Assessment of Policy Options

Justification document for

Framework Guidelines on rules regarding Harmonised Transmission Tariff structures

Ref: ACER-JD-2014-G-01

31 March 2014

Agency for the Cooperation of Energy Regulators
Trg Republike 3
1000 Ljubljana - Slovenia

This document presents the analysis underpinning the policy decisions taken in the Framework Guidelines on rules regarding Harmonised transmission tariff structures. The analysis begins with the problem definition, then identifies policy options, and finally assesses these options against a set of objective criteria. The analysis is supported by the evidence collected from a wide range of industry stakeholders during the framework guideline process.

The Assessment of Policy Options is initiated by the Agency and is passed on to ENTSOG on 31 March 2014. ENTSOG is invited to work on further evidence and on deepening the analysis during the development of the Network Code.

In particular, ENTSOG is invited to contribute to further elaborating the present justification document by:

- Improving the accuracy and comprehensiveness of figures provided in the document, particularly regarding tariff adjustments (Figure 15), comparison between domestic capacity and domestic revenue (Figure 19), and variable costs in the system (Figure 25);
- Further analysing the circumstances influencing the choice of a cost allocation methodology, with a view to the influence of inputs on the tariff variance (Theoretical section of Annex G);
- Enhancing countries case studies (Annex M and Annex N) by improving the accuracy and comprehensiveness of technical inputs.

In addition, ENSTOG and its members are invited to expand the current justification document with additional evidence, underpinning all the points where the Network Code developed by ENTSOG completes the policy options detailed in the Framework Guidelines.

Table of Contents

1 Introduction

The European Union's Third Energy Package (hereinafter 'Third Package') is a legislative package designed to create an internal market for gas and electricity in the European Union. The package was proposed by the European Commission in September 2007, and adopted by the European Parliament and the Council of the European Union in July 2009. It entered into force on 3 September 2009.

The Third Package provides the legal instruments to set up detailed rules for achieving the integration of European gas markets. Within this process, the European Commission ('the Commission') may request the Agency for the Cooperation of Energy Regulators ('the Agency') to prepare framework guidelines. The European Network of Transmission System Operators for Gas ('ENTSOG') is then responsible for drafting network codes (following an invitation by the Commission), aligned with the framework guidelines prepared by the Agency. The Network Code is delivered by ENTSOG to the Agency, which assesses its compliance with the framework guidelines. Once the Agency is satisfied that the Network Codes is in line with the framework guidelines, it will recommend its adoption to the Commission, via the comitology process[1].

As stated in the first recital of Directive 2009/73/EC[2] (hereafter the 'Gas Directive'), "the internal market in natural gas, (…) aims to deliver real choice for all consumers of the European Union, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices, and higher standards of service, and to contribute to security of supply and sustainability."

Producing Framework Guidelines on rules regarding Harmonised transmission tariff structures (hereafter 'the FG') falls in line with this endeavour as the FG aim to reduce cross-border barriers to trade by harmonizing tariff structures in the EU. Clear and streamlined regulatory measures on tariffs help consumers, in particular businesses, to understand the choices available on the market and allow suppliers to develop more competitive pricing policies.

Following the three framework guidelines issued by the Agency - one on capacity allocation mechanisms ('FG CAM', 2011), a second one on Balancing ('FG BAL', 2011) and a third one on Interoperability and Data Exchange Rules ('FG IOP/DE', 2012), the respective network codes have been developed or are being developed.

The internal gas market consists of complementary markets across the gas supply chain, including capacity and commodity markets, where improving liquidity represents a key regulatory objective. Standard products shall improve the efficient functioning of these markets and of the gas sector as a whole.

In this perspective, efficient and cost-reflective gas transmission tariffs for standard capacity products are of primary importance. The FG shall cover tariff issues for all the entry-exit points, with among other things, the aim to prevent possible price discrimination between cross-border and domestic points.

Following its development through the course of 2012 and 2013, in November 2013 the Framework Guidelines on rules regarding Harmonised transmission tariff structures were adopted by the Agency and presented to the European Commission. In December 2013, the Commission formally requested ENTSOG to prepare a Network Code on transmission tariff structures by the end of 2014.

---

[1] When the Third Package is amended according to the *Lisbon Treaty* (Treaty on the Functioning of the EU), network codes will become delegated acts, where the committee voting taking place today (Article 28 of the Gas Regulation) will not have a formal role anymore.

[2] 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, OJ L 211, 14.8.2009, p.94.

Regulation (EC) No 713/2009 (the 'Agency Regulation')[3] requires that the Agency indicates the way in which stakeholders' views were taken into account in the FG development process. Two evaluations of responses summarising industry views on the two FG public consultations were published in this regard.

This justification document goes beyond this requirement and, according to the principles of Better Regulation[4], provides the justification for the most important policy choices.

The format for the document is aligned with the Commission's Impact Assessment Guidelines. It is intended both to facilitate ENTSOG's work in preparing the Network Code, and support the adoption of the Network Code by the Commission via the comitology process.

2 Procedural issues and consultation of interested parties

2.1 Organisation and timing

The preparatory work on the FG began in 2010. Following the request of the 17th Madrid Forum, ERGEG/CEER started working on tariff issues in order to prepare the ground for framework guidelines on tariff issues. The Agency took over the preparatory process at the 20th Madrid Forum in September 2011, and in February 2012, launched a public consultation on the scope and main policy options for the FG.

In June 2012, the Commission formally invited the Agency to develop framework guidelines on rules regarding Harmonised transmission tariff structures for gas. An extensive development and industry consultation process began, which ended with the submission of the final FG to the Commission by ACER in November 2013. The Commission initially intended the FG development process to take six months. This timeline was extended on two occasions for the following reasons:

- Firstly, in December 2012, to allow the Agency more time to consider the impact on the FG of the developing work on CAM incremental capacity arrangements[5] as well as to evaluate stakeholders' input on complex issues including cost allocation methodologies and revenue recovery mechanisms; and
- Secondly, in March 2013, following the Commission's invitation that the Agency further develop the FG chapter on cost allocation methodologies and the determination of the reference price to address its concerns over the level of harmonisation anticipated.

Following the requirements of Article 6(3) of Regulation (EC) No 715/2009 (the 'Gas Regulation') [6], stakeholders' views were collected on several occasions. Three public consultations, one on scoping and another two on the draft FG, as well as an Open House on policy changes, ensured that stakeholders' views were considered and integrated in the policies proposed by the Agency. Key publications, consultations and industry stakeholder events held in the FG development process are listed below:

- 26-27 September 2011: Madrid Forum requests the Agency to scope the project

[3] Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators, OJ L 211/43, 14.08.2009.
[4] http://ec.europa.eu/smart-regulation/better_regulation/documents/brochure/brochure_en.pdf
[5] Principles and processes for the identification and allocation of incremental capacity were initially detailed by CEER, before being handed over to ACER in the second half of 2013. See CEER Blueprint on Incremental Capacity, 23 May 2013
[6] 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 1775/2005, OJ L 211/36 14/08/2009.

- 8 February 2012 – 26 March 2012 : Public consultation on the scope of the FG[7]
- 20 February 2012 : ACER workshop on the scope of the FG
- 29 June 2012: Invitation letter from the Commission to ACER to start drafting the FG
- 5 September 2012 – 5 November 2012: Public consultation on the draft FG and accompanying documents[8]
- 18 September 2012: ACER workshop on the draft FG
- 17 December 2012: ACER request for deadline extension, subsequently granted by the EC
- 23 January 2013: ACER workshop on the draft FG, for discussion of proposals for changes compared to the initial draft FG issued in September 2012
- 4 February 2013: ACER "Open House", 1-11 February 2013: written comments from stakeholders
- 15 March 2013: Commission letter imitating further improvements in particular in relation to cost allocation
- 16 April 2013: ACER's Board of Regulators informally endorses the draft FG without the chapter on cost allocation and determination of the reference price
- 18 July-17 September 2013: Public consultation on the chapter on cost allocation and determination of the reference price including incremental tariff issues, other issues relating to publication requirements[9]
- 7 August 2013: ACER Q&A session on the materials published for consultation
- 3 September 2013: ACER workshop on cost allocation methodologies and incremental tariff issues
- 29 November 2013: Final FG delivered to the Commission

2.2 External expertise

An Expert Group was set up after a call for applications by the Agency in February 2012 consisting of 11 experts and 3 observers (see the list of experts in Annex A).

Studies – Two major consultancy reports supported the process. The study commissioned by CREG and executed by the Brattle Group (2012) evaluated the policy options for gas transmission tariff structures. The Frontier Economics (2013) report commissioned by the Agency provided an assessment of the policy options on Incremental Capacity for EU gas transmission[10]. The latter report assesses the impacts of the major incremental capacity tariff options.

Further studies, like the Think report financed by the Commission[11] (the 'THINK study') and the study of Entry-exit regimes in gas produced by KEMA in 2013 for the Commission[12] either fed into the initial policy and problem identification discussions or directly into the discussions of FG development.

