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State of implementation of the Third Energy Package in the gas sector

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State of implementation of the Third Energy Package in the gas sector

This report focuses on understanding how the EU gas markets are functioning. To do so, the report gives an overview of the gas market legislation, describes the existing gas markets / hubs in the member states and reviews the various metrics used in the literature to define well-functioning gas markets.

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Executive summary

The key objective of this report is to have an overview of both the EU legislation related to wholesale gas market and its implementation via the Network Codes, and the current state of the wholesale gas market progression towards an integrated market.

Policy context

An integrated EU energy market is the most cost-effective way to ensure secure and affordable supplies to EU citizens. Through common energy market rules and cross-border infrastructure, energy can be produced in one EU country and delivered to consumers in another. This keeps prices in check by creating competition and allowing consumers to choose energy suppliers.

The Third Energy Package has been enacted to improve the functioning of the internal energy market and resolve structural problems. It covers five main areas:

— unbundling energy suppliers from network operators

— strengthening the independence of regulators

— establishment of the Agency for the Cooperation of Energy Regulators (ACER)

— cross-border cooperation between transmission system operators and the creation of European Networks for Transmission System Operators

— increased transparency in retail markets to benefit consumers.

Energy is often bought and sold on wholesale markets before reaching the final consumer. To ensure the smooth functioning of these markets and prevent price manipulation, the EU has enacted regulations which prohibit the use of insider information or the spreading of incorrect information concerning supply, demand, and prices.

The EU also passes rules on the use of cross-border energy networks. Known as network codes, these rules regulate who can use cross-border infrastructure and under what conditions.

The EU has also established the Madrid Forum, which meets once or twice a year to discuss the creation of the internal gas market.

In this policy context, the report makes a literature review concerning the wholesale gas market in different European areas and studies some of the Network Codes.

Key conclusions

Since the beginning of the process of energy market integration for gas, various research or European institutions have published metrics or criteria to assess the functioning of the wholesale gas markets. In this report we review those criteria and their application to the European gas markets / hubs. We also review the market definitions, actors, and geography.

As the market integration is a process resulting from the EU legislation, and is based, among others, on cross-border cooperation and infrastructure use and development, we study in more details three of the Network Codes on gas.

Main findings

From the review of the criteria assessing the functioning of the wholesale gas markets we found that by far, the most developed (also called mature or established) gas hubs are the National Balancing Point (NBP) in UK and the Title Transfer Facility (TTF) in NL. In 2016 TTF became the dominant European gas hub in terms of traded volumes and other criteria. There are also some active or advanced hubs that trade in particular in the spot and that are mostly balancing hubs.

On another hand, the adoption of the Network Codes increases transparency, fair access to cross-border trade and flexibility for the supply leading to a more attractive environment for the markets participants. If they are in place in all the member states it is likely for the related hubs to develop. It is hence very important to understand their implementation.

Related and future JRC work

This is the first report in a series related to the gas market(s) in EU. In the future, the work will be continued by selecting data sources regarding gas demand and gas prices in the EU, and available models to analyse them, with possible description of links to other markets (electricity, oil or other regions).

The monitoring of the state of implementation of the Third Energy Package will also be continued.

Quick guide

This report is structured as follows. Section 1 introduces the analysis. Section 2 gives an overview of the gas related EU legislation. Section 3 presents the EU gas markets, including the Gas Target Model, the metrics used by different actors to define a well-functioning market, the existing EU gas hubs and their scoring using the different metrics. Sections 4, 5 and 6 are dealing with the description of three Network Codes (Gas Balancing, Capacity Allocation Mechanism and Harmonized Transmission Tariffs).

1 Introduction

The purpose of this report is to provide the reader with a good understanding of the EU wholesale gas market. As energy markets are regulated, it is necessary to understand both the regulatory aspects and the market mechanisms.

In this first report, we present an overview of the gas related EU energy law, followed by a description of the EU wholesale gas market, including the description of the Gas Target Model and other metrics for well-functioning markets, as well as a description of the EU gas hubs.

Finally, we present three of the Network Codes (NCs) and their implementation. The three codes are the NC on Gas Balancing of Transmission Networks, the one on Capacity Allocation Mechanisms in Gas Transmission Systems, and the one on Harmonised Transmission Tariff Structures for Gas.

A NC is a set of common EU-wide rules in the form of an EU regulation established in accordance with the process in Article 6 of the Gas Regulation ([1]) for a given subject matter. NCs supplement the Gas Regulation and "amend… [its] non-essential elements".

All NCs constitute and form integral parts of the Gas Regulation; its consistent and coherent implementation requires due consideration of the interactions between the Gas Regulation and any given NC, and between NCs.

In the future, the work will be continued by selecting data sources regarding gas demand and gas prices in the EU, and available models to analyse them, with possible description of links to other markets (electricity, oil or other regions).

([1]) Regulation (EC) No 715 / 2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775 / 2005

2 Overview of the EU energy law

The European Union (EU) started with the European Coal and Steel Community (under the Paris Treaty) in 1951, created to prevent another world war. The European Coal and Steel Community was followed by the European Economic Community (under the Treaty of Rome) and the European Atomic Energy Community (under the Euratom Treaty), both established in 1957. It is hence obvious that energy, from the very beginning, is considered a fundamental part of European integration.

The primary legislation (i.e. the Treaties) was applicable to the energy sector, but as the topic was sensitive with regards to the national sovereignty, the member states (MS) did not initially transfer regulatory powers to the EU. Until the 1980s, national monopolies were not under the effect of the EU law.

In the next decade (1980-1990), the opening of the national markets to competition started, as a result of the belief that competition would bring efficiency and benefits for the consumers in terms of prices and choice of suppliers. The transformation of the European energy markets, from state monopolies to markets governed by private companies, led to issuing a large number of regulations and directives.

The goal of an integrated European gas market, enabling the free flow of energy throughout the EU through adequate infrastructure and without technical or regulatory barriers, is based on EU regulations that have been progressively introduced through different packages.

Moreover, article 194 of the Treaty on the Functioning of the European Union (Lisbon, 2007) introduces a specific legal basis for the field of energy based on shared competences between the EU and its member countries.

In **Table 1** we present a timeline of the European legislation and strategies for the gas sector.

Table 1. Main EU energy market legislation and strategies.

First Energy Package 1998	Directive 1998/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas
Second Energy Package 2003	Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC
Third Energy Package 2009	Regulation (EC) 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005
	Regulation 713/2009 establishing an Agency for the Cooperation of Energy Regulators
	Directive 2009/73/EC concerning common rules for the internal market in natural gas and repealing

	Directive 2003/55/EC
Market integrity (REMIT) 2011	Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on Wholesale Energy Market Integrity and Transparency (REMIT)
Network codes 2014-2017	Commission Regulation (EU) 2015/703 establishing a Network Code on interoperability and data exchange rules
	Commission Regulation (EU) No 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks
	Commission Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013
	Commission Decision (EU) 2015/715/EU amending Annex I to Regulation (EC) 715/2009 on conditions for access to the natural gas transmission networks
	Guidance on best practices for congestion management procedures in natural gas transmission networks [SWD(2014) 250]
	Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
Energy Union strategy 2015	Purpose: making energy more secure, affordable and sustainable Dimensions: – security, solidarity and trust – fully integrated internal energy market – energy efficiency – decarbonising the economy – research, innovation and competitiveness in low-carbon and clean energy
Clean Energy Package 2016 (proposal)	Regulation on the Governance of the Energy Union + other proposals
Security of supply 2017	Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010

Source: own compilation on https://ec.europa.eu/energy/en/topics

The first European Energy Directives provided for the liberalisation of energy markets and entered into force in 1998. Following that, several other pieces of energy market legislation were adopted, shifting from market liberalisation to energy market integration, and building the grounds for the Energy Union strategy. In 2003 and 2009, the second and third legislative packages respectively on the internal energy market entered into force. The third package introduced a clear separation of supply and production activities from network operation, a more effective regulatory oversight by independent national energy regulators, and a reinforcement of consumer protection. The goal was to open up the gas markets in the EU, to enhance investments in energy infrastructure and cross-border trade.

The Third Energy Package also created the instruments to achieve the goals set out in the Gas Regulation (EC) No. 715/2009 for a single energy market by developing European-wide network codes and guidelines which form a legally binding set of rules and obligations that govern access to and use of the European energy networks (cross-border capacity allocation mechanisms, rules on balancing, rules on transmission tariffs structures and rules on operability). The Third Energy Package initiated the creation of the European Network of Transmission System Operators for Gas (ENTSOG), as an association between gas transmission system operators (TSOs).

Moreover, the Agency for the Cooperation of Energy Regulators (ACER) was created by the third energy package as an independent European agency with the mission to have a central role in the development of EU-wide network and market rules for enhancing competition. It assists national energy regulatory authorities (NRAs) in performing their duties, coordinates regional and cross-regional initiatives which enhance market integration, monitors the work of the European Network of Transmission System Operators (ENTSOs) and evaluates their network development plans. ACER can issue both non-binding opinions and recommendations to national energy regulators, TSOs and the EU institutions as well as binding decisions in specific cases and on cross-broder issues.

The legislation related to the Third Package is overseen / implemented by Council of European Energy Regulators (CEER), ACER, and the ENTSOs.

The Third Energy Package also provides for issues related to vulnerable consumers (energy poverty), consumers' rights (switch energy providers, receive clear offers, contracts and energy bills), obligations on suppliers with regards to the contents of supply contracts etc.

In addition, more specific EU regulations exist, for example Regulation (EU) No 1227/2011 (REMIT) which introduced a sector-specific legal framework to identify and penalise insider trading and market manipulation in European wholesale markets.

Significant steps have been made towards the establishment of the internal energy market and the other objectives included in the Energy Union strategy (2015). However, the Commission has concluded that further efforts are still required. To support this, the Commission has agreed to monitor each year the progress made towards building the Energy Union. This State of the Energy Union was published for the first time on 18 November 2015 and brought together a series of Commission reports and initiatives. It also includes a report monitoring the progress towards the Energy Union objectives for each MS

separately. The second and the third reports on the State of the Energy Union were published in February and in November 2017.

As energy in the EU is regulated at national level, the aim of the Energy Union is to transform the EU's energy system that currently comprises 28 national frameworks into one EU-wide framework.

Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 aims to prevent gas supply crises and:

— requires that ENTSOG performs an EU-wide gas supply and infrastructure disruption simulation to provide a high level overview of the major supply risks for the EU

— requires EU countries to cooperate with each other in regional groups to assess common supply risks together (e.g. draft common Risk Assessments) and to develop and agree on joint preventive and emergency measures (to be reflected in their Preventive Action Plans and Emergency Plans)

— introduces the solidarity principle where EU countries must help each other to always guarantee gas supply to the most vulnerable consumers, even in severe gas crisis situations

— improves transparency: natural gas companies must officially notify to their national authority their major long-term supply contracts that may be relevant to security of supply (e.g. if the contract exceeds 28 % of the annual gas consumption in the MS)

— ensures that decisions on whether pipelines should have permanent bi-directional capacity (reverse flow) and to take into consideration the views of all EU countries that could potentially benefit.

3 The EU gas market

3.1 The Gas Target Model

In EU Regulation 715/2009 it is stated that: "To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system. The only way to do this is to give network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of along contractual paths."

Part of the agenda of the Third Package was to create a set of EU-wide NCs to facilitate cross-border gas transactions. TSOs should operate their network in accordance with those NCs. These NCs have to be in line with a set of non-binding Framework Guidelines and binding Guidelines on specific subjects developed by respectively ACER and the European Commission. In order to ensure that the Framework Guidelines do not conflict, a Target Model was developed. The 18th Madrid Forum ([2]) invited "the Commission and the regulators to explore, in close cooperation with system operators and other stakeholders, the interaction and interdependence of all relevant areas for network codes and to initiate a process establishing a gas target model".

CEER proposed a hub trading framework, namely the European Gas Target Model (GTM), which was endorsed by the 21st Madrid Forum in March 2012 to foster gas-on-gas competition and share its benefits across the MS.

The main principles of this first GTM are described below.

The European gas market will consist of interconnected entry-exit zones with virtual hubs. Entry-exit zones should allow shippers to trade gas freely within each entry-exit zone, such that internal physical congestion does not unduly restrict gas trading. Achieving the single gas market requires sufficient interconnection between markets; therefore the regulatory regime should signal where investment is needed and provide TSOs with a predictable framework for recovering sufficient revenues to cover costs. Once built, interconnection capacity needs to be easily accessible to shippers on a non-discriminatory basis and at a transparent and fair price. The capacity offered to the market needs to be maximised and contractual congestion should be mitigated, in order to deter capacity hoarding. Shippers need both long-term and short term capacity as gas may be traded both long and short term. Sufficient and accessible interconnection will promote liquidity in hub-based trading, which in turn will assist with the development of market-based balancing.

In January 2015, ACER renewed and updated the GTM while maintaining the core principles. The revised GTM guides the coherent development and implementation of the NCs and specifies the steps required to realise liquid and dynamic gas markets. It is denoted AGTM.

Several reasons were at the origin of revising the GTM, and one of them was the change in the dynamics of supply/demand. Concerning the demand side, the shale gas revolution in USA had a large impact in the sense that it put gas-intensive European industrial enterprises at a competitive disadvantage and it allowed for coal-fired generation to become more profitable than gas-fired power stations (because coal was available at lower prices due to its displacement from

([2]) https://ec.europa.eu/energy/en/madrid-forum-previous-meetings

the American power mix, and the carbon price was low). Concerning the supply side, the European gas production declined.

The model encouraged a self-assessment by the NRAs of the functioning of the national markets. Furthermore, this model recommended measures to overcome situations where the national sectors were not favourable to competition and market liquidity.

Overall, AGTM envisaged the amount of infrastructure that, if utilised efficiently, would enable gas to move freely across market areas towards where it is priced highest. In addition, AGTM defined measures for the harmonisation of the balancing system across MS, and mechanisms to enhance wholesale natural gas market quality, namely the level of trading activity, liquidity, resilience, volatility and competitiveness, to better sustain hedging and price risk management.

The AGTM includes an assessment of the functioning of wholesale markets at national level, developing a revised series of metrics to assess whether a wholesale market is "well-functioning". These metrics are based on the analysis of data and information that were not available when the first GTM was drafted and can be grouped into two key characteristics of markets:

1. They meet market participants' needs: products and liquidity are available that enable effective management of wholesale market risk; and,
2. They have market health: the wholesale market is demonstrably competitive, resilient and has a high degree of security of supply.

The AGTM proposes that all MS assess those metrics by 2017 (and every three years thereafter) in order to determine whether their market will be well functioning. If the market does not function properly, the AGTM suggests considering structural market reforms.

The market integration tools are ([3]):

1. Full market merger: full merger of two or more adjacent markets by merging their virtual trading points and balancing zones;
2. Trading region: partial merger of two or more adjacent markets at the wholesale level by merging their virtual trading points and establishing a cross-border trading balancing zone; and,
3. Satellite market: substantial linking (via pipeline capacity) of a non-functioning gas market to a directly neighbouring, well-functioning wholesale gas market.

3.2 Markets

3.2.1 Regulators and operators

Theoretically, gas can flow freely through the grids in Europe. In a single European energy market, all producers and suppliers are competing with one another. It should be possible to buy and sell gas wherever one wants, to obtain energy at the most competitive price. However, the development of cross-border energy businesses is still under the governance of national rules. An example may be that some players may have an unfair privileged access to energy grids

([3]) Presentation of ACER Gas Target Model - Annex 6 (https://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/default.aspx)

and the prices are set by governments. Investors might not be willing to invest because the outlook does not look very promising. Competition needed to be managed in a better way. Common rules on the equitable use of grids were introduced. The EU has an extremely important role to play here as, if it sets the rules, it also has extensive powers to supervise markets to prevent certain players from unjustly exploiting any kind of monopoly.

NRAs have a key role to play in ensuring that each European country meets its targets for energy markets and implement all EU regulatory policy. They act in the interest of the consumers. They can impose sanctions on operators that fail to comply with the requirements of the regulatory framework or do not implement its decisions.

A TSO is a regulated player in charge of the whole network operation.

There is only one NRA in a country, but there might be several TSOs, as for instance in Germany, where there are 16.

Table 2. List of regulators and gas transmission operators in the EU

Country	**NRA**	**TSO**
Austria	E-control (Energie-Control Austria)	Gas Connect Austria GmbH TAG GmbH (Trans Austria Gasleitung GmbH)
Belgium	CREG (Commission pour la Régulation de l'Electricité et du Gaz)	Fluxys Belgium SA/NV
Bulgaria	EWRC (Energy & Water Regulatory Commission)	Bulgartransgaz EAD
Croatia	HERA (Croatian energy regulatory agency)	Plinacro Ltd
Cyprus	CERA (Cyprus Energy Regulatory Authority)	
Czech Republic	ERO (Energy Regulatory Office)	NET4GAS, s.r.o.
Denmark	DERA (Danish Energy Regulatory Authority)	Energinet
Estonia	ECA (Estonian Competition Authority – Energy Regulatory Dept)	Elering AS
Finland	EV (Energiavirasto – The Energy Authority)	Gasum Oy (Gasum Corporation)
France	CRE (Commission de	GRTgaz

	Régulation de l'Energie)	TIGF SA (Transport et Infrastructures Gaz France)
Germany	BNetzA (Federal Network Agency for Electricity, Gas, Telecommunications, Posts and Railway - Bundesnetzagentur)	bayernets GmbH Fluxys Deutschland GmbH Fluxys Tenp GmbH GASCADE Gastransport GmbH Gastransport Nord GmbH Gasunie Deutschland Transport Services GmbH GRTgaz Deutschland GmbH jordgasTransport GmbH Lubmin-BrandovGastransport GmbH NEL Gastransport GmbH Nowega GmbH ONTRANS Gastransport GmbH OPAL Gastransport GmbH & Co. KG Open Grid Europe GmbH terranets bw GmbH Thyssengas GmbH
Greece	PAE / RAE (Regulatory Authority for Energy)	DESFA S.A. (Hellenic Gas Transmision System Operator S.A.)
Hungary	MEKH (Hungarian Energy and Public Utility Regulatory Authority)	FGSZ Natural Gas Transmission
Ireland	CER (Commission for Energy Regulation)	Gas Networks Ireland
Italy	AEEGSI (Autorita per l'energia elettrica il gas ed il sistema idrico)	Infrastrutture Trasporto Gas SpA Snam Rete Gas S.p.A.
Latvia	PUC (Public Utilities Commission)	Conexus Baltic Grid
Lithuania	NCC (Valstybinė kainų ir energetikos kontrolės komisija / National Control Commission for Prices and	AB Amber Grid

	Energy)	
Luxemburg	ILR (Institut Luxembourgeois de Régulation)	Creos Luxembourg S.A.
Malta	REWS (Regulator for Energy and Water Services)	
Netherlands	ACM (Authority for Consumers and Markets)	Gasunie Transport Services B.V. (GTS) BBL Company V.O.F.
Poland	URE / ERO (The Energy Regulatory Office of Poland)	Gas Transmission Operator GAZ-SYSTEM S.A.
Portugal	ERSE (Energy Services Regulatory Authority)	REN - Gasodutos, S.A.
Romania	ANRE (Romanian Energy Regulatory Authority)	SNTGN Transgaz S.A.
Slovakia	URSO (Regulatory Office for Network Industries)	eustream, a.s.
Slovenia	AGEN (Energy Agency)	PLINOVODI d.o.o.
Spain	CNMC (National Commission for Markets and Competition)	ENAGAS TRANSPORTE S.A.U
Sweden	EI (Energimarknadsinpektionen / Energy Markets Inspectorate)	Swedegas AB
United Kingdom	Ofgem (Office of Gas and Electricity Markets)	GNI(UK) Interconnector (UK) Limited National Grid Gas plc Premier Transmission Limited

Source: own compilation on https://eeueuropa.eu/national-regulatory-authorities-energy-europe/ and https://www.entsog.eu/members

3.2.2 Market definition, contracts, terminology

3.2.2.1 Market definition

The approach followed here is the one from four publications of P. Heather (Heather 2010; Heather 2012; Heather 2015 and Heather and Petrovich 2017).

For a liberalised wholesale market to be developed it is necessary that the industrial, commercial, and residential sectors are fully liberalised. This creates

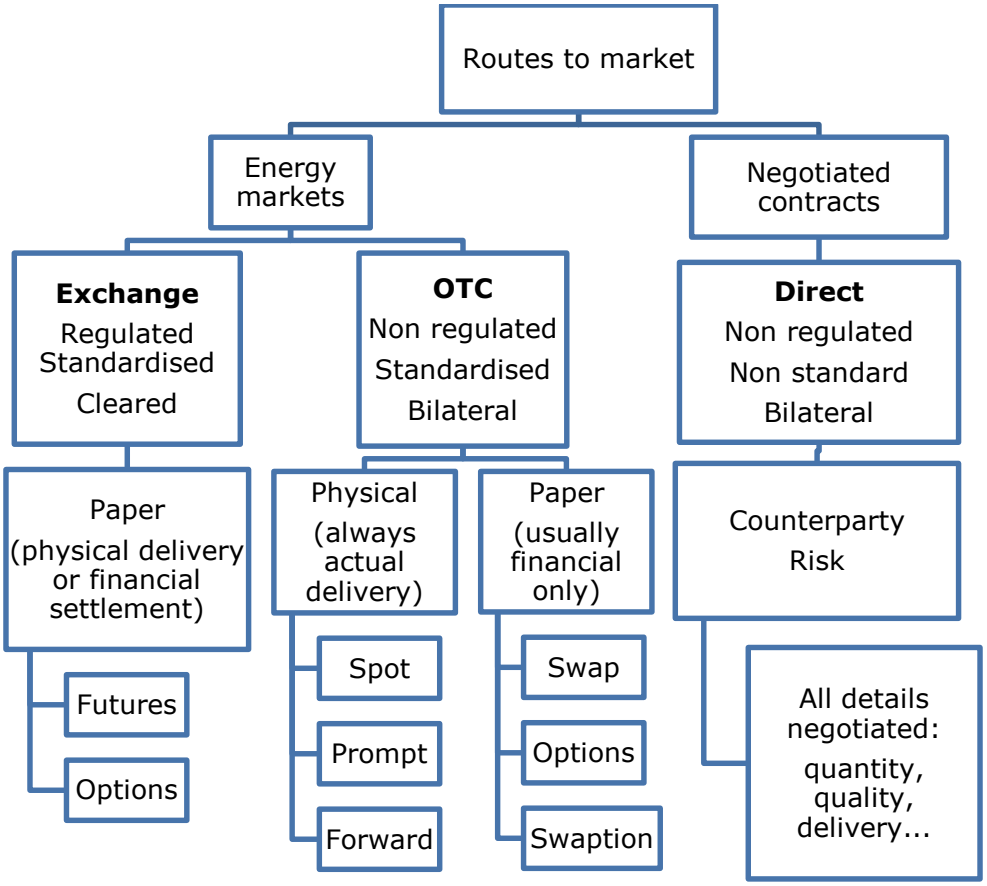
competition between suppliers on one hand and demand for competitive pricing on the other.

There are three main reasons for a company to trade: to buy or to sell gas for balancing a physical portfolio, to make financial hedging, and to speculate.

The first is the most obvious: a company sells to other companies or to end-consumers. The volume will depend on the consumption, production, price and sales forecasts. As the delivery date will approach, several layers of trading will be done to adjust the actual quantities to be delivered.

The reasons for trading determine which "route to market" (Heather 2015) to follow.

Figure 1. The routes to the market



Source: (Heather 2015)

3.2.2.2 Contracts and methods of trading

There are roughly three types of contracts: negotiated, over-the-counter (OTC), and exchange.

The negotiated contracts are individually negotiated on non-standard terms. Every aspect of this contract is negotiated in general over many months for the long term contacts with large quantities to be delivered.

The over-the-counter (OTC) market is a bilateral market where deals are done directly between two traders. The trades are conducted in a standardised way in one, or several, clearly defined time periods. This leads to easy trading, greater transparency, and liquidity. In a bilateral trading relationship only the two parties

know about the exact terms and conditions of the trading deal. For example the price is not published and cannot be seen by other market participants. This market is not regulated and therefore there is counterparty credit and performance risk which needs to be mitigated. On an OTC market, products are traded with similar delivery times to products traded on an exchange.

The exchange is an institutionalised marketplace. It is governed by the relevant financial regulator in each country. The products are standardised, meaning that the contracts are uniform in regard to their structure and form. Due date, place of delivery and the conditions for clearing and settlement are standardised. The set of rules such as the conditions to be admitted to trade on the exchange are made public and are the same for every market participant. Prices and revenues are also made public. Trading partners don't have to be found and the clearing house financially guarantees all of the trades executed. Since the trading process is anonymous, market participants can keep their strategy a secret. Exchange trading gas is becoming more popular since 2008, but the market penetration varies from country to country. The European exchanges that offer gas contracts are: ICE, ICE-Endex, EEX, Powernext, CEGH, and GME. The most important one is ICE ([4]).

The methods of trading are either direct of via brokers, voice or electronic, but most of the trades are made via brokers. The brokers have their own trading platforms.

The length of time forward that it is possible to trade is called the "curve". The traded curve covers the:

- Spot curve (today or tomorrow)
- Prompt curve (all other periods within the month or the next month)
- The near curve (the first two season; there are two 6 months seasons: winter and summer, starting 1st October and 1st April respectively)
- The mid curve (two years forward)
- The far curve (everything beyond that, usually 5 years forward)

The spot and prompt contracts cover days or group of days such as Within Day (WD), Day Ahead (DA), Balance of Week (BOW), Weekend (WE), Balance of Month (BOM), and the Month Ahead (MA). The curve trades in months, quarters, seasons and years.

The reason for trading in the spot and prompt contracts is to physically optimise or balance a portfolio at, or just ahead of delivery. Most trading activity takes place in the prompt and near curve, and the most popular contracts are WD, DA, MA, and the front two seasons. Roughly, 70-80 % of the volume is traded in the spot, prompt, and near curve.

3.2.2.3 Terminology

Other terminologies used for the gas in the gas market are:

- Traded gas: gas bought and sold at the hubs, for physical delivery, for financial hedging or for speculation. It is usually a standard product on OTC or exchange market, mostly for spot, prompt or near mid curve maturity.

([4]) https://www.theice.com/energy/natural-gas-futures

— Contracted gas: gas traded or contracted bilaterally for delivery at a hub and can be a standard product or bespoke, of any time duration (often medium to long term). It includes the traditional Continental European long term contracts (LTCs) as well as the British contracts. They are concluded either directly between the buyer and the seller or on the OTC market. The typical duration is of 20-30 years for the Continental European LTCs and of 8-12 years for the British ones.

— Exchanged gas: gas that is physically nominated and delivered at, or taken from, a hub. It is the physical part of gas contracts.

3.3 Metrics for well-functioning markets

3.3.1 The AGTM metrics

ACER's 2014 Gas Target Model metrics are presented below.

Table 3. ACER's 2014 Gas Target Model metrics

Metric		**Threshold**		
Market participants' need		Day-ahead Product	Front Month product	Forward
Pre-transactional liquidity				
1	Order book volumes	≥ 2,000 MW on each bid-and offer-side	≥ 470 MW on each bid-and offer-side	≥ 120 MW on each bid-and offer-side for 17 months ahead
2	Bid-offer spread	≤ 0.4% of bid-price	≤ 0.2% of bid-price	≤ 0.7% of bid-price for 24 months ahead
3	Order book price sensitivity	≤ 0.02% price distance between average price for 120 MW and best price on each bid- and offer-side	≤ 0.1% price distance between average price for 120 MW and best price on each bid- and offer-side	≤ 0.2% price distance between average price for 120 MW and best price on each bid- and offer-side for 24 months ahead
Transactional liquidity				
4	Number of trades	≥ 420 trades per day	≥ 160 trades per day	≥ 8 trades per day for 22 months ahead

Market health		Spot, prompt and forward market together
5	Herfindahl-Hirschmann Index	≤ 2000
6	Number of supply sources	≥ 3
7	Residual Supply Index	≥ 110%
8	Market concentration for bid & offer activities	≤ 40% market share per company (or group of companies) for the best 120 MW on each bid- and offer-side
9	Market concentration for trading activities	≤ 40% market share per company (or group of companies) for the sale and purchase of gas each

Source: ACER([5])

The metrics are defined here below.

1. Order book volume. Sufficient bid and offer volumes in the order book which deliver gas reasonably far into the future allow market participants to buy and sell gas when they need it and support effective risk management.
2. Bid-offer spread. Low bid-offer spreads mean low transaction costs for market participants and support market participants who have less flexibility with respect to when they can trade (as a percentage).
3. Order book price sensitivity. Low order book price sensitivity means less additional cost for market participants when buying or selling substantial volumes and supports market participants who have less flexibility with respect to when they can trade (as a percentage).
4. Number of trades. Sufficient trading activities support market participants' confidence that prices are transparent and represent a reliable market price.
5. Herfindahl-Hirschmann Index. The Herfindahl-Hirschmann Index (HHI) is a measure of the level of concentration in a market and is often used by competition authorities when investigating mergers or acquisitions. It ranges from 10000/N to 10000, where N is the number of firms in the market and when the shares of the firms are expressed in percents. A higher HHI implies a higher concentration, i.e. fewer suppliers or a greater market share accounted for by a few suppliers.
6. Number of supply sources. The number of supply sources from which a Member State procures gas is a first indicator for the level of concentration in upstream supply to that country. Three or more supply sources per country are considered the minimum to achieve a reasonable diversification of supplies.
7. Residual Supply Index. The Residual Supply Index (RSI) measures the reliance of a market on its largest supplier. The supply capability of all but the largest supplier should amount to 110 % of demand.
8. Market concentration for bid & offer activities. This metric measures the market share per company or group of companies based on the bid and offer

([5]) Presentation of ACER Gas Target Model - Annex 3 (https://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/default.aspx)

order volumes placed. Lower market shares support a higher level of competition.

