the future

Ancillary services are useful for ensuring the security of the system in the short to mid-term. However, **they do not guarantee that sufficient capacity will be available in the future**.

This requires the right investments in the following areas:

- Transportation;
- Generation;
- Storage (if applicable);
- Demand-side management (to alleviate investments in the other categories).

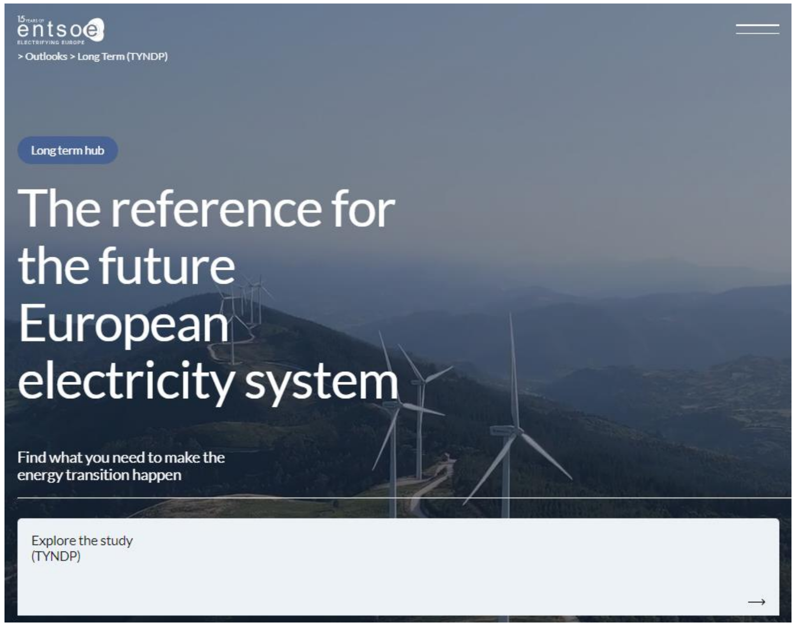
Investments in the network

As explained in previous lessons, investments in the network are financed through **taxes** and/or **congestion surplus** (which are extra revenues generated by Transmission System Operators (TSOs) when there is congestion on electricity transmission lines between two different zones or markets that have distinct electricity prices).

Investment decisions are made by regional monopolies or governmental agencies (which can sometimes be the same entity).

In Europe, decisions regarding transmission investments are made at the European level through a cost-benefit analysis outlined in the Ten-Year Network Development Plans (TYNDP) compiled by ENTSO-E.

See the latest report here: https://tyndp.entsoe.eu/



Investments in electricity generation

Energy markets should be designed to ensure that sufficient investments are made in capacity to cover future demand. Additionally, these investments often need to align with the current political agenda. For example:

- Willingness for energy independence in Europe in the 1970s led to significant nuclear investments.
- The current energy transition is driving major investments in new renewable sources.

There are **diverging objectives between what the market wants** (efficiency, competition, and cost-effectiveness) **and what politics desires** (environmental sustainability, energy security, and social equity).

These two objectives may not always align, creating a need for regulation. Yet, regulation might interfere with the proper functioning of the market and require complementary mechanisms.

Three regulation mechanisms that affect investment and network security

1) **Price caps:** Maximum price that can be charged for electricity. While they protect consumers from price spikes, they can deter investment in new generation capacity, particularly during periods of high demand.

2) **Renewable sources support:** Policies and incentives to support renewable energy development can influence investment decisions. These may include feed-in tariffs, tax credits, and renewable portfolio standards.

3) **Capacity Mechanisms (CMs):** Payments to producers to ensure they maintain and invest in capacity. CM design can be complex and may require careful balancing with market dynamics.

1) Price caps – The missing money problem (1/2)

Assuming there is enough capacity to meet demand even at peak times, the clearing market price rises to reflect the marginal cost of the most expensive unit dispatched. When the margin between available capacity and peak demand tightens, electricity prices rise to the point of reflecting a **scarcity premium**.

For socio-political and technical reasons, prices may be capped. In this case, supply will meet demand, but **the capped price might allow to cover the fixed costs of the "marginaly producing power plant"**, which in turn may deprive the market of the necessary investment in new or replacement capacity.

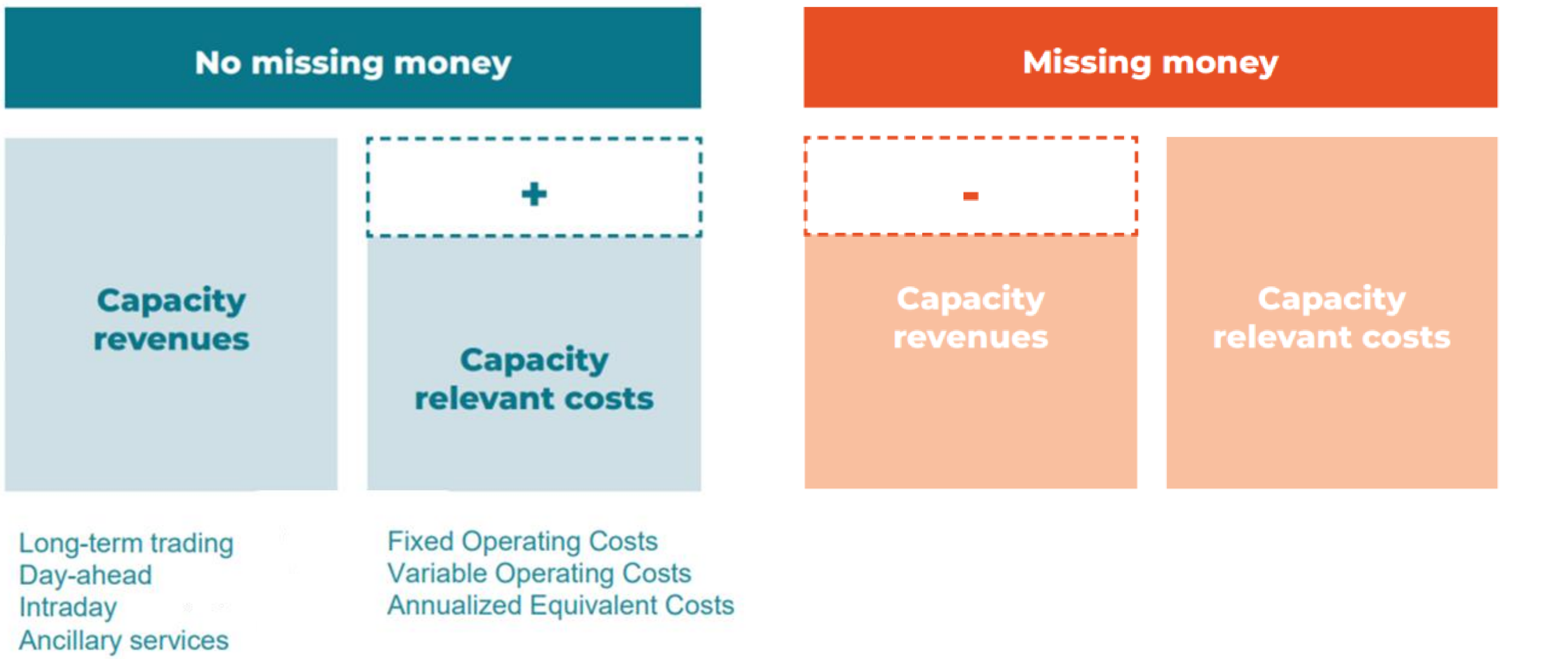
In consequence, the energy-only market may not provide a price signal which would guarantee an adequate level of generation in the middle / long term.

This is the **'missing money'** problem.

1) Price caps – The missing money problem (2/2)

The ‘missing money’ refers to the portion of the costs associated with generation capacity that is not covered by the revenues earned in the market.
As a result, many capacity holders lack a positive business case to **enable current and new capacities to be available on the market**.

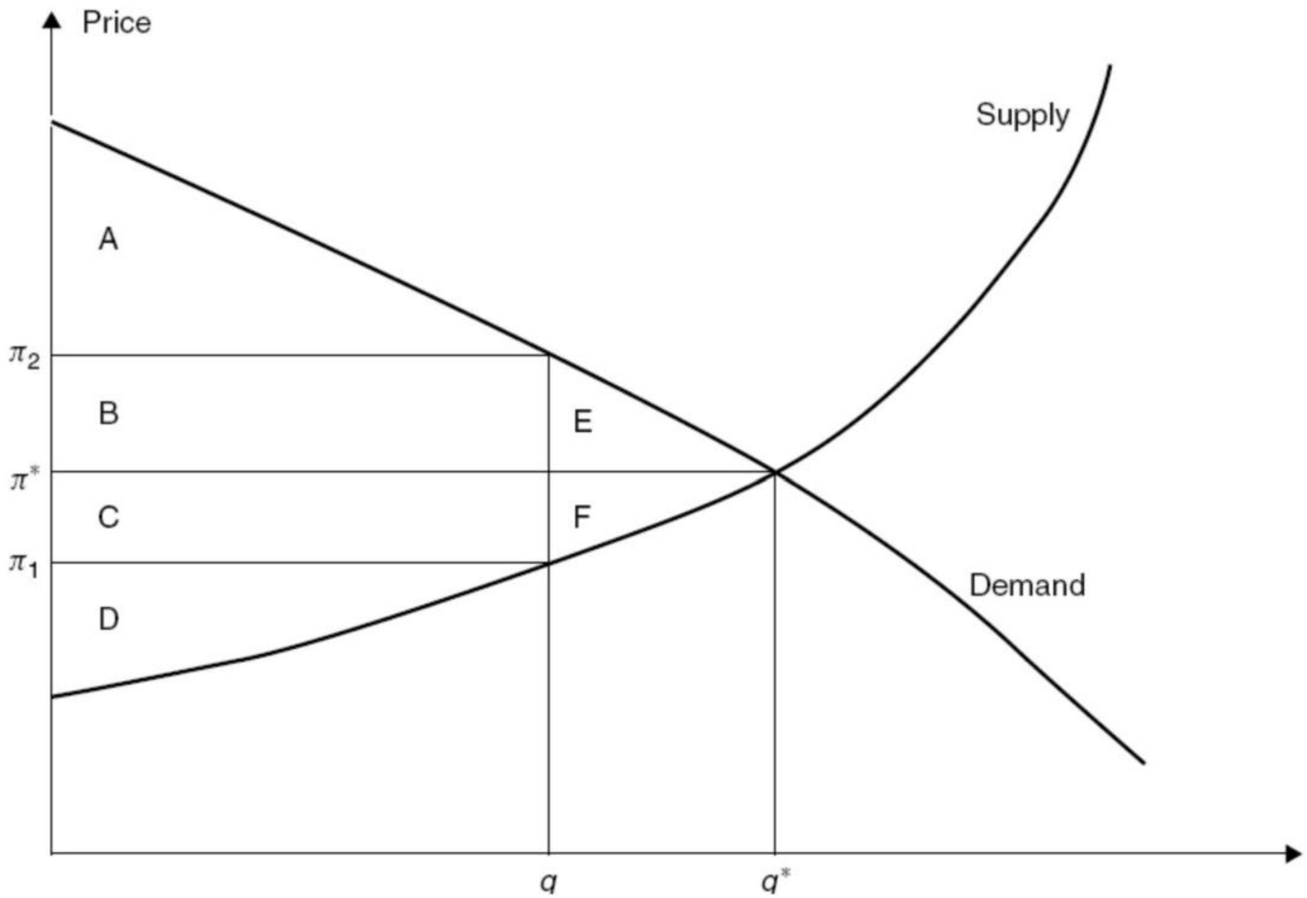
Capacity Mechanisms (CMs) provide additional remuneration to compensate for the missing money to market participants for them to remain in the market and stabilize the system.



1) Price caps – Beware of their deadweight loss

In addition, enforcing a maximum price or price cap results in a ***deadweight loss***, meaning a reduction in social welfare.

In this case, social welfare decreases from ABCDEF to ABCD when a price cap is set at π_2.



2) Renewable sources support – Types of contract (1/2)

Support scheme	Description
Feed-In Tariffs (FIT)	Fixed payment per MWh for renewable electricity over a long-term contract
Feed-In Premium (FIP)	Premium payment added to the market price
Renewable Portfolio Standards (RPS) / Quotas	Obligation for utilities to source a percentage of their electricity from renewables
Contract for Difference (CfD)	Two-way contract ensuring stable prices for renewable electricity (strike price)
Green Certificates / Renewable Energy Certificates (RECs)	Tradable certificates representing 1 MWh of renewable energy
Auction Systems (Competitive Tenders)	Governments or regulators solicit bids from developers
Tax Incentives and Grants	Direct tax credits or subsidies for renewable energy investments

2) Renewable sources support – Types of contract (2/2)

‘Traditional’ Feed-In Tariff (FIT):

‘Modern’ FIT
Contract for Difference (CfD):

Feed-In Premium (FIP):

Example of some price-based contracts.

2) Renewable sources support – impacts from supports

One of the most notable impacts of renewable energy on market prices is the **price suppression effect**. In electricity markets, generation resources are dispatched based on their marginal cost, known as the merit order. As more wind energy enters the market, it lowers the overall clearing price in the day-ahead market because higher-cost resources are displaced.

This effect is more pronounced when wind output is high, and it can lead to very low or even negative prices during periods of high wind generation combined with low demand.

Negative prices are highly accentuated by support mechanisms (FiT, FiP, CfD, etc) since those mechanisms provide to the renewable energy sources the same financial stream of revenues provided that they are dispachted.

2) Renewable sources support – What about negative bid and how to deal with it?

In some cases, electricity prices can drop into negative territory due to an oversupply, where generators are willing to pay to avoid shutting down their operations. Under a **FIP system**, wind parks can still make a profit even with negative prices.

For example, if a wind park receives a premium of €10/MWh and the market price falls to -€9.9/MWh, the producer still earns the €10/MWh premium, resulting in a net price of €0.1/MWh (10 - 9.9). Therefore, the wind park doesn’t lose money and may still bid in negative territory to ensure they are dispatched.

To address negative prices, one option is to **stipulate that if clearing prices go negative, market participants lose their support** (whether under CfD or FIP). In this case, the optimal strategy would be to bid at €0/MWh.

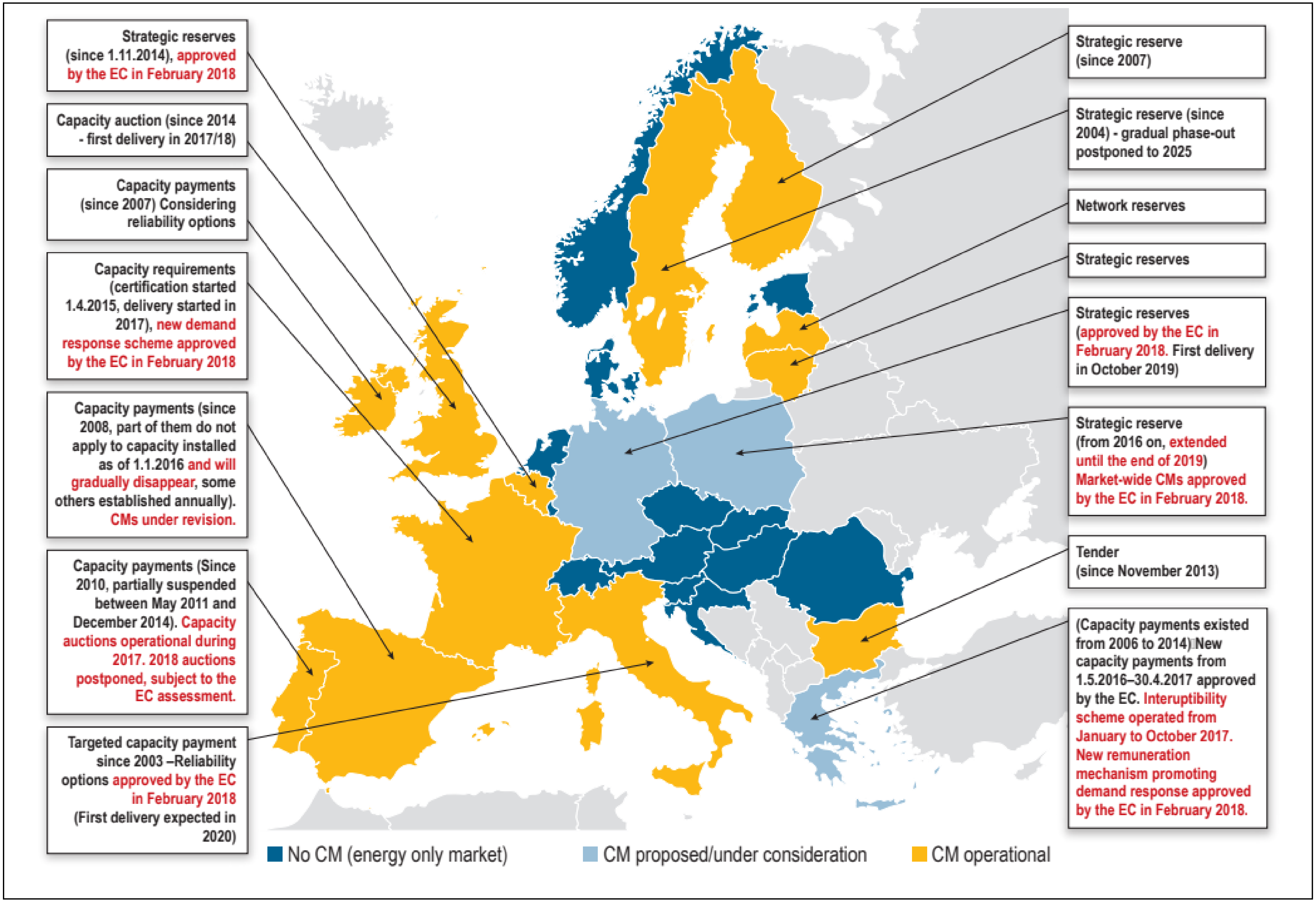
The impact depends on the number of renewable producers: (i) If there are only a few, prices may remain stable; (ii) If there are many, clearing prices will decrease as the number of renewable producers grows, but they will not turn negative.

3) Capacity Mechanisms (CMs) – Presentation

Current market mechanisms that remunerate electricity may not provide sufficient support for investments in **controllable generation units, such as CCGTs,** if energy prices do not remain high enough for a sufficient period.

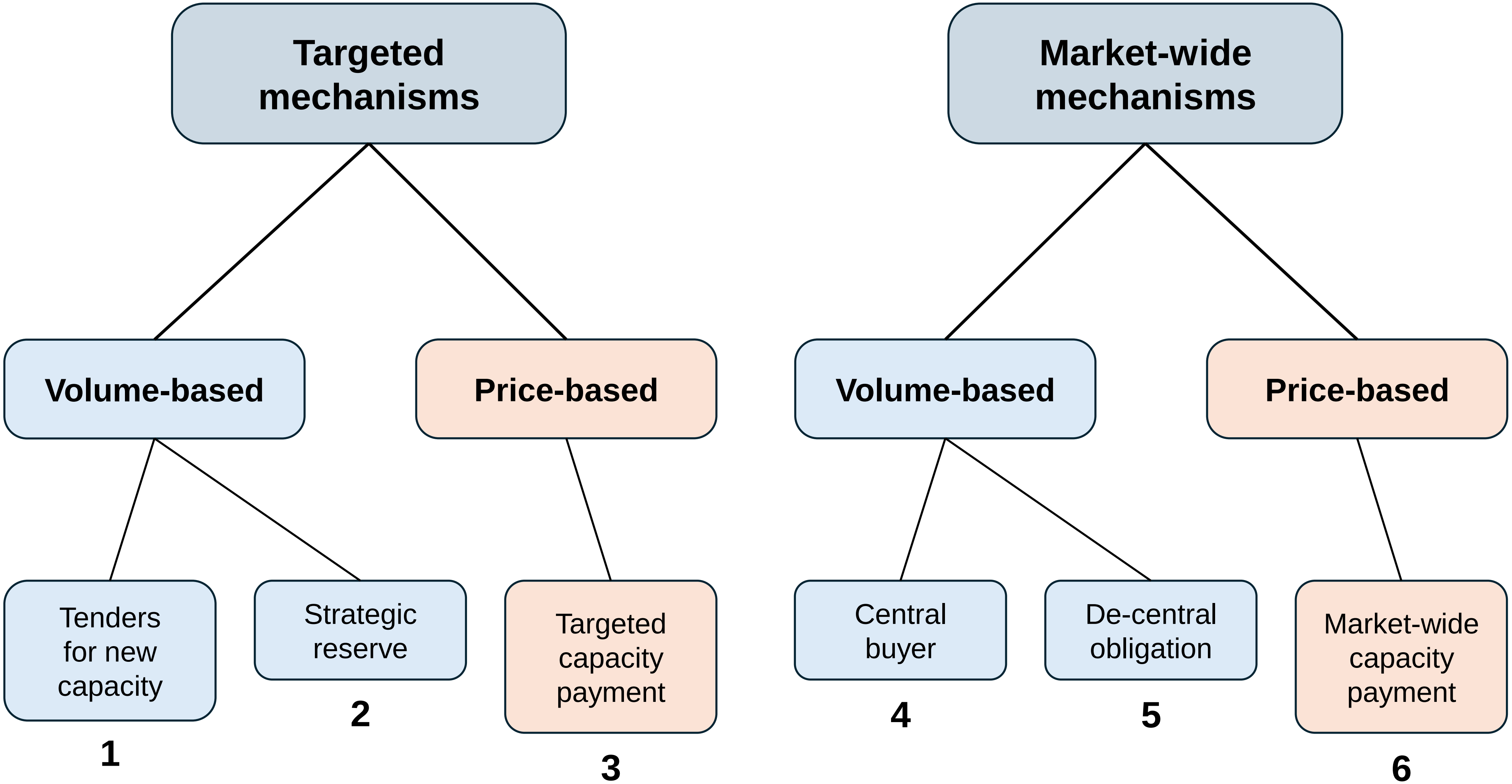
Capacity Mechanisms (CMs) that make separate capacity revenues available to generators and/or demand response would be needed to ensure generation adequacy. Several Member States have already opted for the introduction of one or more capacity mechanisms to address perceived residual market failures.

3) Capacity Mechanisms (CMs) in Europe



CMs in Europe in 2017.

3) Capacity Mechanisms (CMs) – The ‘EU taxonomy’ (1/3)



3) Capacity Mechanisms (CMs) – The ‘EU taxonomy’ (2/3)

Targeted mechanisms are those where the required amount of capacity and the amount expected to be brought forward by the market are identified centrally. The CM then supports only the additional capacity (or ‘top-up’) needed beyond what the market would otherwise provide.

1) Tender for new capacity: Typically, the beneficiary of such a tender receives financial support for constructing a power plant to bring forward the identified top-up capacity. Once the plant is operational, in some models, the top-up capacity operates in the market as usual (without guaranteed electricity sales). It is also possible for the plant to be supported through a power purchase agreement.

2) Strategic reserve: In a strategic reserve mechanism, the top-up capacity is contracted and held in reserve outside the market. It only operates when specific conditions are met (e.g., when no more capacity is available, or electricity prices reach a certain level). Strategic reserves typically aim to keep existing capacity available for the system.

3) Targeted capacity payment: In this model, a central body sets the price of capacity, which is paid to a subset of capacity providers operating in the market. For example, it may apply only to a specific technology or to providers meeting certain criteria.

3) Capacity Mechanisms (CMs) – The ‘EU taxonomy’ (3/3)

In a market-wide mechanism**,** all capacity required to ensure security of supply receives payment, including both existing and new capacity providers. This effectively makes 'capacity' a separate product from 'electricity.’

4) Central buyer: Here, the total required capacity is set centrally and procured through a central bidding process, where potential capacity providers compete, allowing the market to determine the price.

5) Decentralized obligation: In this model, electricity suppliers or retailers are required to contract with capacity providers to secure the total capacity needed to meet their consumers' demand. Unlike the central buyer model, there is no central bidding process, though market forces still establish the price for the required capacity volume.

6) Market-wide capacity payment: In this case, the price of capacity is set centrally, based on estimates of the level of payment needed to bring forward sufficient total capacity, and it is paid to all capacity providers in the market.

3) Capacity Mechanisms (CMs) – Opinions on these CMs

- **Tenders for new capacity:** May not sufficiently support emerging technologies like distributed generation and storage. Could become necessary in the event of a nuclear phase-out.

- **Strategic reserve:** Suitable as a temporary measure, but why exclude strategic reserve generators from the market unless there's an adequacy issue?

- **Targeted capacity payment:** Simple to implement but lacks competition and innovation. It is beneficial that the units remain in the market.

- **Central buyer:** Likely to result in payments to generators that would continue operating without these subsidies. Could lead to market power issues. However, it is a good option for promoting large-scale investments in generation, fostering innovation and competition.

- **Decentralized obligation:** Shares the same drawbacks as the central buyer model but may encourage more competition and innovation. However, it could create transparency issues.

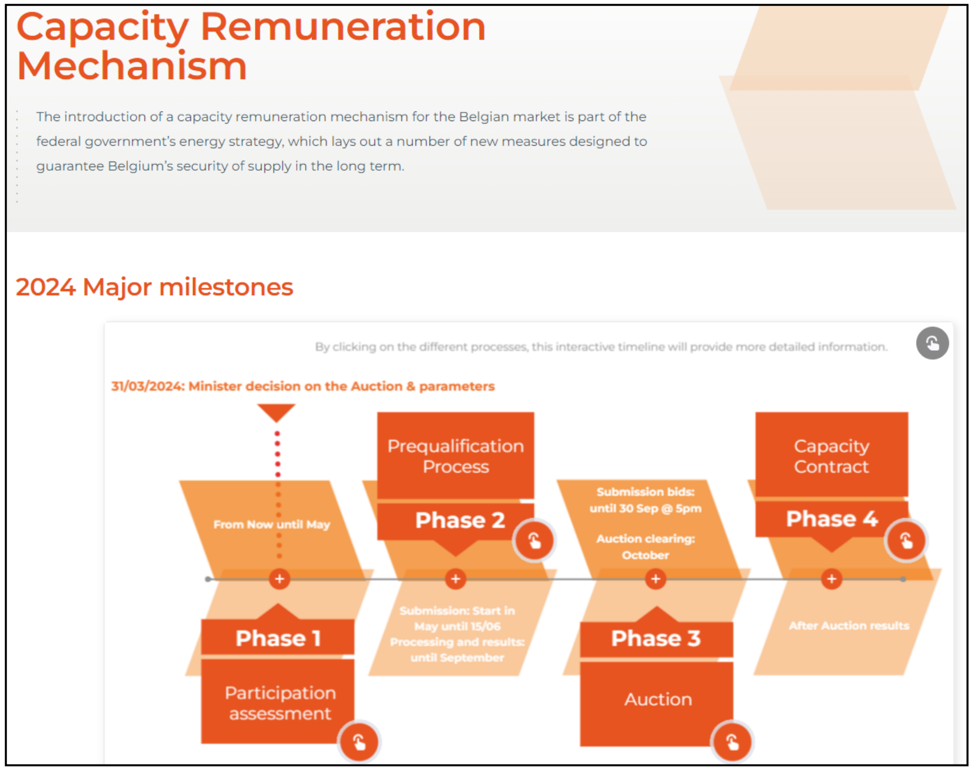
- **Market-wide capacity payment:** Does not promote innovation or competition and will likely result in payments to already bankable generators.

The CRMs in Belgium

In Belgium, it is the central buyer mechanism that is under application.

The TSO, Elia, plays the role of the central buyer. Elia (i) organizes the capacity auctions, (ii) ensures the procurement of sufficient capacity to meet the demand, and (iii) manages the contracts and financial settlements.

Regarding the auction process, capacity providers are supposed to bid at a certain price. Elia evaluates the bids (reliability, price, amount of capacity) and contract with the providers proposing the lowest prices.



ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 09 – The impact of transmission networks on electricity trading

The impact of transmission networks on electricity trading

Transmission constraints and losses can cause significant distortions in the electricity market. In this lesson, we will explore the impact of the transmission network on electricity trading and discuss techniques to mitigate these limitations.

The structure of the lesson is as follows:

I. **Role of TSOs, ENTSO-E, and RSCs;**

II. **Transmission rights;**

III. **Losses.**

I. Role of TSOs, ENTSO-E, and RSCs

Roles of Transmission System Operators (TSOs)

TSOs are responsible for the security of supply within a specific geographical zone, known as a control area, which can range from a country to smaller regions. To ensure that electricity demand is reliably met, they must:

- Develop Ten-Year Network Development Plans (TYNDP) to outline how the grid will evolve to meet future demand and incorporate changes such as new generation sources or transmission lines.
- Evaluate whether the system will have sufficient capacity to cover demand at all times through “System Adequacy Assessments”, which are conducted 5 to 10 years in advance.
- Continuously perform calculations and simulations to assess grid conditions, adapting their assumptions based on new developments in their own network or those of neighboring regions.
- Act within minutes/seconds to mitigate any risks and maintain grid stability.

If, despite these precautions, an incident occurs, the source of the problem can be easily traced, allowing for swift fixes and compensation for any affected grid users.

Roles of ENTSO-E

The multilateral agreement and system operation guidelines assign the **European Network of Transmission System Operators for Electricity (ENTSO-E)** the responsibility of supporting TSOs and their regional strategies.

“ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the security of the interconnected power system in all time frames at pan-European level and the optimal functioning and development of the European interconnected electricity markets, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.”[1]

ENTSO-E fulfills this role by:

- Providing IT tools and systems, such as the common grid model, which help TSOs enhance their operational planning at both regional and pan-European levels.
- Facilitating communication about the roles of Regional Security Coordinators (RSCs) and TSOs.

[1] https://www.entsoe.eu/about/inside-entsoe/objectives/

Roles of Regional Security Coordinators (RSCs)

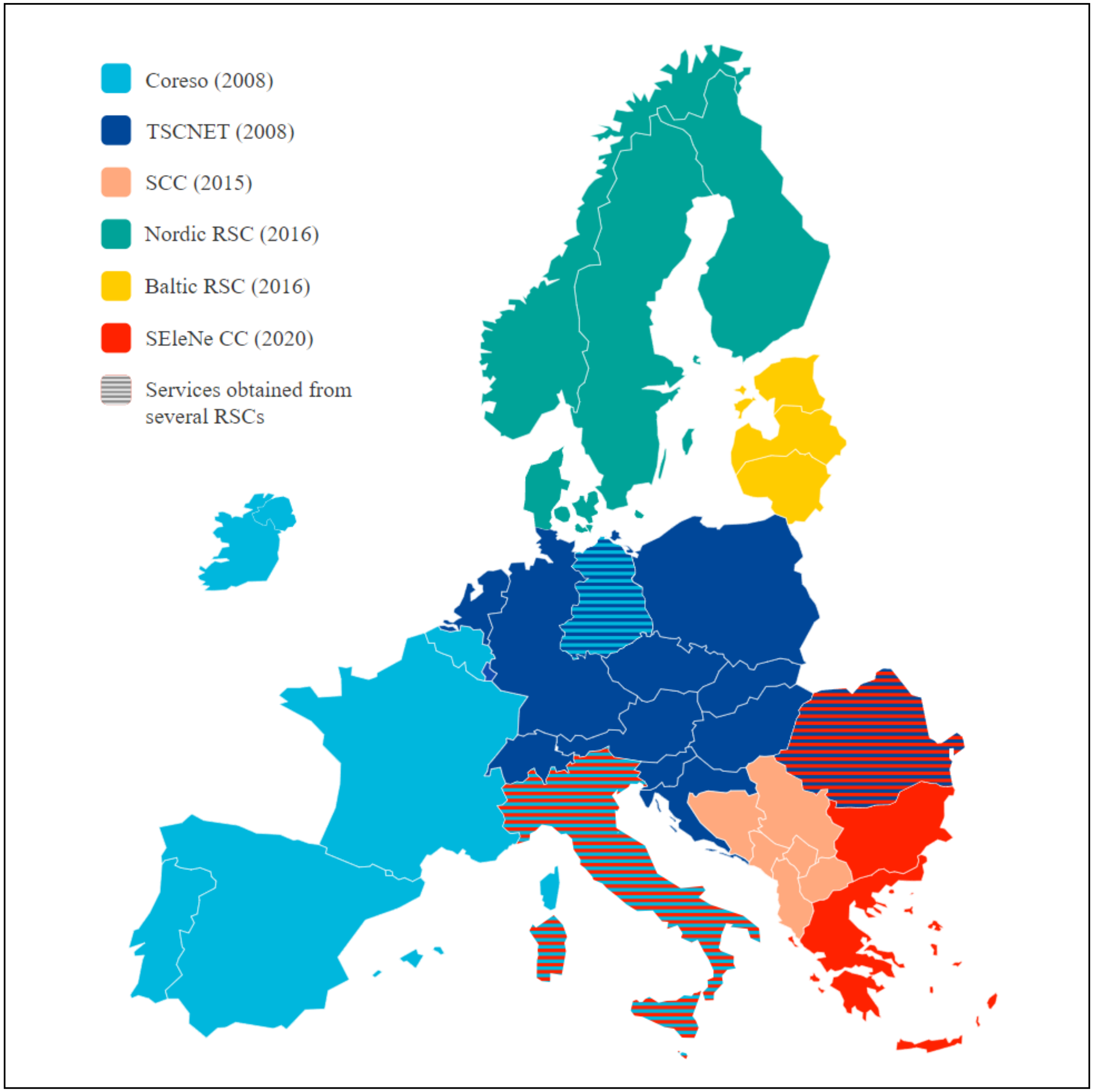
RSCs were established to enhance coordination and information sharing across the grid. They operate independently from national governments and TSO-specific interests.

RSCs engage from one year ahead to one hour before dispatch, running calculations and making recommendations to TSOs.

They are required to deliver five core services:

- Security analysis,
- Capacity calculation,
- Outage coordination (coordinating planned maintenance outages, which was previously limited to neighboring countries),
- Adequacy forecasting,
- **Common grid model (CGM) development**.

Current RSCs in Europe



The common grid model (CGM)

Each TSO publishes its *Individual Grid Model* (IGM), a dynamic representation of its electricity grid.

RSC engineers receive these IGMs from various TSOs and merge them to create a Common Grid Model (CGM), representing the European electricity grid. This service can be provided a year, a week, a day in advance, or even multiple times per day.

With the CGM, all TSOs have the same detailed overview of high-voltage line flows, enabling them to analyze system behavior and ensure grid security.

The CGM serves as the foundation for most RSC processes.

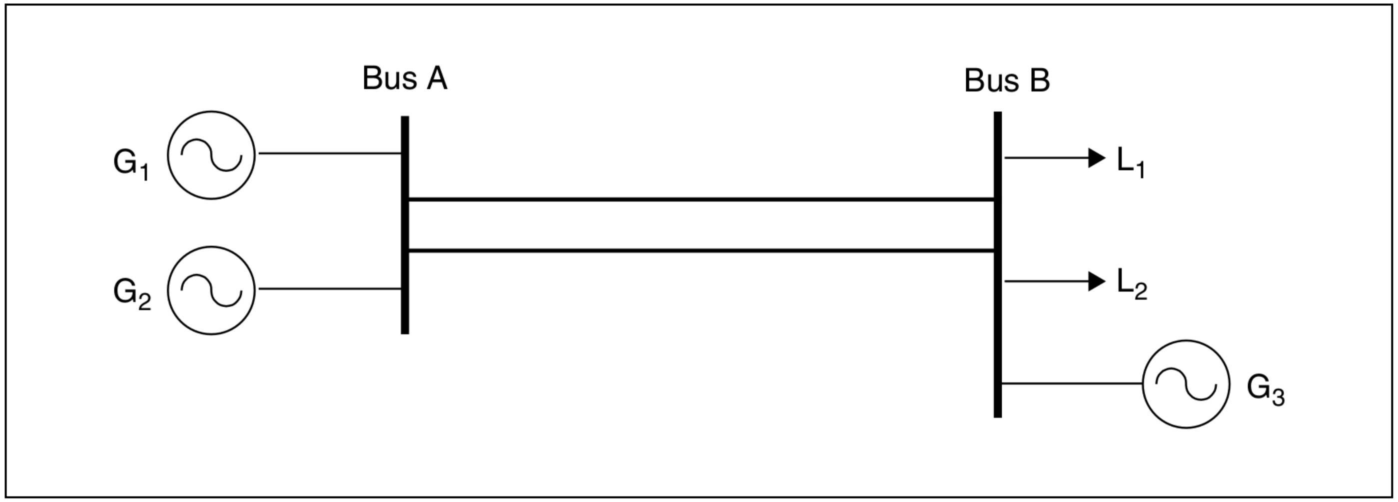
II. Transmission rights

A simple problem

<u>Problem:</u>

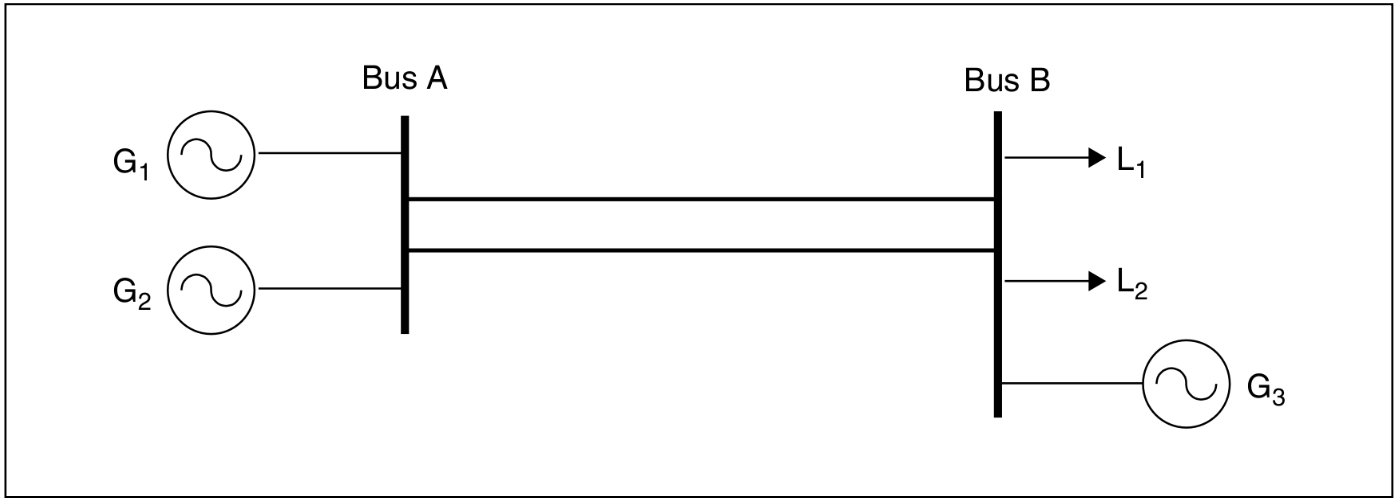
- G1 wants to sell 300 MW to L1;
- G2 wants to sell 200 MW to L2.

Is it always possible?



Transactions curtailment

- G1 wants to sell 300 MW to L1;
- G2 wants to sell 200 MW to L2.



If the transmission lines between Bus A and Bus B can always transfer 500 MW, even under contingency conditions, this is acceptable.

If the transmission capacity is less than 500 MW, it is not possible; **some transactions will need to be curtailed**.

How to curtail transactions?

Determining whether a set of transactions would make the operation of the system insecure is relatively easy, though it can be computationally demanding. **However, determining which transactions should be curtailed is more complex.**

Administrative procedures can be established to prioritize the transactions to be cut back, based on factors such as the nature of the transaction, their order of registration, or historical data.

However, **these administrative curtailments are inefficient and should be avoided, as they do not take into account the relative economic benefits of various transactions**, which may be unknown to the TSO in a decentralized trading system.