3 Problem identification and context[13]

To determine policy options for the FG (the solutions), an understanding of the context, nature and extent of the problem or problems the FG aims to tackle is essential.

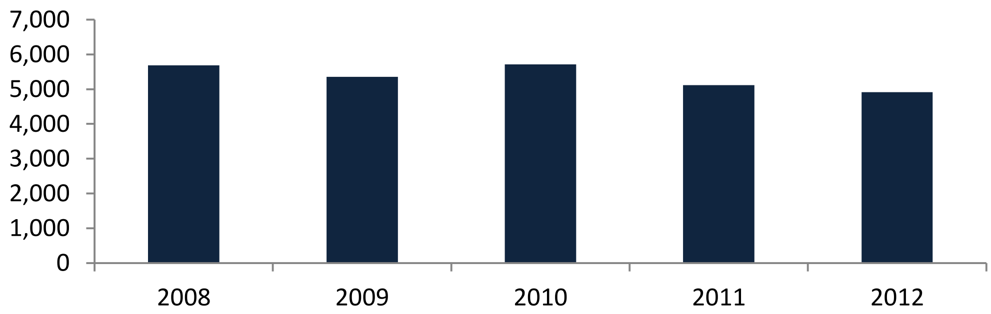
[7] 38 responses received. See section 9 *infra* for full reference.
[8] 43 responses received. See section 9 *infra* for full reference.
[9] 41 responses received. See section 9 *infra* for full reference.
[10] See section 9 *infra* for full reference.
[11] http://think.eui.eu - Electricity and Natural Gas Transmission Grid Tariffication - See section 9 *infra* for full reference
[12] http://ec.europa.eu/energy/gas_electricity/studies/gas_en.htm
[13] This section is largely based on the Agency's and CEER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012 ('Market Monitoring Report'). See section 9 *infra* for full reference.

3.1 Context

In 2012, the EU-27's natural gas demand[14] was 4,910 TWh (Figure 1). Of this, consumption in the household segment represented a 38-40% share[15]. 2012 demand represents a 4.1% reduction on 2011, yet retail gas prices continued to increase[16].

Figure 2 and Figure 3 show, for households and industrial users respectively, the average price paid, combining both commodity and capacity charges, in 2012 (before and after tax) per kWh of gas consumed. The proportion of total end-user EU gas prices made up of gas transmission charges ranges from 5% to 10% in most cases[17].Together, the data demonstrates the extent and materiality of gas consumption in the EU economy.

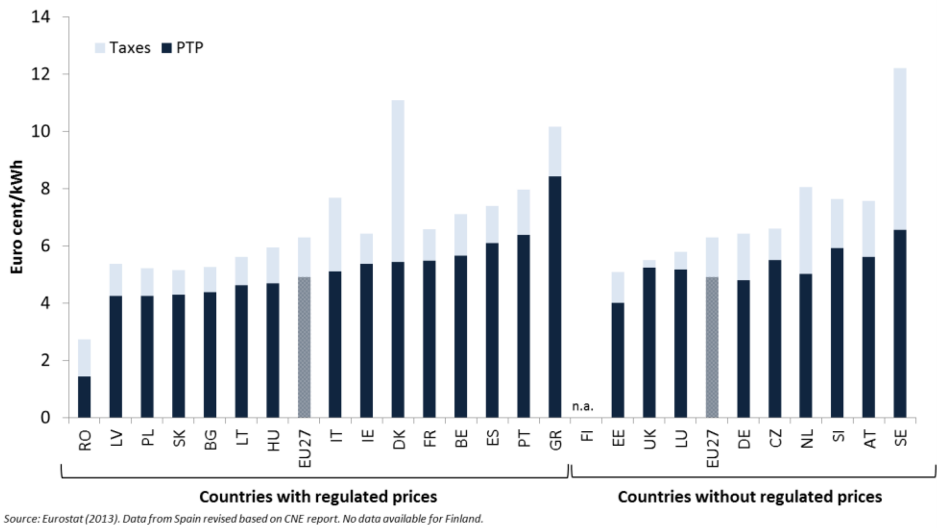
Figure 1: Gas demand in the EU-27 – 2008 to 2012 (TWh)



Source: ACER, based on Eurostat (26/6/2013)
Note: Gross inland gas consumption (GIC).

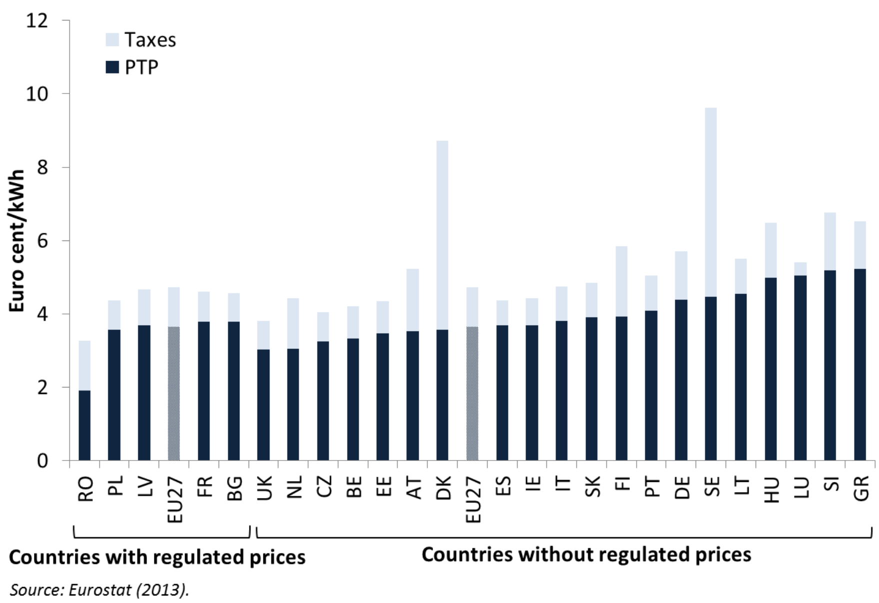
[14] Gross inland annual consumption. Calculations based on Eurostat monthly data in Terra Joule and as Gross Calorific Value (TJ GCV) as of 15 May 2013. Eurostat data are provisional for some countries.
[15] IEA Energy, spring 2013.
[16] Agency's and CEER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012.
[17] TSO charges only; distribution comes on top. Charges can also vary, depending on the nature of flow paths.

Figure 2: Gas POTP[18] and PTP[19] for households – EU-27 – 2012 (euro cents/kWh)



Source: Eurostat (30/5/2013)
Note: Data for Spain were revised based on information from CNE. No data available for Finland. Member States ('MS') are ranked according to PTP.

Figure 3: Gas POTP and PTP for industrial consumption – EU-27 – 2012 (euro cents/kWh)



Source: ACER, based on Eurostat (30/5/2013)
Note: MS are ranked according to PTP

The Gas Target Model (2011)[20], developed by the Commission for European Energy Regulators (CEER), explains the regulatory context in which the FG are developed. Based on legal and economic analysis, via the model, European

---

[18] Post-Tax Total Price
[19] Pre-Tax Total Price

regulators developed a vision for market integration for a horizon of ten years. This vision foresees the integration of European gas markets by combining entry-exit zones with virtual hubs and suggests that competition in wholesale markets is based on the development of liquid hubs across Europe, at which gas can be traded. The integration of markets shall be served by the efficient use of infrastructures, including non-discriminatory access arrangements, in order for:

- Competition to develop in commodity markets, allowing market players to freely ship gas between market areas and respond to price signals to help gas to flow where it is valued most; and

- The network to be used efficiently, while guaranteeing adequate remuneration for network investments. The model has to allow for sufficient and efficient infrastructure investment, supporting the removal of physical congestions that hinder market integration.

3.2 The problem

The genesis of the Agency's analysis of the problem dates back to the scoping phase of the FG development process (February 2012). At the time stakeholders confirmed that, following the shift from point to point tariffs to entry / exit tariffs as required by the Third Package, they were still facing a large variety of tariff structures in the EU. The origins of these diverse structures are varied, and potentially justifiably related to factors such as the maturity of the national gas system; supply and demand characteristics; and topological considerations.

Differences of approach are not necessarily problematic where tariffs derive from an objective and transparent methodology, but inconsistent tariff structures across member states make using EU gas transmission networks for cross-border gas transportation more complex for network users. In addition, where tariff structures lack objectivity or do not reflect system costs, this can lead to inefficient use of the transmission networks, and potentially inefficient cross border gas trades[21]. Unjustifiably high transmission tariffs can negatively affect wholesale market integration, especially if wholesale market (spot or forward) price spreads across hubs fall below relevant cross-border transmission charges at any point in time.