9. Market concentration for trading activities. This metric measures the market share per company or group of companies based on the traded volumes. Lower market shares support a higher level of competition.

As the metrics are used by every MS for the self-assessment, precise details with regards to the definitions and calculations are given in ([5]).

3.3.2 The OIES (P. Heather) metrics

The Oxford Institute for Energy Studies (OIES) performs thorough analyses of the European gas traded hubs (Heather 2010; Heather 2012; Heather 2015, and Heather and Petrovich 2017).

The hubs are assessed based on their maturity and development, from a liquidity and price perspective, in order to see the state of achievement of the "Single Energy Market" for natural gas. The assessment is made by using a certain number of metrics for liquidity and for prices. A ranking of the European gas hubs is also proposed based on those metrics.

The metrics have been built taking into account three areas of concern:

— Liquidity and data transparency. There is a lack of common methodology with regards to the available data and its timeline. It is easy, for instance to know the physical flow volumes on a near real-time basis in UK and NL while it is more difficult and with a greater delay to know them for FR, BE, and DE.

— Physical connectivity. The infrastructure should be such as to allow better physical transportation of gas and prevent price distortion. Each single entry/exit market area has to be balanced every day, and therefore the infrastructure should be flexible enough to permit that. The removal of the bottlenecks in the infrastructure is costly (estimated at €200 bn ([6])) and it is not immediate. Some of the needed projects may not even obtain financial approval due to poor cost/benefit analysis (CBA). This is the main reason, for instance, for keeping two German market areas instead of merging them. One way to circle the problem is to couple only the financial part (also called "market coupling"). An example of market coupling has been done between the Dutch grid and the Gaspool German grid, where the coupling was offered and managed by the Dutch TSO GTS (Gasunie Transport Services) and the German TSO Gasunie Deutschland.

— Political willingness and cultural attitudes. The governments in UK and NL had a political willingness to have liberalised markets and to ensure this, they passed the necessary laws. As a consequence, such markets exist in those two countries. Later on, the Austrian government pushed for reform of the network and for changes in commercial practices and the new VPT hub is on the right track with regards to the liquidity.

  Other EU MS have passed laws derived from the Energy Packages, but few have ensured their effective implementation.

([6]) https://ec.europa.eu/energy/en/topics/infrastructure

On the "cultural" side, it should be noted that there are very different attitudes across Europe with regards to the liberalisation of energy markets and to trading.

Table 4. Metrics of P. Heather

Liquidity metrics		**Description**
1	Market participants	The number of active participants (good indicator for the degree of development of the hub)
2	Traded products	Type of traded products (good indicator to assess if the traded market is used for balancing or for risk management)
3	Traded volumes	Quantity of traded products (good indicator for the market activity and development; sign of a hub's relative importance)
4	Tradability index	ICIS index for liquidity
5	Churn rates	Ratio between the traded volume and actual physical throughput (most important of the liquidity metrics; measure of a gas hub's commercial success)
Price metrics		**Description**
6	Price signals	Frequency of the price signals for traded gas (frequent - i.e. daily - price signals are a prerequisite for a well-functioning traded commodity market as they provide transparency and an efficient allocation of the commodity across different locations and market participants)
7	Price convergence between OTC and exchange	They should not be significantly different
8	Price correlation score between adjacent markets	Assess the efficiency of cross-broder trading and the degree of integration between hubs
9	Price volatility	It is expected for the adjacent hubs' prices to move in the same direction, for both high and low volatilities. It is the most representative metric of market risks: different volatilities between the prices in two hubs indicates that it is not wise to use one hub to financially hedge a physical position in the other

Subjective indicators		Description
10	Political will	Expected implementation date of the Balancing Network Code (BAL NC)
11	Cultural attitudes	Historical attitude of nations to trading, which make Europe-wide implementation of standardised trading rules very difficult (also difficult to pin down)
12	Level of commercial acceptance	Change in the historical gas contracts in Europe. Role of the regulatory authorities and the TSOs in making the change

Source: adapted from (Heather and Petrovich 2017)

A classification of the gas hubs as mature, active, poor and inactive based on a simple scoring methodology applied to the five liquidity metrics is extensively used.

The subjective indicators are not really evaluated except maybe for the political will, but a proxy is considered instead. The proxy is the score proposed by the European Federation of Energy Traders (EFET). The use of this proxy is quite straightforward, as the EFET scores are divided in categories for which different bodies are responsible: NRAs, TSOs and the market, as we will see in the next section.

3.3.3 The EFET metrics

Table 5. EFET metrics

Description		Scoring method
Regulatory (NRA) conditions		
1	Establish a consultation mechanism	1 if group set up and English language
2	Resolve market structural issues (defined role for historical player: gas release programs, transport capacity release programs, market maker obligations, etc.)	½ for release etc.; 1 if market maker
3	Defined Role of Hub operator (what are its responsibilities in comparison with the TSO)	1 if role defined; 2 if governance addressed
4	Agree regulatory jurisdiction if cross-broder	0 if cross-broder and no agreement; 1 if not cross-broder or does have agreement
5	Establishment of exchange	1 if exchange appointed and hub is liquid; ½ if exchange appointed and hub illiquid

TSO conditions		
6	Entry-exit system established	1 for Entry Exit with a single VTP
7	Title Transfer (gas can be traded without physical delivery, usually by transfer between balancing groups)	
8	Cashout rules (long short positions set to zero at the end of the balancing period against payment of penalty in €/MWh)	
9	Accessible to non-physical traders (to trade gas you do not require to flow gas physically from entry to exit)	1 if trade without signup to physical rules
10	Firmness of hub (cash out rules instead of pro rata curtailment of flows in case not enough gas is traded at the hub)	0 if not firm; ½ if firmness "managed" by TSO; 1 if Back-up-Back-down; 2 if fully market-based
11	Credit arrangements non-punitive	
Market conditions		
12	Establish a reference price at the hub for contract settlement	1 if price always available; ½ if deemed
13	Standardised contract (e.g. EFET Master Contract)	1 if specialised contract – EFET or equivalent (or standard is sufficient)
14	Price Reporting Agencies active at the hub	2 if several, 1 if only one PRA
15	Market makers	1/2 if only 1 or 2; 1 if several or not necessary any more
16	Brokers	½ if voice or few ; 1 if systems and many
17	Index becomes reliable and used as benchmark	1 if market parties frequently requested

Source: adapted from (EFET 2017)

3.4 The European gas hubs

3.4.1 The gas geography

The geographical areas in relation to gas markets/hubs are defined differently by institutions such as ENTSOG and International Gas Union (IGU), as well as in the OIES papers or gas Regulations.

Concerning ENTSOG, there is a legal requirement to promote regional cooperation (EU Directive 2009/73/EC and EU Gas Regulation (EC) 715/2009), following which the TSOs are publishing the Gas Regional Investment Plans (GRIPs) on a biennial basis.

Based on an analysis of transmission system interconnections and operation, as well as infrastructure development needs, the ENTSOG TSOs agreed on six regional groupings, in some cases overlapping, to develop the first GRIPs. The groupings are:

- GRIP North-West (9 countries): Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, Sweden, UK
- GRIP South (3 countries): France, Portugal, Spain
- GRIP CEE (10 countries): Austria, Bulgaria, Croatia, the Czech Republic, Germany, Hungary, Poland, Romania, Slovakia, and Slovenia)
- GRIP BEMIP (7 countries): Denmark, Estonia, Finland, Latvia, Lithuania, Poland, Sweden
- GRIP Southern Corridor (9 countries): Austria, Bulgaria, Croatia, Hungary, Greece, Italy, Romania, Slovakia, and Slovenia
- GRIP South-North Corridor (6 six countries): Italy, Belgium, France, Germany, Luxembourg and Switzerland

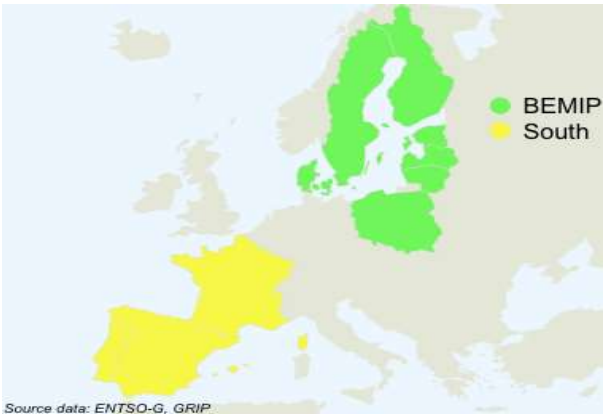
Figure 2. Map of the ENTSOG/GRIP regions North West and Central Eastern Europe

Source: own elaboration on ENTSOG/GRIP

Figure 3. Map of the ENTSOG/GRIP regions North West and Central Eastern Europe

Source: own elaboration on ENTSOG/GRIP

Figure 4. Map of the ENTSOG/GRIP regions BEMIP and South



Source: own elaboration on ENTSOG/GRIP

IGU uses the following (non-overlapping) classification, which includes more countries than the MS:

— North-west Europe: Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, UK

— Central Europe: Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland

— Mediterranean: Greece, Italy, Portugal, Spain, Turkey

— South-east: Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia

— Scandinavia and Baltics: Estonia, Finland, Latvia, Lithuania, Norway, Sweden

Figure 5. Map of the IGU regions

Source: own elaboration on IGU data

Heather (2015) uses another classification, based on the level of development of the gas hubs and on the evolution in price formation (from oil indexation to market pricing). Within each area different levels may coexist.

— North-West Europe (NEW): Belgium, France, Germany, Ireland, Netherlands, UK

— Central European (CE): Austria, Czech Republic, Hungary, Poland, Slovakia

— South-East Europe (SEE): Bulgaria, Croatia, Greece, Romania, Slovenia, Turkey, and all the resting countries from the Balkans

— Iberian Peninsula (SWE): Portugal, Spain

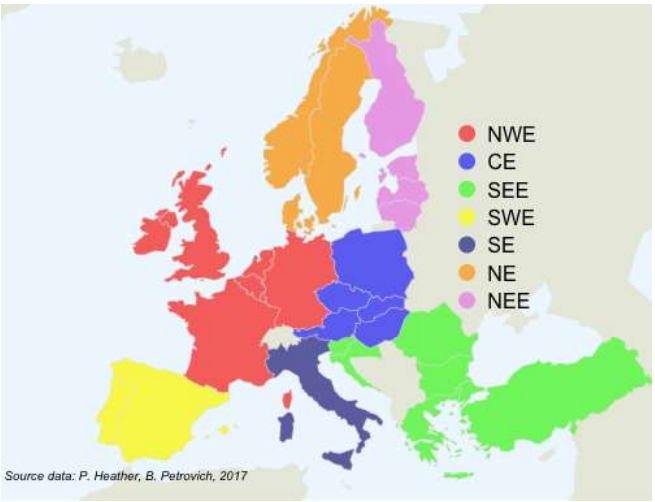
— Southern Europe (SE): Italy

— Northern Europe (NE): Denmark, Sweden

— North-East Europe (NEE): Estonia, Finland, Latvia, Lithuania

— Central Eastern Europe (CEE): Ukraine (not represented on the map).

Figure 6. Map of P. Heather regions



Source: own elaboration on (Heather and Petrovich 2017)

Finally, the Regulation (EU) 2017/1938 on the security of gas supply provides for risk assessment and preventive action and emergency plans at regional level. The regions for their preparation are represented here below.

Figure 7. Map of the regions in the security of gas supply Regulation 2017/1938

Source: own elaboration on DG Energy data

3.4.2 The European natural gas hubs

Gas market liberalization has been implemented using different mechanisms for allocating network services. In the EU, the mechanism is called entry/exit allocation, or virtual hub, and was designed to reduce the need for explicit negotiation of network services.

It is based on the implementation by a TSO, and characterised by a combination of explicit and implicit allocation of gas transmission services. The idea behind it is to simplify the network topology to a simpler set of entry and exit points (a "commercial" network that represent partially the physical network). All explicit allocation is reduced to buying separately entry and exit rights. After that, shippers do not need to buy additional transmission rights (such as flexibility rights) but they are allocated implicitly by TSOs (according to a set of rules defined by the regulator). With it, one avoids the explicit allocation and renegotiation of complex spatial and temporal characteristics of the network, but the counterpart is that it is difficult to compute the capacity to be sold.

The liberalisation of natural gas prices and increasing flexibility in the gas market means that market centres and hubs are continuously being developed. A gas hub is a virtual or physical location within the grid where the exchange of gas volumes takes place; it is a gas market where the commodity is traded on a standardised basis between market participants.

The higher levels of trading at gas hubs will lead to the development of gas spot markets and then to the development of financial gas markets. Financial gas trading means that non-gas players, such as banks, institutional investors and pure trading firms, can enter the market and take on gas-specific risks. Financial gas contracts are used to manage two types of risk in the natural gas market: price and basis risk. Price risk is generated by the volatile spot market prices of natural gas. Basis risk is the risk of change in the price differential between locations, time periods, and qualities of natural gas deliveries, and between

natural gas and other commodities. Transparency and liquidity are the fundamentals for success for a natural gas trading hub.

All the European natural gas hubs are balancing hubs. This means that they are used by Shippers to balance their portfolios near to maturity and at delivery and by the TSO to physically balance the gas grid (in general daily). If the hubs are used by shippers to risk manage their portfolio then they are also trading hubs.

Therefore, trading at balancing hubs mainly involves spot/prompt markets. Spot prices are set according to the prevailing conditions of supply and demand. Published spot price indices are available for natural gas at different hubs from different providers (e.g. from ICIS, Platts), as well as listed across European energy exchanges (e.g. Powernext at the PEG Nord hub, ENDEX at the TTF hub, EEX at the NCG and GasPool hubs). Nevertheless, hubs are increasingly used as financial hubs to hedge risk and manage portfolios through derivative instruments.

The most mature and successful hubs in EU are both balancing and trading ones.

Heather (Heather 2015) defines the concept of maturity and requirements for success.

The maturity of a hub is achieved through a 10-15 years process. The steps to the maturity are:

— Third Party Access (TPA) to the infrastructure (it requires legislative changes to force the incumbents to release infrastructure capacity and gas supply volumes; it gives incentives to independent companies to enter the market)

— Bilateral trading

— Price discovery and disclosure

— Balancing rules and regulations for the physical market and standardised trading contracts for the commercial part

— OTC brokered trading

— Entry of non-physical players

— Creation of exchange products (futures) based on the underlying physical contracts

— Development of the forward curve (used for risk management)

— Use the specific traded products (DA or MA) as indices on which traders price the physical transactions (possible if there is enough liquidity).

The requirements for a successful hub are:

— Liquidity, defined as:

- The ability to quickly buy or sell a commodity without a significant change in its price and without incurring significant transaction costs.
- A liquid market is a place where standard transactions can be executed quickly and where a large transaction volume has only marginal price.

— Volatility, defined as a measure of price movement in relation to market activity (energy markets are typically very volatile)

- Historical volatility is a statistical measurement (dispersion) based on a dataset of realised historical price return observations over a specified time period.
- Implied volatility is the level of volatility expected by the market from the prices of traded gas options (it is calculated using the option pricing formula, for instance Black Scholes)

— Anonymity: the Clearing House is the counterparty to all trades, allowing big and small participants to trade alongside each other.

— Transparency: traded volumes and prices are disseminated to the public in an accurate, reliable and timely manner

— Traded volumes: total actual volume traded in a market

The main participants in a hub may be classified into the following categories: banks and funds, producers, end users, proprietary traders, other European players, OTC brokers, the TSO (which will trade in order to balance the network), institutional investors, private investors, commodity traders.

The EU gas hubs are listed below.

The National Balancing Point (NBP) in the UK started trading in 1996 and represents the most mature hub in Europe. The NBP is a notional point (the whole National Transmission System) created by a network code in UK in order to promote its balancing mechanism, where shippers nominate their buy and sell trades and where the TSO can balance the system on a daily basis. NBP rapidly evolved as a trading point.

The prices at the NBP hub serve as a benchmark for almost all traded gas in the UK. The NBP is connected to Continental Europe by the Interconnector (BE) and the Balgzand Bacton Line (NL).

The Title Transfer Facility (TTF), in the Netherlands, started trading in 2003, but only since 2012 it has been attracting participants, with increasing degree of price transparency and market liquidity. TTF is a virtual trading hub. As of 2014, TTF has taken first place in terms of traded volumes in Europe, overtaking the NBP. This has been partly attributed to increased liquidity at the TTF hub due to a change in balancing regime implemented in June 2014. TTF also remains a preferred benchmark for traders managing their gas portfolios.

Zeebrugge (ZEE), in Belgium, started trading in 2000. Since 2012, there is a virtual hub,). Zeebrugge is also the physical location where the pipeline Interconnector, joining the UK with the Belgian market, and consequently with the Continental Europe markets, converges. Whilst both the NBP and TTF hubs are widely used for financial hedging and risk management, ZEE remains based on the balancing needs of the market participants, and/or spread trading between ZEE, and either NBP or TTF (Heather 2015).

It should be noted that the Luxembourg and Belgian gas markets were merged at the end of 2015. This market integration reflects the European Union's ambition to create a borderless integrated gas market where gas can move freely from one country to another. ZTP is the trading point for the integrated market. The two TSOs keep their distinct identities and organisational structures.

NetConnect Germany (NCG) and GasPool (GP), in Germany, are the two hubs corresponding to two market areas. Both started trading in 2009 although traded

volumes have been increasing since 2014. Trading activity is mainly driven by spot/prompt trades. Futures trading is also increasing, mostly at GasPool , because of the start of the Nord Stream pipeline linking Russia and Germany (in 2012). The German configuration is different from the one in the rest of Europe, because the two hubs are run by several TSOs (8 for GasPool and 6 for NCG). If the German market cannot unite into one market area, this might prevent further development of a German hub.

Point d'Echange de Gaz Nord (PEG Nord) and Trading Region South (TRS), in France, are the two hubs corresponding to two market areas. TRS was launched on 1 April 2015 as the product of the merger between the PEG Sud and the TIGF trading regions in the South of France, and is one of the first cases of successful market integration between gas hubs. TRS was established with the aim of increasing the liquidity and depth of the southern French market. PEG Nord has the majority of the traded volumes. The main problem is that there insufficient physical capacity in the connection of the two zones. PEG Nord is well connected to pipeline gas supplies and to LNG imports, while TRS depends on LNG imports, which may be supplemented by pipeline supplies from PEG Nord. There is a market-coupling scheme between the two areas which may work as long as there is a reasonably good physical infrastructure on both sides. The plans to increase the capacities between N/S have been postponed and should be ended in 2019. PEG Nord and TRS constitute two balancing areas for shippers and allow both for a bilateral OTC exchanges as well as exchanges on Powernext Gas. Different products can be traded at Powernext: within day, day-ahead, month ahead. On PEG Nord monthly, seasonal, quarterly and yearly products can be traded up to two years ahead. The price spread between the two zones The French National Regulator (CRE) wants to establish a unified trading zone for France in 2018.

Punto di Scambio Virtuale (PSV), in Italy, is a virtual point, conceptually located between the entry and the exit points of the Italian network, where shippers can trade gas already entered in the main national grid, on a daily basis. PSV is the reference national balancing zone. Currently, PSV represents one of the main European gas marketplaces, having a unique position in terms of availability of gas from different sources, like Russia, Northern Europe (mainly Norway and The Netherlands), North Africa (Algeria and Libya), LNG imports (3 regasification plants) as well as of storage facilities (around 17 bcm of storage capacity). However a small quantity of gas is traded at the hub. The incumbent, ENI, has been forced to trade starting from 2012-13. Still the south/north transit capacity needs to be realised, mainly because of the arrival of new supplies, including the TAP pipeline in 2010.

Gestore dei Mercati Energetici S.p.A. (GME) was assigned in 2009, on an exclusive basis, with the organisation and economic management of natural gas markets, which consist of the Platform for the trading of natural gas (P-GAS) and the Gas Market (MGAS). In 2013, GME also took over the management of physical forward gas markets. To trade on the P-GAS or MGAS operators must be authorised to carry out transactions at PSV. In the MGAS, the parties authorised may make forward purchases, also functional to balancing of the gas system, and spot purchases and sales of volumes of natural gas.

Virtual Balancing Point (PVB), Spain. The Organised Gas Market on the Iberian Peninsula began operating in December 2015, once the regulatory framework had been established and the Spanish and Portuguese operators designed and

implemented an operating model for the Iberian gas market, which followed the guidelines contained in the European Gas Target Model to adapt to the specific needs of the Iberian gas system. MIBGAS S.A. is the operator of the Iberian gas market.

The MIBGAS trading platform is used for the purchase and sale of natural gas with physical delivery at PVB for Within-Day, Day-Ahead, Balance of Month and Month-Ahead products.

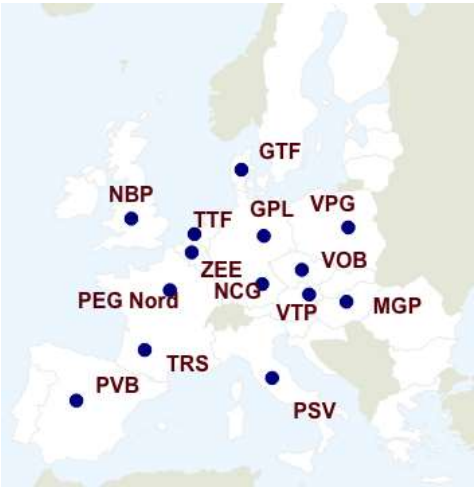
Virtual Trading Point (VTP), Austria. In Austria there is one of the most important trading points in Continental Europe, Baumgarten. Approximatively one third of all Russian gas exports to Europe flows through Baumgarten towards Germany, Italy, Hungary, Slovenia and the national market. The import terminal is owned and operated by Gas Connect Austria. The Central European Gas Hub (CEGH) hub started trading in 2005 and is the leading hub for gas trading in Central and Eastern Europe. In 2013 a virtual hub, the VTP, was created with CEGH as its operator. Trading at VTP is developing, even though the majority of trades is led by spread with the TTF, NCG or PSV hubs.

Gas Transfer Facility (GTF), Denmark. Energinet is an independent public enterprise owned by the Danish Ministry of Climate and Energy. They own, operate and develop the transmission systems for electricity and natural gas in Denmark. The Danish gas market model offers shippers two ways to buy and sell gas: through the virtual point ETF (Exchange Transfer Facility) for trades executed on the Danish gas exchange, Gaspoint Nordic; through GTF (Gas Transfer Facility), the virtual point for bilateral trades in the secondary market.

VOB, in Czech Republic, is at very early stages of trading, but has OTC brokers, and VOB future contracts are offered at the Austrian CEGH exchange.

Other European natural gas virtual trading hubs are the Polish VPG, the Hungarian MGP, but they are hardly trading.

Figure 8. EU gas hubs location



Source: own elaboration

Table 6. EU gas hubs and the TSOs that are operating at them

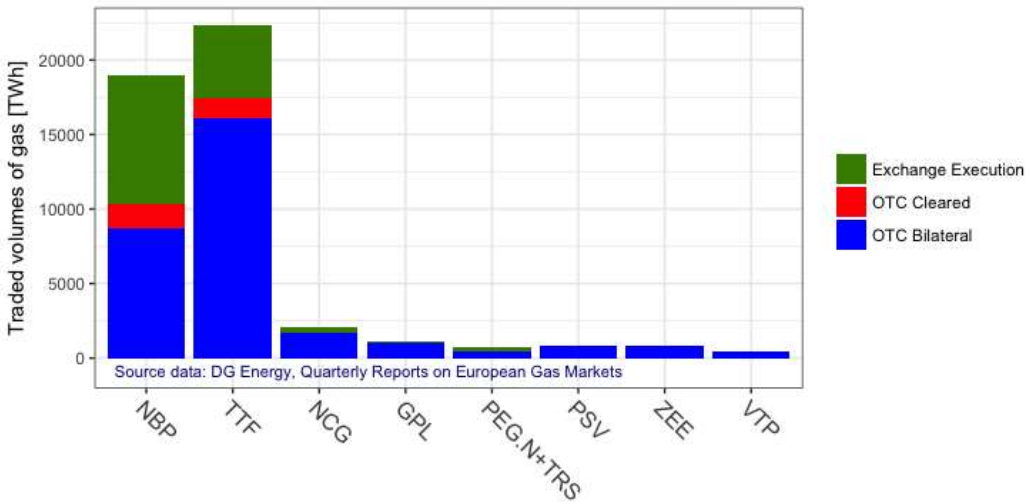
Market area	**Hub**	**TSO**
Austria	VTP (CEGH)	Gas Connect Austria GmbH TAG GmbH (Trans Austria Gasleitung GmbH)
Belgium	ZTP (Zeebrugge Trading Point H-Zone)	Fluxys Belgium S.A.
Belgium	ZEE (Zeebrugge Beach)	Fluxys Belgium S.A.
Czech Republic	VOB	NET4GAS, s.r.o.
Denmark	NPTF	Energinet
Denmark	GTF (Bilateral Trading point)	Energinet
France-N	PEG Nord	GRTgaz
France	TRS	GRTgaz, TIGF
Germany	GP (GasPool)	Fluxys Deutschland GASCADE Gastransport Gastransport Nord Gasunie Deutschland jordgas Transport NEL Gastransport Nowega OPAL Gastransport
Germany	NCG (NetConnect Germany)	bayernets Fluxys TENP GRTgaz Deutschland Open Grid Europe terranets bw Thyssengas
Hungary	MGP	FGSZ
Ireland	IBP	Gas Networks Ireland
Italy	PSV	Snam Rete Gas

Netherlands	TTF (Title Transfer Facility)	Gasunie Transport Services
Poland	VPG	GAZ-SYSTEM
Spain	PVB	ENAGAS
United Kingdom	NBP (National Balancing Point)	National Grid

Source: adapted from ENTSOG

The quantity of gas traded in a hub being the one of the most important characteristics of the liquidity of a hub, we show here below the traded volumes at the EU hubs in 2016.

Figure 9. Traded volumes of gas on the main European hubs in 2016



Source: own elaboration on DG Energy data ([7])

3.4.3 The scoring of the European natural gas hubs

3.4.3.1 Scoring using the AGTM metrics

The results of the performance of wholesale markets via the AGTM metrics are presented in ([8]). They show an improved performance compared to the first assessment in 2013, but most market areas are still some distance away from the indicative AGTM targets, especially for forward liquidity associated metrics. The market health and the market participant needs metrics are strongly correlated. Structural aspects influence the way in which a gas wholesale market can function properly. Markets in North West Europe score better on metrics related to diversity of supply and upstream concentration leading to better performing hubs. TTF and NBP continue to be the EU's best functioning hubs.

([7]) see (EC 2016a), (EC 2016b), (EC 2017)
([8]) ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016 - Gas Wholesale Markets Volume (October 2017) (https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20GAS.pdf)

Based on these results, hubs are categorised in four groups:

— Established hubs

- Broad liquidity
- Sizeable forward markets which contribute to supply hedging
- Price reference for other EU hubs and for long-term contracts indexation

— Advanced hubs

- High liquidity
- More reliant comparatively on spot products
- Progress on supply hedging role but relatively lower liquidity levels of longer-term products

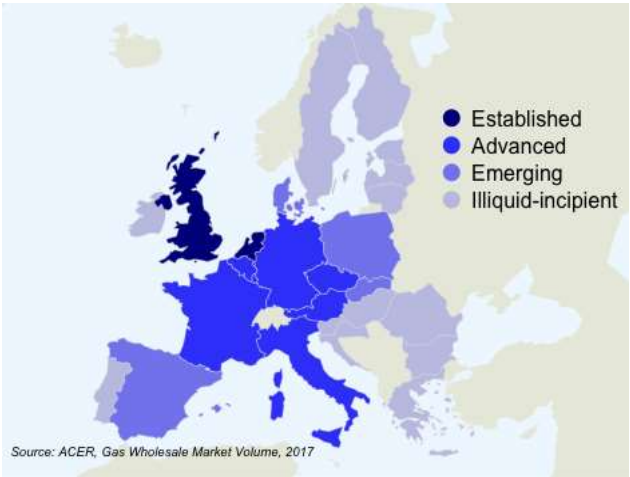
— Emerging hubs

- Improving liquidity from a lower base taking advantage of enhanced interconnectivity and regulatory interventions
- High reliance on long-term contracts and bilateral deals

— Illiquid-incipient hubs

- Embryonic liquidity at a low level and mainly focused on spot
- Core reliance on long-term contracts and bilateral deals
- Diverse group with some jurisdictions having
- organised markets in early stage
- to develop entry-exit systems

Figure 10. ACER's ranking of the European hubs using the 2016 monitoring results



Source: own elaboration on ACER data

3.4.3.2 Scoring using OIES (P.Heather) metrics

The latest report of OIES by P.H. and B.P. (2017) gives an update on the maturity and development of those hubs by applying the methodology in 3.3.2 for the ranking of the hubs for 2016.

