Energy Economics, Winter Semester 2021-2
Lecture 11: Gas Markets

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Introduction to Gas Markets

Natural gas: historical perspective

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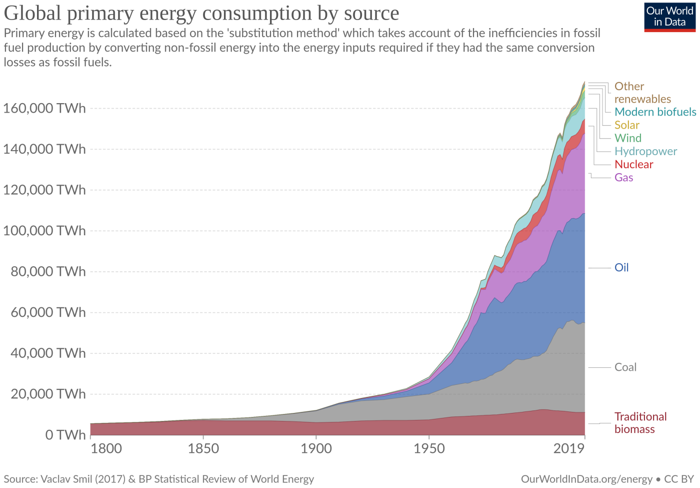
Extraction of natural gas took off in the 1960s with discoveries in the USA, Western Siberia, North Sea and elsewhere, as well as advancing technology to transport, store and use it.

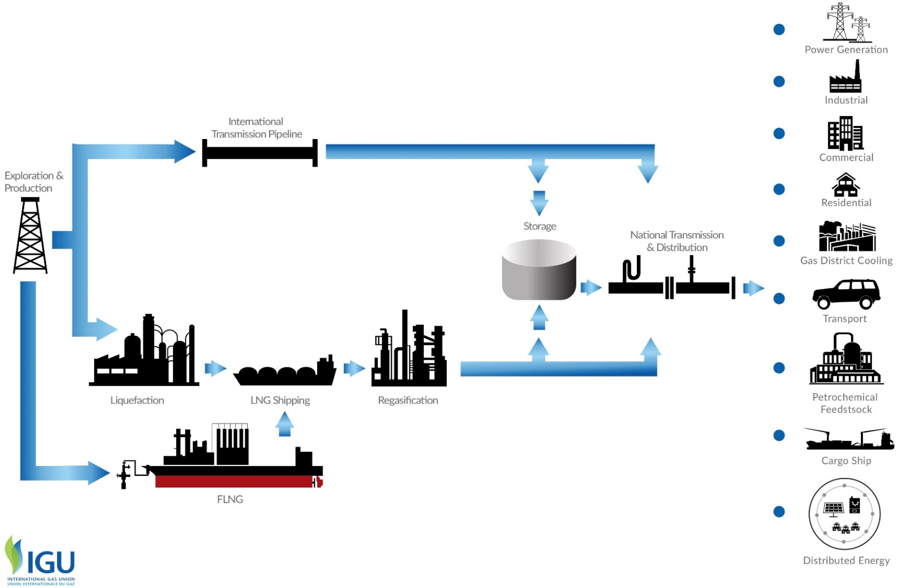


Source: [Our World in Data]

Natural gas in comparison to other energy carriers

- Natural gas is a **naturally-occuring** fossil fuel (like oil and coal, unlike town gas)
- Gas is **easily storable** in overground tanks or underground geological formations (like oil and coal, unlike electricity)
- Originally (i.e. end of 19th century, first half of 20th century) gas was **hard to move around**, so was only used locally (like electricity) or flared
- Since mid-20th century gas can be transported and distributed **by pipeline** (like oil), which makes long-distance transport and delivery to households easier than e.g. coal
- Since late-20th century gas can be transported as liquified natural gas (LNG) **by ship** (like oil and coal)
- Gas is used for energy but also as a **non-energy feedstock** (like oil and coal) for ammonia and other chemicals like methanol and plastics

Natural gas value chain



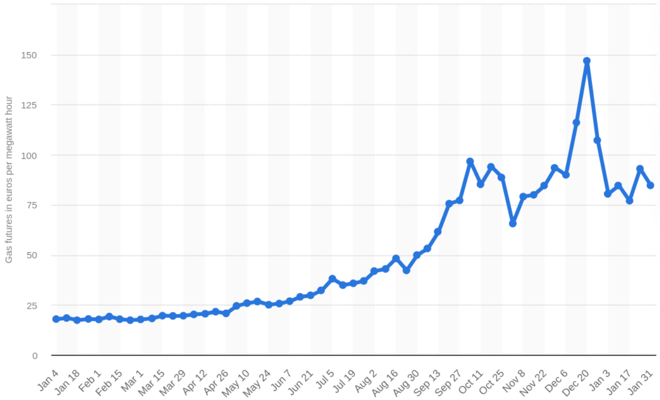
Source: IGU

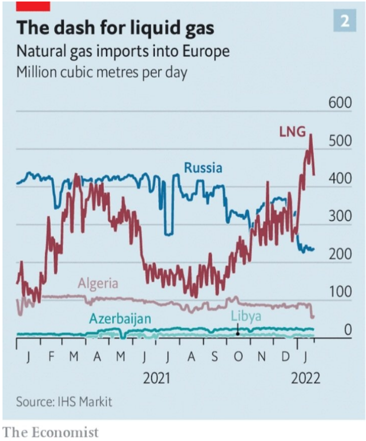
Natural gas as a bridge?

There is a substantial debate about the role of natural gas in the Energy Transition.

- Can we avoid natural gas being used for **geopolitical purposes** by producers?
- Can we use natural gas as a **bridge** from coal to a future fossil-free system? (It should have lower emissions than coal and gas plants can run flexibly to balance VRE.)
- Does **methane leakage** in production and distribution outweigh the climate benefits? (Methane is a potent greenhouse gas, and substantial leakage can make it as bad as coal, but leakage can also be detected and regulated.)
- Can we retrofit fossil gas infrastructure for **hydrogen**?
- How do we replace **feedstock** uses of natural gas?

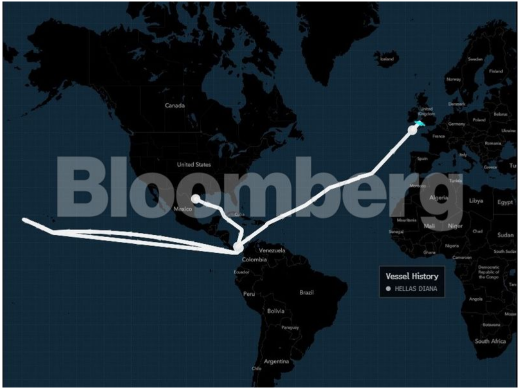
Gas prices had been stable around $\sim$ 20 €/MWh, but in late 2021, grew by factor seven before settling at a quadrupled level.





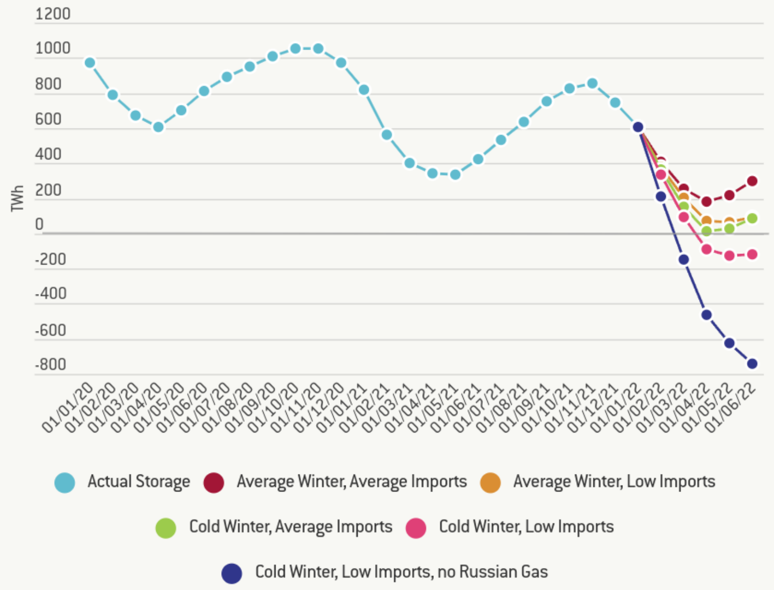
Source: Statista, 2022, Economist

LNG ships have flocked to Europe, including one on its way to Asia from the US, which turned around mid-Pacific to return through the Panama canal.



Source: Bloomberg

Gas crisis 2021-2022



Source: **Bruegel, 2021**

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Can Europe survive without Russian gas in the short-term?

EU27 demand is around 400 bcm/a (billion cubic metres per year), i.e. 4000 TWh/a.

In a typical year, this would be suppled by 60 bcm/a domestic production, 160 bcm/a from Russia and the rest (180 bcm/a) from other imports (Norway, Algeria, UK, LNG, etc.).

LNG re-gasification capacity is around 240 bcm/a, but only currently used at half capacity (constraint is supply from rest of world).

So if we boosted LNG to the max, there would still be a shortfall of 40 bcm/a to be made up by demand reduction (e.g. switch generation to coal), domestic production and pipeline imports from non-Russian countries.

Would require tight coordination!

Update March 2022: IEA reckons in its **analysis** that LNG supply can only be increased by 20-60 bcm/a, leaving significant shortfall.