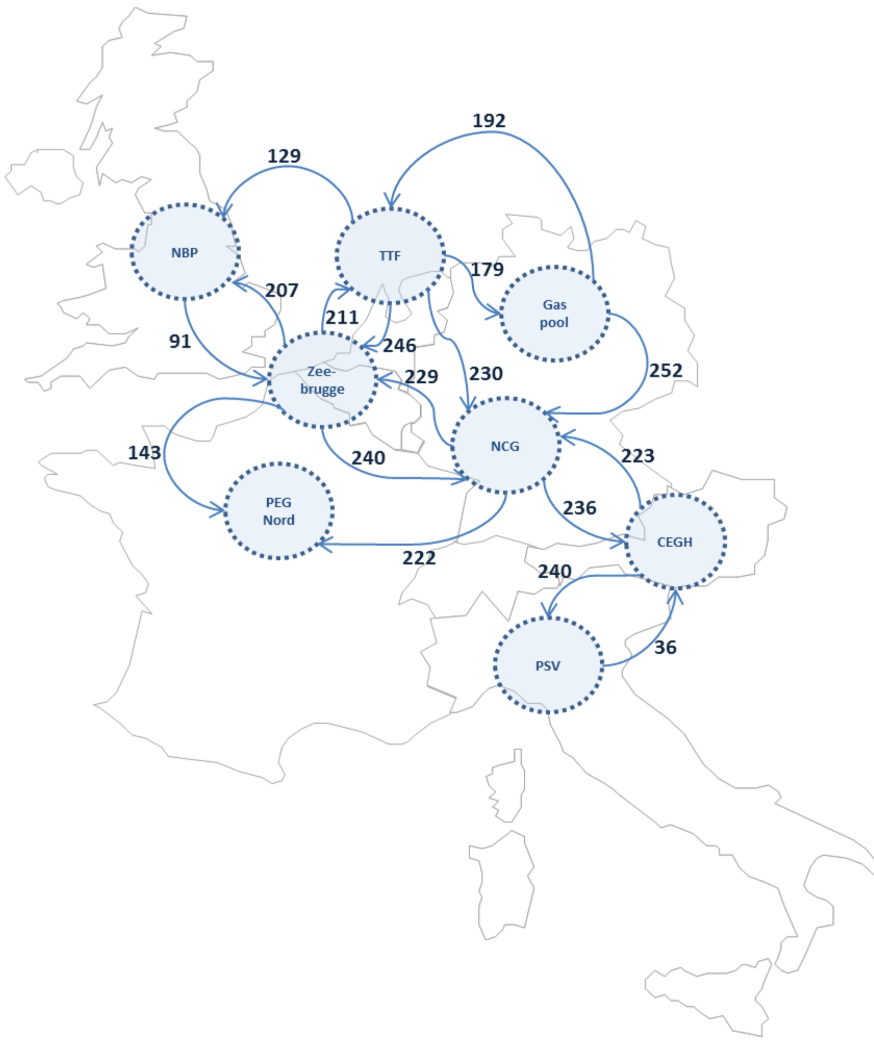
Figure 4 indicates the extent to which this was the case in 2013. As price convergence between larger and more liquid hubs, such as NBP and TTF, continues, this situation could be expected to increase in the future.

Lack of transparency, consistency, and objectivity of tariff structures, form the basis of the over-arching problem which the FG is trying to solve. The sections which follow set out the technical aspects of tariff-setting and the harmonisation problems therein.

[20] http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas_Target_Model/CD/C11-GWG-82-03_GTM%20vision_Final.pdf

[21] See Annex M

Figure 4: number of days in 2013 during which wholesale market day-ahead price spreads fell below transmission charges in EU



Source: ACER based on Platts and ENTSOG

Note: calculations do not include VAT. In the case of UK-NL and UK-BE transactions, the charges of exempted UK-Continental Interconnectors are not included.

Impact of the revenue recovery split between entry and exit points

The following section develops a simple example that illustrates the consequences of differences in entry exit cost allocation within a given network[22].

Different MS allocate the revenue recovery split between entry and exit points in different ways. When allocating costs between entry and (domestic and IP) exit points, a TSO may try to identify the actual costs associated with the entry (or exit) points. Alternatively, the costs can be allocated to entry/exit points in proportion to the booked capacity. Or thirdly, a TSO might split the costs associated with each route equally (50/50) between the relevant entry and exit points.

The latter is illustrated in Figure 5**,** where the assumed cost for the cross-border route is 10 and the cost for the domestic route is 5. In addition, 1 unit of capacity is booked along each of the cross-border and domestic routes. Suppose that for each route, 50% of costs are allocated to the entry point and 50% to the exit point. 50% of the cross-border costs (of €10) and 50% of the domestic costs (of €5) would be allocated to the entry point, resulting in a cost of (0.5 x €10) + (0.5 x €5) = €7.5 being allocated to the entry point. Total gas flows at the entry point are 2, so the unit reference price is 7.5/2 ≈ €3.8. At the cross-border exit point, the cost allocated is simply 0.5 x 10 = €5, and there is 1 unit of flow, so the price is €5. This gives a total (entry + exit) reference price for the cross-border flow of €8.8.

Table 1 illustrates the calculation. Note that €8.8 is less than the assumed cost of the cross-border route, which is €10. If instead 25% of the costs were allocated to the entry point, the costs recovered from the cross-border route would be €9.4. If more costs were allocated to the entry point, the recovered costs would be lower. In this simplified example, if 75% of the costs are allocated to the entry point, the costs recovered from the cross-border route are €8.1.

Figure 5: simplified network

Source: Brattle

[22] This example was taken from the Brattle report. See section 9 *infra* for full reference.

Table 1 Cross-border tariffs for different entry/exit splits

			% of costs allocated to entry									
			90%		75%		50%		25%		10%	
			cross-border route	domestic route	cross-border route	domestic route	cross-border route	domestic route	cross-border route	domestic route	cross-border route	domestic route
Capacity booked	[1]	Assumed	1	1	1	1	1	1	1	1	1	1
Costs:												
Total	[2]	Assumed	10	5	10	5	10	5	10	5	10	5
% allocated to entry	[3]	Assumed	90%	90%	75%	75%	50%	50%	25%	25%	10%	10%
% allocated to exit	[4]	Assumed	10%	10%	25%	25%	50%	50%	75%	75%	90%	90%
Allocated to entry	[5]	[2]x[3]	9.0	4.5	7.5	3.8	5.0	2.5	2.5	1.3	1.0	0.5
Allocated to exit	[6]	[4]x[2]	1.0	0.5	2.5	1.3	5.0	2.5	7.5	3.8	9.0	4.5
Entry tariff	[7]	See note	6.75	6.75	5.6	5.6	3.8	3.8	1.9	1.9	0.8	0.8
Exit tariff	[8]	[6]/[1]	1.0	0.5	2.5	1.3	5.0	2.5	7.5	3.8	9.0	4.5
Total tariff	[9]	[7]+[8]	**7.75**		**8.1**		**8.8**		**9.4**		**9.8**	

Notes and sources:
[7]: Sum of [5] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.

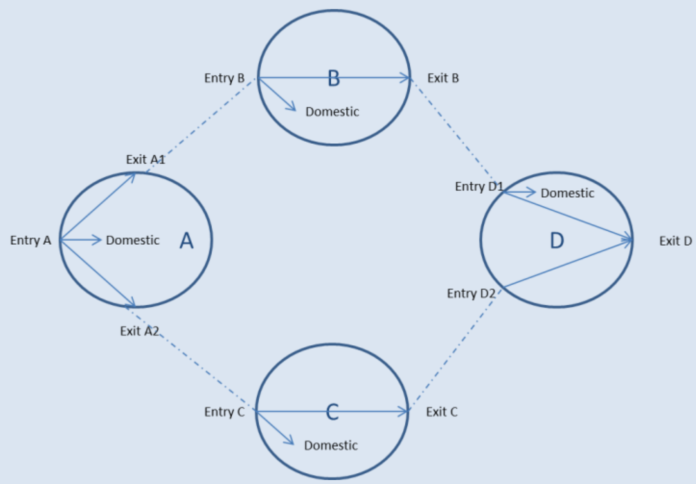
Source: Brattle

Impact of cost allocation on cross-border trade

The following example illustrates the potential impact of a chosen cost allocation methodology on wholesale market integration and trade efficiency. This is a simplified representation of the influence of transmission cost allocation choices on trades between hubs in the context of multiple jurisdictions.

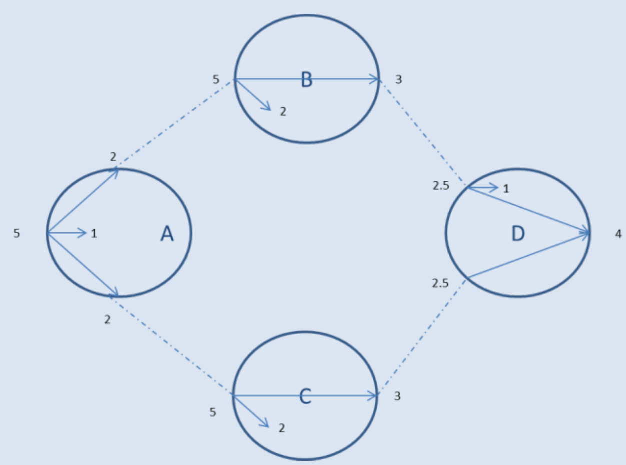
Let us consider 4 networks, A, B, C and D. Gas flows from A to D via either B or C. Exit A1 and Entry B are directly connected and therefore constitute one IP. The same applies, respectively, to Exit A2 and Entry C, to Exit B and Entry D1, and to Exit C and Entry D2.