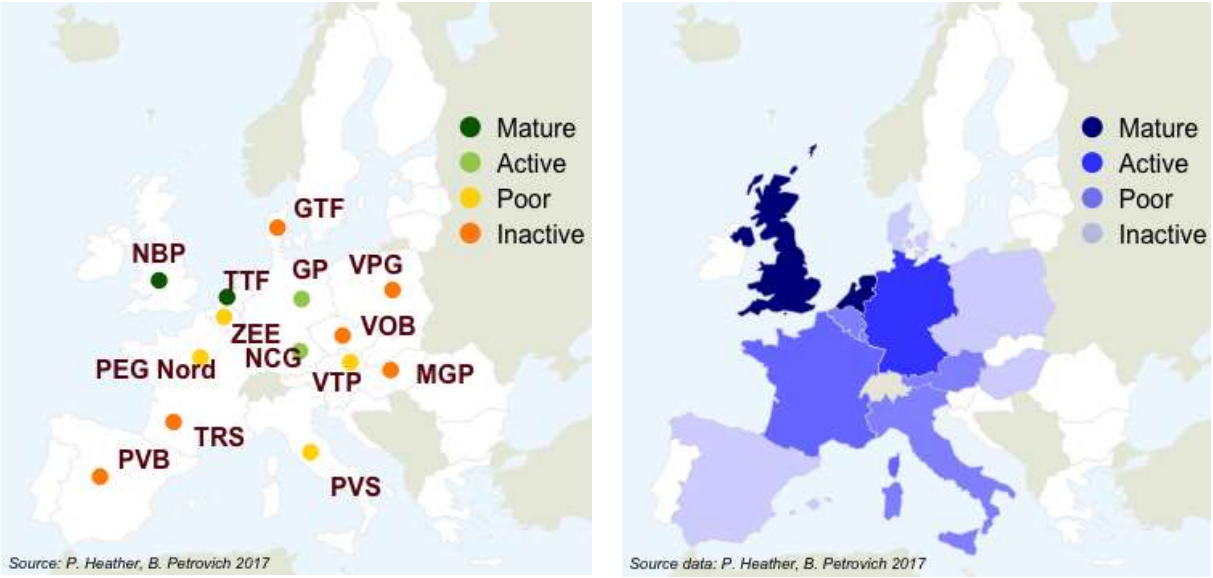
Table 7. OIES (P. Heather's) ranking of the European hubs using the 2016 data

Hub	Active market participants	Traded products	Traded volumes [TWh]	Tradability index (Q4)	Churn rate	Final score	Classification
TTF	> 40	53	22230	20	57.1	15	Mature
NBP	> 40	47	20045	19	22.1	15	Mature
NCG	30	29	2080	16	4	10	Active
GPL	30	23	1110	15	2.5	9	Active
PSV	18	23	885	15	1.2	7	Poor
ZEE+ZTP	15	17	780	10	4.1	7	Poor
PEG Nord	15	18	550	14	1.7	7	Poor
VTP	15	14	530	10	5.7	7	Poor
VOB	< 10	6	105	8	1.1	5	Inactive
TRS	< 10	13	100	7	0.6	5	Inactive
PVB	< 10	9	3	0	0.1	5	Inactive

Source: (Heather and Petrovich 2017)

The results are usually presented as in Figure 11 (left), but we present them also as Figure 11 (right) for a comparison with the ACER's ranking in Figure 10.

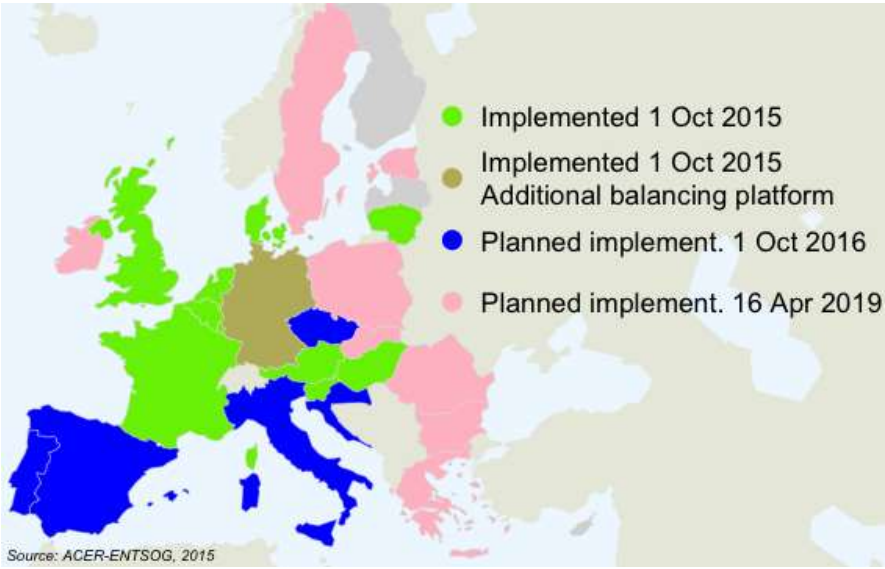
Figure 11. OIES (P. Heather's) ranking of the European hubs using the 2016 data



Source: own elaboration on (Heather and Petrovich 2017)

The political will, represented by the expected implementation dates for EU countries for the BAL NC is here below.

Figure 12. Expected implementation dates for EU countries



Source: own elaboration on ACER-ENTSOG data

3.4.3.3 Scoring using EFET metrics

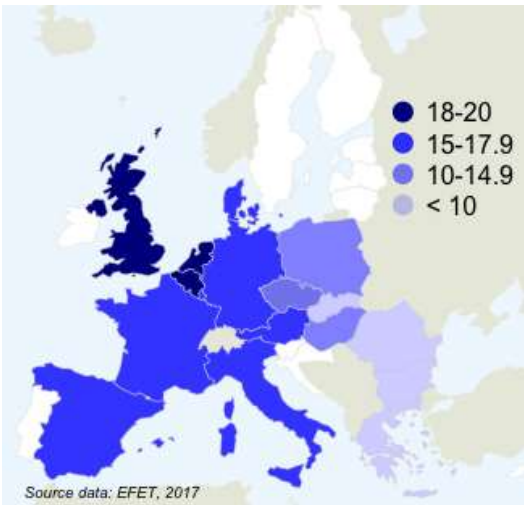
Finally, the EFET metrics applied from 2014-2017 led to the following results. For the year 2017 and for comparison with the other metrics scorings, we present the results as a map in Figure 13.

Table 8. EFET's ranking of European hubs

Hub	2014	2015	2016	2017
NBP	20	20	20	20
TTF	19	19.5	19.5	19
NCG	15.5	19	19	17.5
GASPOOL	16	19	19	17
France	16	16.5	18.5	17.5
ZTP	16	17.5	18	19
Zee Beach	17	17	17	16.5
PSV	10.5	15	15	16
GTF	9	11	14	15.5
VTP	13	13	13.5	16
PVB	7	7	13.5	16
Czech Republic	8	8.5	9.5	13
Poland	4.5	5.5	9.5	10
Hungary	5	6.5	9	12.5
Slovakia	3.5	7	8	8.5
Greece	4.5	5.5	5.5	6.5
Romania	2.5	1.5	2	3
Bulgaria	1.5	1	1.5	1

Source: (EFET 2017)

Figure 13. EFET's ranking of European hubs



Source: own elaboration on EFET data

3.4.4 The gas prices

The following analysis is given in (ACER/CEER 2017) concerning the evolution of gas prices in 2016.

Gas prices in Europe in 2016 had two types of behaviour: decreasing in the first part of the year and increasing during the second one (see Figure 14). The decreasing prices may be explained by lower gas demand and lower oil prices on one hand and high gas storage levels and oversupply on another hand. The reversed trend in the last quarter was mainly explained by growing gas demand for gas-fired power generation, limited EU LNG deliveries, and an increase in US gas prices and coal price increases.

The prices of oil-indexed long-term contracts were relatively competitive throughout 2016 and dropped below hub prices in the last part of the year.

ACER (ACER/CEER 2017) assessed the gas sourcing costs in EU gas markets taking into account both hub prices and long-term contract prices. Yearly average results are presented in Figure 15.

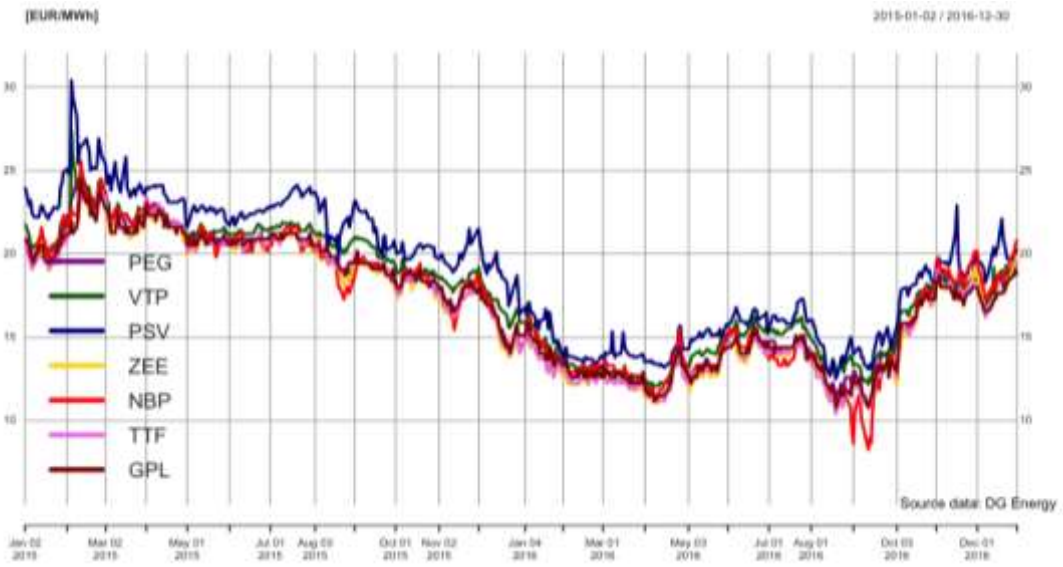
It should be noted that the spread of the sourcing between direct hub and long-term gas contracts is narrowing. The rationale is:

— lower oil prices are impacting oil-indexed gas contracts

— hubs are more directly used in supply contracts' indexations – or alternatively, providing orientation for price renegotiations.

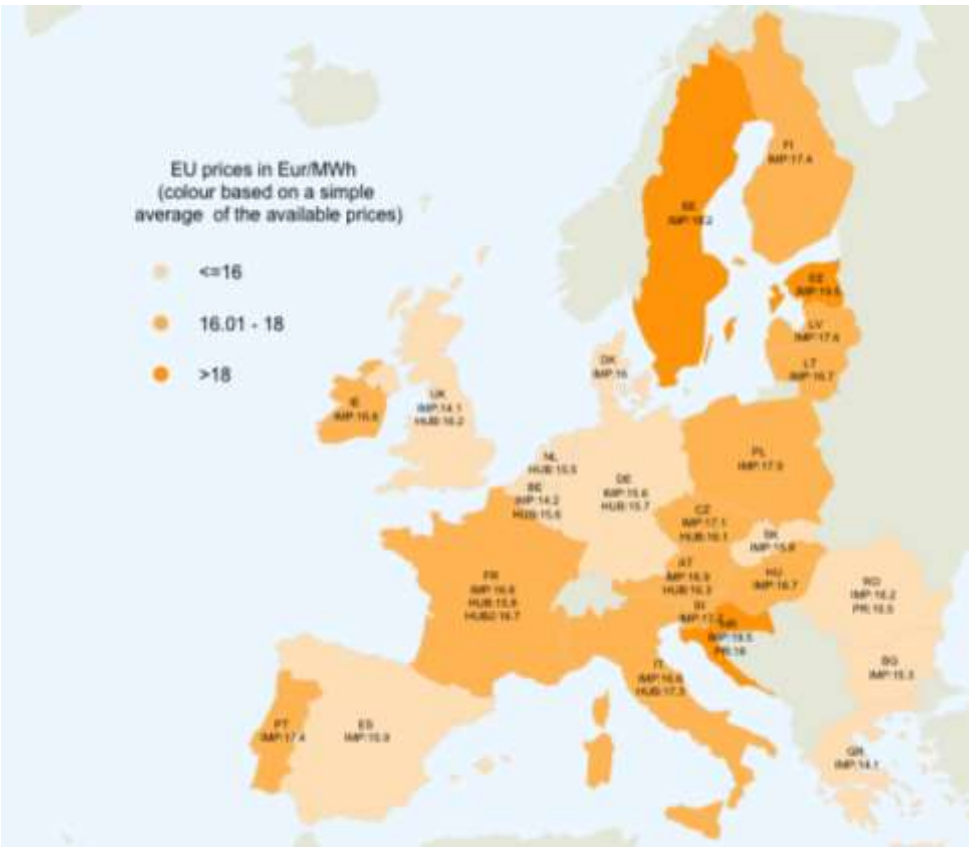
In the future, we will study the gas prices from the point of view of price convergence and correlation.

Figure 14. Gas prices in 2015-2016 at some European natural gas hubs



Source: own elaboration on DG Energy data

Figure 15. EU MSs assessed gas suppliers sourcing prices* 2016 (yearly average)



* IMP stands for import prices declared at the border, PR for production and HUB for hub hedging prices

Source: own elaboration on (ACER 2017) data

4 Network Code on Gas Balancing of Transmission Networks

Balancing with regards to natural gas transportation refers to the activity of dealing with the difference of natural gas quantities injected to and withdrawn from the system. Before looking at balancing itself, the legal background is introduced and this particular mismatch will be examined in the general context of network use.

4.1 Legal Background

— DIRECTIVE 2009/73/EC concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (Directive)

As part of the 3rd Energy Package Directive defined balancing as an *"ancillary service"* [Directive Article 2(14)] and declared that *"… balancing the gas transmission system shall be objective, transparent and non-discriminatory, including rules for the charging of system users of their networks for energy imbalance."* [Directive Article 13(3)]

Furthermore *"…the provision of balancing services … shall be performed in the most economic manner and provide appropriate incentives for network users to balance their input and off-takes. The balancing services shall be provided in a fair and non-discriminatory manner and be based on objective criteria;"* [Directive Article 41(6)b)]

— REGULATION (EC) No 715/2009 on conditions for access to the natural gas transmission networks (Regulation, R.)

The Regulation:

- gives more details about the principles of balancing

  "1. Balancing rules shall be designed in a fair, non-discriminatory and transparent manner and shall be based on objective criteria. Balancing rules shall reflect genuine system needs taking into account the resources available to the transmission system operator. Balancing rules shall be market-based.

  2. In order to enable network users to take timely corrective action, the transmission system operator shall provide sufficient, well-timed and reliable on-line based information on the balancing status of network users.

  The information provided shall reflect the level of information available to the transmission system operator and the settlement period for which imbalance charges are calculated.

  No charge shall be made for the provision of information under this paragraph.

  3. Imbalance charges shall be cost-reflective to the extent possible, whilst providing appropriate incentives on network users to balance their input and off-take of gas. They shall avoid cross-subsidisation between network users and shall not hamper the entry of new market entrants.

  Any calculation methodology for imbalance charges as well as the final tariffs shall be made public by the competent authorities or the transmission system operator, as appropriate.

4. Member States shall ensure that transmission system operators endeavour to harmonise balancing regimes and streamline structures and levels of balancing charges in order to facilitate gas trade." [R. Article 21] and

- stipulates that a network code should establish detailed rules for balancing

  "The network codes … shall cover the following areas, taking into account, if appropriate, regional special characteristics: … (h) rules for trading related to technical and operational provision of network access services and system balancing; … (j) balancing rules including network-related rules on nominations procedure, rules for imbalance charges and rules for operational balancing between transmission system operators' systems;" [R. Article 8(6)]

— REGULATION (EU) No 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks (Balancing Regulation, BR.)

The BR. sets the detailed rules and will be analysed in this section.

4.2 Deadlines

By default the requirements set out in the BR. were to be fulfilled by October 2015. In some cases an extension to October 2016 and April 2019 was granted and the April 2019 deadline can be extended by the national regulatory authority to April 2024. Up until full compliance with the BR. interim measures are permitted.

"In the absence of sufficient liquidity of the short term wholesale gas market, suitable interim measures … shall be implemented by the transmission system operators. Balancing actions undertaken by the transmission system operator in case of interim measures shall foster the liquidity of the short term wholesale gas market to the extent possible." [BR. Article 45(1)]

If interim measures are applied an annual report has to be prepared.

"Where the transmission system operator foresees implementing or continuing to implement interim measures, it shall prepare" an annual report." [BR. Article 46(1)]

4.3 Definitions

'allocation' *means the quantity of gas attributed to a network user by a transmission system operator as an input or an off-take expressed in kWh for the purpose of determining the daily imbalance quantity;* [BR. Article 3(15)]

'balancing action' *means an action undertaken by the transmission system operator to change the gas flows onto or off the transmission network, excluding those actions related to gas unaccounted for as off-taken from the system and gas used by the transmission system operator for the operation of the system;* [BR. Article 3(2)]

'balancing period' *means the period within which the off-take of an amount of natural gas, expressed in units of energy, must be offset by every network user by means of the injection of the same amount of natural gas into the transmission network in accordance with the transport contract or the network code;* [R. Article 2(10)]

'balancing platform' *means a trading platform where a transmission system operator is a trading participant to all trades;* [BR. Article 3(6)]

'balancing portfolio' *means a grouping of a network user's inputs and off-takes;* [BR. Article 3(13)]

'balancing service' *means a service provided to a transmission system operator via a contract for gas required to meet short term fluctuations in gas demand or supply, which is not a short term standardised product;* [BR. Article 3(7)]

'balancing zone' *means an entry-exit system to which a specific balancing regime is applicable and which may include distribution systems or part of them;* [BR. Article 3(1)]

'confirmed quantity' *means the quantity of gas confirmed by a transmission system operator to be scheduled or re-scheduled to flow on gas day D;* [BR. Article 3(8)]

'contracted capacity' *means capacity that the transmission system operator has allocated to a network user by means of a transport contract;*[R. Article 2(19)]

'daily imbalance charge' *means the amount of money a network user pays or receives in respect of a daily imbalance quantity;* [BR. Article 3(9)]

'daily metered' *means that the gas quantity is measured and collected once per gas day;* [BR. Article 3(10)]"

'gas day' *generally means a 24-hour period beginning at 5 am GMT, the actual gas day is marked D, following gas day D-1 and followed by gas day D+1;*

'intraday metered' *means that the gas quantity is measured and collected a minimum of two times within the gas day;* [BR. Article 3(11)]

'network user' *means a customer or a potential customer of a transmission system operator, and transmission system operators themselves in so far as it is necessary for them to carry out their functions in relation to transmission;* [R. Article 2(11)]

'neutrality charge for balancing' *means a charge amounting to the difference between the amounts received or receivable and the amounts paid or payable by the transmission system operator due to performance of its balancing activities which is payable to or recoverable from the relevant network users;* [BR. Article 3(3)]

'nomination' *means the prior reporting by the network user to the transmission system operator of the actual flow that the network user wishes to inject into or withdraw from the system;* [R. Article 2(7)]

'non daily metered' *means that the gas quantity is measured and collected less frequently than once per gas day;* [BR. Article 3(12)]

'notification quantity' *means the quantity of gas transferred between a transmission system operator and a network user or network users or balancing portfolios, as appropriate;* [BR. Article 3(14)]

're-nomination cycle' *means the process carried out by the transmission system operator in order to provide a network user with the message regarding the confirmed quantities following the receipt of a re-nomination;* [BR. Article 3(16)]

'trading participant' *means a network user or a transmission system operator holding a contract with the trading platform operator and satisfying the conditions necessary to transact on the trading platform.* [BR. Article 3(5)]

'trading platform' *means an electronic platform provided and operated by a trading platform operator by means of which trading participants may post and accept, including the right to revise and withdraw, bids and offers for gas required to meet short term fluctuations in gas demand or supply, in accordance with the terms and conditions applicable on the trading platform and at which the transmission system operator trades for the purpose of undertaking balancing actions;* [BR. Article 3(4)]

'within day charge' *means a charge levied or a payment made by a transmission system operator on or to a network user as a result of a within day obligation;* [BR. Article 3(17)]

'within day obligation' *means a set of rules regarding network users' inputs and off-takes within the gas day imposed by a transmission system operator on network users;* [BR. Article 3(18)]

4.4 Imbalance

Generally, in order to use the natural gas high pressure transportation system a network user has to book capacity first and then give a nomination, typically for a gas day. Contracted capacity, nomination and the real flow can be different. Some of the differences pertain to network use while others are undesirable and therefore discouraged.

4.4.1 Not accepted differences in network use

Table 9. Not accepted differences in network use

	Not accepted relation	
Nominated input/off-take	>	Contracted input/off-take capacity
Real input/off-take	>	Contracted input/off-take capacity
Nominated input		nominated off-take
Real input/off-take	<, >	Nominated input/off-take
Real input	<, >	real off-take

— Nominated input/off-take – Contracted input/off-take capacity

Although daily (or even within-day) capacities are available, usually capacities are contracted for a longer term (i.e. month, quarter, year, multiple years). Since contracted capacity means the highest used capacity for a contract term, a nomination lower than the contracted capacity is the most common case. On the

other hand nominations higher than the contracted capacity are normally rejected.

— Real input/off-take – Contracted input/off-take capacity

Just as in case of nomination (and for the same reasons) the most common case is when the real flow is smaller than the contracted capacity. However a flow higher than the contracted capacity can occur (capacity overshoot), and usually results in (w/o a tolerance) a penalty.

— Nominated input – Nominated off-take

A network user has to nominate injection to and withdrawal from the natural gas transmission system. The acceptance of different input and off-take nominations are required by the BR.

— Real input/off-take – Nominated input/off-take

Difference between the actual flow and the (re-)nomination is not unusual either; however it can be surcharged as well.

Real input – real off-take (imbalance)

A mismatch between incoming and outgoing flows is an imbalance which is the subject of this section. The action that it will bring about depends on the extent of imbalance. In the order of growing severity it is just settled financially, or requires intervention to change physical flows either at a system level (Virtual trading point [VTP]) or at a local level (specific entry/exit point).

4.5 Balancing regime

As a general principle the BR. declares that:

"The network users shall be responsible to balance their balancing portfolios in order to minimise the need for transmission system operators to undertake balancing actions set out under this Regulation." [BR. Article 4(1)]

In other words in case network users are not able to balance their daily flows the *"The transmission system operator shall undertake balancing actions in order to:*

(a) maintain the transmission network within its operational limits;

(b) achieve an end of day linepack position in the transmission network different from the one anticipated on the basis of expected inputs and off-takes for that gas day, consistent with economic and efficient operation of the transmission network." [BR. Article 6(1)]

The principle of residual balancing indicates the ability and willingness of network users to balance their portfolios both via physical changes in their injections and withdrawals and via changes in ownership of gas quantities that are already in the system. This also means that in a well-functioning regime the TSO has marginal role in the actual balancing. According to ACER Report on the implementation of the Balancing Network Code of 7 November 2016 [ACER Report 2016] network users need information, access to gas and network flexibility. In order to achieve this goal the TSO and regulatory bodies have to set up the framework that meets certain conditions in connection with the items below:

1. Title transfer
2. Trade notification

3. Trading platform
4. Short term standardised products (STSPs)
5. Virtual trading point (VTP)
6. Incentives
7. Nomination and capacity booking regime
8. Information
9. Neutrality
10. Linepack flexibility

The subsections below will include the explanation of these items, and information about related "interim measures" and "compliance". This latter is based on the ACER Report on the implementation of the Balancing Network Code (Second edition) of 16 November 2017 [ACER Report 2017] Volume II. Evaluation of compliance is simplified compared to the report, and countries appear as complying or not complying in a rigorous and somewhat arbitrary way. Essentially if a country does not comply with the word of the BR., it is regarded as "non-complying". The only way for a country to be classified as complying in case deviations exist is, if their impact on the balancing regime seems to be negligible. In the compliance part 22 countries were looked at, with Belgium and Luxemburg was taken as one (common balancing zone) and Poland being evaluated based on the high calorific zone. Sweden is evaluated individually, despite the intention of merging with the Danish balancing system.

4.5.1 Title transfer

Title transfer means the change in ownership of gas that is already in the natural gas transmission system, and should be independent of physical flows, i.e. non-physical flow related title transfers can be the tool for shippers to wash out opposite portfolio imbalances. The goal is that title transfers take place on a transparent platform in a standardised way and become the major tool for balancing (discussed at 4.5.4).

4.5.2 Trade notification

A Trade notification is the confirmation that an exchange of ownership occurred. From a balancing point of view it is crucial that these confirmations are processed by TSO in the shortest possible time.

"1. Gas transfer between two balancing portfolios within one balancing zone shall be made through disposing and acquiring trade notifications submitted to the transmission system operator in respect of the gas day.

2. The timing for submitting, withdrawing and amending trade notifications shall be defined by the transmission system operator in the transport contract or other legally binding agreement with network users taking into account the time, if any, for processing the trade notifications. The transmission system operator shall enable the network users to submit trade notifications close to the time when the trade notification becomes effective.

3. The transmission system operator shall minimise the time for processing trade notifications. The time for processing shall not take more than thirty minutes

except where the time when the trade notification becomes effective permits to extend the time for processing up to two hours." [BR. Article 5]

Besides processing time, another crucial condition to full compliance with the BR. is the access to market for "paper traders" in order to increase liquidity.

"Network users shall have the possibility to enter into a legally binding agreement with a transmission system operator which enables them to submit trade notifications irrespective of whether they have contracted transport capacity or not." [BR. Article 4(3)]

"A network user may make a trade notification on a gas day irrespective of whether any nomination was made by this network user for that gas day." [BR. Article 5(8)]

Compliance:

	No. of countries (total: 22)
Complying	16
Non-complying	6
Compliance ratio	73%

4.5.3 Trading platform

The Trading Platform is the venue where trades take place. It needs to be easily accessible and preferably enable exchange of standardised products that ensure high turnover (liquidity). Besides being a liquid market that facilitates balancing, another benefit of a Trading Platform is the availability of market prices for the cash-out mechanism (discussed at 4.5.6.1).

Interim measures:

Up until the establishment of a trading platform interim measures are applicable such as a Balancing Platform. The difference between a Trading Platform and a Balancing Platform is, that in the former case the TSO is one of the participants, while in the latter case the TSO is the counterparty to all trades. Alternative to a balancing platform is the balancing service.

"The transmission system operator is entitled to procure balancing services for those situations in which short term standardised products will not or are not likely to provide the response necessary to keep the transmission network within its operational limits or in the absence of liquidity of trade in short term standardised products." [BR. Article 8(1)]

Compliance:

	No. of countries (total: 22)
Complying	14
Non-complying	8
Compliance ratio	64%

4.5.4 Short term standardised products (STSPs)

This is a feature of all well-known exchanges in order to ensure liquidity in the market. In this specific case the BR. stipulates that the possibility of trading with them either on within-day or day ahead basis seven days a week must be ensured. According to the Balancing Regulation there are three possible types of STSPs.

One of them is a title product, which is linked to ownership change and does not necessarily cause any change in the flows. Perhaps it sounds counterintuitive that by buying or selling an instrument that is not directly linked to changes in physical flow would help the TSO in its operational balancing activity. However, this is the right tool to give a signal to shippers to react (adjust physical flows) in order to keep the system in balance. Therefore it is the preferred tool among STSPs.

The other two are the Locational and the Temporal Product. The first one is used when the imbalance affects a specific part of the system, while the second one is needed for a certain time period during the day. According to the Balancing Regulation the combination of the two is also possible.

Compliance:

	No. of countries (total: 22)
Complying	8
Non-complying	14
Compliance ratio	36%

4.5.5 Virtual trading point (VTP)

A virtual trading point is a notional point referring to the system where exchange of gas quantities can take place.

Compliance:

	No. of countries (total: 22)
Complying	15
Non-complying	7
Compliance ratio	68%

4.5.6 Incentives

According to ACER Report 2016:

"Network users shall be incentivised, not obliged, to balance."

"The Code imposed appropriate incentives on network users to balance, particularly through daily cash-out, and only where necessary modest within-day restrictions/incentives were foreseen." [ACER Report 2017 Volume I]

Therefore these two incentives will be analysed in details.

4.5.6.1 Cash-out mechanism

As stated before a functioning market would not only facilitate efficient balancing, but would provide prices for the financial settlement after the gas day. If a Shipper withdraws more than injects, or the other way around, it needs to face the financial consequences, i.e. imbalance charges.

"The daily imbalance charge shall be cost reflective and shall take account of the prices associated with transmission system operator's balancing actions, if any, and of the small adjustment…" [BR. Article 19(3)]

In order to calculate the imbalance charge for each Balancing Portfolio the imbalance quantity and an imbalance unit charge needs to be calculated.

4.5.6.1.1 Daily imbalance quantity calculation

daily imbalance quantity = inputs – off-takes

The daily imbalance quantity can be adjusted where:

> *"(a) a linepack flexibility service is offered; and/or*
>
> *(b) any arrangement is in place whereby network users provide gas, including gas in kind, to cover:*
>
> > *(i) gas unaccounted for as off taken from the system, such as losses, metering errors; and/or*
> >
> > *(ii) gas used by the transmission system operator for the operation of the system, such as fuel gas"* [BR. Article 21(2)]

4.5.6.1.2 Applicable price

According to the BR. a so-called marginal sell or buy price has to be calculated and used with the possibility of a "small adjustment".