Properties and reserves

Gaseous fuels introduction

- **Fossil gas**, also known as **natural gas** (to distinguish it from coal-derived gas), consists primarily of **methane** (CH_4).
  - **H gas** - high-calorific natural gas ($\sim 87 - 99\%$ CH_4 content $\rightarrow$ higher heat value)
  - **L gas** - low-calorific natural gas ($\sim 80 - 87\%$ CH_4 content, rest nitrogen and carbon dioxide, used to be produced in North Germany & Netherlands, phased out)
- **Liquefied petroleum gas (LPG)** (Autogas in DE) - mainly propane and butane, byproduct of oil refinery process
- **Town/coal/coking gas** - byproduct of coke plants (mix of CH_4, H_2, CO, CO_2, N_2)
- **Hydrogen** - used as chemical feedstock, could be used in transport / iron reduction / heating / backup for electricity, could also be produced without CO_2 emissions

Gaseous fuels properties

		Density (kg/m^3)[a]	Upper heating value H_s (MJ/m^3)	Lower heating value H_i (MJ/m^3)
Methane	CH_4	0.7175	39.819	35.883
Ethane	C_2H_6	1.3550	70.293	64.345
Propane	C_3H_8	2.0110	101.242	93.215
Butane	C_4H_{10}	2.7080	134.061	123.810
Hydrogen	H_2	0.08988	12.745	10.783
Carbon monoxide	CO	1.25050	12.633	12.633
Nitrogen	N_2	1.2504		
Oxygen	O_2	1.4290		
Carbon dioxide	CO_2	1.9770		
Air		1.2930		
Natural gas H		0.79	~41	~37
Natural gas L		0.83	~35	~32
Biogas		1.12	~27	~24

[a]At a temperature of 0 °C and a pressure of 1.013 bar

Source: Zweifel / Praktiknjo / Erdmann, 2017

Natural gas conversion

	Nm^3 natural gas	scf[a] of natural gas	kg LNG	MJ	mn BTU	Therm	kWh
Nm^3 natural gas	1	35.3	0.73	37.5	0.035	0.355	10.4
scf[a] natural gas	0.0283	1	0.0207	1.06	0.001	0.01	0.294
kg LNG	1.37	48.36	1	51.3	0.049	0.486	14.2
MJ	0.027	0.94	0.019	1	0.001	0.0095	0.2778
mn BTU	28.2	996	20.6	1055	1	10	293
Therm	2.82	99.6	2.06	105.5	0.1	1	29.3
kWh	0.096	3.40	0.07	3.6	0.0034	0.0341	1

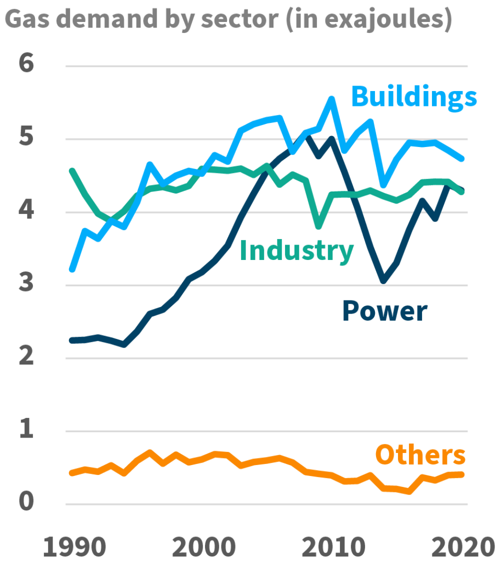
Nm^3: normal cubic metre at 1.013 bar and 0° C, sometimes written cm for cubic metre

scf: standard cubic foot at 1.013 bar and 60° F $=$ 15.6° C

MJ, kWh: at lower heating value (LHV)

Source: Zweifel / Praktiknjo / Erdmann, 2017

EU natural gas demand by sector



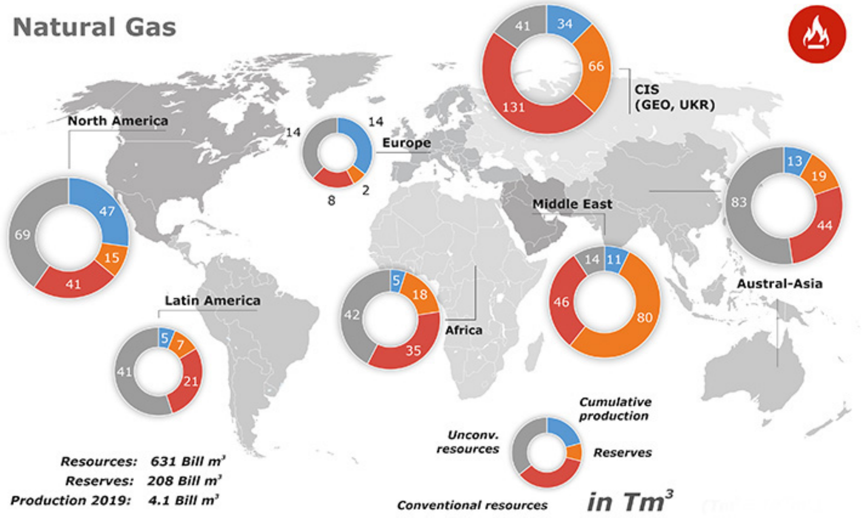
- Gas demand in EU27 dominated by buildings (i.e. space and water heating), industry (i.e. for heat and including non-energy feedstocks for e.g. ammonia) and power generation
- Gas industry expects demand to rise, while scenarios compatible with the Paris Agreement require it to decline in all sectors

Source: Eurostat

- **Conventional natural gas**
  - Extracted from gas deposits by conventional means (vertical drilling)
  - Associated gas - released during oil extraction (often flared but can be utilised)
- **Unconventional natural gas**
  - Shale gas (>1000 m deep) - extracted by fracking
  - Coal bed methane - found in coal formations (300-1000 m deep)
  - Methane hydrates - found on ocean seabed

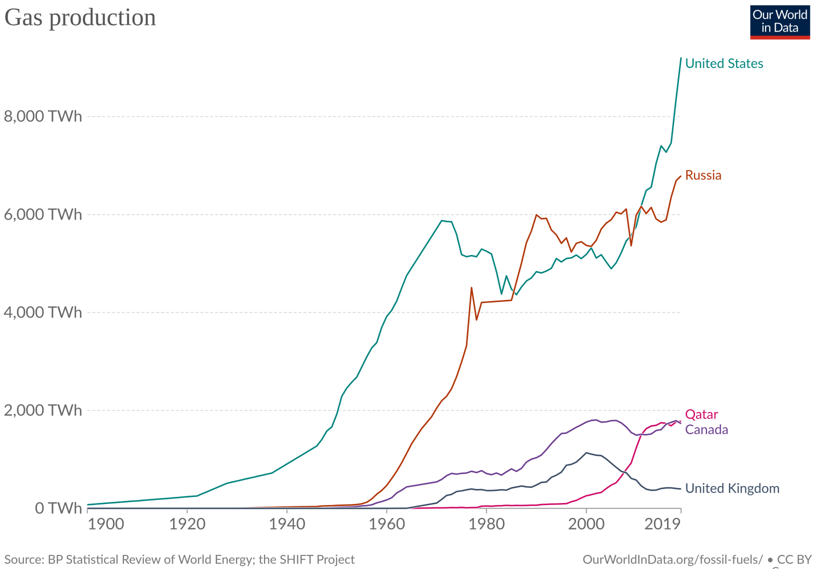
Global gas resources and reserves

Results are in trillion m^3 (German Billion) or $Tm^3 = 10^{12}m^3$.



