TEN-YEAR NETWORK DEVELOPMENT PLAN

2020

ANNEX D – METHODOLOGY

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GENERAL CONSIDERATIONS ON THE METHODOLOGY

The European gas infrastructure supports the completion of the Internal Energy Market and contributes to the achievement of the European climate and energy policies, where sustainability represents one of the major pillars together with security of supply, competition, and market integration.

The objective of the CBA methodology is to provide **guidelines to be applied for the cost-benefit analysis of projects and more generally of the overall gas infrastructure**. This methodology reflects the specific provisions from the Regulation and aims to ensure their consistent application by all parties involved.

The primary field of application of this CBA methodology is within the TYNDP process and the selection of Projects of Common Interest (PCI).

The TYNDP comprises an assessment of the gas system and gas infrastructure projects and subsequently of an assessment of the impact of gas infrastructure projects.

The ENTSOG 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements to measure the level of completion of the pillars of the EU Energy Policy from an infrastructure perspective.

Picture courtesy of GRTgaz

1 ASSESSMENT FRAMEWORK

1.1 SCENARIOS

The assessment framework must be in line with the provision of Annex V(1) of the REG-347, which requires that the input data set represents years "n+5, n+10, n+15, and n+20 where n is the year in which the analysis is performed".

In line with the guidelines included in the 2nd CBA Methodology[1], in order to be able to evaluate projects impact against the targets set by the European policies while keeping the number of results reasonable, by default the assessment framework is defined for 2020, 2025, 2030 and 2040.

The TYNDP 2020 contains different demand scenarios, out of which the data for the following scenarios is selected as input data for the assessment:

For details see the demand chapter of the TYNDP 2020 Scenario report[2].

Figure 1: TYNDP 2020 Scenarios

1 https://www.entsog.eu/methodologies-and-modelling#2nd-cba-methodology

2 https://www.entsog.eu/sites/default/files/2019-11/TYNDP_2020_Joint_ScenarioReport_web.pdf

1.2 NETWORK AND MARKET MODELLING ASSUMPTIONS

1.2.1 APPROACH TO MODELLING

ENTSOG has developed a modelling approach since 2010, based on a specific structure facing the need to consider simultaneously network and market dimensions. The network model represents the gas market within the geographical scope of the TYNDP. Arcs for the network modelling, including the relevant capacities for each infrastructure level can be found in ANNEX C1.

Entry-Exit model

European Union member states and other countries in the European Economic Area are represented in the model. In the following, the term "Zone" will be used generally to refer to a country. In some instances, it refers to a balancing zone.

The basic block of the topology is the balancing Zone (or Zone) at which level demand and supply shall be balanced. The Zones are connected through arcs representing the sum of the capacity of all Interconnection Points between these two Zones (after application of the lesser-of-rule). Interconnectors with a specific regime (e.g. BBL or Gazelle) are represented by Zones with no attached demand node.

Focus on a Zone

The supply and demand balance in a Zone depend on the gas flow incoming from another Zones or direct imports from a supply source. Gas may also come from national production, underground storage and LNG facilities connected to the Zone. The sum of all these entering flows must match the demand of the Zone, plus the need for injection and the exit flows to adjacent Zones.

In case the balance is not possible, a disruption of demand is used as a last resort virtual supply. This approach enables an efficient analysis of the disrupted demand.

Objective function

The primary objective of the modelling is to define a feasible flow pattern to balance supply and demand for every node, using the available system capacities defined by the arcs. There are summer and winter nodes representing the seasonality of the European gas system in Europe linked by storages.

In addition, the use of price assumptions in the input data supports the definition of a feasible flow pattern minimising the objective function[3] representing costs to be borne by the European society.

This optimum differs from national optimums which are potentially not reached through the same flow pattern.

The minimisation of the objective function is based on the concept of marginal price of a node. It is defined as the cost of the last unit of energy used to balance the demand of that node.

1.2.2 NETWORK ASSUMPTIONS AND DESCRIPTION OF THE GAS INFRASTRUCTURE

ENTSOG developed and regularly updates the topology of the gas infrastructure that is used in TYNDP. The topology refers both to the existing and planned infrastructure. The corresponding capacities are publicly available in Annex C1.

The EU-level network modelling used for TYNDP 2020 reflects market areas including transmission, storage and LNG capacities with all internal specifics (if relevant from an infrastructure assessment perspective). Capacities provided to ENTSOG by network operators and project promoters are calculated based on hydraulic modelling. All of that is used in the description of the gas infrastructure.

This EU-level topology reflects at least the following European gas infrastructure:

- Transmission Infrastructure
- LNG terminal infrastructure
- Underground storage infrastructure
- Connection to indigenous production infrastructure
- The gas infrastructure in countries adjacent to the EU as much as the infrastructure in these countries contribute to imports to or exports from Europe.

3 Use of the Jensen solver as developed by Paul Jensen for the Texas University in Austin

Infrastructure levels

Proper selection of infrastructure development level is key for the identification of infrastructure gaps and a reliable system and project assessment. In line with the 2nd CBA Methodology provisions, the following infrastructure levels are considered.

Existing infrastructure level, the reference grid

The Existing infrastructure level is formed by only existing infrastructure already in operation on the 1st of January 2019 and projects with FID status and date of commissioning before 31st December 2019. It allows to assess existing infrastructure in confrontation with different scenarios assumptions. It allows to build a base for further investigations of another infrastructure levels exposing infrastructure gaps.

Low infrastructure level

The Low infrastructure level is formed with existing infrastructure plus projects granted FID status representing the minimum level of infrastructure development considered for further identification of infrastructure gaps.

TYNDP 2020 assesses what the current infrastructure, complemented with FID projects, already achieves and what are the remaining gaps that may require further investment.

Advanced and PCI infrastructure levels

The assessment of the European gas system is complemented by assessing the overall impact of additional infrastructure levels:

- the Advanced infrastructure level including existing infrastructure, projects with FID and Advanced status
- the PCI infrastructure level gathering all the projects from the 4th PCI list, although it includes projects of very different maturity. This infrastructure level also includes the existing infrastructure, and all the FID projects, whether PCI or not.

For more details, please refer to the TYNDP 2020 Infrastructure Report.

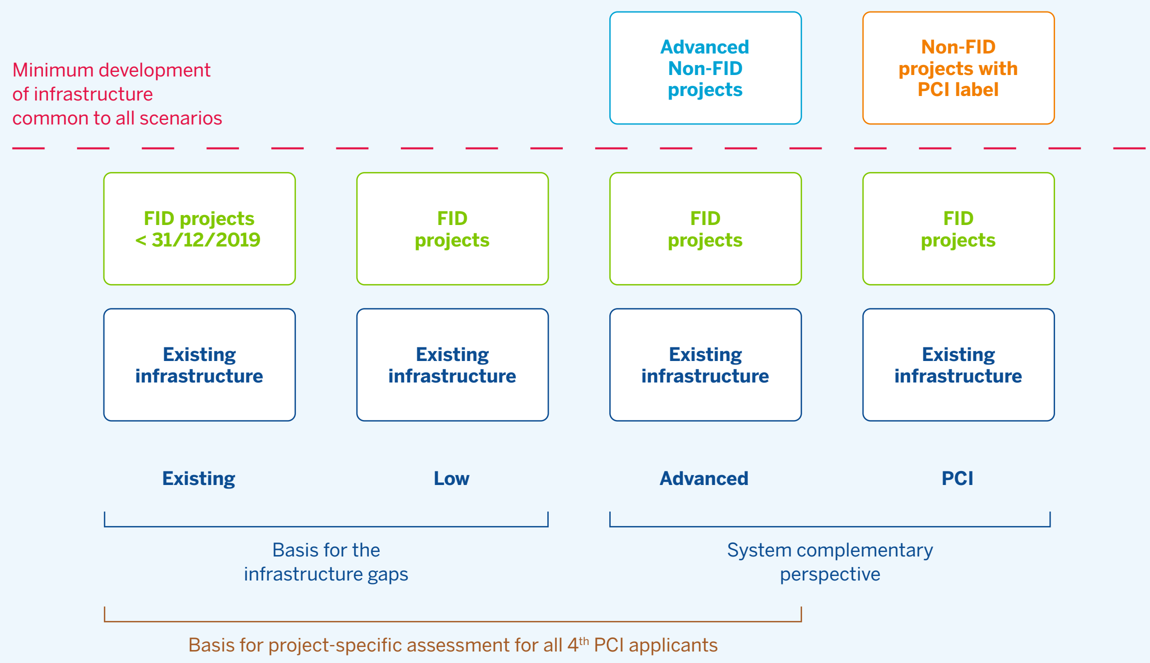

Figure 2: Infrastructure levels

1.2.3 MARKET ASSUMPTIONS

In the 2nd CBA Methodology, the following elements are recommended to be considered:

- Infrastructure tariffs incurred by users of gas infrastructure including transmission, LNG and storage systems. Capacity and commodity charges have been considered in view of flow modelling perspective, as well as possibly the share of capacity booked upfront on medium to long-term basis to accurately reflect the impact of tariffs on the use of capacity.
- Information on gas supply prices regarding variability among supply sources or import routes and possibly long-term supply contracts when data is available.

This information is also published by ENTSOG.

1.2.4 ROUTE DISRUPTION

Most of the gas consumed in Europe is imported through pipelines and LNG cargos. The disruption of a supply route can have a significant impact on the infrastructure and its ability to satisfy demand.

The assessment focuses on the disruptions listed in the Union-wide simulation of gas supply and infrastructure scenarios carried out for the risk assessment defined in Article 7, Regulation (EU) 2017/1938 (hereafter SOS Regulation) concerning security of gas supply. More specifically, those disruption cases expected to show a risk of demand curtailment in the Union-wide simulation are assessed in this section:

1. **Ukraine route**
2. **Belarus route**
3. **Imports to Baltic states and Finland**
4. **Algerian import pipelines**

The assessment is limited to the impact of a supply disruption occurring during a peak day and a 2-week cold spell.

For disruption simulations, demand curtailment follows the logic of unified allocation. In unified allocation, all member States within the risk group cooperate by avoiding a demand curtailment to the extent possible by transporting other supply and furthermore by sharing the curtailment equally in such a way that they try to reach the same curtailment rate.

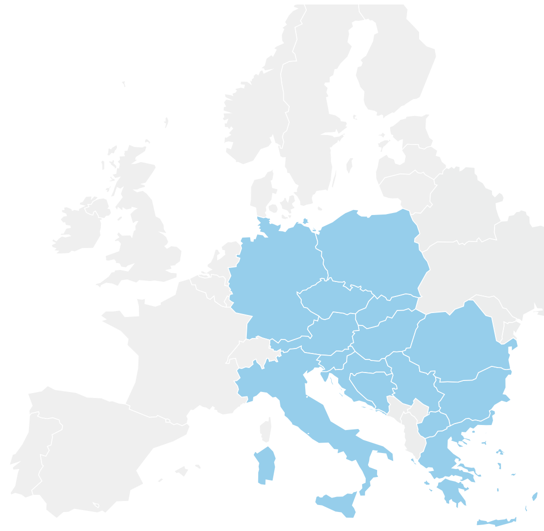

Figure 3: Risk group for Ukraine transit disruption (Austria, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Germany, Greece, Hungary, Italy, Luxembourg, North Macedonia, Poland, Romania, Serbia, Slovenia, Slovakia, Switzerland)*

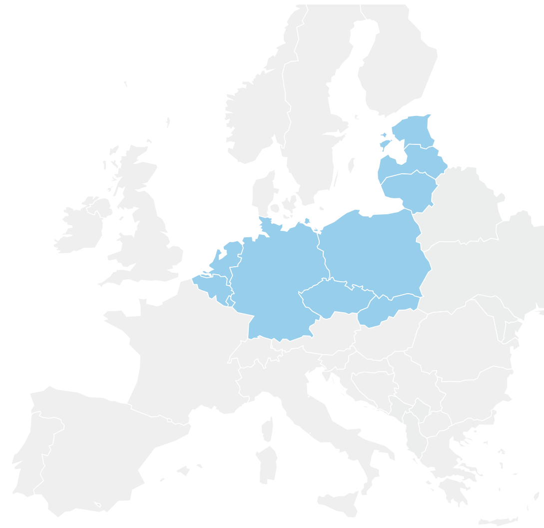

Figure 4: Risk group for Belarus disruption (Czech Republic, Belgium, Finland, Estonia, Germany, Latvia, Lithuania, Luxembourg, Netherlands, Poland, Slovakia)

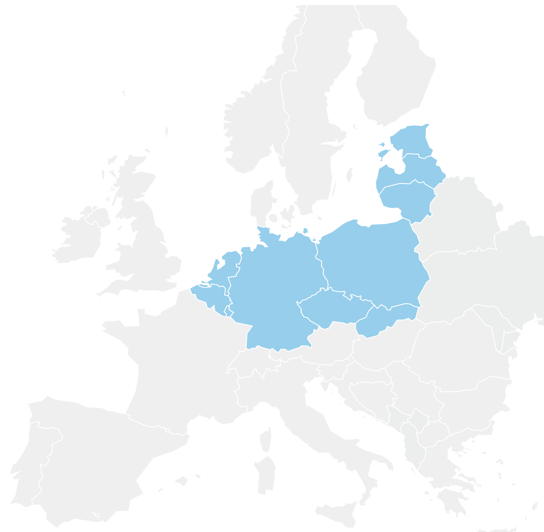

Figure 5: Risk group for Baltic states and Finland disruption (Estonia, Finland, Latvia, Lithuania and Czech Republic, Belgium, Germany, Luxembourg, Netherlands, Poland and Slovakia**)

Figure 6: Risk group for Algerian pipes and LNG disruption (Austria, Croatia, France, Greece, Italy, Malta, Portugal, Slovenia and Spain)

* Compared to ENTSOG EU-wide SoS simulation, the risk group for Ukraine transit disruption considered in TYNDP 2020 has been extended to other concerned non-EU countries (by adding Bosnia and Herzegovina, North Macedonia, Serbia and Switzerland.