"A marginal sell price and a marginal buy price shall be calculated for each gas day pursuant to the following:

> *(a) a marginal sell price is the lower of:*
>
> > *(i) the lowest price of any sales of title products in which the transmission system operator is involved in respect of the gas day; or*
> >
> > *(ii) the weighted average price of gas in respect of that gas day, minus a small adjustment.*
>
> *(b) a marginal buy price is the higher of:*
>
> > *(i) the highest price of any purchases of title products in which the transmission system operator is involved in respect of the gas day; or*
> >
> > *(ii) the weighted average price of gas in respect of that gas day, plus a small adjustment."* [BR. Article 22(2)]

"The small adjustment shall:

> *(a) incentivise network users to balance their inputs and off-takes;*
>
> *(b) be designed and applied in a non-discriminatory manner in order to:*
>
> > *(i) not deter market entry;*
> >
> > *(ii) not impede the development of competitive markets;*

(c) not have a detrimental impact on cross-border trade;

(d) not result in network users' excessive financial exposure to daily imbalance charges." [BR. Article 22(6)]

"…The value of the small adjustment shall not exceed ten percent of the weighted average price unless the transmission system operator concerned can justify otherwise" [BR. Article 22(7)]

Once both the imbalance quantity and the applicable price are available the product of the two will give the daily imbalance charge. This charge is to be paid to the network users that injected more than withdrew and payable by those network users that injected less than withdrew.

Interim measures:

As long as prices are not available from a functioning market *"the price derivation may be based upon an administered price, a proxy for a market price or a price derived from balancing platform trades"*.[BR. Article 49(2)]

Regarding quantity a tolerance can be applied *"in case network users do not have access:*

(a) to a short term wholesale gas market that has sufficient liquidity;

(b) to gas required to meet short term fluctuations in gas demand or supply; or

(c) to sufficient information regarding their inputs and off-takes." [BR. Article 50(1)]

"The tolerance level shall be the maximum quantity of gas to be bought or sold by each network user at a weighted average price. If there is a remaining quantity of gas that constitutes each network user's daily imbalance quantity which exceeds the tolerance level, it shall be sold or bought at marginal sell price or marginal buy price." [BR. Article 50(4)]

"The tolerance level shall be calculated on the basis of each network user's inputs and off-takes, excluding trades at the virtual trading point, for each gas day. …"[BR. Article 50(6)]

"The tolerance level applicable for a non-daily metered off-take … shall be based upon the difference between the relevant forecast of a network user's non-daily metered off-takes and the allocation for non-daily metered off-take." [BR. Article 50(7)]

Compliance:

	No. of countries (total: 22)
Complying	10
Non-complying	12
Compliance ratio	45%

4.5.6.2 Within day obligations (WDOs)

The BR. suggests a predominantly daily balancing regime, but permits WDOs where they seem inevitable due to system characteristics. They have to be "modest" [ACER Report 2017] and justifiable. Furthermore the application of WDOs is up to a set of conditions (e.g. adequate information supply, priority of end of the gas day position in financial settlement, extensive consultation with stakeholders, etc.).

"A transmission system operator is only entitled to apply within day obligations in order to incentivise network users to manage their within day position in view of ensuring the system integrity of its transmission network and minimising its need to undertake balancing actions." [BR. Article 24(1)]

	No. of countries (total: 22)
Complying	20
Non-complying	2
Compliance ratio	91%

4.5.7 Nomination and capacity booking regime

This subsection is rather focusing on nomination rules than capacity booking. As for capacity booking the requirement is the establishment of an entry-exit system and flexible access to capacities (e.g. within-day capacities).

With regards to (re-)nomination on interconnection points the BR. defines the deadlines before the gas day and within the gas day. The BR. clearly indicates that network users have to have the opportunity to modify their nominations within the gas day up until at least three hours before the end of the gas day (D). In case of re-nomination the flow must be able to start at most two hours after the re-nomination. BR. defines the cases of rejection of (re-)nominations at interconnection points.

"1. The transmission system operator may reject:

(a) a nomination or re-nomination no later than two hours after the nomination deadline or the beginning of the re-nomination cycle in the following cases:

(i) it does not comply with the requirements as to its content;

(ii) it is submitted by an entity other than a network user;

(iii) the acceptance of the daily nomination or re-nomination would result in a negative implied nomination flow rate;

(iv) it exceeds the network user's allocated capacity;

(b) a re-nomination no later than two hours after the beginning of the re-nomination cycle in the following additional cases:

(i) it exceeds the network user's allocated capacity for the remaining hours, unless this re-nomination is submitted in order to request interruptible capacity, where offered by the transmission system operator;

(ii) the acceptance of the hourly re-nomination would result in an expected gas flow change before the end of the re-nomination cycle.

2. The transmission system operator shall not reject a network user's nomination and re-nomination on the sole ground that this network user's intended inputs are not equal to its intended off-takes.

3. In case a re-nomination is rejected, the transmission system operator shall use the network user's last confirmed quantity, if any." [BR. Article 17]

Compliance:

Compliance is evaluated based on nomination conditions.

	No. of countries (total: 22)
Complying	18
Non-complying	4
Compliance ratio	82%

4.5.8 Information

From a balancing point of view the most important information that the network user has to have is access to its actual balance before and during the gas day. Because of it within-day supply of updated information is necessary.

"Where the transmission system operator is required to provide information to network users to enable them to manage their exposures associated with within day positions, it shall be provided to them regularly. Where applicable, this information shall be provided upon a request submitted by each network user once." [BR. Article 24(2)]

Depending on the frequency of meter reading the precise monitoring of a network user's position can be a challenge, and of course in those cases where the allocations cannot be done unambiguously by metered data, alternative data (e.g. forecasts) will be used as a substitute.

"Where a measured quantity cannot be obtained from a meter, a replacement value may be used. This replacement value shall be used as an alternative reference without any further warranty from the transmission system operator." [BR. Article 33(2)]

To ensure that reliable data are available, and allocations are based on reliable data as well, the BR. defines how network users and operators of connected systems in the same balancing zone have to supply meter data to the TSO and forecasting party.

The Balancing Regulation differentiates between intraday, daily and non-daily measurements. In general in all three cases the network user is eligible to two updates either based on meter reading or forecast.

In order to carry out the financial settlements after the gas day, an initial allocation of quantities needs to be done at no later than the end of the gas day following the gas day in question (end of D+1).

Interim measure:

In case end of D+1 deadline is not feasible for initial allocation, D+3 is applicable.

Compliance:

	No. of countries (total: 22)
Complying	7
Non-complying	15
Compliance ratio	32%

4.5.9 Neutrality

Besides encouraging network users to balance their portfolios, on the other side the neutrality principle is to ensure TSO's marginal role in balancing the system and discourage the TSO to impede network users in their balancing efforts.

"The transmission system operator shall not gain or lose by the payment and receipt of daily imbalance charges, within day charges, balancing actions charges and other charges related to its balancing activities, which shall be considered as all the activities undertaken by the transmission system operator to fulfil the obligations set out in this Regulation." [BR. Article 29(1)]

"Where an incentive to promote efficient undertaking of balancing actions is implemented, the aggregate financial loss shall be limited to the transmission system operator's inefficiently incurred costs and revenues." [BR. Article 29(3)]

For enforcing the neutrality principle the following information have to be available to network users:

"Transmission system operators shall publish the relevant data regarding the aggregate charges referred to in paragraph 1 and the aggregate neutrality charges for balancing, at least at the same frequency as the respective charges are invoiced to network users, but no less than once per month." [BR. Article 29(4)]

Compliance:

In this case the evaluation was less rigorous. If neutrality related amounts were not relevant due to the nature of the balancing system or were not handled separately in the compensation mechanism the country was still deemed complying.

	No. of countries (total: 22)
Complying	16
Non-complying	6
Compliance ratio	73%

4.5.10 Linepack flexibility service

The linepack flexibility service can give extra flexibility to network users based on the fact that the system remains safely operable in a given pressure range. As a consequence the TSO can offer this service to the extent it does not jeopardise system integrity.

However, due to the fact that this is an extra service offered by the system operator, the neutrality principle in this case is not applicable.

"The neutrality mechanism … shall not apply to the linepack flexibility service unless otherwise decided by the national regulatory authority." [BR. Article 43(5)]

The possibility of offering linepack flexibility service is contingent on different conditions:

"1. Linepack flexibility service can only be provided once all the following criteria are met:

> *(a) the transmission system operator shall not need to enter into any contracts with any other infrastructure provider, such as storage system operator or LNG system operator, for the purpose of provision of a linepack flexibility service;*
>
> *(b) the revenues generated by the transmission system operator from the provision of a linepack flexibility service shall at least be equal to the costs incurred or to be incurred in providing this service;*
>
> *(d) the transmission system operator shall not charge, either directly or indirectly, a network user for any costs incurred by the provision of a linepack flexibility service, should this network user not contract for it; and…*

2. The transmission system operator shall prioritise the reduction of within day obligations over the provision of a linepack flexibility service." [BR. Article 44]

4.6 Case Study: The Dutch balancing regime

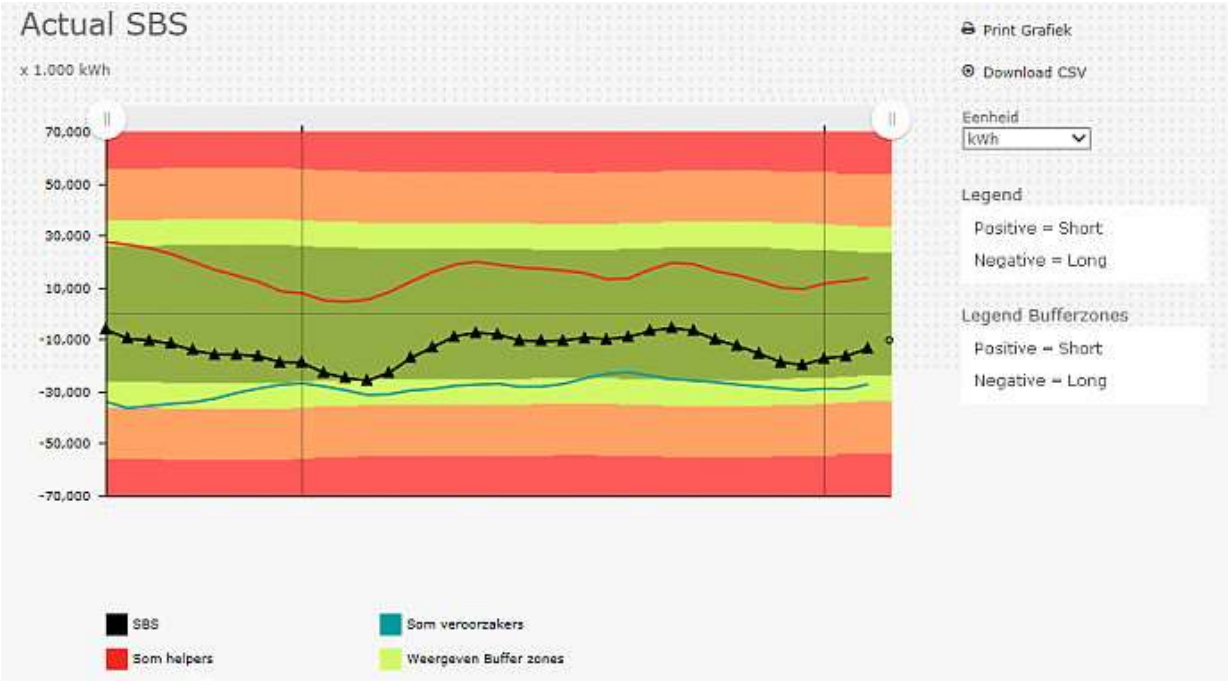
The study is based on the information found on the website ([9]) of Netherlands Gasunie Transport Services (GTS).

GTS owns and operates (TSO) the national grid. The major trading hub (established in 2003) for the gas already injected to the system is the Title Transfer Facility (TTF). This virtual marketplace is available for paper trading. The exchange where natural gas trades take place is ICE ENDEX.

When calculating the balance of a particular Shipper (portfolio balance), both physical injections/withdrawals and transactions at TTF are taken into account on an hourly basis. The Dutch system is using the terms System Balance Signal (SBS) for system level net balance and Portfolio Imbalance Signals (POSs) referring to Balancing Portfolios. The actual balance of the system is published according to the figure below.

([9]) https://www.gasunietransportservices.nl

Figure 16. System balance signal (SBS)

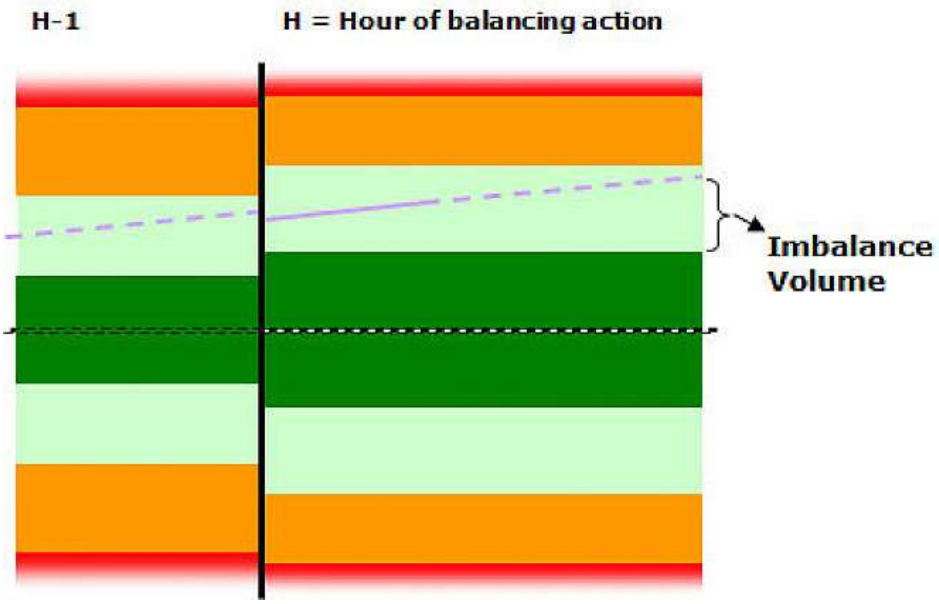


Source: (https://www.gasunietransportservices.nl)

The black line represents the physical balance of the system (SBS). The graph shows the system balance in a somewhat counterintuitive way, as the negative range represent surplus in the system, while the positive range a deficit. This kind of presentation is of common use, since the TSO needs to buy natural gas (cost element) when the system has a surplus, and vice versa in case of a deficit. The red and blue lines represent helpers and causers (veroorzakers). Causers are the ones that have an imbalance of the same sign as the system. Causers will bear the financial consequences of a balancing action.

Balancing actions take place on ICE ENDEX within-day market by the TSO placing a sell or buy bid. The graph below illustrates how balancing actions are carried out by the TSO. The aim of TSO is to keep the imbalance in the dark green zone, and if it is outside that zone, then to bring it back. Depending on the severity of imbalance the TSO either buys an end-of-day product (less severe) or a 1-hour product (more severe).

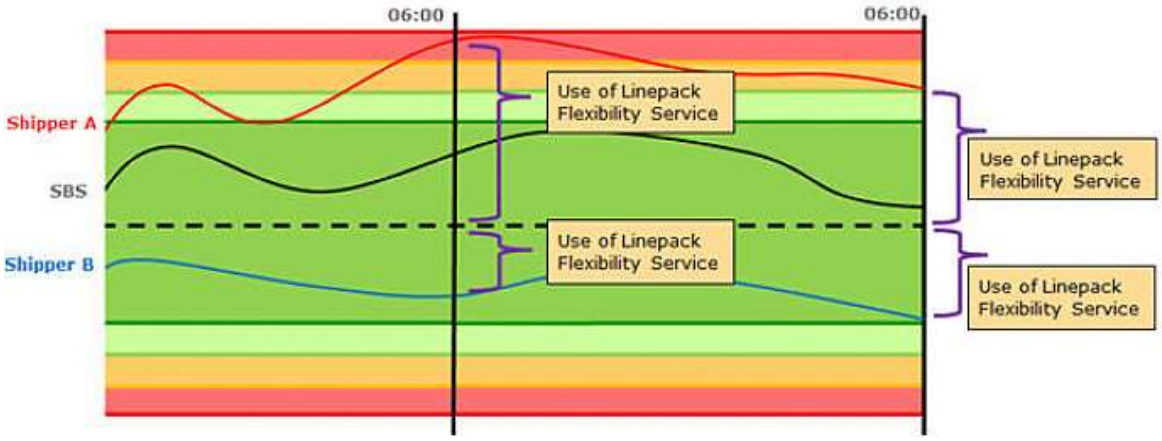
Figure 17. Balancing action



Source: (https://www.gasunietransportservices.nl)

GTS offers Linepack Flexibility Service (LFS) for a charge, based on the principle that the SBS is in the dark green zone at the end of the gas day. This means that for those shippers that use LFS, the linepack quantity is available at the end of the gas day to even out their imbalances. However, actual exchange of gas between the Shipper and the TSO will not occur, the imbalance is rolled over to the beginning of the next gas day. This service is available to those shippers as well that have neither capacity booked nor nomination for the given gas day.

Figure 18. Linepack flexibility service



Source: (https://www.gasunietransportservices.nl)

4.7 ACER evaluation

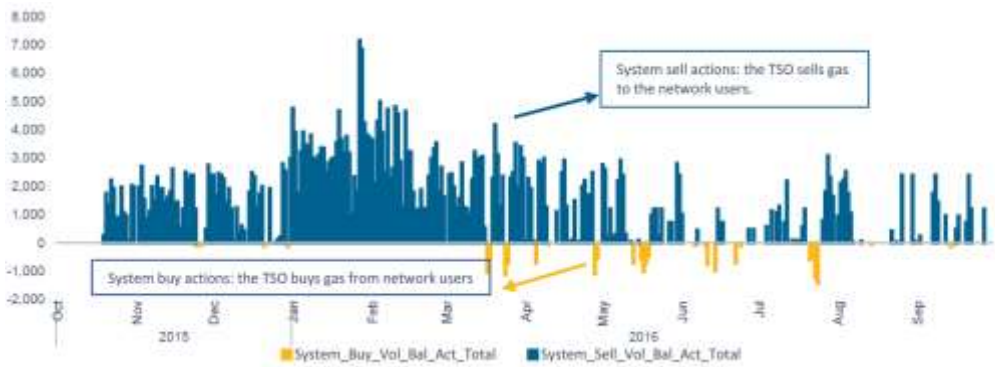
Besides monitoring compliance ACER looked at quantitative data and has worked out indicators to evaluate balancing regimes. This section is an extract from ACER Report 2017 Volume I.

4.7.1 Definitions

— **TSO balancing action.** The TSO's balancing actions are measured in energy units and can be buy or sell actions. TSO balancing actions mean that the TSO is buying or selling on behalf of the system. TSO buying actions should be associated with actions to get more gas onto a short system. TSO selling actions are associated with addressing a gas surplus in the system that is a long system.

— **Sell and Buy System/TSO actions.** A sell action from a TSO decreases the quantity of gas in the network, via either turning down the entry or turning up the exit points of the balancing zone though network users' renominations. On the other hand, a buy action from a TSO has the intention of increasing the quantity of gas in the network, via either turning up the entry or turning down the exit points of the balancing zone through network users' renominations. The TSO will sell gas when the system is long, or expected to be unacceptably long and it will buy gas in the opposite case, in its role of system balancer. Hence, a TSO Buy for balancing purposes can be referred to as a System Buy. Similarly, a TSO Sell for balancing purposes can be referred to as a System Sell. The chart below shows the **TSO/system buy and sell actions** for the Gas year 2015/16 with daily granularity.

Figure 19. TSO/system buy and sell actions



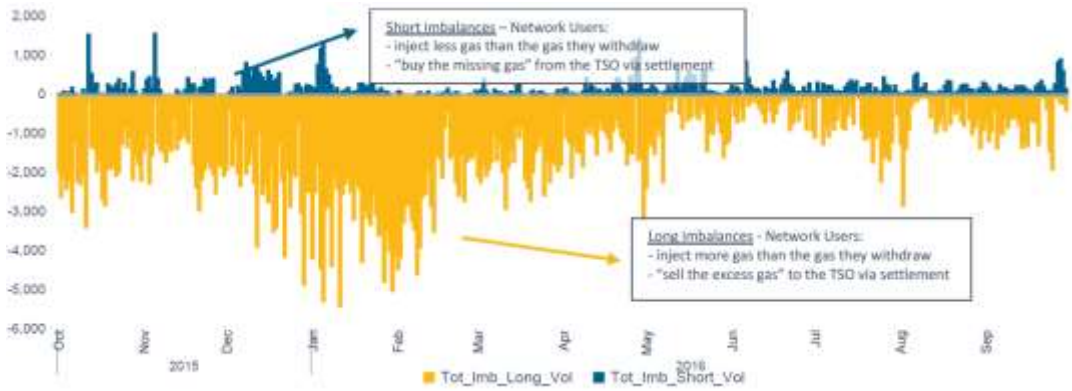
Source: (ACER Report 2017)

— **Network Users' Imbalances.** The difference between each network user's injections into and withdrawals from the transmission network, plus the net gas exchanged at the VTP, defines the network user's imbalance. Imbalances are aggregated according to the sign of the imbalance, yielding an aggregated network users' over-delivery (sum of all "long" accounts on the day) and, separately, aggregated network users' under-delivery (sum of all "short" accounts on the day). The individual network users' imbalances are not publicly available.

— **Long and Short Imbalance Positions.** The aggregated network users' imbalance is labelled as "long" for those network users that inject, individually, more gas into their daily balance account than the gas they

withdraw. In the Report convention, "long" imbalances have a negative sign and therefore occupy the negative area of the respective chart. On the other hand, the network users' imbalance is labelled as "short" for those network users that, individually, inject less gas than the gas they withdraw. In the Report convention, "short" imbalances have a positive sign and therefore occupy the positive area of the respective chart. The inversed convention is used to show how these positions affect the neutrality account. If the network users are short, the TSO in its role of settlement agent sells gas via imbalance cash-out to network user. If the network users are long, the TSO in its role as settlement agent buys gas via imbalance cash-out from network users. The chart below focuses on the **Imbalance position of all network users**. It shows the aggregated daily imbalances for all **long** network users below the zero line, and the aggregated daily imbalance of all **short** network users above the zero line.

Figure 20. Imbalance positions of all network users



Source: (ACER Report 2017)

- **Cumulative Commercial Imbalances.** It is the combined commercial effect of network users and TSO balancing actions. The accumulation takes account of all the balances up to and including a given Gas Day. The imbalances could have either a positive or a negative sign.
- **Neutrality Energy Flows or Transactions.** As explained through the definitions above (**Sell and Buy System/TSO actions** and **Long and Short Imbalance Positions**), there are four energy transactions associated with neutrality. In this Report, energy and their related cashflows are considered on both a daily and (gas) yearly basis.
- **Net energy.** The quantities of energy purchased and sold via the four energy flows are unlikely to net to zero. The net energy represents the difference between energy sales and purchases originating from the four neutrality energy flows. For example, when energy sales are greater than purchases neutrality has made a **net energy sale**. Furthermore, when purchases are greater than sales then neutrality has made a **net energy purchase**.
- **Net financial neutrality.** The financial effects of the four energy flows are also unlikely to net to zero. Net financial neutrality is the sum of financial inflows to neutrality less financial outflows. In other words, it is the net amount of money associated with TSO/System Sells and Network User Imbalance Short Positions less the amount of money associated with TSO/System Buys and Network User Imbalance Long Positions. Where net

financial neutrality is positive (cashflow), surplus cash is available for redistribution to network users. Where net financial neutrality is negative (cashflow), the deficit will be recovered from network users. The chart below presents the daily total net sum of revenues and costs the system collects associated with the four basic **neutrality energy transactions**, cumulated over the period of analysis: System Buy/Sells and Network User Imbalance Long/Short Positions. In particular, the chart shows the development of the net financial neutrality cumulating the daily values over the analysis period.

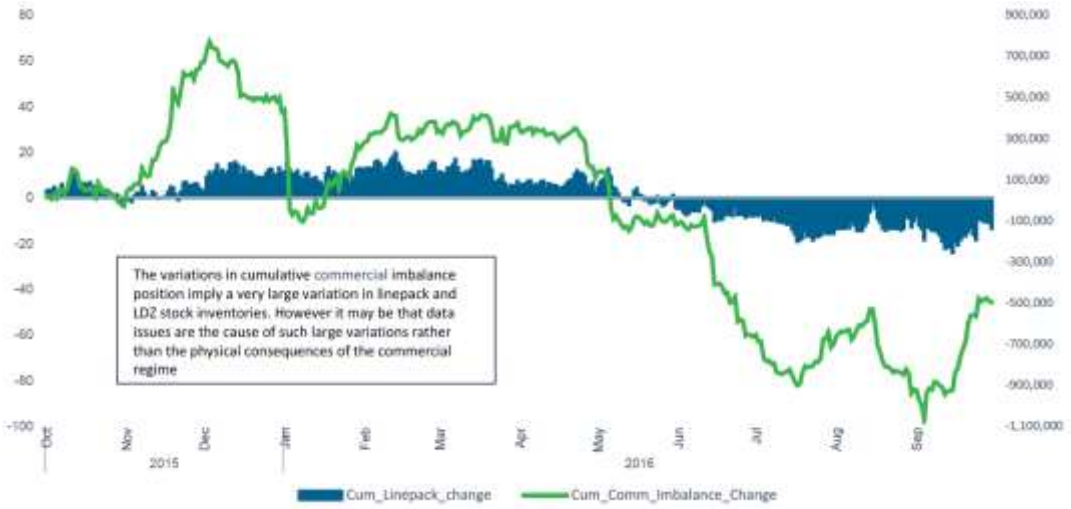
Figure 21. Neutrality energy transactions

Source: (ACER Report 2017)

- **The interaction between net energy and net financial neutrality.** The net financial neutrality indicates whether the operation of the balancing regime is generating a cash surplus or cash deficit associated with the four energy transactions. The net energy position influences the net financial neutrality. For example, if the net energy position represents a net sell, the associated quantity of net gas sale will have contributed a revenue to the cashflows. Similarly, if the net energy position is a buy, then this should be associated with a cost in the net financial neutrality. These revenues and costs, in the end, are distributed back to the network users via the neutrality charge. For avoidance of doubt, the net energy and net financial will not necessarily have the same sign.
- **Net adjusted financial neutrality.** The net adjusted financial neutrality is a measure designed to remove the effect of the net energy from the net financial neutrality. Where net energy is positive the likely cost of the net purchase will have contributed to net financial neutrality. Similarly, where net energy is negative the likely revenue will have contributed to net financial neutrality. The approach applies an estimated gas price to the net energy and then adjusts the net financial neutrality to remove the net energy's contributory value. The adjusted value is distributed back to the network users. The idea is to deliver an estimate of the overall financial effect of neutrality that is energy neutral and can be used for comparative purposes. This provides a better indication of the overall cost or revenue generated in individual regimes.
- **Linepack.** The volume of gas in the system at a given point in time is referred to as inventory, stock, or linepack. The linepack is the cumulative difference of total inputs less total off-takes. Typically, linepack levels are calculated by multiplying the physical volume of the network by the pressure levels observed or derived.

— **Linepack flexibility.** Gas systems can be safely operated within a certain pressure range. A range of linepack levels corresponds to this pressure range. This is the linepack flexibility acceptable for the system. In a well-functioning balancing regime, network users access an appropriate proportion of linepack flexibility. Economically efficient access to existing system flexibility should be provided without creating unduly excessive costs to users. Inappropriate costs to the TSO associated with excessive linepack level variation should also be avoided. The Report plots, where available, two graphics: one on **Cumulative Commercial Imbalances** and another on **physical linepack data**. The combined effect of commercial actions of network users and any balancing actions taken by the TSO will have an effect on the physical linepack position. Changes in the linepack position, i.e. the difference between the opening and closing linepack position, should at least partly reflect the net daily commercial imbalance position changes. Where day-on-day physical linepack changes are not close to the anticipated effect arising from the day's commercial imbalances, the reasons should be investigated and explained to ensure confidence in the operation of the regime. Reasons behind such differences may be i) errors arising as a result of a persistent bias in metering ii) the illustration that commercial balancing actions are not driven by physical balancing needs20; (iii) other TSO actions, effectively outside of the Code's jurisdiction.