Figure 6: adjacent networks



For each network, the allowed revenue consists of 10 units, to be allocated between entries, domestic and exit points.

Figure 7: 1st allocation of costs over networks A, B, C and D

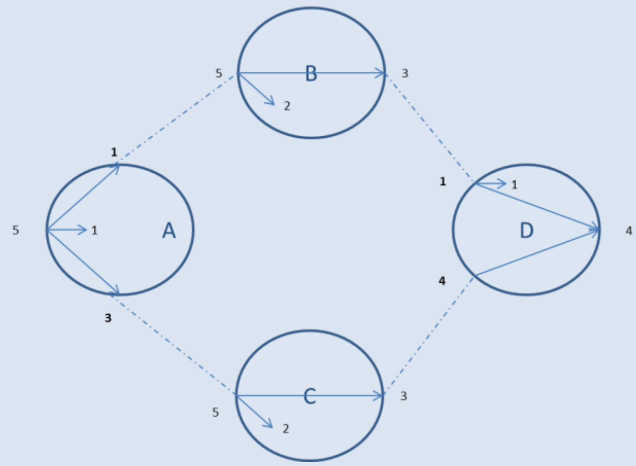


In the first situation, costs are equally divided among Exits A1 and A2 of network A (2 units), and Entries D1 and D2 of network D (2.5 units), while networks B and C allocate costs identically (5 units to entries, 3 to exits).

As a result, the route from Entry A to Exit D bears identical costs via both networks, B and C:

Entry A+ Exit A+ Entry B/C+ ExitB/C+ Entry D + Exit D=5+2+5+3+2.5+4=**21.5**

Figure 8: 2nd allocation of costs over networks A, B, C and D



In the second situation, the cost allocation remains unchanged for networks B and C. Costs at exit A1 are lowered (1 unit), compensated by an increase of costs at exit A2 (3 units). Similarly, lower costs at entry D1 (1 unit) are compensated by higher costs at entry D2 (4 units).

The resulting cost from Entry A to Exit D via network **B** becomes:

Entry A+ Exit A1+ Entry B + Exit B + Entry D1 + Exit D=5+1+5+3+1+4=**19**

The resulting cost from Entry A to Exit D via network **C** becomes:

Entry A+ Exit A2+ Entry C + Exit C + Entry D2 + Exit D=5+3+5+3+4+4=**24**

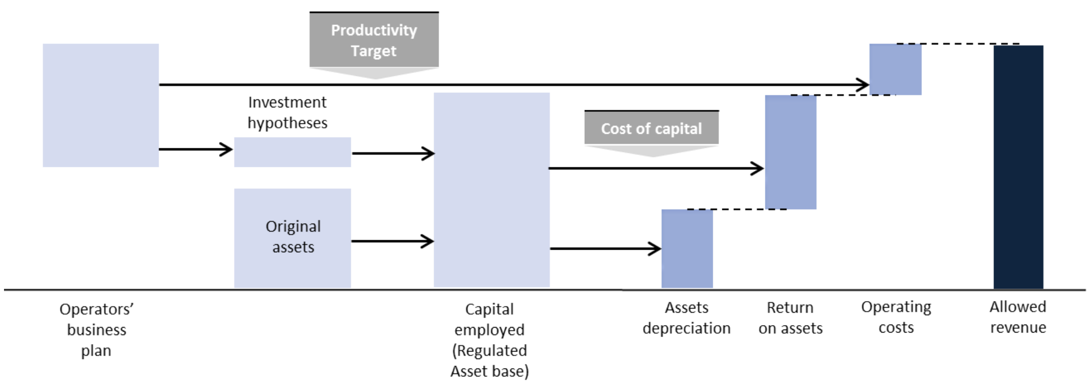
In the first situation, although resulting from different choices made regarding the cost allocations at networks A and D, the transportation costs between hub A and hub D remain the same, whether crossing via networks B or C. In the second case, however, the route via network B is favoured. As an outcome, in situations where transmission costs would be the factor limiting transactions, the liquidity of hub B would increase, if transportation costs would come favourable on network B, at the expense of the liquidity of hub C, all other factors, including wholesale prices being unchanged. **If the differences in the transmission costs do not reflect underlying costs, an inefficient use of transmission assets is promoted with distorting effects on hub activity.**

3.3 Tariff level and regulated revenues

The overall tariff level is derived from the allowed or expected regulated revenue, understood as the maximum level of revenues set or approved by the NRA that a TSO is permitted to collect within a defined period of time (typically a year) for providing the regulated service. Different approaches for determining the allowed revenues (or costs) exist in the EU. These approaches can be categorised as cost-of-service (or rate-of-return) regulation, and price/revenue cap (or incentive) regulation. The determination of the allowed revenues of a TSO depends on its specificities and is determined at a national level, in line with the subsidiarity principle (see Section 5.4 below). Annex F provides a comparative description of the both approaches.

Under a price or revenue cap approach, the national legal and regulatory framework defines the main categories of costs to be taken into account by the regulator. These costs include capital costs (composed of depreciation of assets and return on fixed capital), and operating costs. The calculation of these two cost components is based on the Regulated Asset Base (RAB), which may take into account the investment projections of the operators. Figure 9 Figure 9below includes possible elements constituting the allowed revenue; it should however be noted that variants are possible (i.e. regarding the use of the operators' business plan as an input, or the approach to new investments).

Figure 9: Composition of the allowed revenue



Source: CRE

3.4 Tariffs

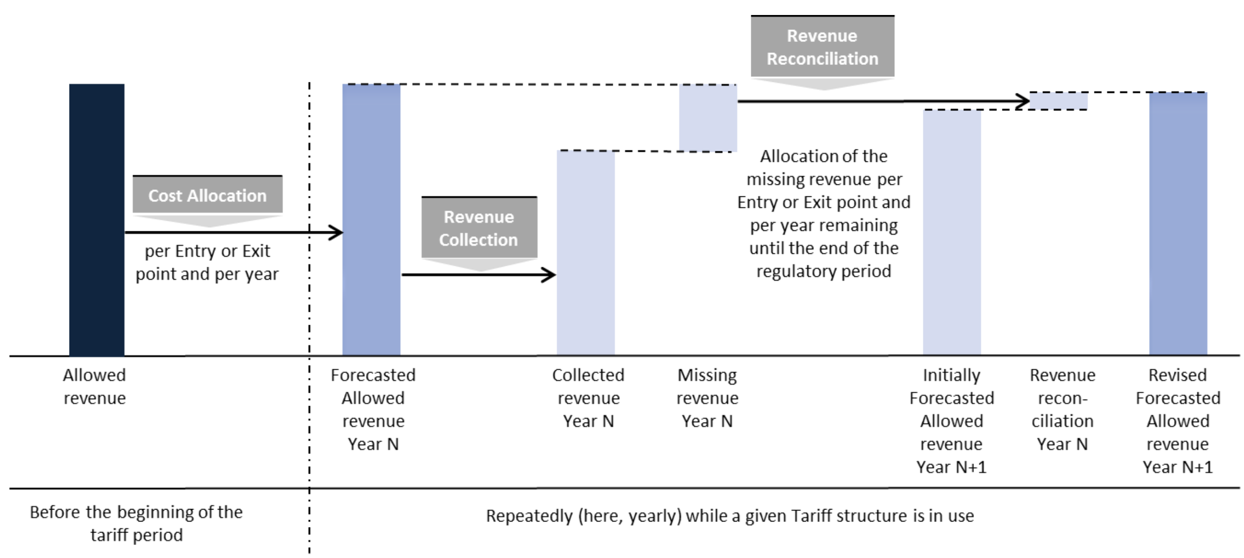
Transmission tariffs are charges levied on transmission network users by TSOs for using transmission services[23]. Transmission charges are used to recover TSOs' regulated allowed revenues. Transmission services relate to the right to flow gas onto and off an entry-exit system at a given entry or exit point. The definition of the transmission services of the Tariff FG, specified in Chapter 1 of the Framework Guidelines, is subject to further revision and justification by ENTOG in preparing the Network Code.

From a user's perspective, tariffs should reflect the cost of service, in a way that cross-subsidies are minimised between these users. From a regulatory perspective, tariffs are set so that an efficient TSO will recover its costs. The tariff calculation methodology follows four main chronological steps:

[23] The FG applies to all transmission services subject to the transmission services definition specified in Chapter 1. Transmission services includes third party access services as specified in Annex 1 of Regulation 715/2009 , and ancillary services, as specified in Article 1(14) of the Gas Directive.