** Compared to ENTSOG EU-wide SoS simulation, the risk group for Baltic States and Finland considered in TYNDP 2020 has been extended to other exposed countries. The FID project GIPL is part of the low infrastructure level and connects the group made up of the Baltic states plus Finland to Poland and therefore allows for cooperation between all concerned countries.

2 INPUT DATA ITEMS

2.1 TOTAL GAS DEMAND

The total gas demand is comprised of the final demand (Industrial, Residential & Commercial and Transport) and the gas demand for power generation. The evolution of the total gas demand in areas with existing gas demand only depends on the scenario. ENTSOG focuses his simulations on network-related demand and supply depending on the data availability by Eurostat and Member States.

For gas demand in new consumption areas, the gas demand depends on the infrastructure connecting this area to gas supply (also known as gasification).

In addition to the demand within the geographical scope of the TYNDP, exports have also been considered.

Details on the gas demand can be found in the demand chapter of the TYNDP 2020 Scenario Report[6].

Seasonal and high case demand situations[4]

Gas demand in Europe shows a strong seasonal pattern, with higher demand in winter than in summer. These variations are largely driven by temperature-related heat demand in the residential and tertiary sectors. In the long-term, considering some level of electrification in the heating sector, also an increasing seasonality in the gas demand for power generation is assumable. This is due to the role of gas-fired power plants being the back-up for variable renewables in a "kalte Dunkelflaute" (German for "cold dark doldrums" describing a 2-week cold spell with very low variable renewable electricity generation).

In addition, the day of highest consumption in the year is a key input that represents one of the most stressful situations to be covered by the gas infrastructure (including transmission, distribution and storage).

As a result of these situations, seasonal variation and high case demand data is contemplated. In table 1 the different cases are represented.

The Design Case (DC) is the maximum level of gas demand used for the design of the network to capture the maximum transported energy and ensure consistency with national regulatory frameworks. 2-Week Demand is a maximum aggregation of gas demand reached over 14 consecutive days once every 20 years in each country to capture the influence of a cold spell on supply and especially on storage.

Average Summer (AS)	Final Injection Period Demand
	Power Injection Period Demand
Average Winter (AW)	Final Withdrawal Period Demand
	Power Withdrawal Period Demand
Design Case (DC)	Final Peak Demand
	Power Peak Demand
2 Week Cold Spell (2W)	Final 2W Demand
	Power 2W Demand
Dunkelflaute (DF)	Final 2W Demand
	Power Demand Dunkelflaute

Table 1: Seasonaland high case variations

4 Detailed information in TYNDP 2020 Scenario Report https://www.entsos-tyndp2020-scenarios.eu/

2.2 TARIFFS

Tariff data used in TYNDP 2020 is published by ENTSOG as part of this annex D.

The approach applied for TYNDP 2020 was also presented during ENTSOG 10th July 2019 Workshop "On the supply potentials and market related assumptions for TYNDP 2020"[5].

Transmission tariffs valid on 1st July 2019

The TYNDP 2020 assessment considers at least this minimum set of tariff components:

- **Capacity tariffs**

tariffs paid by network users based on the capacity they book during a specific period, i. e. the right to flow gas. These tariffs do not depend on the actual usage of this right, i. e. flowing gas. Most TSOs already applied such capacity tariffs in 2019[6]. Typically, a capacity tariff is defined in

$$\mathrm{EUR/(quantity/period)/runtime_d}$$

Where:

quantity/period is a capacity unit. This should be converted into "energy" units, i. e. "commoditised" for TYNDP calculations. In some countries, the capacity tariff is defined in "energy per period" while in others it is defined in "volume per period", requiring the use of a specific Calorific Value to move to the same unit.

$\mathbf{runtime_d}$ is the duration of the capacity product considered.

Capacity tariffs are approved by National Regulatory Authorities (NRAs) as a result from the application of a specific Reference Price Methodology (RPM) chosen in each member state and following requirements of the Tariff Network Code (TAR NC).

Implementation of the TAR NC is still ongoing in the European Union, and TSOs are shifting to TAR NC principles. The most frequent RPMs in Europe are currently Postage Stamp (PS) and Capacity-Weighted Distance (CWD). Each RPM is based on specific cost drivers, which are used to derive yearly capacity tariffs – also called "reference prices" – which follow the formula above and are more specifically defined in EUR/(quantity/period)/year.

Yearly capacity tariffs are set as a reference because all tariffs for short-term products are derived from them. Examples of cost drivers include distance and pipeline diameter, among others. Tariffs are valid in each member state and for each TSO, based on national rules for the duration of the tariff period (often 1 year, sometimes more).

At Interconnection Points (IPs) between TSO networks, it is typical that capacity tariffs are charged at the exit from a TSO network and at the entry into another TSO network.

However, in cases where a market merger took place, specific rules apply and TSOs do not collect tariffs at internal IPs within the merged system. This is the case for example in the BeLux market between Belgium and Luxembourg, where the former IP tariffs have been removed. For instance, there is no tariff either at the IP between Denmark and Sweden which have created a single balancing zone, and at internal IPs within the new Baltic gas market which brings together TSOs from Finland, Estonia, and Latvia.

For TYNDP purposes, ENTSOG uses capacity tariffs – and commodity tariffs for TSOs where they are applied (see details below) – which are validated by the NRAs, in order to compute infrastructure costs, following a scenario of a constant 1 GWh/d flow allowed by yearly bookings.

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5 https://entsog.eu/sites/default/files/2019-07/9_ENTSOG%20-%20Supply%20and%20Infrastructure%20costs_FINAL.pdf

6 Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (also referred to as the Tariff Network Code) specifies that TSO transmission services revenue shall be recovered by capacity-based transmission tariffs by default (Article 4(3)).

Hence, the RPM is the methodology used by TSOs or NRAs to calculate capacity tariffs, which are in turn an input for TYNDP calculations. Accordingly, the RPMs is not directly a topic for the TYNDP.

The following figure summarises the articulation of the main tariff principles defined in the TAR NC and their effects on TYNDP calculations, in case entry tariffs for an IP are publicly available (i. e. where proxies are not needed, cf. section on project tariffs below). The full tariff to flow gas at an IP is the sum of this value for entry and the value derived from equivalent calculations for the exit side of another network.

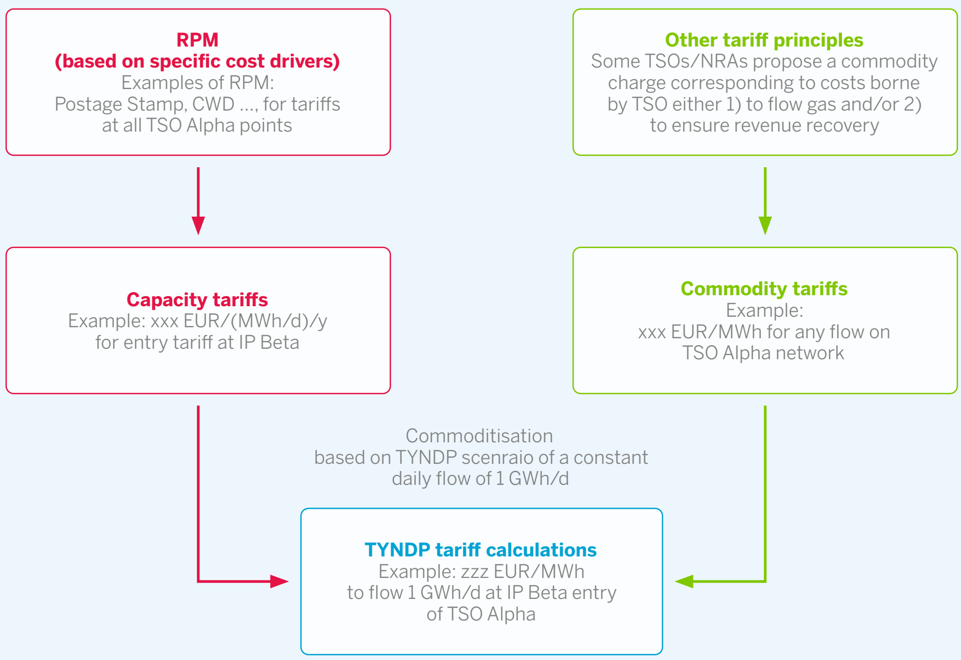

Figure 7: Principles for tariff calculations at the entry of an IP with published tariffs

Commodity tariffs

tariffs paid by network users in relation to their actual gas flows during a specific period. Almost half European TSOs currently apply such commodity tariffs.

Following TAR NC requirements, and in accordance with the previous figure, commodity tariffs are used either 1) to cover costs generated by gas flows and/or 2) to manage revenue recovery. In many countries with commodity tariffs, they are already set per energy unit (e. g. EUR/MWh). However, a few countries define commodity tariffs per volume unit (e. g. EUR/m³), which requires the use of a specific Calorific Value – generally collected from the ENTSOG Transmission Capacity Map[7] by using the average value for each IP – to shift to the same energy unit.

Commodity tariff is expressed as

$$\text{Commodity tariff} = \text{EUR/quantity}$$

Where:

quantity is the amount of gas flowed for the assessed period.

For example, in case of EUR/GWh it refers to the tariff incurred for a flow of 1 GWh.

7 https://www.entsog.eu/maps

"Load factor" of the network user

to convert capacity tariffs into tariffs per unit of commodity/gas flowed, i.e. commoditise tariffs, a load factor value of 100 % has been used. The load factor is defined here as the ratio of the average daily flow to the peak daily flow during the year. By considering an open and efficient market, it is assumed that network users fully employ the capacity they book, and that gas is flowed at a uniform rate throughout the year. ACER uses the same approach for their annual Market Monitoring Report (MMR), where they posit a load factor of 100 % too. This is detailed in Annex 1 of MMR 2016 published in 2017[8], and the up-to-date MMR 2019[9] published in 2020 also refers to the same approach.

The resulting equivalent commodity tariffs and consequently the corresponding flows are sensitive to the value of the load factor used to "commoditise" capacity. To guarantee an adequate comparison of the assessment results, a unique common load factor of 1 has been used among existing and future infrastructures.

Duration of the capacity contract

in relation with the topic of capacity tariffs, the duration of the capacity contract is one of the elements to consider. In TYNDP 2020 it was assumed that yearly products were used. This is for three reasons.

- First, yearly tariffs at IPs correspond to the so-called 'reference prices' in the Tariff Network Code (TAR NC), and they are the basis on which all short-term tariffs are calculated.
- Second, in 2018, ENTSOG's Implementation Monitoring and Baseline for Effect Monitoring of the Tariff Network Code[10] (cf. page 60/78) showed that, for many TSOs participating in data collection for that report, yearly bookings still represented a significant majority of total bookings at IPs (75 % of total capacity bookings as of 2017), despite a probable and gradual shift to short-term bookings in coming years. For these TYNDP tariff calculations, it was assumed that yearly products still represented a substantial share of capacity bookings[11].
- Third, following the same approach as detailed in the MMR 2016, ACER still considers yearly products in their recent MMR 2019 as the reference for their tariff simulation at IPs[12].