Figure 22. Cumulative commercial imbalances – physical linepack data



Source: (ACER Report 2017)

4.7.2 Indicators:

4.7.2.1 TSO's balancing actions

Table 10. TSO's balancing actions

Total Balancing Action Quantities	GWh
Total Balancing Action Quantities	(% of Zone Entry)
Percentage of Total Balancing Action Buy Quantities	(% over all balancing Quantities)
Balancing actions taken	No of days
Average Price of Balancing action Buys	(EUR/MWh)
Average Price of Balancing action Sells	(EUR/MWh)

Source: (ACER Report 2017)

4.7.2.2 Network users' imbalance cash-out

Table 11. Network users' imbalance cash-out

Total Imbalance Cash-out Quantities	GWh
Total Imbalance Cash-out Quantities	% of zone entry quantities
Percentage of Total Network Users' Buy Quantities (in Total Imbalance Cash-out Quantities)	% of all cash-out quantities
Average Network Users' Long Position Cash-out Price	EUR/MWh
Average Network Users' Short Position Cash-out Price	EUR/MWh
TSO balancing action percentage	% of TSO's balancing action quantities + network users' imbalances

Source: (ACER Report 2017)

4.7.2.3 Neutrality

Table 12. Neutrality

Gross energy transacted	GWh
Net energy position	GWh
Absolute sum of cashflows	Thousand EUR
Net financial position	Thousand EUR
Net neutrality per unit of market volume	EUR/MWh
Net adjusted neutrality per unit of market volume	EUR/MWh
Maximum yearly cumulative neutrality	Thousand EUR
Minimum yearly cumulative neutrality	Thousand EUR

Source: (ACER Report 2017)

4.7.2.4 Linepack levels

Table 13. Linepack levels

Max opening linepack level	GWh
Average opening linepack level	GWh
Lowest opening linepack level	GWh
Highest absolute day-on-day linepack change	GWh
Average absolute day-on-day linepack change	GWh
Highest absolute commercial imbalance position change	GWh
Average absolute commercial imbalance position change	GWh
Max cumulative net imbalance	GWh
Min cumulative net imbalance	GWh

Source: (ACER Report 2017)

4.8 EFET market report

The BR. and as a consequence this section is mingling conditions of a well-functioning market and rules of balancing. This is understandable considering

that liquid market is a prerequisite for efficient balancing. For this reason it seems reasonable to look at the analysis of EFET of different markets. Please see Table 5 and Table 8.

5 Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems

5.1 Legislation

The current Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems ([10]) (CAM NC) was approved on 16 March 2017 and entered into force on 6 April 2017. The following deadlines are specified in the Code:

— 31 December 2018: when Transmission System Operators (TSOs) have to submit to ENTSOG all information required by ENTSOG to comply with its obligations pursuant to paragraph 1 (Article 38.2)

— 31 March 2019: when ENTSOG has to submit to ACER the above information, after having monitored and analysed how TSOs have implemented this Code, ensuring the completeness and correctness of all relevant information (Article 38.1).

— 6 April 2019: when ACER has to report on the conditionalities stipulated in contracts for standard capacity products for firm capacity, having regard to their effect on efficient network use and the integration of the Union gas markets (Article 38.4).

The repealed CAM NC ([11]) was approved on 14 October 2013, entered into force on 4 November 2013, and was applied from 1 November 2015. It was valid until 5 April 2017.

5.2 Overview of the Code

5.2.1 Scope

The CAM NC establishes capacity allocation mechanisms in gas transmission systems for existing and incremental capacity ([12]). It applies to Interconnection Points ([13]) (IPs), and may apply to entry points from and exit points to third countries, subject to the decision of the relevant National Regulatory Authority (NRA). It does not apply to exit points to end consumers and distribution networks, entry points from Liquefied Natural Gas (LNG) terminals and production facilities, and entry points from or exit points to storage facilities. The CAM NC applies to technical capacity ([14]), interruptible capacity ([15]), additional

([10]) REGULATION (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013 (http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R0459).

([11]) REGULATION (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and supplementing Regulation (EC) No 715/2009 of the European Parliament and of the Council (http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32013R0984).

([12]) A possible future increase via market-based procedures in technical capacity or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimisation and subsequently allocated subject to the positive outcome of an economic test.

([13]) A physical or virtual point connecting adjacent entry-exit systems or connecting an entry-exit system with an interconnector, in so far as these points are subject to booking procedures by network users.

([14]) The maximum firm capacity that the transmission system operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network.

([15]) Gas transmission capacity that may be interrupted by the transmission system operator in accordance with the conditions stipulated in the transport contract.

capacity ([16]), and incremental capacity, and sets up an auction procedure for capacity allocation where standard capacity products ([17]) are used (alternative capacity allocation mechanisms ([18]) may be used for incremental capacity). In addition, NRAs may limit up-front bidding by any single network user ([19]).

5.2.2 Cooperation

The CAM NC promotes cooperation and coordination between adjacent TSOs in terms of maintenance and information systems, including access of users to auction systems or booking platforms.

The maximum technical capacity shall be made available to network users, taking into account system integrity, safety and efficient network operation. Adjacent TSOs shall establish a joint method for optimisation of capacity, and perform in depth analysis taking into consideration the Union-wide TYNDP, national investment plans, and competing capacities ([20]).

A dynamic approach to recalculation of capacity is prescribed, where the TSOs decide on the frequency of the recalculation.

Where optimisation causes costs to TSOs, recovery is allowable via the regulatory framework.

Adjacent TSOs shall exchange nomination ([21]), re-nomination ([22]), matching, and confirmation information at IPs.

5.2.3 Allocation of Firm Capacity Products

Auctions shall be used for the allocation of firm capacity ([23]) products, except where alternative allocation mechanisms for incremental capacity are used. All IPs shall have the same auction design, all auctions shall start simultaneously, and standard capacity products shall be used, from long to short duration (yearly, quarterly, monthly, daily and within-day standard capacity products), both bundled ([24]) and unbundled. Allocation shall be independent, except for incremental capacity and competing capacity.

The units used shall be kWh/h or kWh/d (flat flow rate assumed).

The CAM NC defines that 20% of the existing technical capacity shall be set aside and offered as shown in

---

([16]) Any additional capacity made available through the application of one of the congestion-management procedures as provided for in points 2.2.2, 2.2.3, 2.2.4 and 2.2.5 of Annex I of REGULATION (EC) No 715/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:02009R0715-20150525).

([17]) A certain amount of transport capacity over a given period of time, at a specified interconnection point.

([18]) An allocation mechanism for offer level or incremental capacity designed on a case-by-case basis by the transmission system operators, and approved by the national regulatory authorities, to accommodate conditional demand requests.

([19]) A customer or a potential customer of a transmission system operator, and transmission system operators themselves in so far as it is necessary for them to carry out their functions in relation to transmission.

([20]) Capacities for which the available capacity at one point of the network cannot be allocated without fully or partly reducing the available capacity at another point of the network.

([21]) The prior reporting by the network user to the transmission system operator of the actual flow that the network user wishes to inject into or withdraw from the system.

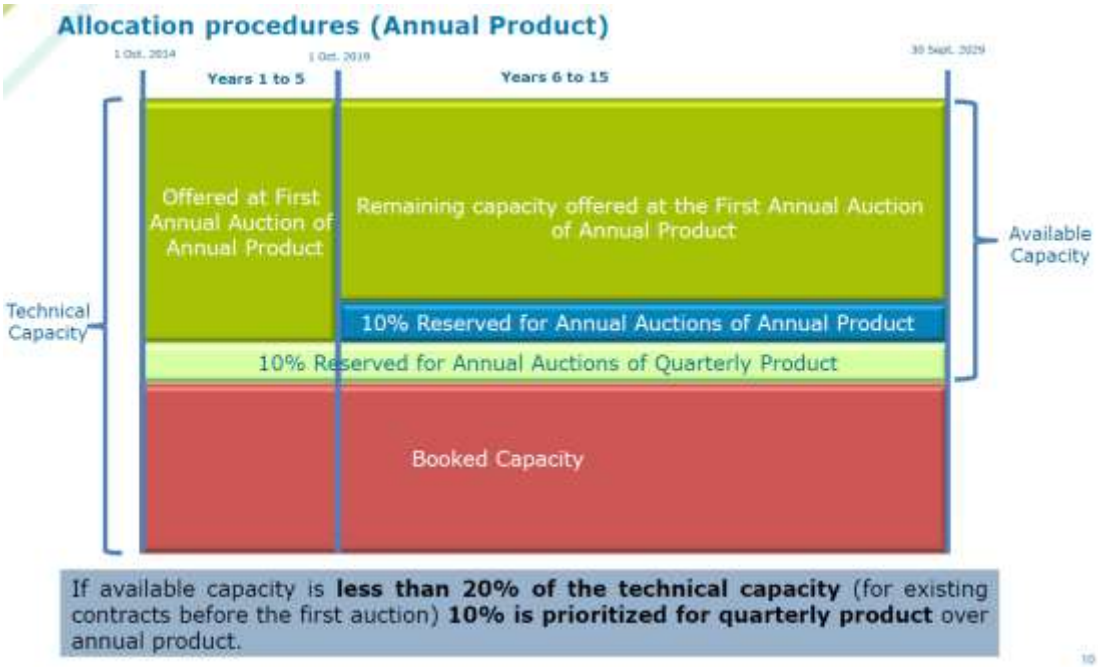
([22]) The subsequent reporting of a corrected nomination.

([23]) Gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator.

([24]) A standard capacity product offered on a firm basis which consists of corresponding entry and exit capacity at both sides of every interconnection point.

Figure **23**.

Figure 23. Allocation of 20% of the existing technical capacity



Source: Enagas ([25])

The capacity auctions shall have the following specifications:

5.2.3.1 Annual yearly auction

— Gas year: starting 1 October

— Auctions held once a year, on the 1st Monday of July, unless otherwise specified in the auction calendar ([26])

— Between 8.00 to 17.00 UTC ([27]) (winter) or 7.00 to 16.00 UTC (summer)

— Minimum 5 years, maximum 15 years, for incremental maximum 15 years after start of operation

— Ascending clock auction algorithm

— Bundled or unbundled capacity

— Users informed about amount of firm capacity available at least 1 month before auction starts

— Allocation results made available no later than the next business day after closing, simultaneously to all participants

([25]) Enagás Integration with European Regulation (November 2013) (http://www.enagas.es/stfls/EnagasImport/Ficheros/373/762/Integration%20with%20European%20Regulation,0.pdf).

([26]) A table displaying information relating to specific auctions which is published by ENTSOG by January of every calendar year for auctions taking place during the period of March until February of the following calendar year and consisting of all relevant timings for auctions, including starting dates and standard capacity products to which they apply.

([27]) Coordinated Universal Time.

— For incremental capacity, results made available no later than the next business day, economic results shall be made available no later than 2 business days after closing

— Aggregated information to the market

5.2.3.2 Annual quarterly auction

— Gas quarters: starting 1 October, 1 January, 1 April, 1 July

— Auctions held four times a year:

- On the 1st Monday of August for quarters 1 to 4,
- On the 1st Monday of November for quarters 2 to 4,
- On the 1st Monday of February for quarters 3 and 4,
- On the 1st Monday of May for quarter 4,

unless otherwise specified in the auction calendar

— Between 8.00 to 17.00 UTC (winter) or 7.00 to 16.00 UTC (summer)

— Ascending clock auction algorithm

— Bundled or unbundled capacity

— Users informed about amount of firm capacity available 2 weeks before each quarterly auction starts

— Allocation results made available no later than the next business day after closing, simultaneously to all participants

— Aggregated information to the market

5.2.3.3 Rolling monthly auction

— Gas months: calendar months

— Auctions held every month, on the 3rd Monday of the month, allocating capacity for the following month, unless otherwise specified in the auction calendar

— Between 8.00 to 17.00 UTC (winter) or 7.00 to 16.00 UTC (summer)

— Ascending clock auction algorithm

— Bundled or unbundled capacity

— Users informed about amount of firm capacity available 1 week before each monthly auction starts

— Allocation results made available no later than the next business day after closing, simultaneously to all participants

— Aggregated information to the market

5.2.3.4 Rolling day-ahead auction

— Gas day: from 5.00 to 5.00 UTC the following day (winter) or from 4.00 to 4.00 UTC the following day (summer)

— Auctions held once a day.

— Between 15.30 to 16.00 UTC (winter) or 14.30 to 15.00 UTC (summer), allocating capacity for the following gas day

— Uniform-price auction algorithm

— Bundled or unbundled capacity

— Users informed about amount of firm capacity available at the time the bidding round opens

— Allocation results made available no later than 30 minutes after closing, simultaneously to all participants

— Aggregated information to the market

5.2.3.5 Within-day auction

— Subject to capacity being made available

— Auctions held every hour during the gas day.

— First bidding round opens on the next hour following the publications of results of the last day-ahead auction (including interruptible capacity)

— First bidding round closes at 1.30 UTC (winter) or 0.30 UTC (summer)

— Allocation effective from 5.00 UTC (winter) or 4.00 UTC (summer)

— Network users can place, withdraw, amend bids before closure of bidding round

— Each hour, capacity for +4 hours is allocated

— Duration of each bidding round is 30 minutes

— Uniform-price auction algorithm

— Bundled or unbundled capacity

— Users informed about amount of firm within-day capacity available after the end of the day-ahead auction

— Users with unsuccessful day-ahead bids can have the option to have them entered automatically in the subsequent within-day auction

— Allocation results made available within 30 minutes of closure of bidding round

— Aggregated information to the market at least at the end of the day

The two auction algorithms defined in the CAM NC are the ascending clock auction algorithm ([28]) and the uniform-price auction algorithm ([29]). Their characteristics are:

5.2.3.6 Ascending clock auction algorithm

— Volume bids against escalating prices starting at the reserve price ([30])

— Duration of first round: 3 hours, duration of subsequent rounds: 1 hour

([28]) An auction in which a network user places requested quantities against defined price steps, which are announced sequentially.

([29]) An auction in which the network user in a single bidding round bids price as well as quantity and all network users, who are successful in gaining capacity, pay the price of the lowest successful bid.

([30]) The eligible floor price in the auction.

— 1 hour gap between bidding rounds

— Users wishing to participate must participate in the first round

— Bids equal or smaller than the capacity offered in the specific auction

— Subsequent bids equal or smaller than the initial bid

— Bids may be entered, modified and withdrawn during a bidding round

— A large price step and small price step are defined

— Large price step and small price step shall be published in advance

— Large price step is an integer number of small price steps

— Large price step shall be selected to minimise the length of the auction

— Small price step shall be selected to minimise unsold capacity

— If aggregate demand is less than or equal to offered capacity at the end of the first round, the auction closes

— If aggregate demand is greater than the offered capacity at the end of the first round or subsequent rounds, a further bidding round opens with price equal to the price in the previous round + large price step

— If a first time undersell occurs, a further bidding round opens with price equal to the price in the round preceding the undersell + small price step

— If the aggregate demand is greater than the offered capacity at the end of the first time undersell minus one small price step, the auction closes

— The clearing price, fixed ([31]) or floating ([32]), is the price that led to the first undersell and successful bids are the successful bids of the first undersell

— The aggregated demand of all users is published as soon as possible after each round

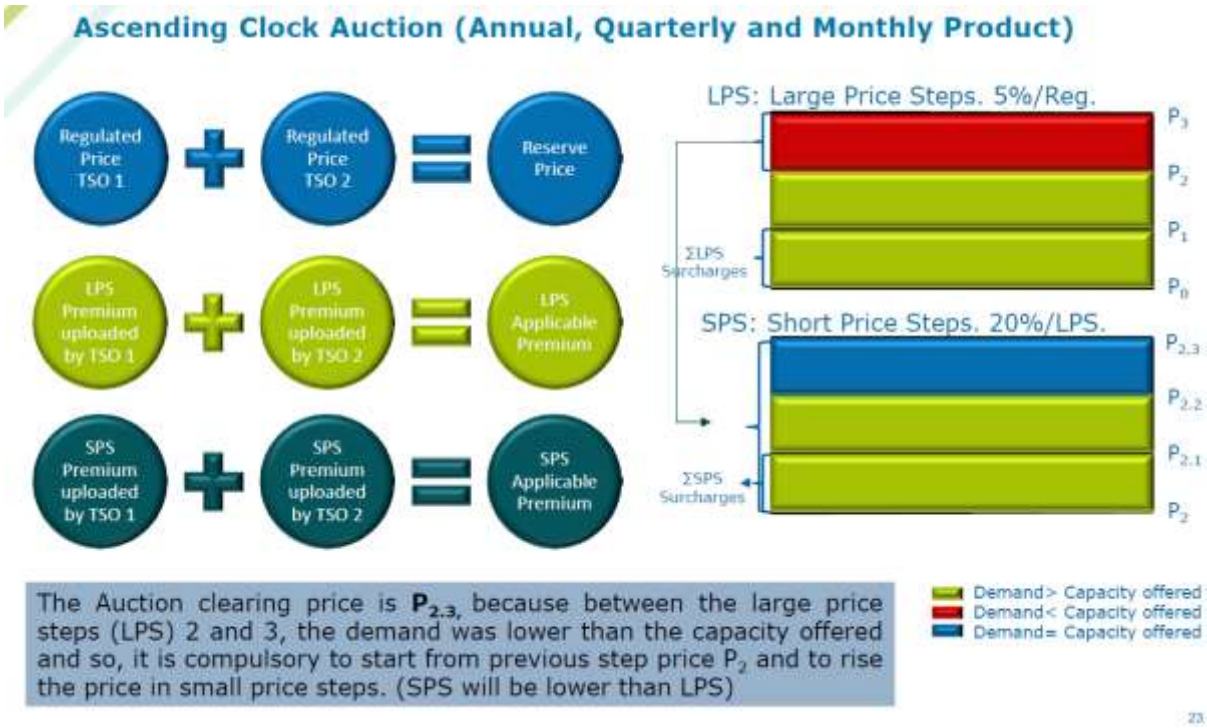
— If auction has not ended by the start of the next auction, capacity will be offered in the next relevant auction

An example of an ascending clock auction is shown in Figure 24.

([31]) A price calculated in accordance with Article 24(b) of COMMISSION REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas where the reserve price is not subject to any adjustments.

([32]) A price calculated in accordance with Article 24(a) of COMMISSION REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas where the reserve price is subject to adjustments such as revenue reconciliation, adjustment of the allowed revenue or adjustment of the forecasted contracted capacity.

Figure 24. Example of ascending clock auction



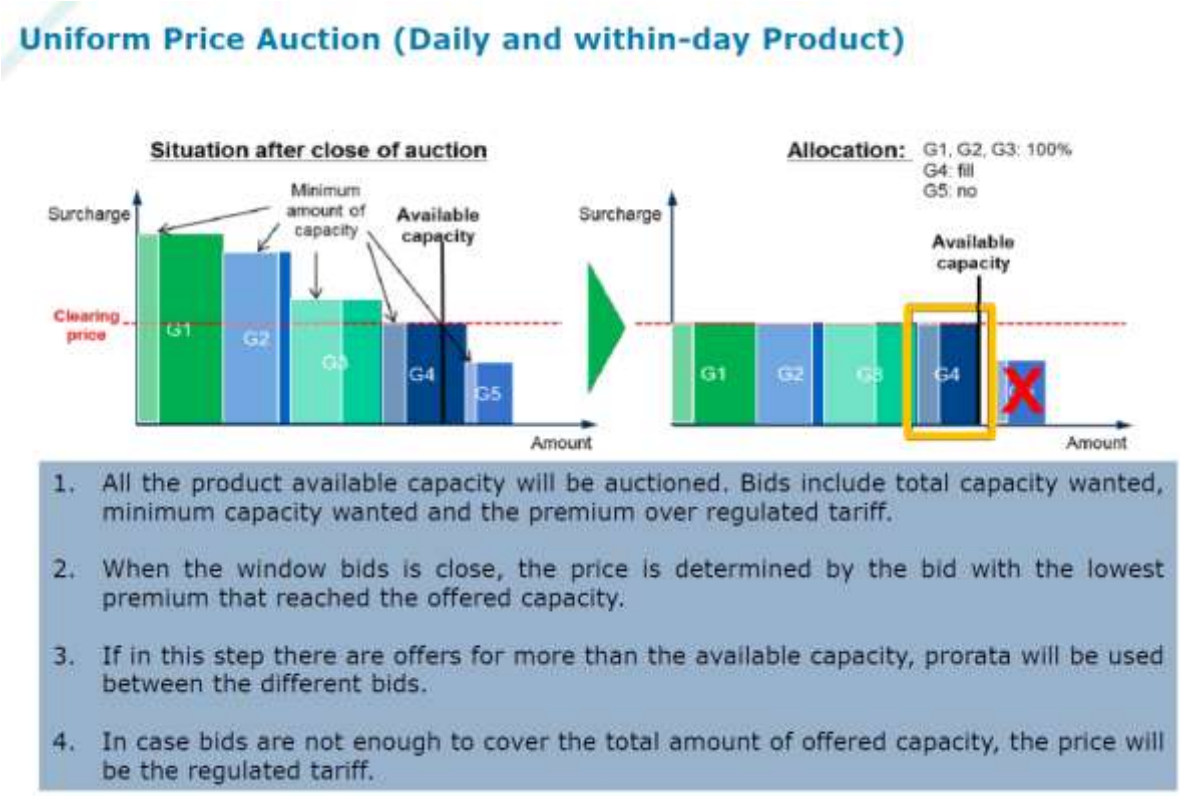
Source: Enagas ([25])

5.2.3.7 Uniform-price auction algorithm

- A single bidding round with price and quantity bids
- Each network user can submit up to 10 bids
- User specifies amount of capacity request + minimum amount of capacity willing to accept + bid price (equal or greater than reserve price)
- TSOs rank the bids starting from the highest price
- Pro rata allocation is used if two users have placed the same price bid and the unallocated capacity is less than the aggregated capacity requested by users
- If unallocated capacity is less than minimum capacity a user is willing to accept then bid is not successful and next lower bid is considered
- Clearing price is the price of the lowest successful bid, if demand exceeds offer
- Clearing price is the reserve price, otherwise
- Fixed payable price or floating payable price

An example of an ascending clock auction is shown in Figure 25.

Figure 25. Example of uniform price auction



Source: Enagas ([25])

5.2.4 Bundling of Capacity at Interconnection Points

The CAM NC specifies that adjacent TSOs shall jointly offer bundled capacity products. It is stressed that all firm capacity, as far as possible, shall be offered as bundled capacity on a booking platform with a single allocation procedure. If more firm capacity is available on one side of the IP, TSO of that side may offer that capacity as unbundled. However, the duration of contracts of unbundled capacity is limited (not exceeding the duration of unbundled capacity on the other side of the IP, otherwise one year). Unbundled capacity may be nominated as such and traded in the secondary market. A single nomination is envisaged for bundled products. Bundled capacity can only be resold as bundled.

Virtual interconnection points ([33]) (VIPs) shall be established where there are two or more IPs between adjacent TSOs. VIPs shall be established before 1 November 2018.

The Code specifies that ENTSOG shall create a catalogue of main terms & conditions for bundled capacity before 6 January 2018 and publish a template within six months. ACER shall provide an opinion on the template within three months and ENTSOG shall publish the final template within three months. New bundled capacity products may use this template.

Network users with unbundled products shall aim to bundle their capacity via contractual arrangements. TSOs shall offer a free-of-charge capacity conversion service of unmatched unbundled capacity from 1 January 2018 (with payment

([33]) Two or more interconnection points which connect the same two adjacent entry-exit systems, integrated together for the purposes of providing a single capacity service.

limited to a possible auction premium for the part of the contracted bundled capacity which network users already hold as mismatched unbundled capacity). The capacity conversion shall be applicable to yearly, quarterly and monthly contracts and to users with existing unbundled capacity at one side of an IP and bundled capacity at the same IP. ENTSOG was tasked to issue the capacity conversion model by 1 October 2017.

All capacity shall be bundled as early as possible and the duration of bundling arrangements cannot exceed the duration of original unbundled contract. Unbundled capacity contracts cannot be renewed.

5.2.5 Incremental Capacity Process

The incremental capacity process ([34]) includes an economic test ([35]) which is performed by the TSO or the NRA for each offer level ([36]) of an incremental capacity project after binding commitments of network users for contracting capacity. The following parameters are used:

— Present Value (PV) of binding commitments of network users for contracting capacity

— PV of estimated increase in the allowed revenue ([37]) or target revenue ([38]) of the TSO

— f-factor ([39]), as defined by NRAs

The incremental capacity project is initiated when the economic test is positive in both sides for at least one offer level. Investment costs are reflected in an increase in the allowed or target revenues.

The CAM NC specifies a single economic test by the involved TSOs of an IP in order to facilitate the offer of bundled capacity products. In this case, redistribution of revenues between TSOs is possible under certain conditions.

In terms of publication requirements, the TSOs seek approval by the NRAs for all economic test data used (reference prices estimated for the time horizon of the initial offer of incremental capacity used in the calculation of the PV of binding commitments of network users, PV of estimated increase in the allowed revenue or target revenue, f-factor, the range of the level for the mandatory minimum

([34]) A process to assess the market demand for incremental capacity that includes a non-binding phase, in which network users express and quantify their demand for incremental capacity, and a binding phase, in which binding commitments for contracting capacity are requested from network users by one or more transmission system operators.

([35]) A test applied to assess the economic viability of incremental capacity projects.

([36]) The sum of the available capacity and the respective level of incremental capacity offered for each of the yearly standard capacity products at an interconnection point.

([37]) The sum of transmission services revenue and non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period which such transmission system operator is entitled to obtain under a non-price cap regime and which is set in accordance with Article 41(6)(a) of Directive 2009/73/EC.

([38]) The sum of expected transmission services revenue calculated in accordance with the principles set out in Article 13(1) of Regulation (EC) No 715/2009 and expected non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period under a price cap regime.

([39]) The share of the present value of the estimated increase in the allowed or target revenue of the transmission system operator associated with the incremental capacity included in the respective offer level as set out in Article 22(1)(b) to be covered by the present value of binding commitments of network users for contracting capacity calculated as set out in Article 22(1)(a).

premium ([40]) for each offer level and IP applied in the first auction and possibly in subsequent auctions in which the incremental capacity is offered).

A market demand assessment shall be performed at least in each odd year by TSOs after the start of the annual yearly auctions taking into consideration non-binding demand indications by network users. The resulting market demand assessment report shall take into account the following criteria:

— Whether no yearly standard capacity is available for the year during which the incremental capacity can become available and for the three following years.

— Whether the Union-wide TYNDP identifies a gap and the incremental capacity project could close this gas.

— Whether a national Network Development Plan (NDP) identifies a transport requirement.

— Whether network users submitted non-binding requests for a sustained number of years.

The design phase starts immediately after the market demand assessment report is published and if the report concludes that there is demand for the incremental capacity. Technical studies shall identify the coordinated offer levels based on the report and the technical feasibility of the project. During the design phase, the relevant TSOs shall conduct a joint public consultation and shall coordinate accordingly in order to, amongst others, offer the incremental capacity as bundled products.

After the design phase is finalised and the joint public consultation is complete, the project proposal shall be sent to the relevant NRAs for coordinated approvals and, eventually, coordinated decisions. In case no agreement is reached by the NRAs on the proposed alternative allocation mechanism, ACER shall decide.

The TSOs offer the incremental capacity together with available capacity, as standard bundled products, in the annual yearly capacity auction. Auctions for different offer levels are conducted in parallel and independently. A new auction may be initiated if required.

An alternative allocation mechanism is possible covering maximum 15 years (may exceptionally be extended to 20 years). It can be used when:

— The ascending clock auction is deemed to be unsuitable

— If more than two entry-exit systems are involved

— If bids with duration of more than one year are requested

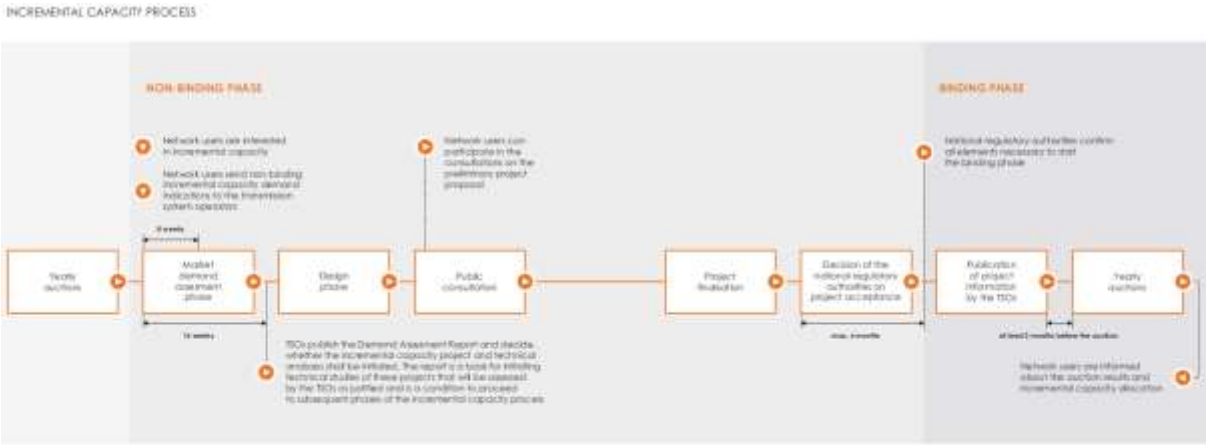
When an alternative allocation mechanism is used, conditional binding bids and prioritisation of booking duration or higher amounts of capacity may be possible. If prioritisation is applied, 10-20% of capacity may be set aside, decided by the NRAs.

Requirements apply to existing incremental capacity projects unless approval for capacity allocation was granted by NRAs before 1 August 2017.

([40]) Article 33(4) of COMMISSION REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R0460)

An overview of the timeframe of the incremental capacity process can be seen in Figure 26.

Figure 26. The incremental capacity process



Source: GAZ-SYSTEM ([41])

5.2.6 Interruptible Capacity

Starting from 1 January 2018, TSOs may offer interruptible capacity products longer than 1 day only if monthly, quarterly or yearly standard products for firm capacity were sold at auction premium, sold out or not offered. Daily interruptible products shall be offered in both directions if firm capacity was sold out day-ahead or not offered. Daily interruptible products shall be offered at least in opposite direction for unidirectional IPs.