Physical transmission rights

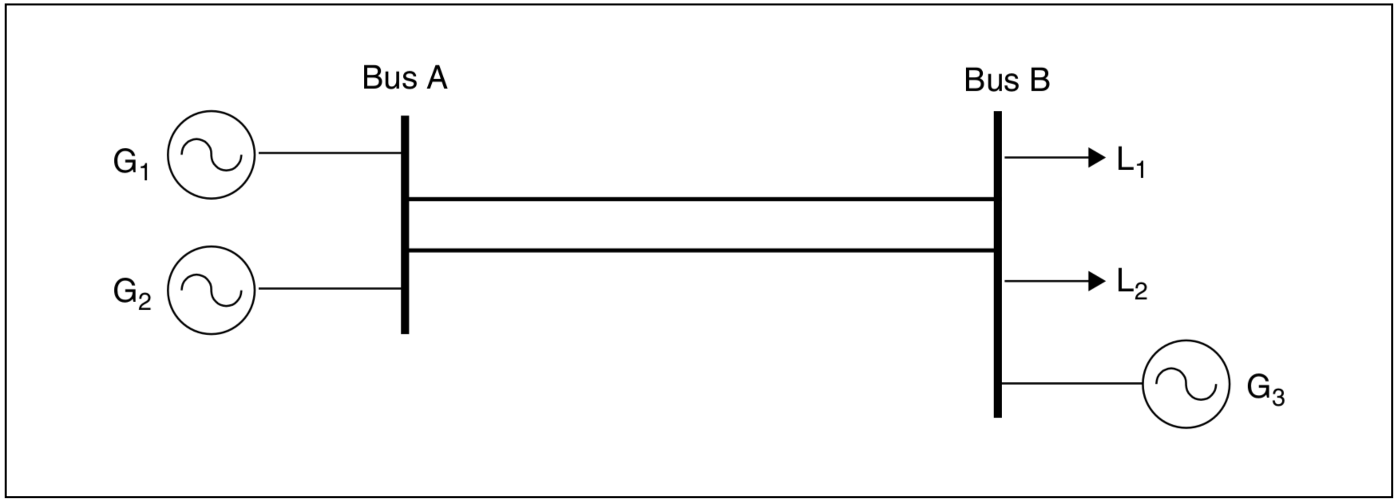
Advocates for decentralized trading believe that buyers and sellers are best positioned to decide whether they wish to use the network.

When signing a contract, buyers and sellers should be offered the option to purchase the right to use the transmission system for their transaction.

Physical Transmission Rights (PTR) entitling its holder to physically transfer a certain volume of electricity between two bidding zones within a given period of time. The transfer takes place in a specific direction via a nomination to the TSOs.

PTRs are purchased at auctions, allowing parties to determine whether these additional costs are justifiable.

Example of costs for physical transmission rights



Suppose that:

- G1 and L1 (300 MW) have agreed on a price of €30/MWh;
- G2 and L2 (200 MW) have agreed on a price of €32/MWh;
- At the same time, G3 offers energy at €35/MWh.

Therefore:

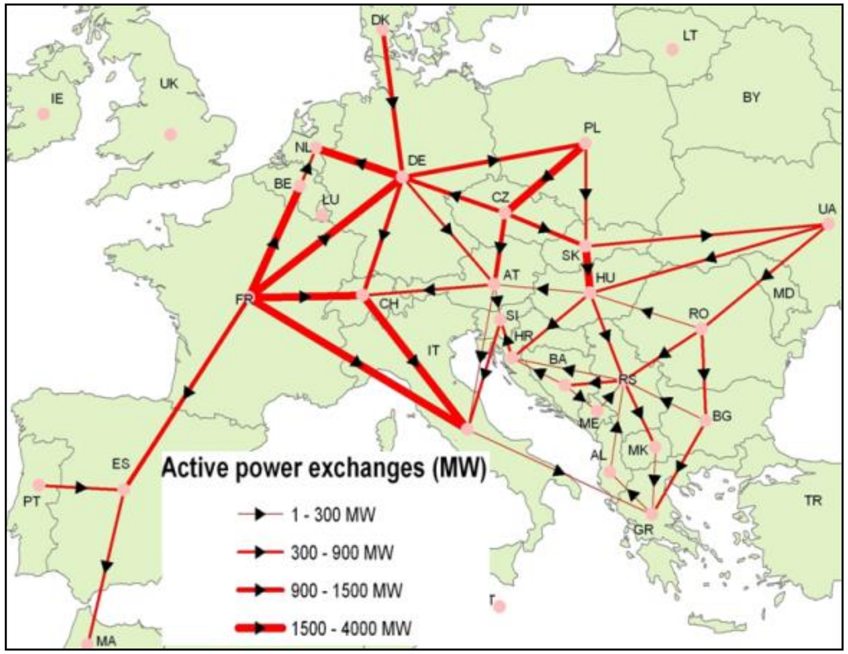
- L2 should not pay more than €3/MWh for the transmission rights;
- L1 could pay up to €5/MWh before preferring to purchase energy from G3.

Problem with transmission rights

Problem 1: In Europe, the situation is more complex due to the presence of multiple lines. The path that power takes through a network is not determined by the wishes of market participants but by physical laws.

Problem 2: Even if it were determined by the wishes of market participants, issues would still arise, as power can be traded from A to B and from B to A, creating counter-flows.

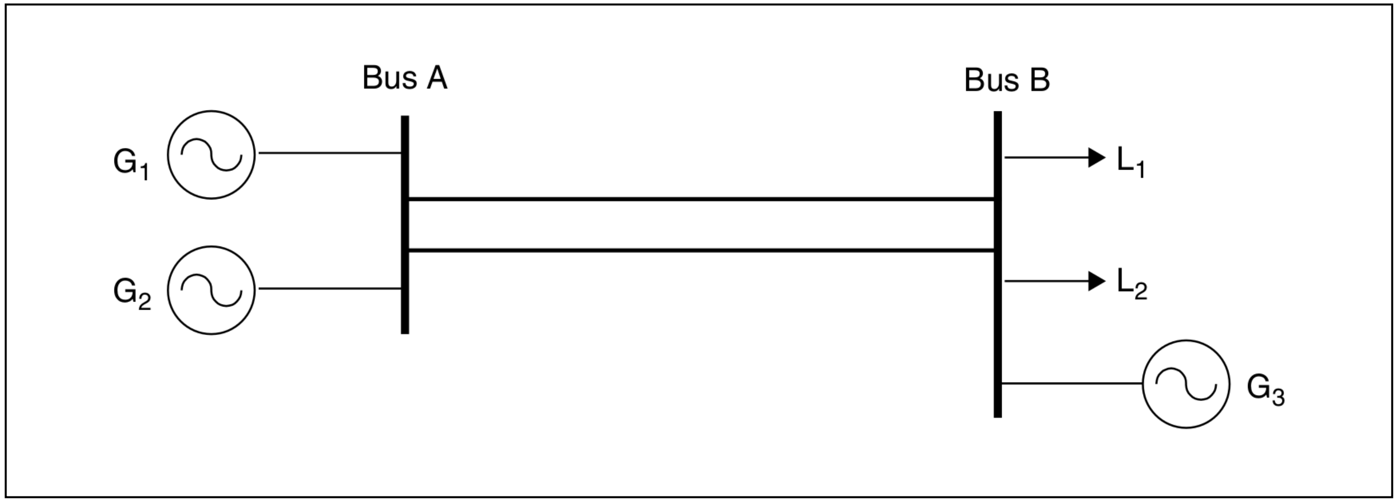
Problem 3: There is a risk of market power: physical transmission rights can enhance the ability of certain participants to exert market power.



Overview border-crossing power exchanges.

Risk of market power

Example: The most expensive generator (G3) may seek to secure the transmission rights between A and B to fend off competition from generators connected to A. **If G3 buys the transmission rights, it effectively blocks G1 and G2 from selling to Bus B**.



To avoid this problem, a UIOSI (Use-It-or-Sell-It) principle has been attached to physical transmission rights.

Transmission rights in practice

Historically, the right to trade across borders was granted to utilities, which were often state-owned and vertically integrated.

In 1996, a directive was established that specified TSOs must provide non-discriminatory access to their networks.

However, this is not entirely the case, as some long-term contracts remain in place.

In a market-based environment, there are two main methods for selling transmission rights:

1) **Explicit Auction**

2) **Implicit Auction** (also known as market coupling – cf dedicated lessons)

Explicit auction – Periods before day-ahead

An explicit auction involves TSOs auctioning transmission rights to the **highest bidders**, separately from the trading of energy.

In practice, these auctions are conducted through the Joint Allocation Office (JAO), a consortium of 20 TSOs from 17 countries that employs harmonized auction rules and timings.

In most of Europe, access to forward electricity markets across borders is based on transmission rights, and cross-border long-term transmission rights can only be allocated through explicit auctions.

Auctions are organized for at least monthly and yearly transmission rights.

Explicit auction – Limitation and discussion

Market participants face challenges due to the separation of transmission rights from energy trading. To bid for these rights, **traders must accurately predict hourly price differences between zones, which is a challenging task**.

Accurately predicting these differences requires a comprehensive understanding of various market dynamics, including generation patterns, demand fluctuations, congestion, and network constraints.

Additionally, there is ongoing discussion about the procedures to follow if a TSO needs to curtail long-term transmission rights due to network issues.

The key question is how the TSO will compensate the market players who have purchased these rights.

Day-ahead and implicit auction (1/2)

In an implicit auction, transmission rights are integrated directly into the energy trading process. In Europe, the day-ahead market has been interconnected across countries, forming the Single Day-Ahead Coupling (SDAC).

Here the clearing process done through EUPHEMIA:

1) **Bid matching:**

Bids from each national market are collected. For each market, electricity supply and demand bids are matched based on the local price. If a region has surplus generation (more offers to sell than demand), it would tend to have a lower price. Regions with higher demand relative to supply would have a higher price.

2) **Transmission capacity allocation:**

The algorithm checks for price differences between regions. If two neighboring markets have different prices and there is available transmission capacity between them, electricity is scheduled to flow from the lower-priced region to the higher-priced region. The flow continues until one of three things happens:

- Prices converge between the two regions;
- All available transmission capacity is used (i.e., congestion occurs);
- All supply and demand bids are matched.

Day-ahead and implicit auction (2/2)

3) Price formation:

The clearing price in each zone is determined based on the marginal cost of the last accepted electricity offer in that market. In uncongested regions, prices will converge to a single market clearing price. In congested regions (where the transmission line is fully used), prices may remain different, reflecting the supply and demand balance within each region.

4) Congestion management:

When congestion occurs (i.e., a transmission line is fully utilized and can't accommodate further flows), prices in the exporting region (low-price region) and importing region (high-price region) remain different. This price difference is known as the congestion rent, which reflects the economic value of the limited transmission capacity.

5) Results:

Results include the market clearing price for each region, cross-border electricity flow indicating the scheduled electricity transfers between zones, and congestion rents, if applicable, for overloaded transmission lines.

Types of transmission rights

Physical Transmission Rights (PTR):

Type of right that entitles the holder to physically transfer a certain volume of electricity within a specified period of time between two bidding zones in a specific direction.

If the trader decides not to utilize the right, the UIOSI (Use-It-or-Sell-It) principle applies. The trader is compensated for the value of the right in a day-ahead auction, with the price difference across the border serving as the implicit price for the transmission right.

Financial Transmission Rights (FTR):

Type of right that entitles the holder to receive financial remuneration (or obligate the holder to provide financial remuneration) based on the day-ahead allocation results between two bidding zones during a specified period of time in a specific direction.

After day-ahead

Currently, intraday transmission rights are offered free of charge.

They operate on a first-come, first-served basis, with rights allocated to the first participants matched on the continuous trading platform until no more rights are available or until the border is closed (i.e., one hour before delivery).

This system is not market-based; therefore, **no transmission rights are specifically reserved for the intraday stage**. Only the rights that have not been utilized in the day-ahead stage are allocated for intraday trading.

Currently, most transactions occur through continuous trading due to the small volumes sold. However, ACER (the European Union Agency for the Cooperation of Energy Regulators) is advocating for auctions that would allow for the sale of transmission rights similar to the day-ahead process.

III. Losses

Losses in transmission networks

Losses occur in electricity networks. Since one or more generators must produce this lost energy and these generators expect to be compensated for all the energy they generate, a mechanism must be established to account for losses and their associated costs in electricity networks.

There are three types of losses:

Fixed losses: They are caused by hysteresis and eddy current losses in the iron core of transformers, as well as the corona effect in transmission lines. Fixed losses are proportional to the square of the voltage and are independent of power flows; as a first approximation, they can be considered constant.

Non-technical losses: This refers to energy that is stolen from the network.

Variable losses: Also known as transport-related losses or copper losses, they are proportional to the resistance of the branch and the square of the current flowing through it. Variable losses are usually much higher than other types of losses.

In Western European countries, 1% to 3% of the energy produced is lost in the transmission network, and 4% to 9% is lost in the distribution system.

Handling losses under bilateral trading

Because losses are not a linear function of the flows in the transmission system, the losses incurred by a transaction do not only depend on the amount of power traded and the locations of the two parties involved. **These losses also depend on all the other transactions occurring within the network.**

Allocating these losses or their costs among all market participants is a challenge that does not have an easy solution. A fair mechanism would ensure that participants who contribute more to the losses bear a larger share of the costs compared to others.

ELEC0018-1
Energy market and regulation

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Chapter 10 – Energy sharing

Introduction to the chapter

The European Union has introduced policies through directives to promote renewable energy, aiming to address challenges such as reducing CO_2 emissions, enhancing energy independence, and combating energy poverty. These policies have also opened up new opportunities, including increased citizen involvement in energy production.

One notable development is the concept of **energy sharing**, a collective approach to energy management. In Wallonia, a region of Belgium, two main energy-sharing solutions are available.

The first involves **peer-to-peer electricity exchange** facilitated by a retailer's platform, where participants must all be customers of the same retailer.

The second leverages the legal framework for **energy communities**, allowing members to trade energy among themselves while keeping their individual contracts with their respective electricity retailers.

Outline of the chapter

To properly understand energy sharing, this chapter will be organized into the following parts:

I. Understanding a residential electricity bill and the impact of self-production

II. Analysis of peer-to-peer electricity exchange through a retailer’s platform

III. Examination of the legal framework for energy communities and their various models

PART I:

Understanding a residential electricity bill and the impact of self-production

The electricity bill of a Belgian consumer

The surge in PV installations, particularly among private individuals, has transformed them into “prosumers”, who both produce and consume electricity. Before exploring the impact of individual renewable energy production on their electricity bills, let us first examine what it involves.

The electricity bill for an individual comprises four components:

1. Cost of energy: The cost of the electricity actually consumed, determined by the tariff of the chosen supplier. This cost varies according to contracts, applied tariffs (fixed or variable), and level of consumption.

2. Renewable energy (RE) contribution: The costs of policies designed to encourage the development of renewable energy, such as feed-in tariffs.

3. Grid fees: Transmission costs billed by the TSO for the transport of high-voltage electricity and distribution costs billed by the DSO for the distribution of electricity to the individual’s home.

4. Taxes and levies: Levies, contributions, federal and regional taxes.

Composition of an electricity tariff sheet

Prix fixes de l'énergie - 1 an

Redevance fixe [1]		Prix par kWh (€cent/kWh)					Coûts énergie verte [5]
61,48 €/an		Type d'usage	Normal	Bihoraire Heures pleines	Bihoraire Heures creuses	Exclusif Nuit	(€cent/kWh)
	+	Consommation [2]	23,513	24,764	20,247	20,247	+ 2,996
	−	Injection [3]	7,802	9,468	3,576		

Coûts de réseaux (distribution et transport) [6]

Gestionnaire du réseau de distribution	Distribution						
	Normal	Bihoraire		Exclusif Nuit	Activité de mesure Relevé annuel	Tarif prosumer [7]	Transport
		Heures pleines	Heures creuses				
	€cent/kWh	**€cent/kWh**	**€cent/kWh**	**€cent/kWh**	**€/an**	**€/kWe/an**	**€cent/kWh**
TECTEO - RESA	9,34	10,37	5,87	5,16	24,90	67,62	2,61

Suppléments

Suppléments (€cent/kWh)	
Cotisation sur l'énergie	0,20417
Redevance raccordement [8]	0,07500

Accise fédérale [11] (€cent/kWh)	
Consommation entre 0 et 3.000 kWh	4,51300
Consommation entre 3.000 et 20.000 kWh	5,03288
Consommation entre 20.000 et 50.000 kWh	4,81876

Data for May 2023 for a residential customer located in the Walloon Region, Belgium, and connected to the RESA network.

The peak/off-peak hours billing system charges different rates for electricity based on the time of day. Full hours, during high demand periods, have higher rates, while off-peak hours, during low demand periods, have reduced rates.

Example of an electricity bill

Let us consider Mr. Dupont, a private individual with an annual consumption of 4,000 kWh. He does not own any photovoltaic (PV) panels. In May 2023, his total consumption was 1/12th of his annual consumption, with 68% of it occurring during peak hours and the remaining 32% during off-peak hours. Below is a breakdown of his bill for May 2023, based on the figures from the previous tariff sheet:

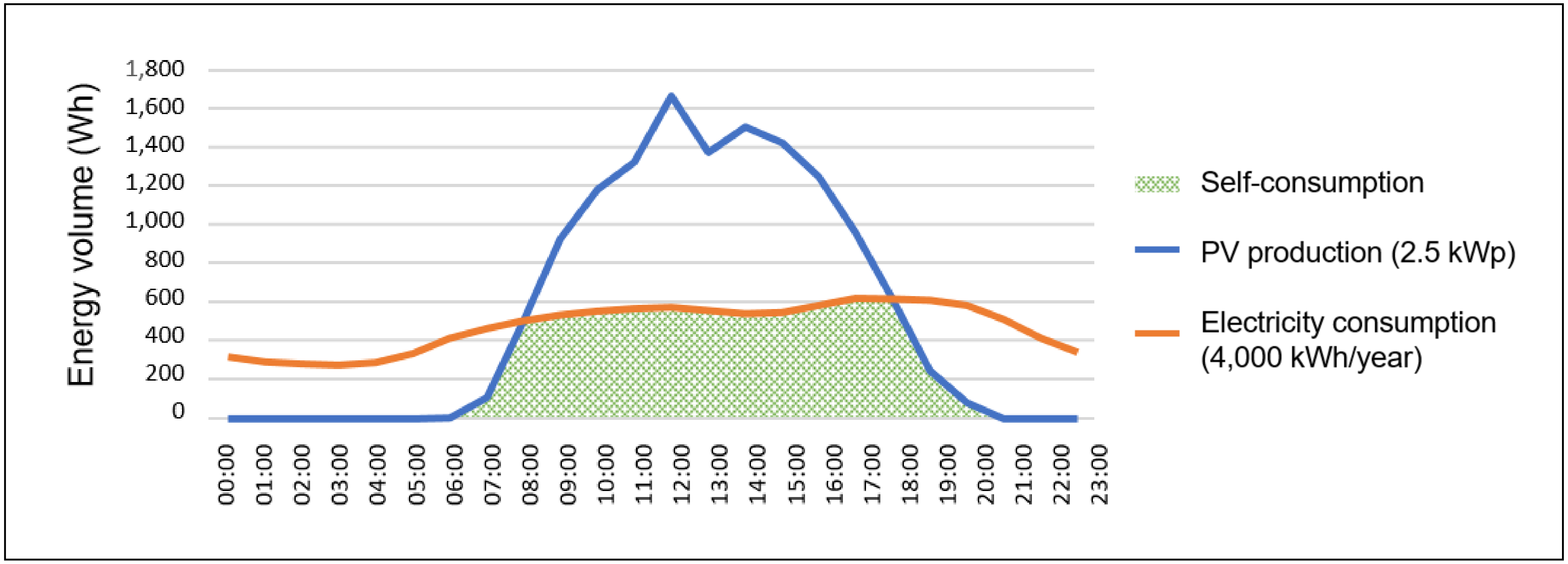
Billing Data	Nature	Number of units (kWh)	Unit price (€c/kWh)	Amounts (EUR)	VAT
Peak hour consumption	Cost of energy	213.66	24.764	52.91	21%
Off-peak hour consumption	Cost of energy	100.54	20.247	20.36	21%
RE contribution	RE contribution	314.2	2.996	9.41	21%
Peak hour distribution	Grid fees	213.656	10.37	22.16	21%
Off-peak hour distribution	Grid fees	100.544	5.87	5.90	21%
Transmission costs	Grid fees	314.2	2.61	8.20	21%
Special excise duty	Taxes and levies	314.20	5.033	15.81	21%
Network access rights	Taxes and levies	314.20	0.279*	0.88	Exemption under Art.28, 5° of the VAT Code
Total invoice amount	-	-	-	**135.63**	-

*Cotisation sur l'énergie + Redevance raccordement.

PV production allows self-consumption

As soon as Mr. Dupont becomes the owner of a PV system, he becomes a prosumer. He can cover all or part of his electricity needs with the electricity he produces himself.

This self-consumed electricity does not flow into the grid; it is entirely free behind the meter!

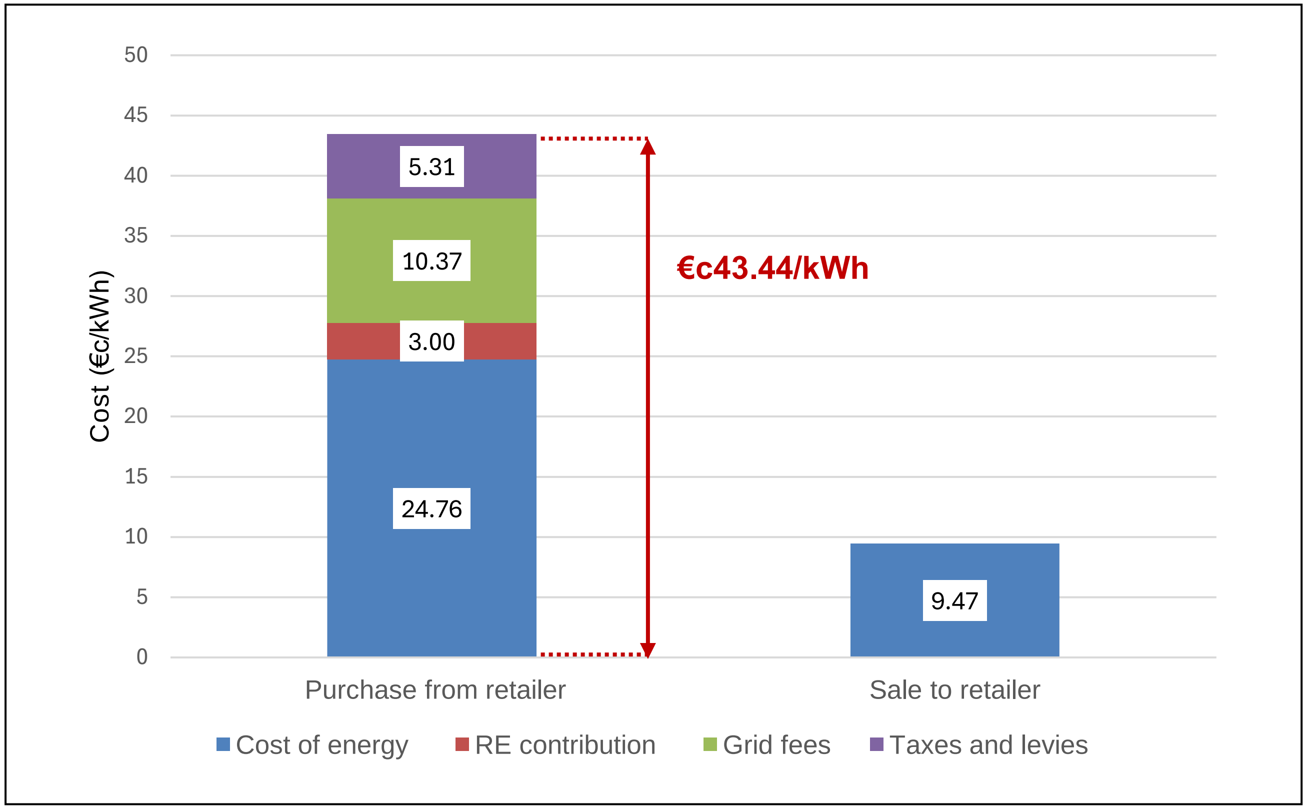


Electricity consumption and production of an individual over a sunny day (May 2023).

Feeding electricity back into the grid

When PV production is less than consumption, Mr. Dupont buys additional electricity required from a retailer, paying for the energy, grid fees, and taxes.

When production exceeds consumption, Mr. Dupont sells the surplus on the wholesale market. Typically, for procumers energy is bought at about five-times the price at which it is sold.*



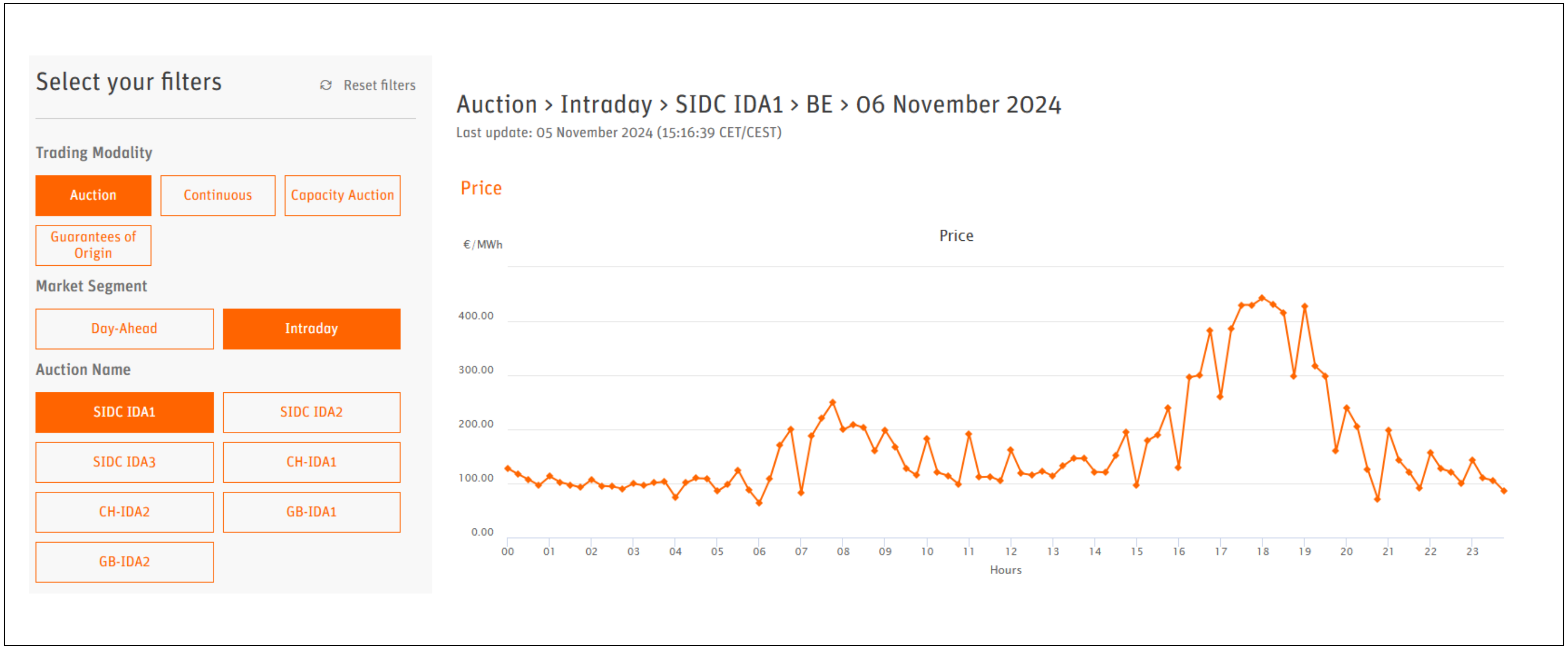
Purchase and sale from a retailer ***during a peak hour*** *(including VAT).*

*The backward spinning meter case is not considered in the calculation.

Selling back to the grid is not very profitable

The injection price is low because PV systems produce most electricity during the daytime when there is often an oversupply, driving market prices down. Suppliers also need to maintain profit margins, further reducing the amount paid for injected electricity.

However, selling may be more profitable during periods of high energy demand, when prices are higher, and when electricity is not needed on-site.



The problem with existing contracts

Retailers act as intermediaries between the electricity markets and end consumers.

Most retail electricity contracts fall into two categories: fixed-price* or variable-price contracts. In the case of variable-price contracts, the price per kWh is typically updated monthly based on a weighted average of spot market prices.

Only a few retail contracts use dynamic pricing, where the cost of electricity is calculated by multiplying the amount of energy consumed during each market period by the spot price for that period.

Currently, by offering similar (“unsophisticated”) contracts, retailers mainly compete on price alone. **This situation often leads to market consolidation**, which reduces competition, limits choice in electricity contracts, and can result in high prices.

Retailers are interested in contracts that enable them to participate more actively in the energy markets.

*Even fixed-price contracts are fixed only for a limited time period.

PART II:

Analysis of peer-to-peer electricity exchange through a retailer's platform

The solution provided by digital platforms

Digital retailer platforms enable prosumers to access a variety of electricity supply products and customise them according to their preferences. For example, when a prosumer generates electricity through solar panels, they may not be able to immediately use all the energy for self-consumption. The excess energy is then fed back into the grid.

Instead of selling this surplus electricity to their retailer at a low fixed price determined when signing the contract, the prosumer can sell it through their retailer on the spot market, potentially making a larger profit. Alternatively, they can share it with another consumer through **a peer-to-peer (P2P) energy-sharing** arrangement. P2P energy-sharing does not require the two parties to be in close proximity; however they must be customers of the same retailer and be connected to the same network.

A P2P product allows consumers to **hedge against rising energy prices**, actively participate in the energy transition, and ensure the origin of their electricity.

An example of a P2P energy sharing

Mr. Mars and Mrs. Venus are customers of the same retailer, each with a fixed-price electricity contract. On a sunny day, solar panels of Mr. Mars generate 3 kWh of electricity over an hour. His household uses only 2 kWh, so he must feed the remaining 1 kWh into the grid.

Meanwhile, Mrs. Venus wants to use her washing machine, which consumes 1 kWh. Through the retailer's sharing platform, they arrange for Mrs. Venus to use the 1 kWh of surplus electricity from Mr. Mars at a reduced price.

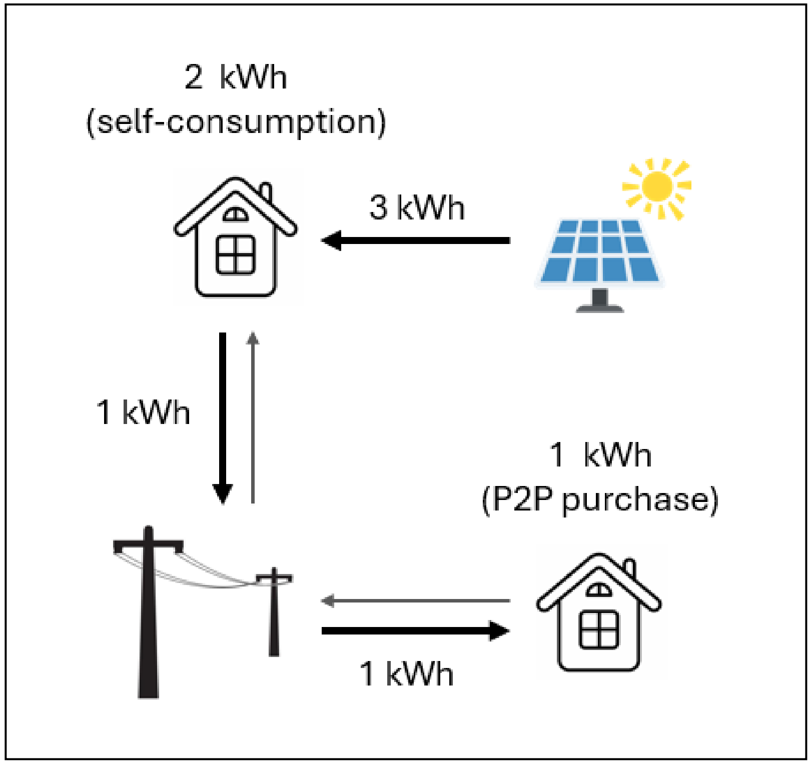
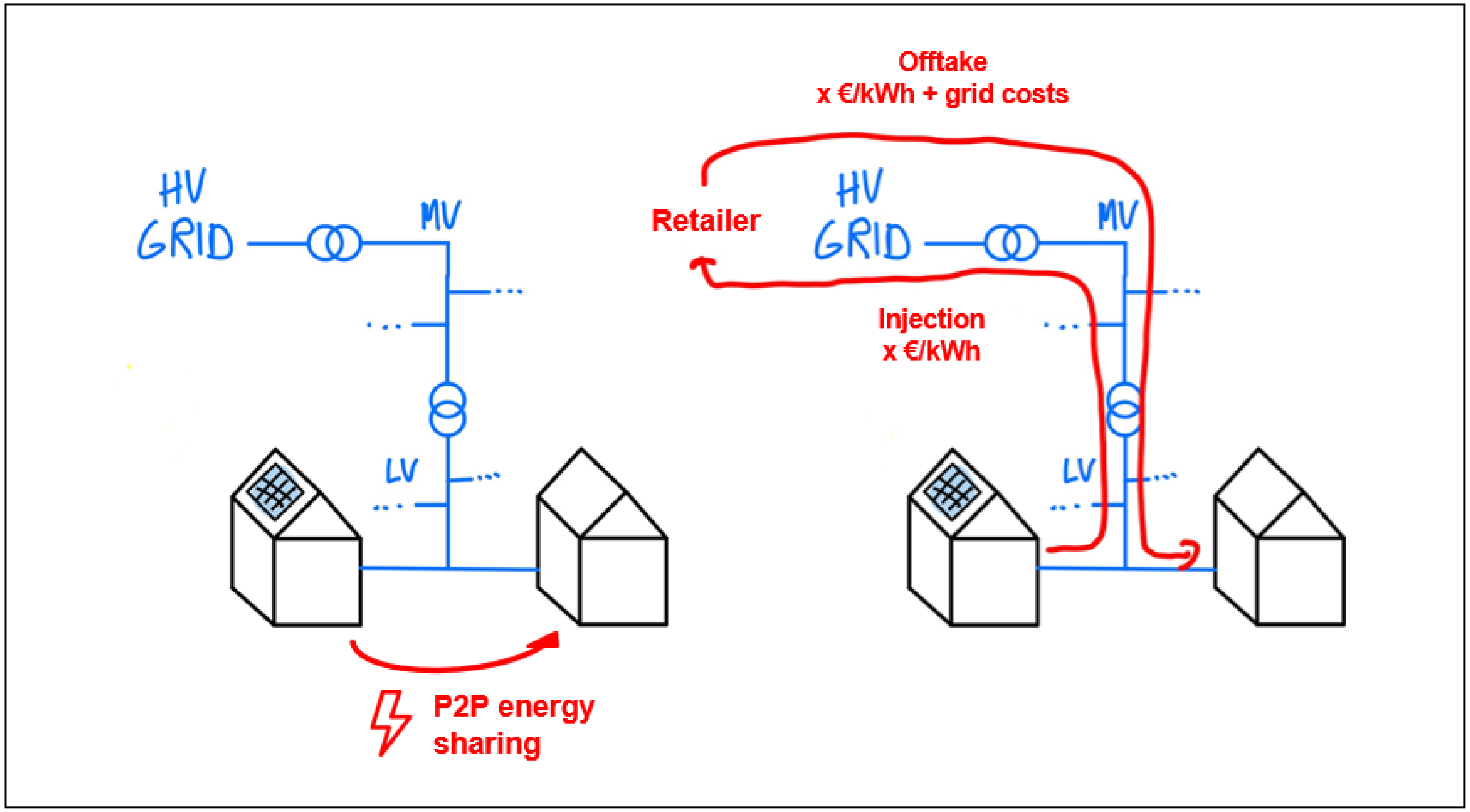


Illustration of a P2P energy share



It is important to note that the shared electricity is **not physically delivered** directly from the prosumer to the consumer. Instead, the electricity purchased through a P2P energy sharing arrangement comes from the public grid, with applicable fees applied.

The 'cost of energy' applied to the volume of electricity, however, is based on a sharing agreement established between the parties involved.

PART III:

Analysis of the framework of energy communities and their different models

Energy sharing in energy communities

The P2P energy-sharing model is based on a platform that is specific to a single retailer. It is also possible to utilise the legal framework for energy communities. **Members of an energy community can trade energy among themselves while maintaining their contracts with their respective electricity retailers**.

Within this community, members can exchange electricity during each market period, based on their consumption and their production. **These exchanges are reflected in adjusted meter readings for each participant**, showing the amount of energy traded between members.

These adjusted meter readings are then sent to the retailers. This leads to changes in the electricity bill sent by the retailer to each member, as the electricity exchanges within the community are taken into account in the final invoicing.

We will take a closer look at the different models of energy communities, with a specific focus on the **Renewable Energy Community (REC)**.

The roles of the members of an energy community

An energy community is composed of the following members:

The producer: This is the owner of the production unit that generates the energy shared with the other members. It could be an individual who owns a PV system on their roof or someone who invests in a wind turbine.

The consumer: This is the end user who consumes the energy produced as part of the sharing arrangement. A participant in the energy community can be both a producer and a consumer (prosumer).

The energy-sharing representative: This is the intermediary between the DSO and the participants in the sharing arrangement. They handle all administrative aspects (setup, billing, etc.) and can also be a producer or consumer within the energy sharing system. The energy-sharing representative also transmit the repartition keys to the DSO.

The DSO (Distribution System Operator): This is the entity responsible for collecting consumption data from the grid, which is then transmitted to the supplier and the energy-sharing representative for billing purposes.

Respective characteristics of RECs and CECs

A **Renewable Energy Community (REC)** is a group of actors (individuals, businesses, local authorities) whose **main commercial or professional activity** is not participating in one or more energy communities.

They come together to develop, produce, consume, and sell renewable energy. They own production installations such as solar panels, wind turbines, or biomass systems **located nearby**, which they manage to achieve their goal of harnessing renewable energy for economic and environmental benefits.

These production installations can be placed on buildings or freely within the local perimeter. Participation is limited by geographical and/or technical criteria within a proximity area.

In the case of a Citizen Energy Community (CEC), there are no restrictions on potential participants. Additionally, energy production from non-renewable sources is permitted, but it is restricted to the electricity sector. The community's scope is also not limited and can be broader compared to the sharing within an REC.

Common characteristics of RECs and CECs (1/2)

The community must have a legal personality distinct from its participants. It can own assets, enter contracts, and participate in the electricity market on its own behalf, rather than as an extension of its participants.

The community is based on free and voluntary participation and is autonomous. The community must operate independently, with decision-making power vested within the community itself, without undue influence from external entities.

The community can engage in the following activities in the electricity market:

- **Electricity production**
- **Electricity supply**
- **Self-consumption** of electricity produced on its own premises
- **Sharing** among its participants
- **Aggregation practices**
- Participation in **flexibility services**
- **Electricity storage**
- Providing charging solutions for electric vehicles
- Provision of energy efficiency or other energy-related services
- Sale of electricity

Common characteristics of RECs and CECs (2/2)

The community must specify in its statutes the environmental, social, or economic objectives it pursues. The main goals may focus on sustainability, social equity, economic benefits, or energy access.

The statutes must establish clear rules to ensure the community is controlled effectively by its members and operates independently. This includes **mechanisms to prevent external influence from overriding the community's objectives, preserving its autonomy and integrity.**

The community must formally **notify the CWaPE** about its formation. Additionally, it must receive approval for its electricity-sharing activities, ensuring compliance with regulations and a secure framework for the exchange of electricity.

Details and distinctions between RECs and CECs can be discerned in the legal texts.

Renewable Energy Community (REC) in legislation

Article 22 of Directive 2018/2001:

1. Member States shall ensure that final customers, in particular household customers, are entitled to participate in a renewable energy community while maintaining their rights or obligations as final customers, and without being subject to unjustified or discriminatory conditions or procedures that would prevent their participation in a renewable energy community, provided that for private undertakings, their participation does not constitute their primary commercial or professional activity.

2. Member States shall ensure that renewable energy communities are entitled to:

(a) produce, consume, store and sell renewable energy, including through renewables power purchase agreements;

(b) share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, subject to the other requirements laid down in this Article and to maintaining the rights and obligations of the renewable energy community members as customers;

(c) access all suitable energy markets both directly or through aggregation in a non-discriminatory manner.

3. Member States shall carry out an assessment of the existing barriers and potential for the development of renewable energy communities in their territories.

4. Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that:

(a) unjustified regulatory and administrative barriers to renewable energy communities are removed;

(b) renewable energy communities that supply energy or provide aggregation or other commercial energy services are subject to the provisions relevant for such activities; 21.12.2018 EN Official Journal of the European Union L 328/121

(**c**) the relevant distribution system operator cooperates with renewable energy communities to facilitate energy transfers within renewable energy communities;

(d) renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and cost-reflective network charges, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost sharing of the system in line with a transparent cost-benefit analysis of distributed energy sources developed by the national competent authorities;

(e) renewable energy communities are not subject to discriminatory treatment with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators, or as other market participants;

(f) the participation in the renewable energy communities is accessible to all consumers, including those in low-income or vulnerable households;

(g) tools to facilitate access to finance and information are available;

(h) regulatory and capacity-building support is provided to public authorities in enabling and setting up renewable energy communities, and in helping authorities to participate directly;

(i) rules to secure the equal and non-discriminatory treatment of consumers that participate in the renewable energy community are in place.

5. The main elements of the enabling framework referred to in Paragraph 4, and of its implementation, shall be part of the updates of the Member States' integrated national energy and climate plans and progress reports pursuant to Regulation (EU) 2018/1999.

6. Member States may provide for renewable energy communities to be open to cross-border participation.

7. Without prejudice to Articles 107 and 108 TFEU, Member States shall take into account specificities of renewable energy communities when designing support schemes in order to allow them to compete for support on an equal footing with other market participants.

Citizen Energy Community (CEC) in legislation

Article 16 of Directive 2019/944:

1. Member States shall provide an enabling regulatory framework for citizen energy communities ensuring that:

(a) participation in a citizen energy community is open and voluntary;

(b) members or shareholders of a citizen energy community are entitled to leave the community, in which case Article 12 applies;

(c) members or shareholders of a citizen energy community do not lose their rights and obligations as household customers or active customers;

(d) subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities;

(e) citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system. 14.6.2019 EN Official Journal of the European Union L 158/151

2. Member States may provide in the enabling regulatory framework that citizen energy communities:

(a) are open to cross-border participation;

(b) are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them subject to conditions set out in paragraph 4 of this Article;

(c) are subject to the exemptions provided for in Article 38(2).

3. Member States shall ensure that citizen energy communities:

(a) are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner;

(b) are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation;

(c) are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943;

(d) with regard to consumption of self-generated electricity, citizen energy communities are treated like active customers in accordance with Point (e) of Article 15(2);

(e) are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers. For the purposes of Point (e) of the first subparagraph, where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority.

4. Member States may decide to grant citizen energy communities the right to manage distribution networks in their area of operation and establish the relevant procedures, without prejudice to Chapter IV or to other rules and regulations applying to distribution system operators. If such a right is granted, Member States shall ensure that citizen energy communities:

(a) are entitled to conclude an agreement on the operation of their network with the relevant distribution system operator or transmission system operator to which their network is connected;

(b) are subject to appropriate network charges at the connection points between their network and the distribution network outside the citizen energy community and that such network charges account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the citizen energy community in accordance with Article 59(7);

(c) do not discriminate or harm customers who remain connected to the distribution system.

Community-based energy-sharing between prosumers not living in the same building: the case of Brussels

The surplus electricity that is not used by the prosumer can be sold at a higher rate than the market purchase price, but the goal is to create a ‘win-win’ situation for both the producer and the consumer involved in the transaction.

The ‘cost of energy’ component is negotiated to ensure it is attractive to the buyer and beneficial to the seller. However, **grid fees will still apply**. The distribution costs, on the other hand, may become more favourable depending on the participants' locations within the electrical grid.

Participants are supplied by:

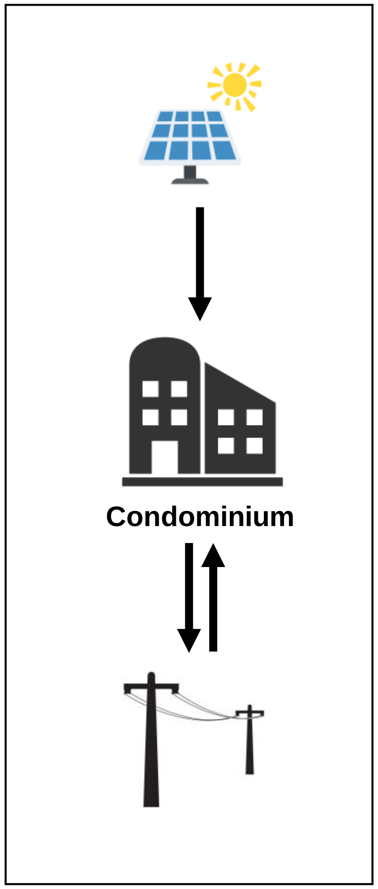
Type A: electricity produced in the building where they reside; Type B: the same low-voltage transformer station; Type C: the same Elia substation; Type D: different Elia substations.

Energy Sharing	Type A	Type B	Type C	Type D
100%	€66.40	€100.14	€125.95	€136.96
50%	€101.69	€118.56	€131.46	€136.97
35%	€112.25	€124.06	€133.09	€136.97
Standard distribution tariff	€126.81			

Simulation of the distribution tariff in the Sibelga network (Brussels, Belgium) for a consumption of 1,000 kWh for the 2023 tariff year for a customer with a capacity of less than 56 kVA. Type A is the most advantageous.

Community-based energy sharing in a condominium

A condominium is a type of property where multiple individuals (**owners**) hold separate units within a single building. Owners may choose to live in their units themselves (**owner-occupants**) or rent them out to **tenants**. All unit owners collectively form the **condominium association**, which is responsible for managing the shared spaces and resources of the building, including any PV system on the roof.



Usually, the PV installation is owned by this association and is connected behind the association's main meter, which measures the consumption of common areas within the building. This setup allows the energy generated to offset energy needs in common areas of the building, reducing overall energy costs for shared spaces.

However, a challenge with PV systems in condominiums is that **they are typically connected behind this single main meter**. Community-based energy sharing solutions help address this issue by allowing for separate accounting and billing of energy consumed from the grid versus energy consumed from the PV system, ensuring fair distribution of energy savings among the owners.

Energy sharing within a condominium in legislation

Article 21.4 of Directive 2018/2001:

“Member States shall ensure that renewables self-consumers located in the same building, including multi-apartment blocks, are entitled to:

(a) to generate renewable energy, including for their own consumption, store and sell their excess production of renewable electricity, including through renewables power purchase agreements, electricity suppliers and peer-to-peer trading arrangements, without being subject:

- **(i)** in relation to the electricity that they consume from or feed into the grid, to discriminatory or disproportionate procedures and charges, and to network charges that are not cost-reflective;
- **(ii)** in relation to their self-generated electricity from renewable sources remaining within their premises, to discriminatory or disproportionate procedures, and to any charges or fees;

(b) to install and operate electricity storage systems combined with installations generating renewable electricity for self-consumption without liability for any double charge, including network charges, for stored electricity remaining within their premises;

(c) to maintain their rights and obligations as final consumers;

(d) to receive remuneration, including, where applicable, through support schemes, for the self-generated renewable electricity that they feed into the grid, which reflects the market value of that electricity and which may take into account its long-term value to the grid, the environment and society;

They are permitted to arrange sharing of renewable energy that is produced on their site or sites between themselves, without prejudice to the network charges and other relevant charges, fees, levies and taxes applicable to each renewables self-consumer. Member States may differentiate between individual renewables self-consumers and jointly acting renewables self-consumers. Any such differentiation shall be proportionate and duly justified.”

The repartition key for energy sharing in an energy community

The distribution of the injected energy is calculated for each market period. The distribution is determined according to repartition keys, which are mathematical rules for distributing the volumes among the occupants.

A repartition key $k = [k_1, \dots, k_n]$ is simply the vector representing how the volume of energy allocated to sharing is distributed among the *n* participants.

$$k_i = \text{percentage of the energy attributed to member } i$$

$$\sum_i k_i = 1$$

$$k_i \geq 0$$

k_i values may vary over time.

Types of repartition keys

In Wallonia, the repartition keys must be sent to the DSO, such as ORES or RESA. These keys provide the necessary data for the DSO to adjust the energy allocation across different users or areas accurately. Using these repartition keys, the DSO modifies the raw meter readings, adjusting them to reflect the redistributed energy volumes. These corrected meter readings are then sent to the market, where they serve as the basis for billing and are subsequently forwarded to retailers. **This process ensures that all involved parties receive accurate billing data that reflects the adjusted energy distribution.**

The key must be approved by the CWaPE. Three standard repartition keys are always accepted:

1. The equal static repartition key
2. The specific static repartition key
3. The dynamic repartition key proportional to consumption

The choice of keys is important to accurately reflect the intent of the energy community: it is fundamentally about determining to what extent each occupant has the right to consume the energy produced by the PV installation.

Equal static repartition key

	Before sharing	Sharing	After sharing		
	Consumptions	Allocated volumes	Shared volumes consumed	Allocated consumptions	Surplus
Shared volume	-	1,000	-	-	-
Participant 1	160	250 – 25%	160	0	90
Participant 2	300	250 – 25%	250	50	0
Participant 3	350	250 – 25%	250	100	0
Participant 4	120	250 – 25%	120	0	130
Total	930	1,000	780	150	220

Energy actually shared: 78%   Self-consumption: 84%

Energy volumes are shared in a fixed and equal manner among participants up to cover their entire consumption. Any remaining energy is retained by the energy community.

It will be easy to add or remove a participant from the energy-sharing arrangement, with distribution percentages automatically adjusted.

Specific static repartition key

	Before sharing	Sharing	After sharing		
	Consumptions	Allocated volumes	Shared volumes consumed	Allocated consumptions	Surplus
Shared volume	-	1,000	-	-	-
Participant 1	160	400 – 40%	160	0	240
Participant 2	300	200 – 20%	200	100	0
Participant 3	350	200 – 20%	200	150	0
Participant 4	120	200 – 20%	120	0	80
Total	930	1,000	680	250	220

Energy actually shared: 68% Self-consumption: 73%

The difference with an equal static key is that energy volumes are allocated among participants based on predefined percentages outlined in an agreement. These percentages can, for example, reflect the individual investment share in the production units.

This key allows for setting priorities in the distribution of energy volumes.

However, with a static key (whether equal or specific), it is possible to end up with a surplus even if the total consumption of the building is sufficient to cover the production.

Dynamic repartition key proportional to consumption

	Before sharing	Sharing	After sharing		
	Consumptions	Allocated volumes	Shared volumes consumed	Allocated consumptions	Surplus
Shared volume	-	1,000	-	-	-
Participant 1	160	172 – 17.2%	160	0	12
Participant 2	300	323 – 32.3%	300	0	23
Participant 3	350	376 – 37.6%	350	0	26
Participant 4	120	129 – 12.9%	120	0	9
Total	930	1,000	930	0	70

Energy actually shared: 93%   Self-consumption: 100%

Energy volumes are dynamically allocated among participants based on their energy consumption, as much as possible according to demand:

$$v_i = \frac{c_i}{\sum_{j=1}^{n} c_j} \times V$$

- v_i is the volume allocated to participant i
- c_i is the energy consumption of participant i
- n is the number of participants
- V is the total volume to be shared among participants

Fairness aspect for the choice of the repartition key

The choice of the repartition key is crucial for the energy community and must be thoroughly discussed in advance.

The fairness of the dynamic key can be questioned. While the distribution may be optimal from an external perspective (e.g., environmental and community benefits), **it might not seem fair from an internal perspective**. For example, one might ask: “Why does my neighbour, who consumes more electricity and who is less attentive, end up saving more?”

The CWaPE specifies that up to three repartition keys can be used simultaneously, but no more. The first key is applied, followed by a second key for the remaining unallocated energy, and finally, a third key if needed. For example, one might first use a fixed repartition key and then apply a dynamic key to allocate the remaining unused energy.

Another important factor is the pricing of the shared energy.

Pricing aspect for the choice of the repartition key

Let us go back to the energy-sharing model within a condominium. The excess electricity produced by the PV system on the building's roof, which is not consumed by the owners, is sold to the tenants who participate in the energy community. The revenue from selling the excess electricity goes to the owners.

The main factors for setting the price of the shared electricity are:

(i) the price of energy on the external market
(ii) the investment made and the desired profitability

For energy-sharing to be effective, it is essential that both parties (owners and tenants) benefit.

If the price is set too low, tenants will make greater savings, but this may discourage the owners, possibly putting the project at risk.

On the other hand, if the price is too high, the owners will increase their revenue from energy sales, but this may discourage tenants, leading to reduced energy consumption.

This creates **a kind of balance between the interests of owners and tenants**.

Charges on shared energy in an energy community

Renewable energy contributions and taxes are applied uniformly to both shared and retailer-supplied energy, meaning that shared energy does not reduce these costs, except in the case of energy-sharing within a condominium, where specific grid fee reductions apply.

According to the tariff methodology for DSOs in the Walloon Region, applicable for the 2025-2029 regulatory period and adopted by CWaPE on May 31, 2023, **grid fees are reduced by 80% for shared energy in the case of energy-sharing within a condominium.**

To simplify administration, **all charges, including those for shared energy are invoiced through the retailer** who provides a single invoice that includes both grid-supplied and shared energy costs.

Example: Benefits from energy sharing within a condominium

Mr. Dupont decides to move to a condominium in the city, becoming a tenant. The condominium is equipped with PV panels, and an energy-sharing arrangement is in place. Mr. Dupont wants to participate in it.

Let us compare the price of electricity purchased from the retailer to the price of electricity purchased under the energy-sharing arrangement, considering one peak hour.

<u>Data:</u>

(i) Mr. Dupont's consumption remains exactly the same

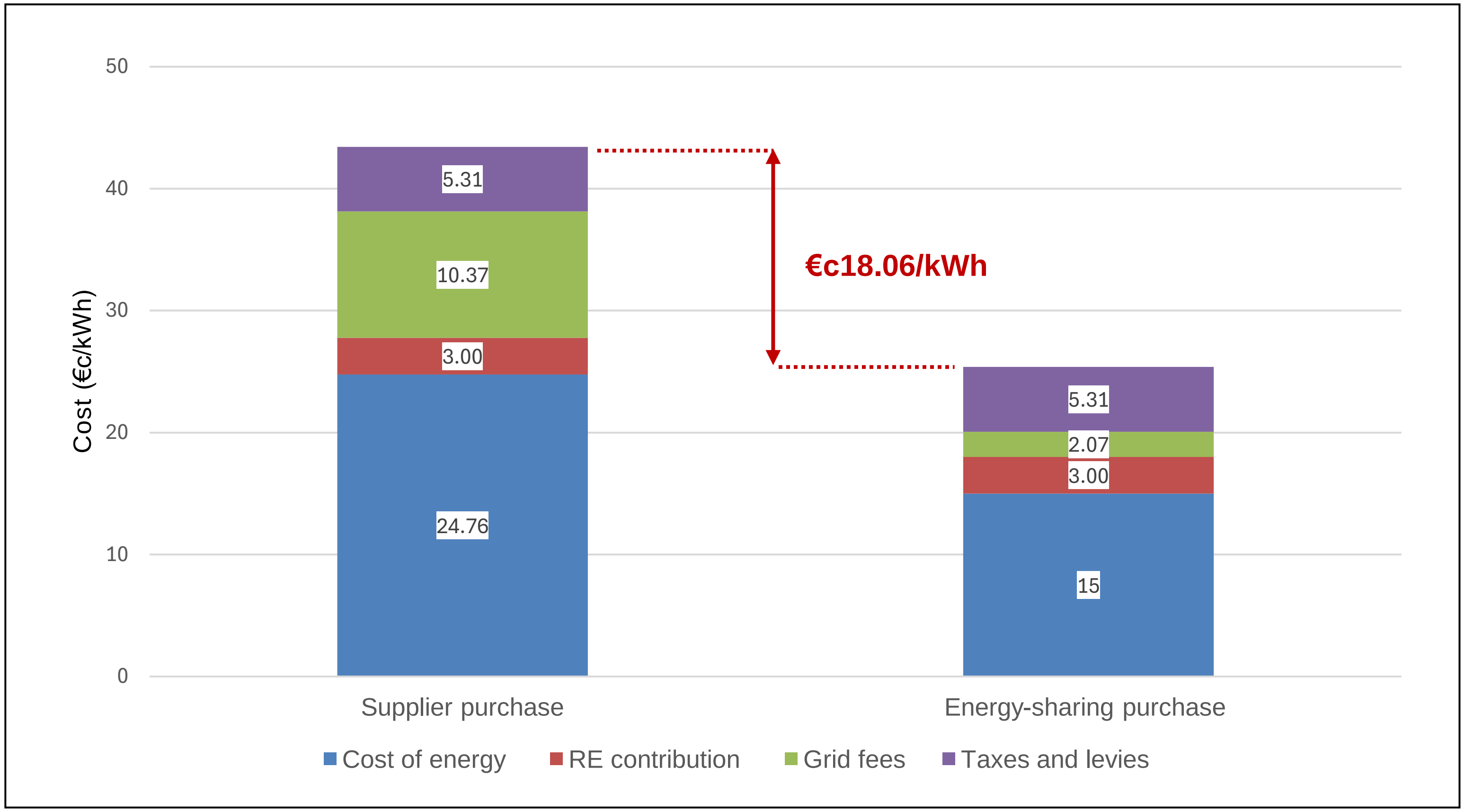
(ii) The costs applied to the different components of Mr. Dupont's bill are based on the same tariff sheet (see page 49)

(iii) The excess production from the PV system is sold at a price of €c15/kWh

Example: Benefits from energy sharing within a condominium

Grid fees are reduced by 80% for shared energy in the case of energy-sharing within a condominium. Mr. Dupont's grid fees are calculated as:
10.37 × 20% ≈ **€c2.07/kWh**.

Mr. Dupont's benefit is the savings he makes when purchasing shared energy:
43.44 – (15 + 3 + 2.07 + 5.31) = **€c18.06/kWh**.



Exercise 2:

1. Let us use the Athena residence in Ougrée, Belgium, as a basis for the assumptions in this exercise. What are the annual benefits from energy sharing for (a) the condominium and (b) each occupant (tenant or owner)?

Data:

(i) A condominium with 76 units, each with an annual consumption of 1,600 kWh

(ii) It is assumed that each occupant (owner or tenant) has the same consumption profile

(iii) The equal static allocation key is applied

(iv) There is a PV system with a capacity of 60 kWp and a capacity factor of 13% owned by the condominium association

(v) One-third of the PV production is used by the shared spaces of the condominium. The remaining part is sold in its entirety within the energy sharing agreement at €0.15/kWh instead of being sold to the retailer at €0.078/kWh

(vi) The price of electricity purchased from the retailer is €0.4344/kWh

Exercise 2:

2. What would happen if some participants were removed from the energy-sharing arrangement of the condominium?

"Athena" Residence.

Solution:

Part 1:

a) A PV installation of 60 kWp with a capacity factor of 13% has an annual production of: 60 × 0.13 × 8,760 = **68,328 kWh**.

One-third of the PV production is used for the shared space of the condominium, and the remaining is sold in its entirety within the energy-sharing agreement at €0.15/kWh instead of €0.078/kWh. This results in an annual benefit for the condominium of:

68,328 × 2/3 × (0.15 – 0.078) = **€3,279.74.**

b) Each occupant receives 68,328 × (2/3) / 76 **≈ 599.37 kWh** at a rate of €25.38/kWh instead of €43.44/kWh, resulting in a benefit of:

599.37 × (0.4344 – 0.2538) = **€108.25/year**.

Any owner occupant will benefit from both gains, i.e., 1/76th of the condominium benefit + €108.25, which results in 3,279.74 / 76 + 108.25 = **€151.40/year**

Part 2:

The benefits of sharing the production from the PV system are distributed among all participants. Therefore, excluding some tenants from the sharing arrangement can increase the gains for the owner-occupants and the remaining tenants. This raises an equity issue, as it would mean depriving some tenants of the benefits of sharing in order to boost the gains of those who remain in the arrangement.

Moreover, removing too many participants would decrease self-consumption, thereby reducing the volume of shared energy and, consequently, the benefits for the remaining participants.

Summary of the different cases of energy sharing

Parameters	Community-based energy-sharing in a same building	Renewable Energy Communities (REC)	Citizen Energy Communities (CEC)
Reference	Article 21.4 of Directive 2018/2001	Article 22 of Directive 2018/2001	Article 16 of Directive 2019/944
Production	From renewable energy sources located in or on the building	From renewable energy sources	Only electricity, from renewable or non-renewable sources
Perimeter	Within the same building	Close to the production facilities	Not limited
Legal entity obligation	No	Yes	Yes
Participants & control	Group of active clients acting collectively within or on the same building	Shareholders or members of the community, including individuals, local authorities or small and medium-size businesses	No restrictions on participants; effective control by members or shareholders who are individuals, local authorities or small businesses
Activities	Only energy-sharing	See page 63	See page 63

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 11 – Overview of gas markets

Gas infrastructure and markets

This chapter on gas markets is presented by a guest speaker from Fluxys, a leading Belgian company specializing in natural gas transmission, storage, and liquefied natural gas (LNG) terminalling.

Fluxys' extensive experience and active role in European gas infrastructure make them highly qualified to deliver this presentation. The material for this chapter is available on the course webpage:

https://damien-ernst.be/teaching/elec0018-1-energy-markets/

ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 12 – Overview of oil markets

Outline of the chapter

The purpose of this lesson is to explore the significance of oil in the global economy and the intricate systems that govern its production and distribution, with a main focus on the U.S. whose (international) policy has influenced the sector very much.

The lesson is structured into the following six sections:

I. The oil supply chain

II. Specifics of the oil industry

III. Key milestones in the industry

IV. Determinants of oil prices

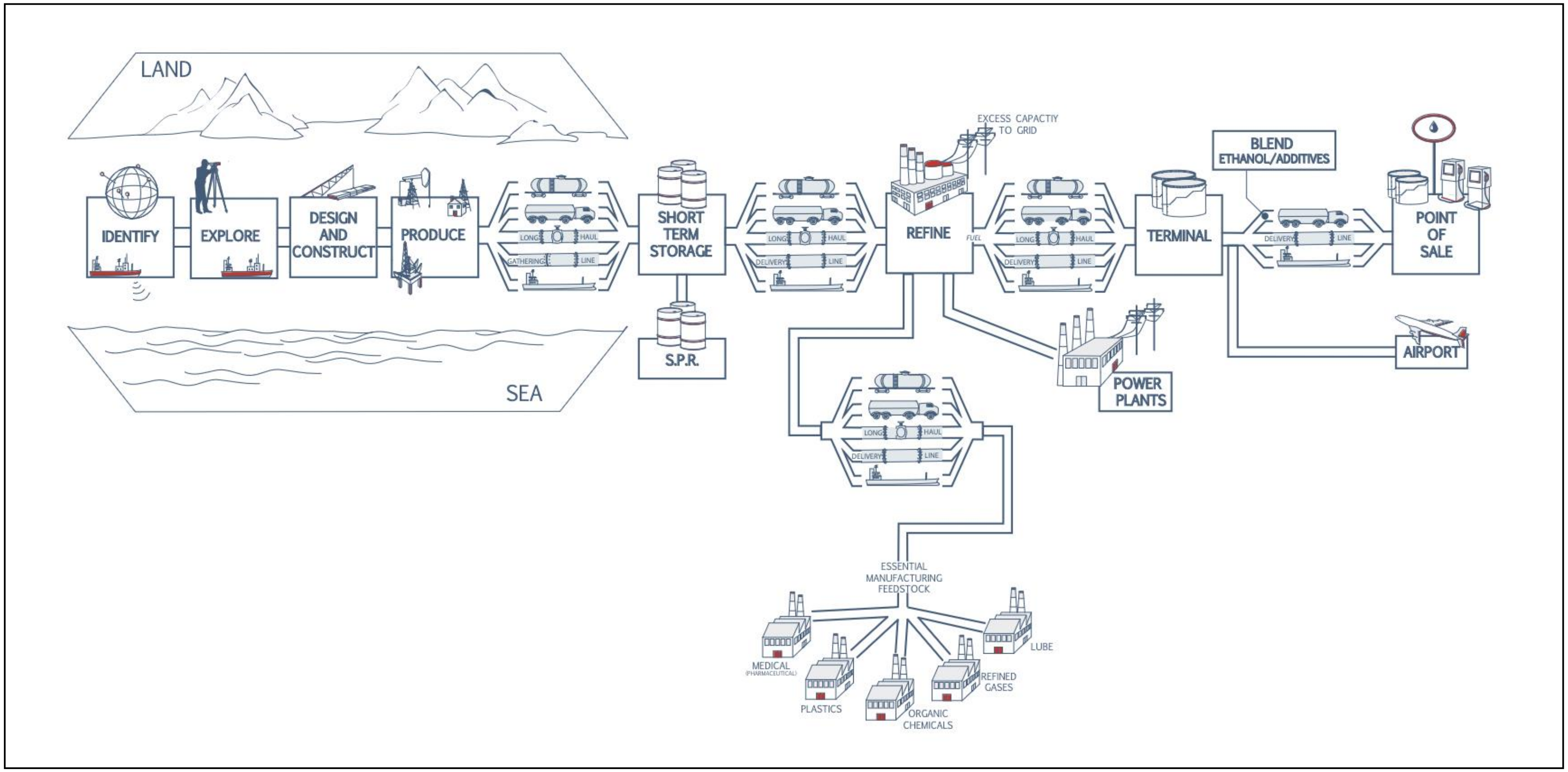
V. Oil contracts and types of hedging

VI. Focus on U.S. oil markets

I. The oil supply chain

The oil supply chain structure (1/2)

- **Upstream:** Identification, exploration, construction and production;
- **Midstream:** transportation, storage for the wholesale marketing of crude oil;
- **Downstream:** refining, marketing and distribution of products derived from crude oil.



The oil supply chain.[1]

[1] https://www.energyinfrastructure.org/-/media/energyinfrastructure/images/about-us-ei/supply-chain-and-production/oil-supply-chain-vs-2.pdf

The oil supply chain structure (2/2)

Identify

Modern oil geologists examine surface rocks and terrain, with the additional help of satellite images. However, they also use a variety of other methods to find oil. They can use sensitive gravity meters to measure tiny changes in the Earth's gravitational field that could indicate flowing oil, as well as sensitive magnetometers to measure tiny changes in the Earth's magnetic field caused by flowing oil. They can detect the smell of hydrocarbons using sensitive electronic noses called sniffers. Finally, and most commonly, they use seismology, creating shock waves that pass through hidden rock layers and interpreting the waves that are reflected back to the surface.

Explore

When a prospect has been identified and evaluated and passes an oil company's selection criteria, an exploration well is drilled in an attempt to conclusively determine the presence or absence of oil or gas. Five geological factors have to be present for a prospect to work and if any of them fail neither oil nor gas will be present:

- A source rock
- Migration
- Trap
- Seal or cap rock
- Reservoir

Hydrocarbon exploration is a high risk investment and risk assessment is paramount for successful exploration portfolio management. Exploration risk is a difficult concept and is usually defined by assigning confidence to the presence of five imperative geological factors, as discussed above.

Design and Construct

Although there is some variability in the details of well construction because of varying geologic, environmental, and operational settings, the basic practices in constructing a reliable well are similar. The ultimate goal of the well design is to ensure the environmentally sound, safe production of hydrocarbons by containing them inside the well, protecting groundwater resources, isolating the productive formations from other formations, and by proper execution of hydraulic fractures and other stimulation operations.

Produce

The first step in the oil supply chain is production. During production, crude oil is produced on both land and at sea. Oil production includes drilling, extraction, and recovery of oil from underground.

Transport

At multiple stages of the oil supply chain process, oil is transported to storage, refineries, terminals, and finally to the point of sale. There are four basic modes of transportation of crude oil from production to the point of sale: trains, trucks, ships, and pipelines.

Storage

Once the oil has been produced, it is transported to short-term storage. Short-term storage serves as the staging area for crude oil distribution throughout the entire supply chain. Storage facilities allow for adjustments in supply and demand throughout the entire supply chain. The Strategic Petroleum Reserve (SPR) is an emergency fuel storage of crude oil maintained by the United States Department of Energy used to mitigate supply disruptions.

Refine

Refineries act as the main transformation point for all crude oil into various consumer products. After receiving oil from storage facilities, refineries use various chemical separation and reaction processes to transform crude oil into usable products such as: fuel oil, diesel oil, jet fuel, and multiple essential manufacturing feedstocks.

Feedstocks

From the refineries, feedstocks are transported to manufacturing facilities where they play a critical part of many manufacturing supply chains, such as medical equipment, plastics, organic chemicals, refined gases, and lubricants.

Terminal

Refined fuel that is ready for use is transported to terminals. Terminals are located closer to transportation hubs and are the final staging point for the refined fuel before the point of sale. After entering the terminal ethanols and additives are added to the final refined product before fuel is transported.

Point of Sale

Once the refined fuel leaves the terminal, it is transported to its final point of sale, which includes fuel stations and airports. Trucking, shipping, and delivery lines provide the final, finished product which can be delivered across the country.

The oil supply chain legend.

II. Specifics of the oil industry

A global industry

The ease of transporting and storing oil, which has contributed to the development of a global oil market. This contrasts with the high cost of transporting coal.

Penetration of oil in the global energy balance can be attributed to several key factors among them:

- **High energy density** (41.868 MJ/kg compared to 26–33 MJ/kg of coal);
- **Liquid form**;
- **Exceptional versatility in usage**;
- **Aggressive commercial strategies** by multinational companies in the sector;
- **Cost-effective production**.

Highly capitalistic industry

Initially competitive, the oil industry evolved into an oligopolistic structure in the late 19th century, largely reshaped by **Rockefeller's strategic approach**.

By securing preferential rates with railroads and acquiring competing refineries, Rockefeller gained control over transportation and refining, reducing costs and driving competitors out. His company, Standard Oil, came to dominate the market, setting new standards for industrial organization and practices. Rockefeller chose the "Standard Oil" name as a symbol of the reliable "standards" of quality and service that he envisioned for the nascent oil industry.[1]

Significant capital investments are required across the supply chain, from exploration and transportation to refining, with exploration posing substantial risks, as one in four drills is unproductive.

[1]Grayson, Leslie E. (1987). Who and How in Planning for Large Companies: Generalizations from the Experiences of Oil Companies. Springer. p. 213. ISBN 9781349084128. Retrieved June 27, 2017.

But what is oil?

Petroleum, also known as crude oil or simply oil, is a naturally occurring yellowish-black liquid mixture composed mainly of **hydrocarbons**, found in geological formations.

A sample of petroleum.

Hydrocarbons

A hydrocarbon (HC) is an organic compound composed exclusively of carbon (C) and hydrogen (H) atoms. Its general formula is C_nH_m .

Hydrocarbons are often divided into two categories:

- Saturated: C_nH_{2n+2};
- Unsaturated: C_nH_{2n}.

Hydrocarbons also include acyclic hydrocarbons (without a cyclic structure) and cyclic hydrocarbons—often referred to as 'aromatics', which have a cyclic structure.

Varieties of oil (1/2)

Crude oil is not a homogeneous product, and its production cost varies by location and over time. There are various types of crude oil, and quality depends on two main factors:

1. **Density**: Measured relative to the density of water, which has an API (American Petroleum Institute) gravity of 10 degrees. A higher API gravity (>10°) indicates that the oil is lighter than water.

   The API gravity is calculated as follows:

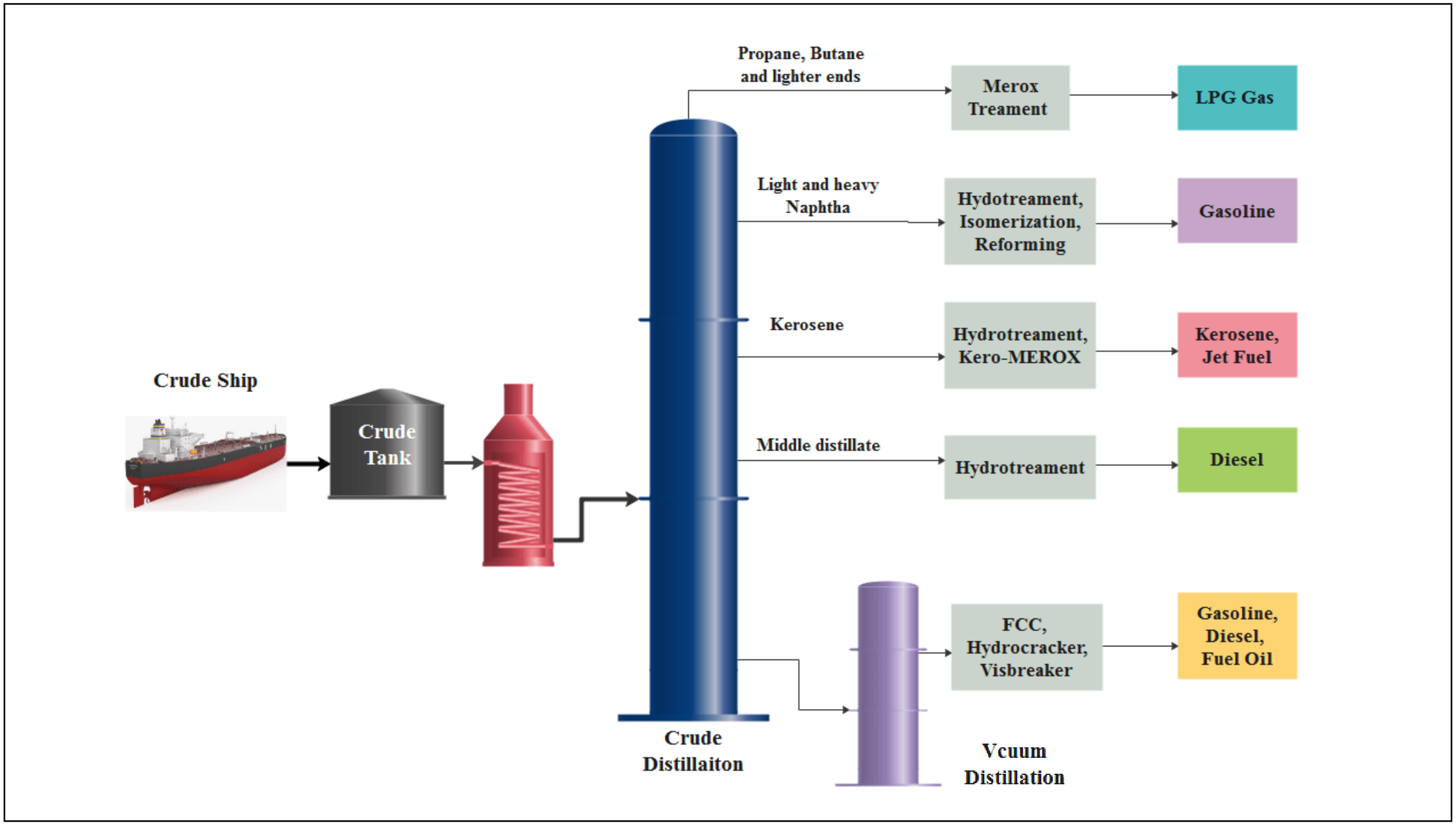
$$\text{API} = \frac{141.5}{d} - 131.5$$

   where $d = \rho_{crude\ oil}/\rho_{H_2O}$ is the specific gravity of the crude oil (dimensionless), $\rho_{crude\ oil}$ and ρ_{H_2O} are the densities of crude oil and water.

2. **Impurity content**, particularly sulfur content.

Varieties of oil (2/2)

- **Petroleum gas (LPG)**: Propane (C_3H_8) and Butane (C_4H_{10});
- **Gasoline** (mainly C_7H_{16});
- **Kerosene** ($C_{10}H_{22}$ to $C_{14}H_{30}$);
- **Diesel** (mainly $C_{16}H_{34}$).



https://thepetrosolutions.com/types-configurations-petroleum-oil-refineries/

Hydrocarbon cracking (1/2)

Hydrocarbon cracking is the process of breaking long hydrocarbon chains into shorter ones, yielding products that are easier to refine and use. The process requires high temperatures.

Hydrocarbon cracking includes four main types:

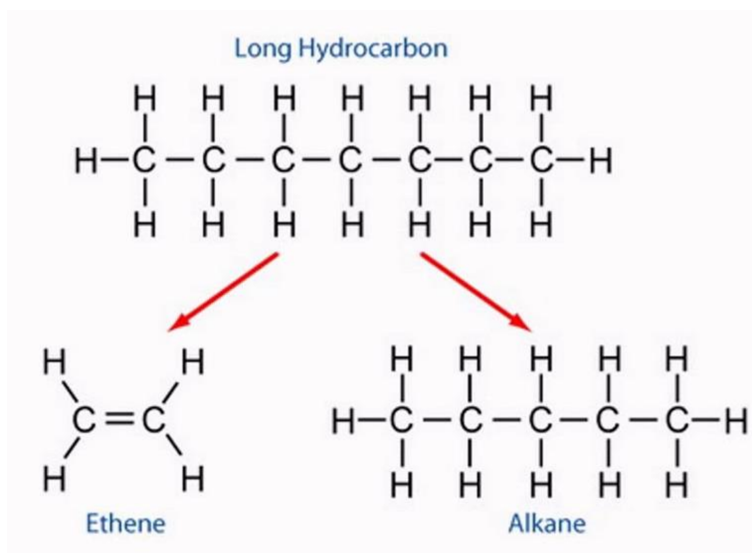
- **Thermal cracking**: This is a process that uses high temperatures, often above 450°C, and sometimes high pressures to break down large, heavy hydrocarbons into smaller, more useful molecules. Thermal cracking is one of the earliest forms of cracking and typically produces a mix of lighter hydrocarbons, including alkenes.

- **Steam cracking**: Steam cracker units are facilities where feedstocks such as naphtha, liquefied petroleum gas (LPG), ethane, propane, or butane are thermally cracked with steam in a series of pyrolysis furnaces to produce lighter hydrocarbons;

Hydrocarbon cracking (2/2)

- **Fluid catalytic cracking (FCC)**: This type of cracking uses a catalyst in a fluidized state to break down heavy hydrocarbons at lower temperatures than thermal cracking. The FCC process, typically occurring at temperatures around 500°C, produces gasoline, olefins, and other valuable products.

- **Hydrocracking**: This process produces high-quality gasoline, jet fuel, and diesel, and it also removes sulfur and nitrogen impurities from the feedstock, making it particularly useful in producing cleaner fuels.



Heptane: C_7H_{16}

Pentane: C_5H_{12}

Ethene: C_2H_4

Example of catalytic cracking.[1]

[1] https://www.youtube.com/watch?v=zr8l7KVXy1g

Differential rent of oil

Chemically, the classification of crude oils is based on API gravity that we remind:

$$\text{API} = \frac{141.5}{d} - 131.5$$

- **Extra heavy oil**: API gravity below 10.0° (i.e. $\rho_{crude\ oil}$> 1000 kg/m³), consisting of the longest chains.
- **Heavy crude oil**: API gravity below 22.3° (i.e. $\rho_{crude\ oil}$ from 920 to 1000 kg/m³), with longer chains;
- **Medium oil**: API gravity between 22.3° and 31.1° (i.e. $\rho_{crude\ oil}$ from 870 to 920 kg/m³), with moderately long hydrocarbon chains;
- **Light crude oil**: API gravity higher than 31.1° (*i.e.* $\rho_{crude\ oil}$< 870 kg/m³), containing shorter hydrocarbon chains;

The lighter and shorter the hydrocarbon chains, the more valuable the product tends to be. Light crude products like gasoline and diesel sell better than heavy crude products like fuel oil and bitumen, creating a market value difference known as the **differential rent.**

Disparities – Technical production costs

The disparities in production costs are influenced by various factors, including **geological conditions**, **proximity to consumption areas**, and **political stability**.

Offshore oil production can be significantly more expensive than onshore operations. For example, costs in the Middle East range from $2 to $5 per barrel***** for onshore production, while offshore production in the Gulf of Guinea can reach $40 to $50 per barrel. The complexities of offshore production are exemplified by the challengers of exploiting the Kashagan Offshore challenges and the Deepwater Horizon disaster.

Nevertheless, the development of offshore oil production has been particularly prominent in regions like the North Sea, where advancements in technology and infrastructure have made it feasible despite the higher costs.