Source: BGR, 2019

Global gas extraction



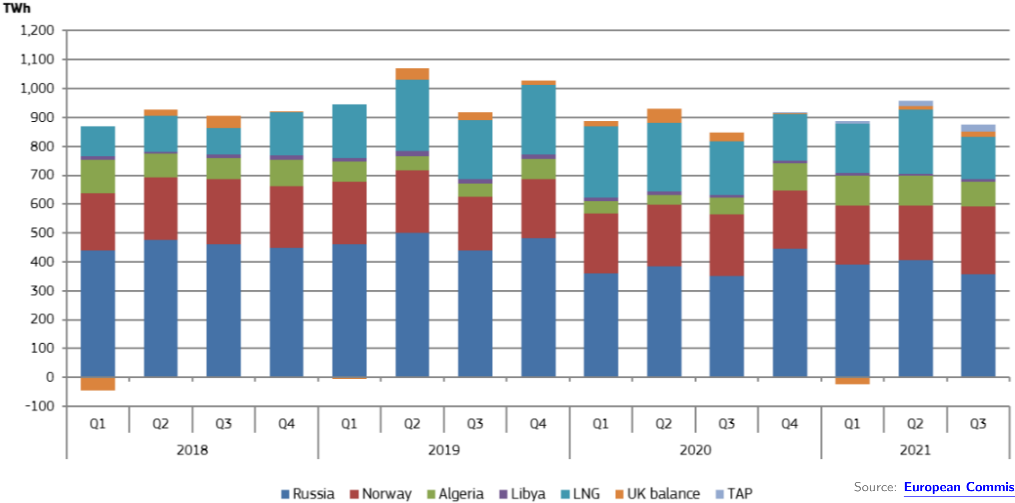
Source: Our World in Data, 2019

Russian pipeline imports dominate supply in Central/Eastern Europe

Source: Wikimedia

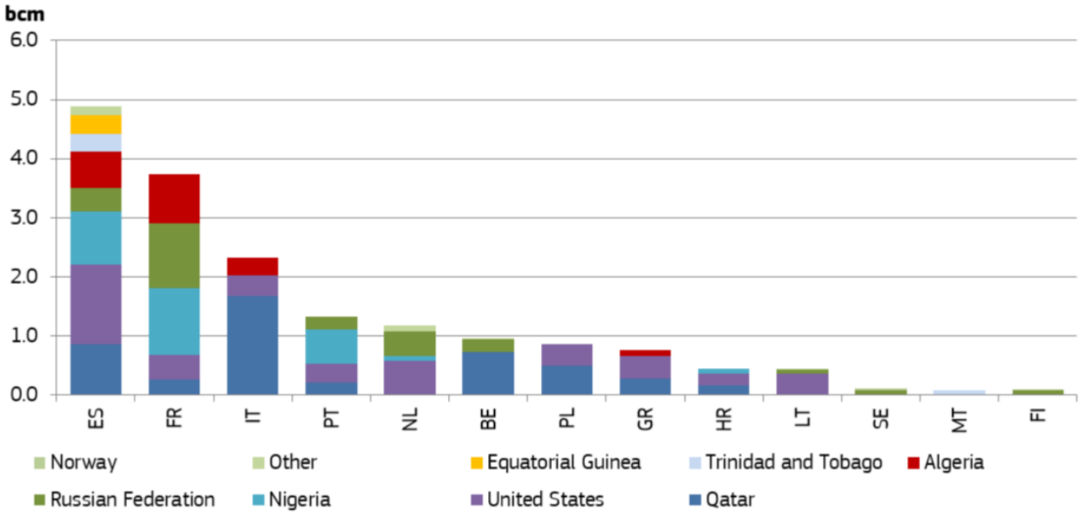
EU imports of natural gas by source

The EU imports around 4000 TWh/a of natural gas through pipelines and LNG. (TAP = Trans Adriatic Pipeline)



Source: European Commission, 2021

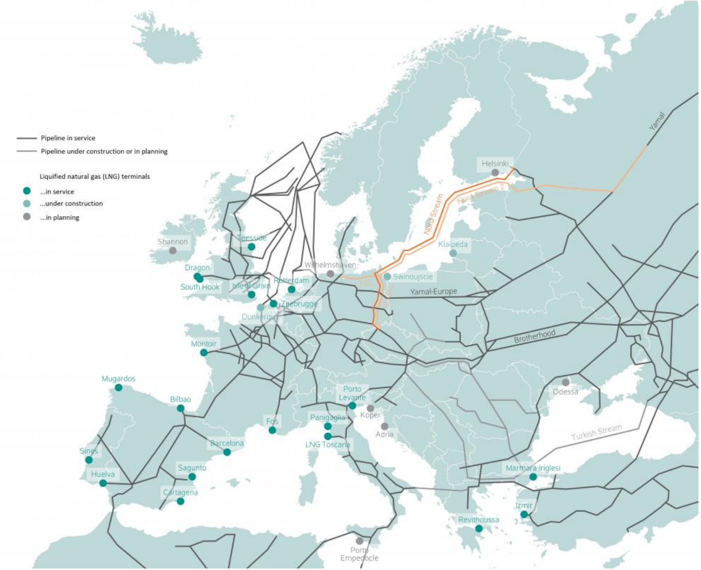
EU LNG imports to member states in Q3 2021



Source: European Commission, 2021

Gas Pipelines

European pipeline network



Source: DIW, 2018

The **throughput** Q [m^3/h] of a gas pipeline is given by (approximately)

$$Q \sim \sqrt{\frac{P_1^2 - P_2^2}{\ell/d^2}}$$

where P_1 and P_2 are the pressures at the start and end of the pipe, ℓ is the length of the pipeline section (between two compressor stations) and d is the diameter. More complicated formulae can account for height differences and pipe roughness.

Pipeline **capacity** is the maximum thoughput.

Pipeline pressures can be up to 80 bar, with a diameter of up to 1200 mm and covering a distance of up to 6000 km.

Compressor stations along the pipeline compensate for pressure losses (0.1 bar per 10 km) due to frictional losses/changing elevation and are placed at intervals of 80-400 km. Compressors use energy from natural gas, consuming around 10% of gas over 5000 km.

Single 80 bar pipeline can transport up to 3 mcm/h (or 26 bcm/a) at speeds up to 40 km/h.

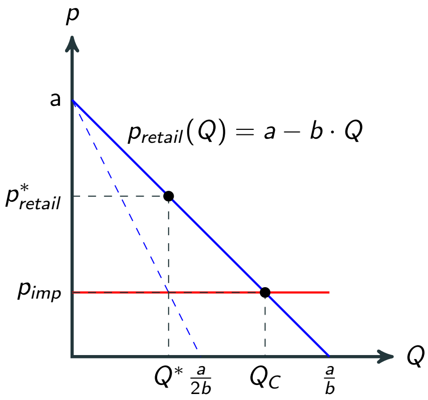
Economics of Gas Pipelines

- Long-distance gas transport is not necessarily a natural monopoly - can have **pipe-to-pipe** competition (i.e. parallel pipes) or **pipe-in-pipe** competition (where companies co-own pipeline).
- Have strong economies of scale (when doubling capacity, costs rise only 66%).
- **Hold-Up Problem:** After realizing a pipeline project, the investor finds themself in a strategically weak position based on the irreversible nature of the investment (**sunk cost**). The pipeline operator's profit depends on the goodwill of the contract partner located at the end (beginning) of the pipeline.

- Two companies: monopolistic gas importer who supplies the retail market, and a monopolistic pipeline operator who is also a dominant gas producer in the exporting country
- In the first step of the game theoretic model the pipeline operator optimizes their pipeline capital stock K. In the second step the import price $p_{imp}(K)$ is determined by negotiations between the two monopolists
- Both parties optimize independent from each other their profit (**non-cooperative game**)
- Mathematical solution of the model in the opposite order: First the condition for the import price is determined, i.e. the result of the negotiations between the two monopolists in step two. Then determine K.
- To determine $p_{imp}(K)$, the gas producer is able to infer the import price resulting from gas import's optimisation based on the domestic demand curve. It then optimises its profit at the given import price.

Retail Gas Price set by the Monopolistic Gas Importer

For linear inverse demand function $p_{retail}(Q) = a - b \cdot Q$ and given import price p_{imp} (importer's marginal cost neglecting other cost elements), the gas retailer optimises its profits.



The retailer maximises their profit as a function of Q:

$$\max_Q \Pi_{imp}(Q) = \max_Q Q\cdot(p_{retail} - p_{imp}) = \max_Q Q\cdot(a - b\cdot Q - p_{imp})$$

Differentiating by Q to find the maximum:

$$\frac{d\Pi_{imp}}{dQ} = a - p_{imp} - 2 \cdot b \cdot Q = 0$$

so that the optimal sales volume is $Q^* = \frac{a - p_{imp}}{2b}$ and the profit-maximising retail price is $p^*_{retail} = a - b \cdot Q = \frac{a + p_{imp}}{2}$. The monopolist retailer determines the quantity based on the intersection of the marginal revenue curve $a - 2 \cdot b \cdot Q$ (dashed line) and the import price p_{imp} .

Game Theoretical View of the Pipeline Operator and Extractor

Now turn to producer and pipeline operator (e.g. Gazprom) that seeks to maximise its profit knowing the importer's demand function and hence optimal Q^*. They can only control p_{imp} given their cost function $c(K)$ (for the costs of extracting and transporting the gas), which depends on the capacity K and is independent of Q or p_{imp}. They maximise profit:

$$\max_{p_{imp}} \Pi_{producer}(p_{imp}) = \max_{p_{imp}} (p_{imp} - c(K)) \cdot Q = \max_{p_{imp}} (p_{imp} - c(K)) \cdot \frac{a - p_{imp}}{2b}$$

By solving for the maximum

$$\frac{d\Pi_{producer}}{dp_{imp}} = -\frac{p_{imp}}{b} + \frac{a + c(K)}{2b} = 0$$

we find the optimal import price to be $p^*_{imp} = \frac{a+c(K)}{2}$. Note that this is larger than $c(K)$ as long as $a > c(K)$. Plugging this into $Q^* = \frac{a-p_{imp}}{2b}$ we get $Q^* = \frac{a-c(K)}{4b}$ and into $p^*_{retail} = \frac{a+p_{imp}}{2}$ we get $p^*_{retail} = \frac{3a+c(K)}{4}$.

Non-Cooperative Solution as Nash equilibrium

This solution whereby each game player knows the strategies of the others but has nothing to gain by changing their own behaviour is a known as a **Nash equilibrium**.

The profits of the importer are given by

$$\Pi^*_{imp} = Q^* \cdot (p^*_{retail} - p_{imp}) = \frac{1}{4b}\left(\frac{a - c(K)}{2}\right)^2$$

and for the extractor/pipeline operator by

$$\Pi^*_{producer} = (p^*_{imp} - c(K)) \cdot Q^* = \frac{1}{2b}\left(\frac{a - c(K)}{2}\right)^2$$

so in sum:

$$\Pi^*_{non-coop} = \Pi^*_{imp} + \Pi^*_{producer} = \frac{3}{4b}\left(\frac{a - c(K)}{2}\right)^2$$

Now what happens if they cooperate?