Interruptible capacity shall be offered in auctions after firm capacity of the same duration has been offered, with the exception of within-day capacity where an over-nomination procedure ([42]) shall be used. For the annual yearly, for all annual quarterly and for all rolling monthly capacity auctions, network users shall be notified 1 week before the auction starts about the amount of interruptible capacity to be offered.

The minimum interruption lead times are decided by the TSOs, with the default minimum time being 45 minutes after the start of the re-nomination cycle for that gas hour. Interruptions are coordinated between TSOs.

The contractual time stamp shall be used in order to determine which interruptions shall take place when the total nominations exceed the capacity of an IP. Pro rata reduction is applied when two or more nominations have the same ranking. The reasons of interruption are included in the contract directly or in the general terms and conditions which are applicable to the contract.

5.2.7 Capacity Booking Platforms

The CAM NC prescribes that the TSOs shall offer one or a limited number of web-based booking platforms for capacity booking. Booking platforms shall:

([41]) GAZ-SYSTEM Amended network code on capacity allocation mechanisms in gas transmission systems (http://en.gaz-system.pl/fileadmin/pliki/do_pobrania/JoMil/ENG_NEW_CAM_NC_information_brochure.pdf)

([42]) The entitlement of network users who fulfil minimum requirements for submitting nominations to request interruptible capacity at any time within-day by submitting a nomination which increases the total of their nominations to a level higher than their contracted capacity.

— Comply with the rules for offer and allocation of firm capacity in the CAM NC

— Offer firm bundled capacity as prescribed in the CAM NC

— Include functionality for secondary capacity

In addition, only users that comply with the requirements of the relevant TSOs shall be able to use the corresponding booking platform. Furthermore, capacity at any IP or VIP shall be offered in one booking platform.

The relevant TSOs of an IP or VIP shall reach agreement on the booking platform to be used within 6 months from entry into force of this Code. If this does not happen, NRAs shall assign within 6 months a booking platform for maximum 3 years. If the NRAs don't reach an agreement within 6 months, ACER shall decide on the booking platform to be used for maximum 3 years. ENTSOG and ACER may facilitate the process of booking platform selection.

5.3 Differences between the Current and the Repealed CAM NC

The current CAM NC introduces or modifies the following:

— Minimum number of gas years for which the TSO may offer existing capacity: 5 years (there was no minimum before)

— Date of annual yearly capacity auctions: 1st Monday of July (was 1st Monday of March)

— Number and dates of annual quarterly capacity auctions: 4 auction on the 1st Monday of August, November, February, and May (there was one auction on the 1st Monday of June only)

— Interruptible capacity for annual, quarterly, and monthly products may only be offered after the corresponding annual, quarterly, and monthly firm product was sold at an auction premium, was sold out, or was not offered

— Standardisation of the way market participants can indicate demand for incremental capacity

— Standardisation of the rules of incremental capacity allocation by offering it together with the existing capacity

— Standardisation of the process of determining economic viability of an investment

— Establishment of cooperation between TSOs, NRAs, and market participants within the regular incremental process

— Article on tariffs removed and references to Regulation (EU) 2017/460 added.

5.4 Status of Implementation

5.4.1 Booking Platforms

As of January 2017, all relevant TSOs are connected to a booking platform ([43]). The only exception is the IP of Amber Grid (LT), which is the only IP of a TSO whose country has derogation.

([43]) ENTSOG CAM NC Implementation Monitoring Report 2016 (13 June 2017) (https://www.entsog.eu/public/uploads/files/publications/Implementation%20Monitoring/2017/l_entsog_IMR_cam_2016_03.pdf)

At the moment, there are three booking platforms ([44]) where standard procedures described in the CAM NC are used:

— PRISMA (https://platform.prisma-capacity.eu/#/start)

- Portugal, Spain, France, Germany, Belgium, Luxembourg, Netherlands, UK, Ireland, Denmark, Czech Republic, Austria, Italy, Slovenia

— GSA (https://aukcje.gaz-system.pl/)

- Polish sides of the IPs and at the interconnection point between Poland and the Czech Republic

— RBP (https://rbp.eu/)

- Slovakia, Hungary, Croatia, Romania, Bulgaria, Greece

It has to be noted that there are two IPs without agreement on booking platform at the German-Polish border ([43]).

Figure 27. Capacity booking platforms in the EU

Source: ENTSOG ([43])

([44]) ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016 - Gas Wholesale Markets Volume (6 October 2017) (http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20GAS.pdf)

5.4.2 Compliance

From the survey conducted by ENTSOG, there are 41 TSOs that are required to apply the CAM NC. From these ([43]):

— 32 TSOs fully comply with the CAM NC (applying all or at least all mandatory requirements)

— 9 TSOs claim that they partially comply to the CAM NC

— the Member States of 5 TSOs have derogations (one TSO of which voluntary partially implemented the CAM NC)

— 3 TSOs have IPs that are not relevant to the CAM NC

There are 328 IP sides in the European Energy Market. From these ([43]):

— For 37 IP sides the application of the CAM NC is not mandatory (35 with non-EU countries, 2 with derogation)

— For 4 IP sides there is an exemption from the national Energy Act

Standard capacity products have been introduced in all relevant IP sides. However, there are some delays in implementation of CAM NC provisions still present. Application of the CAM NC is not possible in some IPs as technical capacity is already booked on a long term basis.

The latest list of IPs published by ENTSOG/ACER ([45]) provides a best assessment of the entry and exit IP sides where the CAM NC is applicable.

According to ACER ([46]), following surveys in the first quarter of 2016, the overall average level of implementation of the NC CAM, with all mandatory NC CAM provisions weighted evenly, is 82%, which is deemed to be a good level of implementation. On the other hand, the average level of implementation of the core requirements of the CAM NC, i.e. auctioning of standard products via booking platforms, is 94%, which is deemed to be a high level of implementation.

The implementation of the following prescriptions of the CAM NC is lagging behind:

— capacity bundling, so that network users can easily access IP capacity using a single nomination procedure,

— VIPs, so that booking is further simplified for network users, and

— capacity maximisation, where NRAs are not involved in the joint calculation method for removal of mismatches at the two sides or an IP, the TSOs have not agreed on the frequency of the dynamic recalculation, and the TSOs don't make use of network user data of future flows.

Overall, ACER stresses that the dynamic recalculation of technical capacity needs to be improved.

([45]) ENTSOG/ACER List of Interconnection Points defining the scope of the CAM Network Code and CMP Guidelines (20 June 2016) (https://www.entsog.eu/public/uploads/files/publications/Implementation%20Monitoring/2016/CAP0657-16_CAM%20ANNEX%20II%20IP%20list%20with%20products%20march%202016_final.xlsx)

([46]) ACER Implementation Monitoring Report on the Capacity Allocation Mechanisms Network Code (27 October 2016) (http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Implementation_Monitoring_Report_on_the_Capacity_Allocation_Mechanisms_Network_Code.pdf)

It has to be noted that all implementation assessments are based on the repealed CAM NC ([11]) rather than on the current CAM NC ([10]).

5.4.3 Capacity Conversion Model

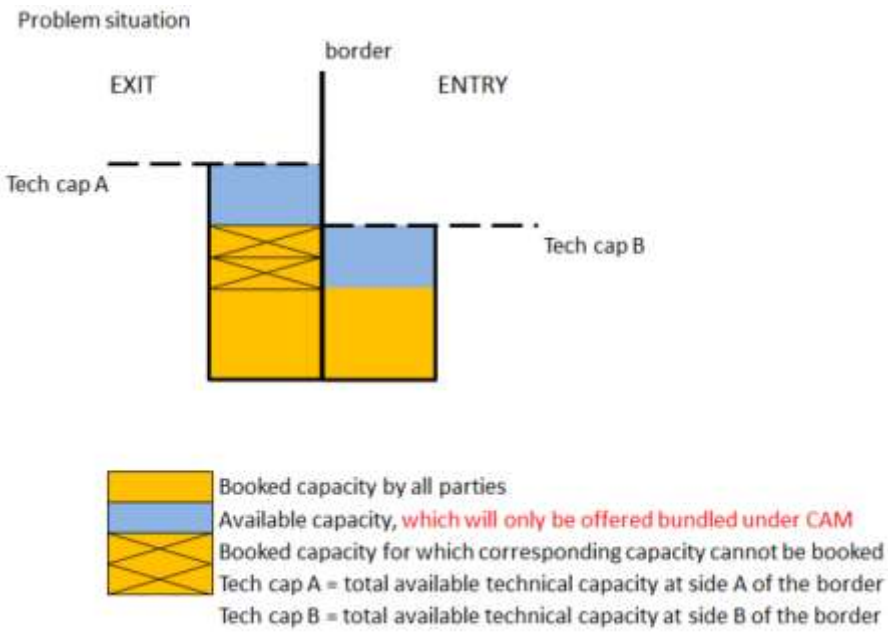
ENTSOG issued the capacity conversion model on 24 July 2017 ([47]) (the deadline in the CAM NC was 1 October 2017), with the service being offered from 1 January 2018.

Requests for capacity conversion are submitted by network users that hold unbundled capacity, before (ex-ante) or after (ex-post) the respective auction for bundled capacity, in accordance with the relevant contractual arrangements. The TSO performs the conversion subject to the allocation of bundled capacity to the network user. The capacity that becomes available after the conversion is offered in the subsequent auctions by the relevant TSO.

A network user may request a conversion up to the capacity and up to the duration of its unbundled capacity contract.

Figure 28 provides a diagrammatic representation of the capacity conversion problem, where the available bundled capacity is shown in relation to the unbundled capacity already held by a network user.

Figure 28. Capacity conversion problem



Source: ENTSOG ([47])

([47]) ENTSOG's Capacity conversion model - CAP0717-17 (24 July 2017) (https://www.entsog.eu/public/uploads/files/publications/CAM%20Network%20Code/2017/CAP0717-17_170724_ENTSOG_Capacity-conversion-model_final%20GA.pdf)

5.4.4 Effect

The ratio of bundled capacity to sold capacity for the 2015/2016 gas year, as calculated by ENTSOG ([43]), is shown in Figure 29.

Figure 29. Bundled capacity to sold capacity

Source: ENTSOG ([43])

Overall, about 33% of the total firm capacity booked was booked as part of a bundled product.

The significant difference between the quarterly products and the yearly, monthly and daily products can be attributed to the date and frequency of the annual quarterly capacity auctions in the repealed CAM NC, as described in paragraph 5.3, both of which are modified in the current CAM NC ([48]).

The relative low ratios can be explained as follows:

— The NRA decided to apply the CAM NC to an IP even though it is not necessary (i.e. IP with third country or IP with an exempted country)

— There are still significantly many old long-term unbundled capacity contracts which can only be matched with unbundled capacity on the other side of the IP

— There are differences in technical capacities of IP sides resulting in capacities being offered as unbundled

— There are different booking platforms on IP sides

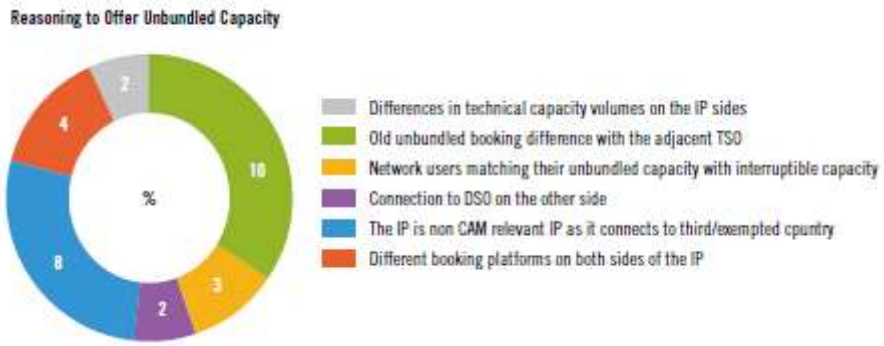
— There are network users that are matching unbundled capacity on one IP side with interruptible capacity on the other IP side.

([48]) ENTSOG Auction Calendar 2017/2018 for Capacity Allocation Mechanism Network Code - CAP0682-16 (7 October 2016) (https://www.entsog.eu/public/uploads/files/publications/CAM%20Network%20Code/2016/CAP0682_161007_CAM%20NC%20auction%20calendar%202017-2018.pdf)

— The NRA decided to apply the CAM NC to an IP side although that side is connected to a Distribution System Operator (DSO)

Figure 30 shows the reasons why TSOs were offering unbundled capacity instead of bundled capacity.

Figure 30. Reasoning for offering unbundled capacity

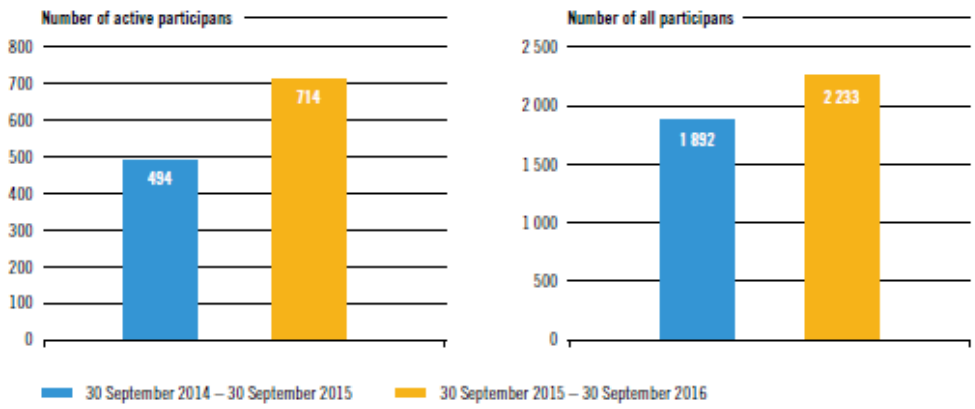


Source: ENTSOG ([43])

In addition to the ratio of bundled capacity to sold capacity, ENTSOG has also calculated the ratio of bundled capacity to firm capacity in the secondary market, which is only 0.38% ([43]). Main reason for this is the fact that the CAM NC entered into force in 2015 and before its entry in force, contracts were unbundled (normally, capacity in the secondary market comes from old contract).

Furthermore, ENTSOG recorded the number of participants and the number of active participants in the 2014/2015 and 2015/2016 gas years ([43]), as shown in Figure 31. It is evident that both the number of participants and, more importantly, the number of active participants has increased, confirming that indeed the CAM NC facilitates access of network users to different European markets.

Figure 31. Number of participants and number of active participants



Source: ENTSOG ([43])

ACER and CEER have also been assessing the market effects of the CAM NC ([44]). In terms of bundled capacity products, it is observed that on average only 1% of

the capacity offered as bundled in the PRISMA booking platform was booked, as shown in Figure 32. This is attributed to the following:

— the current market conditions at the majority of IP sides, where transportation costs are higher than spreads, resulting in reduced interest for engagement in price arbitrage between hubs

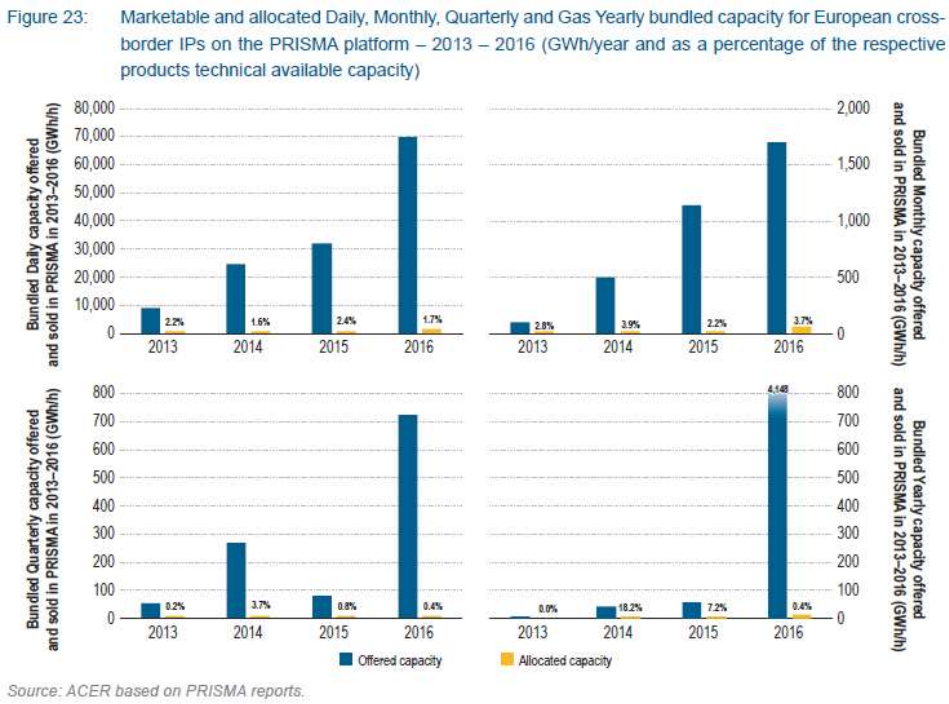
— the bundled and unbundled capacity mismatch, which is though likely to be resolved with the introduction of ENTSOG's Capacity conversion model ([47])

— the lack or insufficient transparency in the calculation of technical capacity by TSOs

— the lack of standardised capacity products at some borders

— the high shares of long-term capacity bookings not fully utilised.

Figure 32. Bundled capacity offered and sold in PRISMA

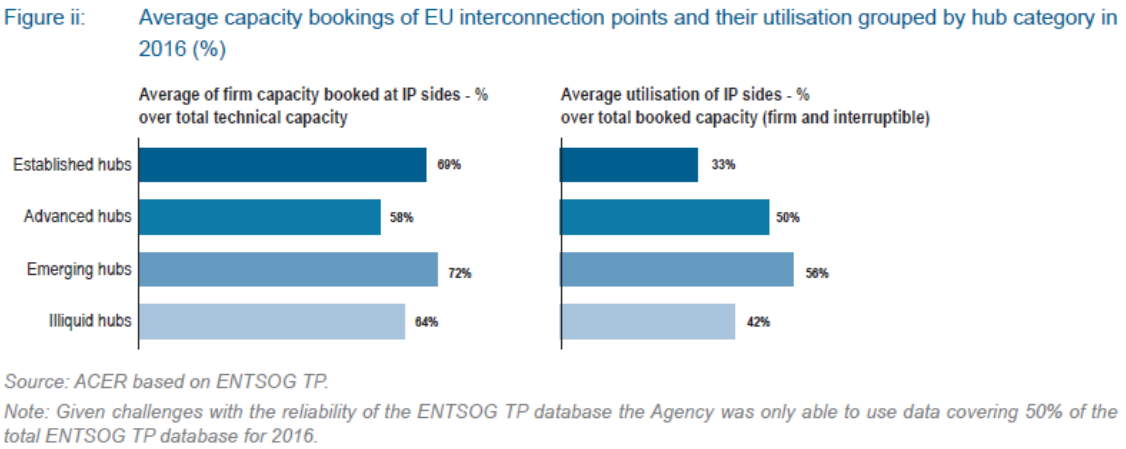


Source: ACER/CEER ([44])

The average booking ratio of IP sides in 2016, as shown in Figure 33, was 60%, with all hub types having similar average booking ratios. However, results vary significantly when looking into individual IP sides, as demonstrated in Figure 34. It is notable that IP sides located in important routes are almost fully booked.

The high booking levels at certain IP sides can be explained by high levels of long-term capacity booked years ago, when the market conditions were more favourable. Low booking levels reveal lower interest and lower attractiveness of the specific route. In partially booked IP sides, the uncertainty over the capacity tariffs and the frequent changes in transportation tariffs contribute to the relatively low booking levels.

Figure 33. Average ratio of booked firm capacity to technical capacity / average utilisation in 2016 per hub type



Source: ACER/CEER ([44])

Figure 34. Average ratio of booked firm capacity to technical capacity in 2016 in selected IP sides

Source: ACER/CEER ([44])

Although peak capacity needs to be taken into consideration when determining the required technical capacity, ACER and CEER note that, as contractual congestion is registered only at 9% of EU IP sides, a situation of overcapacity in parts of the gas network is quite likely in the near future.

Finally, it is interesting to note the following statement in the ACER/CEER Report: "In general, the issues with the network codes and framework guidelines implementation, experienced by market participants and reported in the 'Barriers in gas wholesale markets survey' ([49]), relate mainly to the differences between present day gas market conditions ('oversupply' and 'sizeable unused capacity')

([49]) ACER Barriers to gas wholesale trading (February 2017) (http://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/Kantor_report_on%20barriers%20to%20gas%20wholesale%20trading.pdf)

and those at the time of their drafting (‘golden age of gas’, scarcity of transportation capacity)".

6 Network Code on Harmonised Transmission Tariff Structures for Gas

This chapter is based on the text of the Network Code on Harmonised Transmission Tariff Structures for Gas ([50]) and on ENTSOG's implementation document ([51]). The TAR NC is the fourth network code in the gas sector, following the NCs on capacity allocation mechanisms, gas balancing of transmission and interoperability and data exchange rules.

The TAR NC interacts with:

— Amended CAM NC: certain rules of the TAR NC refer specifically to Interconnection points ('IP'), subject to the Amended CAM NC. The listed rules in the TAR NC address tariff-related issues of the Amended CAM NC: Chapter III 'Reserve prices', Chapter V 'Pricing of bundled capacity and capacity at virtual interconnection points ('VIP')', Chapter VI 'Clearing and payable price', Article 28 on discounts, multipliers and seasonal factors from Chapter VII 'Consultation requirements', Article 31(2)–(3) on publication of certain tariff information on ENTSOG's Transparency Platform ('TP') from Chapter VIII 'Publication requirements' and Chapter IX 'Incremental capacity'. The Amended CAM NC governs the process for offering incremental capacity, while the TAR NC sets out the tariff principles for incremental capacity.

— Transparency Guidelines: Chapter VIII 'Publication requirements' sets out tariff transparency obligations that further elaborate and harmonise the tariff transparency obligations in the Transparency Guidelines.

— BAL NC: the TAR NC treats the balancing activity of a TSO as a 'third' service category independent of transmission and non-transmission services. Balancing costs receive separate treatment given the application of a neutrality mechanism under the BAL NC.

— INT NC: the TAR NC incorporates all the definitions introduced by the INT NC.

— Chapter 2.2 of Annex I to the Gas Regulation ('CMP Guidelines'): although the Gas Regulation defines physical and contractual congestion, there is an indirect link between the TAR NC and the CMP Guidelines. The CMP Guidelines stipulate the detailed measures for solving contractual congestion, which can affect the TSO's revenue recovery, as when implementing an oversubscription and buy-back procedure.

6.1 Legislation

The current the Network Code on Harmonised Transmission Tariff Structures for Gas (TAR NC) was approved on 16 March 2017, published in the Official Journal on 17 March 2017 and entered into force on 6 April 2017. Some deadlines are specified, among which 31 May 2019 which is the deadline when the procedure consisting of the final consultation on the reference price methodology in

([50]) REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (http://eur-lex.europa.eu/legal-+content/EN/TXT/PDF/?uri=CELEX:32017R0460&from=EN)

([51]) Implementation Document for the Network Code on Harmonised Transmission Tariff Structures for Gas - Second Edition (https://www.entsog.eu/public/uploads/files/publications/Tariffs/2017/TAR1000_170928_2nd%20Implementation%20Document_High-Res.pdf)

accordance with Article 26, the decision by the national regulatory authority in accordance with paragraph 4 (Article 27), the calculation of tariffs on the basis of this decision, and the publication of the tariffs in accordance with Chapter VIII shall be concluded. The procedure shall be repeated at least every five years starting from the deadline.

The TAR NC sets out the rules on harmonised transmission tariff structures for gas, including rules on the application of a reference price methodology, the associated consultation and publication requirements as well as the calculation of reserve prices for standard capacity products.

6.2 Scope

The TAR NC apply to all entry and exit points of gas transmission networks except Chapters III (Reserve prices) , V (Pricing of bundled capacity and capacity at VIPs), VI (Clearing and payable price), Chapter IX (Incremental capacity), Article 28 in Chapter VII (Consultation requirements) on NRA consultation on discounts, multipliers and seasonal factors, Article 31(2)-(3) in Chapter VIII (Publication requirements) on the publication of certain tariff information on the ENTSOG's Transparency Platform (TP), which apply only to IPs.

For non-IPs, there are two categories:

— non-IPs that are entry-points-from/exit-points-to third countries

— other non-IPs, such as domestic exit points, entry-points-from/exit-points-to storage facilities. Such a distinction is necessary when analysing which TAR NC rules that are by default limited

to IPs can be extended to non-IPs. If the NRA takes the decision to apply the CAM NC to entry or/and exit points from/to third countries, then Chapters III, V, VI, Article 28 and Chapter IX shall also apply to those points.

Derogations limited in time exist for certain MS, under Article 49 of Directive 2009/73/EC.

6.3 Definitions

The definitions in the Gas Directive ([52]), the Gas Regulation, the BAL NC ([53]), the INT NC ([54]) and the CAM NC ([55]) shall also apply for the TAR NC.

In addition, the following definitions are directly given in Article 3:

'reference price' means the price for a capacity product for firm capacity with a duration of one year, which is applicable at entry and exit points and which is used to set capacity-based transmission tariffs;

([52]) Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0073)

([53]) Commission Regulation (EU) No 312 / 2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks

([54]) Commission Regulation (EU) 2015 / 703 of 30 April 2015 establishing a network code on interoperability and data exchange rules

([55]) CAM

'reference price methodology' (RPM) means the methodology applied to the part of the transmission services revenue to be recovered from capacity-based transmission tariffs with the aim of deriving reference prices;

'non-price cap regime' means a regulatory regime, such as the revenue cap, rate of return and cost plus regime, under which the allowed revenue for the transmission system operator is set in accordance with Article 41(6)(a) of Directive 2009/73/EC;

'non-transmission services revenue' means the part of the allowed or target revenue which is recovered by non- transmission tariffs;

'regulatory period' means the time period for which the general rules for the allowed or target revenue are set in accordance with Article 41(6)(a) of Directive 2009/73/EC;

'transmission services revenue' means the part of the allowed or target revenue which is recovered by transmission tariffs;

'transmission tariffs' means the charges payable by network users for transmission services provided to them;

'intra-system network use' means transporting gas within an entry-exit system to customers connected to that same entry-exit system;

'cross-system network use' means transporting gas within an entry-exit system to customers connected to another entry-exit system;

'homogeneous group of points' means a group of one of the following types of points: entry interconnection points, exit interconnection points, domestic entry points, domestic exit points, entry points from storage facilities, exit points to storage facilities, entry points from liquefied natural gas facilities (hereinafter, referred to as 'LNG facilities'), exit points to LNG facilities and entry points from production facilities;

'allowed revenue' means the sum of transmission services revenue and non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period which such transmission system operator is entitled to obtain under a non-price cap regime and which is set in accordance with Article 41(6)(a) of Directive 2009/73/EC;

'transmission services' means the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission;

'non-transmission tariffs' means the charges payable by network users for non-transmission services provided to them;

'target revenue' means the sum of expected transmission services revenue calculated in accordance with the principles set out in Article 13(1) of Regulation (EC) No 715/2009 and expected non-transmission services revenue for the provision of services by the transmission system operator for a specific time period within a given regulatory period under a price cap regime;

'non-transmission services' means the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator;

'multiplier' means the factor applied to the respective proportion of the reference price in order to calculate the reserve price for a non-yearly standard capacity product;

'price cap regime' means a regulatory regime under which a maximum transmission tariff based on the target revenue is set in accordance with Article 41(6)(a) of Directive 2009/73/EC;

'cost driver' means a key determinant of the transmission system operator's activity which is correlated to the costs of that transmission system operator, such as distance or technical capacity;

'cluster of entry or exit points' means a homogeneous group of points or group of entry points or of exit points located within the vicinity of each other and which are considered as, respectively, one entry point or one exit point for the application of the reference price methodology;

'flow scenario' means a combination of an entry point and an exit point which reflects the use of the transmission system according to likely supply and demand patterns and for which there is at least one pipeline route allowing to flow gas into the transmission network at that entry point and out of the transmission network at that exit point, irrespective of whether the capacity is contracted at that entry point and that exit point;

'seasonal factor' means the factor reflecting the variation of demand within the year which may be applied in combination with the relevant multiplier;

'fixed payable price' means a price calculated in accordance with Article 24(b) where the reserve price is not subject to any adjustments;

'tariff period' means the time period during which a particular level of reference price is applicable, which minimum duration is one year and maximum duration is the duration of the regulatory period;

'regulatory account' means the account aggregating at least under- and over-recovery of the transmission services revenue under a non-price cap regime;

'auction premium' means the difference between the clearing price and the reserve price in an auction;

'floating payable price' means a price calculated in accordance with Article 24(a) where the reserve price is subject to adjustments such as revenue reconciliation, adjustment of the allowed revenue or adjustment of the forecasted contracted capacity.