*****One barrel of oil equals 159 liters, and one ton of oil is approximately 7.3 barrels.

The Deepwater Horizon disaster

The Deepwater Horizon disaster was a catastrophic offshore oil spill that occurred on April 20, 2010, in the Gulf of Mexico. The disaster began with an explosion on the Deepwater Horizon drilling rig, **which was operated by BP**. The explosion and subsequent fire resulted in the sinking of the Deepwater Horizon and the deaths of 11 workers, and 17 others were injured.

This led to a blowout at the Macondo well, resulting in the release of millions of barrels of oil into the ocean over a period of nearly 87 days. It is one of the largest environmental disasters in history.

Disparities – Porter’s Five Forces framework

In the long term, the oil industry must contend with the following factors:

- **Competition among existing players** (Insiders);
- **Threat of new entrants** (Outsiders);
- **Threat of substitutes**;
- **Power of customers**, which was particularly evident during the COVID-19 crisis and is influenced by the relatively low lifting costs of oil;
- **Bargaining power of suppliers**, as illustrated by the influence of OPEC+.

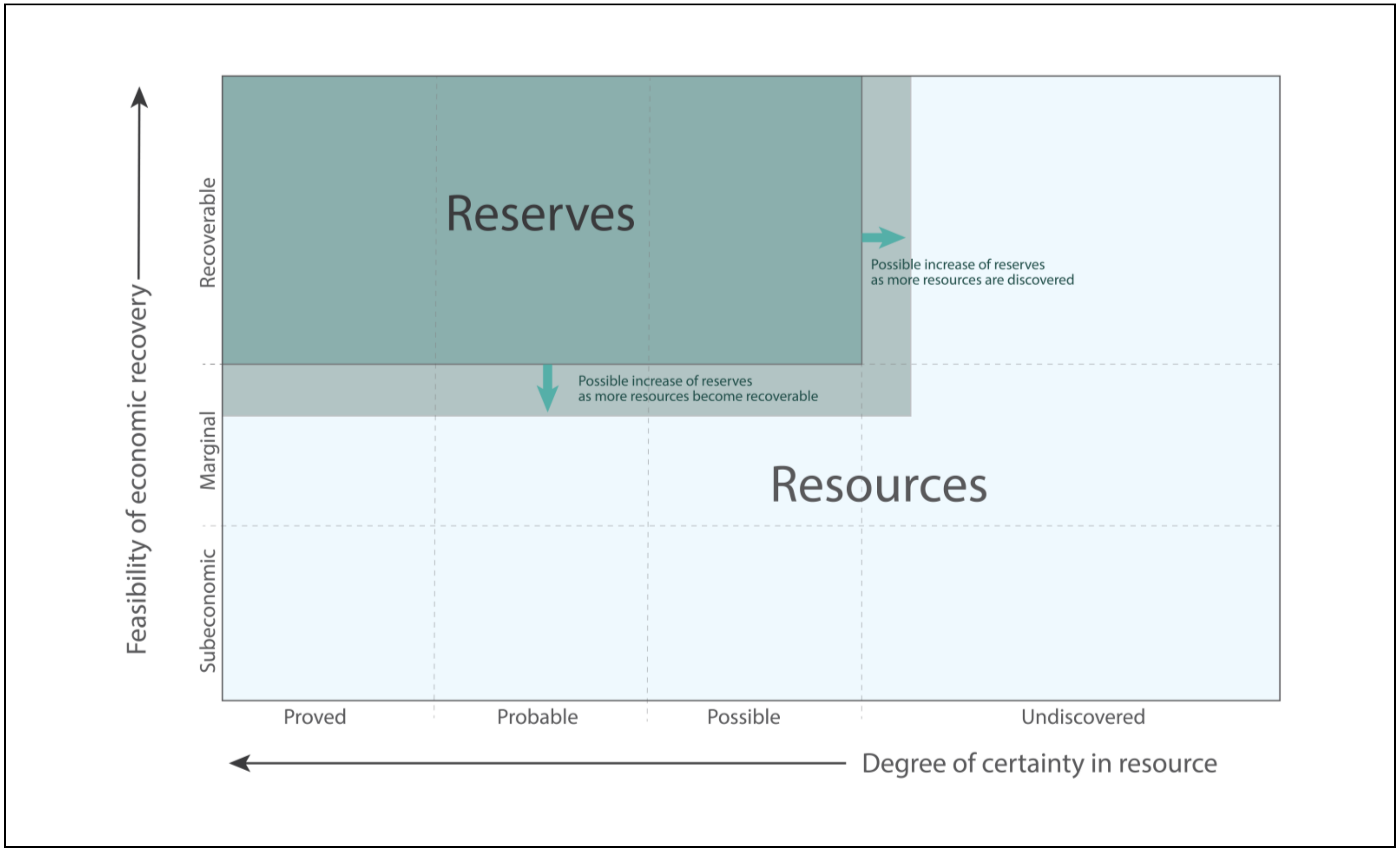
This model is known as **Porter’s Five Forces framework**[1], developed by Harvard University professor Michael Porter.

Additionally, the industry is affected by various regulations.

[1]Michael E. Porter, "How Competitive Forces Shape Strategy", Harvard Business Review, May 1979 (Vol. 57, No. 2), pp. 137–145.

Disparities – Notion of reserve (1/2)

Once discovered, **natural ‘resources’ are defined as ‘reserves’ if they are determined to be economically recoverable**. The possible expansion of the ‘reserves’ category is shown on the figure to represent the dynamic nature of mineral resource extraction; economic and technological developments may allow for previously unknown or economically unviable resources to be extracted.



Disparities – Notion of reserve (2/2)

Twenty percent of the barrels come from the 20 largest wells located in the Persian Gulf, Mexico, Venezuela, Brazil, Algeria, Russia, Azerbaijan, and Kazakhstan.

The concept of reserves is considered "relative" because it depends on multiple factors that can change over time (e.g., technology, economics, regulations, discovery of new reserves, production rates)

Thus, the **R/P ratio** and reserve estimates fluctuate over time, reflecting the relative and dynamic nature of what we consider "reserves" based on current technology, economics, and policies. This explains why the R/P ratio increased from 44 years in 2009 to 55 years in 2012; it reflects updated estimates due to these changing factors.

Reserves of National Oil Companies (NOCs) in the end of 2023

Reserves in billions of barrels for major NOCs:

- Venezuela: 303;
- Saudi Arabia: 267;
- IR Iran: 209;
- Iraq National Oil Company: 145;
- United Arab Emirates: 113;
- Kuwait: 102;
- Libya: 48;
- Nigeria: 38;
- Algeria: 12;
- Gabon: 2.

Source: https://publications.opec.org/asb/chapter/show/123/2113

Exercise

Knowing that:

- **Saudi Aramco** has proven reserves of around 295 billion of barrels;
- The **daily worldwide oil consumption** is around 100 million barrels.

For how many years could Aramco serve the worldwide oil consumption?

Solution

$$\frac{295 \times 10^9 \text{ barrels}}{100 \times 10^6 \text{barrels/day}} = 2.95 \times 10^3 \text{ days} \approx 8.08 \text{ years}$$

Saudi Aramco could supply approximatively 8 years of worlwide oil consumption.

Unconventional oil (1/3)

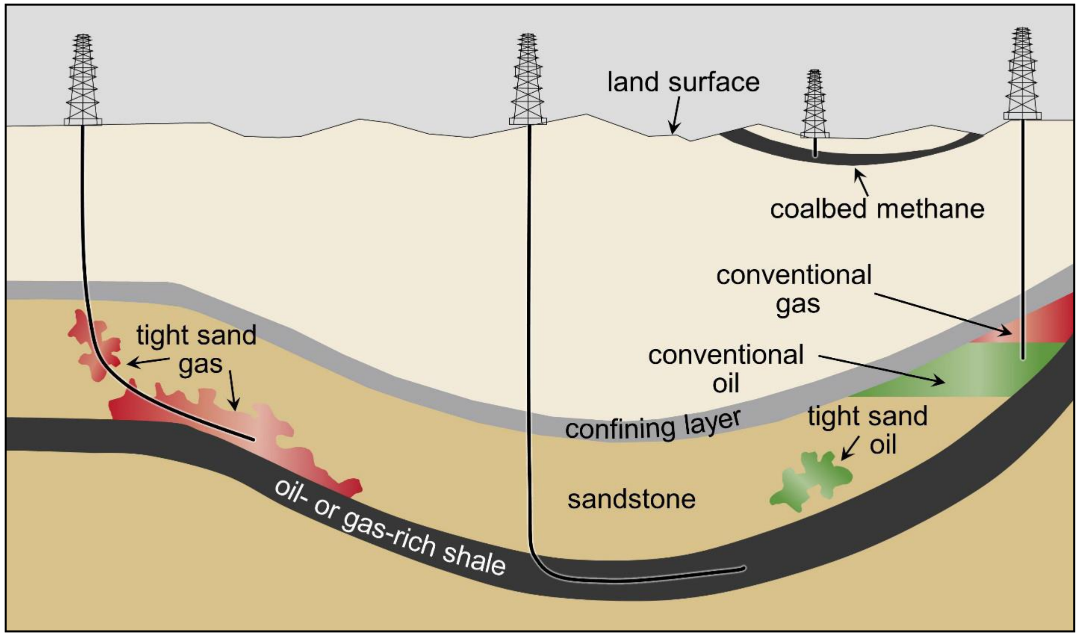
Unconventional oil refers to crude oil extracted from sources that require advanced technologies for production. As example of those sources we have: oil sands, shale oil, or deepwater reserves. On the contrary, conventional oil is obtained from easily accessible reservoirs.

From a chemical perspective, there is no difference between these types. The differentiation between conventional and unconventional resources mainly comes from the reservoir's geological characteristics and the fluid properties (permeability and viscosity).

Unconventional oil (2/3)

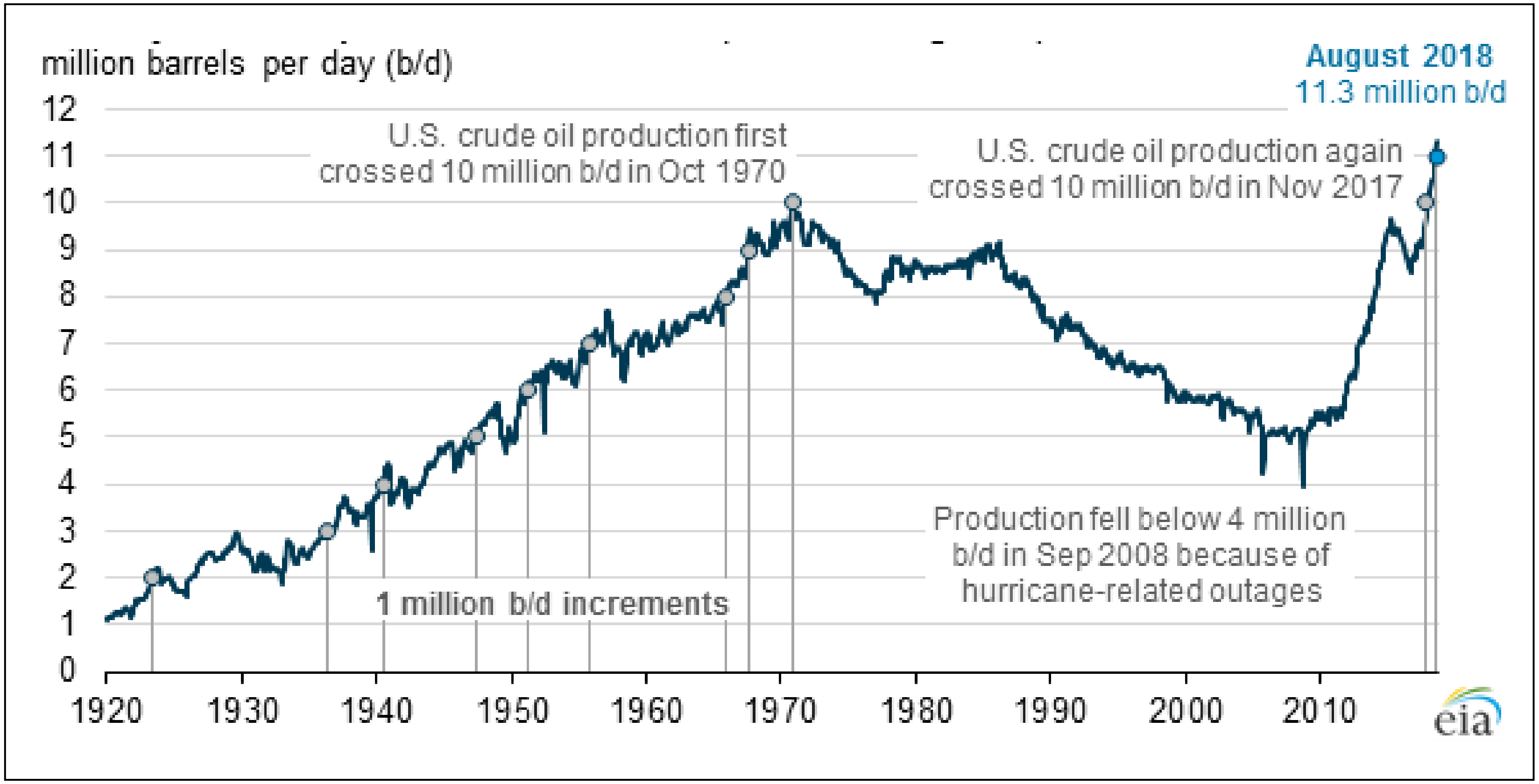
These advanced technologies include:

- Hydraulic fracturing (fracking): injecting high-pressure water, sand, and chemicals into a well to fracture the rock and release the oil or gas.
- Steam injection: injecting steam into a well to heat the oil and reduce its viscosity, making it easier to extract.
- Mining: bitumen is mined and then processed to extract the oil.



Unconventional oil (3/3)

The emergence of unconventional oil in the 2000s was driven by high oil prices in 2008, which made unconventional oil production profitable. This development has an impact on the reserves-to-production (R/P) ratio.



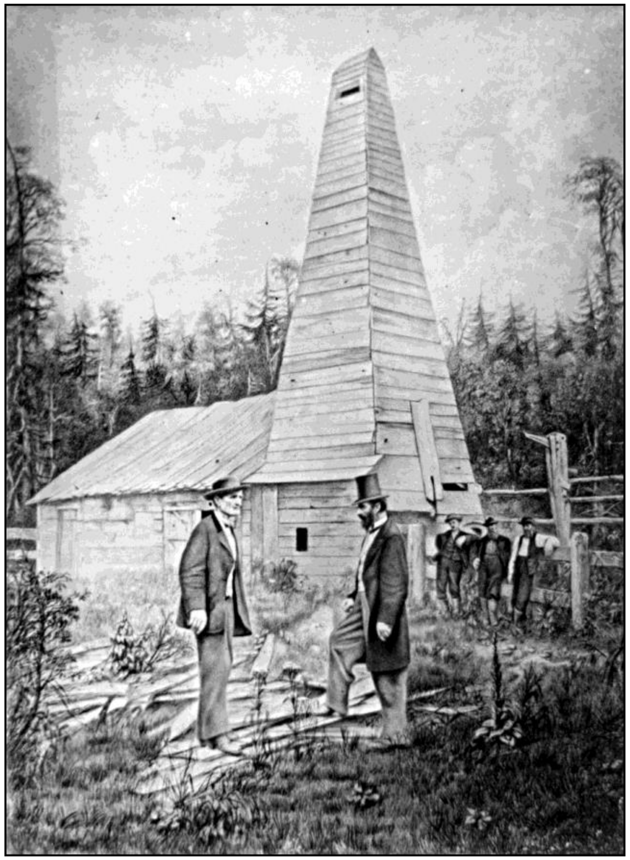
Monthly U.S. field production of crude oil (January 1920-August 2018). [1]

[1]https://commons.wikimedia.org/w/index.php?curid=74033050

III. Key milestones in the industry

From 1859 to 1870

The oil industry was primarily American, characterized by chaotic competition and strong price volatility due to daily fluctuations in discoveries.



*Edwin L. Drake, to the right, and **the Drake Well** in the background, in Titusville, Pennsylvania, where the first commercial well was drilled in 1859 to find oil.*

From 1870 to 1911

While the oil industry remained predominantly American, a shift toward monopolization occurred under the influence of D. Rockefeller, the founder of Standard Oil.

Standard Oil achieved monopoly status by employing at least two key strategies:

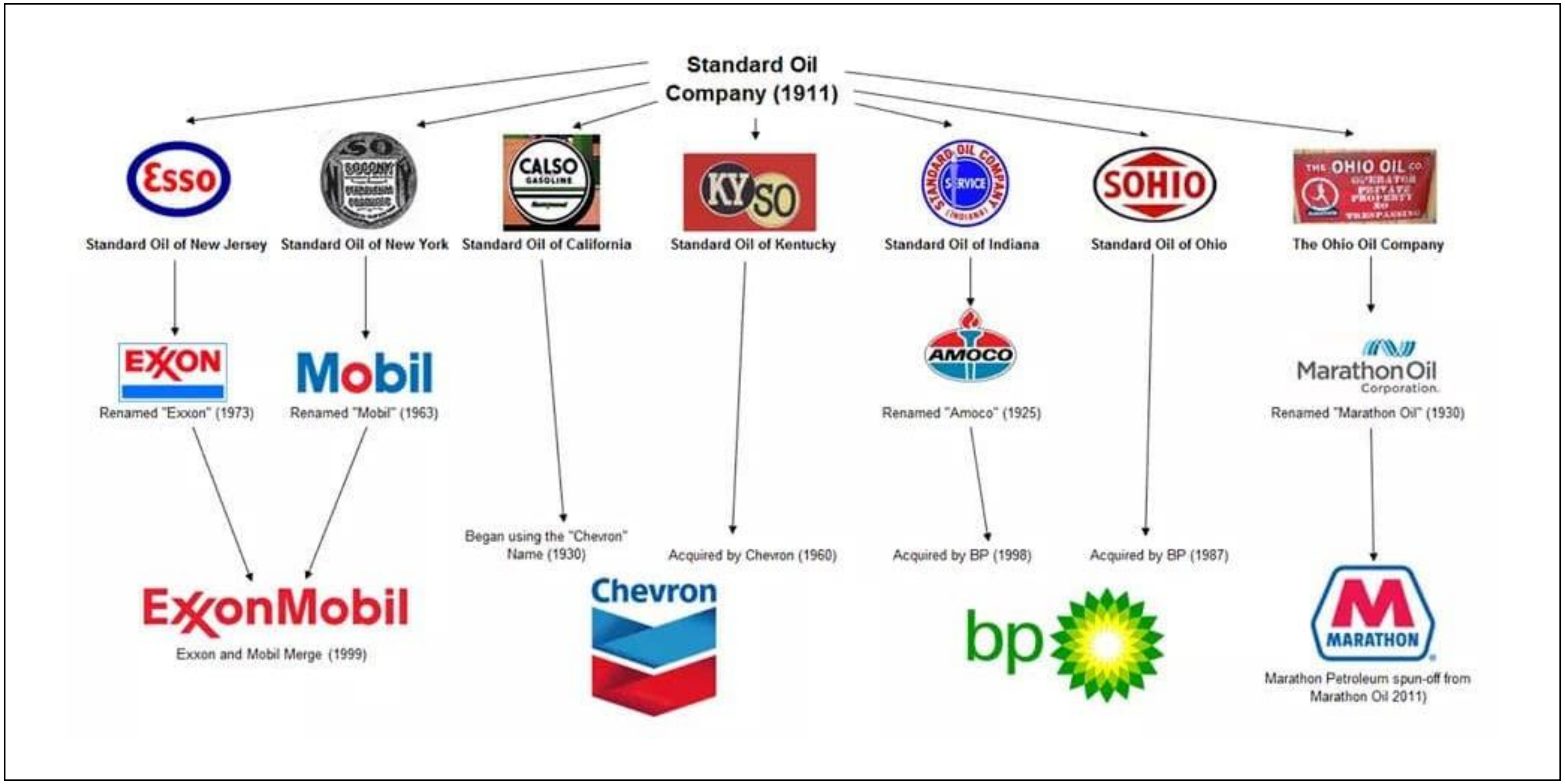
- **Strategic Focus on Transportation and Refining**: Rather than concentrating on the uncertain process of oil exploration and production (where only 1 in 4 wells was productive), Standard Oil prioritized transportation and refining. These essential, lower-risk segments of the oil industry provided a more stable foundation for growth and control.

Standard Oil company logo.

- **Aggressive Pricing to Eliminate Competition**: Once large enough to influence market prices, Standard Oil sold its oil at significantly reduced prices, undercutting competitors until they could no longer sustain operations. This aggressive pricing strategy allowed Standard Oil to drive rivals out of business and consolidate its market dominance.

1911: Standard Oil company decomposition

The Sherman Act, passed in 1890 by the U.S. Congress, ultimately led to the breakup of Standard Oil, resulting in the formation of 33 independent companies following a Supreme Court decision in 1911.



Standard Oil company decomposition. [1]

[1]https://www.mazdaofnorthmiami.com/history-of-miami-henry-flagler-3-of-5-2/

From 1911 to 1928 – Decreasing marginal costs

The global oil market became internationalized and more competitive, this time among multinational corporations. This era witnessed the rise of major companies such as Standard Oil of New Jersey, Royal Dutch Shell, Anglo-Persian Oil Company (now British Petroleum), Gulf Oil, Socony Mobil Oil, Standard Oil of California (SoCal, now Chevron), and Texaco.

Marginal cost refers to the expenses incurred to manufacture one additional unit of a good. As a manufacturing process becomes more efficient or as economies of scale are realized, the marginal cost often declines over time. However, there comes a point when it may become increasingly more expensive to produce one additional unit.

In the context of the oil industry, as companies improve their extraction and production processes or achieve economies of scale (where the cost per unit decreases as production increases), it often happens that the marginal cost of accessing crude oil declines over time.

The decline in the long-term marginal cost of accessing crude oil encouraged companies to cooperate and avoid destructive competition.

From 1911 to 1928 – Cartelization

This cooperation can manifest as the formation of **cartels**, where a group of producers agree to limit production to maintain higher prices and secure their profitability. Cartels can help stabilize an industry by reducing competition, but they can also lead to anti-competitive practices.

The risk of cartelization is particularly pronounced when industry insiders (established companies with lower marginal costs) seek to prevent new entrants from competing. These new entrants may have access to more cost-effective extraction methods or technologies, which could disrupt the market by driving prices down.

To protect their interests, insiders may collude to limit competition and maintain their market position, working against the principles of free market competition.

From 1928 to 1960

The highly internationalized global oil industry became dominated by the ‘Seven Sisters’ cartel, which comprised:

- Anglo-Iranian Oil Company (now BP),
- Gulf Oil (later part of Chevron),
- Royal Dutch Shell,
- Standard Oil Company of California (SoCal, now Chevron),
- Standard Oil Company of New Jersey (Esso, later Exxon, and since 1999 part of ExxonMobil),
- Standard Oil Company of New York (Socony, later Mobil, and since 1999 part of ExxonMobil),
- Texaco (merged with Chevron in 2001).

Three of the seven multinational corporations **agreed on production levels and prices**, and the remaining four followed suit. The cartel controlled over 90% of international trade and more than 75% of refining and distribution.

The agreement established the “Gulf Plus System” to set a price for a barrel of oil anywhere in the world.

Gulf Plus System from 1928 to 1943

Single quotation, single base point: $P_j = P_1 + a\ D_{ij}$

- P_j is the price at destination j;
- The base point i is **the Gulf of Mexico** (east coast of the USA);
- The price P_1 is the Platt's cotation of crude oil (a Cleveland trading newspaper that published the daily price of crude oil);
- The D_{ij} is the distance between the base point i and the destination j;
- a is the cost per unit of distance to transport a barrel of oil.

<u>Question</u>: If you were a major oil company, how could you trick this system to maximize your revenues?

Gulf Plus System from 1928 to 1943

The Gulf Plus System, which used a single base point and single pricing quotation, led to "ghost freight" charges. These charges occurred when crude oil was sourced from the Middle East rather than from the USA.

Despite the actual shipping origin, freight costs were calculated as if the oil were shipped from the USA, resulting in inflated and sometimes misleading freight charges.

Gulf Plus System from 1943 to 1947

Single quotation, double base point:

$P_j = P_1 + a\, D_{ij}$ if point j is closer to the Gulf of Mexico than the Persian Gulf,
$P_j = P_1 + a\, D_{kj}$ if point j is closer to the Persian Gulf than the Gulf of Mexico.

- P_j is the price at destination j;
- **First base point $\boldsymbol{i}$ is the Gulf of Mexico**;
- **Second base point $\boldsymbol{k}$ is the Persian Gulf**;
- P_1 is the Platt's cotation of crude oil.

The neutral point is located in Malta. Anything west of Malta should originate from the USA, while anything to the east should come from the Middle East.

Gulf Plus System from 1947 to 1959

Double quotation, double base point:

$P_j = P_1 + a\ D_{ij}$ if point j is closer to the Gulf of Mexico,
$P_j = P_2 + a\ D_{kj}$ if point j is closer to the Persian Gulf.

- P_j is the price at destination j;
- First base point i is the Gulf of Mexico;
- Second base point k is the Persian Gulf;
- **$\boldsymbol{P_1}$ is the Platt's cotation of crude oil at the Gulf of Mexico;**
- **$\boldsymbol{P_2}$ is the Platt's cotation of crude oil at the Persian Gulf.**

Question: What could happen if $\boldsymbol{P_2}$ becomes lower and lower than $\boldsymbol{P_1}$?

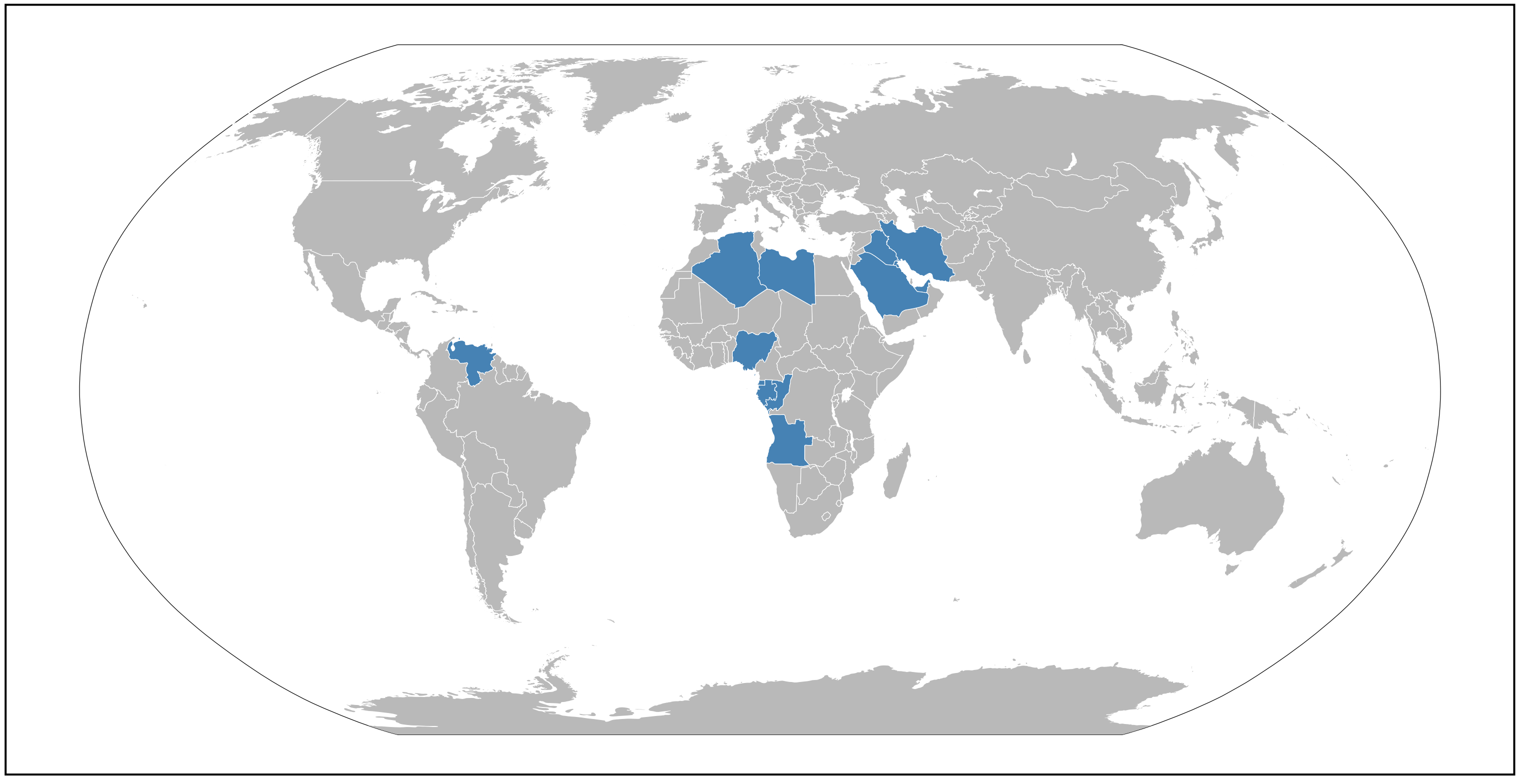
Gulf Plus System from 1947 to 1959

In the context of oil pricing, if the price of oil in the Middle East (P_2) was lower than the price in the United States (P_1), the “neutral point” — the geographical location where it became equally economical to ship oil from either the Middle East or the U.S. — shifted westward.

By the early 1950s, this neutral point had moved all the way to the east coast of the United States. This shift meant that, for much of the U.S., importing oil from the Middle East became more cost-effective than relying on domestic supplies, influencing the U.S. market's reliance on Middle Eastern oil and impacting global trade dynamics.

In 1960

The Organization of the Petroleum Exporting Countries (OPEC) was created by five producer countries: Saudi Arabia, Kuwait, Iran, Iraq, and Venezuela. It was later joined by Qatar, Indonesia, Libya, Abu Dhabi, Algeria, Nigeria, Ecuador, and Gabon.



OPEC members in 2020. [1]

[1] https://commons.wikimedia.org/w/index.php?curid=4428362

From 1960 to 1971

OPEC restructured global oil production in favor of oil-producing states. Its coordination allowed for nationalization and favorable pricing without Western interference. Before OPEC, states faced penalties for altering oil production governance. These penalties included military coercion (e.g., in 1953, the US and UK sponsored a coup against Mohammad Mosaddegh after he nationalized Iran's oil production) and economic sanctions (e.g., the Seven Sisters slowed down oil production in one non-compliant state while ramping up production elsewhere).

Alongside OPEC, competition emerged from so-called **‘independents’**, predominantly Anglo-Saxon multinationals such as Amoco, Arco, Conoco, Getty Oil, Occidental, and Sinclair. Additionally, **public companies** from importing countries, like Compagnie Française des Pétroles (Total) in France and Eni in Italy, also contributed to this competitive landscape.

However, demand has been increasing while the supply side struggles to meet this rising demand, giving rise to concerns about potential shortages reminiscent of the 1970s and fueling discussions on resource depletion.

1971: End of Bretton Woods system

The Bretton Woods system, established in 1944, was a monetary order that aimed to promote international economic stability after World War II. Under this system, countries agreed to peg their currencies to the U.S. dollar, which was itself convertible to gold at a fixed rate of $35 per ounce.*****

Countries participating in the Bretton Woods system were required to maintain fixed exchange rates between their currencies and the U.S. dollar. This led to some problems:

- After World War II, the U.S. economy grew rapidly, leading to an increase in the supply of U.S. dollars. Many of these dollars circulated outside the United States as a result of foreign aid, military spending, and international trade;
- As more U.S. dollars accumulated in foreign markets, countries began to hold large reserves. If a country held more dollars than it could convert to gold (due to the U.S. holding a limited amount of gold), this created potential instability.
- To finance its spending, the U.S. government printed more dollars, leading to inflationary pressures. If more dollars were in circulation without a corresponding increase in gold reserves, it could devalue the dollar.

*1 ounce ~ 28.35g

From 1971 to 1973

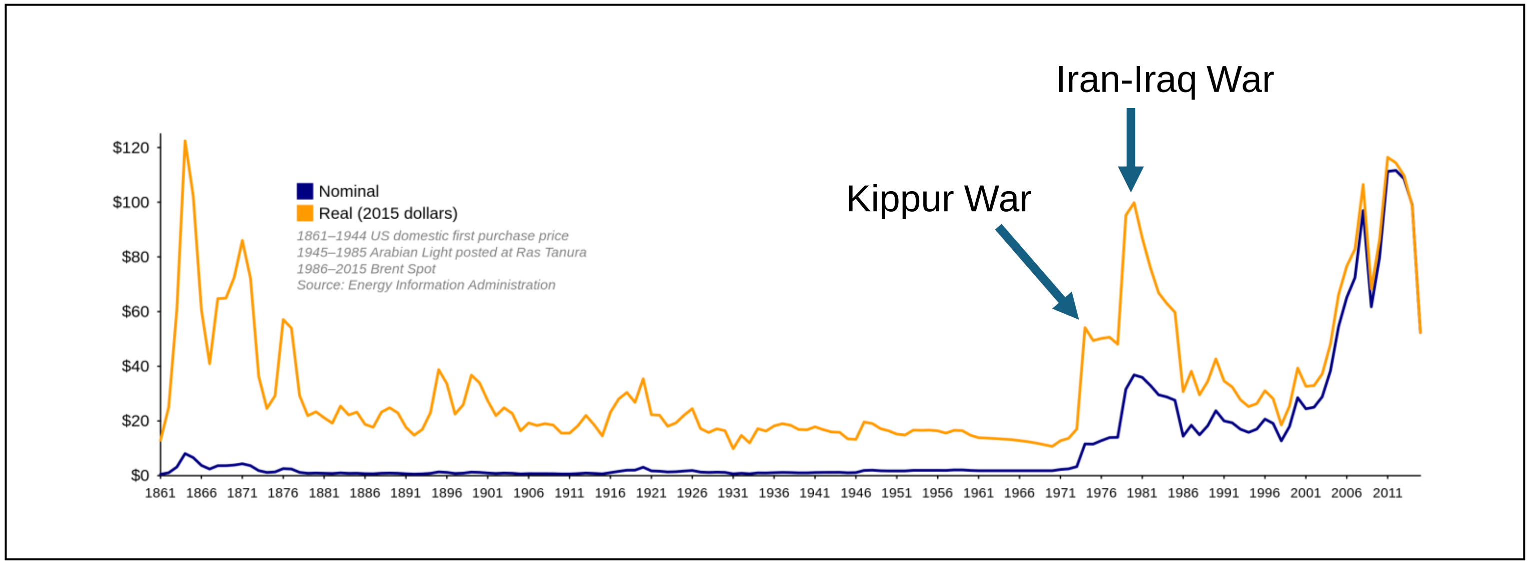
In 1971, President Nixon ended the Bretton Woods system by suspending the direct convertibility of U.S. dollars to gold. This move was prompted by a significant decline in U.S. gold reserves, rising inflation, and growing doubts about the dollar's stability. The value of the dollar declined relative to gold, and the dollar was no longer guaranteed by a fixed gold value.

As the dollar's value fluctuated due to its separation from gold, oil-producing nations faced a decline in their revenue. To counteract this, OPEC announced in September 1971 that they would adopt a gold-based pricing system for oil. However, this system did not remain in place for long.

The OPEC gold pricing system swiftly evolved into the petrodollar system, where oil-exporting countries earned U.S. dollars through the sale of their oil. By 1973, during the oil crisis, OPEC member countries began **pricing oil exclusively in U.S. dollars**, which established a new standard for global oil transactions. This shift was driven by a desire to stabilize oil revenues following the collapse of the Bretton Woods system.

From 1973 to 1981

The seventies have seen **two oil crises:** The detonating events were the **Yom Kippur War** (1973-1974), a conflict between Israel and a coalition of Arab states led by Egypt and Syria, and the **Iran-Iraq War** (1979-1981), where both countries relied on oil revenues to fund their military efforts.



1973–1974: During the First Oil shock, prices quadrupled to around $12/barrel during, driven by an OPEC embargo.
Mid-1970s: Prices stabilized at a high level but remained around $12-15/barrel.

1979–1980: Prices doubled to nearly $39/barrel due to the Second Oil Shock.

During this period, new oil fields were brought into production, particularly in the North Sea.

https://commons.wikimedia.org/w/index.php?curid=4040114

IV. Determinants of oil prices

Economic and geopolitical factors influencing oil prices

1) Depletion of reserves;
2) Demand;
3) Production;
4) Speculation and the value of the U.S. dollar;
5) Exporters' absorption capacity and economic tensions.

1) Depletion of reserves

The depletion of oil reserves leads to diminishing supply, which can increase extraction costs and drive prices higher due to scarcity concerns. The existence of a **scarcity rent** is a significant determinant of international oil prices, as market prices typically exceed the marginal cost of production.

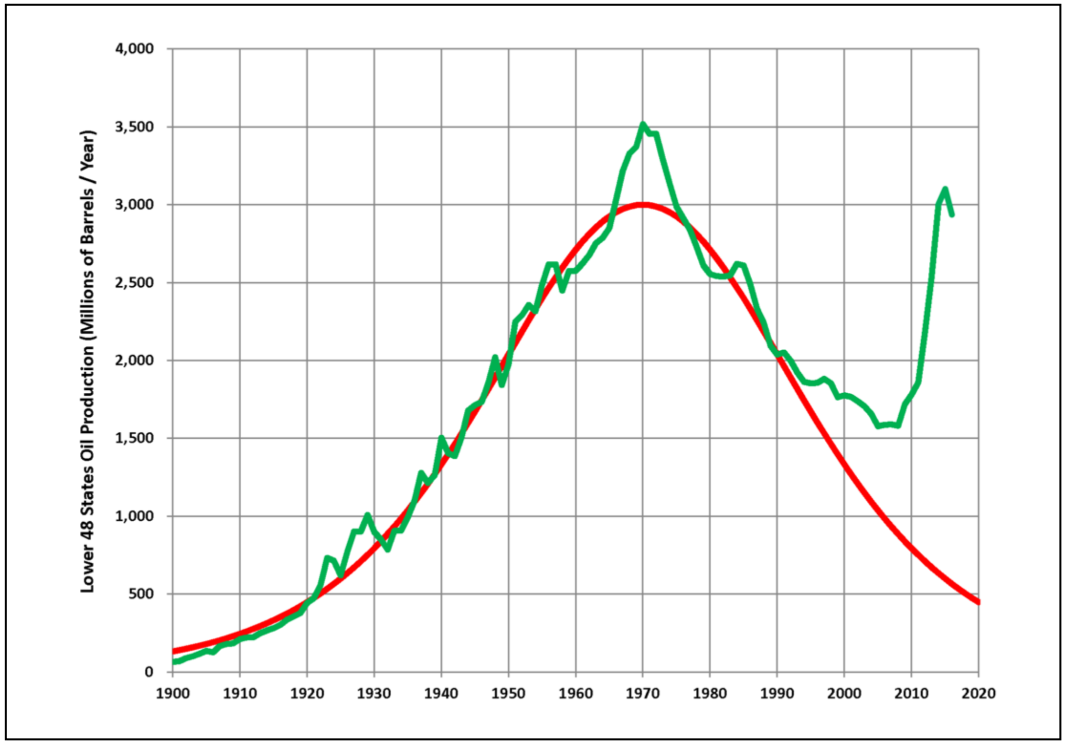
Various economic theories help explain these dynamics:

- **Hotelling's Theory:** Harold Hotelling's theory asserts that the price of non-renewable resources should rise over time at the rate of interest, reflecting their diminishing availability.
- **Pakravan's Theory:** F. Pakravan suggests that oil-producing nations should carefully balance output to manage prices effectively. By controlling production levels, OPEC can stabilize prices and ensure long-term sustainability, even as reserves deplete.
- **Pindyck's Theory:** Robert Pindyck examines how price volatility and uncertainty impact investment decisions in the oil industry, suggesting that fluctuations can lead to underinvestment.

The peak oil Theory

Developed by King Hubbert, the theory posits that all production from a reservoir follows a **Hubbert curve**. The peak is reached when the quantities extracted equal those remaining to be extracted. A key challenge is the need to estimate proven reserves (P), which depend on crude oil prices and the intensity of technological progress: P = f(crude oil price, technological progress intensity).

The estimation of proven reserves is often "strategic" and can frequently be overestimated or underestimated in various cases (e.g., OPEC, Russia, etc.).