Solution under Cooperation

Suppose now the importer and pipeline operator+extractor **cooperate** to maximise their total profit Π_{coop}. Now they are a single vertically-integrated monopoly and optimise:

$$\max_Q \Pi_{coop}(Q) = \max_Q (p_{retail} - c(K)) \cdot Q = \max_Q (a - b \cdot Q - c(K)) \cdot Q$$

Now we find (like monopoly example with linear cost function from early lecture)

$$Q^* = \frac{a - c(K)}{2b}, \qquad p^*_{retail,coop} = \frac{a + c(K)}{2}$$

Since $c(K) < p_{imp}$, this cooperative retail price is lower than the non-cooperative price, so the consumer welfare increases under the cooperative solution.

In addition, the profits of the two monopolists also increases if they cooperate, so that overall welfare increases:

$$\Pi^*_{coop} = (p^*_{retail,coop} - c(K)) \cdot Q^*_{coop} = \frac{1}{b}\left(\frac{a - c(K)}{2}\right)^2$$

There is a welfare loss if two monopolists along the value chain don't cooperate (**double marginalisation**). What is worse than a monopoly: two monopolies.

So how does this effect the investment in capacity K?

Under non-cooperation the pipeline investor makes profit

$$\Pi^*_{producer} = \frac{1}{2b}\left(\frac{a - c(K)}{2}\right)^2$$

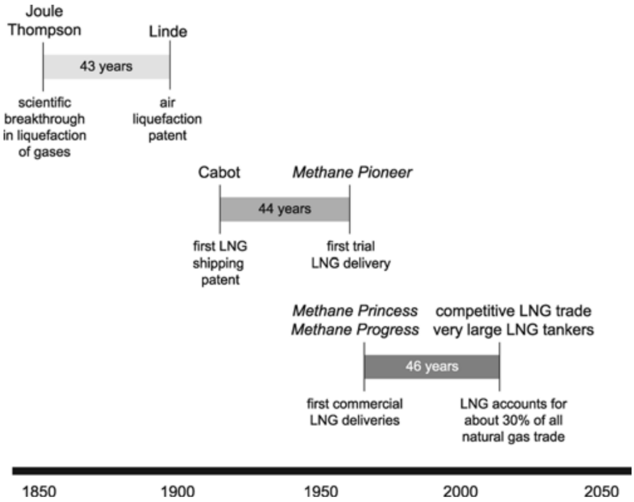
whereas for the same capacity, the pipeline investor makes twice as much

$$\Pi^*_{coop} = \frac{1}{b}\left(\frac{a - c(K)}{2}\right)^2$$

Since the pipeline investor will increase K until the marginal profit equals the marginal cost of extension, this higher profit will lead to a higher optimal capacity K.

Liquified Natural Gas

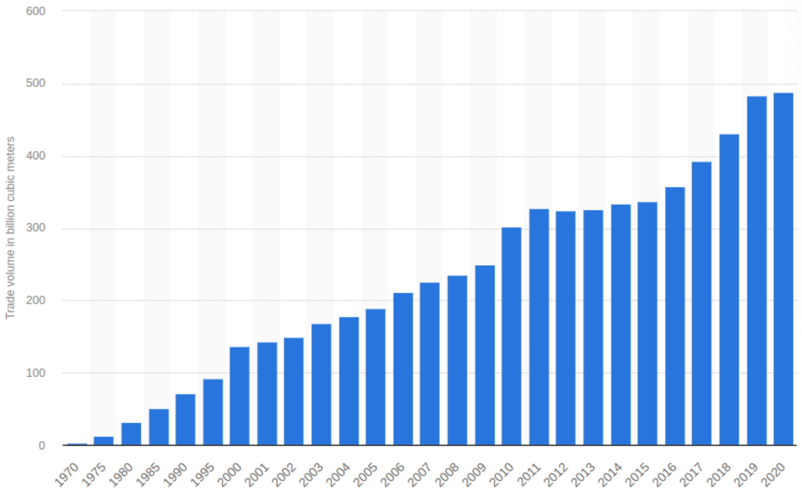
History of Liquified Natural Gas (LNG)



- 1959: first (small) LNG shipment in 1959 in *Methane Pioneer*
- 1964: exports of LNG from Algeria to UK begin in tankers *Methane Princess/Progress*
- 1970s: Japan comes to dominate, because no domestic resources and pipeline imports to Japan are not possible
- 1984: Japanese imports accounted for 75% of all LNG trade
- 1999: Japan still 66% of total

Source: Vaclav Smil 'Energy Transitions' (2010)

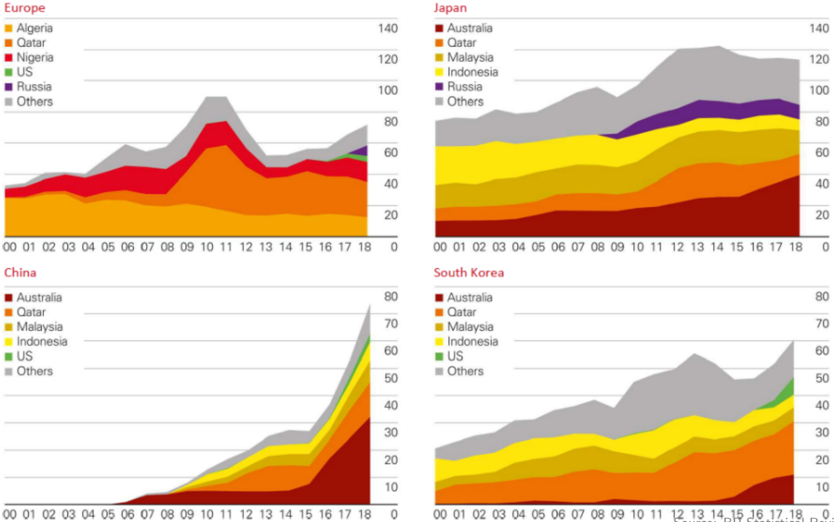
LNG really took off since 2000 due to remarkable cost reductions (larger and larger tankers).
LNG imports to Europe from the Middle East, North Africa and Asia are rising fast.



Source: [Statista 2022]

LNG imports by source (bn cubic metres per year)

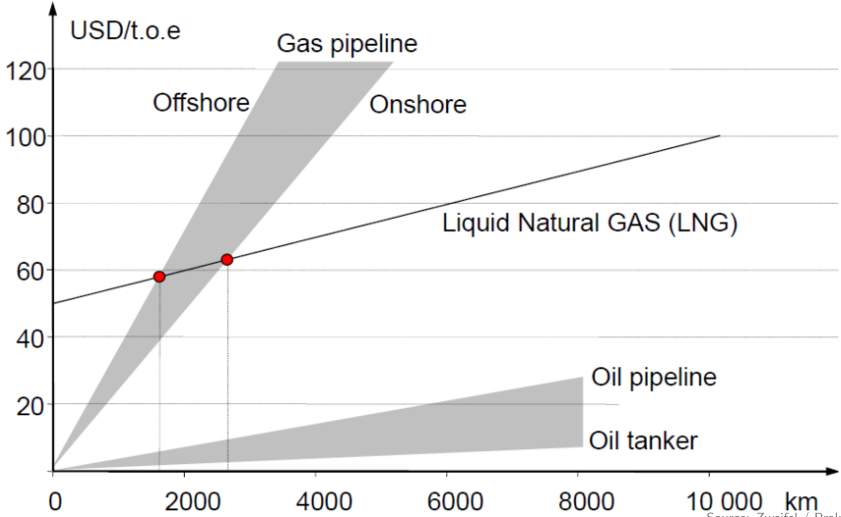
Much of recent growth is coming from Asia.