Therefore, the assumed duration of the capacity contract is one year in TYNDP 2020.

Unit of measure to be used

all tariff elements should be converted to a common unit of measure. Such a unit should be defined in Euro per volume, i.e. expressed in energy unit (EUR/MWh), which represents a "commoditisation" of costs borne by network users.

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8 https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20GAS.pdf (cf. footnote 167 on page 64/67)

9 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202019%20-%20Gas%20Wholesale%20Markets%20Volume.pdf (cf. figure iv on page 65/67)

10 https://www.entsog.eu/sites/default/files/entsog-migration/publications/Tariffs/2018/TAR0878_171108_TAR%20NC%20Implementation%20and%20Effect%20Monitoring%20Report%202017_Low-Res.pdf

11 In agreement with ACER, the 2020 edition of ENTSOG's Implementation Monitoring and Baseline for Effect Monitoring of the Tariff Network Code did not keep the indicator on capacity bookings, which was little relevant with the TAR NC scope. https://www.entsog.eu/sites/default/files/2020-04/TAR_MR2020_03_Final.pdf (cf. footnote 14 on page 41/70)

12 https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202019%20-%20Gas%20Wholesale%20Markets%20Volume.pdf (cf. figure iv on page 65/67)

Exchange rate

for countries using another currency than the Euro, the reference to exchange rates was to use rates from the European Central Bank[13] which were valid on 1st July 2019.

For this exercise, as described above regarding the "load factor" of the network user, the capacity tariff is not used directly, but converted into a commodity cost, and the following formula will be applied (factoring in some preliminary unit conversions where needed):

$$\text{Transmission Tariff} = \frac{\text{Capacity Tariff}}{\text{LF}} + \text{Commodity Tariff}$$

Where **LF** is the load factor of the user, with a value between 0 and 1, but strictly higher than 0. As said above, the assumed load factor is 100 % (i. e. 1) for this exercise. It means that network users are assumed to flow gas uniformly throughout the year, at the maximum rate permitted by the yearly booked capacity.

In addition, for cases where several IPs exist at a border between two entry-exit systems, the capacity-weighted average of the individual IP tariffs of the points was calculated in order to define a single value at the border level. Otherwise, for established Virtual Interconnection Points (VIPs) as per the Capacity Allocation Mechanism Network Code (CAM NC), which is the most frequent case, the tariff published at each VIP was used.

LNG terminals tariffs

GLE provided ENTSOG with two documents to refer to regarding the existing LNG infrastructure tariffs.

The main document was the CEER report from December 2017 with update for Belgium, France and Spain in 2019.

As mentioned in this report, the tariff structure of the bundled (unloading + LNG storage + regasification service) varies significantly between terminals. The report tries to have comparable values by considering *"the costs derived from the application of the tariff for the bundled (unloading + storage + regasification) service, to a 1,000 GWh LNG cargo, which regasifies the whole LNG amount in a period of 15 days"*.

Then, the case study is repeated, *"considering not only the terminal bundled service tariffs (unloading + storage + regasification), but also the entry tariffs from LNG terminals to the transmission network (that is, the tariffs that users have to pay to introduce gas from LNG terminals to the relevant balancing zone".*

The results from this case study are used to derived tariffs for LNG infrastructure in the TYNDP 2020. Whenever data for a specific country was not available, the average of rates was used.

Country	Terminal	EUR/MWh
Belgium	Zeebrugge	0.72
France	Fos Caveau Fos Tonkin Montoir	1.66 1.48 1.09
Greece	Revithoussa	n. a.
Italy	Panigaglia Rovigo Toscana	1.22 4.64 3.78
Lithuania	SC Klaipedos Nafta	0.15
Poland	Świnoujście	2.24
Portugal	Sines	1.53
Spain	Huelva, Cartagena, and Sagunto Barcelona, Bilbao and Mugardos	1.49 1.44

Table 2: LNG terminals tariffs

13 https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/index.en.html

LNG shipping costs

As part of TYNDP extra-EU supply price methodology, for LNG sources, ENTSOG includes also shipping costs. Below the table of the shipping costs used by ENTSOG.

More details can be found in the section dedicated to extra-EU supply prices.

LNG Basin/Receiving Region	Asia	Atlantic	Baltic	Med. 1	Med. 2
LNG North America	0.70	0.60	0.70	0.65	0.75
LNG Middle East	0.75	0.90	1.00	0.75	0.70
LNG North Africa	1.30	0.25	0.35	0.10	0.20
LNG South Sahara	1.20	0.55	0.65	0.55	0.75
LNG Australia & SE Asia	0.60	1.35	1.45	1.15	1.15
LNG South America 1	1.00	1.00	1.10	1.05	1.15
LNG South America 2	1.35	0.50	0.60	0.55	0.65
LNG Norway	1.50	0.20	0.15	0.35	0.45
LNG Russia	0.60	0.20	0.15	0.35	0.45

Table 3: Shipping costs from LNG basin to receiving region ($/MMBtu)

Storages tariffs

For the SSO tariff, GSE provided ENTSOG with a standard value of 1.5 euro per MWh/d (bundled product for injection and withdrawal charges along with the working volume charge).

In the TYNDP, SSO tariff is assumed equal to 1.5 EUR/MWh which corresponds to the seasonal gas price spread.

However, GSE highlights that currently, the seasonal spread is used as the main driver for the value of storage revealed by the market. In the recent years, the spread has decreased and remains low. As a result, in the upcoming ten years, there is a risk that too many storage facilities may close or close in the wrong locations.

This possible reduction of gas storage capacity has not been projected in the TYNDP (except in the case where a decommissioning project or capacity modification has been submitted to ENTSOG), as there is only limited data available and SSO do not publish in advance a list of sites that are going to shut down.

Storage facilities provide value to the energy system in four key ways:

The seasonal value

The difference between futures gas price in summer and futures gas price in winter (also known as summer-winter spread or seasonal spread) is the key value which is recognized by the market.

It allows market participants to purchase and store gas in the summer when prices are normally lower and withdraw and deliver it during the winter when the prices are normally higher.

In fact, this value looks at the seasonality of prices and represents the expected premium of the price of gas to be delivered during the winter period with respect to the price of gas to be delivered during the summer period.

The trading value

It allows market participants to exploit the difference between spot and futures gas prices, by assuming an increase of the spot price in a tight situation that can push the price of futures up.

In fact, this value looks at volatility of prices (price movements) that can be exploited by traders especially during periods of high volatility or that can also be used as a natural hedge to price fluctuations. In the second case, it acts as an insurance against the risk of market price spikes, with a view of containing gas procurement costs.

The insurance value

Gas storage plays a key role in ensuring security of supply by reducing the risk of supply disruptions even in emergency situations. The market cannot predict unexpected events.

The system value

This means that pipeline systems integrated with gas storage can be sized optimally resulting in lower costs for the end-users and that gas storage allows pipelines located upstream of storage to operate at high load factors year-round, despite wide swings in demand. By providing alternative gas volumes already in place close to demand centres, gas storage can react on very short notice and at a large scale.

The seasonal spread (the metric used by shippers to value gas storage) only reflects the seasonal value, and does not recognize the trading, insurance and system values. These three values corresponding to externalities are not internalised within the market price.

Project tariffs

To ensure a comprehensive and sound assessment of gas infrastructure, tariffs borne by the infrastructure users from the commissioning of an infrastructure project were considered in addition to the tariffs from the already existing infrastructure. This is relevant both

- From a system assessment perspective, as the assessed system includes a number of projects, and serves as a counterfactual for the incremental project assessment.
- From a project assessment perspective.

The approaches used for tariffs at IPs, LNG terminals and storage facilities in project are similar, but with some specificities.

As for tariffs regarding IP projects, how much of the costs of a project will be reflected on an interconnection point is subject to various uncertainties such as: the share of the project cost that will be directly reflected on the IP tariffs (which will presumably depend on the type of need the project fulfils as well as the relevant reference price methodology for TSO tariffs); whether the project will be subject to Cross-Border Cost Allocation (CBCA) with part of its costs covered in a different country; whether the project will benefit from the European Union's financial assistance.

Despite all these uncertainties, accurate system and project assessment impose to make an assumption for all the different projects considered. For this reason, the key element will be to fix a reference to be used consistently across projects, to ensure comparability.

For IP projects, in TYNDP 2020 the "combined approach" from the 2nd CBA Methodology was applied. It means that, to derive tariffs for IP projects where no tariff is published, tariff information at neighbouring existing points – mostly IPs, to a minor extent LNG terminals or SSO sites – is combined to get proxies. More precisely, the combined approach allows to infer tariffs, based on a decision tree, depending on the availability of tariff information at neighbouring existing points.

Regarding any existing and future point connecting entry-exit systems A and B, the IP tariff value to exit A and enter B is defined as per the following decision tree (the objective is to use published tariffs where available, otherwise to use proxies):

1. The actual exit tariff from A + the actual entry tariff in B at the corresponding IP; if not applicable or available, then it is necessary to use proxies:
2. The average exit tariff from A + the average entry tariff in B at all existing IPs already connecting A to B, if any; if not applicable or available, then
3. The average IP exit tariff from A to any system + the average IP entry tariff in B from any system; if not applicable or available, then
4. The average IP exit tariff from any system to system B + the average IP entry tariff in B from any system; if not applicable or available, then
5. The average IP exit tariff from A to any system + the average IP entry tariff in any system from system A; if not applicable or available, then
6. In the last resort, the average value of all tariffs calculated for IPs (following steps 1, 2, 3, 4 or 5), storages, LNG terminals and interconnector pipelines.

The figure below gives an illustration of steps 2 and 3 described above regarding IP tariffs.

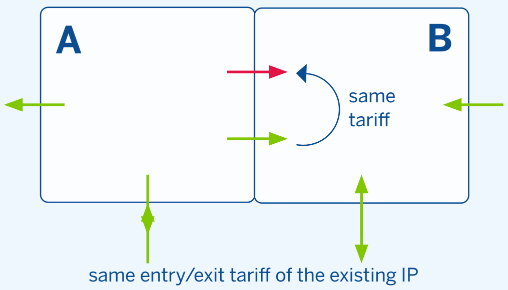

Figure 8: Combined approach in case of an existing IP at the considered border

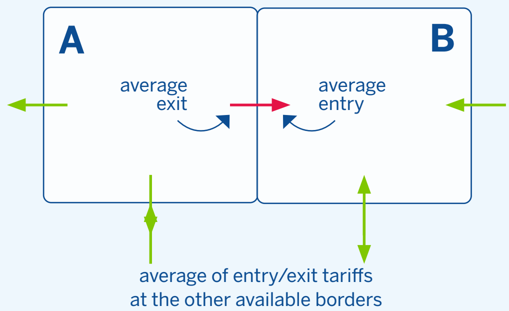

Figure 9: Combined approach in case of no existing IP at the considered border

In Figure 8, which describes the strategy to get the tariff proxy as in step 2) above, there is already a point connecting systems A and B in the direction from A to B (green arrow). The tariff for the point corresponding to the red arrow is assumed to be the same as the tariff for the point marked by the green arrow (exit from A with the green arrow + entry in B with the green arrow).

In Figure 9, which describes the strategy to get the tariff proxy as in step 3) above, there is no point already connecting systems A and B. The tariff for the point corresponding to the red arrow is assumed to be the combination of average exit tariffs from system A to other systems + average entry tariffs into system B from other systems.

As for tariffs regarding LNG projects, the tariff value for any LNG terminal corresponds to the following decision tree:

1. The actual LNG regasification tariff at this LNG terminal; if not applicable or available, then
2. The average regasification tariff in the country; if not applicable then
3. The average regasification in Europe.

As for tariffs regarding SSO projects, the tariff value for any SSO point corresponds to the standard SSO tariffs provided by GSE (1.5 EUR/MWh, cf. above).

Long Term Capacity Booking

For transmission tariffs, as explained above, TYNDP 2020 calculated the commoditised cost of using the TSO capacity, plus the actual commodity tariff if any.

For LNG tariffs, TYNDP 2020 considered the data available on LNG websites, corrected with a coefficient, which takes into account the historical values of the terminal use.

Long Term Capacity Contracts

With regard to transmission tariffs, in line with 2nd CBA Methodology provisions, TYNDP 2020 takes into consideration also elements regarding long-term capacity contracts. These contracts, if signed before the time-horizon considered for the assessment, represent a given for the user, and therefore sunk costs that are not expected to impact on its short-term use of the capacity. When considering the tariffs associated to the capacity booked through these contracts, the capacity component is disregarded (as it will not impact on the short-term use of the capacity). Long term capacity contracts data used in TYNDP 2020 are collected from ENTSOG Transparency Platform and considered in TYNDP assumptions based on the validity period reported in the Transparency Platform[14] (e. g. 2020–2025). Once the contract validity period is over, ENTSOG does not make any assumption on their renewal.