TAR NC splits all the regulatory regimes (defined in Article 41(6)(a) of the Gas Directive) into two categories: price cap and non-price cap. The main difference between the two is reflected in what is set:

— either the maximum transmission tariff based on revenue for a price cap regime, leading to the concept of target revenue ;

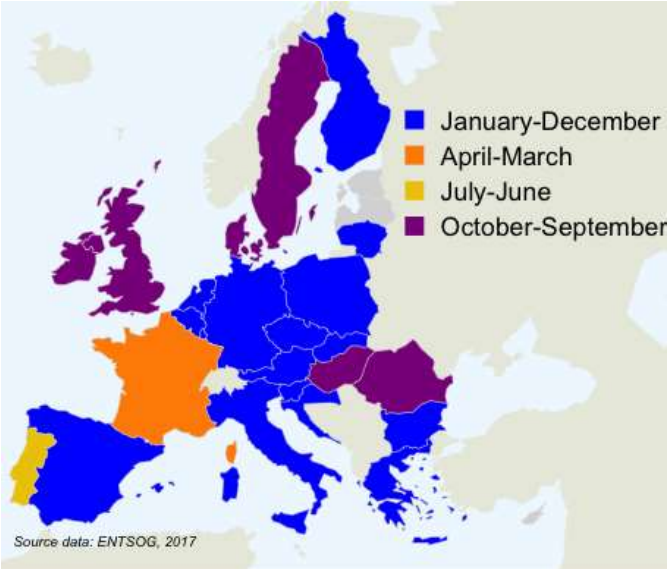
— or the revenue for a non-price cap regime; it is the concept of allowed revenue.

As of September 2017, the majority of the EU TSOs function under the non-price cap regime. A combination of price cap and non-price cap regimes applies in the Czech Republic and Italy, and the price cap regime applies in Slovakia.

The regulatory periods are different in the MS. The same holds for the tariff periods. They are represented in Figure 35 and Figure 36.

Figure 35. Regulatory periods in EU MS

Figure 36. Tariff periods in EU MS



6.4 Transmission and non-transmission services and tariffs

The condition for a service to be considered a transmission service is to meet both of the following two criteria:

Its costs are caused by the cost drivers of both technical or forecasted contracted capacity and distance.

Its costs are related to the investment in and operation of the infrastructure (which is part of the regulated asset base for the provision of such services).

If a service does not meet both conditions, then it may be considered either a transmission or a non-transmission service, following the findings of the periodic consultations carried on by the NRA or TSO (and described in Articles 26 and 27).

The definition of the application of the tariffs and their link to the revenue is in Figure 37.

Transmission tariffs may be set such as to take into account the conditions for firm capacity products. The transmission service revenue shall be recovered from transmission tariffs which are capacity-based transmission tariffs.

Exceptions apply in the sense that part of the transmission services revenue may be recovered by commodity-based transmission tariffs satisfying:

— flow-based charge,

- levied for the purpose of covering the costs mainly driven by the quantity of the gas flow;
- calculated on the basis of forecasted or historical flows, or both, and set in such a way that it is the same at all entry points and the same at all exit points;
- expressed in monetary terms or in kind

— a complementary revenue recovery charge,

- levied for the purpose of managing revenue under- and over-recovery;
- calculated on the basis of forecasted or historical capacity allocations and flows, or both;
- applied at points other than interconnection points;
- applied after the NRA has made an assessment of its cost-reflectivity and its impact on cross-subsidisation between IPs and points other than IPs.

The non-transmission services revenue shall be recovered by non-transmission tariffs for a non-transmission service. Those tariffs shall be:

— cost-reflective, non-discriminatory, objective and transparent;

— charged to the beneficiaries of a non-transmission service with the aim of minimising cross-subsidisation between network users (within or outside a MS, or both).

Where a given non-transmission service benefits all network users, its costs shall be recovered from all network users.

Currently, there are many services offered by TSOs which must be assessed in the future against the TAR NC classification (transmission vs. non-transmission). Examples of such services are:

— Blending and/or ballasting (e. g. Belgium, Italy);

— Odourisation (e.g. Belgium, Denmark, France, Greece, Hungary, Ireland, Italy, Lithuania, Romania);

— Biogas services (e.g. France, Germany, Ireland, Italy, Lithuania);

— Services provided on regional networks (e. g. France, Italy);

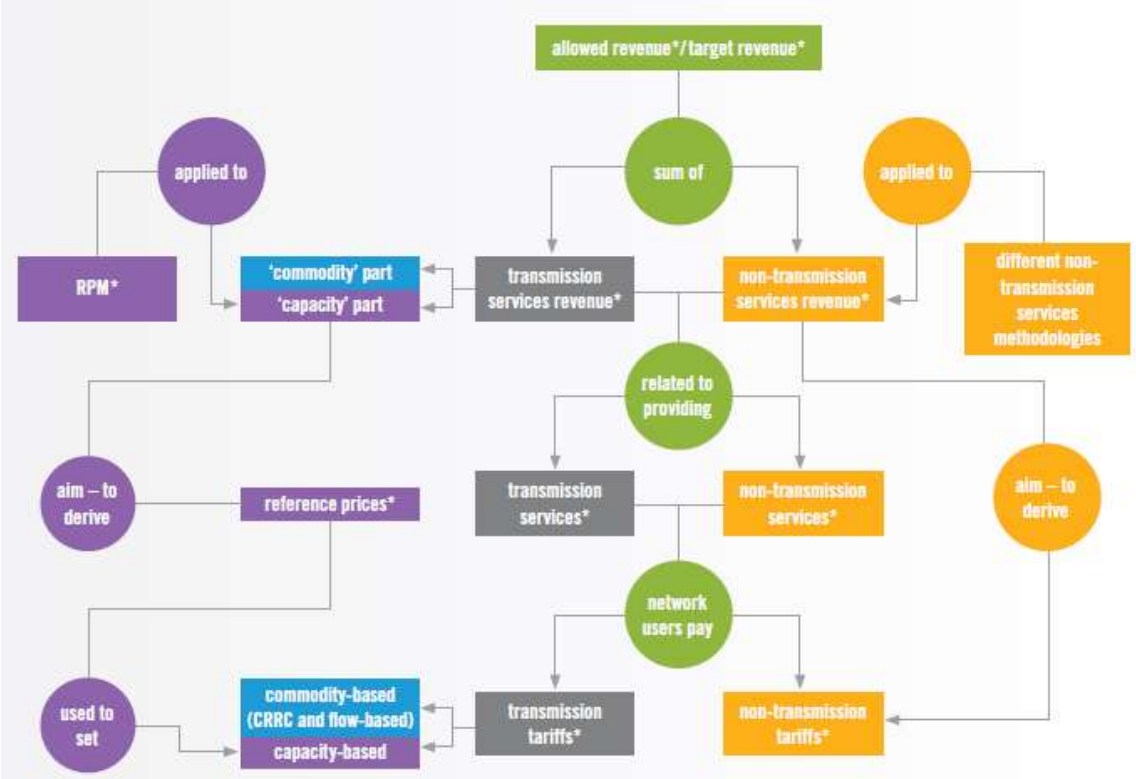
— Dedicated compression services (e.g. France, Great Britain, Ireland, Lithuania, Poland);

— Dedicated metering services (e.g. Belgium, Lithuania, Germany, Ireland, Italy, France, Great Britain);

— Dedicated pressure services (e.g. Belgium, France, Germany, Ireland, Italy, Lithuania);

— Dedicated connections (e.g. Austria, Belgium, Germany, Great Britain, Greece, Hungary, Ireland, Italy, Lithuania).

Figure 37. Definition concerning revenue and tariffs



Source: ENTSOG ([51])

6.5 Cost allocation assessment

6.5.1 Cost allocation assessment method

The NRA or the TSO (as decided by the TSO) shall perform cost allocation assessments (and publish them as part of the final consultation defined in Article 26) for:

— Transmission services revenue recovered by capacity-based tariffs and based exclusively on cost-drivers of

- technical or forecasted contracted capacity, or
- technical or forecasted contracted capacity and distance;

— Transmission services revenue recovered by commodity-based tariffs and based exclusively on cost-drivers of

- amount of gas flow or
- amount of gas flow and distance.

The intent of the cost allocation assessments is to guarantee against undue cross-subsidies on capacity or commodity by checking that the revenue-to-cost ratio for intra-system use is broadly similar to the revenue-to-cost ratio for cross-system use.

Both cost allocation assessment for revenues recovered by capacity- and commodity-based tariffs shall be carried out using the formulae:

$$\boldsymbol{Ratio_{\beta}^{\alpha}} = \frac{\boldsymbol{Revenue_{\beta}^{\alpha}}}{\boldsymbol{Driver_{\beta}^{\alpha}}} \left[\frac{\boldsymbol{Eur}}{\boldsymbol{MWh/day}}\right] \qquad [1]$$

$$\boldsymbol{Comp_{\beta}} = \frac{2\times\left|\boldsymbol{Ratio_{\beta}^{\alpha_1}} - \boldsymbol{Ratio_{\beta}^{\alpha_2}}\right|}{\boldsymbol{Ratio_{\beta}^{\alpha_1}} + \boldsymbol{Ratio_{\beta}^{\alpha_2}}} \times \mathbf{100}\% \qquad [2]$$

With the notations:

$\alpha = \begin{cases} intra & \text{if intra} - \text{system network} \\ cross & \text{if cross} - \text{system network} \end{cases}$,

$\beta = \begin{cases} cap & \text{if capacity} - \text{based} \\ comm & \text{if commodity} - \text{based} \end{cases}$,

$\alpha_1 = intra$, $\alpha_2 = cross$.

The formulae are used in the following way.

Let us suppose that we perform the cost allocation assessment for transmission services capacity-based revenue (which means that in both previous equations $\beta = cap$). We compute the intra-system capacity ratio (first equation with $\alpha = \alpha_1$) and the cross-system capacity ratio (first equation with $\alpha = \alpha_2$). Next we compute the capacity cost allocation comparison index between the two ratios using the second equation. This index is computed as ratio between a variability measure (here the range) and a measure of the average (here the mean).

Moreover, there is a constraint on the cross-system network stating that the capacity use at all entry points is equal to the capacity use at all exit points and that the revenue is split based on this constraint. The revenue of the intra-system network is equal to the difference between the overall revenue and the revenue from the cross-system.

The $Driver$ stands for the value of cost drivers for the system, such as the sum of the average forecasted capacities contracted at each entry/exit point (or cluster of points). It is measured in MWh/day.

If this capacity cost allocation comparison index exceeds 10% ($Comp_{\beta} > 10\%$), the NRA shall provide a justification in the decision referred to in Article 27(4). The same methodology is used for the cost allocation assessment for transmission services commodity-based revenue ($\beta = comm$).

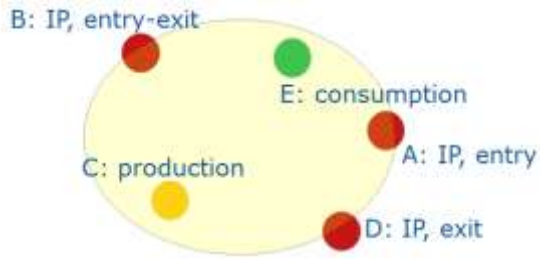
The purpose of such calculations is to guarantee against undue cross-subsidies by checking that the revenue-to-cost ratio is approximatively the same for intra- and cross-system use.

6.5.2 Cost allocation assessment example

Let us consider the following fictional example of a simple entry/exit system, schematically represented in

Figure 38.

Figure 38. Simple entry/exit system for the cost allocation example



Source: own elaboration

The system is formed by five points, two entry points, two exit points, and one point which is both entry and exit. The type of points and the capacities in GWh/d associated to the intra- and cross-systems are given in Table 14.

Table 14. Capacities of the simple entry/exit system

	Type	Capacity (total)	Capacity cross-system	Capacity intra-system	Capacity cross-system	Capacity intra-system
Entry						
A	IP	500	500 x **F**	500 x (1-**F**)	143	357
B	IP	600	600 x **F**	600 x (1-**F**)	171	429
C	Production	300	300 x **F**	300 x (1-**F**)	86	214
Exit						
B	IP	200	200			
D	IP	200	200			
E	Consumption	1,000		1,000		

Source: own elaboration

A way to compute the capacity use at all entry points of the cross-system from the constraint on the cross-system network (stating that the capacity use at all entry points is equal to the capacity use at all exit points) is to use the same factor **F**, as a multiplier for the capacity use at each entry point, which yields:

$$\mathbf{F} * \sum Capacity_{cross}^{entry} = \sum Capacity_{cross}^{exit}$$

Here:

$$\mathbf{F} = \frac{200 + 200}{500 + 600 + 300} = \frac{2}{7}$$

To have a complete example, we should now define the distances between the points of the entry/exit points of the system and the total capacity revenue and well as the share of revenue for the entry points and the share of the revenue for the exit points. The Cost Drivers have to be computed too.

Table 15. Distances (in km) between entries and exits

		Exit		
		B	**D**	**E**
Entry	**A**	550	300	250
	B	0	600	400
	C	350	200	400

Taking into account the capacity and the distance of every entry of the system to one specific exit, a capacity weighted average distance can be calculated for this exit point. This average distance of one exit point is determined by the sum of each entry capacity, times the distance to this respective entry point from the considered exit point, divided by the sum of all entry capacities. An average distance for a specific exit point is hence:

$$\overline{Distance_{exit_i}} = \frac{\sum_j Distance_{entry_j exit_i} \times Capacity_{entry_j}}{\sum_j Capacity_{entry_j}}$$

Same type of calculation of average distances for each entry point to the group of exit points is made. In contrast to exit points, for entry points there is a distinction regarding the average distance to intra-system exit points and to cross-system exit points. The distance to intra-system exit points is the actual distance to the exit point Consumption (E), while the distance to the cross-system exit points is again calculated as the capacity weighted average between the cross-system exit points. This distinction is made to later define the intra/cross system drivers for entry points.

In this example, the Driver for an exit point is the respective capacity at the point times the average distance to the entry points in this given system. The Drivers for each entry point are calculated by similarly. For entry points although, the Drivers will again be split and allocated to intra- and cross-system use. This is required for the assessment.

$$Driver_{exit_i} = \overline{Distance_{exit_i}} \times Capacity_{exit_i}$$

Table 16. Average distances and drivers for entry and exit points

Entry point	Average distance for an entry point		Drivers for entry points	
	To intra exits	To cross exits	Intra-use	Cross-use
A	250	425	89,250	60,775
B	400	600	171,600	102,600
C	400	300	85,600	25,800

Exit point	Average distance for an exit point	Drivers for exit points
B	475	95,000
D	407	81,400
E	346	346,000

Let us assume that the total capacity revenue is of 500,000 € and that the entry/exit split is 40/60 % (decided arbitrarily). To complete the computation we also need the tariffs; we might set them arbitrarily (because this is not an example for tariffs derivation) for the exit and entry points. However, in this example, the only necessary one is the tariff for the consumption point (E), which allows computing the Exit revenues from Intra. We will set this tariff equal to **120** €.

Table 17. Cost allocation assessment

Capacity revenue	500,000			
Entry share	40%			
Exit share	60%			
Entry revenues	200,000			
Exit revenues	300,000			
Entry revenues for Intra[1]	142,857			
Entry revenues for Cross[2]	57,143			
Exit revenues from Intra[3]	**120** x 1,000= 120,000			
Exit revenues from Cross	180,000			**Test**
Revenue for Intra	262,857		Ratio intra	38%
Revenue for Cross	237,143		Ratio cross	65%
Cost Driver for Entry Intra [4]	346,450		**Comparison index**	**26%**
Cost Driver for Exit Intra	346,000		**Justification required**	
Cost Driver for Intra[5]	692,450			
Cost Driver for Entry Cross[6]	189,175			
Cost Driver for Exit Cross[7]	176,400			
Cost Driver for Cross[8]	365,575			

[1] Equal to the Entry revenues x (1-F)

[2] Equal to the Entry revenues x F

[3] Here equal to the product between the tariff for the consumption point (E) (here equal to 120) and the capacity of the consumption point

[4] Equal to the sum of the drivers for all entries (Intra-use)

[5] Equal to the sum of the Cost Driver for Entry Intra and Cost Driver for Exit Intra

[6] Equal to the sum of the drivers for all entries (Cross-use)

[7] Equal to the sum of the drivers for all exits (Cross-use)

[8] Equal to the sum of the Cost Driver for Entry Cross and Cost Driver for Exit Cross

6.6 Reference price methodologies

The choice of RPM is a central topic of the TAR NC and a key decision for a TSO/NRA. The RPM determines how to allocate the TSO's costs among entry and exit points, how the TSO recovers its revenue, and how to charge network users.

The collection of transmission services revenue must be based primarily on capacity charges.

The TAR NC does not restrict the choice of RPM, since a TSO/NRA can consider any methodology as long as the assessment involves a comparison to the capacity weighted distance (CWD) reference price methodology counterfactual in the final consultation document. The TAR NC does not describe any possible RPM except for the CWD counterfactual.

The reference price methodology:

— Will be set / approved by NRA

— Will be subject to the findings of the periodic consultations

— Will provide a reference price

— The same methodology applies to all entry and exit points in a given entry-exit system.

Adjustments are possible in accordance with Article 9 or as a result of:

— benchmarking by the NRA, whereby reference prices at a given entry or exit point are adjusted so that the resulting values meet the competitive level of reference prices;

— equalisation by the TSO(s)/NRA, whereby the same reference price is applied to some or all points within a homogeneous group of points;

— rescaling by the TSO(s)/NRA, whereby the reference prices at all entry or all exit points, or both, are adjusted either by multiplying their values by a constant or by adding to or subtracting from their values a constant.

Figure 39. Different adjustments in use or envisaged to be used by the EU TSOs as of September 2017

The choice of the RPM shall comply with Article 13 of the Gas Regulation and with the following requirements:

— to be reproducible (for the reference prices and their accurate forecast)

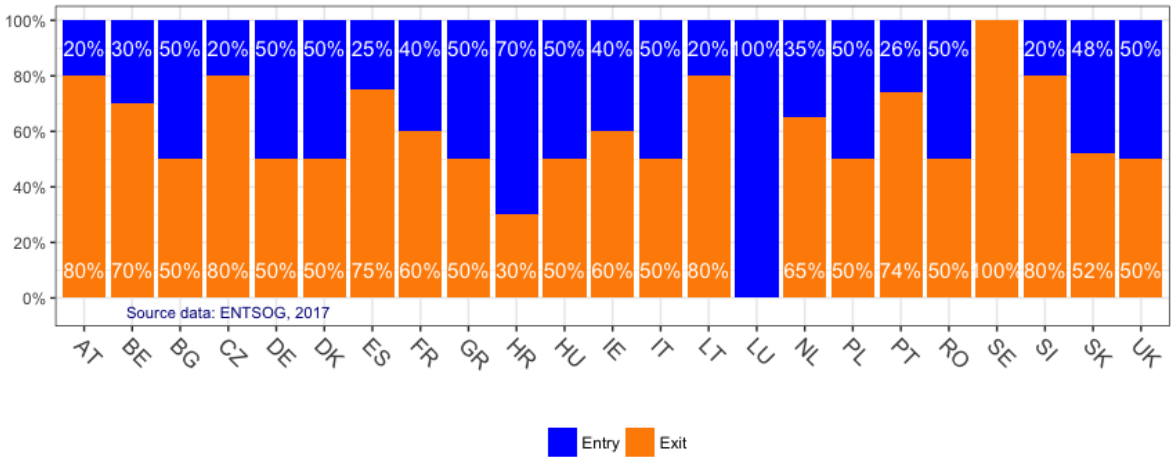
— to be cost-reflective

— to ensure non-discrimination and prevent undue cross-subsidisation

— to be able to perform volume risk management

— to ensure that the reference prices do not distort cross-border trade.

Figure 40. Current entry-exit splits applied by European TSOs



Source: ENTSOG ([51])

6.6.1 Capacity weighted distance reference price methodology

Even if this methodology is not mandatory, TSOs will have to compare the tariffs under their RPM with the tariffs obtained using the capacity weighted distance (CWD) reference price methodology.

The philosophy behind the CWD is that the share of the revenue to collect from each entry or exit point should be proportional to its contribution to the cost of the system's capacity and to the distance between it and all exit points or all entry points. The resulting tariff would be uniform per unit of capacity and distance.

6.6.1.1 Parameters

The parameters used as an input to the methodology are:

— The part of revenue to be recovered from capacity-based transmission tariffs

— The forecasted contracted capacity at each entry / exit

— The shortest distance between an entry and an exit should be used (when entry and exit points can be combined in a relevant flow scenario)

— The entry-exit split which should be 50/50.

6.6.1.2 Steps

The sequential steps of the methodology are:

Computation of the weighted average distance for

— each entry using the formula $\mathrm{AD_{En}} = \frac{\sum_{\text{all Ex}} \mathrm{CAP_{Ex}} \times \mathrm{D_{En,Ex}}}{\sum_{\text{all Ex}} \mathrm{CAP_{Ex}}}$

— each exit using the formula $\mathrm{AD_{Ex}} = \frac{\sum_{\text{all En}} \mathrm{CAP_{En}} \times \mathrm{D_{En,Ex}}}{\sum_{\text{all En}} \mathrm{CAP_{En}}}$

with

AD_{En}, AD_{Ex} the weighted average distance for entry respectively exits points

CAP_{En}, CAP_{Ex} the forecasted contracted capacity at entry/exit points

$D_{En,Ex}$ the distance between entry/exit points

Computation of the weight of cost for:

— each entry using the formula $\mathrm{W_{c,En}} = \frac{\mathrm{CAP_{En}} \times \mathrm{AD_{En}}}{\sum_{\text{all En}} \mathrm{CAP_{En}} \times \mathrm{AD_{En}}}$

— each exit using the formula $\mathrm{W_{c,Ex}} = \frac{\mathrm{CAP_{Ex}} \times \mathrm{AD_{Ex}}}{\sum_{\text{all Ex}} \mathrm{CAP_{Ex}} \times \mathrm{AD_{Ex}}}$

Identification of the part of the transmission services revenue to be recovered at all entries ($R_{\sum En}$) and all exits ($R_{\sum Ex}$) by applying the entry/exit split.

Computation of the part of the transmission services revenue to be recovered at:

— each entry using the formula $\mathrm{R_{En}} = \mathrm{W_{c,En}} \times \mathrm{R_{\sum En}}$

— each exit using the formula $\mathrm{R_{Ex}} = \mathrm{W_{c,Ex}} \times \mathrm{R_{\sum Ex}}$

Computation of the resulting reference price at:

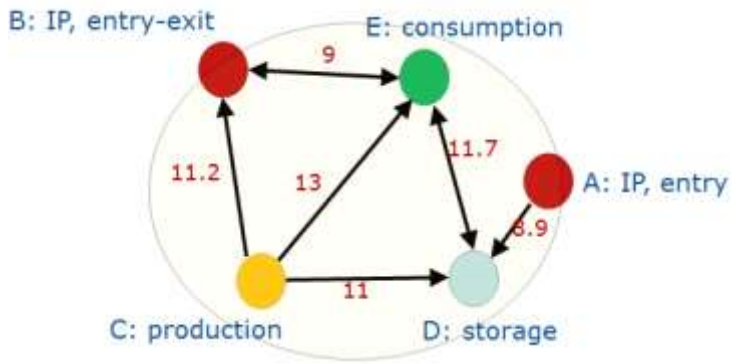
— each entry using the formula $\mathrm{T_{En}} = \frac{\mathrm{R_{En}}}{\mathrm{CAP_{En}}}$

— each exit using the formula $T_{Ex} = \frac{R_{Ex}}{CAP_{Ex}}$

6.6.2 Example of application of the CWD methodology

We consider one fictional TSO entry/exit system with four entries and three exits and six pipelines, as represented in Figure 41, where a simple arrow indicates the flow direction, and a double one indicates that the flow is in both directions. The distances between the points are also indicated (in km).

Figure 41. Simple entry/exit system for application of the CWD



Source: own elaboration

Table 18. Description of the system in the CWD example

Points	Type	Entry	Exit	Distances	
A	IP	Yes	No	**AD**	8.9
B	IP	Yes	Yes	**CD**	11
C	Production	Yes	No	**DE**	11.7
D	Storage	Yes	Yes	**BC**	11.2
E	Consumption	No	Yes	**BE**	9
				CE	13

Source: own elaboration

The part of the revenue to be recovered from capacity-based transmission tariffs: 1000€.

Entry-exit split : 50/50.

Table 19. Capacity data for the system in the CWD example

Capacity data			
	Entry points	**Entry technical capacity**	**Forecasted contracted Entry**
IP	A	20	15
IP	B	70	60
Production	C	20	20
Storage	D	8	4
	Exit points	**Exit technical capacity**	**Forecasted contracted Exit**
IP	B	100	90
Storage	D	8	2
Consumption	E	70	70

Table 20. Calculations in the CWD example

Shortest pipeline path						
	Exit points (CAP_{Ex})					
Entry points (CAP_{En})	B (90)	D (2)	E (70)	**AD_{En}**	**Sum prod**	**$W_{c,En}$**
A (15)	29.6	8.9	20.6	**25.46**	**936.23**	**40%**
B (60)	0	20.7	9	**4.14**		**27%**
C (20)	11.2	11	13	**11.98**		**26%**
D (4)	20.7	0	11.7	**16.56**		**7%**
AD_{Ex}	**7.58**	**16.12**	**11.67**			
Sum prod	**1532.01**					
$W_{c,Ex}$	**45%**	**2%**	**53%**			

Table 21. Results of the CWD example

Revenue, reference price				
Entry points	$W_{c,En}$	Total revenue	R_{En}	T_{En}
A (15)	40%	500	200	13.30
B (60)	27%		135	2.25
C (20)	26%		130	6.50
D (4)	7%		35	8.75
Exit points	$W_{c,Ex}$	Total revenue	R_{Ex}	T_{Ex}
B (90)	45%	500	225	2.50
D (2)	2%		10	5.00
E (70)	53%		265	3.79

In this example we did not use any discount for the storage.

6.6.3 Adjustments of tariffs and rules for systems with more than one TSO

— A discount of at least 50 % shall be applied to capacity-based transmission tariffs at entry points from and exit points to storage facilities.

— At entry points from LNG facilities and at entry points from and exit points to infrastructure developed with the purpose of ending the isolation of MS in respect of their gas transmission systems, a discount may be applied to the respective capacity-based transmission tariffs for the purposes of increasing security of supply.

— The same RPM shall be applied jointly by all TSOs within an entry-exit system within a MS.

— In order to allow for the proper application of the same RPM jointly, an effective inter- transmission system operator compensation mechanism shall be established.

Table 22. Current storage discounts

MS	TSO Entry discount	TSO Exit discount
AT	100%	Highly discounted
BE	0%	100%
BG	70%	70%
CZ	No general discount applied	No general discount applied
DE	50%	50%
DK	100%	100%
ES	100%	100%
FR	85% on average	85% on average
HR	%	90%
HU	90%	100%
IE	No discount on capacity charge	No discount on capacity charge
IT	14% (only if costs are allocated to each pipeline)	14% (only if costs are allocated to each pipeline)
NL	25%	25%
PL	80%	80%
PT	0%	No tariffs applied
RO	0%	0%
SE	100%	100%
SK	0%	0%
UK	0% (capacity charge), 100% (commodity charge)	0% (capacity charge), 100% (commodity charge)

Source: ENTSOG ([51])

6.7 Reserve prices

— For yearly standard capacity products for firm capacity, the reference prices shall be used as reserve prices.

— The level of multipliers and of seasonal factors and the level of discounts for the standard capacity products for interruptible capacity may be different at interconnection points.

— Where the tariff period (see

— **Figure 36**) and gas year (1 October – 30 September) do not coincide, separate reserve prices may be applied respectively:

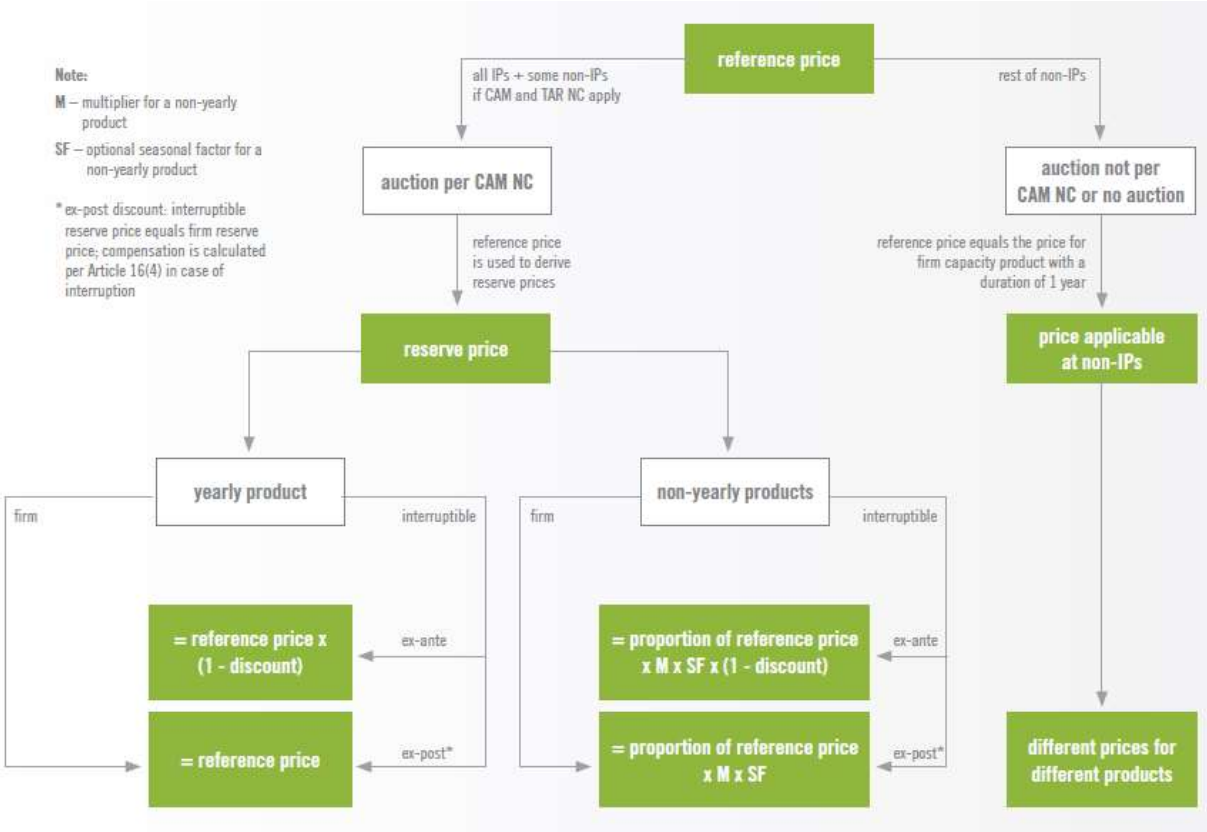
- for the time period from 1 October to the end of the prevailing tariff period; and
- for the time period from the beginning of the tariff period following the prevailing tariff period to 30 September.