- **Setting of allowed or expected revenues, along the lines indicated above**;
- **Ex-ante tariff calculation**, including the calculation of reserve prices for auction, and based on assumptions on parameters such as capacity bookings;
- **Revenue collection** based on capacity sold or volumes transported;
- **Ex-post reconciliation,** if applicable, aimed at covering the gap between the foreseen and actually collected revenues, so that any unintended under- or over-recovery of TSO revenues can be addressed. These elements, their interaction and chronology are summarised in Figure 10 below.

Figure 10: Evolution of the Allowed revenue with the successive reconciliations of the regulatory account



Source: ACER

3.5 Tariff structure

The core features of the tariff structure are:

- **Tariff setting period**[24] **–** this is the period of time over which a given tariff will apply. In most member states tariffs are set annually, but in some member states tariffs are determined at the start of the regulatory period for up to four years. Due to the materiality of transmission charges, advance notice on changes to the level of tariffs is important to network users.
- **Capacity/commodity split**[25] **–** this is an ex-ante assessment of the proportion of allowed revenues to be recovered from capacity charges (and therefore subject to the cost allocation methodology), and the proportion to be recovered from flow based charges and therefore subject to a GWh/day charge.
- **Entry/exit split**[26] **–** in most member states this is an ex-ante assessment of the proportion of allowed revenues to be recovered from entry charges and the proportion to be recovered from exit charges. In some member states the entry/exit split is determined as an output of the cost allocation methodology.

[24] Development and evaluation of harmonised measures are subject to an impact assessment developed in the NC process.
[25] Later discussed in connection to cost allocation methodologies
[26] Later discussed in connected to cost allocation methodologies

- **Cost allocation methodology** - this is the methodology which determines the share of the TSO's (allowed) revenues which is to be collected from the expected sale of transmission services at every entry or exit point;
- **Reference price -** this is the primary output of the cost allocation methodology. Under most cost allocation methodologies, reference prices include a multiplicative or additive scaling in order to meet the allowed revenues, and/or the application of 'secondary adjustments' such as equalisation or benchmarking. Reference prices form the basis of the capacity tariffs levied on entry and exit capacity.
- **Revenue reconciliation mechanism**[27] - this is the method by which any under/over recovery of collected revenues relative to allowed revenues is reconciled.
- **Reserve price -** this is the value of the annual capacity product for each entry and exit point calculated after the application of the cost allocation methodology. Where auctions are used, the reference price is used as the reserve price for the annual capacity product and the basis for setting the reserve prices for capacity products of shorter duration and for interruptible capacity. Where auctions are not used to allocate capacity the reference price is used as the regulated price for the annual capacity product.
- **Multiplier** – this is a factor to calculate reserve prices for non-yearly standard capacity products applied to the proportional yearly reference price, before the application of a seasonal factor. Multipliers can be used to incentivise short or long term capacity bookings or to optimise efficient revenue recovery, promoting an efficient use of the system.
- **Seasonal factor –** this is the factor that is applied to reserve prices in order to facilitate the efficient utilisation of the infrastructure in different seasons of the year**.** Seasonal factors can be applied to promote efficient capacity utilisation at times of peak demand.
- **Payable price -** this is the price to be paid, at the time of use, by the network user to the TSO, for capacity. The payable price may be subject to reference price changes relative to the prevailing price at the time of capacity booking. Where capacity auctions are used to allocate capacity, the payable price may also include premium bid in excess of the reference price.

The multiplicity of approaches to tariff structures currently adopted among member states is reflected in the differences of approach to each of these elements. Where networks exhibit different characteristics, different approaches may be justified. Each of the tariff structure components listed may apply in more than one way and achieve the objectives of the Third Package. But, at an EU wide level, the extent of the divergence of approaches, and the complexity and lack of transparency could limit network users' choices, particularly where the approaches taken result in cross subsidies or inefficient transmission capacity tariff signals, which contradict those objectives.

The differences of approach between member states to each of the elements of tariff structures can result in significant differences in the level of charges faced by network users, both for ostensibly similar entry and exit points within an entry-exit zone, and for seemingly similar entry points in neighbouring entry-exit zones[28]. The choices that network users may make about system utilisation as a consequence of this, have the potential to undermine the efficiency of EU gas trades. The section that follows delineates the extent of the divergence of approach between member states in more detail.

[27] In price cap systems, no revenue recovery mechanism is used and the volume risk is borne by the TSOs
[28] See a theoretical analysis in Annex **C**

4 Extent of the Problem

As noted above, significant variations in transmission tariff structures are currently observed across Europe.

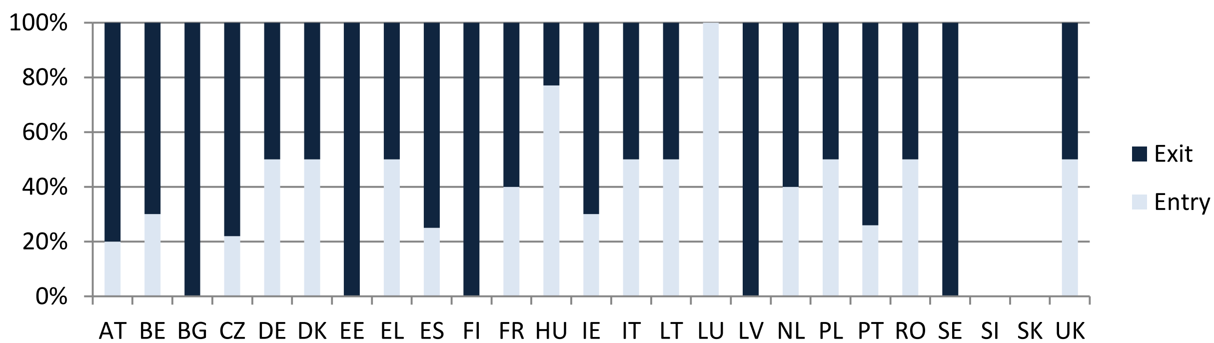
4.1 Tariff variations across Europe

Based on the map displaying cross-border tariffs by IP (see Figure 12 below), one can observe the following:

- In the majority of EU countries, TSOs now apply entry/exit transmission charging models.
- Regarding the way charges are calculated, entry/exit tariffs either result from revenue recovery objectives or are determined by the application of a cost-allocation methodology centred on underlying cost drivers. An overview of the approaches to tariff calculation and entry/exit recovery splits in use in 2012 is given in Table 2 below.
- Concerning the entry/exit split:

  A majority of European countries (20) apply charges at both entry and exit points. However, Figure 11 shows a great variation in the split between revenues recovered at both points. 8 countries apply a strict 50/50 split, 5 rely fully on exits, 3 apply roughly a 20/80 entry/exit split, 1 applies an 80/20 entry/exit split, and 1 country relies fully on entries. As a general trend, it could be noted that 21 countries recover half or more of the revenue from exit points, and 13 countries recover 60 or more of the revenue from exit points.

Figure 11: Entry-exit split applied in Europe



Source: ACER & Kema Entry/Exit study

  In countries where TSOs apply a 50/50 entry/exit split at least on a preliminary basis as an input reference, (e.g. some TSOs in Germany, Poland and Slovakia), show more comparable charges between their entry and exit points. In some other countries, the NRA or the TSO pre-sets charges in such a way that revenue is recovered to a larger extent from exits than from entries – this is the case in Austria, Spain and the Czech Republic. Different entry/exit splits can stimulate or privilege certain flow directions, but are not wrong per se if objectively and transparently determined.