Long Term Supply Contracts

Long-Term Supply Contracts represent commercially sensitive information that are beyond the remit of TSOs, in line with the unbundling principle, and may not be publicly available. Those contracts are subject to renegotiation at or before their term and the outcome of such renegotiation is uncertain. This information can be therefore considered by ENTSOG in TYNDP 2020 only to the extent that this information is publicly available. The minimum supply potential of a supply source is defined as the current long-term contracts, and their expected extension with reference to the national projection of production and domestic demand, possible production and infrastructure constraints, as well as the historical EU supply share.

14 https://transparency.entsog.eu

2.3 SUPPLY

2.3.1 GAS SUPPLY POTENTIAL

For each climatic case and each import supply sources, a range is defined as:

- **Minimum:** The Minimum Supply Potential as defined in the TYNDP 2020 Scenario Report
- **Maximum:** The Maximum Supply Potential as defined in the TYNDP 2020 Scenario Report
- **Maximum for LNG:**
  - Flexibility from the LNG tanks was used as additional LNG supply for Peak day and 2-week cold spell in both weeks.
  - In the first week, the global LNG flows are limited to the level observed in Average Winter from the previous modelling of the whole year.
  - In the second week, additional cargos can arrive allowing supply to reach the daily maximum supply potential of Average Winter.

The actual use of supply is a result of the model taking into account the minimum and maximum constraints.

The working gas volume of the storages starts and ends with the same level (30 %) for the whole year (with country specific exceptions when this level is different). The modelled storage fill rate at the beginning of winter is determined by the whole year simulation. The working gas level, the withdrawal capacities and the withdrawal curves define the constraints for the storage use during high demand situations. The actual use of storages is a result of the model taking into account these constraints.

2.3.2 SUPPLY PRICE METHODOLOGY

Within the modelling tool, each supply source (for LNG, different LNG basins[15] are considered) is described as a supply curve reflecting the supply potential and the gas price in the respective scenario for the given year.

Since TYNDP 2018, ENTSOG has implemented a new supply price methodology in order to reflect different supply prices among supply sources.

As for the price assumptions, also the supply price methodology was presented during ENTSOG 10th July 2019 Workshop "On the supply potentials and market related assumptions for TYNDP 2020"[16].

Below, the main assumptions behind this methodology are presented. Some of those assumptions are also explained in the TYNDP 2020 Scenario Building Guidelines[17].

LNG prices are based on the Netback Asia approach (backward from Asia to Europe) under the assumption that Asia will remain the main driver of LNG demand and the LNG price-maker.

LNG prices to EU are defined for each LNG basin. To these prices, shipping costs and regasification costs are then added. WEO 2019 was used as reference for Asia LNG price evolution.

With regards to the shipping costs to Europe, in line with TYNDP 2018 and stakeholders' feedback, ENTSOG considers four different receiving areas (Atlantic, Baltic, Mediterranean 1 and Mediterranean 2). From one LNG basin, countries belonging to the same receiving area will have the same shipping cost. This approach allows to avoid that small differences among shipping costs will overly influence gas flow results.

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15 Australia, Peru, North-America, Sub-Sahara, Middle East, Trinidad and Tobago

16 https://entsog.eu/sites/default/files/2019-07/9_ENTSOG%20-%20Supply%20and%20Infrastructure%20costs_FINAL.pdf

17 https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/06/TYNDP_2020_Scenario_Building_Guidelines_Final_Report.pdf

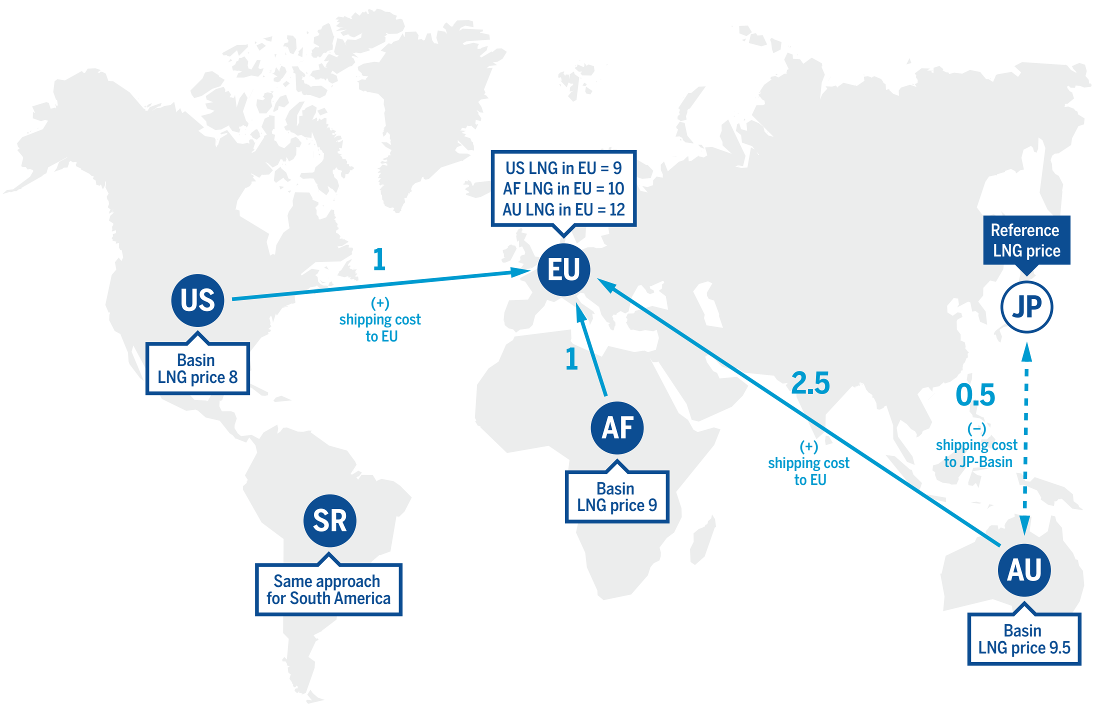

Figure 10: LNG price methodology (from 10th July 2019 workshop)

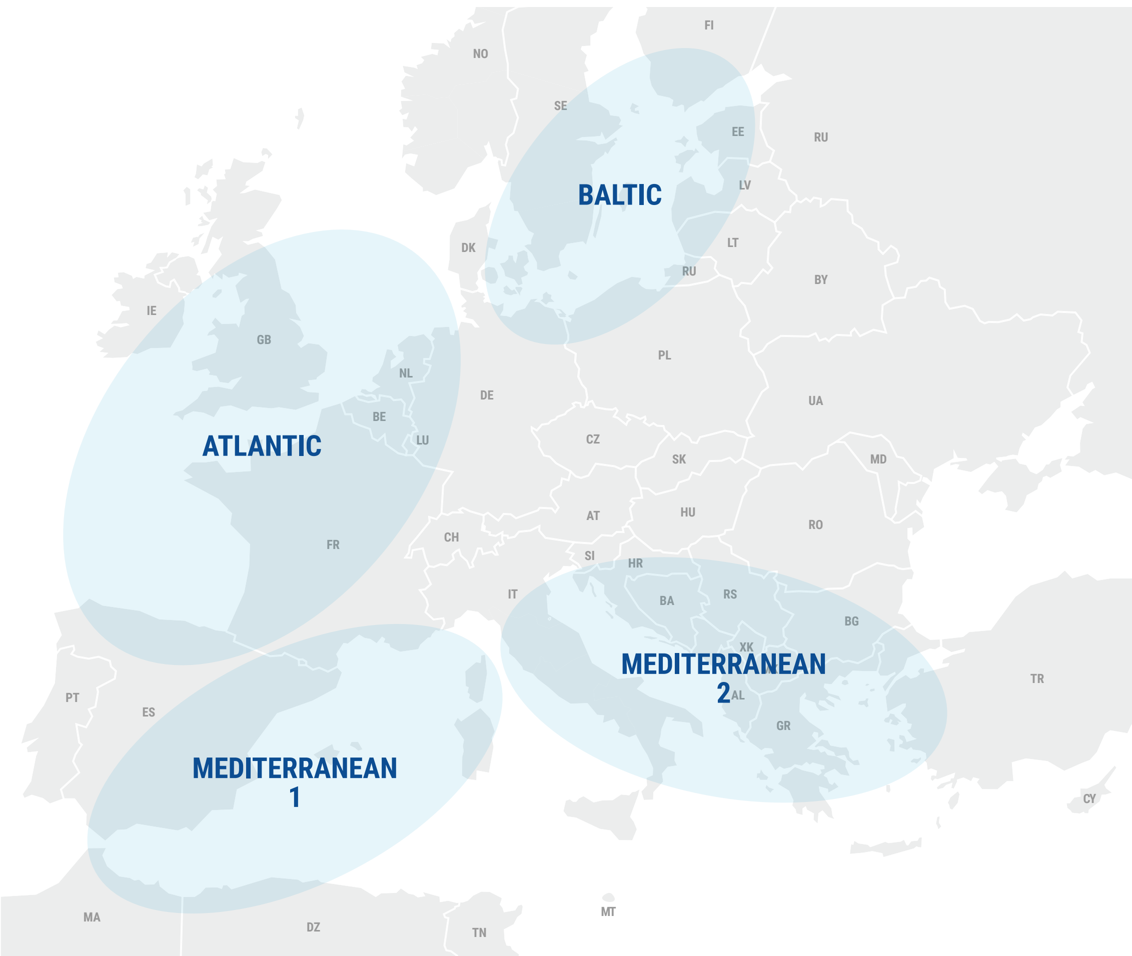

Figure 11: LNG receiving areas and shipping costs (from 10th July 2019 workshop)

Prices for Extra-EU supply delivered through pipelines are defined as follow:

Norway: Norwegian gas pipe price will be competitive with LNG reaching Atlantic countries considering regasification costs and long-term capacity booking contracts. The final price of Norwegian LNG and pipe gas in Europe will also take into account, respectively, the different country regasification costs and transportation costs;

Russian for North-West Europe: assumption that Russian gas is as competitive as Norwegian gas in Germany;

Russian for East Europe: other countries have direct import routes from Russia or through other extra-EU countries like Ukraine or Belarus. In those countries the price of Russian gas is defined taking into account the average spread (versus Germany) observed in the European Commission Quarterly Reports 37 (from 2016 to 2018) plus additional assumptions when this value is not available (see Table below);

Algeria: assumption that the Algerian supplier will be indifferent whether to sell its gas via LNG or pipe. The final price of Algerian LNG and pipe gas in Europe will also take into account, respectively, the different country regasification costs and transportation costs.

Libya: considered as expensive as Algeria pipe gas in Italy, the only European country directly connected to Libya;

Azerbaijan: since Italy is the exit point of the South Gas Corridor projects (from Azerbaijan production fields to the Trans Adriatic Pipeline), Azerbaijan gas is considered as expensive as Algerian gas and Libyan gas in Italy, factoring in long-term capacity booking contracts;

Turkmenistan: The first drop of gas from Turkmenistan has been set as expensive as the last drop of gas of Azeri potential.

Turkey: in TYNDP 2020, Turkey is not considered as a supply itself and therefore no reference price is identified. The gas that Europe could import from Turkey could be from different sources such as Azerbaijan, Russia, and LNG. Given the reference costs of those supplies and the related transportation costs, the model will minimize the cost for Europe.