Source: BP Statistical Review of World Energy 2019

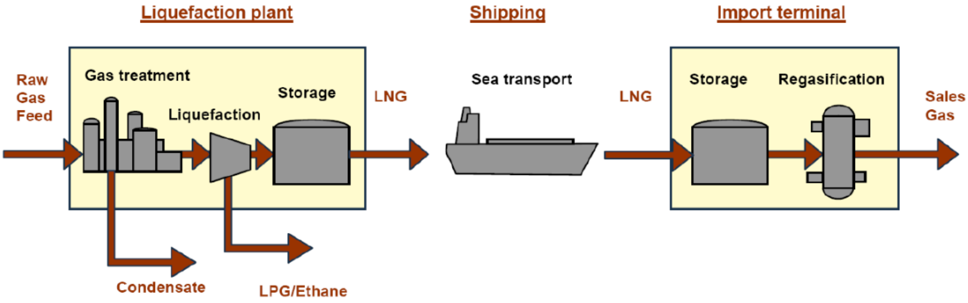
Transportation Cost of Hydrocarbons

60 \$/toe is around 5 \$/MWh, 1.5 \$/MMBtu, 0.05 \$/Nm^3

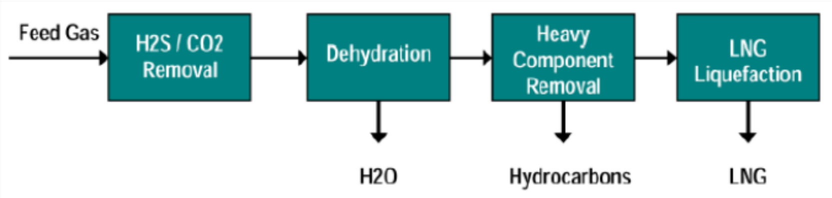


Source: Zweifel / Praktiknjo / Erdmann, 2017

Liquified Natural Gas (LNG) Process Chain

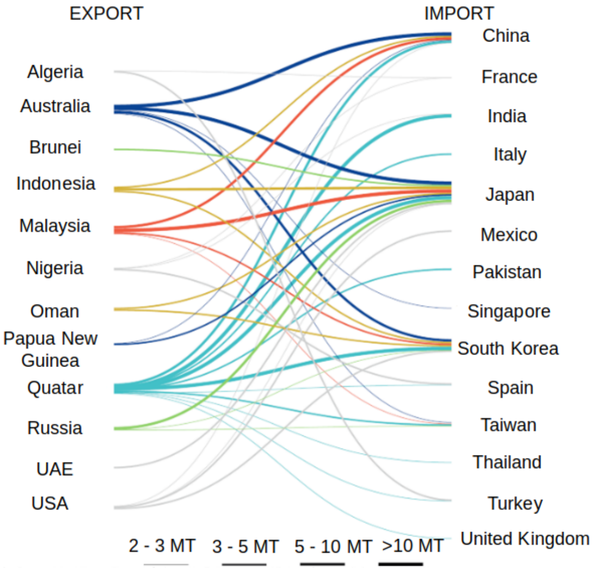


Boiling point of methane -162°C; ~600 times volume reduction



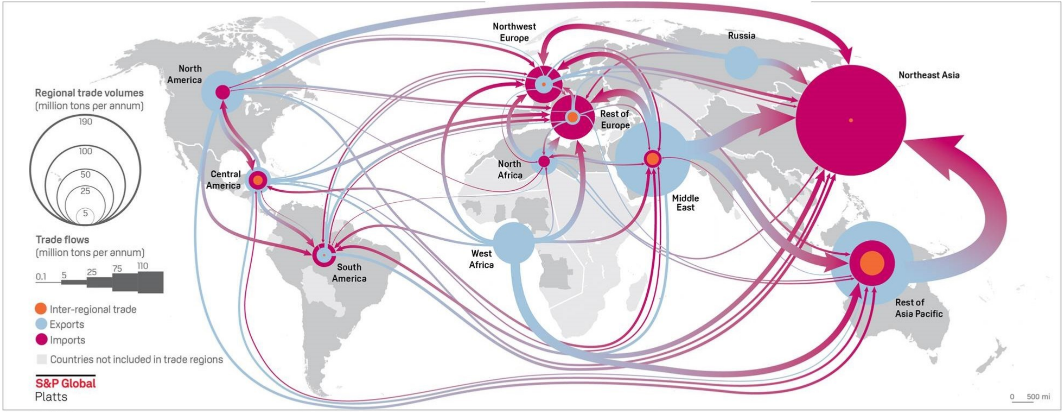
Source: BV 2009 / GIIGNL, Osaka Gas

Major LNG Trading Flows in 2018



Source: Source: GIIGNL, 2019

Major LNG Trading Flows in 2018



Source: Source: Platts

Cost Structure of LNG Process Chain

Costs for a standard LNG chain of 3.5-4.8 mn tons/a (4.8-6.6 bn m^3/a), totalling $\sim$ 0.06€/m^3

Liquefaction plant	
Investment outlay	900 M€
Operating expenses	0.04 €/m^3
Tanker fleet	e.g. 2 vessels with 135 kt each
Investment outlay	360 M€ for both
Operating expenses	0.014 €/m^3
Regasification plant w. storage	e.g. storage 3*80k m^3 (Cartagena)
Investment outlay	320 M€
Operating expenses	0.015 €/m^3
Own gas energy requirement	1/3 of transport gas

Source: Zweifel / Praktiknjo / Erdmann (2017), after Cayrade (2014)

LNG Project Cost Comparison

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				Project			Liquefaction Plant			
Project	Location	mtpa	Trains	CAPEX $bn	$/tpa	$/mmbtu	% project CAPEX	CAPEX $bn	$/tpa	$/mmbtu
Gorgon	Australia	15.6	3	53.0	3,397	11.9	62%	32.9	2,106	7.37
Prelude FLNG	Timor Sea	3.6	1	12.0	3,333	11.7	60%	7.2	2,000	7.00
Wheatstone	Australia	8.9	2	34.0	3,820	13.4	52%	17.7	1,987	6.95
Ichthys	Australia	8.4	2	36.0	4,286	15.0	45%	16.2	1,929	6.75
Queenland Curtis	Australia	8.5	2	20.0	2,353	8.2	60%	12.0	1,412	4.94
PNG	PNG	6.9	2	19.0	2,754	9.6	49%	9.3	1,349	4.72
Yamal	Russia	16.6	3	27.2	1,639	5.7	80%	21.8	1,311	4.59
Angola LNG	Angola	5.2	1	10.0	1,923	6.7	60%	6.0	1,154	4.04
Donggi-Senoro	Indonesia	2.0	1	2.9	1,450	5.1	90%	2.6	1,305	4.57
Gladstone	Australia	7.8	2	19.0	2,436	8.5	53%	10.1	1,291	4.52
Pacific LNG	Australia	9.0	2	26.0	2,889	10.1	45%	11.7	1,300	4.55
Tangguh Expansion	Indonesia	3.8	1	8.0	2,105	7.4	50%	4.0	1,053	3.68
Petronas PFLNG1	Malaysia	1.2	1	1.5	1,290	4.5	75%	1.2	968	3.39
Elba Island	USA	2.5	1	2.3	924	3.2	90%	2.1	832	2.91
Petronas PFLNG2	Malaysia	1.5	1	1.7	1,100	3.9	75%	1.2	825	2.89
Freeport	USA	15.0	3	13.3	887	3.1	90%	12.0	799	2.80
Corpus Christi T1-2	USA	9.0	2	10.4	1,160	4.1	90%	9.4	1,044	3.66
Corpus Christi T3	USA	4.5	1	3.0	667	2.3	100%	3.0	667	2.33
Cameron LNG	USA	13.5	3	11.0	815	2.9	90%	9.9	733	2.57
Cove Point	USA	5.3	1	4.2	789	2.8	90%	3.8	710	2.48
Bintulu Train 9	Indonesia	3.6	1	2.5	694	2.4	90%	2.3	625	2.19
Caribbean FLNG	TBA	0.5	1	0.4	800	2.8	75%	0.3	600	2.10
Golar FLNG	Cameroon	2.4	1	1.9	800	2.8	75%	1.4	600	2.10
Sabine Pass Trains 1-4	USA	18.0	4	11.0	611	2.1	90%	9.9	550	1.93
Sabine Pass Train 5	USA	4.5	1	3.8	844	3.0	100%	3.8	844	2.96

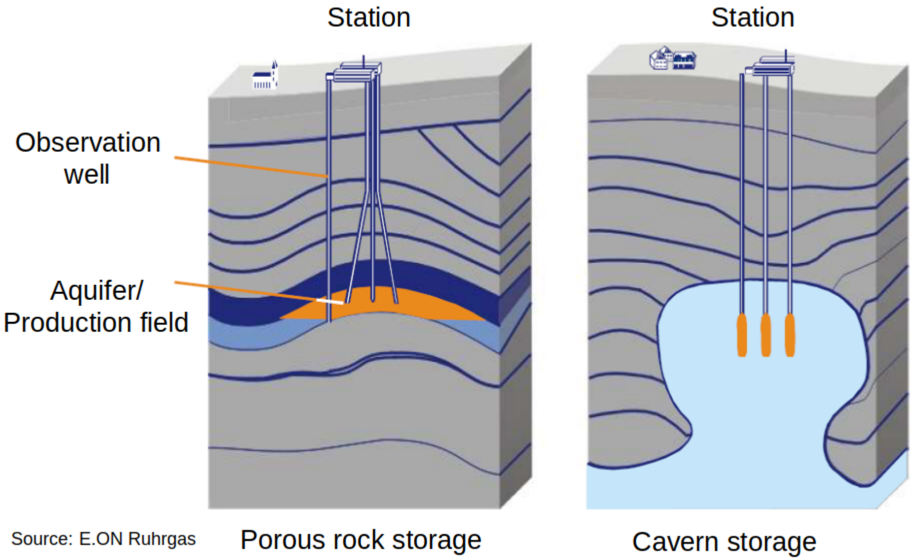
Source: Songhurst, OIES, 2018

LNG Impact on Global Gas Markets

- LNG trade leads to integration of regional gas markets
- LNG supply chain is more flexible
- LNG helps to develop more remote gas fields
- Diversification helps mitigate the holdup problem

Gas Storage

Gas storage technologies



Source: E.ON Ruhrgas

Gas storage facilities: Underground

Porous rock storage

- uses existing geological underground formations (e.g. depleted oil and gas fields, aquifers)
- relatively inexpensive (but higher investment costs for aquifers)
- large storage volume, but more cushion gas required
- low injection and withdrawal rate

Cavern storage

- artificial hollows carved out in underground rock or salt formations
- higher investment
- less cushion gas required
- higher withdrawal rate; fast switching between injection and withdrawal mode
- provide short-term flexibility

Gas storage facilities: Above-ground

LNG storage

- Insulated tanks at LNG terminals
- No cushion gas needed
- High injection/withdrawal rates