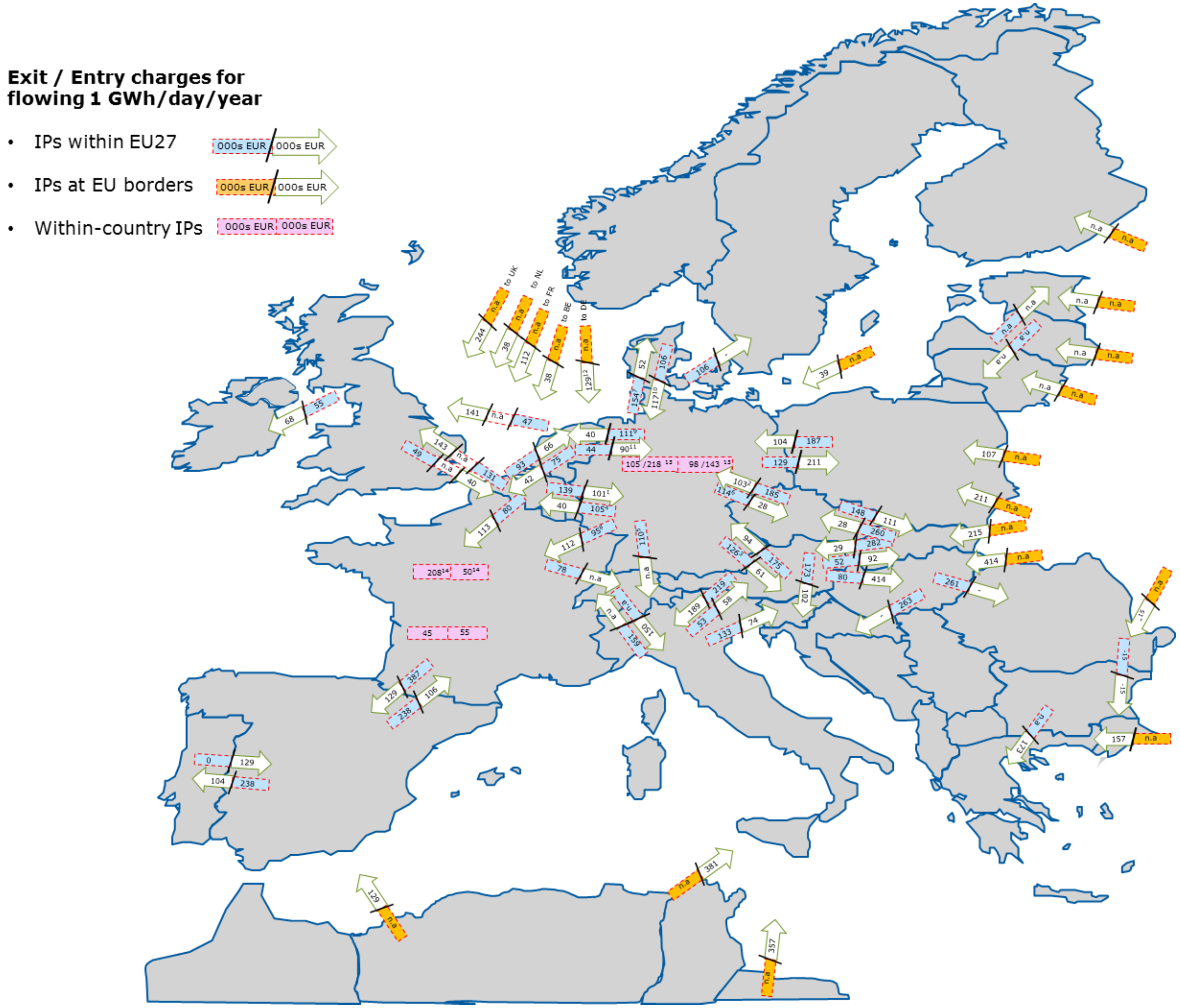
- The larger the domestic gas transportation network, and the less numerous the number of cross-border points, the higher the resulting IP tariff (e.g. in France, Italy, and Spain). This does not necessarily imply that the implied per km transportation charge will be higher. The fact that offshore cross-border interconnection point prices are usually set at higher levels might be due to comparably more expensive underlying investments. However, in the absence of cost data, this cannot be demonstrated.
- No data was obtained for Baltic IPs, for exempted pipelines (such as the IUK interconnector and BBL), for countries with cross-border auctions (such as Switzerland), and for separate transmission lines used for the purpose of transit (such as those in Romania and Bulgaria).

A few particular cases are worth highlighting:

- Portugal does not charge exit fees at its IPs with Spain[29], on the basis that flows from Portugal to Spain are mainly backhaul. Sweden, on the contrary, does not apply entry tariffs (these are paid concurrently with Denmark's exit capacity) and only charges at domestic exits[30].
- In some cases, remarkable differences can be found in Germany by IP and TSO. This influences the price spread from which a shipper can profit when trading between the same pair of hubs, depending on the TSO and/or IP being used.
- Austrian TSOs' exit charges towards Italy are higher than those applied to other bordering countries. Further transparency over the cost allocation methodology is necessary to allow assessing these differences in tariff levels.

[29] This entry/exit split can arguably enhance Iberian market integration, but it is still to be coordinated by Spain and Portugal in order to avoid tariff distortions.
[30] Sweden does not have cross-border exits.

Figure 12: Average gas transportation charges through the EU-27 borders



Notes:

At those cross-border points featuring more than one IP – but with dissimilar tariffs - a single charge per border was estimated as the weighted average of charges according to offered capacity per IP and/or distinct TSO. More information can be found in the Annex on EU 27 IP tariffs.

For example, cross-border flows in Germany can attract different charges, depending on the IP and/or TSO at the same IP. In Germany, cross-border tariff ranges for the assumed 1GWh/day/year flow may vary as follows (min/max in thousand EUR):

[1] BE to DE: 72/108
[2] CZ to DE: 69/138
[3] DE to AT: 86 /161
[4] DE to BE: 59 /128
[5] DE to CH: 68 /151
[6] DE to CZ: 105 /128
[7] DE to DK: 140 /161
[8] DE to FR: 87 /128
[9] DE to NL: 100 /140
[10] DK to DE: 109 /182
[11] NL to DE: 40/123
[12] NW to DE: 108/141

"DE" above is used to refer to flows to/from Germany, although – more precisely - actual flows go to and from either German domestic zone (NCG or GASPOOL).

[13] Range of min/max E/E charges to flow gas between TSO zones in Germany.

[14] North to South/South to North; single E/E payment.

Between TIGF / GRTgaz Sud zones. Entry and Exit payments.

[15] Transit charges, independent of transmission charges.

Charges for simulated flows were estimated on the basis of yearly contract duration, using units of measurement published by TSOs. In those cases where tariff units of measurement were not published on a yearly basis, a direct conversion was performed. At some IPs, different tariffs could apply to different capacity contracting periods, but this was not considered in this year's exercise. More details can be found in the Annex on EU27 IP tariffs.

Source: Agency analysis based on TSO and NRA data – See ACER 2012 Market Monitoring Report, page 194

Note: Simulation of cross-border charges for flowing 1 GWh/day/year by Entry/Exit IP, based on published 2013 tariffs (in thousand euros).

4.2 Cost allocation regimes

Table 2 summarises the main aspects of the tariff systems in place across the EU-27[31], except Cyprus and Malta, which had no commercial gas sectors, at the end of 2012. Given that the Network Code on tariffs is still in development, member states have no obligation to incorporate EU-wide provisions[32] at this stage. However, the table provides some indication on the status quo, as well as actions that will be needed in the future in order to harmonise transmission tariff methodologies. The comparison is mainly based on the KEMA/COWI (2013) study on entry/exit regimes, as well as on NRA input. From the table it is apparent that, although the majority of member states apply an entry/exit regime, there is considerable heterogeneity in the implementation of tariff regimes, in terms of:

- The applied entry/exit split;
- The applied capacity/commodity split;
- The approach to locational capacity pricing signals;
- The methodology applied (distinct from postage stamp);
- The applicable regulation/ contracts in relation to transit lines.

The differences were noted by the respondents to the public consultation launched by the Agency. Difficulties in accessing information at member state level were highlighted in the Scoping consultation, where stakeholders requested a review of the cost allocation methodologies applied.

In this context the Agency has reviewed the cost allocation methodologies, tariff structures and transparency provisions for tariffs to answer to the concerns of stakeholders and provide a framework for aligning national provisions to the objectives and the E/E requirements of the Third Package.

[31] Data collection covers 2012 and does not include Croatia.

[32] The provisions established by the 3rd Package are: tariff transparency, cost reflectiveness, and no determination of fixed paths (no point-to-point charging). These are already mandatory for all MS.

Table 2: Tariff regimes in EU25 as of 31.12.2012 (see table footnotes in Annex D)

Country	Tariffication Model		Number of entry/exit systems	Locational signals considered	Postage stamp	Price Control Mechanism		Role of NRA in tariffs setting		Role of TSO		Revenue Recovery Entry / Exit split		Dedicated transit pipelines with particular conditions		Tariff recovery basis		Comments by NRAs (e.g. on current/expected changes)
	Entry/Exit	Other				Revenue Cap	Price Cap	Methodology fix	Approval	Methodology proposal	Calculation	Entries %	Exits %	yes	no	% Capacity	% Commodity	
Austria	✓		1	✓					✓	✓		20	80		✓	100	0	
Belgium	✓		1	✓		✓		✓	✓			~ 30	~ 70		✓	~ 93	~ 7	
Bulgaria		✓	n.a		✓			✓	✓				100	✓			100	
Czech Republic	✓		1		✓	✓		✓	✓			22	78		✓[31]	~ 97	~ 3	
Denmark	✓		1		✓			✓			✓	50	50		✓	~ 75	~ 25	
Estonia		✓	n.a		✓	✓		✓	✓		✓		100	✓			100	
Finland		✓	n.a		✓	✓			✓	✓	✓				✓	100		
France	✓		3	✓		✓		✓				~40	~60		✓	100		[23]
Germany	✓		2	✓ [2]	✓	✓		✓			✓	50	50 [3]		✓	100		
Greece	✓ [26]		1		✓	✓		✓	✓	✓	✓		100		✓	~ 90	~ 10	[25]
Hungary	✓		1	✓		✓ [5]		✓				~ 82	~ 18	✓ [15]		~ 78	~ 22	
Ireland	✓		1						✓			[7]			✓	~ 90	~ 10	
Italy	✓		1	✓				✓	✓		✓	50	50		✓	~ 85	~ 15	
Latvia		✓ [1]	n.a		✓[9]			✓	✓		✓		100	✓				
Lithuania		✓	n.a		✓		✓	✓	✓					✓ [10]		~ 70	~ 30	
Luxembourg		✓	n.a		✓	✓		✓	✓			100			✓	100		
Netherlands	✓		1	✓			✓	✓	✓		✓	40	60		✓	100		
Poland	✓		1		✓	✓			✓			50	50	✓ [11]		~ 80	~ 20	[29]
Portugal	✓		1			✓ [23]		✓ [27]	✓ [13]		[28]	26	74		✓	~ 90	~ 10	[32]
Romania		✓ [24]	n.a		✓	✓		✓	✓	✓				✓ [15]		6	94	
Slovakia	✓		1	✓			✓	✓	✓		✓	~ 48	~ 52		✓	100		
Slovenia	✓		1	✓		✓		✓	✓		✓	~ 23	~ 77		✓	100		
Spain	✓		1					✓							✓	[19]		
Sweden		✓	n.a		✓			✓	✓		✓		100		✓	100 [20]		
United Kingdom	✓		1	✓		✓			✓	✓	✓	50	50		✓	[22]		