Country	Route to	From	TYNDP 2020 (average from last 3 years)
DE	Germany	Russia	0.00
BG	Bulgaria	Romanian transit system	0.29
CZ	Czech Republic	Czech transit system	0.98
EE	Estonia	Russia	3.62
FI*	Finland	Russia	2.37
GR	Greece	Bulgarian transit system	−0.83
HU	Hungary	Ukraine	1.24
LT	Lithuania	Belarus	2.07
LV	Latvia	Estonian transit system	1.41
MK**	North Macedonia	Bulgarian transit system	0.29
PL***	Poland	Belarus, Yaml Europs pipeline, Ukraine	2.07
RO	Romania	Ukraine	1.51
SK	Slovakia	Ukraine	1.46

* Average of spread for baltic states ** Bulgarian spread ***Lithuanian spread

Table 4: Spread Russian gas between Germany and other countries

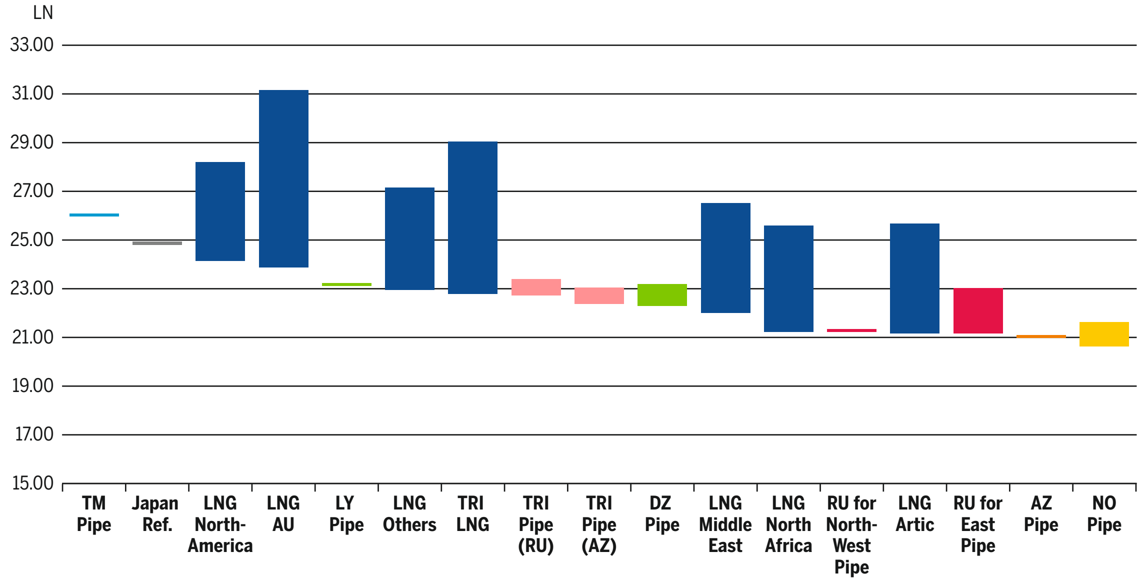

Figure 12: Example of the merit order (in EUR/MWh) of the supply sources in the Reference case (Japan reference price here is purely indicative). The range of each supply is defined by considering the supply price + entry cost to deliver the supply to EU as well as the shipping cost for LNG.

The supply price approach implemented in ENTSOG TYNDP allows for a better reflection of supply prices differences. However, since the uncertainty related to the supply price is high, especially in the long-term, the projects assessment is complemented by the analysis of different supply price situation (called supply configuration) where one specific source is considered being more expensive or cheaper than the others.

- LNG MIN/MAX where LNG minimisation corresponds to high LNG price and LNG maximisation corresponds to low LNG price
- RU MIN/MAX where Russia Minimisation corresponds to high Russian Price and Russia maximisation corresponds to low Russian Price
- SOUTH MIN/MAX (DZ, LY, AZ, NA LNG) where South minimisation corresponds to high South price and South maximisation corresponds to low South gas supply price.

2.3.3 SUPPLY PRICE CURVE

Within the modelling tool, each supply source (for LNG, different LNG basins are considered) is described as a supply curve reflecting the supply potential and the gas price in the respective scenario for the given year.

This section provides more information on the ranges for gas prices used for building the supply curves under this modelling approach.

For each supply source, the following is done:

- An initial price is determined (setting an initial price plus cost to reach EU for each source is explained in section 2.3.2)
- A Supply Price Curve is determined by drawing a straight line between two points with (X,Y) coordinates, where the X_axis is the supply used in GWh/day, and the Y_axis is the price of the additional supply in EUR/MWh.
  - Low point (0 supply used, initial price – 2.5 EUR/MWh).
  - High point (SupplyMax, initial price + 2.5 EUR/MWh)

Where SupplyMax is the maximum potential for the given supply along the years. This means that, if the maximum potential is used, the average price of the supply will be the initial price.

This approach ensures to have more competition among sources and avoid "all or nothing" situations where cheapest sources are used fully first.

On top of this price curve, to reach the EU gas market, the following is added:

- For pipe supply, the entry tariff cost into EU
- For LNG, the shipment cost

Note: The above process explains why, when interpreting the figure 12 in section 2.3.2, one must understand that the first drop of "RU for North-West Pipe" gas is actually 2.5 EUR/MWh cheaper than the initial price presented here, and hence will be used before the last drop of "NO Pipe" gas.

Three additional corrections are made to the price curves:

1. In order to match some benchmark like average price of imported gas in Europe, all curves are translated upward or downward, depending on the year and the demand scenario. This does not change the merit order of the sources, nor the TYNDP or PS-CBA indicators results.
2. In minimization (respectively maximization) price configuration, the minimized (respectively maximized) supply has its price curve shifted upward (respectively downward) by 5 EUR/MWh.
3. Winter supply curves are shifted upward with a summer-winter spread consistent with the storage tariffs.

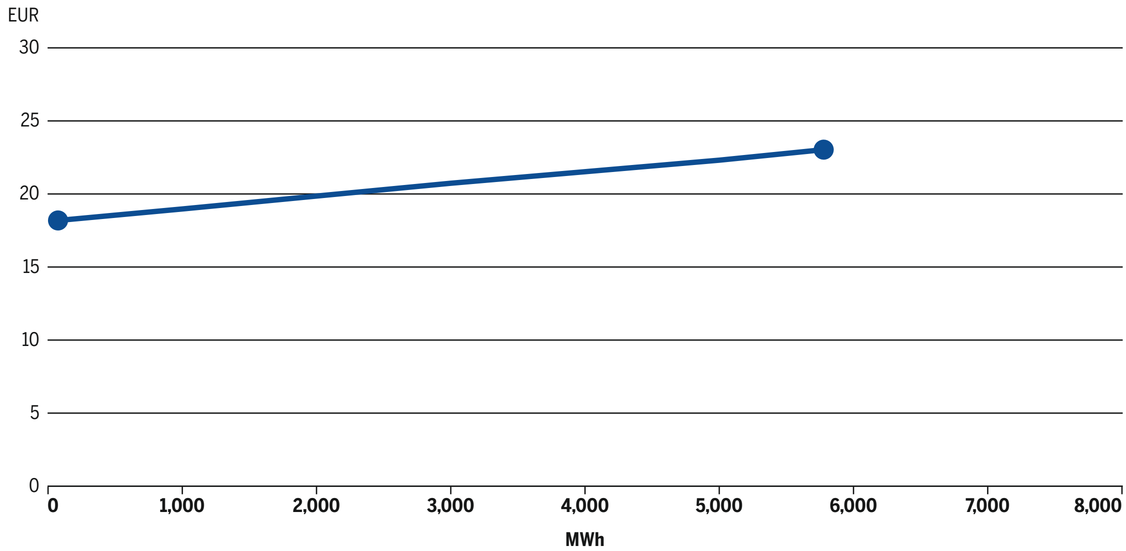

Figure 13: Supply Price Curve example

The following tables gives the values used for 2020 and 2025.

Supply	InitialPrice translated −2.5	InitialStep	InitialPrice translated +2.5	FinalStep
AZ	19,171	0	24,171	446
DZ	20,130	0	25,130	1,098
LNGAN	18,979	0	25,977	787
LNGAU	21,150	0	26,150	1
LNGME	17,893	0	22,893	1,445
LNGNO	18,751	0	23,751	169
LNGPE	19,910	0	24,910	1
LNGSS	19,289	0	24,289	1,360
LNGTT	18,824	0	23,824	1
LNGUS	20,340	0	25,340	1,459
LY	20,211	0	25,211	217
NO	18,751	0	23,751	3,486
RUm	19,235	0	24,235	6,092
TM	24,171	0	29,171	874

Table 5: 2020 price curves

Supply	InitialPrice translated −2.5	InitialStep	InitialPrice translated +2.5	FinalStep
AZ	22,616	0	27,616	446
DZ	23,575	0	28,575	1,098
LNGAN	22,424	0	29,422	787
LNGAU	24,595	0	29,595	1
LNGME	21,338	0	26,338	1,445
LNGNO	22,196	0	27,196	169
LNGPE	23,355	0	28,355	1
LNGSS	22,734	0	27,734	1,360
LNGTT	22,269	0	27,269	1
LNGUS	23,785	0	28,785	1,459
LY	23,656	0	28,656	217
NO	22,196	0	27,196	3,486
RUm	22,680	0	27,680	6,092
TM	27,616	0	32,616	874

Table 6: 2025 price curves

2.4 EXISTING INFRASTRUCTURE (CAPACITY, STORAGE VOLUMES)

The existing transmission infrastructure is defined as the firm capacities available on a yearly basis as of 1st January 2019. In addition to the existing transmission infrastructure, the existing LNG and storage infrastructure is considered.

The transmission infrastructure is defined by the technical capacities between countries. For this, the technical capacities at interconnection points between these countries are aggregated after the application of the lesser-of-rule[18].

LNG infrastructure is defined by the regasification capacity along the average year and during high demand situations. The LNG tank volumes have operational characteristics specific for each terminal; a flexibility factor defines the share of the tank volume that can be expected to be available during high demand situations. This flexibility has been defined by GLE.

In addition to the working gas volumes and the withdrawal and injection capacities, withdrawal and injection curves for storages are taken into account. These curves define the abilities of storages to withdraw or inject gas depending on the fill level. The curves for the TYNDP 2020 have been provided by GIE.

2.5 PROJECT DATA

Project data has been collected directly from promoters. More information can be found directly in the TYNDP 2020 Infrastructure Report and related Annex A1 and Annex A2[19].

The following project information are collected from promoters and used in ENTSOG TYNDP assessment:

- transmission capacity increment, as the value of the capacity (in GWh/d) brought by the project realisation,
- decrease of capacity submitted as decommissioning project or capacity modification as the value of the capacity (in GWh/d) brought by the project realisation,
- LNG yearly volume, as the expected increment in the maximum yearly volume that the terminal can regasify (in bcm/y),
- underground storage working gas volume, injection and withdrawal, as respectively, the capacity increment stemming from project realisation,

The final capacity value used in the modelling are the results from the application of the "lesser-of-rule".

2.6 DATA COLLECTION

Project data has been collected from promoters between 8th April 2019 and 30th April 2019.

2.7 GENERAL AND TECHNICAL INFORMATION

The general and technical information covers the price information for gas depending on the year and scenario as well as project-specific data like the capacity increment, the expected commissioning date, the FID status, the advanced status and the PCI status according to the 2019 selection (the 4th PCI List). This information was submitted by the project promoters during the project data collection and is used to aggregate the different infrastructure levels based on the individual projects.

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18 The lesser-of-rule applied by ENTSOG aggregates available capacities on the two sides of a point to generate consistent capacity for modelling purposes. In case operator A submits an exit capacity with the value of 100 and operator B submits at the same point but in entry a capacity with value of 50, the latter will be considered as final value.

19 Link to Annex A

3 INDICATORS

The Regulation has identified four main criteria: market integration, security of supply, competition, and sustainability[20]. The European system and projects are assessed against those criteria.

In line with those criteria, the 2nd CBA Methodology recommends considering the following potential benefits of gas infrastructure projects:

- Reduction of the cost of gas supply and price convergence between markets;
- Reduction in supply dependence and increase of the number of supply sources that a country has access to;
- Enhancement of market integration;
- Contribution to security of supply;
- savings in CO_2 emissions, related to
  - integration of renewable energy (including biomethane and other synthetic gases)
  - and/or substitution of higher-carbon energy sources (like coal in power generation) by gas;
- Replacement of more expensive fuels in new or existing markets.

The above-mentioned benefits can be:

- Quantified, measured through specific indicators;
- Quantified and monetised, assigning a specific monetary value;
- Qualitative, when benefits cannot be quantified.

The 2nd CBA Methodology is based on a multi-criteria analysis, combining a monetised CBA with non-monetised elements. In line with this concept, the above benefits are taken into account along with cost information, allowing for a level-playing field and comprehensive assessment of the European gas system and of projects on all criteria.

This can be summarised in the figure below.

Some indicators are used only for the project-specific cost-benefit analysis (PS-CBA) while others are used for both the system assessment and the PS-CBA.

As part of ENTSOG "Roadmap for Future Projects CBA Assessment"[21], indicators are refined over time as part of the successive TYNDP processes. This represents an opportunity to regularly improve projects CBA assessment in a timely and efficient manner.