Gas tanks

- Low or high pressure
- Not economical for high volumes
- Local storage

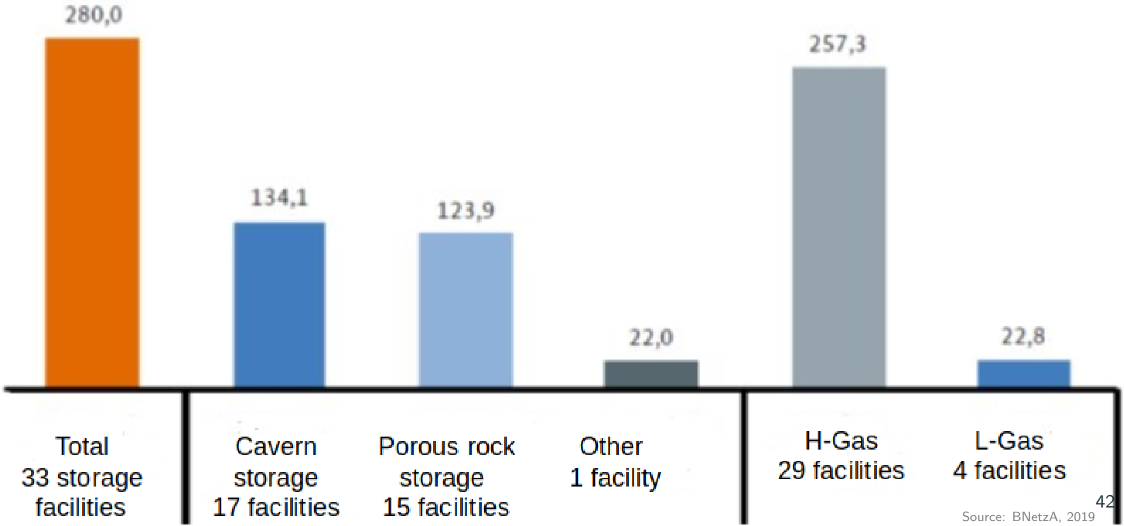
Line pack

- Gas stored inside pipeline through increased pressure
- Used to balance daily demand fluctuations

Gas storage facilities in Germany

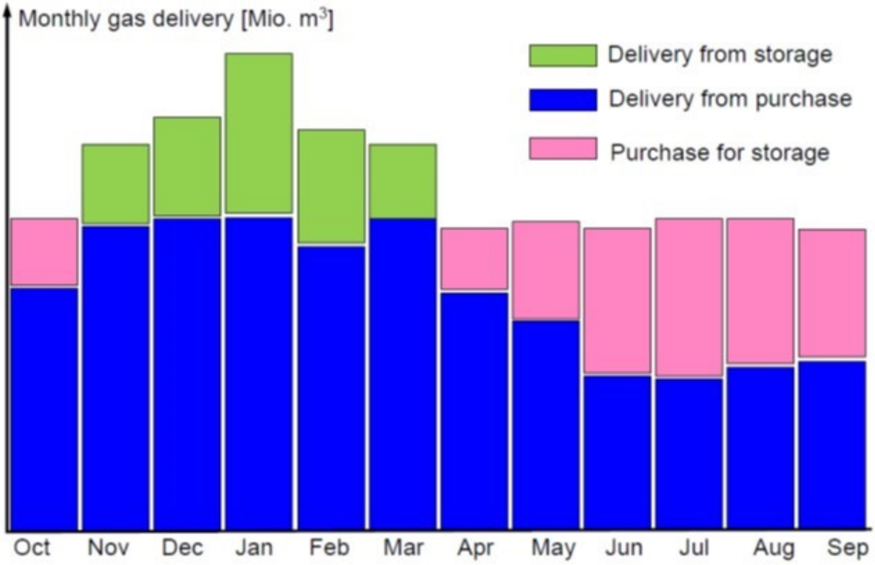
Technische Universität Berlin

Max. usable working gas volume on 31.12.2018, in TWh. See **AGSI website** for latest.



Source: BNetzA, 2019

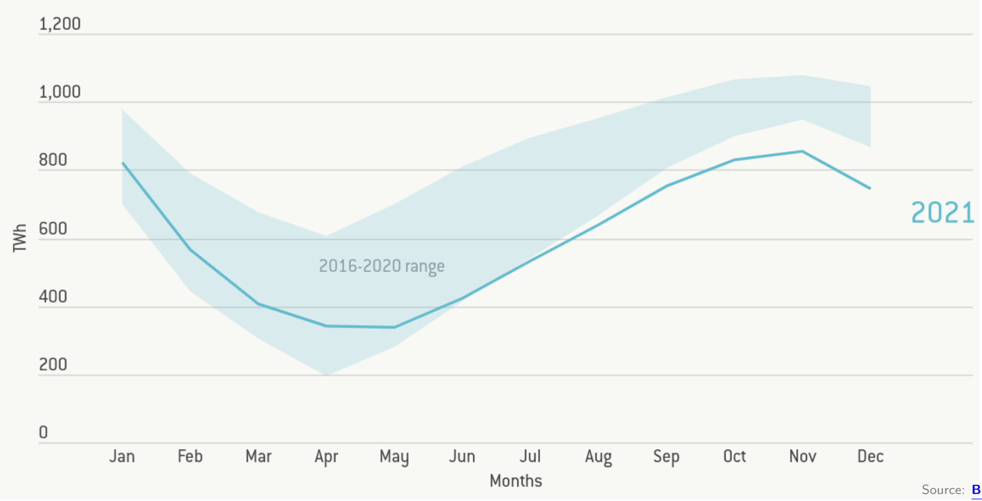
Merchant Use of a Gas Storage



Source: Prof. Erdmann

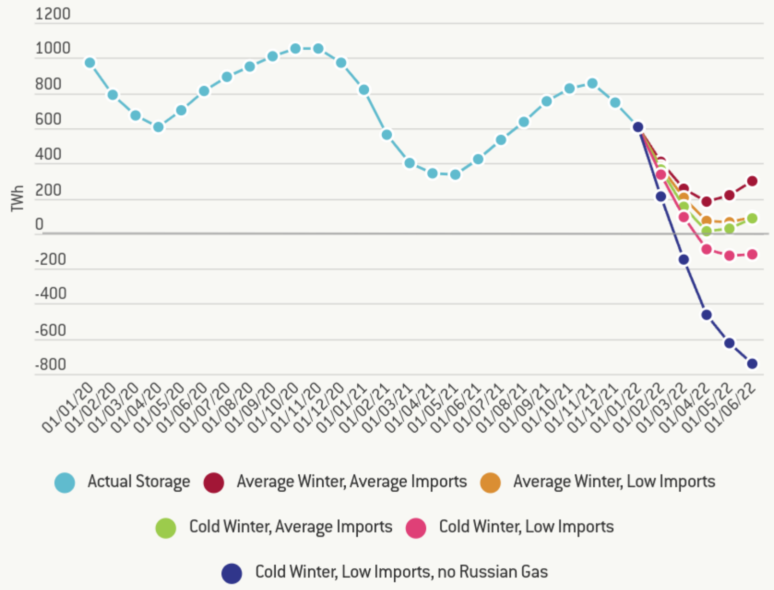
EU27: Filling level development

The filling level follows seasonal patterns; 2021 is an outlier because of insufficient filling over summer 2021 due to cold spring, low domestic production and low Russian supplies.



Source: Bruegel, 2021

EU27: Scenarios for 2022



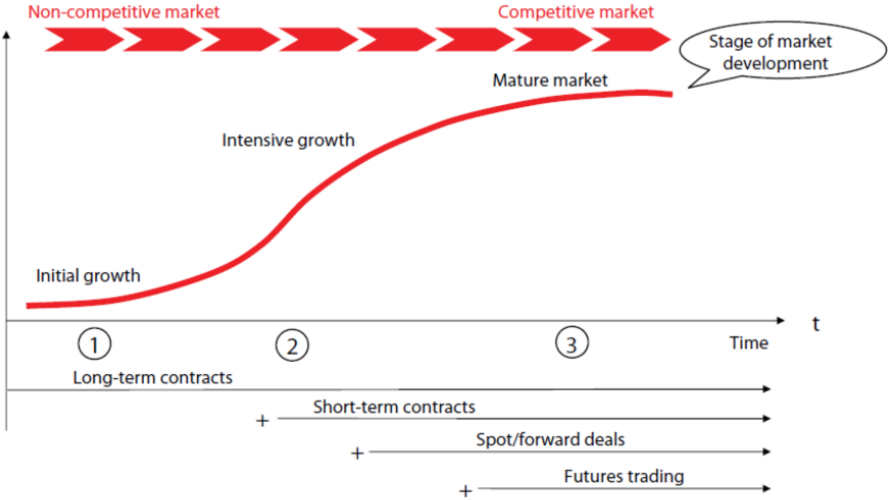
Source: Bruegel, 2021

Value of gas storage

- Storage buffers supply and (daily & seasonally fluctuating) demand
- Value of storage is determined by the cost of alternative sources of flexibility (transportation and capacity charges): production swings, take-or-pay, interruptible contracts, spot market
- **System value** from ability to inject a certain amount of gas in summer and withdraw it in winter
- Compensated by price during withdrawal minus price during injection, i.e. arbitrage with **seasonal spread** (difference in seasonal price)
- Ability to utilise the storage volume more than once (inject and withdraw gas) during the season to profit from short-term price volatility

Wholesale Markets for Gas

Dynamics of Gas Market Development



Pricing mechanism's development stages:

1 - cost-plus

2 - escalation formulas (based on alternative fuels prices)

3 - based on futures prices (commodities markets)

Source: Energy Charter Secretariat (2007) with reference to Konoplyanik

Regulatory push for move from LTC to spot market

The European Union's Third Energy Package, which entered into force in 2009, sought to promote an internal gas and electricity market.