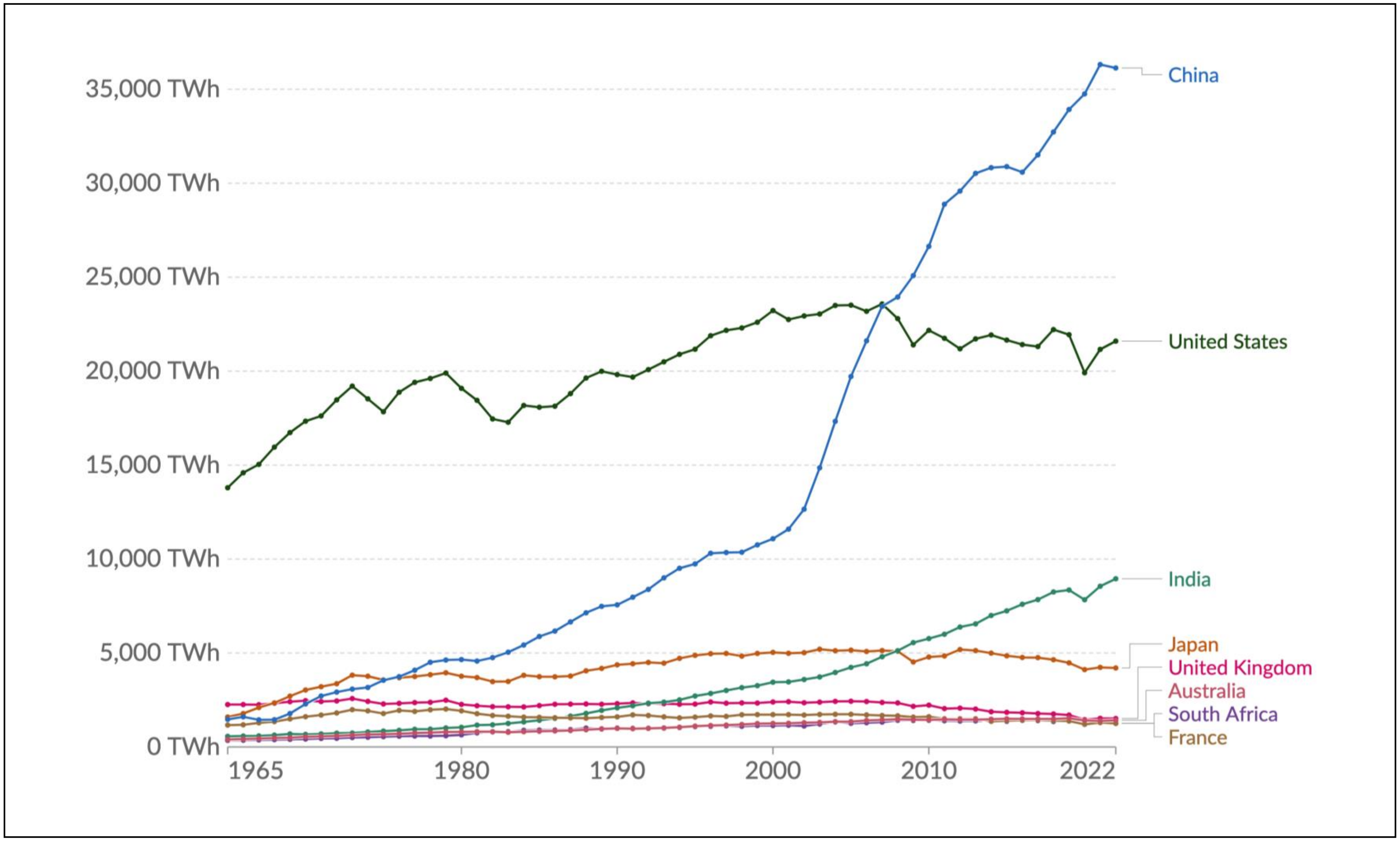


Hubbert's upper-bound prediction for US crude oil production (Hubbert curve) in 1956 versus actual production through 2016.

Source: https://en.wikipedia.org/wiki/Hubbert_peak_theory

2) Demand

Demand growth in Asia (China and India).



Fossil fuel consumption in selected countries from 1965 to 2022.

3) Production (1/2)

Several key factors on the production side contribute to fluctuations in global oil prices. These determinants shape both the supply dynamics and the market power of major producers:

- **Structure of Production**: The organization and ownership of oil production facilities significantly influence pricing. Market power concentration, especially in a few influential companies or countries, can amplify the impact of production decisions on global oil prices.

- **Production Volumes**: Increases in oil production volumes typically exert downward pressure on prices by boosting supply. However, sustained increases depend on the capacity of major producers and geopolitical stability in oil-rich regions, which affects the elasticity of oil supply.

- **Export Market Share**: Exporting countries' share of the global oil market has been a crucial price determinant, particularly through the influence of OPEC. For example, during the first oil crisis, OPEC accounted for approximately 86% of global oil exports, granting it significant leverage in controlling oil prices. This share decreased to around 53% by 2008, reflecting shifts in production and export capacity among both OPEC and non-OPEC countries.

3) Production (2/2)

- **Industry Consolidation**: The transformation of the dominant oil companies, known historically as the "Seven Sisters," into the "Five Majors" (ExxonMobil, Chevron, BP, Shell, and Total) has reshaped the competitive landscape. The consolidation of these firms has strengthened their role in stabilizing or influencing oil prices through coordinated investment and production strategies.

- **Capacity Utilization Rates**: The degree to which oil producers utilize their available capacity directly affects prices. Higher utilization rates signal strong demand or supply constraints, often resulting in price increases. Conversely, low utilization rates may reflect weaker demand or an oversupply, putting downward pressure on prices.

- **Cost of Accessing Crude Oil**: Production costs, which include the expenses associated with locating, extracting, and transporting crude oil, vary widely depending on geographic and technological factors. Higher access costs, often found in offshore or unconventional oil sources, tend to drive up prices, especially when cheaper sources become less available.

4) Speculation and value of the U.S. dollar

Petrodollars are the **U.S. dollars earned by oil-producing countries from their oil exports**. This concept emerged in the 1970s when rising U.S. imports of increasingly expensive crude oil significantly increased the dollar reserves of foreign producers.

Petrodollar recycling refers to the reinvestment of these dollar-denominated oil revenues into global financial markets. The U.S. dollar had already established itself as the world's leading currency before the rise of petrodollars, and it has maintained this position despite the growth of U.S. energy production and expanding trade deficits.

The relationship between the U.S. dollar's exchange rate and oil prices is intricate; shifts in the dollar can impact oil prices, while U.S. monetary policy adjusts in response to these exchange rate movements. This interdependence helps explain how U.S. economic cycles are closely tied to fluctuations in oil prices.

Source: https://www.investopedia.com/articles/forex/072915/how-petrodollars-affect-us-dollar.asp

5) Exporters' absorption capacity and economic tensions

When oil prices increase, production initially rises but eventually stabilizes and declines past a certain price point, suggesting a limit to the investment capacities to absorb the revenues generated.

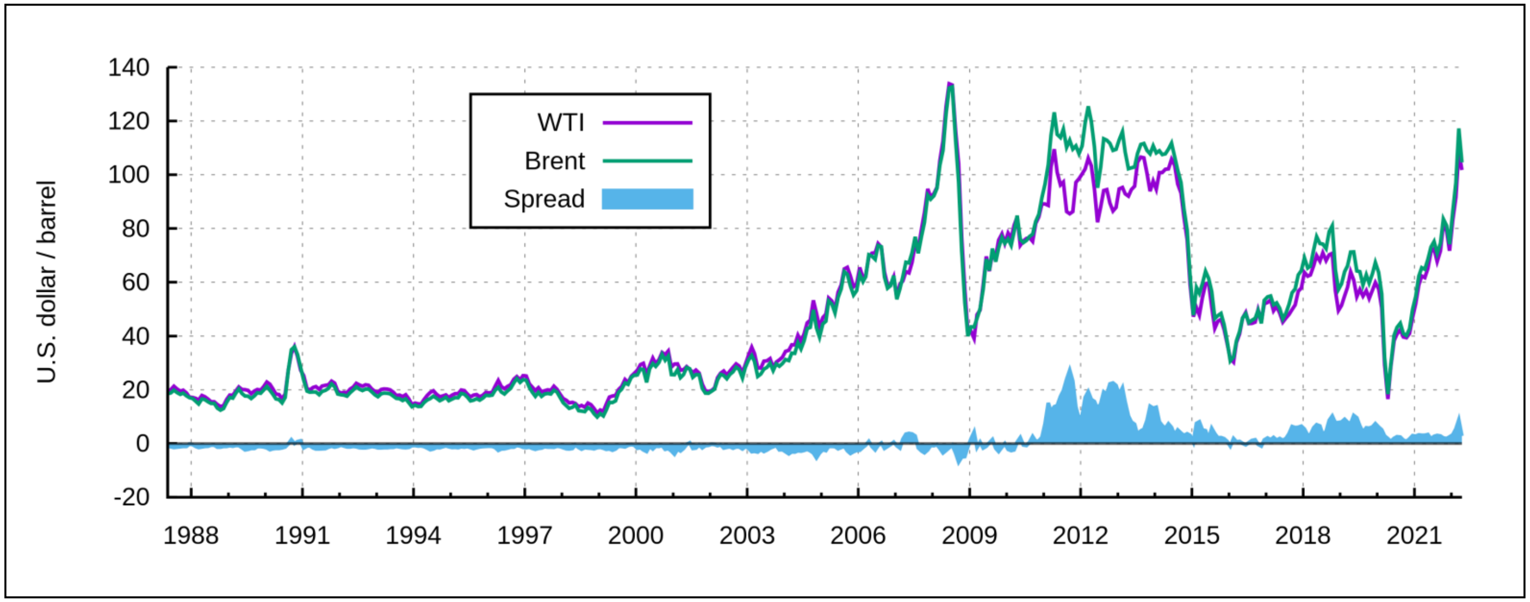
Oil-exporting states often establish sovereign wealth funds to invest in sectors that can replace oil revenues over time.

Additionally, factors such as political tensions (e.g., the Gulf War) and natural disasters can impact oil prices.

Oil price – WTI vs. Brent

Nowadays, two benchmark references for determining the price of oil:

- Price on the New York Mercantile Exchange (**NYMEX**): West Texas Intermediate (**WTI**). WTI crude has an API gravity of 39.6°, making it very 'light'.
- Price on the Intercontinental Exchange (**ICE**): North Sea **Brent** Crude. Brent has an API gravity of 38°—still quite light, though not as light as WTI.



Spot price of West Texas Intermediate in relation to the price of Brent crude.[1]

<u>Question</u>: What are nowadays the arguments for potential increases or decreases in oil prices?

[1] https://commons.wikimedia.org/w/index.php?curid=50518908

Answers to the question

Arguments in favor of future price increases:

- Sustained strong demand in Asia and emerging countries with growing populations;
- Rising costs of oil access due to stricter environmental regulations and higher insurance costs;
- Lack of investment in upstream capacity;
- Producers' preference for high prices;
- Diplomatic and military tensions leading to speculation.

Arguments in favor of future price decreases:

- Energy efficiency and substitution policies (e.g., coal, gas, renewables, and nuclear) in importing countries;
- High potential of unconventional oil;
- Growing role of new oil-exporting countries in Africa and Asia, reducing supply disruption risks;
- Technological advancements, particularly in offshore drilling and shale oil, leading to reduced crude oil production costs;
- Electrification of the heating and transport sectors.

Some press papers

Reuters World US Election Business Markets Sustainability Legal Breakingviews Technology

Energy | OPEC | Fuel Oil | Exploration & Production | Transport Fuels

Oil jumps nearly 3% after OPEC+ delays output hike, US election in focus

By **Arathy Somasekhar**

November 4, 2024 9:22 PM GMT+1 · Updated 18 hours ago

Aa

Could war in the Gulf push oil to $100 a barrel?

Oct 7, 2024 ... The biggest fear in oil markets has been that tensions would escalate into a full-blown regional war pitting Israel against Iran.

India to be among global oil demand growth drivers in 2023-2050 – OPEC

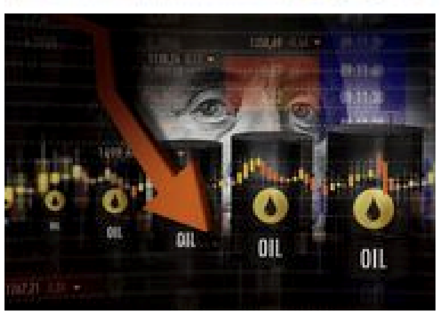
Nurluqman Suratman

25-Sep-2024

Economics

OPEC+ Kicks the Can Down a Very Uphill Road

With prices slipping, the cartel delays a planned supply increase.



Markets

The Oil Price That Matters Now Is $50 a Barrel, Not $100

The price of crude is more likely to decline than increase in the foreseeable future.

Sources: Bloomberg; Reuters; The Economist.

V. Oil contracts and types of hedging

Oil contracts

In the oil industry, there are three main types of contracts that enable an oil company to exploit a resource within a country:

- Concession contracts;
- Production-sharing contracts;
- Service contracts.

Concession contracts

Under a concession contract, a producing state grants a concessionary oil company (typically private) the right to explore for oil and develop any discoveries made, under clearly defined terms.

In return, the producing state may receive various forms of revenue, depending on the terms of the concession contract:

- **Bonuses**: Payments made upfront, often through auctions.
- **Surface Royalties**: Payments proportional to the area of land exploited.
- **Production Royalties**: Payments proportional to the volume of oil produced.
- **Corporate Income Tax**: Tax paid by the concessionaire on their income.

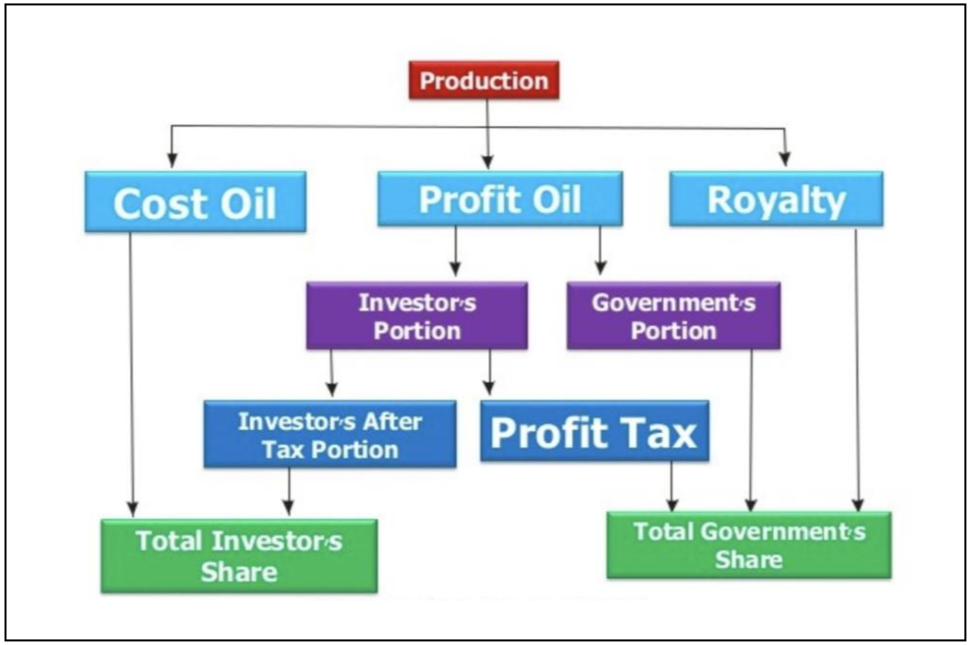
What is a Royalty?
A royalty is a "royal right" (originally referring to minerals) granted by the sovereign to an individual or corporation. In the oil industry, royalties are payments made by the producer of minerals, oil, or natural gas to the owner of the land or mineral rights.

Typically, a concession is granted for a limited duration, ranging from 10 to 20 years.

Production sharing contracts

A producer state authorizes a foreign company to explore for and extract oil in partnership with its national company (usually state-owned).

The producing state retains ownership of the discovered oil, while the foreign company is entitled to recover its incurred costs ("cost oil") and receive a share of the oil ("profit oil").



Historically, this share was split with 65% for the state and 35% for the company; today, the split has shifted to 85% for the state and 15% for the company. This system was introduced by Indonesia in 1966 and later by Peru in 1971.

An alternative model, known as the **'buy-back' system**, also exists. In this model, cost oil remains to cover exploration and production expenses, but profit oil is replaced by a fixed fee, independent of the oil price or production volume. This system was first negotiated in 1995 between Iran and the American company Conoco.

Services contracts

In technical assistance contracts, the **foreign company provides its expertise in exchange for financial remuneration**, regardless of the research outcomes or associated risks.

The company has no ownership of any crude oil discovered.

However, certain clauses incentivize discoveries, such as a preferential price on a portion of the production or a bonus proportional to the discovery.

<u>Question</u>: What is the prefered contract of oil companies?

Answers to the question

To Maximize Revenue:

Concession contracts involve higher risk due to exploration but offer high returns in the event of a discovery.

To Minimize Risk:

Technical assistance contracts eliminate exploration risk, but they also result in lower revenue since the company does not own any of the oil.

Types of hedging

When the price was effectively "regulated" by the Seven Sisters cartel or by OPEC, hedging was of little interest.

Since 1980, **spot prices** have fluctuated daily based on supply and demand dynamics.

Following the oil crisis, volatility in the spot market increased due to agents acting in contradictory ways, leading to the **emergence of derivatives markets**, including:

1) Forward and futures contracts;
2) Options;
3) Swaps.

1) Forwards and futures contracts

As in the electricity market, forwards and futures are contracts in which two parties agree to buy and sell an asset at a specified price by a certain date.

Forward	Future
Private and customizable agreement that settles at the end of the agreement.	Standardized terms.
Traded over the counter (OTC).	Traded on an exchange, where prices are settled on a daily basis until the end of the contract.
No oversight.	Regulated by the Commodity Futures Trading Commission (CFTC).
Counterparty risk.	Almost no chance for default.

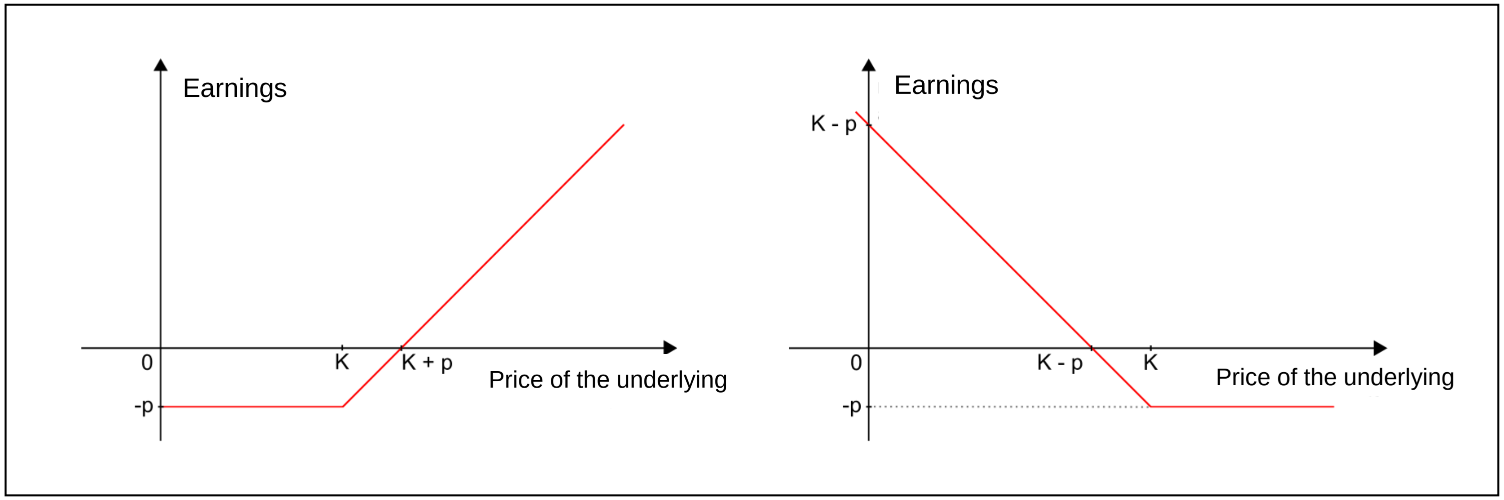
Source: https://www.investopedia.com/ask/answers/06/forwardsandfutures.asp

2) Options

An option is **a type of futures contract without a firm commitment**, where obligations are asymmetrical (seller's obligations ≠ buyer's obligations). The buyer pays a premium and has the right to buy or sell the underlying asset at a predetermined price (the "strike price"). **The issuer of the option faces higher risk, while the buyer's risk is limited to the premium paid.**

An American option can be exercised at any time up to maturity, while a European option can only be exercised at maturity.

An option is defined by four components: **its nature** (Call, the right to buy, or Put, the right to sell), **the strike price**, **the specified date**, and **the premium**.



(a) Earnings profile for a call buyer with premium p and strike price K;
(b) Earnings profile for a put buyer with premium p and strike price K.

3) Swaps

Swaps are financial contracts where two parties agree to exchange specific financial assets, obligations, or cash flows to manage exposure to certain market risks, such as price fluctuations. In the oil industry, swaps are commonly used to hedge against price volatility, enabling companies to stabilize revenues and costs.

It is a tailor-made contract, functioning because **each party anticipates opposite market movements**. In a forward or futures contract, the buyer anticipates that the asset's price will increase, so he aims to lock in a lower price now. Meanwhile, the seller believes the price will either stay the same or decrease, so he is willing to secure today’s higher price.

3) Example of a Swap in the Oil Industry

Consider a situation where an airline company (Party A) wants to protect itself from rising oil prices, while an oil producer (Party B) wants to safeguard against a drop in oil prices. They could enter into an oil price swap:

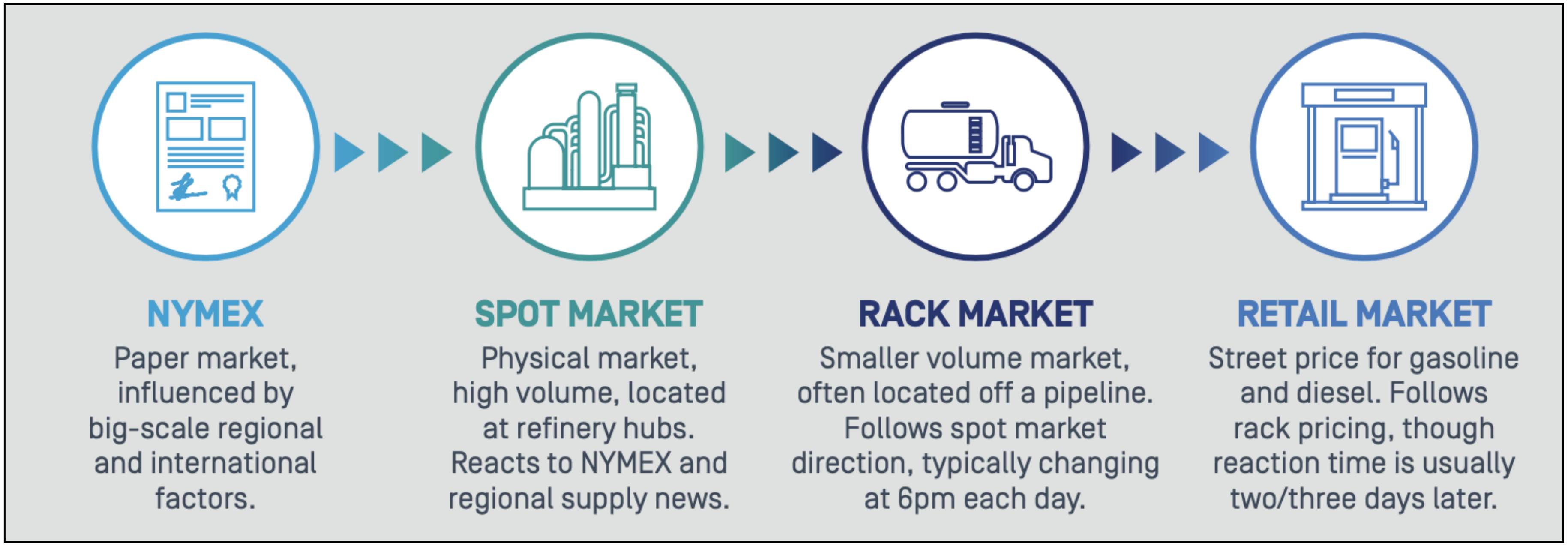
1. **Terms**: Party A agrees to pay Party B a fixed price per barrel for oil it consumes (e.g., $80 per barrel), while Party B agrees to pay Party A Warnings floating price based on the market rate of oil at that time.

2. **How It Works**: Each month, if the market price of oil is higher than $80, Party B pays the difference to Party A, compensating Party A for the higher fuel cost. Conversely, if the market price is below $80, Party A pays the difference to Party B, ensuring Party B has a stable income.

This arrangement provides price certainty: the airline is protected from high fuel costs, and the oil producer benefits from a steady income even if market prices fall.

VI. Focus on U.S. oil markets

The oil market chain in the U.S.



Source: Oil Price Information Service (OPIS) (2023). Fuel Buying 101.

The NYMEX or futures market (1/2)

The New York Mercantile Exchange (NYMEX), also known as ‘Merc’, ‘the futures market’ or simply ‘the print’ is a mostly electronic platform where buyers and sellers can trade fuel commodities (on paper) for delivery dates ranging from a month up to 18 months in the future, giving it the name ‘futures market’.

This market is often called a ‘paper’ market because few physical barrels ever change hands; instead, trading volume consists mainly of contracts exchanged among participants.

The Commodity Futures Trading Commission (CFTC) regulates NYMEX, ensuring accountability for every 1,000-barrel contract traded.

The NYMEX or futures market (2/2)

Two other key features of NYMEX:

- Trades are anonymous;
- The exchange guarantees counterparty performance, minimizing risks of defaults like the Enron collapse in 2001.

NYMEX prices tend to respond to significant factors, including currency market shifts, geopolitical events, OPEC decisions, supply reports (like weekly U.S. inventory and production figures), refinery incidents, and weather events.

The spot fuel market (1/3)

Spot purchases refer to fuel that is physically traded either through pipelines or on water (via barges or cargo). The term ‘spot’ indicates that the negotiation occurs for immediate delivery. Unlike the NYMEX, **the physical product changes hands directly, as Refiner X sells diesel to End-User Y for a tank at Location Z**.

Spot deals are always conducted in bulk, with a minimum of 5,000 barrels and typically ranging up to 50,000 barrels.

There are seven major U.S. spot markets located in specific refinery hubs, so it is essential to identify the one that corresponds to your local wholesale market.

Note: One barrel of oil equals 159 liters, and one ton of oil is approximately 7.3 barrels.

The spot fuel market (2/3)

Who buys and sells?

- **Refiners** produce fuel and may need to buy more if they do not have enough or sell excess fuel if they have too much.
- **Traders** are speculators who bet on market movements, taking large physical positions based on their predictions.
- **Brokers** facilitate transactions by matching buyers with sellers and collecting a commission; they never handle the fuel themselves.
- **End-users** include fleets, truck stops, or jobbers looking to supplement their rack purchases with spot purchases. However, end-users must be able to trade sufficient volume on the pipeline and have enough storage to accommodate a spot-sized fuel shipment.

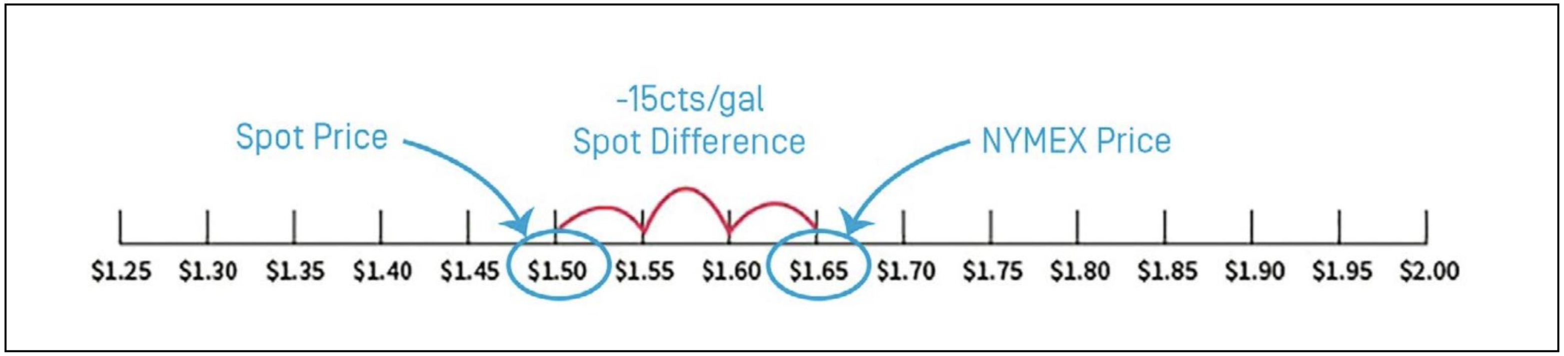
The spot market generally reacts to what the NYMEX does, but it also responds to its own set of forces, including weather events, refinery outages, and infrastructure disruptions.

The spot fuel market (3/3) – The spot basis

The spot basis refers to the relationship between the paper market and the spot market, specifically between a commodity on the NYMEX and its corresponding commodity in the physical bulk market. This relationship can **sometimes be positive, sometimes negative**, and occasionally "flat" compared to futures prices.

If the current-month, often called the spot-month, RBOB gasoline blendstock is trading on the NYMEX at $1.65/gallon*****, a Gulf Coast refiner may indicate that they are selling spot for 15 cents under that price. Traders are typically busy and may not specify ‘15 cents under NYMEX RBOB’, but that is the implied meaning. **The minus 15 cents represents what you are negotiating against the NYMEX price, and this amount is also referred to as a ‘differential’.**

The differentials fluctuate based on market conditions both in the U.S. and globally.



*****One gallon is approximately equal to 3.78 litres.

The wholesale rack market (1/4)

A rack is a fuel distribution point, usually located along a pipeline, where fuel is supplied. It is called a “rack” because trucks pull up to an actual loading rack to receive fuel from their suppliers. There are approximately 400 racks in the United States, with 220 situated on pipelines and the remainder not.

Unlike spot transactions, which typically involve high volumes, **rack transactions usually consist of ‘truck and trailer’ quantities** (approximately 8,000 gallons).

Who pulls fuel from a rack?

- Jobbers: Distributors who resell fuel, treating it as a revenue center;
- Retailers: Businesses that sell fuel to consumers;
- End Users: Organizations or individuals who directly use the fuel.

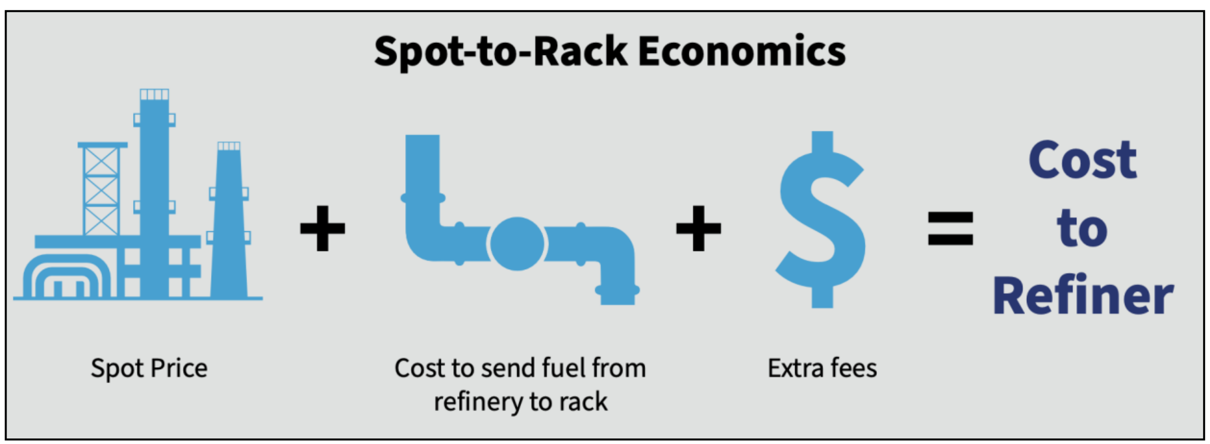
The wholesale rack market (2/4)

An example of spot-to-rack pricing: Atlanta is served by the Gulf Coast spot market.

<u>Assumptions:</u>

- The cost to ship diesel from the Gulf Coast to Atlanta is approximately $0.0375/gallon.
- Extra fees amount to $0.0125/gallon (e.g. terminal fees, security fees, …).
- Today's average spot price for Gulf Coast ultra-low-sulfur diesel is $2.58/gallon (calculated as NYMEX price +/- differential).

Question: What is the total cost to the refiner in this example?



A spot price increase or decrease day-to-day changes that equation AND impacts the refiner price at the rack.

The wholesale rack market (3/4)

The refiner's total cost to get the diesel from their refinery to the Atlanta rack is **$2.63/gallon** ($2.58 + $0.0375 + $0.0125).

Now, let us say that a day later, the cost at the Gulf Coast rises from $2.58/gallon to $2.63/gallon; a 5-cent per gallon increase.

Using the same calculations as above, the 'spot replacement' cost jumped from $2.63/gallon yesterday to $2.68 today. You can bet that refiners, who monitor the spot market throughout the day, will not 'eat' those 5 cents per gallon.

They will raise their rack prices by some or all of that amount to account for the change in their market cost.

This increase is expected to take effect around 6 p.m. local time at the corresponding rack.

The wholesale rack market (4/4)

The only charges included in a rack price are those incurred in transporting the fuel from the refinery to the distribution rack. Rack prices do not include taxes or freight charges for carrying the fuel from the rack to the retail station.

The products sold at the rack include most grades of gasoline, distillates, biodiesel, renewable diesel, pure ethanol, and, in some cases, jet fuel. Propane is sold at racks that are separate from those for refined products, but it can also be found at racks that sell refined products.

The retail market (1/2)

The retail portion of the fuel chain is the most visible to the public and likely the most complex to navigate. In the previous section, we discussed wholesale racks, where fuel resellers, retailers, and end users pick up fuel in ‘truck and trailer’ quantities at one of roughly 400 terminals in the U.S.

Aside from some ancillary shipping-related charges, there is no tax included in a rack price. Up until this point, we have not considered the cost of getting the fuel from the rack to the station, but that changes once we reach the retail price level.

The retail market (2/2)

A station seeks to **set a price that reflects the perceived value of the brand in the market**, balancing customer expectations with competitive pricing. This is a complex process aimed at attracting customers, maximizing fuel volume sold, and optimizing profit margins.

Elasticity of demand plays a crucial role here, as some stations experience high elasticity (meaning that lowering their price leads to an increase in volume sold), while others have low elasticity, where lowering prices does not significantly boost sales and instead just reduces profits. It is a very complicated scenario.

Conclusion

- **Oil supply chain**: upstream, midstream, and downstream segments;
- **Industry diversity**: disparities in oil types, technical costs, and reserves availability;
- **History**: dating back to the first oil well in 1860;
- **Price determinants**: reserve depletion, supply, demand, speculation, and economic tensions;
- **Oil contracts**: concession agreements, production sharing agreements, service contracts, hedging types (Forwards/Futures, Options, Swaps);
- **Oil markets**: Futures, Spot, Rack, Retail.

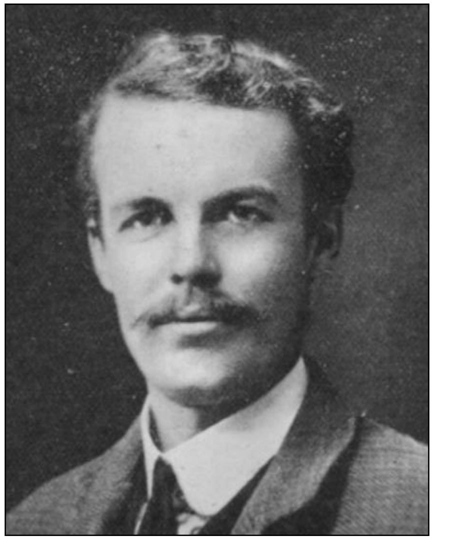
ELEC0018-1
Energy market and regulation

Lecturer: Damien Ernst – University of Liège (*dernst@uliege.be*)

Chapter 13 – Overview of carbon markets

Climate change as an externality and taxes for tackling it

Arthur Cecil Pigou (1877 – 1959) was an English economist who conceptualized pollution as an **externality**, which is **unaccounted-for cost or benefit of an activity that affect social welfare**.

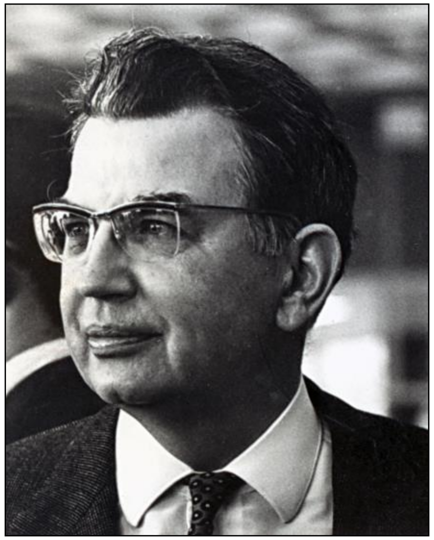


He identified negative externalities as social costs not accounted for in economic transactions, where private benefits could exceed social costs, leading to inefficient resource allocation.

Pigou proposed that these externalities could be addressed through so-called Pigouvian taxes, imposed by the state to internalize these costs and optimize economic welfare. Environmental economists adapted it to address issues like climate change, viewed as a **market failure** caused by unpriced social costs of carbon emissions.

Internalize climate change with market-based mechanisms

In his 1960 paper, *'The Problem of Social Cost',* **Ronald Harry Coase** (1910 – 2013), another English economist, critiques Pigou's approach and offers a new perspective.



When property rights are well-defined and transaction costs are low, private parties can negotiate solutions to externalities without the need for government intervention. Property rights refer to the arrangements that define the ownership, use, and transfer of resources and assets.

Coase emphasized that **externalities** involve reciprocal relationship. For example, a factory emitting pollution imposes costs on nearby residents, but restricting the factory's operations could impose costs on the factory owners. Resolving the issue involves balancing these reciprocal effects.

According to Coase, government intervention might be unnecessary in many cases if private negotiations are feasible. However, when transaction costs are high, government regulation or corrective policies (like taxes or subsidies) might still be needed.

Pricing pollution with carbon markets

Since carbon dioxide is the main greenhouse gas driving climate change, this lesson will focus on its trading, often referred to simply as '**carbon markets**'. Carbon markets are a practical application of the Coase theorem, which emphasizes market-based solutions to address externalities like climate change.

The Coase theorem suggests that when property rights are clearly defined – in this case, **the right to emit CO_2** – and transaction costs are low, market mechanisms can enable efficient solutions. Building on this idea, **carbon markets assign a monetary value to carbon emissions, internalizing their environmental and social costs.**

By setting a price on emissions and allowing their trading, **carbon markets incentivize economic actors to adopt cleaner solutions where it is most cost-effective**. This approach ensures that pollution is accounted for in economic decision-making while minimizing the overall costs of the ecological transition.

Outline of the chapter

In this lesson, we will explore the origins of carbon markets, the organisations that established them, and examine the functioning of market-based mechanisms, with a focus on allowance auctions and trading.

This will allow us to understand the price of carbon and its evolution over the past 20 years in Europe.