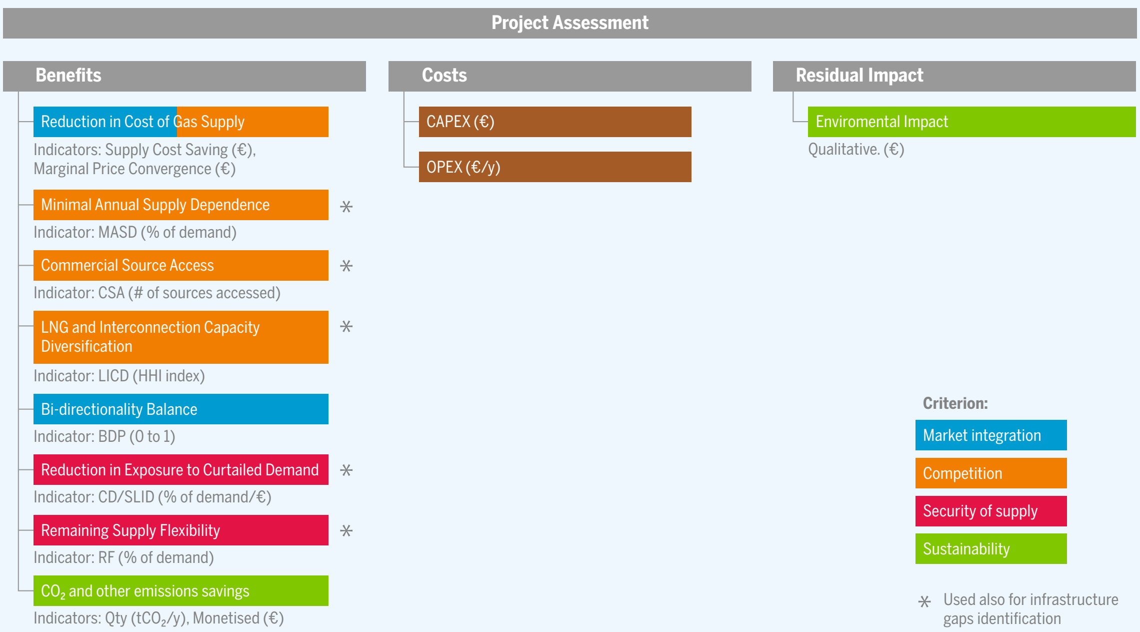

Figure 14: CBA metrics and Regulation criteria

20 Art. 4 of Regulation (EU) 347/2013: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32013R0347&from=en

21 https://www.entsog.eu/sites/default/files/2019-03/4.%20ADAPTED_2nd%20CBA%20Methodology_Accompanying%20document%20-%20Roadmap%20for%20future%20projects%20CBA%20assessment_for%20Commission%20Approval_EC%20APPROVED.pdf

3.1 INDICATORS USED FOR ASSESSMENT IN TYNDP

In the definition of the indicators, the term capacity corresponds to the technical firm capacity.

3.1.1 SINGLE LARGEST INFRASTRUCTURE DISRUPTION (SLID)

This indicator intends to investigate the impact of the disruption of the **single largest infrastructure of a country** during a Peak day.

The SLID computation can be presented as an indicator or a disruption configuration. Either way, the result is the disrupted quantity (demand curtailment) measured following the disruption of the single largest infrastructure entering a given country (excluding storage and national production).

The SLID is computed in a peak day situation, with the associated supply and national production in this configuration. This computation allows to identify potential bottlenecks for the considered country and the other European countries.

The simulation of the single largest infrastructure of the different countries look at the impact of such disruptions at a European level.

The list of SLID capacities is published by ENTSOG as Annex D – SLID Values.

3.1.2 LNG AND INTERCONNECTION CAPACITY DIVERSIFICATION (LICD)

This indicator intends to look at the diversification from the perspective of market integration. It measures the diversification of paths that gas can flow through to reach a market area. Import routes are not considered and capacities are capped by the country demand.

The LICD is an HHI indicator[22] and ranges from 0 to 10,000. The lower the value, the better the diversification is. Where a market would have two borders the LICD cannot be lower than 5,000. For a market having three borders the LICD cannot be lower than 3,333.

The indicator is calculated following the below formula.

$$\mathrm{LICD} = \left(\frac{\mathrm{LNG\ border}}{\mathrm{Total\ Capa\ border}} * 100\right)^2 + \sum_{1}^{\mathrm{N\ borders}} \left(\frac{\mathrm{Capa\ border_l}}{\mathrm{Total\ Capa\ border}} * 100\right)^2$$

Where

$$\mathrm{Capa\ border_i} = \min\left[\sum_{k}^{\mathrm{IP}} \mathrm{IP_k border_i}\,, \mathrm{Dyearly}\right]$$

$\mathbf{D_{Yearly}}$ is the gas demand (GWh/d) of the area in average year conditions. This is considered in order to avoid that capacities exceeding the area demand (such as in transit routes) would distort the indicator output showing an unduly high level of the indicator.

$\mathbf{IP_k\ border_i}$ is the capacity at the interconnection point $\mathbf{IP_k}$ at the $\mathbf{border_i}$ with the neighbouring area $\mathbf{i}$.

And where

$$\boldsymbol{LNG\ border = min\left[\sum_{m} LNG\ terminal_m, Dyearly\right]}$$

$\mathbf{LNG\ terminal_m}$ is the send-out capacity of the LNG terminal $\mathbf{m}$.

$$\mathrm{Total\ capa\ border} = \mathrm{LNG\ border} + \sum_{i=1}^{\mathrm{N\ borders}} \mathrm{Capa\ border_i}$$

All capacities should be considered after application of the lesser-of-rule.

22 Herfindahl-Hirschman index, an indicator of concentration or, conversely, diversification.

3.1.3 REMAINING FLEXIBILITY (RF)

In addition to assessing demand curtailment risks, the remaining flexibility assesses how resilient to climatic stress a country is. The remaining flexibility aims at capturing the extra supply flexibility a country can access through its infrastructure.

This flexibility is measured by the increase of demand an area can accommodate before an infrastructure or supply limitation is reached somewhere in the European gas system. This indicator is to be calculated independently area-by-area under stressful situations (such as climatic and supply or infrastructure stress).

The value is expressed as a percentage of the demand for a given area. The higher the value, the better the resilience.

A zero value would indicate that the country is not able to fulfil any additional demand without perturbating other countries and a 100 % value would indicate that it is possible to supply twice the level of the demand.

3.1.4 DEMAND CURTAILMENT AND CURTAILMENT RATE (CR)

To achieve the energy pillar of Security of Supply it is important to identify whether there are countries in Europe that risk to face any demand curtailment (i. e. to be not fully supplied). The analysis should allow to identify where projects provide benefits coming from mitigating possible demand curtailment.

This indicator has been calculated considering cooperation among countries: under such cooperative approach, areas within a given region (Same groups will share the same level of curtailment (if any) unless an infrastructure-related limitation prevents them to do so. This cooperative approach is in line with Regulation (EU) 2017/1938 on Security of Supply[23].

Identification of demand curtailment risk should be performed individually for:

- **Normal (climatic) conditions**
- **Climatic stress conditions**, in case of extreme temperatures with lower probability of occurrence than normal conditions (e. g. occurring with a statistical probability of once in 20 years, 1/20);
- **Supply stress conditions**, in case of supply stress due to specific route disruptions (e. g. Russian transit through Ukraine);
- **Infrastructure stress conditions**, in case of disruption of the single largest infrastructure of a country. **Curtailment Rate (CR)** is the ratio of demand curtailment by the demand.

A monetised value (in EUR/MWh) is used in TYNDP 2020 as Cost of Disruption of Gas (CoDG) to quantify the monetary impact of any avoided demand curtailment.

For TYNDP 2020, two different values are used:

- **a uniform value** (as per TYNDP 2018)
- **specific country values** (from ACER study on the "Estimation of the cost of disruption of gas supply in Europe"[24])

The uniform value is derived as:

$$\text{CoDG} = \text{Total EU28 GDP/Gross Inland Consumption} = 600\ \text{EUR/MWh}$$

In the simulations to determine the amount of possible curtailed demand a uniform CoDG value ensure that countries will act in a cooperative way significantly reducing the impact of very severe disruptions in the most vulnerable countries. Additionally, using a uniform value of CoDG across the countries ensures comparability and harmonised assessment of projects.

When applying the 600 EUR/MWh value to the avoided curtailed demand, ENTSOG has considered a 5 % probability (1-in-20 years) in order to take into account the lower probability of occurrence of peak and stressful situations.

At the same time, stakeholders have asked to include also a country-specific monetary value. To meet such expectations, for TYNDP 2020, ENTSOG has used specific CoDG values per country, as defined in ACER "Estimation of the cost of disruption of gas supply in Europe" study. The use of these values was discussed also with the European Commission and ACER within the PCI Cooperation Platform. Below the table of the values used.

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23 https://www.entsog.eu/sites/default/files/entsog-migration/publications/sos/ENTSOG%20Union%20wide%20SoS%20simulation%20report_INV0262-171121.pdf

24 http://www.acer.europa.eu/en/Gas/Infrastructure_development/Documents/ACER_CoDG_Final_Report_20181119_clean.pdf

Country	ACER CoDG
Austria	62.1
Belgium	93.3
Bosnia Herzegovina	63.4
Bulgaria	49.1
Croatia	63.4
Czechia	51.8
Denmark	102.4
Estonia	60.6
Finland	59.8
North Macedonia	59.6
France	81.5
Germany	114.1
Greece	66.6
Hungary	68.9
Ireland	71.0
Italy	87.4
Sardinia	87.4
Latvia	55.5
Lithuania	44.9
Luxembourg	73.3
Malta	72.4
Netherlands	62.8
Poland	62.0
Portugal	72.0
Romania	71.8
Serbia	63.3
Slovakia	83.5
Slovenia	69.0
Spain	81.2
Sweden	54.6
Switzerland	72.4
United Kingdom	88.3
Northern Ireland	88.3
Cyprus	72.4

Table 7: Cost of Disruption of Gas values per country

3.1.5 MINIMUM ANNUAL SUPPLY DEPENDENCE (MASD)

The MASD indicator aims at identifying countries showing a strong dependence to a specific supply source and allows to identify cases where this dependence is related to an infrastructure bottleneck (physical dependence).

It should be calculated vis-à-vis each source under a whole year.

The lower the value of MASD, the lower the dependence.

As for the curtailed demand and rate, this indicator has been calculated considering cooperation within relevant regions: under such cooperative approach, areas within a given region will share the same level of dependence unless an infrastructure-related limitation prevents them to align their dependence.

The Minimum Annual Supply Dependence to source S is calculated as follows (steps 1 to 3 are repeated for each source):

1. **The availability of source S is set down to zero**
2. **The availability of the other sources remains in line with the defined supply assumptions**
3. **Modelling of the European gas system under the whole year**

The Supply Source Dependence of the Area Z to the source S is defined as:

$$SSD_{Z,S} = \frac{DC_{Z,S}}{Demand_Z}$$

Where:

$\mathbf{DC_{Z,S}}$ is the demand curtailment (in GWh) in **Z** when **S** is not available

$\mathbf{Demand_Z}$ is the demand of **Z** (in GWh)

For each source S, TYNDP 2020 assesses the dependence of those countries that are part of at least one of the respective supply risk group as defined by Annex I of Regulation (EU) 2017/1938 regarding Security of Supply. For instance, when assessing the dependence of Europe towards Russian supply, the Iberian Peninsula – which is not part of any of the Eastern supply risk groups – can fully cooperate with the rest of Europe to the extent it is not exposed to demand curtailment.

For MASD LNG, all the European countries can fully cooperate in case of demand curtailment.

With regards to LNG, the following approach has been chosen for calculating MASD:

TYNDP 2020 considered all LNG sources as one global source on the basis that LNG is a global market and prices are set worldwide. From a competition perspective, and MASD being calculated on a whole year, this may be considered as the most sensible approach; dependence on the overall LNG is considered as there is no dependence on single basin (global energy market).