The components included ownership unbundling (generation and supply from transmission) and a (non-binding) push to move away from long-term contracts to spot pricing in the gas market.

Why?

LTC prices are intransparent and showed big differences between regions. It was hoped liberalisation would encourage competition, create more market liquidity and bring down prices for consumers.

Long-term gas supply contracts in Europe

LTCs in decline for past 15 years; note that LTCs not just for pipeline import, but also LNG.

	Before 1990	1991–2007	2008–2014	2015–2018
Number of contracts	31	121	28	18
Total ACQ, billion cubic metres/year (bcm/y)	109	292	98	54
Average contract duration, years	23	18	15	14
Share of pipeline contracts	68%	53%	50%	22%
EU average gas consumption, bcm/y	345[a]	440	472	444
Share of total ACQ in consumption	32%	66%	21%	12%

ACQ annual contract quantity

[a]1990 consumption

Source: Chyong, 2019

Vertical Integration or Long-Term Contracts

In a world without vertical integration of (foreign) gas supplier and (domestic) gas importer, **long-term gas contracts** necessary in order to secure cash-flows required for pipeline (and other gas infrastructure) investments.

Selection of Gazprom's long term contracts 2007:

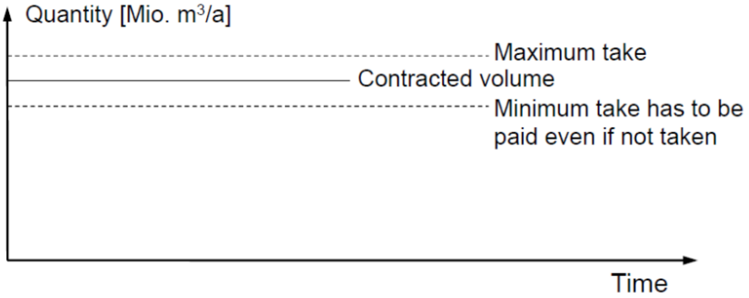
- E.ON Ruhrgas – until 2035, 20 bcm/year
- Wintershall – until 2030
- ENI – 2035, 3 bcm/year (Italy)

Gazprom as shareholder of European gas companies 2007:

- Wingas (50% minus 1 share, 100% since 2013): 2000 km Gas transmission lines, Natural gas storages in Germany with 2 bcm gas volume
- Europolgaz (48%), Eesti Gas (37.2%), Lietuvos Dujos (37.1%), Latvijas Gaze (34%), Gasum (25%), VNG (10.52%), Interconnector (10%)

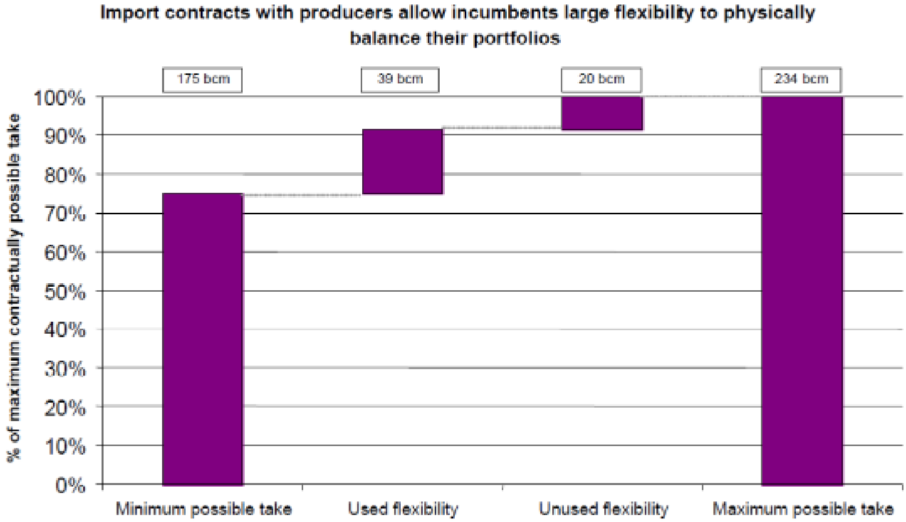
Take-or-Pay-Clause in Long Term Contracts

A long-term contract (LTC) must specify both **volume** and **price**. Both are associated with risks. For a **take-or-pay** contract, the **volume risk** is taken by the importer. If they use less than the contracted **minimum take**, they have to pay for it anyway.



The **price risk** is taken by the exporter, who may **index the price** according to the heating oil price (common up to 2010s) or to spot market prices (more common today).

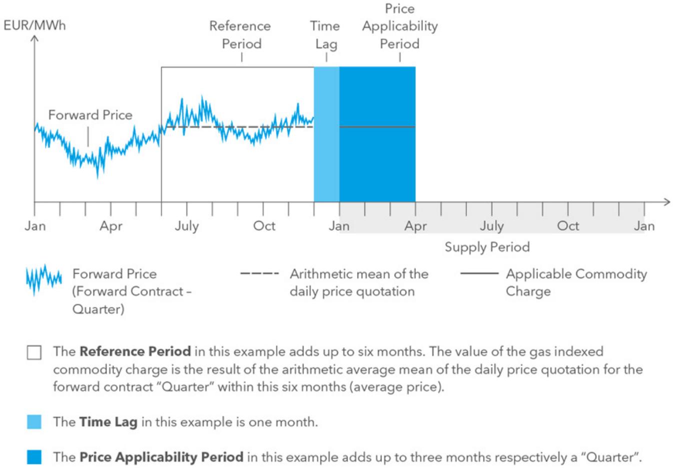
Volume Flexibility Under Long Term Contracts



Source: European Commission, Energy sector inquiry 2005-2006

Price-Indexing

Price-indexing refers to determining the price of long-term contracts based on other indices.



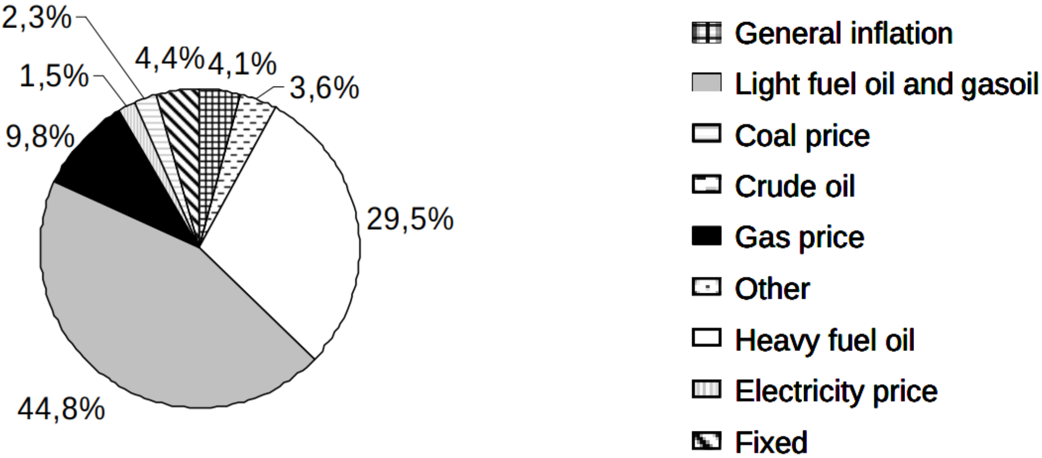
This example shows a 6/1/3 rule (6/3/3 is more typical for long-term gas contracts).

- 6 months: period over which we take average for price.
- 1 month: time lag to allow for calculation.
- 3 months: delivery period to which price applies.

Source: WINGAS

In past, gas often linked to oil

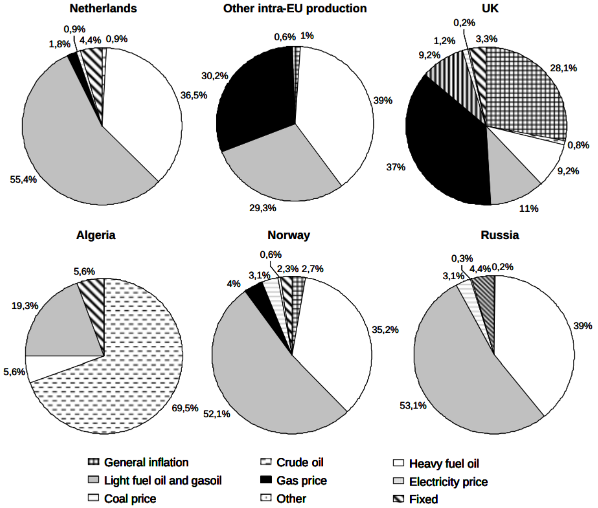
In 2004, oil-derivatives dominated the price indexation in the European Union:



Source: EC 2007 Energy Sector Enquiry

In past, gas often linked to oil

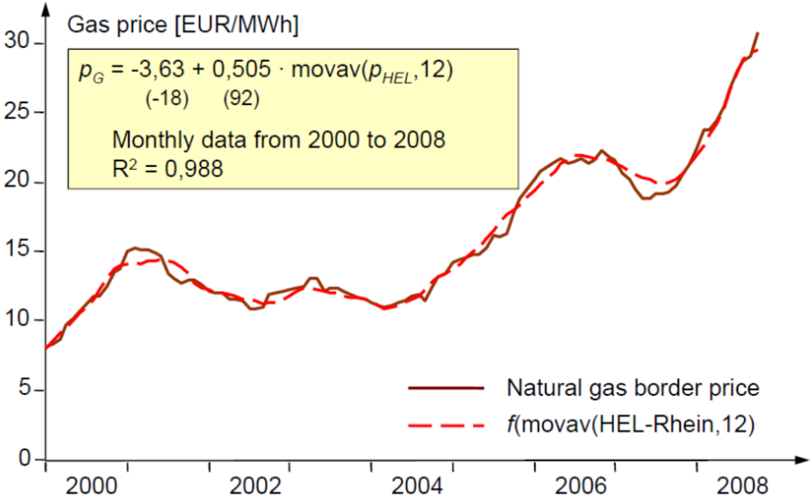
In 2004, there was a wide variety of products used for indexation in different regions.