Source: ACER analysis based on the KEMA/COWI (2013) study on entry/exit regimes and NRA data – see ACER 2012 Market Monitoring Report, p197

5 Objectives

5.1 General objectives

The general objective of the FG is the creation of the necessary regulatory framework on harmonised transmission tariff structures, which will allow for a well-functioning, efficient and open internal gas market. This objective is in line with Articles 3 and 194 of the Treaty on the Functioning of the EU:

- To establish a functioning internal market in gas, in the spirit of solidarity between the Member States (Article 3(3) TEU; Article 194(1) TFEU);
- To ensure security of energy supply in the Union (Article 194(1)(b) TFEU);
- To promote the interconnection of energy networks (Article 194(1) (d) TFEU).

5.2 Specific objectives

The specific objectives are in line with the EU energy policy objectives, which are outlined in Articles 1, 13 and 14 of the Gas Regulation:

- To facilitate the emergence of a well-functioning and transparent wholesale market with a high level of security of supply in gas and to provide mechanisms to harmonise the network access rules for cross-border exchanges in gas;
- To improve competitiveness and transparency in the gas market;
- To set non-discriminatory rules for access conditions to natural gas transmission systems taking into account the special characteristics of national and regional markets with a view to ensuring the proper functioning of the internal market in gas;
- To set tariffs or methodologies transparently, taking into account the need for system integrity and its improvement, and reflect the actual costs incurred insofar as such costs correspond to those of an efficient and structurally comparable network operator.

5.3 Operational objectives

The operational objectives set out basic requirements rather than detailed technical rules. They provide a flexible framework that takes into account national specifics as well as EU policy objectives. The new practices and methods shall be transposed into the network code and facilitate its possible future revisions.

The operational objectives include:

- Aligning and harmonising the interpretation of each cost allocation methodology and determination of the reference price;
- The harmonisation of the approach, tools and frequency for revenue reconciliation;
- The harmonisation of the range within which a reserve price may vary, including provisions on proportionate pricing;
- The harmonisation of the approach to payable price;
- Enabling the Network code on Capacity allocation mechanisms, including:
    - Principles for setting tariffs at Virtual interconnection points;
    - Principles for bundled capacity products.

5.4 Legal base and principles of subsidiarity and proportionality

The procedure for the adoption of a detailed EU regulation on harmonised transmission tariff structures is set out in Articles 6 and 8 of the Gas Regulation, where the right of the Commission to request from the Agency the submission of framework guidelines is established, with a view to the eventual development of a network code.

The subsidiarity principle is enshrined in the same provisions, where it is foreseen that the network codes shall be developed for cross-border network issues and market integration issues, without prejudice to introducing national codes for non-cross-border issues.

The Commission's request for the Agency draft the FG is in line with the principle of subsidiarity, according to which the EU shall act only insofar as the objectives of the proposed action cannot be sufficiently achieved by the member states, as it only exercises the rights which it has been attributed by the Gas Regulation.

In line with the principle of proportionality, under which the content and form of any EU action shall not exceed what is necessary to achieve the objectives of the Treaty, these framework guidelines are compatible with the aim of the completion of the internal gas market, while their scope of application is within the limits set by the Gas Regulation.

6 Policy options and enforcement design choices

As set out in Chapter 3, tariff setting and transmission tariff structures comprise many components. In developing the FG the Agency's approach has been, for each of the major components, firstly to consider whether a harmonised approach is necessary, and secondly, if harmonisation is necessary, what kind of harmonisation would best serve the objectives.

This chapter aims to identify and describe the different policy options to address the problems as described in Chapter 3. For each component three broad policy options were considered. The three policy options are adapted for each broad tariff component and include the policy option of no further EU action *(Baseline scenario);* increased transparency with some harmonised parameters; or fully deterministic EU harmonisation policy options. An overview of all options is provided in Chapter 8, Figure 21.

6.1 Cost allocation and reference price methodology

When considering cost allocation and reference price methodologies, the following three policy options were considered:

- **Option 1:** *no further EU action to address the issue (baseline scenario);*
- **Option 2:** *further/ increased transparency;*
- **Option 3:** *fully harmonised parameters at EU level (including three sub-variants)*

The **baseline scenario** does not foresee further EU intervention. Under this option no new EU policies would be introduced and cost allocation methodologies would continue to be wholly determined at national level. Under this option, any steps taken to harmonise tariff structures would be on a voluntary basis between member states.

No evidence of such high-level voluntary coordination between MS has been observed for cost allocation and reference price methodologies by the Agency to date. For example, the analysis provided in the 2012 Agency's

Market Monitoring Report[33] suggests that the European perspective was not a priority among MS when setting transmission charges.

In the process of drafting the FG[34], the Agency observed:

- The noticeable difficulty for MS to coordinate on cost allocation issues also exposed in Figure 12.
- Significant differences in the practical implementation of cost allocation methodologies (entry/exit splits were used differently, secondary adjustments were applied differently) at the national level.
- Stakeholders finding it difficult or impossible to access the necessary information at the right level of detail in the member states, which hindered them to reproduce tariff calculations.
- Stakeholders requesting the review of prevailing methodologies.

The Agency also collected some data on complaints to NRAs in relation to the setting of transmission tariffs. This data revealed a limited number of complaints, however the Agency had no access to information on complaints expressed via alternative channels, like working groups or arbitration (Figure 22), making it difficult to draw clear conclusions about satisfaction levels from the data.

Option 2, further or increased transparency, would create new obligations concerning the transparency of the various approaches to tariff calculation. These obligations could include, for example, a requirement for TSOs to make a downloadable version of their cost allocation methodology available to network users on their website, or a requirement to publish advance forecasts of tariff levels. This could provide more open and consistent information to the market, and could create more possibilities for network users to replicate and potentially challenge tariff structures, but it would not necessarily safeguard against the application of non-cost-reflective or discriminatory tariff levels, and would not necessarily trigger any harmonisation in tariff structures.

The various approaches to cost allocation and reference price methodologies currently observed in the EU show strong specificities. Table 2 highlights that many combinations of the theoretical concepts are possible, and that many different practical implementations of the same theoretical concepts exist (like cost concepts, etc.).[35] Additional transparency can contribute to a better understanding of national cost allocation methodologies, but the use of specific national concepts, including their publication, would not necessarily contribute to a common understanding of the issues in the EU. The concern over the lack of cross-border coordination identified in the baseline scenario remains also valid under Option 2.

Option 3 foresees specific harmonisation provisions. Within this option the following three sub-options are explored:

- *Variant 3.a: Top-down approach – ex-post assessment of the cost allocation and reference price methodologies*

Variant 3.a foresees a set of indicators verifying the appropriateness of the cost allocation and reference price methodology outputs without looking into its details (the inputs). The indicators would allow NRAs to evaluate how the cost allocation methodologies perform in terms of non-discrimination and cost-reflectivity. Cost allocation and reference price methodologies would be required to satisfy specific thresholds for these indicators when approved, and tariff adjustments would be triggered in the case of misalignment. The more sophisticated

[33] See 4.1
[34] See section 2 *supra*
[35] See Kema report for the various approaches to E/E zone, see Annex **C** for the approaches to price and revenue cap regulation; in addition, interactions with NRAs revealed that the concept of regulatory period covers different realities.

measurement tools are developed, the more such an approach could address cost reflectivity and non-discrimination between user classes.

- *Variant 3.b: Bottom up approach - harmonised description of allowed methodologies*

Variant 3.b would require the harmonisation of both the theoretical and practical approach to cost allocation and reference price methodologies through a harmonised description (parameters and tariff calculation) of a limited number of allowed methodologies. This harmonisation process implies:

(1) Harmonising the theoretical understanding and practical implementation of selected cost allocation methodologies in combination with the principles that apply on the entry/exit split and capacity/commodity split;
(2) Limiting the number of methodologies to be used, the way the secondary adjustments may apply, and clarifying the associated inputs for the proposed methodologies.