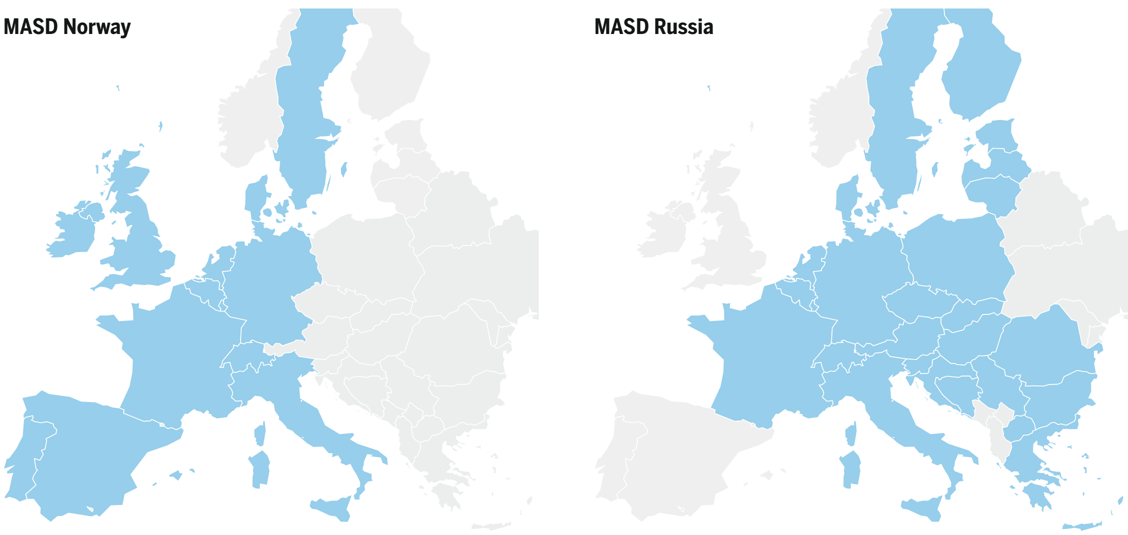

Figure 15: Risk groups

3.1.6 COMMERCIAL SUPPLY ACCESS (CSA) AND SUPPLY SOURCE DIVERSIFICATION INDICATOR (SSDI)

The Commercial Supply Access (CSA) indicator measures the number of commercially available supply sources an area can access (including national production as source).

The ability of an area to access a given source is measured through a supply source diversification metric. CSA provides the aggregate view across all supply sources.

It is calculated for each area under a whole year.

This indicator measures the ability of each Zone to take benefits from an alternative decrease of the price of each supply source (such ability does not always mean that the Zone has a physical access to the source).

For the calculation of this indicator:

- the minimum supply constraint is removed for each supply source
- the maximum supply constraint is removed for the studied supply source

It is calculated for each Zone under a whole year as the succession of an Average Summer and Average Winter.

The Supply Source Price Diversification of all Zones to source S is calculated as follows:

Step 1: The maximum supply constraint for source S is removed.

Step 2: All sources have their price curves set flat at the same price (including national production).

Step 3: The price level of source S is decreased by 20 % ensuring that source S is maximised.

Step 4: The marginal price curves are computed for each Zone (see description below).

Step 5: The price level of source S is further decreased by 10 % (from 80 % to 72 %).

Step 6: The marginal price curves are computed again for each Zone (see description below).

Marginal price curve

For a given Zone, the marginal price curve mentioned in step 4 and step 6 is a set of marginal prices ($\mathbf{MP_k}$)that are determined for successive simulations with different percentage of demands.

The process for the $\mathbf{k^{th}}$ simulation is the following:

- Consider the original demand for the given scenario
- For each Zone, take $\mathbf{x_k}$% of the demand, where the $\mathbf{x_k}$ values are ranging from 0.1 % to 99.9 %.
- Reduce the lower constraints (minimum supply constraints) to $\mathbf{x_k}$% of their original values.
- Run a simulation, and for each Zone retrieve the resulting marginal price $\mathbf{MP_k}$.

SSDi formula

- $\text{MP change}_{[k,k+1]} = \frac{1}{2} * [\text{Abs}\left(\frac{\text{MP}_{k+1\ \text{Step6}}}{\text{MP}_{k+1\ \text{Step4}}} - 1\right) + \text{Abs}\left(\frac{\text{MP}_{k\ \text{Step6}}}{\text{MP}_{k\ \text{Step4}}} - 1\right)]$
- $Demand\ range\ percentage_{[k,k+1]} = x_{k+1} - x_k$

$$\boldsymbol{SSDi = \frac{1}{10\%} * \sum_k (MP\ change_{[k,k+1]}) * (Demand\ range\ percentage_{[k,k+1]})}$$

For each demand range **[k,k+1]**, an average drop of marginal price is computed (except for the two extreme ranges, the first and last 0.1%, where only one marginal price is used).

The larger the SSDi, the better the access from a price perspective.

Finally, the diversification of a Zone is characterised by both:

- the number of sources for which the SSDi is high
- the magnitude of a given SSDi.

SSDi should be calculated independently for the different supply sources (SSDi_S1, SSDi_S2,...), and simultaneously for all areas.

The CSA indicates the number of sources for which the SSDi exceeds 20%, which means that a decrease in the price of this supply source would impact at least 20 % of the country supply bill.

$$\text{CSA} = \text{number of sources for which SSDi} \geq \text{CSAthreshold}$$

Concerning LNG, TYNDP considers LNG as one global and competitive market. Local LNG price difference is generally related to specific supply contracts.

3.1.7 MARGINAL PRICE

For each climatic case, the marginal price of gas supply of a Zone is a direct output of the optimisation.

It is calculated for each Zone under a whole year as the succession of an Average Summer and an Average Winter, resulting potentially in two different marginal prices (one for summer and one for winter).

The lower the difference between the marginal prices of two Zones, the better the Price Convergence.

Marginal Price is monetised in the Supply Cost Savings.

3.1.8 WEIGHTED MARGINAL PRICE DEVIATION

$$\boldsymbol{WCF = \sum_{i=1}^{n}(|MP_i - REF\ EX| * \frac{D_i}{D_{EU}});}$$

$$\boldsymbol{D_{EU} = \sum_{i=1}^{n} D_i}$$

Weighted Convergence Factor is an average deviation calculated for each specific scenario, year and infrastructure level, calculated only for the gas reference price configuration (where no specific gas source is significantly cheaper or more expensive).

Where:

$\mathbf{MP_i}$ represents the Marginal price in country **i**

$\mathbf{D_i}$ represents the demand value for country **i**

$\mathbf{D_{EU}}$ is a total demand in Europe in specific scenario and infrastructure level

REF EX is a demand-weighted average of Marginal Prices in EU for specific Scenario and Infrastructure level

3.2 INDICATORS USED ONLY IN THE PS-CBA

3.2.1 SUPPLY COST SAVINGS

$$\text{supply cost saving} = \sum_{1}^{n} (S_1^n * C_1^n) \text{ with project} - \sum_{1}^{n} (S_1^n * C_1^n) \text{ without project}$$

This indicator is meant to capture the benefits stemming from projects reducing the overall European cost of gas supply.

The monetary analysis of the cost of gas supply is based on the calculation of the gas bill in the situations with and without the project. The benefits are calculated at the European level and according to the above formula.

Where:

$\mathbf{S_1^n}$ represents the supply

$\mathbf{C_1^n}$ represents the cost of the gas supply, including the price of the gas delivered at the Europe borders and the tariffs (the latter when considered in the assessment)

In order to consider potential temporary price situations characterising a supply source, a sensitivity on the price associated to that specific source was considered. This sensitivity is represented by the supply price configuration explained above.

3.2.2 BI-DIRECTIONALITY

$$\text{BDP} = \text{Min } \left(1; \frac{\text{Added capacity at IP to other direction}}{\text{Existing capacity in prevailing direction}}\right)$$

The indicator is only to be calculated as part of project assessment and can by nature only be calculated for transmission projects.

The indicator measures the balance between the capacities in each direction of an interconnection. It should be recommended to calculate it at the Interconnection Point (IP) level.

The indicator is calculated according to the above formula.

Where:

Denominator: Existing capacity in prevailing direction (GWh/d);

Numerator: Added capacity at IP to other direction (GWh/d): capacity of the project against the prevailing direction;

In the case of a project creating a new bi-directional IP, the numerator shall be the smaller added capacity. In case the project changes the prevailing direction, the capacity in the new prevailing direction shall be the denominator.

The maximum value of the indicator is one (1). In case the project is a Reverse Flow, it will score above zero (0).

3.2.3 SUSTAINABILITY

New gas projects can contribute to sustainability by enabling the replacement of more pollutant fuels (primarily oil and coal) with gaseous fuels.

This indicator is not calculated for the system assessment but only for the project-specific assessment since any decrease in emissions represent an improvement of the incremental situation.

3.2.3.1 Emission savings computation

In TYNDP 2020, benefits from fuel switch have been measured in terms of:

- CO_2 emission
- other externalities (i. e. NO_X, SO_2 and PM2.5)

The TYNDP 2020 scenarios data allow for a more refined distinction among the type of gases that can replace more pollutant fuels. The following categories were considered for the TYNDP 2020 assessment:

- savings from switching to methane
- savings from switching to methane produced through P_2CH_4 technologies
- savings from switching to biomethane
- savings from switching to hydrogen produced through P_2H_2 technologies
- savings from switching to imported hydrogen (or gas imports assumed to be decarbonised pre- or post-combustive)

Each TYNDP 2020 scenarios storyline jointly developed by ENTSOG and ENTSO-E defines a penetration of methane, biomethane and hydrogen and represents the input to the calculation of emission savings used in the TYNDP 2020 project assessment[25].

Data was entirely developed top-down by the ENTSOs, with exception of National Trends scenario which data was provided directly by TSOs based on National Energy and Climate Plans (NECPs).

The different quantities of emission savings were computed based on the following assumptions:

- emission savings are computed by looking at potential fuel switches for each assessment year (year Y vs year X). The same assumptions are made on the replacement of fuels. Given the share of renewables and nuclear defined in each scenario, gas replaces coal, oil and other more carbon-intensive fuels
- increased gas consumption in each sector is assumed to replace other carbon-intensive fuels up to their volume in the energy mix (the increase of gas demand results in fuel switches only when there is a corresponding decrease of the demand for other carbon-intensive fuels) and having taken into consideration the technologies efficiency for each fuel
- emissions increase from methane is considered in case of methane replacing nuclear
- for positive emission from the additional methane demand two different approaches are implemented and represent, respectively, the situation where an increase in the emission from the gas demand not replacing already other more polluting fuels is taken into account in the assessment or it is considered neutral
- savings from methane conventional production are subtracted from the overall savings from methane and attributed to project only in case they enable such production and/or enable country gasification

A complete excel file with the steps followed to compute the sustainability savings is published as part of the project-assessment package.

25 https://public.tableau.com/profile/tyndp2020scenarios#!/vizhome/DanteFinalScenarioWebsite/GasData

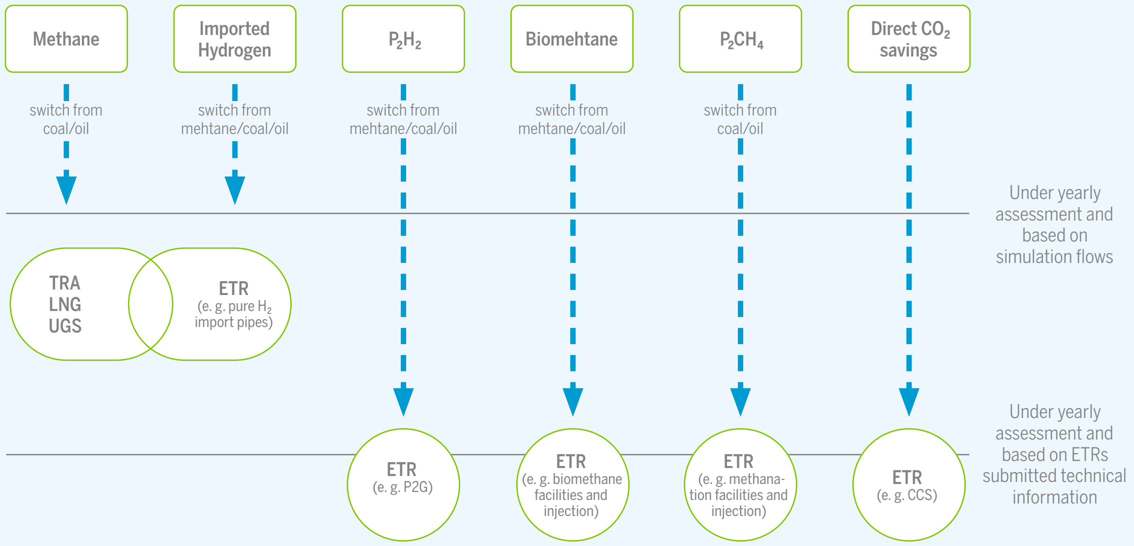

Figure 16: Allocation of emission savings among project categories

3.2.3.2 Emission savings allocation

With regards to sustainability, Regulation (EU) 347/2013 states in its article 4 that gas projects should contribute to sustainability by supporting intermittent renewable generation and enhancing deployment of renewable gas.