The lesson is divided into four parts:

I. The Kyoto Protocol

II. The European Emissions Trading System (EU ETS)

III. The auctioning and trading of EU Allowances (EUAs)

IV. The history of EUA pricing and its impact on fossil fuel power plants

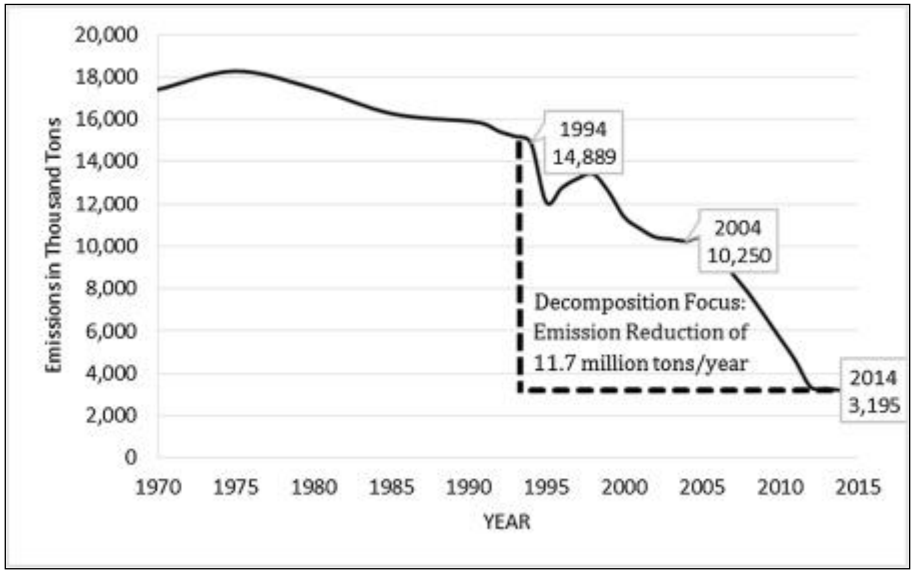
I. The Kyoto Protocol

The sulphur dioxide market as a pioneer

The origins of carbon markets can be traced back to the 1970s in the United States, with the introduction of emissions trading for sulphur dioxide (SO_2) by the U.S. Environmental Protection Agency.

In 1990, the U.S. introduced the first nationwide SO_2 trading scheme. Its goal was to reduce acid rain by cutting SO_2 emissions from fossil fuel power plants by 50% compared to 1980 levels. **The scheme's innovation was allowing power plants to trade emissions allowances**, thereby determining how reductions would be achieved through market forces rather than direct government mandates.

The success of the SO_2 trading program in reducing emissions at a lower cost than direct regulation made it a compelling case for the use of market-based mechanisms, such as carbon trading.



From 1994 to 2004, SO_2 emissions in U.S. decreased by 11.7 million tons/year (a 79% decline).[1]

[1] https://doi.org/10.1016/j.tej.2016.12.00

The negotiation of the Kyoto Protocol

In 1997, the Third Conference of the Parties (COP 3) to the United Nations Framework Convention on Climate Change (UNFCCC) was held in Kyoto, Japan. During this conference, the **Kyoto Protocol** was negotiated, marking the first legally binding agreement to set GHG emission reduction targets for developed countries and economies in transition.

In the treaty, the U.S. successfully advocated for the inclusion of market-based mechanisms to help meet emissions reduction targets.

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TODAY

► NATIONAL

Nago sets plebiscite
The Nago Municipal Government formally announces that a plebiscite will be held Dec. 21 on whether the Okinawa city should support construction of an offshore heliport for the U.S. military.
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► ASIA-PACIFIC

Taiwan on the record
Winners and losers in Taiwan's local elections seek to reassure U.S. officials they expect no change in dealings with the U.S. or China.
Page 6

► WORLD

What human rights?
Hillary Clinton highlights the lack of progress for many women in a speech at a U.N. ceremony marking the 50th anniversary of the Universal Declaration of Human Rights.
Page 7

► BUSINESS

Japan T-bond seller
In a sharp reversal, Japan becomes a net seller of U.S. Treasury securities

160 nations adopt Kyoto Protocol

Developed countries to cut their gas emissions by 5.2%

By SUMIKO OSHIMA and ASAKO MURAKAMI
Staff writers

KYOTO — Some 160 nations on Thursday adopted a historic agreement to fight global warming that calls on industrialized nations to cut the total volume of their greenhouse gas emissions by 5.2 percent between 2008 and 2012.

After an all-night negotiating session, the Third Conference of Parties to the United Nations Framework Convention on Climate Change produced the Kyoto Protocol, which for the first time ever sets legally binding targets and commitments for green-

KYOTO COP3

greenhouse gases, is required to reduce emissions by 7 percent, the European Union by 8 percent and Japan by 6 percent.

The enforcement issue was pushed aside, but parties to the convention will meet in the future to determine how to penalize countries that fail to meet their targets.

An article on developing nations' "voluntary" participation in the fight against global warming — strongly demanded by the U.S. at the Kyoto conference — was deleted. Developing nations opposed the clause, fearing an eventual mandate that they be required to curb emissions.

The six types of gases singled out for reductions are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride.

Whether to include all six was a main point of contention; initially, only the U.S. wanted all listed in the protocol.

It was also agreed that a "clean development mechanism" will be established, under which "credits" will be given to developed countries that provide financial assistance to developing countries in their efforts to reduce gas emissions.

In addition, a country will be allowed to subtract the amount of greenhouse gases absorbed by forests within its borders from its emissions.

The protocol allows the European Union to keep its "bubble" scheme, under which its 15 members will have different targets but will work together toward a common emissions-reduction goal.

Ritt Bjerregaard, head of the EU negotiating team, said that although an 8 percent reduction for the EU was agreed to, how the target will be achieved remains to be worked out.

"It's clear that we will have to go back and analyze the results of the conference," she

RAUL ESTRADA-OYUELA (center), chairman of the Committee of the Whole at the global warming conference that ended Thursday in Kyoto, is congratulated after the committee approved a draft protocol for gas emissions cuts. KYODO PHOTO

Hashimoto vows efforts

Gist of Kyoto Protocol

Front page of The Japan Times on December 12, 1997, the day after the signing of the Kyoto Protocol.[1]

[1] https://www.japantimes.co.jp/news/2022/12/04/national/history/japan-times-1997-160-nations-adopt-kyoto-protocol/

Understanding the Kyoto Protocol

In the Kyoto Protocol, countries are grouped based on their responsibilities for climate action:

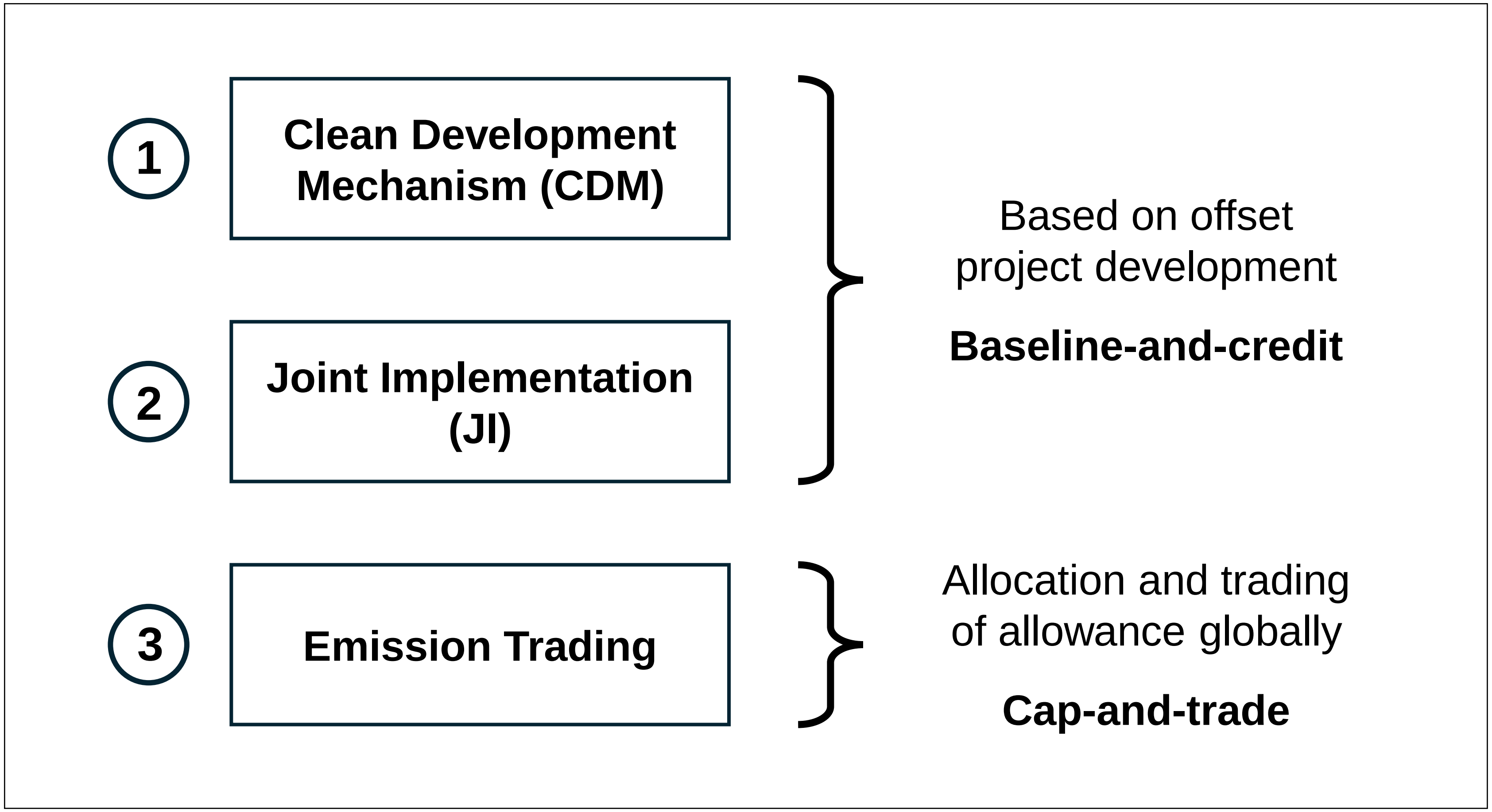
- **Industrialised countries**: Advanced economies that were historically responsible for the majority of GHG emissions, including the U.S., Canada, Japan, and the EU member states. They are committed to reducing their GHG emissions. For instance, the EU set a target of an 8% reduction in emissions by 2012 compared to 1990 levels.

- **Economies in transition**: Emerging economies that were previously part of the Soviet Union or Eastern Bloc, such as Russia, Ukraine, and other former Soviet republics. These countries are subject to the same emissions reduction targets as industrialized nations but were allowed more flexibility. For example, Russia was allowed to maintain emissions at 1990 levels.

- **Developing nations**: These include countries with lower historical contributions to GHG emissions, such as India, Brazil, and Kenya. They are not required to reduce emissions but are encouraged to pursue sustainable development.

The market-based mechanisms of the Kyoto Protocol

The **Kyoto Protocol** established three market-based mechanisms that aim to drive market-based emission reduction in industrialised countries and economies in transition:



Market-based mechanisms of the Kyoto Protocol.

The Kyoto Protocol – The baseline-and-credit model (1/3)

Both CDM and JI use the **baseline-and-credit model**, which compares emissions from a **project** to a reference level known as the **baseline**.

The **baseline scenario**, also called business-as-usual emissions, represents the amount of emissions that would occur **under normal circumstances**, without any intervention or additional efforts to reduce emissions. This baseline determines the actual reduction in emissions achieved by a project.

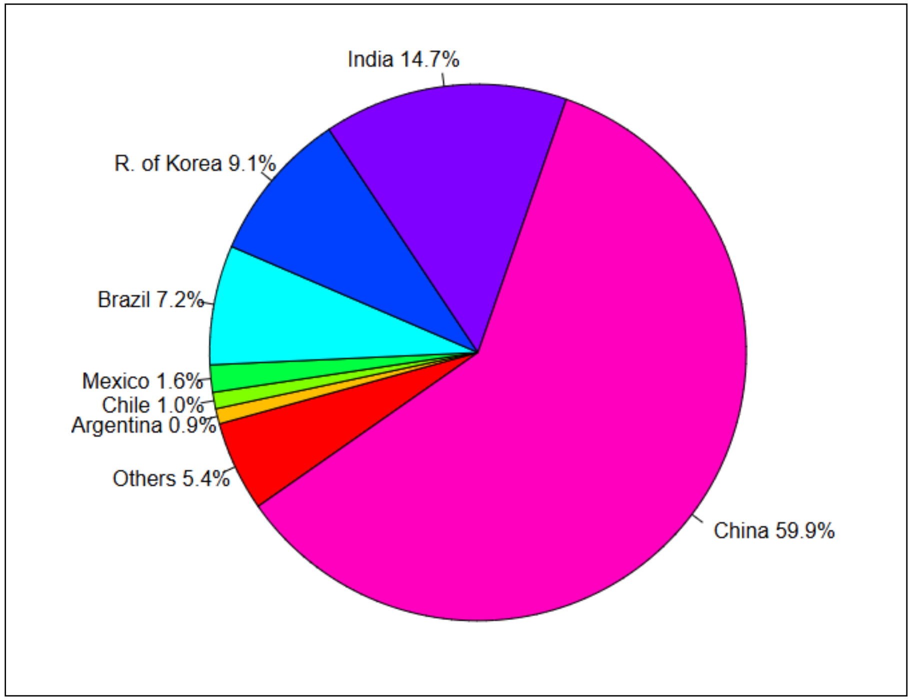
A **project** refers to specific activities or interventions designed to reduce emissions compared to this baseline. For example, a project in a developing country might involve building a wind farm, replacing a coal-fired plant. This switch directly reduces CO_2 emissions compared to the baseline scenario, where the coal plant would have been operating.

The project generates **carbon credits** by demonstrating that emissions are lower than they would have been under the baseline scenario. Each carbon credit is equivalent to one ton of CO_2 equivalent that has been effectively prevented from entering the atmosphere. These carbon credits are tangible, tradable units that can be sold to other countries or companies needing to meet their own emissions reduction targets.

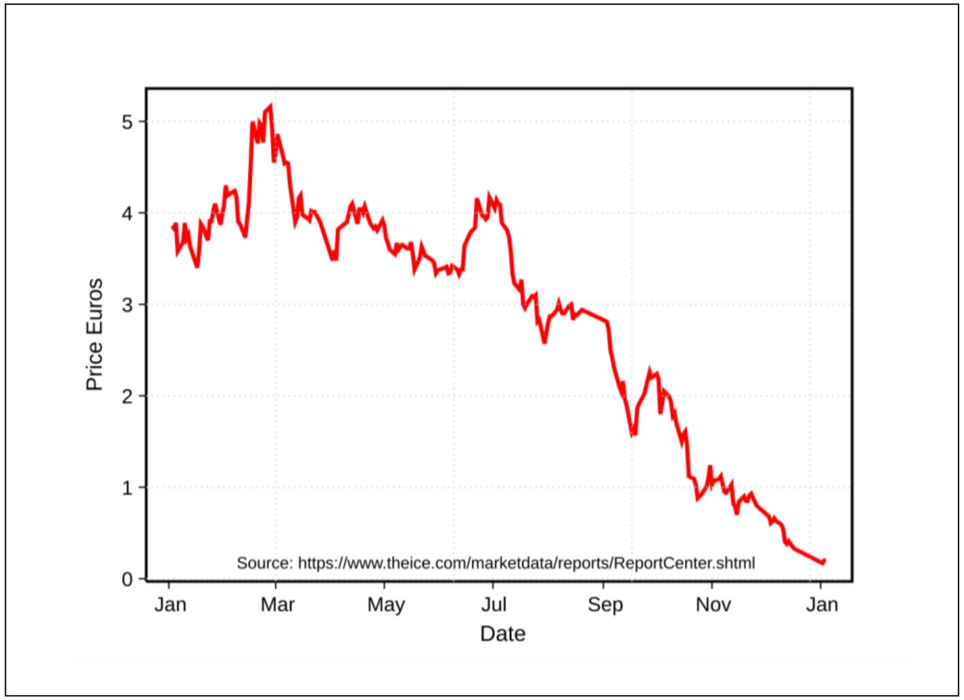
The Kyoto Protocol – The baseline-and-credit model (2/3)

The CDM enables countries with emission reduction commitments to **implement projects in developing nations**. These projects earn **Certified Emission Reduction (CER)** credits.

Examples include renewable energy initiatives like wind farms, rural electrification projects using solar panels, or energy efficiency measures such as the adoption of efficient cookstoves.



CERs by country of origin – October 2012.[1]



CERs monthly spot prices in 2012.[1]

[1] https://en.wikipedia.org/wiki/Certified_emission_reduction

The Kyoto Protocol – The baseline-and-credit model (3/3)

JI, in contrast, focuses on projects implemented **between developed countries** with emission reduction obligations under the Kyoto Protocol. It generates **Emission Reduction Units (ERUs)** through initiatives in host countries that also have emissions caps.

JI has been particularly impactful in Eastern Europe (and post-Soviet states), where countries with surplus emissions capacity from industrial declines in the 1990s hosted projects that attracted investment and improved technology.

The main difference between CDM and JI lies in **their focus and their effect on development**. CDM targets developing countries, promoting sustainable development alongside emissions reductions. JI, on the other hand, operates within the boundaries of capped systems in developed countries, ensuring a 'zero-sum' transfer of allowances within these limits, which made the mechanism more reliable compared to the CDM. However, JI had a smaller global reach than CDM.

Concerns regarding CDM and JI project-based mechanisms

Critics argue that the CDM and JI **diverts attention away from reducing emissions domestically**, as it allows countries to meet their targets by investing in projects abroad. Moreover, the quality of some CDM projects, like large hydroelectric dams, caused significant environmental disruption and social displacement.

For example, the Allain Duhangan Hydroelectric Project (192 MW) in India, registered under the CDM in 2005, faced significant criticism.

It diverted crucial water resources, damaged local ecosystems, and disrupted livelihoods without providing adequate compensation or consultation to affected communities.

View of the plant.[1]

[1] https://ejatlas.org/conflict/allain-duhangan-hydropower-project-india

The Kyoto Protocol – The cap-and-trade model (1/2)

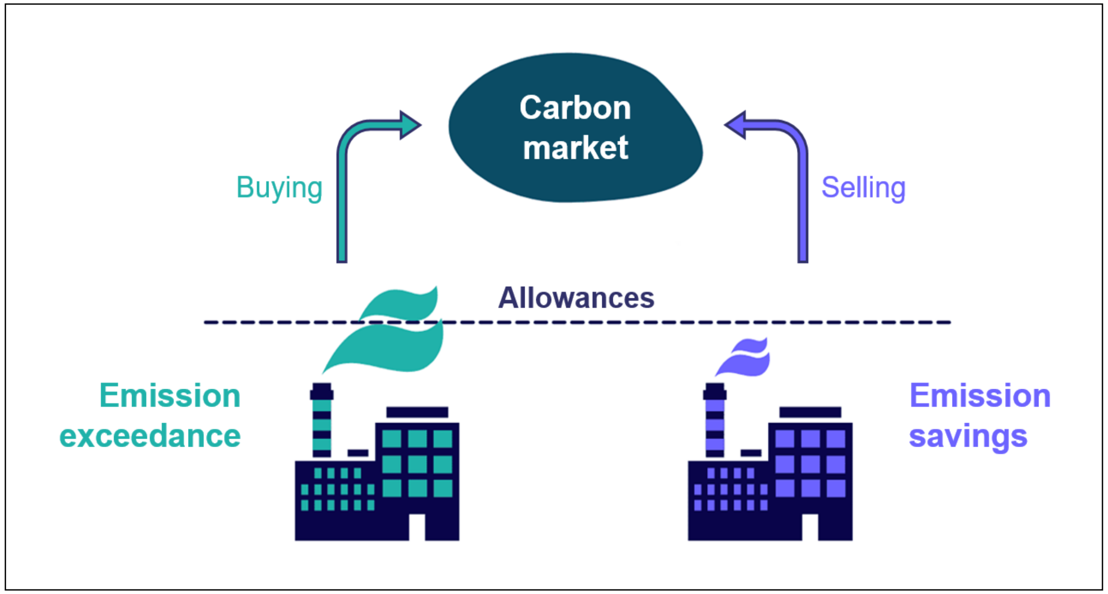
The third market mechanism of the Kyoto Protocol is the **emissions trading**, which operates under a **cap-and-trade** model.

In this system, countries or companies are assigned a **cap** or limit on their emissions. This cap represents the **right to emit** a certain amount of CO_2 (or other GHGs).

If entities *emit below* their assigned cap, they create **surplus allowances** (unused rights to emit) which can be measured in tons of CO_2 equivalent. These surplus allowances can be sold to other entities that exceed their emission caps.

If an entity *exceeds* its cap, it must either **reduce emissions** to meet the limit or **buy allowances** from others who have surplus. This creates an incentive to lower emissions, as it can be more cost-effective to reduce emissions than to purchase allowances.

The Kyoto Protocol – The cap-and-trade model (2/2)



Allowances trading system.[1]

The cap-and-trade system ensures the **same net effect** on the atmosphere by maintaining a fixed overall limit on emissions, as long as each traded allowance represents a one-ton reduction in emissions below the cap and is retired after use.

Allowances trading provides companies with flexibility. For instance, they can **purchase allowances** during periods of higher emissions, or **sell surplus allowances** during periods of lower emissions, without exceeding the overall cap.

The allocation of allowances, their purchase during auctions, and their trading will be discussed in detail later in the lesson.

[1] https://www.hellocarbo.com/blog/communaute/prix-du-carbone/

II. The European Emissions Trading System (EU ETS)

The rise of Emissions Trading Schemes (ETS)

Despite the initial push for market-based solutions, the U.S. Senate never ratified the Kyoto Protocol. In 2001, President George W. Bush officially withdrew U.S. support for the agreement.

However, this setback did not prevent many countries and regions from implementing or planning their own **Emissions Trading Schemes (ETS)**, recognizing them as effective tools for mitigating climate change outside the international framework.

The chronology of the European ETS

In 2005, the Kyoto Protocol came into force, coinciding with the launch of the **European Emissions Trading System (EU ETS)**, the first regional ETS in the world. Based on the cap-and-trade principle, it initially targeted the energy sector and heavy industries.

In 2008, the **EU ETS** incorporated Kyoto mechanisms, allowing European companies to use credits from CDM and JI projects.

From 2012 onward, the scope of the **EU ETS** expanded to cover additional sectors, such as industry, agriculture, aviation and even **maritime transport in 2024**. Other reforms included the introduction of an EU-wide emissions cap.

2005 - 2007	2008 - 2012	2013 - 2020	2021
Phase I	**Phase II**	**Phase III**	**Phase IV**
Pilot phase: Learning by doing.	Stabilization: 1st commitment period under the Kyoto Protocol.	European harmonization and consolidation.	Structural reform and further development.

Overview of EU ETS phases.

The development of ETS around the world (1/2)

During the 2010s, ETS proliferated globally:

- **New Zealand** (2008)**:** Launched its ETS, covering multiple sectors, including agriculture;
- **United States**: Several states introduced regional systems, such as the Regional Greenhouse Gas Initiative (RGGI) (2009) in the northeast;
- **Tokyo** (2010) and **South Korea** (2015): Implemented ETS at the local and national levels, respectively;
- **China**: Began pilot ETS projects in various provinces starting in 2013, laying the groundwork for its national system, which officially launched in 2021.

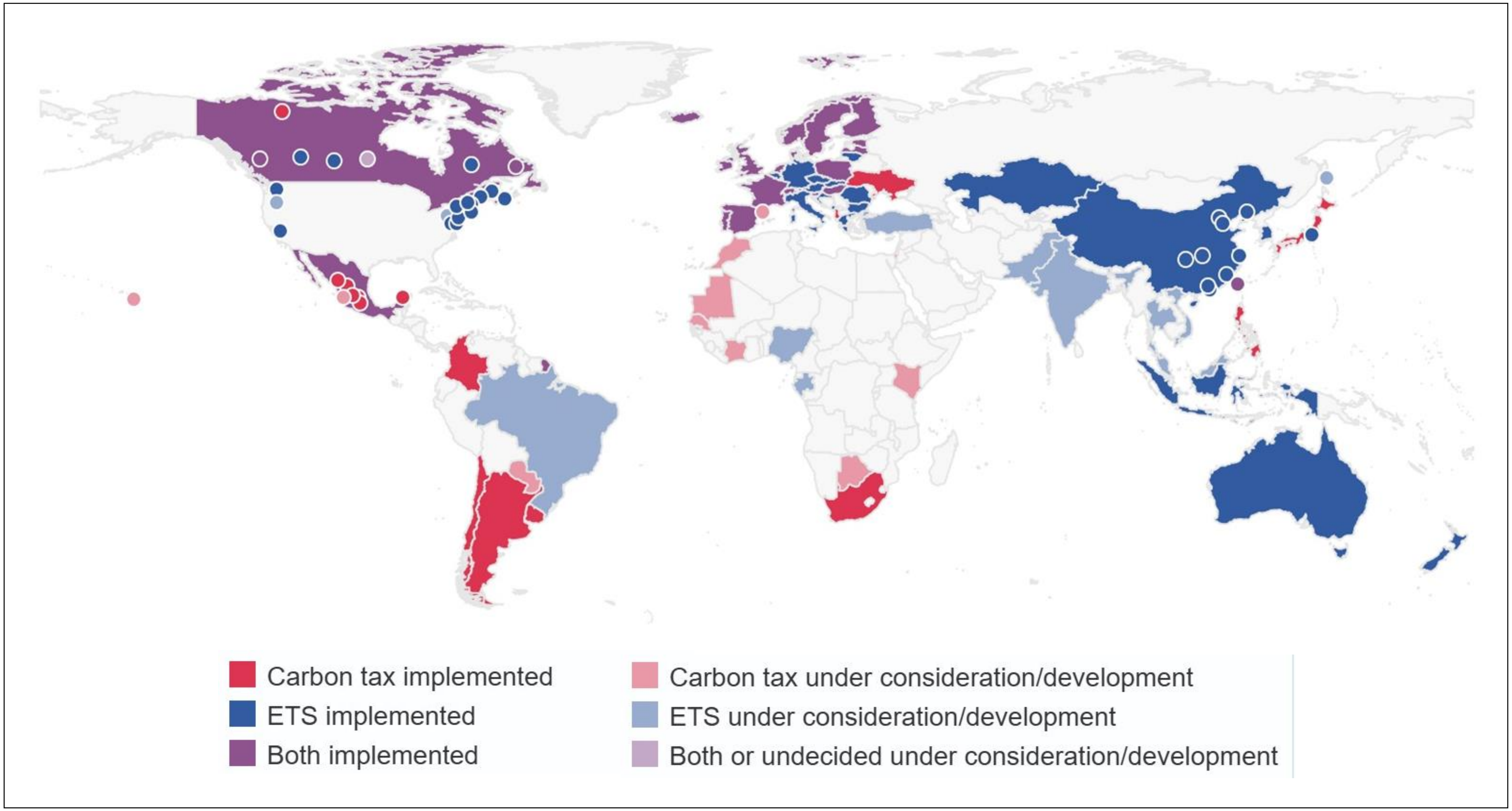
Beyond ETS and carbon taxes, innovative carbon pricing mechanisms have been developed:

- **Canada**: A baseline-and-credit system was introduced in British Columbia;
- **Australia**: The Safeguard Mechanism operates as a baseline-and-offset system.

*Excess emissions are compensated through external projects.

The development of ETS around the world (2/2)

As of recent years, over 20% of GHG emissions are covered by carbon pricing, according to the World Bank.



Compliance carbon pricing tools around the world, 2024.[1]

[1] https://carbonpricingdashboard.worldbank.org/compliance/instrument-detail

Concerns regarding the EU ETS (1/2)

Phase I of the EU ETS (2005–2007) is often criticized as a key example of the emissions trading system's initial design flaws. Nearly all allowances (over 95%) were allocated **for free** to emitters in 2007, based on historical emissions (grandfathering).

This approach aimed to facilitate the integration of industries into the system but often overestimated actual emissions, resulting in a **significant surplus of allowances**.

Historic of EU carbon allowance price (EUR).[1]

[1]https://tradingeconomics.com/commodity/carbon

Concerns regarding the EU ETS (2/2)

Additionally, allowances from Phase I could not be carried over to Phase II (2008–2012). This lack of flexibility led to a rush to sell surplus allowances as the phase ended, further driving down prices.

Moreover, the economic slowdown in the late 2000s caused emissions to be lower than expected, exacerbating the surplus and reducing demand for allowances.

The primary goal of emissions trading systems like the EU ETS is to **internalize the cost of GHG by creating a financial incentive for industries to reduce their emissions**. The price of allowances shows the cost of emitting carbon. When the price is low, companies have little to no financial motivation to invest in cleaner technologies or improve energy efficiency.

Why was overallocation allowed?

The EU ETS was a new and complex mechanism, and policymakers prioritized gaining industry acceptance over creating a strict cap. Allowing overallocation and free allowances was seen as a way to **prevent resistance from key sectors**.

Member states were also involved in determining their national allocation plans, leading to lobbying and lenient caps to favour domestic industries.

At the time, there was limited reliable data on actual emissions, leading to overestimation when setting caps.

The issues in Phase I led to important changes in later phases:

- Phase II: Introduced stricter caps, more accurate allocation, and integration with CDM and JI mechanisms.
- Phase III: Shifted to auctioning allowances instead of giving them for free, applied a single EU-wide cap, and created tools like the **Market Stability Reserve (MSR)** to handle surplus allowances.

The Market Stability Reserve (MSR)

The MSR began operating in January 2019 in response to the oversupply of allowances in the EU ETS. It has been designed to **automatically adjust the supply of allowances** based on certain levels of surplus and/or carbon prices. It is essentially a tool to help balance the market by **withdrawing allowances from circulation** when there are too many available, and **reintroducing them** when there are too few, helping to stabilize the market without directly manipulating carbon prices.

In 2018, the revision of the EU ETS included a significant increase in the **MSR intake rate**, which refers to the percentage of surplus allowances that are automatically placed in the MSR. This intake rate was **doubled from 12% to 24%** until 2023. Additionally, the **minimum number** of allowances placed into the MSR was raised from **100 million to 200 million**.

Since its implementation, the MSR has **not substantially raised carbon prices**, with average spot prices only slightly increasing. However, it is important to note that **carbon prices could have fallen significantly without the MSR**, as it has helped prevent a further oversupply of allowances from depressing the market. The long-term effectiveness of the MSR remains to be seen, as it will depend on how effectively it can respond to future market imbalances.

The risk of carbon leakage

Carbon leakage happens when companies move their production to countries with weaker climate policies to avoid the costs of emission regulations, like those under the EU ETS.

The main reason for carbon leakage is cost. If climate policies in one region, such as the EU, make production more expensive, companies in industries that use a lot of energy or produce high emissions might relocate to countries with fewer environmental rules.

High-risk sectors for carbon leakage account for over 45% of the EU's emissions in industries covered by the Emissions Trading System (ETS). These sectors include cement, aluminium, iron and steel, fertilizers, electricity and hydrogen.

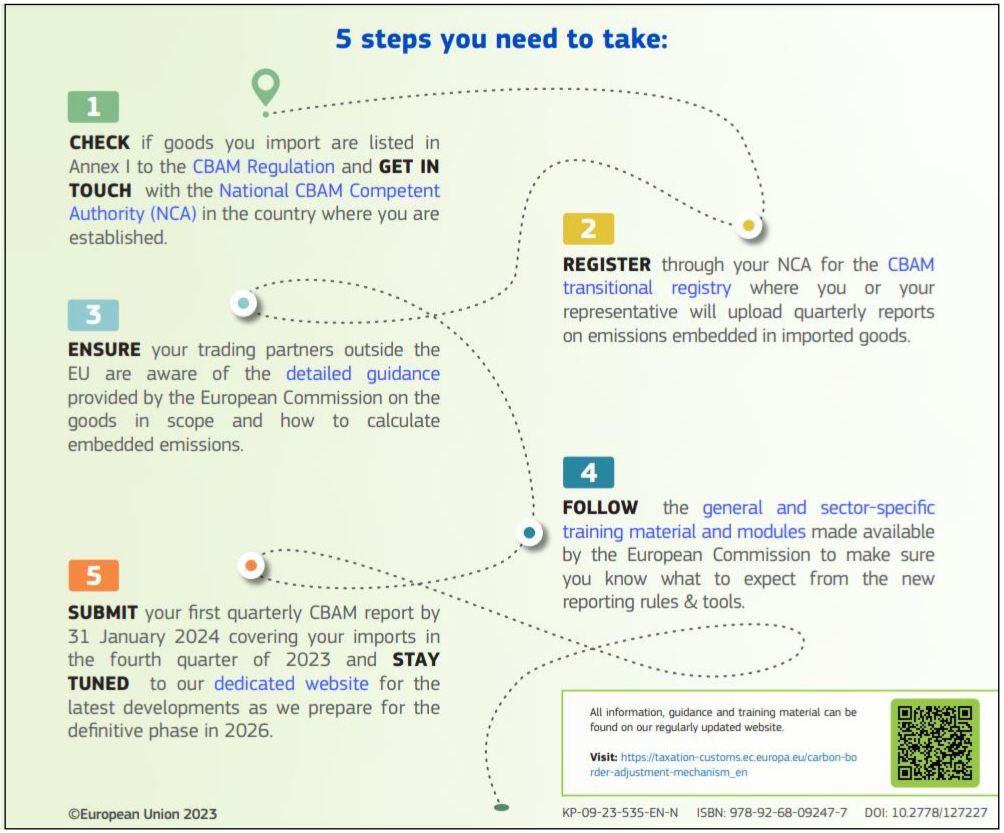
To stop carbon leakage and protect the competitiveness of its industries, the EU has established the **Carbon Border Adjustment Mechanism (CBAM).**

The Carbon Border Adjustment Mechanism (CBAM)

The CBAM is the world's first system designed to put a fair price on the carbon emitted during the production of carbon-intensive goods imported into the EU.

Starting in **2026**, EU importers of goods in CBAM sectors will need to:

- Register in the CBAM system;
- Declare the emissions produced during the manufacturing of imported goods;
- Annually, importers must purchase and submit certificates equivalent to the emissions generated during production. These certificates will be priced based on the weekly primary ETS market price.



CBAM: Checklist for EU importers.[1]

Free allowances currently provided to ETS sectors under the EU system will be gradually phased out for CBAM sectors to ensure fair competition.

[1] https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

III. The auctioning and trading of EU Allowances (EUAs)

EU Allowances (EAUs) – Allocation and auctioning (1/2)

European Union Allowances (EUAs) represent the right to emit GHG. Some companies in sectors like industry and heating, which are regulated by the EU ETS, receive **free allowances** from the European Commission. However, this free allocation has been gradually reduced in **Phase IV** of the EU ETS (2021-2030). Since **Phase II**, electricity generators no longer receive free allowances, except in certain Member States needing to modernize their power sector.*****

Since 2013, **auctioning** has been the main method for regulated companies to purchase EUAs under the EU ETS.

*A reserve of allowances is established for new entrants and for the expansion of existing installations.

EU Allowances (EAUs) – Allocation and auctioning (2/2)

For the 2021-2030 period, **up to 57%** of EUAs will be auctioned. The remaining allowances will be allocated for free to prevent carbon leakage.

Of the EUAs to be auctioned:

- **90%** is distributed among all Member States based on their historical emissions at the start of the system. This ensures that countries with higher historical emissions are allocated more allowances to auction.
- **10%** is reserved for 16 Member States to support solidarity. These 16 countries are generally those with lower-income economies or a higher need for financial assistance to transition to low-carbon economies. These Member States include countries like Bulgaria, Croatia, Estonia, Latvia, Lithuania, Hungary, Poland, Romania, Slovakia, Slovenia, and others.

EEX as the common auction platform (1/2)

The Auctioning Regulation outlines the rules governing the timing, administration, and other aspects of the auctioning process under the EU ETS. These rules ensure consistency and transparency in the allocation of allowances.

The **European Energy Exchange (EEX)**, based in Leipzig, Germany, serves as the common auction platform. It works alongside its **clearing system**, **European Commodity Clearing AG (ECC)**. The **EEX** is responsible for conducting the auctions, while the **ECC** ensures the financial settlement and clearing of transactions.

In simpler terms, the EEX handles the bidding process, while the ECC handles the financial transactions and ensures that the buying and selling of allowances are executed smoothly.

EEX as the common auction platform (2/2)

On **November 4, 2020**, the **European Commission** signed a five-year contract with EEX and ECC. This contract can be extended for up to seven years, as agreed upon in the joint procurement agreement between the Commission and Member States.

EUAs are auctioned by **28 countries**, including **25 EU Member States** as well as **Iceland**, **Liechtenstein**, and **Norway**. These countries participate in a **common auction platform**, which was selected through a joint procurement procedure.

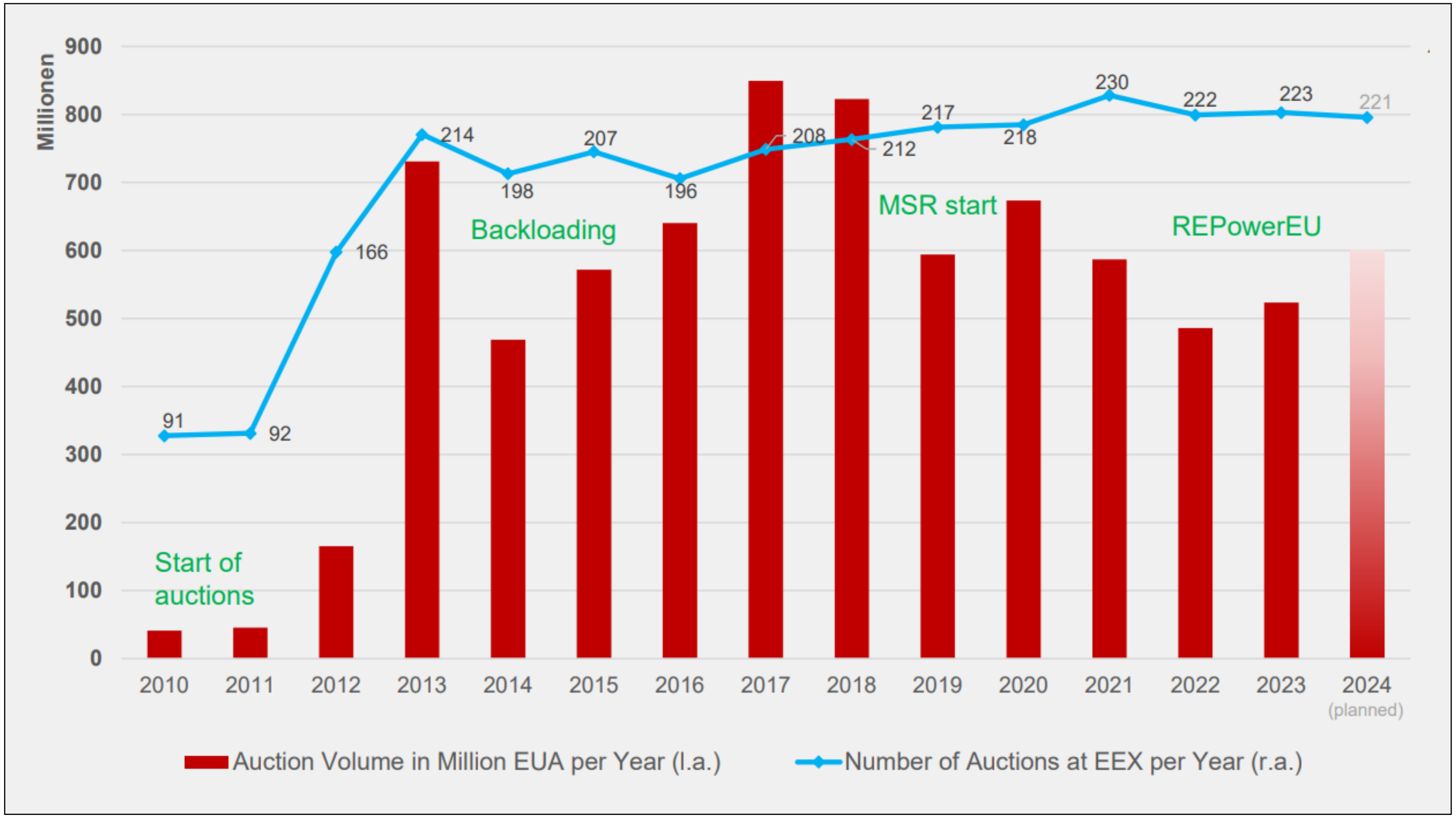
To clarify, **each participating country** receives a certain amount of EUAs and is responsible for auctioning them. The **agents** answering to the auction are typically entities designated by each country (such as a national auction body or another authorized representative). These agents manage the auction process for their respective country's allowances, while the EEX platform facilitates the broader auctioning process across all participating countries.