Source: EC 2007 Energy Sector Enquiry

In Germany in past, strong coupling with heating oil

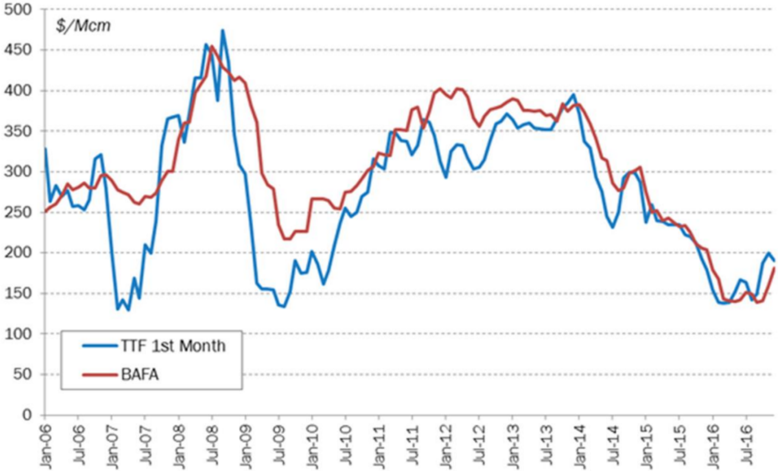
Because heating oil was a substitute for gas, the light heating oil Rheinschiene (HEL-Rhein) was used.



Source: BAFA

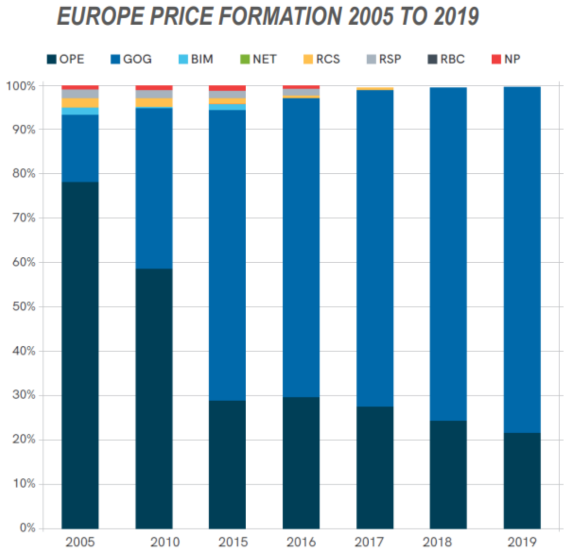
Today: stronger link to gas spot prices

But since early 2010s more contracts are linked to gas spot prices such as the TTF virtual hub in the Netherlands. (BAFA is Germanborder import price.)



Source: Gazprom

Move from oil-indexing to gas-on-gas competition



- Move from oil-price-indexing (OPE) to gas-on-gas competition (GOG), e.g. based on hub pricing at TTF
- Share of oil-indexation in Europe dropped from 78% in 2005 to 22% in 2019

Source: Gazprom; Wholesale Gas Price Survey 2020 Edition

Third-Party Access to Gas Infrastructure

Non-discriminatory (effective and transparent) access to gas transportation systems is a crucial prerequisite for a liquid market for natural gas.

Unbundling for gas TSOs (see EU Gas Directive 2009/73/EC): Transmission and distribution activities are separated from the rest of the value chain

- Ownership unbundling
- Independent system operator (ISO)
- Independent transmission operator (ITO)

Certification to ensure compliance with unbundling requirements for transmission system owner or TSO controlled by person(s) from third country(ies)

'Gazprom clause'

Gas Network Access Models

Point-to-point system (used in Germany until 2006)

- gas traders book specific transportation route from an entry to an exit point
- distance-based or flatrate fee
- somewhat intransparent, high costs

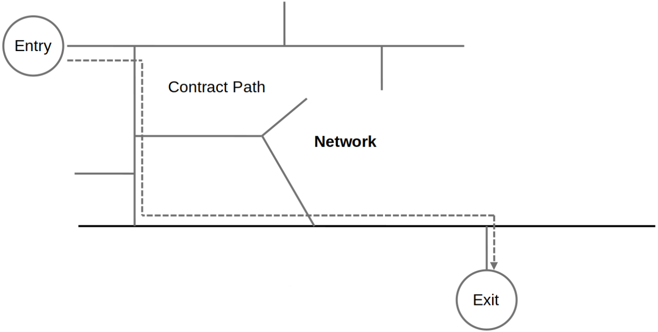
Entry-exit system (used in Germany since 2006)

- entry and exit capacities are booked separately
- entry fee and exit fee – no distance-related fee
- traders with entry capacities can sell gas to traders with exit capacities
- each exit point can be supplied from any entry point

Entry-exit system enables wholegas gas trading on virtual trading point (**virtual hub**) / market area level: gas is traded independently of its location in a market area.

Point-to-point model

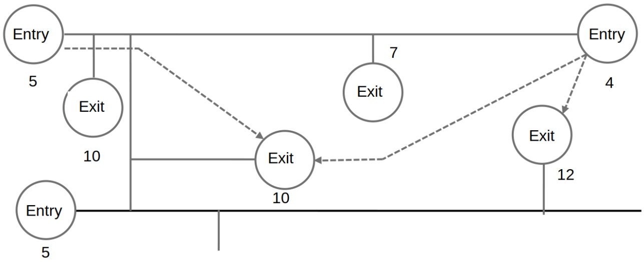
- Shippers specify entry and exit points and the transportation path.
- Actual physical flow may differ from the contracted path.
- Entry and exit capacities cannot be separated from each other and from the gas (commodity) transaction.
- Led to intransparency and high costs.



Source: Hewicker & Kesting, 2009

Entry-exit model (used in Germany since 2006)

- Shippers book entry and exit capacity independently from each other.
- No need to specify transportation path or distance.
- Contracts for entry and exit capacities are independent from each other and from commodity transactions.
- Entry and exit tariffs are set independently for each entry/exit point
- All network operators in a network zone cooperate and set tariffs on a cost-reflective basis.



Source: Hewicker & Kesting, 2009

Gas hubs both physical and virtual

Physical gas hubs where many pipelines meet e.g.

- Henry Hub (USA) – connecting point of 14 pipelines
- Zeebrugge (Belgium)
- Baumgarten (CEGH, Austria)

Virtual gas hubs for trading, e.g.

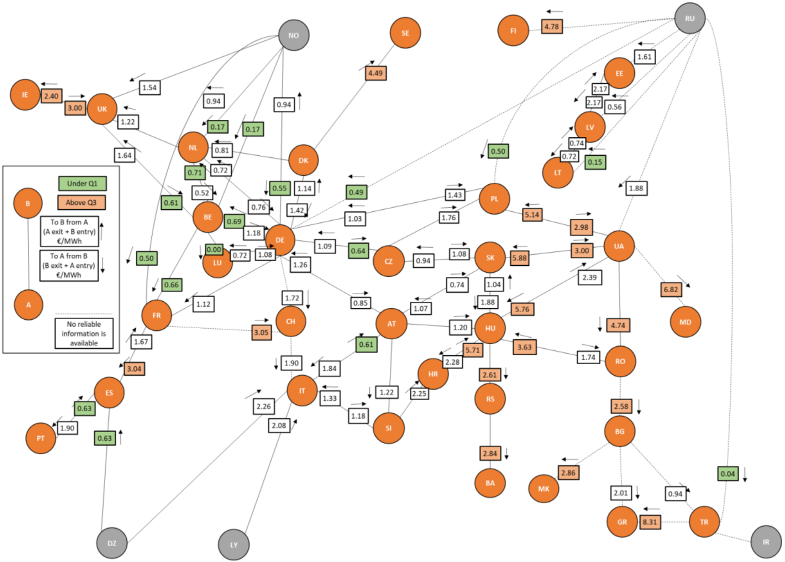
- NBP, National Balancing Point (UK)
- TTF, Title Transfer Facility (Netherlands)

(Cf. electricity grids with physical substations versus bidding zones.)

European gas regions, markets and hubs

Source: OIES (2017) with reference to www.worldatlasbook.com and P. Heather

Transmission tariffs in August 2017



Source: **European Commission, 2018**