Figure 16 summarises how the benefits from emission savings are allocated to which project type.

3.2.3.2.1 Under yearly assessment

Gas projects can contribute to fuel switch on a daily basis by replacing more emitting fuels in "base load" sectors like power generation or transport.

Their contribution to emission saving will depend on how the project is actually used in the different simulations. For this reason, yearly emission savings have been allocated by ENSTOG based on the flows resulting from the actual simulations, including the sensitivity on project tariffs.

Below the main assumptions:

- assessment was carried on all TYNDP 2020 scenarios, all infrastructure levels and under three different project tariff configurations
- assessment was carried on the reference supply price configuration with exception for projects enabling new extra-EU supply for which a more conservative approach was adopted by focusing on the supply price configuration where the enabled supply is minimised
- emission savings were considered only for countries where the project is built and whose IP is actually used by the assessed project in the simulations (i. e. a project built in Finland does not contribute to emissions savings in Portugal)
- independently from the tariff sensitivity considered, infrastructures already included in the different infrastructure levels have been always prioritised over the assessed projects by assuming that any existing capacity remained free will be used first (irrespectively from the cost of transporting the gas through the project and through the alternative routes)
- emission savings benefits have been then allocated using the following formula

$$\frac{Emission\ Savings\ (tco_2)}{Total\ Entry\ Capacity\ Without\ Project\ \left(\frac{GWh}{d}\right) + Project\ Capacity\ (\frac{GWh}{d})} \cdot Flows\ Project\ \left(\frac{GWh}{d}\right)$$

Example 1: given a demand of 2,000 GWh/d, without the project the country receives 1,200 GWh/d through IP1 (1,200 GWh/d out of 1,200 GWh/d available total entry capacity) and 800 GWh/d from IP2 (800 GWh/d out of 800 GWh/d available total entry capacity). Flowing gas through IP2 is cheaper than through IP1. With the commissioning of project creating additional capacity at IP2 of 600 GWh/d, the country can increase the gas imports through IP2 by reducing to 1,000 GWh/d the flows through IP1 and increasing to 1,400 GWh/d the flows through IP2. However, given the same composition of the gas transported, such switch in capacities justified by a different transportation cost (or different gas supply price) does not enable any additional gas demand increase and therefore does not trigger a benefit in terms emission savings. No emission saving benefits are allocated to the project.

Example 2: given a demand of 2,000 GWh/d, without the project the country receives 1200 GWh/d through IP1 (1,200 GWh/d out of 1,200 GWh/d available total entry capacity) and 400 GWh/d from IP2 (400 GWh/d out of 400 GWh/d available total entry capacity). Flowing gas through IP2 is cheaper than through IP1. With the commissioning of project creating additional capacity at IP2 of 1,000 GWh/d, the country can increase the gas imports through IP2 by reducing to 600 GWh/d the flows through IP1 and increasing to 1,400 GWh/d the flows through IP2. Differently from example 1, without the project all the gas demand could not be satisfied. Still the project capacity is larger and the use of it from the simulations is larger than the amount of gas demand to be covered (being IP2 also cheaper than IP1). When allocating the emission saving benefits to the project, the existing infrastructure is therefore prioritised and the benefits from the projects accounted only for the part actually linked to the enabled gas demand (i. e. 400 GWh/d).

The benefits are then allocated based on the above formula:

$$\frac{Emission\ Savings\ (500tCO_2)}{Total\ Entry\ Capacity\ Without\ Project\ \left(1600\frac{GWh}{d}\right) + Project\ Capacity\ (1000\frac{GWh}{d})} \cdot Flows\ Project\ \left(400\frac{GWh}{d}\right) = 76.9\ tCO_2$$

These benefits are monetised and displayed in MEUR/y in the line "Flow based" in the PS-CBA Project Fiche.

A final minimum and maximum value of savings to be attributed to the projects is included in the PS-CBA Project Fiches and represents respectively the situation where an increase in the emission from the gas demand not replacing already other more polluting fuels is taken into account in the assessment or it is considered neutral.

	Example 1		Example 2	
	without	with	without	with
New project capacity (GWh/d)	0	600	0	1,000
Total country "X" gas demand (GWh/d)	2,000	2,000	2,000	2,000
Total country "X" gas demand contributing to fuel switch (GWh/d)	1,200	1,200	1,200	1,200
Entry capacity to country "X" (GWh/d)	2,000	3,400	1,600	2,600
– entry capacity IP1 (GWh/d)	1,200	1,200	1,200	1,200
– entry capacity IP2 (GWh/d)	800	1,400	400	1,400
Gas flows to country "X" (GWh/d) – from simulations-	2,000	2,000	2,000	2,000
– flows thorugh existing infrastructure – IP1 (GWh/d)	1,200	600	1,200	1,600
– flows thorugh existing infrastructure – IP2 (GWh/d)	800	800	400	400
– flows through project – IP2 (GWh/d)	0	600	0	1,000
Remaining existing capacity to be prioritised before project (GWh/d)		600		600
Amount of flows from projects considered for allocation (GWh/d)		0		400
Total country(ies) emission savings from fuel switch (tCO_2)	500	500	500	500
Total country(ies) emission savings from fuel switch (tCO_2)		0		75.9

Table 8: Allocation of emission savings based on flows under yearly situation. Examples.

3.2.3.2.2 Sustainability assessment for Energy Transition project

In TYNDP 2020 ENTSOG has collected and assessed Energy Transition project (ETR).

By ETR it is meant a project which facilitates the integration of renewables, the achievement of decarbonisation and efficiency targets, reduction of other air pollutants, sector coupling initiatives and, more generally, all projects specifically aimed at the energy system transformation for reaching sustainability goals and not already included in the previous project categories.

Based on the type of ETR project and the related technical information submitted by the concerned promoter, ENTSOG has allocated emission savings to ETR projects.

When not available, ENTSOG has integrated promoters input with additional standard assumptions (e. g. full load hour for P2G facilities).

Depending on the type of gas enabled by the project, only CO_2 savings or both CO_2 savings and other externalities were considered.

For this TYNDP 2020 edition ENTSOG has calculated for ETR projects only the benefits related to the replacement of methane with hydrogen, synthetic methane or biomethane. When not possible to clearly track the destination of the enabled gas, ENTSOG has not considered the additional benefits from the replacement of other fuels such as coal or oil.

For example, while for a biomethane refuelling station it can be fairly demonstrated that the project, by enabling the use of biomethane, will also bring benefits in terms of oil-fuel replacement, this is not always obvious for other projects where the decarbonised or renewable gases will be directly injected into the grid. Therefore, the benefits that ENTSOG has calculated for ETR projects must be considered as the minimum emission savings these projects could actually contribute to, by replacing methane.

A dedicated Annex is published as part of TYNDP 2020 project assessments that includes the results of the ETR evaluation, and the way benefits were calculated.

3.2.3.3 Emission savings monetisation

The allocated emission savings benefits have been monetised according to the following reference sources:

Saving	Source
CO_2 emission reduction	TYNDP 2020 scenarios CO_2 prices.
NO_X reduction	Jasper "Economic Analysis of Gas Pipeline Projects" (2011) values per country-level and EU-23 average value in case of no data vailability*. Values have been converted from fuel replaced (in GJ) in EUR as per Jasper input.
SO_2 reduction	
PM 2.5 reduction	

* http://www.jaspersnetwork.org/display/for/Economic+Analysis+of+Gas+Pipeline+projects

Table 9: Reference source for monetisation of CO_2 emission savings and other externalities.

3.2.3.4 Additional benefits

As part of TYNDP 2020 PS-CBA, promoters had the possibility to further complement this assessment by providing additional consideration on the project impact on sustainability if not already considered by ENTSOG assessment.

Benefits provided by the promoter are included in the tables in section C.3. of each PS-CBA Project Fiche in the dedicated line "Additional benefit (Promoter)".

3.2.3.5 Environmental Impact

Any gas infrastructure has an impact on its surroundings. This impact is of particular relevance when crossing some environmentally sensitive areas. Mitigation measures are taken by the promoters to reduce this impact and comply with the EU Environmental acquis[26].

More details are available in the 2nd CBA Methodology in chapter 3.2.2 Indicators[27].

Provided information are included in the published TYNDP 2020 Project Fiches.

3.2.4 CAPEX/OPEX

Costs represent an inherent element of a CBA analysis. According to Annex V(5) of the Regulation, "the cost-benefit analysis shall at least take into account the following costs: capital expenditure, operational and maintenance expenditure over the technical lifecycle of the project and decommissioning and waste management costs, where relevant".

The following cost information were collected for TYNDP 2020:

- **Capital expenditure** (CAPEX), including initial investment costs and replacement costs (if any)
- **Operational and maintenance expenditure** (OPEX)

More information is available in the guidelines described in the 2nd CBA Methodology.

All cost data is considered at constant (real) prices.

As part of the TYNDP and PCI processes, constant prices refer to the year of the TYNDP project collection.

26 Directive 2001/42/EC of the European Parliament and of the Council of 27 June 2001 on the assessment of the effects of certain plans and programmes on the environment: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32001L0042&from=EN

27 https://www.entsog.eu/sites/default/files/2019-03/1.%20ADAPTED_2nd%20CBA%20Methodology_Main%20document_EC%20APPROVED.pdf

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LIST OF **ABBREVIATIONS**

ACER	Agency for the Cooperation of Energy Regulators
Bcm/Bcma	Billion cubic meters/Billion cubic meters per annum
CAM NC	Capacity Allocation Mechanism Network Code
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CIS	Commonwealth of Independent States
DIR-73	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.
EBP	European Border Price
EC	European Commission
EIA	Energy Information Administration
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	European Trading Scheme
EU	European Union
FEED	Front End Engineering Design
FID	Final Investment Decision
GCV	Gross Calorific Value
GIE	Gas Infrastructure Europe
GHG	Greenhouse Gases
GLE	Gas LNG Europe
GRIP	Gas Regional Investment Plan
GSE	Gas Storage Europe
GWh	Gigawatt hour
e-GWh	Gigawatt hour electrical
GQO	Gas Quality Outlook
HHI	Herfindahl-Hirschman-Index
H-gas	High calorific gas
HDV	Heavy duty vehicles
HGV	Heavy goods vehicles
IEA	International Energy Agency
IP	Interconnection Point
ktoe	A thousand tonnes of oil equivalent. Where gas demand figures have been calculated in TWh (based on GCV) from gas data expressed in ktoe, this was done on the basis of NCV and it was assumed that the NCV is 10 % less than GCV.
L-gas	Low calorific gas
LDV	Light Duty Vehicles
LNG	Liquefied Natural Gas

mcm	Million cubic meters
MMBTU	Million British Thermal Unit
MS	Member State
MTPA	Million Tonnes Per Annum
mtoe	A million tonnes of oil equivalents. Where gas demand figures have been calculated in TWh (based on GCV) from gas data expressed in mtoe, this was done on the basis of NCV and it was assumed that the NCV is 10 % less than GCV.
MWh	Megawatt hour
e-MWh	Megawatt hour electrical
NDP	National Development Plan
NCV	Net Calorific Value
NERAP	National Energy Renewable Action Plans
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of the Petroleum Exporting Countries
OPEX	Operational expenditure
PCI	Project of Common Interest
P2G	Power-to-Gas
REG-703	REGULATION (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules
REG-347	Regulation (EU) No 347/2013 of the European Parliament and of the council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009
REG-715	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.
REG-SoS	Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.
RES	Renewable Energy Sources
SIF/SWF	Seasonal Injection Factor/Seasonal Withdrawal Factor
SoS	Security of Supply
Tcm	Tera cubic meter
TSO	Transmission System Operator
TWh	Terawatt hour
e-TWh	Terawatt hour electrical
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage (facility)
WI	Wobbe Index

COUNTRY CODES (ISO)

AL	Albania
AT	Austria
AZ	Azerbaijan
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
BY	Belarus
CH	Switzerland
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
DZ	Algeria
EE	Estonia
ES	Spain
FI	Finland
FR	France
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
LY	Libya
MA	Morocco
ME	Montenegro
MK	FYROM
MT	Malta
NL	Netherlands, the
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
RU	Russia
SE	Sweden
SI	Slovenia
SK	Slovakia
TM	Turkmenistan
TN	Tunisia
TR	Turkey
UA	Ukraine
UK	United Kingdom

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