Why a common exchange trading platform?

A common exchange trading platform offers key advantages:

- It enhances transparency by providing recognized **reference prices** and **publishing market data**, including prices and volumes.
- It pools liquidity by attracting a large number of trading participants to a single, unified system.
- It enhances stability and security through the high degree of automation in standardized trading and settlement processes.
- It eliminates counterparty risks since clearing and settlement are managed by the clearing house, ECC.
- It ensures equal treatment and non-discrimination by adhering to strict regulatory standards and maintaining **anonymity for participants**.

EEX auctions for the EU ETS



EEX: Over 2,800 successful auctions for the EU ETS to date.[1]

[1]https://www.eex.com/fileadmin/EEX/Downloads/Markets/Environmentals/20240905_EU_ETS_-_Participation_in_the_auctions_and_outlook_secondary_market.pdf

The participation to the auctions market

Eligibility to participate in EUAs auctions is governed by the Auctioning Regulation. The following categories of participants are permitted:

- **Compliance buyers**: These include operators of stationary installations (e.g., power plants and industrial facilities), aircraft operators, and shipping companies;
- **Business groupings of compliance buyers**: Groups representing multiple compliance buyers can pool resources and bid collectively;
- **Investment firms and credit institutions**: These entities may act as intermediaries or trade allowances for financial purposes;
- **Other intermediaries**: Specifically authorized entities, approved by the participant's home Member State (e.g. Vertis, STX Group, South Pole).

Participants must meet certain admission requirements under EU and EEX regulations, including:

- **Establishment in the EU**: This requirement applies to all participants except compliance buyers, who may be located outside the EU;
- **Nominated registry account**: Participants must hold an account in the Union Registry, which tracks the ownership and transfer of allowances;
- **Nominated bank account**: Participants need a designated bank account.

The calendar of the auctions market

The auction calendar is determined by EEX in compliance with the requirements of the Auctioning Regulation. **It specifies the timing, frequency, and distribution of auction volumes.**

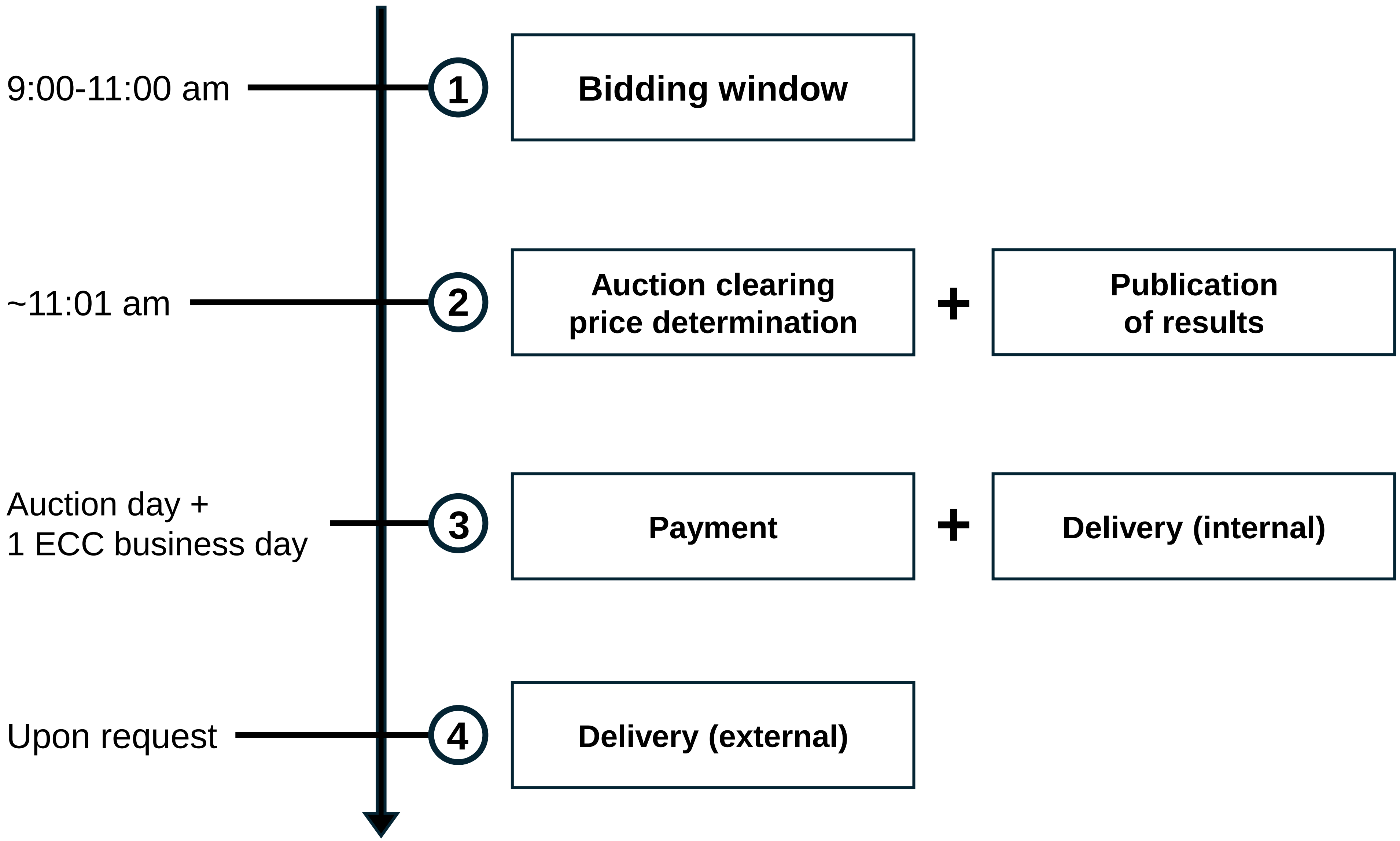
The calendar includes the dates and volumes of EUAs **(**and aviation allowances) to be auctioned. These volumes are calculated annually based on the provisions of the ETS Directive and may be further adjusted by the Market Stability Reserve.

Allocations for special mechanisms, such as the Innovation Fund and the Modernization Fund, are also incorporated into the calendar.

To ensure accessibility and transparency, the auction calendar and daily auction results, including prices and volumes, are published on the EEX website.

Overview of the auction process

The auction process can be structured into **four chronological stages**. Let us examine each one.



Stages of the auction process (1/3)

1) 9:00-11:00 am

- **Bidding Window**
  - Products available:
    - T3PA*****: Spot EUAs for Phases 3 and 4 of the EU ETS. A lot refers to the unit size for bidding, and each lot contains **500 EUAs**. A EUA represents the right to emit one ton of CO_2 equivalent, so each lot corresponds to **500 tons of CO_2 emissions**. In the auction, you can bid in multiples of 500;
    - EAA3*****: Spot EU Aviation Allowances (EUAAs) for Phases 3 and 4 of the EU ETS. Like EUAs, EUAAs have a lot size of 500 allowances, each representing one ton of CO_2 equivalent emissions.
  - Bidding rules:
    - Participants could submit, modify, or withdraw bids during the bidding window;
    - Bids could be placed directly through the Auction System, indirectly via the EEX Helpdesk, or through an intermediary;
    - Bids are submitted **anonymously**, meaning participants cannot identify who has placed a bid, but they can still view the bids in the system.

*T3PA and EAA3 stand for 'Trading phase 3 Primary Auction' and 'European Aviation Auction phase 3', respectively.

Stages of the auction process (2/3)

2) ~11:01 am

- **Auction clearing price determination**:
  - Bids are ranked in descending order based on the bid price.
  - In cases of tied bids, an algorithm is used for random selection to determine the order;
  - Bid volumes are accumulated, starting from the highest bid;
  - **The clearing price is set at the point where the total bid volumes meet or exceed the number of allowances available for auction**. This price applies to all successful bidders.
- **Publication of results**:
  - The main auction results are published both in the Auction System and on the auction platform's website.

Stages of the auction process (3/3)

3) Auction day + 1 ECC business day

- **Payment**:
  - Funds are transferred from the Clearing Member of a Trading Member to the ECC.
  - The ECC then transfers the payment to the Auctioneer.
- **Delivery (internal)**:
  - Allowances are transferred within the ECC Union Registry Account from the Auctioneer (seller) to the Trading Member (or an intermediary) who successfully secured allowances in the emissions auction (buyer).

4) Upon request

- **Delivery (external)**:
  - Allowances are transferred from the ECC Union Registry Account to the Union Registry Account of the Trading Member.

An example of the auction clearing price (1/2)

Here is a list of different bidders (A to F), showing their bid prices and the corresponding volumes of EUAs:

Bidder	Price	Volume
A	€62	500,000
B	€66	600,000
C	€64	300,000
D	€65	800,000
E	€65	500,000
F	€75	10,000
Total:		2,710,000

How to conduct an auction for 1 million EUAs?

An example of the auction clearing price (2/2)

When arranged in descending order based on the bid price, the list is as follows:

Bidder	Price	Volume	Allocation
F	€75	10,000	10,000
B	€66	600,000	600,000
D	€65	800,000	390,000
E	€65	500,000	0
C	€64	300,000	0
A	€62	500,000	0
Total:		2,710,000	**1,000,000**

In this example, Bid volumes are accumulated, starting from the highest bid, until the total bid volumes meet or exceed the number of allowances available for auction. The clearing price is then set at this point, and this price applies to all successful bidders. **Bidders D and E are sorted randomly** using an algorithm.

Bidder D determines the clearing price as the last successful bidder, with the allowances allocated at an auction clearing price of €65 per allowance.

Trading in allowances: the secondary market

When EU countries and companies release EUAs into circulation through auctions, these allowances can be freely traded. Any individual or company with an account in the EU registry can participate in buying and selling EUAs, **regardless of whether they are covered by the EU ETS**.

Trading on the carbon market can occur either directly between a buyer and seller or through stock exchanges and intermediaries. While all EUAs have the same characteristics and are interchangeable, **the trading products differ based on delivery time and payment terms.** These products include spot allowances, futures contracts, and options.

The secondary market – Available markets

- **Spot market:** EUAs are bought and sold for immediate settlement. In practice, that means the **transaction must be completed within three days**.

- **Futures market:** Buyers and sellers agree on a **price and delivery date in the future**, with payment typically made on the delivery date. The most commonly traded futures are December contracts, as these align with the annual compliance cycle of the EU ETS. Companies use these contracts to cover their emission obligations for the upcoming year, and they are settled and delivered around mid-December each year.

  In futures trading, traders can also avoid receiving the actual allowances by closing their position before the delivery date. To do this, they make a second trade that cancels the first one. The difference in price between the two trades is paid in cash, instead of delivering the allowances.

- **Options market**: Participants **trade the right, but not the obligation, to buy or sell EUAs at a predetermined price** before the expiration date.
  - A call option gives the buyer the right to purchase allowances, providing an opportunity to profit if prices rise.
  - A put option gives the buyer the right to sell allowances, offering protection if prices drop.

Auctions market and secondary market – Differences

	Auctions market	Secondary market
Authorized	Operators of stationary installations, aircraft operators and the maritime industry, as well as investment firms, credit institutions and business groupings (under special conditions)	Every entity meeting the EEX membership preconditions
Registry account	Union registry account	Union registry account, but only required in case of physical delivery
Procurement	EUA auctions (max. 1/day), buy side only	Continuous exchange trading, buy and sell
Minimum lot size	500 EUAs	1,000 EUAs
Trading window	Almost every exchange trading day 9:00 – 11:00 CET	Every exchange trading day 8:00 – 18:00 CET
Markets	Spot	Spot, Futures, Options
Capital cost	Payment after the auction	Derivatives: payment can be made after the contract expires, often near the compliance deadline

IV. The history of EUA pricing and its impact on fossil fuel power plants

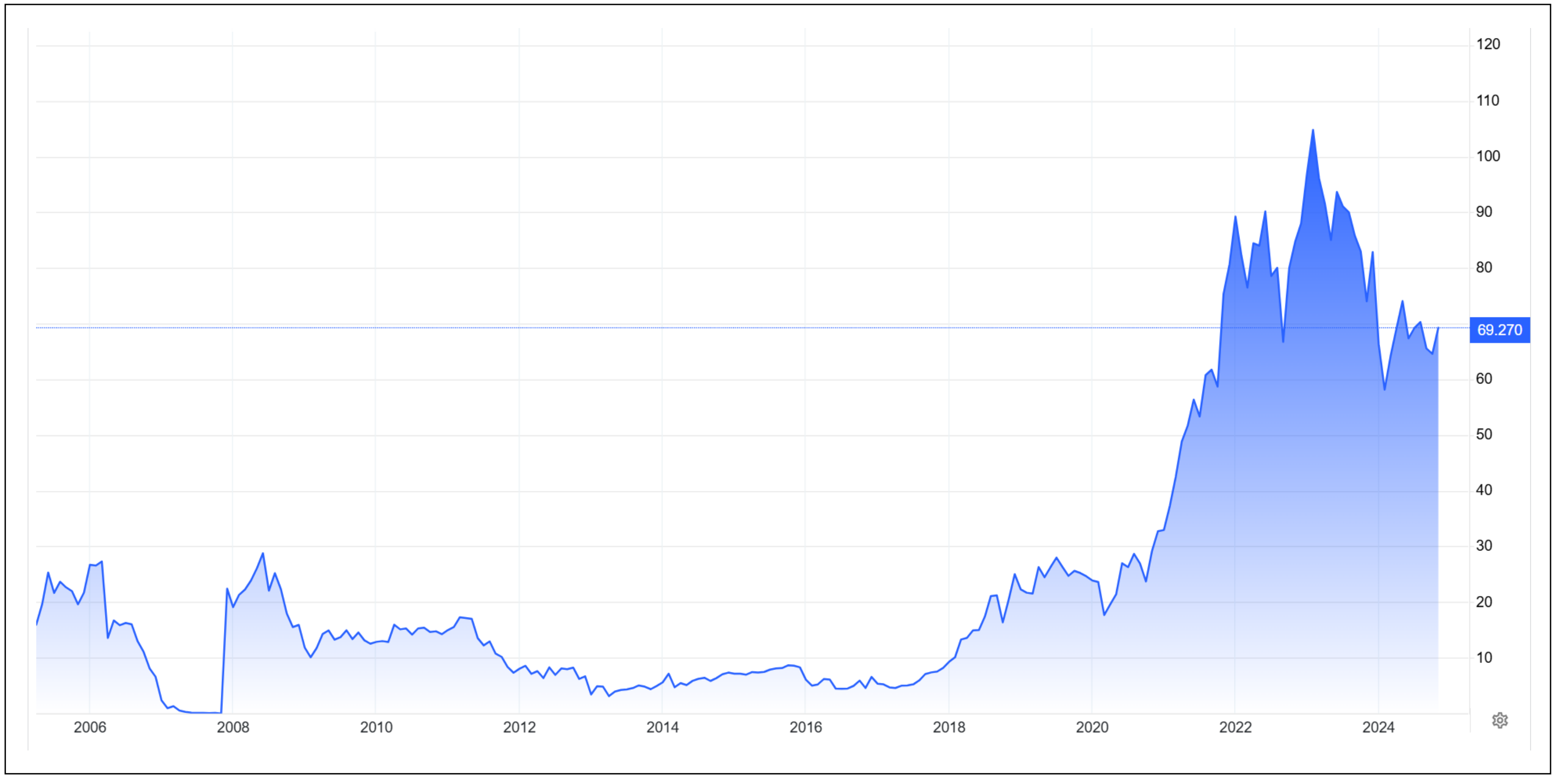
What are the drivers of EUA prices in history? (1/2)

Let us revisit the EUA trading price curve we saw earlier and briefly explain the variations in EUA prices from 2005 to the present.

We can distinguish two distinct periods:

1) **Early phases (2005–2020):** oversupply and consistently low prices

2) **Post-2020:** steady rise in EUA prices



Historic of EU carbon allowance price (EUR).[1]

[1]https://tradingeconomics.com/commodity/carbon

What are the drivers of EUA prices in history? (2/2)

1) Early Phases (2005–2020):

- **The financial crisis (2007–2008)** reduced industrial activity, energy consumption, and emissions. This drop in EUA demand pushed prices near zero during this period.
- In the initial three phases, the EU ETS focused on regulatory setup. Over-allocation of allowances led to a significant surplus, causing prices to remain below €30.

2) Post-2020:

- EUA prices rose steadily following several revisions:
  - Under the revised MiFID II regulation in 2018, EUAs were classified as financial instruments, attracting participation from hedge funds and investment funds.
  - Introduced in 2019, the Market Stability Reserve (MSR) allowed regulators to withdraw excess allowances from the market, tightening supply and helping prices recover.
- Between 2021 and 2023, EUA prices stabilized around €80/tCO_2, driven by increasing demand and reduced supply.

The impact of rising EUAs prices on high-carbon technologies

Could the post-2020 price increase make fossil fuel power plants without carbon capture and storage (CCS) economically unviable?

Let us refer to Dominique Finon's March 2017 note[1] to address this question.

The goal of Finon's analysis is to **determine the carbon prices that would make low-carbon technologies (LCTs) competitive with high-carbon technologies (HCTs)**. The LCTs studied in his note include coal-fired power plants with CCS and nuclear power plants, compared to HCTs such as natural gas combined-cycle gas turbines (CCGT) and coal-fired power plants, assuming a capital cost of 8% for the high-carbon technologies.

Explanation of the calculation:

- The carbon value of a low-emitting plant (such as a coal plant with CCS or a nuclear plant) is based on the emissions avoided when this plant replaces a higher-emitting alternative, like a coal or gas plant.
- At first, there is no price on carbon, and the low-carbon plant tends to have higher building costs compared to the one that emits more.

[1]https://static1.squarespace.com/static/54ff9c5ce4b0a53decccfb4c/t/592b93d720099e2f4b12042f/1496028121500/Finon+Note+carbon+price+and+LCT+competitive.pdf

Case studies of the Finon's analysis

The following scenarios explore the effects of **capital cost variations** on equilibrium carbon prices and the competitiveness of LCTs relative to HCTs:

- **Case 1 – Common capital cost (8%):**

  Both LCTs and HCTs operate with the same capital cost of 8%.

- **Case 2 – Government-guaranteed LCTs (5% capital cost):**

  A government guarantee lowers the capital cost for LCTs to 5%, while emitting technologies retain a capital cost of 8%.

- **Case 3 – Increased risk for LCTs (12.5% capital cost):**

  LCTs face higher perceived risks, raising their capital costs to 12.5%. HCTs maintain an 8% capital cost.

Results of the Finon's analysis

Ref. fossil tech.	Case 1		Case 2		Case 3	
-	Coal with CCS	Nuclear	Coal with CCS	Nuclear	Coal with CCS	Nuclear
Gas CCGT 8% capital cost	85 €/tCO_2	60 €/tCO_2	50 €/tCO_2	20 €/tCO_2	120 €/tCO_2	132 €/tCO_2
Coal plant 8% capital cost	35 €/tCO_2	30 €/tCO_2	20 €/tCO_2	12.5 €/tCO_2	54 €/tCO_2	60 €/tCO_2

Based on this analysis, we can determine CO_2 price thresholds that make HCTs economically unviable compared to LCTs. For example, a coal power plant with an 8% capital cost becomes uncompetitive compared to a coal power plant with CCS (also at 8% capital cost) if the CO_2 price reaches or exceeds €35/ton.

Similarly, a gas-fired CCGT plant with an 8% capital cost would no longer be economically viable compared to a coal power plant with CCS if the CO_2 price exceeds €85/ton. When compared to nuclear power with similar capital costs, a gas-fired CCGT plant becomes unviable at a CO_2 price of €60/ton.

Key takeaways of the Finon’s analysis

- **Capital cost sensitivity:**

  LCTs are very sensitive to capital costs because they usually require more investment to build compared to HTCs.

- **Impact of de-risking:**

  Government support, such as guarantees or financial safety measures (like long-term contracts or loan guarantees), can lower the carbon prices needed to make LCTs competitive.

- **Risk aversion:**

  If investors see LCTs as risky, it raises capital costs, making them less competitive and requiring higher carbon prices to balance the costs.

- **Subsidies as an alternative:**

  Instead of using de-risking measures, targeted subsidies can directly reduce investment costs and help make LCTs more competitive.

The Clean Spark Spread and Clean Dark Spread metrics (1/2)

The Clean Dark Spread (CDS) and Clean Spark Spread (CSS) are financial metrics used to **assess the profitability of electricity generation from coal-fired and gas-fired power plants**, respectively. Both metrics share the same formula but apply to different fuels:

$$\text{Spread (CDS or CSS)} = \text{Electricity price} - (\text{Fuel cost} + \text{Carbon cost})$$

where:

- ‘Electricity price’ is the market price at which electricity is sold;
- ‘Fuel cost’ is the cost of the fuel used for electricity generation (**coal for CDS and natural gas for CSS**);
- ‘Carbon cost’ is the cost of emissions, calculated as the carbon price per ton of CO_2 emitted.

The Clean Spark Spread and Clean Dark Spread metrics (2/2)

For example, let us assume a carbon price of €60/tCO_2 and a carbon intensity of 350 kgCO_2/MWh for a Gas CCGT. In this case, the carbon cost would be calculated as:

$$\text{Carbon cost} = 0.35\ \text{t}CO_2/\text{MWh} \times €60/\text{t}CO_2,$$

thus adding €21/MWh to the cost of electricity produced.

This increase makes electricity generation from gas plants less competitive compared to low-carbon technologies.

An example: Analysing the price increase from 2019 to 2021 using the CSS and CDS metrics (1/2)

Evolution of the CSS (50% efficiency) and the CDS (42% efficiency) for year-ahead futures contracts (Cal +1) in Europe.[1]

[1] https://www.creg.be/sites/default/files/assets/Publications/Studies/F2289FR.pdf

An example: Analysing the price increase from 2019 to 2021 using the CSS and CDS metrics (2/2)

The **surge in carbon prices in Europe**, which exceeded €60/tCO_2 in the first half of 2021, significantly impacted energy markets:

- Higher carbon prices made coal less competitive than gas for electricity generation. Since coal emits more CO_2 per MWh, it faced higher carbon costs under the EU ETS.

- During the first two quarters of 2021, the CSS was higher than the CDS for year-ahead futures contracts (delivery in 2022). This meant it was cheaper to produce electricity using natural gas than coal during this period.

- As natural gas prices continued to rise, coal regained its competitiveness for electricity generation. By the third quarter of 2021, the CDS surpassed the CSS for futures contracts, including deliveries for winter 2021-2022 and annual contracts for 2022.

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ELEC0018-1
Energy market and regulation

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Chapter 14 – Geopolitics and perspectives

Organization of this lesson

In this lesson, we will interweave factual descriptions of landmark events in the field of energy with discussions about the possible outcomes and the effects these events may have on international politics and the power struggles between nations.

Five landmark events will be discussed in five sections:

I. The rise of oil production in the Americas;

II. The rise of the liquefied natural gas industry and the end of the golden age of gas pipelines;

III. Prices of photovoltaic panels and batteries slashed by the Chinese manufacturing sector;

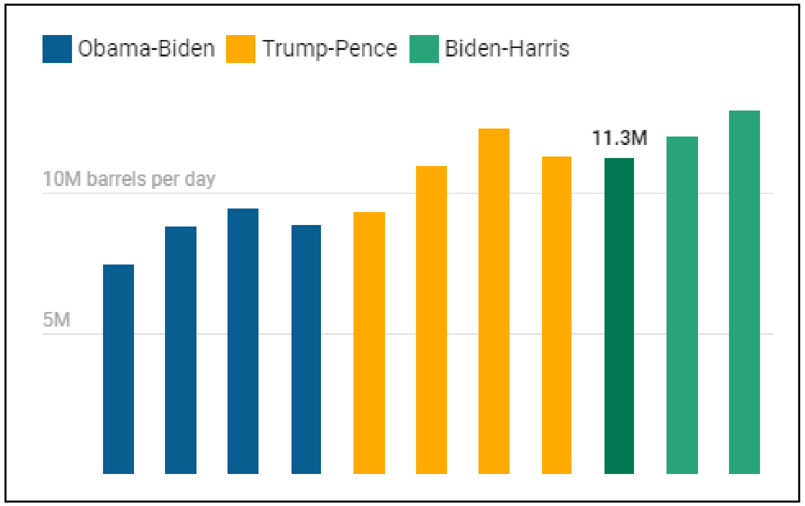
IV. Development of remote renewable energy hubs for the production of carbon-neutral energy-rich molecules;

V. Military strikes on energy infrastructures.

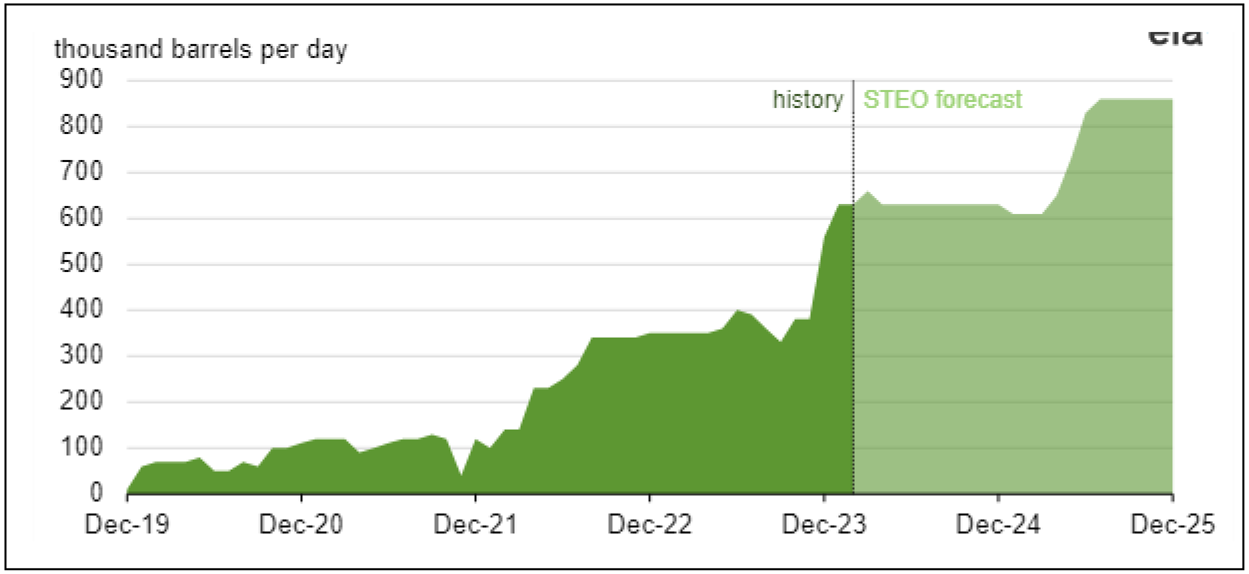
I. The rise of oil production in the Americas

Increase in oil production

Oil production is increasing in North America, Central America, and South America. The Americas are becoming net oil exporters!



How U.S. crude oil production increased over three presidencies.

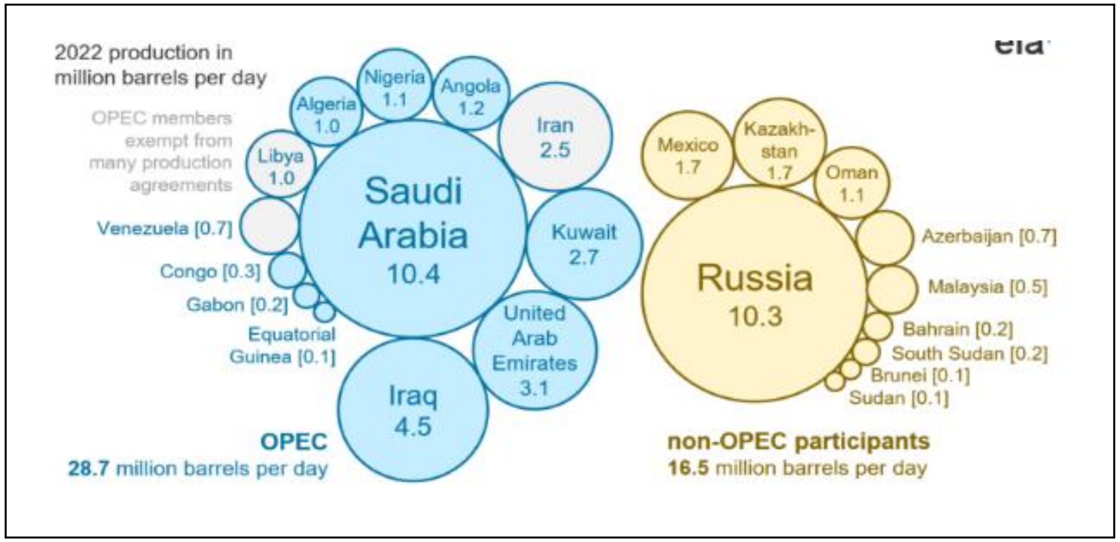


Guyana monthly gross oil production (Dec. 2019 – Dec. 2025).

Consequences of increased oil production (1/2)

The U.S. will likely intervene much less in the Middle East, as it will no longer depend on this region for its oil supply. It is important to note that events occurring in this area will still affect the prices that U.S. consumers pay for petroleum-based products, but they will have a minimal impact on the U.S. trade balance.

The power of OPEC+ to manipulate market prices through production cuts will significantly weaken. With the increase in oil production in the Americas, these countries are losing market share and their ability to maintain high oil prices, which could result in significant financial difficulties for them.



Total oil production from OPEC+.

Note: OPEC+ expands beyond the original OPEC members to include other major oil-producing countries, notably Russia, Mexico, and others.

Consequences of increased oil production (2/2)

OPEC+ says goodbye to its $100-a-barrel oil quest

By Javier Blas, Bloomberg • Last Updated: Jun 03, 2024, 10:52:00 AM IST

Synopsis
The OPEC+ cartel appears to be shifting away from its pursuit of $100-a-barrel oil, announcing a deal to gradually increase production through 2025. This move could lower oil prices and ease global inflation, impacting market dynamics and Saudi Arabia's financial outlook as it seeks to balance grandiose spending plans with declining oil revenues.

After relentlessly pursuing $100-a-barrel oil, the OPEC+ cartel has all but thrown in the towel. Whether the U-turn is a tactical retreat, or a strategic shift, is still unclear. But for now its impact would be the same: **Oil prices** would be somewhat lower and **global inflation** would ease.

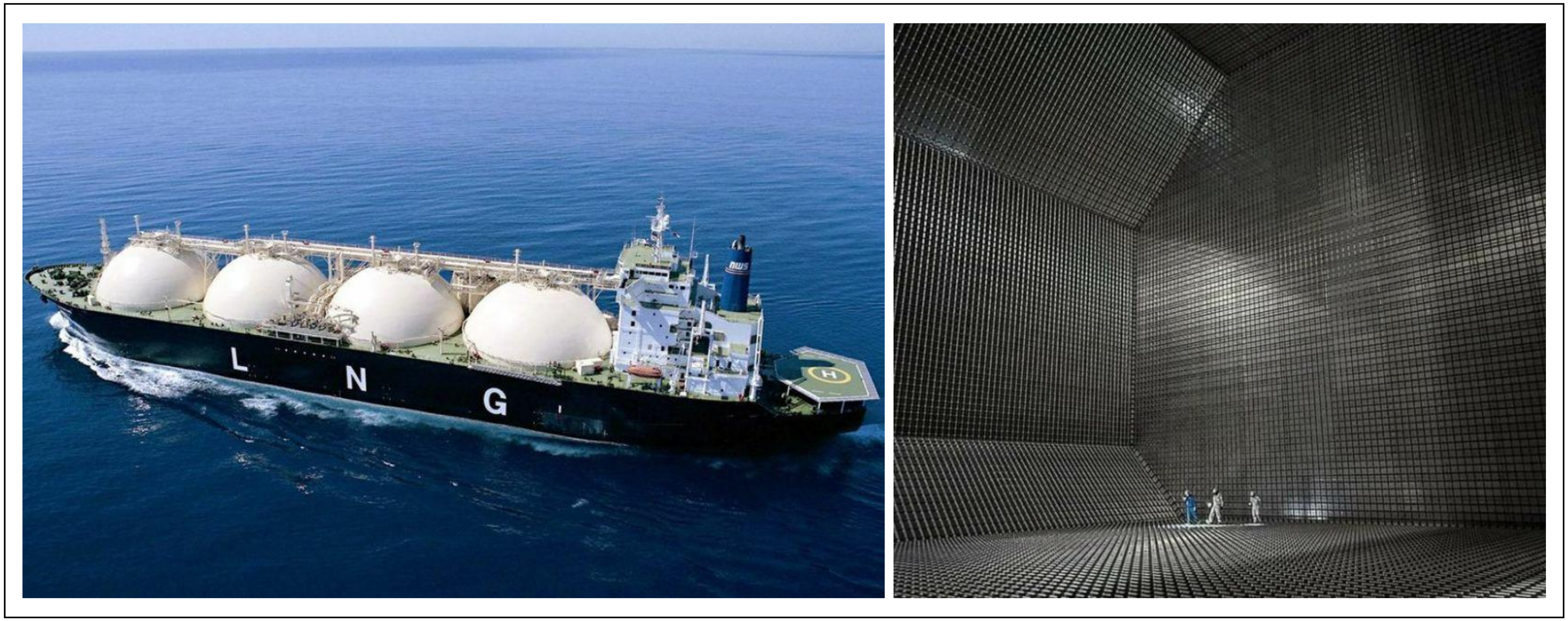
IMF flags weakening external balances for Saudi Arabia

Bloomberg - 05 Sep 2024, 01:43 PM

Avoiding a deficit requires oil prices to hit US$96 a barrel, more than US$20 above current levels.

II. The rise of the liquefied natural gas industry and the end of the golden age of gas pipelines

Liquefied natural gas (LNG) carrier

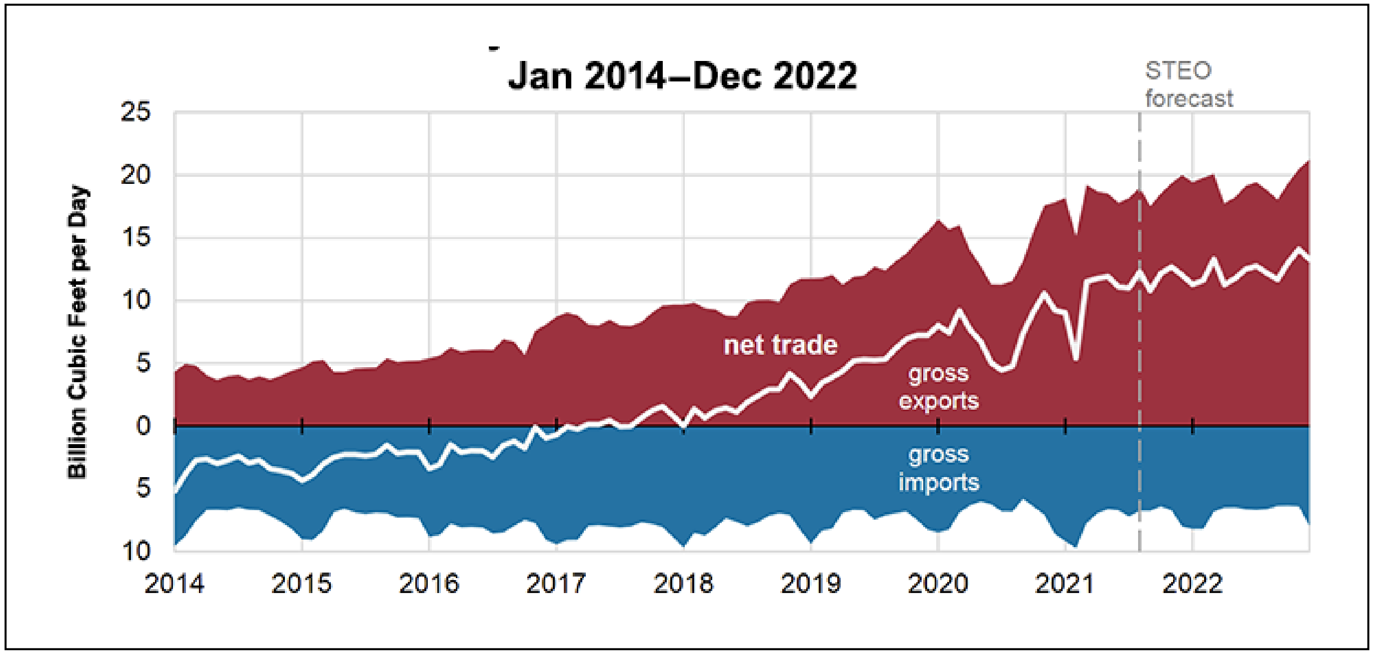


LNG carrier and the interior of one of its tanks.

Liquefied natural gas (LNG) rise driven by several factors

New and cost-effective gas extraction technologies (e.g., fracking) are enabling previously untapped regions to develop a large surplus of gas that can only be exported via LNG terminals.

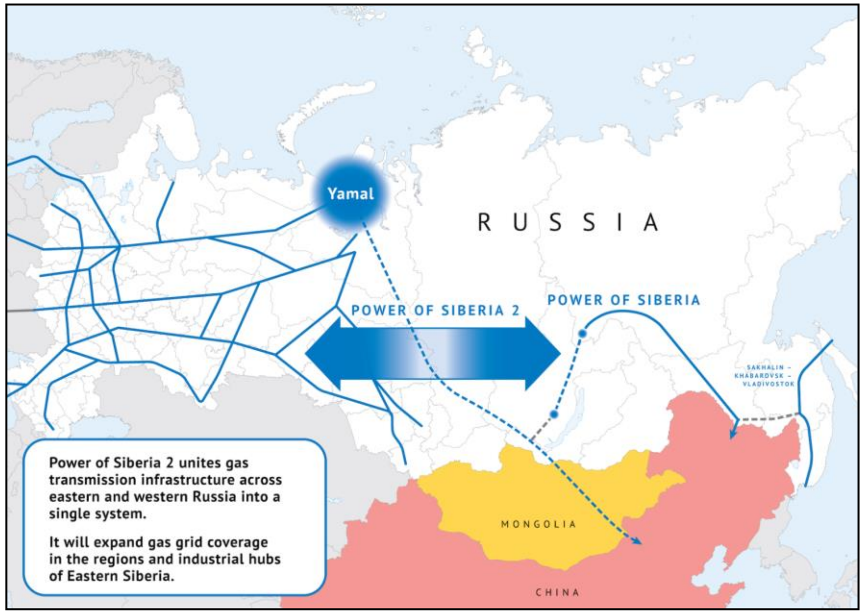
Since the energy crisis of 2022, when Russia partially interrupted gas supplies to Europe, countries are increasingly reluctant to rely on a single supplier country for significant volumes of their gas. They have more confidence in the LNG market, where it is easier to switch suppliers.



Monthly U.S. natural gas net trad (Jan. 2014 – Dec. 2022).

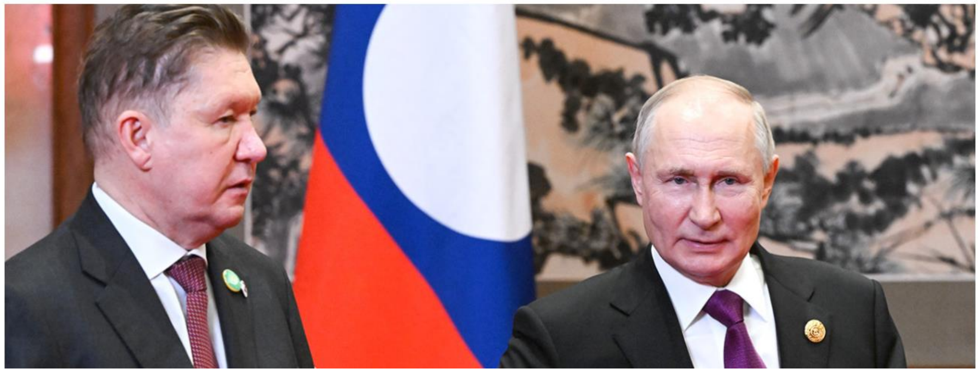
Source: U.S. Energy Information Administration, Short-Term Energy Outlook (STEO)

Power of Siberia 2 pipeline will probably never be built…



As Power of Siberia 2 Pipeline Stagnates, So Do Russia's Hopes for Pivoting Gas Exports Eastward

MT By Moscow Times Reporter
June 20, 2024



Consequences of the rise of the LNG industry

The concept of a nation having significant influence over other nations due to its gas wealth is likely to diminish.