— The respective reserve prices shall be binding for the subsequent gas year or beyond it in case of fixed payable price, beginning after the annual yearly capacity auction, unless:

- the discounts for monthly and daily standard capacity products for interruptible capacity are recalculated within the tariff period if the probability of interruption changes by more than twenty percent;
- the reference price is recalculated within the tariff period due to exceptional circumstances under which the non-adjustment of tariff levels would jeopardise the operation of the TSO.

For non-yearly standard capacity products for firm capacity, the reserve prices shall be calculated as set out in this Chapter. For both yearly and non-yearly standard capacity products for interruptible capacity, the reserve prices shall be calculated as set out in this Chapter. CAM NC introduces 5 standard capacity products: yearly, quarterly, monthly, daily, and within-day.

Figure 42. Definitions reference and reserve prices



Source: ENTSOG ([51])

6.7.1 Multipliers and seasonal factors

Rules for the multipliers and seasonal factors are given here below.

The level of multipliers (M) will be is the following ranges:

— for quarterly standard capacity products and for monthly standard capacity products, $1 \leq M \leq 1.5$;

— for daily standard capacity products and for within-day standard capacity products, $1 \leq M \leq 3$. In duly justified cases, the level of the respective multipliers may be less than 1, but higher than 0, or higher than 3.

Where seasonal factors (SF) are applied, the arithmetic mean over the gas year of the product of the multiplier applicable for the respective standard capacity product and the relevant seasonal factors shall be within the same range as for the level of the respective multipliers (previously defined).

Figure 43. Application of seasonal factors in EU MS

6.7.2 Reserve prices for non-yearly standard capacity products for firm capacity with/without seasonal factors

The reserve prices for non-yearly standard capacity products for firm capacity without seasonal factors are calculated as follows:

— For quarterly, monthly, daily products as $P_{st} = \frac{M \times T}{365} \times D$ (for leap years, 365 is substituted with 366)

— For within-day products as $P_{st} = \frac{M \times T}{8760} \times H$ (for leap years, 8760 is substituted with 8784)

With

— P_{st} the reserve price

— M the level of the multiplier

— T the reference price

— D the duration of the standard capacity product in gas days

— H is the duration of the within-day standard capacity product in hours.

Where seasonal factors are applied, the reserve prices previously calculated will be then multiplied by the respective seasonal factor.

The methodology for the seasonal factors is based on the forecasted flows, unless the quantity of the gas flow at least for one month is equal to 0 (when it will be based on the forecasted contracted capacity).

Table 23. Multipliers, seasonal factors and interruptible discounts for quarterly products at an IP

Multiplier	**Multiplier and seasonal factor**	**Multiplier and interruptible discount**
Multiplier describes the pricing relationship between the short-term product and the yearly product	Seasonal factor allows for variations in the seasonal value of the same standard capacity products	Although the firm price is the same price for a given 'category' of products, there can be different interruptible prices – depending on factors Pro and A
Quarterly – the same multiplier for all four products - Q1 firm 1.5 - Q2 firm 1.5 - Q3 firm 1.5 - Q4 firm 1.5	Quarterly – the same multiplier for all four products but different seasonal factors Assumptions: - Q1 and Q4 have 92 days, Q2 has 90 days, Q3 has 91 days - Multiplier is 1.5 Initial values: - Q1 firm 1.5 × 1.5 - Q2 firm 1.5 × 1.7 - Q3 firm 1.5 × 0.8 - Q4 firm 1.5 × 0.7 Average product: (1.5 × 1.5 × 92 + 1.5 × 1.7 × 90 + 1.5 × 0.8 × 91 + 1.5 × 0.7 × 92) / (92 + 90 + 91 + 92) = [1.5 (1.5 × 92 + 1.7 × 90 + 0.8 × 91 + 0.7 × 92)] / 365 ≈ 1.760 Correction factor: 1.5/1.760 Corrected values:	Quarterly – the same multiplier for all four products but different probability of interruption / factor 'A'. Assumptions: - 2 products P1 and P2 with 'Pro' of 0.1 and 0.25 in Q1 - 2 products P3 and P4 with 'Pro' of 0.15 and 0.2 in Q2 - 'A' factor is 1 in Q1 and 2 in Q2, no seasonal factor at all - Q1 has 92 days (d), Q2 has 90 days - Reserve price (RP) for annual product is 365 - Multiplier is 1.5 Calculation of discount: Di = Pro × A × 100 × RP × (d / 365) × 1.5 Discount for P1 in Q1 = 10 % × 1 × 100 % ×365 × (92 / 365) × 1.5 = 13.80

	- Q1 firm 1.5 × 1.5 × (1.5 / 1.760) = 1.5 × 1.28 - Q2 firm 1.5 × 1.7 × (1.5 / 1.760) = 1.5 × 1.45 - Q3 firm 1.5 × 0.8 × (1.5 / 1.760) = 1.5 × 0.68 - Q4 firm 1.5 × 0.7 × (1.5 / 1.760) = 1.5 × 0.60 After correction, average products falls within multiplier range: [1.5 (1.28 × 92 + 1.45 × 90 + 0.68 × 91 + 0.60 × 92)] /365 = 1.5	Discount for P2 in Q1 = 25 % × 1 × 100 % ×365 × (92 / 365) × 1.5 = 34.50 Discount for P3 in Q2 = 15 % × 2 × 100 % × 365 × (90 / 365) × 1.5 = 40.50 Discount for P4 in Q2 = 20 % × 2 × 100 % ×365 × (90 / 365) × 1.5 = 54.00

Source: ENTSOG ([51])

6.7.3 Reserve prices for standard capacity products for interruptible capacity

The reserve prices for standard capacity products for interruptible capacity are given by:

$$P_{int} = P_{st} \times (100\% - Di_{ex-ante})$$

where $Di_{ex-ante}$ is the level of an ex-ante discount:

$$Di_{ex-ante} = Pro \times A \times 100\%$$

and

$$Pro = \frac{N \times D_{int}}{D} \times \frac{CAP_{av.int}}{CAP}$$

(*Pro* is the probability of interruption and $A \geq 1$ is an adjustment factor including the economic value).

The notations used are:

— *N* is the expectation of the number of interruptions over *D*;

— D_{int} is the average duration of the expected interruptions, in hours;

— *D* is the total duration of the standard capacity product for interruptible capacity, in hours;

— $CAP_{av.int}$ is the expected average amount of interrupted capacity for each interruption where such amount is related to the respective type of standard capacity product for interruptible capacity;

— CAP is the total amount of interruptible capacity for the respective type of standard capacity product for interruptible capacity.

As an alternative to applying *ex-ante* discounts, the NRA may decide to apply an *ex-post* discount, whereby network users are compensated after the actual interruptions incurred. Such *ex-post* discount may only be used at interconnection points where there was no interruption of capacity due to physical congestion in the preceding gas year. The *ex-post* compensation paid for

each day on which an interruption occurred shall be equal to three times the reserve price for daily standard capacity products for firm capacity.

6.8 Reconciliation of revenue

If the TSO functions under a non-price cap regime, then

— (the under- or over-recovery of the transmission services revenue shall be minimised having due regard to necessary investments;

— the level of transmission tariffs shall ensure that the revenue is recovered by the TSO in a timely manner;

— significant differences between the levels of transmission tariffs applicable for two consecutive tariff periods shall be avoided to the extent possible.

If the TSO functions under a price cap regime (or applies a fixed payable price approach), no revenue reconciliation shall occur and all risks related to under- or over-recovery shall be covered exclusively by the risk premium.

Subject to the requirements of periodic consultations, non-transmission services revenue may be reconciled.

Under- and over-recovery is defined as

$$R_A - R,$$

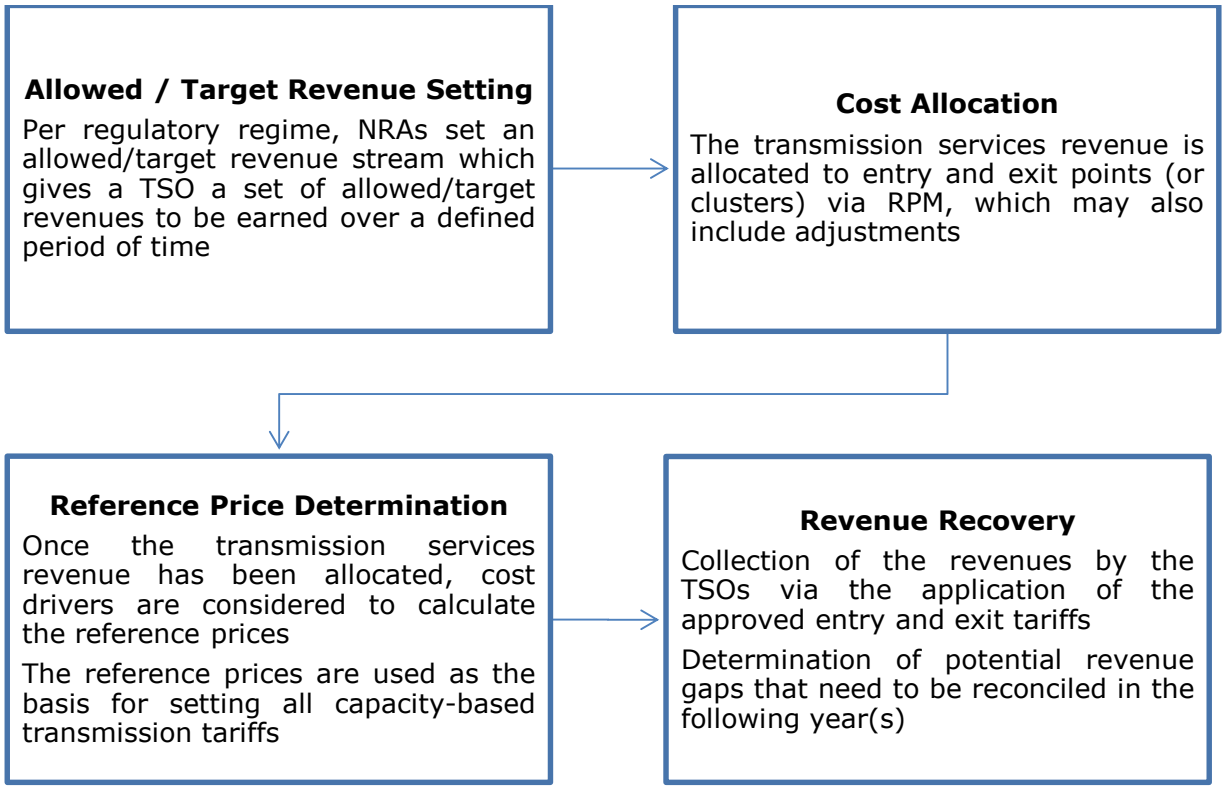
where R_A is the actually obtained revenue related to the provision of transmission services and R is the transmission services revenue.

If the difference is positive, it shall indicate an over-recovery, while if the difference is negative, it shall indicate an under-recovery.

The TSO's under- or over-recovered transmission services revenue shall be attributed to the regulatory account.

The full or partial reconciliation of the regulatory account shall be carried out in accordance with the applied RPM. The regulatory account shall be reconciled with the aim of reimbursing to the TSO the under-recovery and of returning to the network users the over-recovery.

Table 24. Links between revenue reconciliation, cost allocation, reference price determination and revenue recovery:



Source: ENTSOG ([51])

6.9 Pricing of bundled capacity and capacity at virtual interconnection points

6.9.1 Pricing of bundled capacity

The reserve price for a bundled capacity product shall be equal to the sum of the reserve prices for the capacities contributing to such product.

The reserve prices for corresponding entry and exit capacities shall be made available when the bundled capacity product is offered and allocated by means of a joint booking platform.

The revenue originating from the bundled capacity product sales corresponding to the reserve price for such product shall be attributed to the respective TSOs as follows:

— after each transaction for a bundled capacity product;

— in proportion to the reserve prices for the capacities contributing to such product.

The auction premium originating from the bundled capacity product sales shall be attributed in accordance with the agreement between the respective TSOs.

6.9.2 Pricing of capacity at a virtual interconnection point

A virtual interconnection point (VIP) is an entry and/or exit point that results from the aggregation of two or more IPs that connect the same two adjacent entry-exit systems for the purposes of providing a single capacity service.

The reserve price for an unbundled standard capacity product offered at a VIP, denoted by $P_{st,VIP}$ shall be calculated in accordance with either of the following approaches:

— calculated on the basis of the reference price, where the applied RPM allows for taking into account the established VIP;

— equal to the weighted average of the reserve prices, calculated on the basis of the reference prices for each IP contributing to such VIP, where the applied RPM does not allow for taking into account the established VIP, as:

$$P_{st,VIP} = \frac{\sum_i \left(P_{st,i} \times CAP_i\right)}{\sum_i CAP_i}$$

Where:

- i is an IP contributing to the VIP
- $P_{st,i}$ is the reserve price for a given unbundled standard capacity product at IP_i;
- CAP_i is technical capacity or forecasted contracted capacity, at IP_i.

6.10 Clearing price and payable price

6.10.1 Calculation of clearing price at interconnection points

A clearing price is the price resulting from the auction. The two components that make up the clearing price are the reserve price and, if any, the auction premium. A clearing price may diverge from the payable price ([56]).

The clearing price P_{cl} for a given standard capacity product at an IP shall be calculated as:

$$P_{cl} = P_{R,au} + AP$$

Where $P_{R,au}$ is the applicable reserve price for a standard capacity product and AP is the auction premium, if any.

6.10.2 Calculation of payable price at interconnection points

The payable price for a given standard capacity product at an IP shall be calculated in accordance with either of the following formulas:

— where the floating payable price approach is applied:

$$P_{flo} = P_{R,flo} + AP$$

Where: P_{flo} is the floating payable price; $P_{R,flo}$ is the reserve price for a standard capacity product; AP is the auction premium, if any.

— where the fixed payable price approach is applied:

$$P_{fix} = (P_{R,y} \times IND) + RP + AP$$

([56]) For the reasons of this divergence, see ([51]) p.107

Where: P_{fix} is the fixed payable price; $P_{R,y}$ is the applicable reserve price for a yearly standard capacity product; IND is the ratio between the chosen index at the time of use and the same index at the time the product was auctioned; RP is the risk premium reflecting the benefits of certainty regarding the level of transmission tariff, where such premium shall be no less than 0; AP is the auction premium, if any.

6.10.3 Conditions for offering payable price approaches

If the TSO functions under a non-price cap regime, the conditions for offering payable price approaches are:

— when only existing capacity is offered:

- the floating payable price approach shall be offered;
- the fixed payable price approach shall not be allowed.

— for incremental capacity and existing capacity offered in the same auction or same alternative allocation mechanism:

- the floating payable price approach may be offered;
- the fixed payable price approach may be offered if either an alternative allocation mechanism (as in Article 30 of Regulation (EU) 2017/459) is used; or a project is included in the Union list of projects of common interest

If the TSO functions under a price cap regime, the floating payable price approach or the fixed payable price approach, or both, may be offered.

6.11 Consultation and publication

6.11.1 Periodic consultation

One or more consultations shall be carried out by the NRA or the TSO(s). To the extent possible the consultation document should be published in the English language.

Table 25. Current responsibility for the periodic consultation

MS	Responsible for conducting the consultation		MS	Responsible for conducting the consultation
AT	NRA		IT	NRA
BE	TSO		LV	To be decided
BG	TSO/NRA		LT	TSO/NRA
CZ	NRA		NL	NRA
HR	To be decided		PL	TSO
DK	TSO/NRA		PT	NRA
FI	NRA		RO	NRA
FR	NRA		SK	TSO
DE	NRA		SI	To be decided
GR	NRA		ES	NRA
HU	NRA		SE	To be decided
IE	TSO/NRA		UK	TSO

Source: ENTSOG ([51])

The final consultation shall include the following information:

1. the description of the proposed RPM as well as:
   - the justification and the values of the parameters used that are related to the technical characteristics of the system;
   - the value of the proposed adjustments for capacity-based transmission tariffs;
   - the indicative reference prices subject to consultation;
   - the results, the components and the details of these components for the cost allocation assessments;
   - the assessment of the proposed RMP;
   - if the proposed RPM is other than the CWD, its comparison against the latter;
2. technical characteristics of the transmission system;
3. information on transmission and non-transmission tariffs:
   - where commodity-based transmission tariffs are proposed: (1) the manner in which they are set; (2) the share of the allowed or target revenue forecasted to be recovered from such tariffs; (3) the indicative commodity-based transmission tariffs;

- where non-transmission services provided to network users are proposed: (1) the non-transmission service tariff methodology therefor; (2) the share of the allowed or target revenue forecasted to be recovered from such tariffs; (3) the manner in which the associated non-transmission services revenue is reconciled as referred to in Article 17(3); (4) the indicative non-transmission tariffs for non-transmission services provided to network users;

4. if the fixed payable price approach is considered to be offered under a price cap regime for existing capacity:

- the proposed index;
- the proposed calculation and how the revenue derived from the risk premium is used;
- at which IP(s) and for which tariff period(s) such approach is proposed;
- the process of offering capacity at an interconnection point where both fixed and floating payable price approaches referred to in Article 24 are proposed.

The final consultation shall be open for at least two months.

Within one month following the end of the consultation, the TSO(s) or the NRA shall publish the consultation responses received and their summary. The summary should be provided in the English language (to the extent possible).

6.11.2 Periodic national regulatory authority decision-making

The consultation documents will be forwarded to ACER, which shall analyse some of the aspects of the consultation document. Within two months following the end of the consultation, ACER shall publish and send to the NRA/TSO and the Commission the conclusion of its analysis, in English. ACER shall preserve the confidentiality of any commercially sensitive information.

Within five months following the end of the final consultation, the NRA shall take and publish a motivated decision on all items described in 6.11.1, and shall send it to ACER and the Commission.

The procedure consisting of the final consultation on the RPM, the calculation/publication of tariffs on the basis of this decision may be initiated as from the entry into force of this Regulation and shall be concluded no later than 31 May 2019.

6.11.3 Consultation on discounts, multipliers and seasonal factors

At the same time as the final consultation previously mentioned, the NRA shall conduct a consultation with the NRAs of all directly connected MS and the relevant stakeholders on:

— the level of multipliers;

— if applicable, the level of seasonal factors;

— the levels of discounts.

After the end of the consultation a motivated decision shall be taken and each NRA shall consider the positions of NRAs of directly connected MS.

When adopting the decision, the NRA shall take into account the consultation responses received and the following aspects:

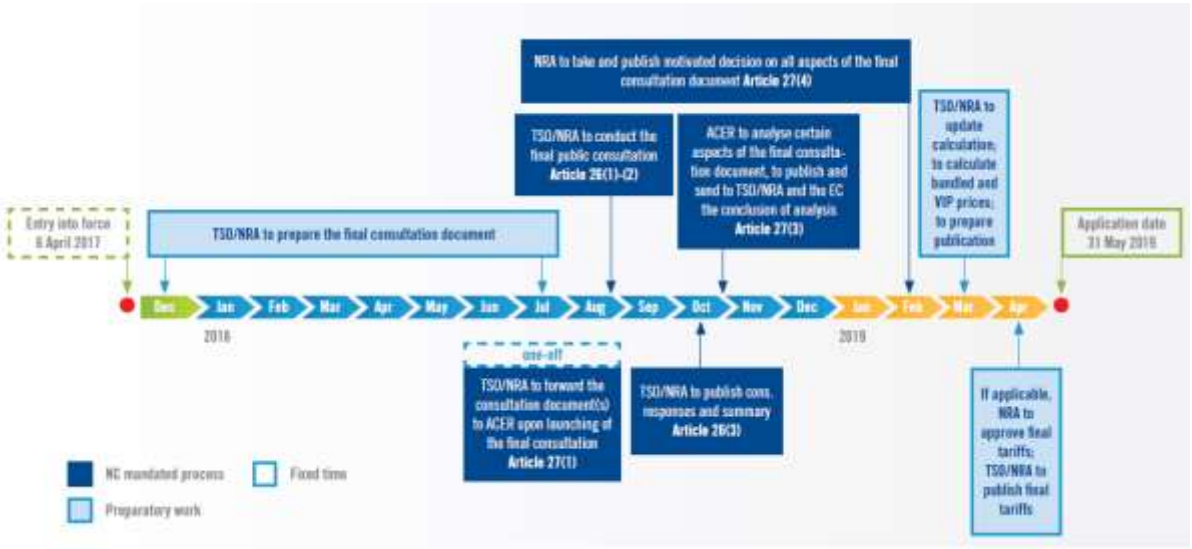
— for multipliers:

- the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;
- the impact on the transmission services revenue and its recovery;
- the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices;
- situations of physical and contractual congestion;
- the impact on cross-border flows;

— for seasonal factors:

- the impact on facilitating the economic and efficient utilisation of the infrastructure;
- the need to improve the cost-reflectivity of reserve prices.

Figure 44. Final consultation timeline



Source: ENTSOG ([51])

6.11.4 Information to be published before the annual yearly capacity auction

For IPs and, where the NRA takes a decision to apply the CAM NC Regulation, points other than IPs, the following information shall be published before the annual yearly capacity auction:

— for standard capacity products for firm capacity:

- the reserve prices applicable until at least the end of the gas year beginning after the annual yearly capacity auction;
- the multipliers and seasonal factors applied to reserve prices for non-yearly standard capacity products;
- the justification of the NRA for the level of multipliers;
- where seasonal factors are applied, the justification for their application.

— for standard capacity products for interruptible capacity:

- the reserve prices applicable until at least the end of the gas year beginning after the annual yearly capacity auction;
- an assessment of the probability of interruption including:
- the list of all types of standard capacity products for interruptible capacity offered including the respective probability of interruption and the level of discount applied;
- the explanation of how the probability of interruption is calculated for each type of product;
- the historical or forecasted data, or both, used for the estimation of the probability of interruption.

6.11.5 Information to be published before the tariff period

The following information shall be published before the tariff period by the NRA/TSO(s):

— technical capacity at entry and exit points and associated assumptions;

— forecasted contracted capacity at entry and exit points and associated assumptions;

— the quantity and the direction of the gas flow for entry and exit points and associated assumptions, such as demand and supply scenarios for the gas flow under peak conditions;

— the structural representation of the transmission network with an appropriate level of detail;

— additional technical information about the transmission network, such as the length and the diameter of pipelines and the power of compressor stations;

— the allowed or target revenue, or both, of the TSO;

— the information related to changes in the revenue from one year to the next year;

— the following parameters:

- types of assets included in the regulated asset base and their aggregated value;
- cost of capital and its calculation methodology;
- capital expenditures, including:
    - methodologies to determine the initial value of the assets;
    - methodologies to re-evaluate the assets;
    - explanations of the evolution of the value of the assets;
    - depreciation periods and amounts per asset type.
- operational expenditures;
- incentive mechanisms and efficiency targets;
- inflation indices.
- the transmission services revenue;
- the following ratios for the revenue:

    - capacity-commodity split, meaning the breakdown between the revenue from capacity-based transmission tariffs and the revenue from commodity-based transmission tariffs;
    - entry-exit split, meaning the breakdown between the revenue from capacity-based transmission tariffs at all entry points and the revenue from capacity-based transmission tariffs at all exit points;
    - intra-system/cross-system split, meaning the breakdown between the revenue from intra-system network use at both entry points and exit points and the revenue from cross-system network use at both entry points and exit points;
- if the TSO functions under a non-price cap regime, the following information related to the previous tariff period on regarding the reconciliation of the regulatory account:
- the actually obtained revenue, the under- or over-recovery of the allowed revenue and the part attributed to the regulatory account;
- the reconciliation period and the incentive mechanisms implemented.
- the intended use of the auction premium.
- where applied, commodity-based transmission tariffs;
- where applied, non-transmission tariffs for non-transmission services;
- the reference prices and other prices applicable at points.
- the difference in the level of transmission tariffs for the same type of transmission service applicable for the prevailing tariff period and for the tariff period for which the information is published;
- the estimated difference in the level of transmission tariffs for the same type of transmission service applicable for the tariff period for which the information is published and for each tariff period within the remainder of the regulatory period;
- at least a simplified tariff model, updated regularly, accompanied by the explanation of how to use it, enabling network users to calculate the transmission tariffs applicable for the prevailing tariff period and to estimate their possible evolution beyond such tariff period.

6.11.6 Form and period of publication

The previous information shall be published on ENTSOG's Transparency Platform (https://transparency.entsog.eu/). It shall be accessible to the public, free of charge and of any limitations as to its use.

It shall be published:

— in a user-friendly manner;

— in a clear, easily accessible way and on a non-discriminatory basis;

— in a downloadable format;

— in one or more of the official languages of the MS and, unless one of the official languages of the MS is English, to the extent possible, in English.

The deadline for the publication is

— no later than thirty days before the annual yearly capacity auction for the information to be published before the annual yearly capacity auction;

— for the information to be published before the tariff period, no later than thirty days before the respective tariff period;

— for the respective transmission tariffs updated within the tariff period, immediately after the approval.

Each update of the transmission tariffs shall be accompanied by information indicating the reasons for the changes in their level.

6.12 Incremental capacity

The minimum price at which TSO shall accept a request for incremental capacity is the reference price.

For the calculation of the economic test, reference prices shall be derived by including into the RPM the relevant assumptions related to the offer of incremental capacity.

Where the fixed payable price approach is considered to be offered for incremental capacity, the reserve price shall be based on projected investment and operating costs. Once the incremental capacity is commissioned, such reserve price shall be adjusted proportionally to the difference, irrespective whether positive or negative, between the projected investment costs and the actual investment costs.

In case the allocation of all incremental capacity at the reference price would not generate sufficient revenues for a positive economic test outcome, a mandatory minimum premium may be applied in the first auction or alternative allocation mechanism in which the incremental capacity is offered. The mandatory minimum premium may also be applied in subsequent auctions when the capacity is offered that initially remained unsold or when capacity is offered that was initially set aside.

The level of the mandatory minimum premium shall enable a positive economic test outcome with the revenues generated by the offered capacity in the first auction or alternative allocation mechanism in which the incremental capacity is on offer. The range of the level for the mandatory minimum premium shall be submitted to the relevant NRAs for approval.

A mandatory minimum premium approved by the NRA shall be added to the reference price for the bundled capacity products at the respective IP and shall exclusively be attributed to the TSOs for which the mandatory minimum premium was approved. This default principle for the attribution of a mandatory minimum premium is without prejudice to the split of a possible additional auction premium or an alternative agreement between the involved national regulatory authorities.

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List of abbreviations and definitions

ACER	Agency for the Cooperation of Energy Regulators
AGTM	ACER Gas Target Model
BOM	Balance Of Month
BOW	Balance Of Week
CAM	Capacity Allocation Mechanism
CBA	Cost/Benefit Analysis
CEER	Council of European Energy Regulators
CEGH	Central European Gas Hub
CWD	Capacity Weighted Distance
DA	Day Ahead
DSO	Distribution System Operator
EC	European Commission
EFET	European Federation of Energy Traders
ENTSOG	European Network of Transmission System Operators for Gas
EU	European Union
GP	GasPool
GRIP	Gas Regional Investment Plans
GTF	Gas Transfer Facility
GTM	Gas Target Model
HHI	Herfindahl-Hirschmann Index
IGU	International Gas Union
IP	Interconnection Point
LFS	Linepack Flexibility Service
LNG	Liquefied Natural Gas
LTC	Long Term Contract
MA	Month Ahead
MS	Member State
NBP	National Balancing Point
NC	Network Code
NDP	Network Development Plan
NCG	NetConnect Germany
NRA	National Regulatory Authority
OTC	Over-The-Counter
PEG Nord	Point d'Echange de Gaz Nord
PRA	Price Reporting Agency

POS	Portfolio Imbalance Signal
PSV	Punto di Scambio Virtuale
PV	Present Value
PVB	Virtual Balancing Point
REMIT	Regulation on wholesale Energy Market Integrity and Transparency
RPM	Reference Price Methodology
RSI	Residual Supply Index
SBS	System Balance Signal
SF	Seasonal Factors
STSP	Short Term Standardised Product
TP	Transparency Platform
TPA	Third Party Access
TRS	Trading Region South
TSO	Transmission System Operator
TTF	Title Transfer Facility
TYNDP	Ten Year Network Development Plan
UTC	Coordinated Universal Time
VIP	Virtual Interconnection Point
VTP	Virtual Trading Point
WD	Within Day
WE	Weekend Third
ZTP	Zeebrugge Trading Point

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