LNG prices are expected to fall significantly. With the emergence of new players in the LNG market, gas prices are likely to converge towards the marginal production cost of the most expensive producer, which could result in gas-rich countries becoming less wealthy.

In terms of pricing, LNG will always be significantly more expensive than coal, which costs around 15 €/MWh. Currently, only gas transported by pipeline can compete with coal, despite coal's high CO_2 emissions. It is very likely that Asian countries will never switch from coal to gas for their electricity supply, even though coal-fired power plants emit much more CO_2 (900 kgCO_2/MWh of electricity produced compared to 400 kg for gas-fired power plants).

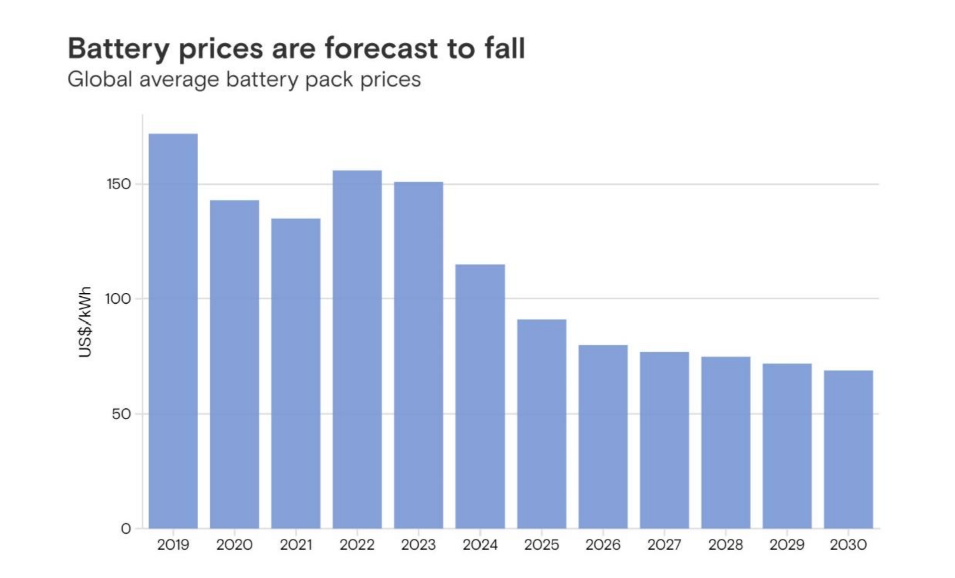
This situation could lead to **significant tensions between Asia and Europe regarding climate change negotiations.**

III. Prices of photovoltaic panels and batteries slashed by the Chinese manufacturing sector

Drop in the price of photovoltaic (PV) panels and batteries

PV panels now cost around €0.1/Wp. In China, factories are already able to produce battery packs at around €50/kWh.

Module class	€/Wp	Trend since July 2024	Trend since January 2024
Crystalline modules			
High Efficiency	0.16	- 11.1 %	- 30.4 %
Mainstream	0.115	- 4.2 %	- 17.9 %
Low Cost	0.07	- 6.7 %	- 22.2 %



Price for PV + battery electricity at the equator (in €/MWh)

Let us estimate the cost of electricity produced by a 1 MWp PV installation combined with batteries to smooth out fluctuations in energy production.

Assuming a load factor of 25% for the PV panels and that they produce the same quantity of electricity every day (a reasonable assumption at the equator), we also assume that the batteries are sized to store half of the daily amount of electricity generated.

Since the 1 MWp PV installation would produce $1 \times 0.25 \times 24 = 6$ MWh per day, this would require investing in a 3 MWh battery pack.

The CAPEX cost for the PV installation and battery pack would be:

$(0.1 \times 1{,}000{,}000) + (3 \times 1{,}000 \times 50) =$ €250,000.

Neglecting losses in the batteries, the PVs and battery pack would generate over their lifetime of 20 years:

$1 \times 8{,}760 \times 20 \times 0.25 = 43{,}800$ MWh.

This would lead to an average CAPEX cost per MWh produced of:

$\frac{250{,}000}{43{,}800} \approx$ **€5.7/MWh**.

Prices for forward electricity products in Belgium (in €/MWh)

Month	Today	Yesterday	% D/D	5 days high	5 days low	Year high	Year low
Oct	74,84 €	74,36 €	+0,65%	76,78 €	74,36 €	88,81 €	70,53 €
Nov	88,54 €	88,86 €	-0,36%	92,87 €	88,54 €	105,27 €	88,54 €
Dec	87,83 €	87,33 €	+0,57%	91,98 €	87,33 €	96,52 €	87,33 €

Quarter	Today	Yesterday	% D/D	5 days high	5 days low	Year high	Year low
Q4-24	83,68 €	83,45 €	+0,27%	87,14 €	83,45 €	102,69 €	69,45 €
Q1-25	88,75 €	88,13 €	+0,70%	92,31 €	88,13 €	108,71 €	75,81 €
Q2-25	66,29 €	66,38 €	-0,15%	69,84 €	66,29 €	84,40 €	63,25 €
Q3-25	70,44 €	70,25 €	+0,27%	73,55 €	70,25 €	85,29 €	70,25 €

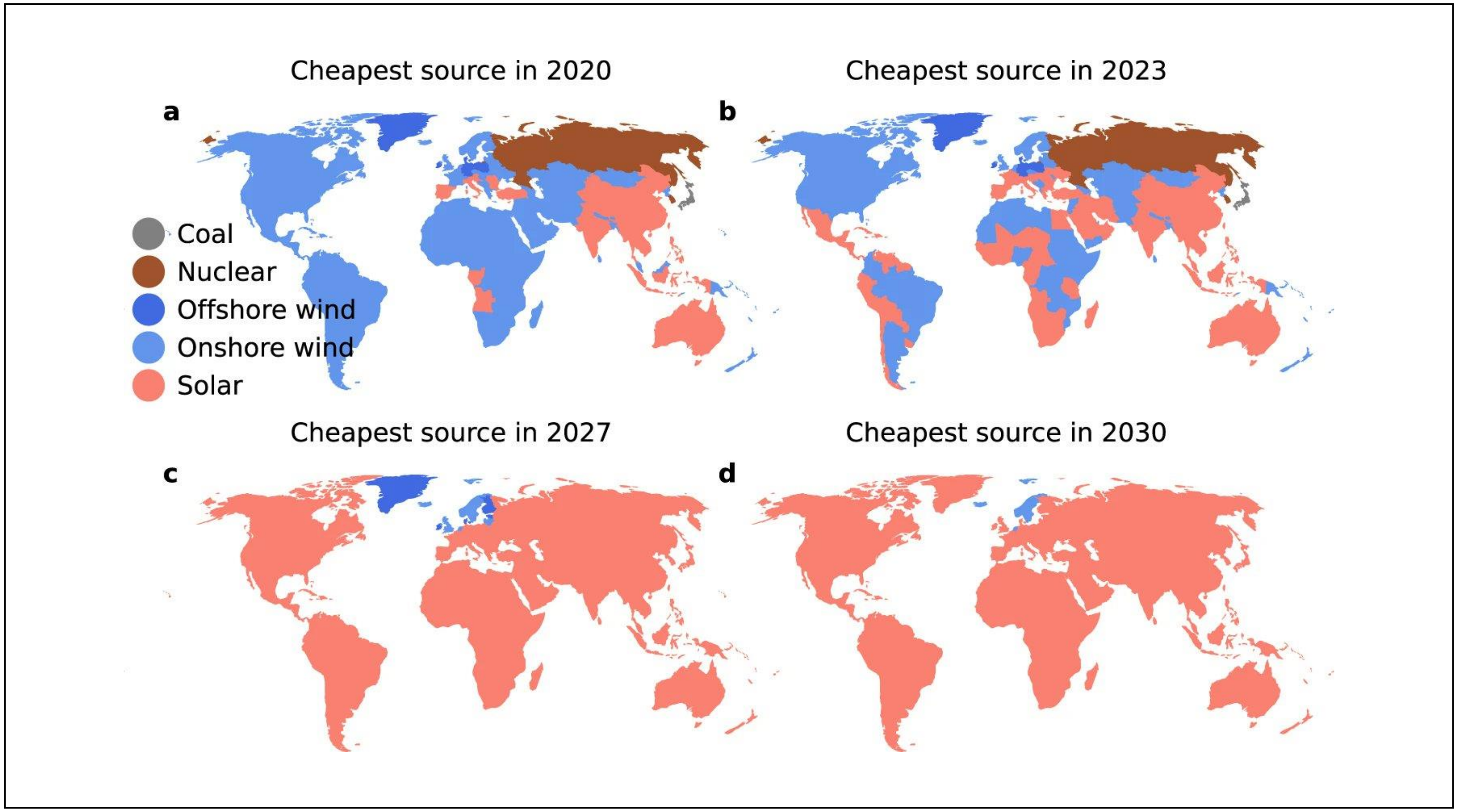
Year	Today	Yesterday	% D/D	5 days high	5 days low	Year high	Year low	Historic high	Historic low
2025	80,67 €	80,44 €	+0,29%	84,06 €	80,44 €	97,86 €	67,92 €	267,50 €	67,92 €
2026	83,81 €	82,42 €	+1,68%	85,93 €	82,42 €	91,50 €	66,81 €	128,21 €	66,81 €
2027	77,22 €	75,76 €	+1,93%	77,22 €	75,76 €	84,62 €	62,80 €	84,62 €	62,80 €

Quotation from September 11th, 2024, end of day.

<u>Observation:</u> It would not be excessive to describe electricity priced at €5.70/MWh as ‘free electricity’. This illustrates just how cheap PV panels and batteries have become!

Will solar PV become the world's cheapest electricity source?

Will solar PV soon be the cheapest source of electricity in most places around the world? A recent research paper published in Nature Communications suggests yes. Most surprisingly, this conclusion includes both short- and long-term storage costs for renewable energy sources.



Reference to the paper: Nijsse, F.J.M.M., Mercure, JF., Ameli, N. et al. ***The momentum of the solar energy transition****. Nature Communications,* ***14****, 6542 (2023). https://doi.org/10.1038/s41467-023-41971-7*

Consequences of the affordability of PVs and batteries

Countries and companies investing in gas as a flexible bridge to renewable energy may be misguided, as batteries will primarily handle renewable energy fluctuations.

African nations, long held back by limited affordable electricity, could see phenomenal growth as PV and battery installations capitalize on abundant sunshine.

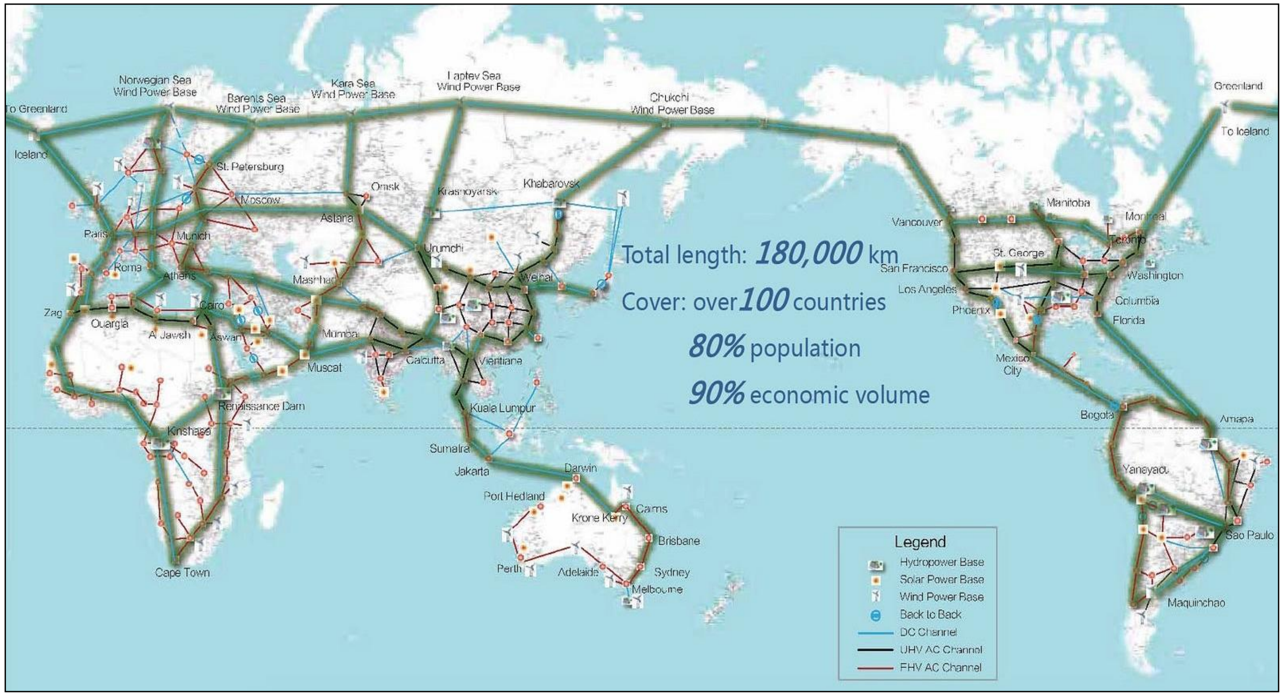
Energy-intensive industries may relocate to equatorial regions with cheap, stable electricity. This could pose challenges for countries like Germany, which have energy-intensive industries and will not benefit in the same way from cheap photovoltaic power.

<u>Note:</u> While PV energy is becoming incredibly cheap, we should not underestimate the ability of the fossil fuel industry to compete on price, even in Africa. Indeed, even if gas is sold at around €35/MWh on the Dutch TTF (the reference price for the EU market), U.S. gas producers are doing just fine with a gas price below €10/MWh at the Henry Hub. Furthermore, it is reported that Qatar can produce LNG at a cost of less than €2/MWh.

Consequences of the affordability of PVs and batteries

Countries lacking abundant solar energy could address this issue by initiating the development of a **Global Grid** to globalize electricity as a commodity, ensuring more uniform pricing worldwide.

A Global Grid would also naturally mitigate renewable energy fluctuations, significantly lowering renewable electricity costs.



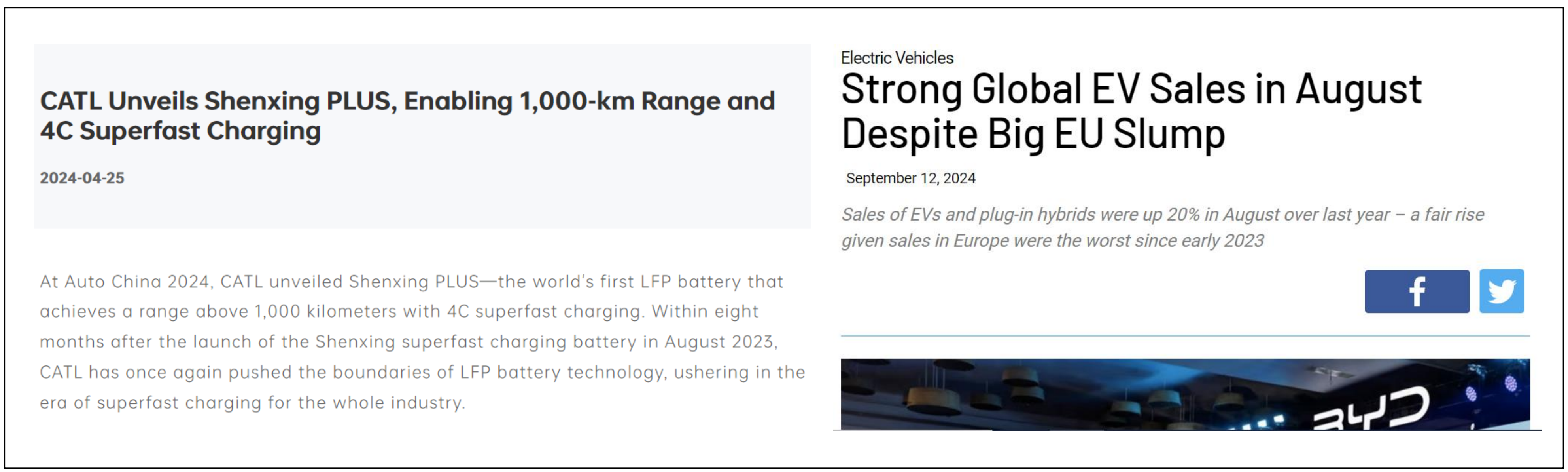
A mapped prototype of the Global Grid proposed by GEIDCO.

*More on the Global Grid: Chatzivasileiadis, S., Ernst, D., & Andersson, G. (2013). **The global grid**. Renewable Energy, 57, 372-383. https://hdl.handle.net/2268/144423*

Consequences of the affordability of PVs and batteries

The drop in battery prices is making electric vehicles (EVs) significantly cheaper per kilometer than internal combustion engine (ICE) cars. Increased battery energy density now allows for affordable EVs with ranges exceeding 1,000 km.

Additionally, the arrival of 4C batteries enables very fast recharging (60 min / 4 = 15 min) at fast-charging stations. These factors suggest that the ICE market may collapse within the coming decades, or even just years.



CATL Unveils Shenxing PLUS, Enabling 1,000-km Range and 4C Superfast Charging

2024-04-25

At Auto China 2024, CATL unveiled Shenxing PLUS—the world's first LFP battery that achieves a range above 1,000 kilometers with 4C superfast charging. Within eight months after the launch of the Shenxing superfast charging battery in August 2023, CATL has once again pushed the boundaries of LFP battery technology, ushering in the era of superfast charging for the whole industry.

Electric Vehicles

Strong Global EV Sales in August Despite Big EU Slump

September 12, 2024

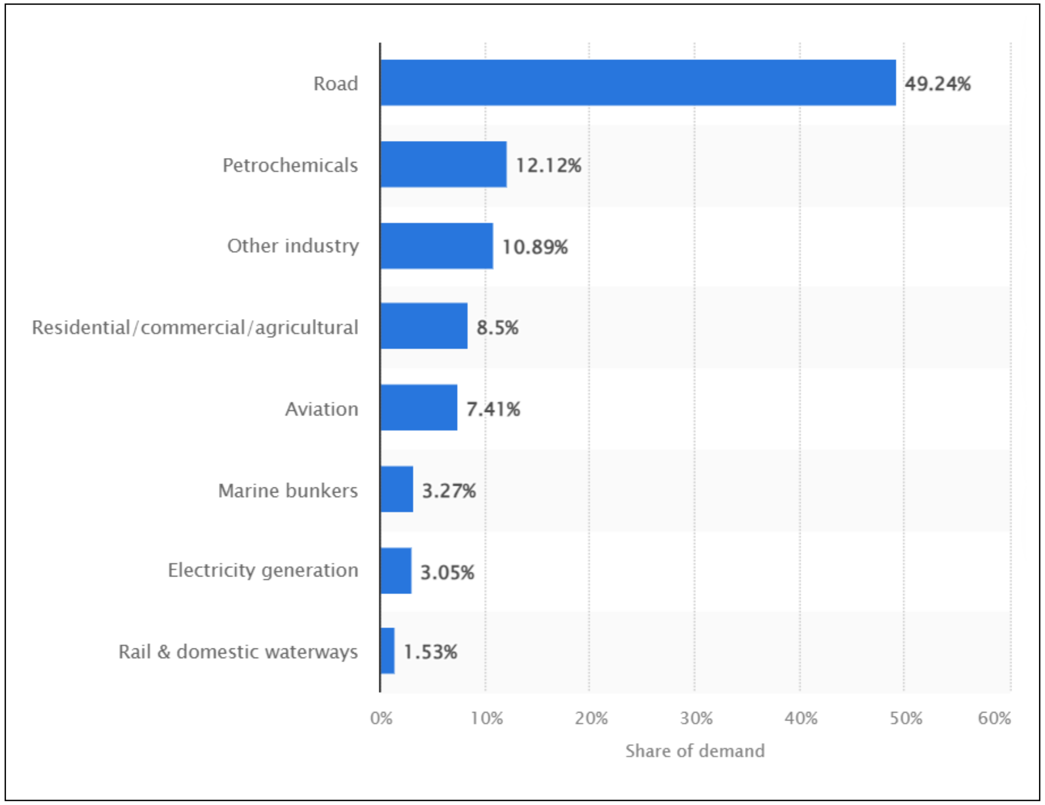
Sales of EVs and plug-in hybrids were up 20% in August over last year – a fair rise given sales in Europe were the worst since early 2023

Consequences of the affordability of PVs and batteries

This is troubling news for OPEC+. The organization is already losing market share (see section I) and now faces a gradual loss of its road transport business, which accounts for around half of oil demand.

Given this, many OPEC+ countries risk losing their influence if they do not reform. To remain relevant on the global stage, they must reinvent themselves as dynamic economies, independent of oil industry subsidies.

Significant challenges lie ahead for countries like Iran, Russia, and Saudi Arabia.



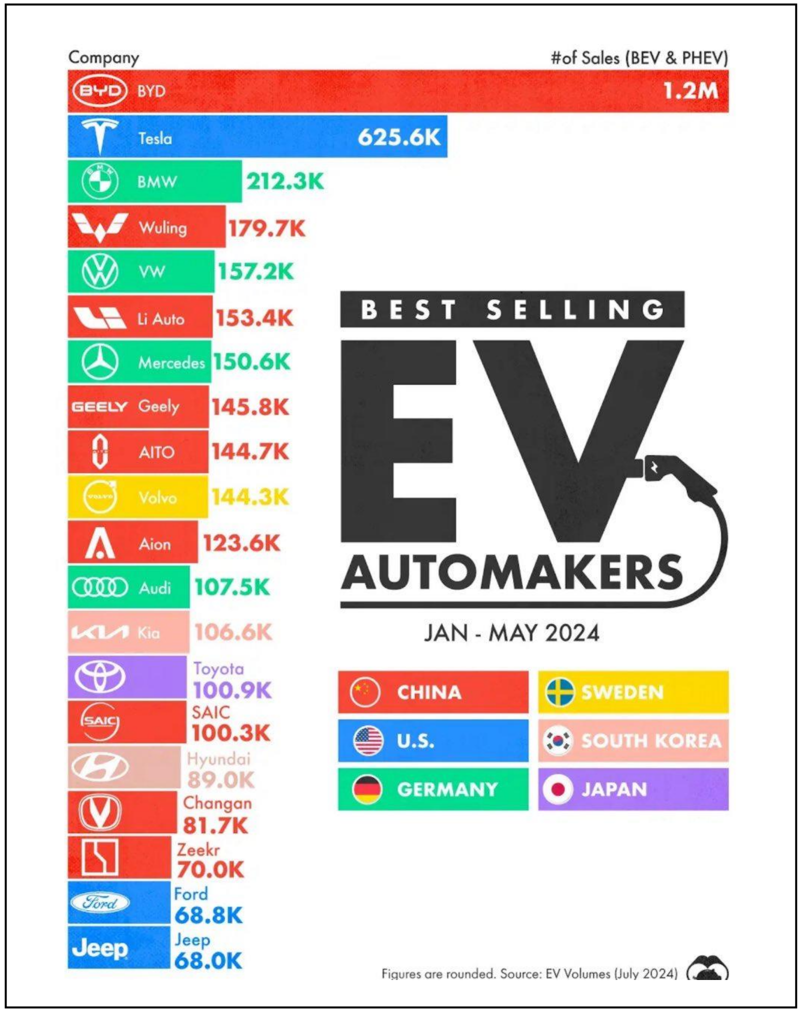
Distribution of oil demand in the OECD in 2022, by sector.

Consequences of the affordability of PVs and batteries

If policies remain unchanged, China is set to become the global manufacturing hub for photovoltaic panels, batteries, and electric vehicles.

This shift is likely to fuel tensions with other countries that want to protect their industries (especially automotive) from being overwhelmed by China in a global cleantech market.

Imposing tariffs on Chinese products until domestic industries can catch up could be an effective solution, particularly for the EU, which seeks to avoid replacing its dependence on fossil fuel imports with a reliance on cleantech imports.



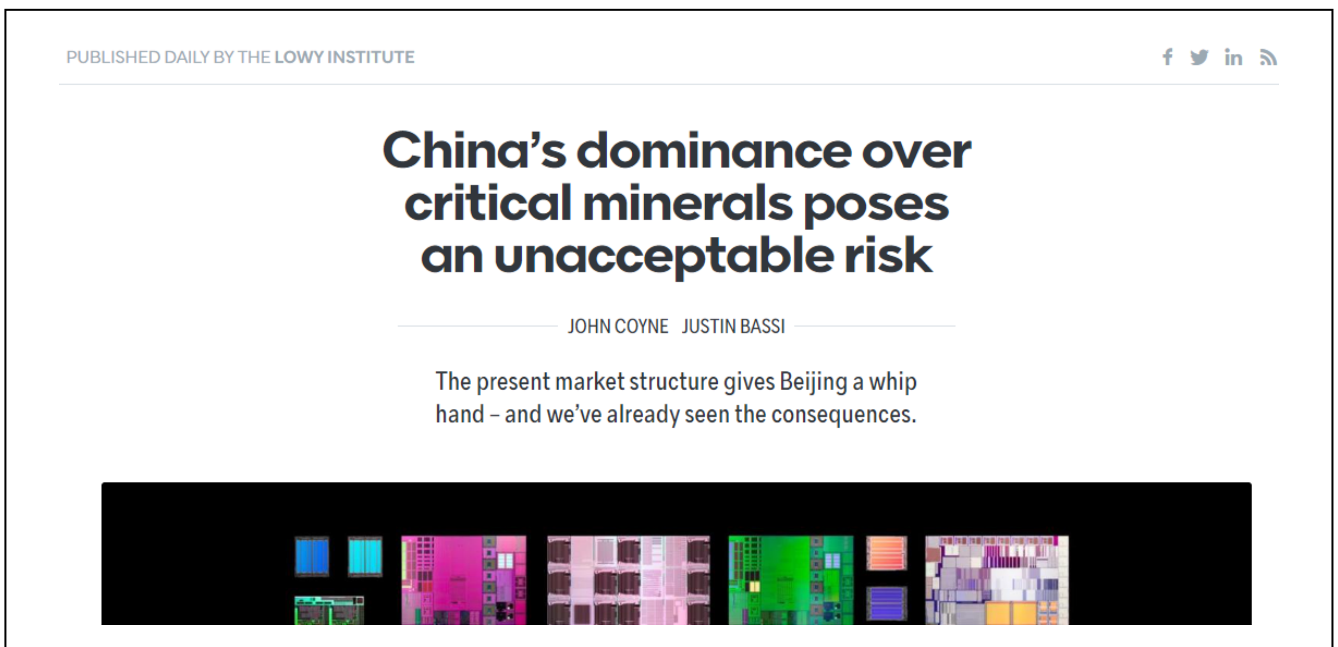
The Chinese carmaker BYD sells about twice as many electric vehicles as all German carmakers combined.

Consequences of the affordability of PVs and batteries

China's cleantech industry benefits from its control over critical minerals essential to the energy transition. A realist approach suggests that the EU will never become a cleantech superpower without securing its own supply of these vital resources.

To address this, the EU has two main strategies:

- developing mines within EU territory;
- pursuing deep-sea mining in EU exclusive economic zones or international waters.



Development of mines in the EU territory

The EU possesses substantial mineral resources that have been overlooked due to stringent environmental regulations limiting mining activities.

With advancements in clean mining technologies, the EU could develop mines with far lower environmental impact compared to those in less-regulated regions.

Additionally, mining robots could help minimize exposure to unsafe working conditions, further supporting responsible resource extraction.

Rare Earth Deposit Discovered in Norway: A Good News for European Mineral Sovereignty?

Interview 11 juin 2024

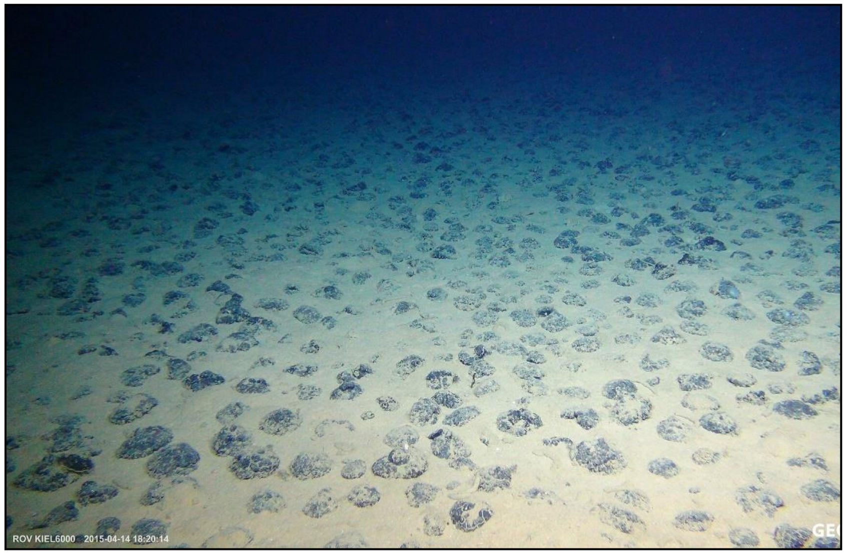
Le point de vue de Emmanuel Hache

A few days ago, 8.8 million tonnes of rare earths were discovered in south-east Norway. An essential chemical element in the low-carbon, ecological and digital transition, this discovery could reshuffle the cards in terms of Europe's autonomy and mineral security at a time when China accounts for almost 69% of the world's mining production and the European Union remains extremely dependent on external supplies. What influence could this discovery have on the global rare earths market? How can Europe benefit? Emmanuel Hache, Senior Research Fellow at IRIS and specialised in energy forecasting and the economics of natural resources (energy and metals), provides some answers.

Deep sea mining

Polymetallic nodules, found at depths of 4–6 km in major oceans and even in shallow waters like the Baltic Sea, are a vital resource for clean technology industries. Exploiting these nodules should be a European priority, as their environmental impact is significantly lower than traditional land-based mining.

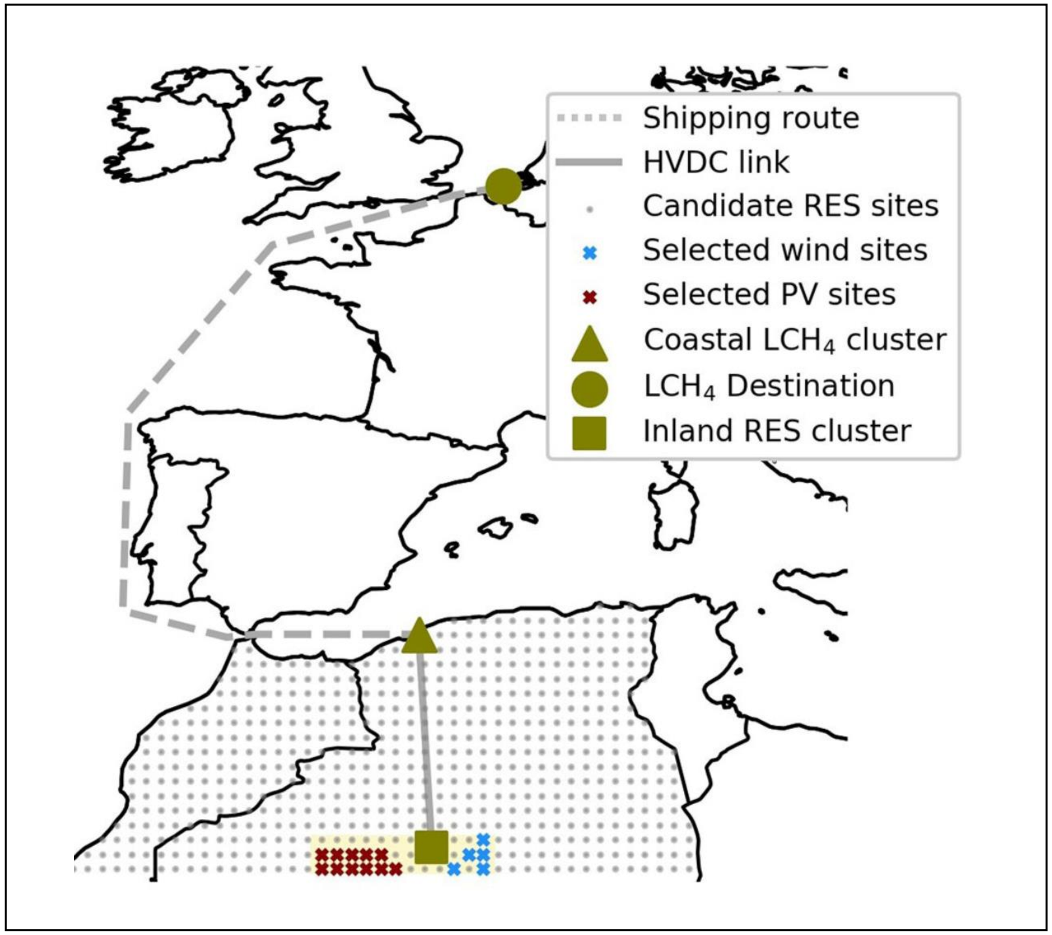
The European company DEME, based in Belgium, is a global leader in deep-sea mining and has developed advanced machines capable of efficiently harvesting these nodules.



IV. Development of remote renewable energy hubs for the production of carbon-neutral energy-rich molecules

The Remote Renewable Energy Hub (RREH)

A Remote Renewable Energy Hub (RREH) is an energy center situated far from major demand areas, designed to harvest abundant, high-quality renewable energy.



An example of an RREH is where solar and wind energy is collected in the Algerian desert, transmitted to the coast via an HVDC link, converted into carbon-neutral CH_4, and then shipped to the EU.

Why RREH is the new hot thing in the energy sector?

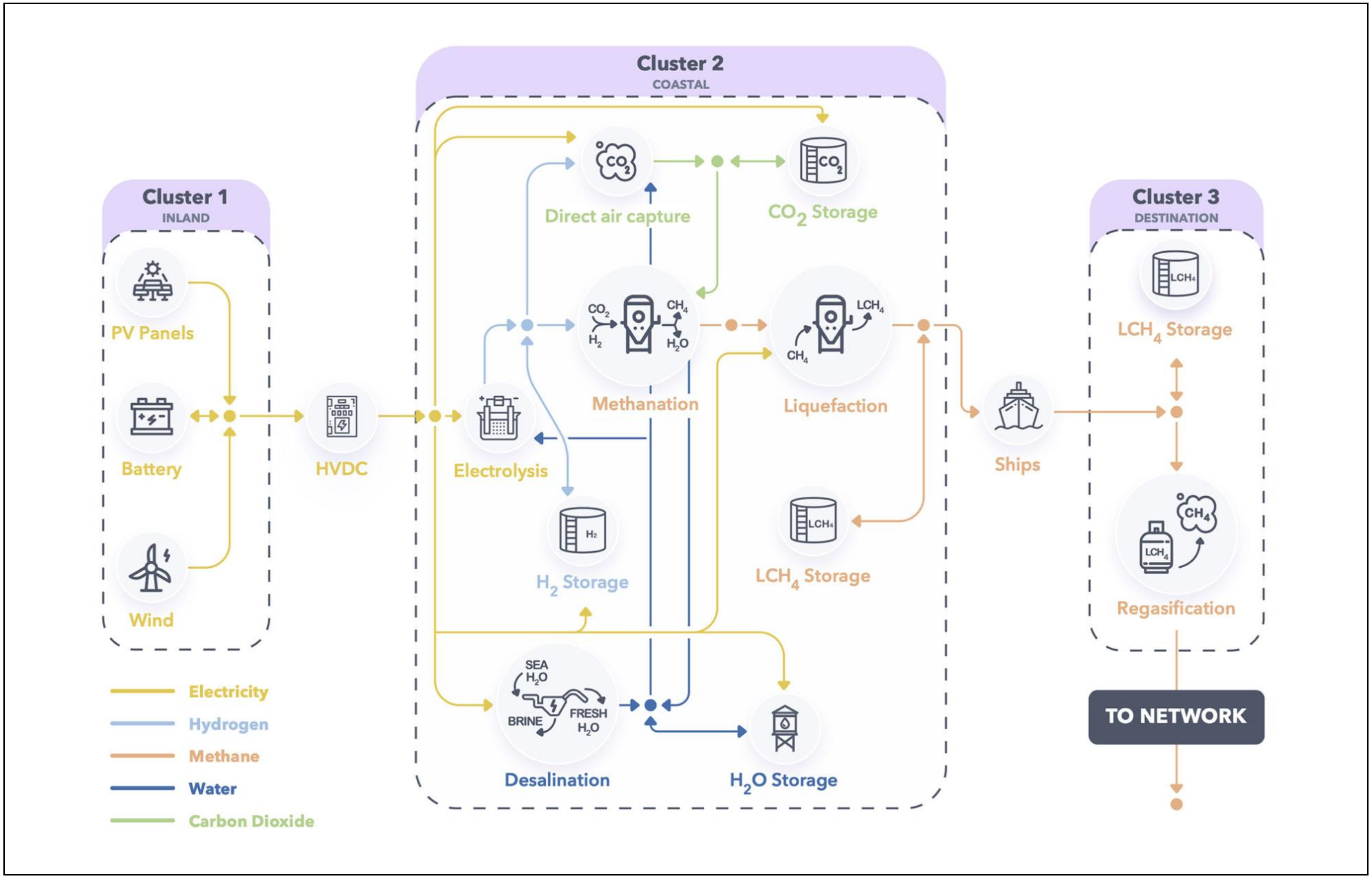
Renewable energy production near load centers is often constrained by space and lower-quality primary energy sources. RREHs create new opportunities to decarbonize economies at a low cost.

These hubs can produce decarbonized fuels like H_2 or NH_3, as well as **non-decarbonised but CO_2-neutral fuels** through technologies like direct air capture (DAC), electrolysis, and Fischer-Tropsch synthesis. This approach offers vast potential to decarbonize hard-to-abate sectors, such as aviation.

RREHs can also be rapidly deployed in parallel worldwide, leveraging consistent technology and providing benefits to local communities.

More on those RREH in: Dachet, V., Lokotar, I., & Ernst, D. (2024). ***Remote renewable energy hubs: A leadership opportunity that Europe must seize****. Confrontations Europe.* https://hdl.handle.net/2268/318392

An example of a RREH for CH_4 production



Fertilizer production with RREHs

Many RREH projects are emerging focused on NH_3 synthesis, as it is the most cost-effective energy-dense molecule to produce in these hubs. NH_3 plays a crucial role in food production, as it is widely used for nitrogen fertilizers.

Currently, NH_3 is predominantly synthesized from CH_4.

Consequences of the emerging of RREHs

RREHs will compete directly with the fossil fuel industry, particularly in supplying decarbonized kerosene for aviation and NH_3 for fertilizers.

This poses significant challenges for oil- and gas-rich nations, as RREHs leverage the rapidly decreasing costs of clean technologies. With the ability to be constructed quickly and simultaneously across regions, RREHs could displace large segments of the fossil fuel sector.

The rise of RREHs could rapidly diminish the wealth of fossil-fuel-dependent countries, potentially altering global power dynamics **faster than expected.**

V. Military strikes on energy infrastructures

Recent events (1/4)

09/28/2022: Attack on NS1 and NS2 (Baltic Sea).

Recent events (2/4)

06/01/2024: Electricity in the Belgorod region of Russia was cut off after a drone attack and explosions at substations in Stary Oskol.

Recent events (3/4)

09/01/2024: Drone attack on the 2520 MW Konakova power station (North of Moscow) and on the gas distribution network to which it was connected.

Recent events (4/4)

WORLD NEWS

Ukraine braces for hardest winter due to intensified Russian attacks on energy infrastructure

Consequences of military strikes on energy infrastructures

Countries are recognizing that even with substantial wealth and military power, cheap drones and technologies can inflict severe damage and cause critical losses to energy infrastructure.

This emerging threat has the potential to shift global power dynamics, as demonstrated by drones' impact on the Ukrainian battlefield.

Consequently, these risks are expected to drive the adoption of distributed energy systems, which are inherently more resilient against attacks.

Additionally, this will likely lead to the creation of new mechanisms for managing electricity networks to enhance their resilience against strategic disruptions.