This approach provides full transparency and more simplicity by limiting the number of applicable cost allocation methodologies. Limiting the number of methodologies would make it easier for network users to become familiar with the methodologies employed and thus better manage risk in more than one market. The flexibility implicit in the variant would allow implementation of the methodology that fits best the technical and commercial conditions of a given national transmission grid.

(3) *Variant 3.c: fully deterministic approach*

This variant mandates the application of a specific methodology by way of a fully deterministic set of circumstances. This is the most ambitious of the harmonisation options and would likely trigger the largest changes in the methodologies applied at the national level. It requires a detailed understanding of the network circumstances and how those can or cannot be combined with certain methodologies. Variant 3.c would put forward rules in terms of methodology choices and reduce the flexibility at national level foreseen in Variant 3.b. It could provide stakeholders active in more member states with a good understanding of the methodologies and their outcomes.

6.2 Revenue reconciliation mechanism[36]

The approach to revenue recovery and revenue reconciliation has important implications for tariff level stability, predictability and, potentially, cross subsidy between network users. Where tariffs are not set to fully recover allowed revenues, or do not recover allowed revenues as intended, significant under or over recovery of revenues can arise. Significant and unexpected swings in the level of tariffs can result in potential tariff discrimination or cross subsidy between network users, as greater amounts of allowed revenue are recovered via the revenue reconciliation method rather than the cost allocation methodology.

In considering the approach to revenue reconciliation mechanisms, three policy options were identified:

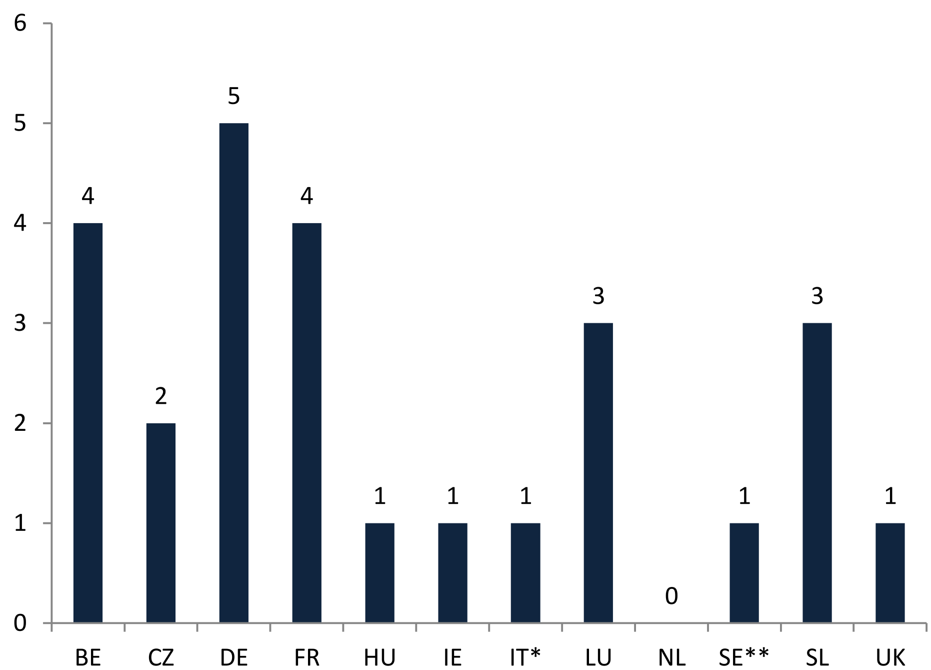
- **Option 1:** *no further EU action to address the issue (baseline scenario);*
- **Option 2:** *transparency and harmonisation of the reconciliation principles;*
- **Option 3:** *harmonisation of the reconciliation tool and its application (restrictions on the reconciliation tool in terms of magnitude and frequency).*

[36] See 27 *supra*

The **baseline scenario** does not foresee further EU intervention. Under this option no new EU policies would be introduced and the approach to revenue reconciliation would continue to be wholly determined at the national level. Under this option, any steps taken to harmonise the approach to revenue reconciliation would be on a voluntary basis between member states.

Based on the indicative data collected by the Agency and presented in Figure 13 and Figure 14, member states take diverging approaches across the EU. These figures are based on limited information collected from the NRAs, in response to a survey conducted by ACER. Comprehensive data was not made available to the Agency[37].

Figure 13: number of years over which the reconciliation of under/over recoveries is currently spread

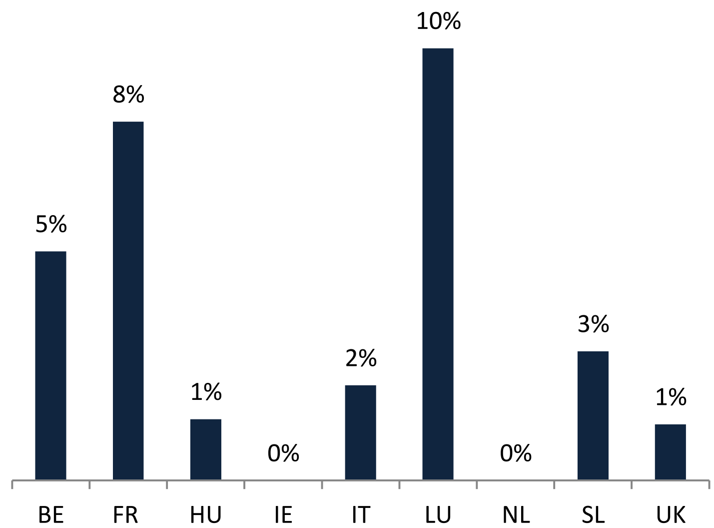


Source: ACER

Notes:
**In Italy if the share of reconciliation over the amount of allowed revenue is higher than 2%, the amount of reconciliation exceeding that threshold is split over 4 years.*
***Starting from 2015, Sweden will adopt an ex-ante regulation approach over a period of 4 years.*

[37] Please note that the Agency has no data collection powers in this respect.

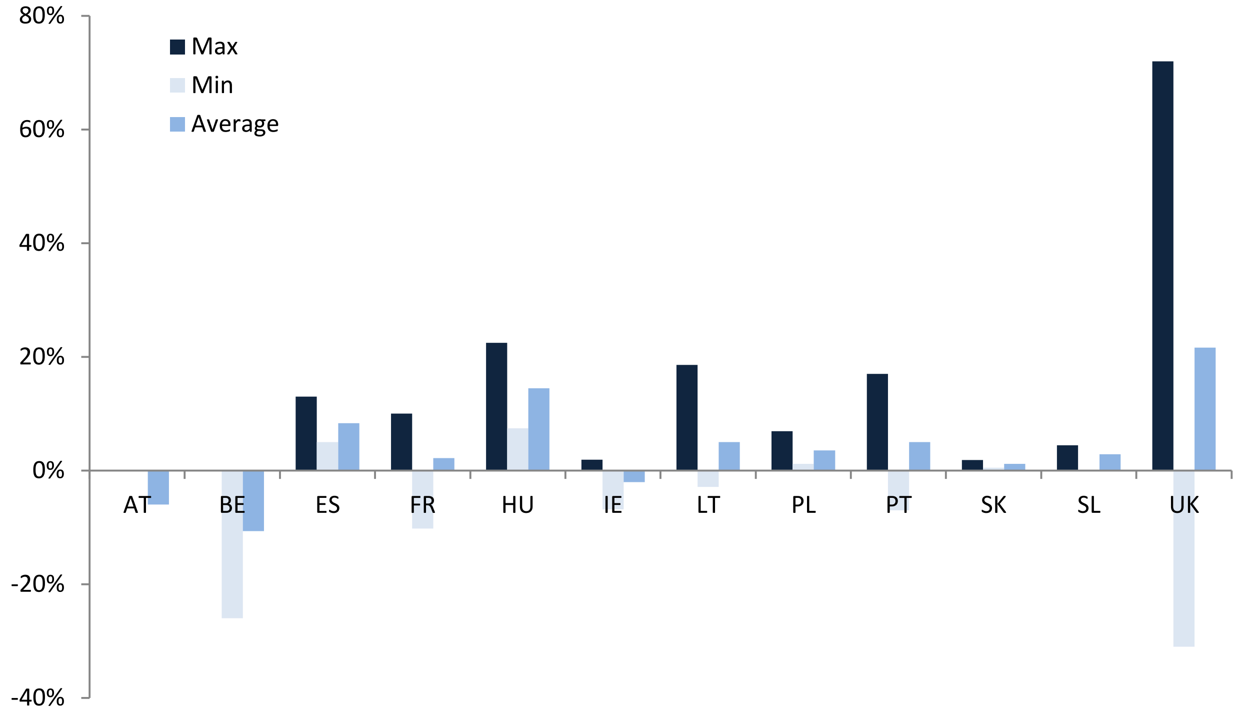
Figure 14: amount of revenue subject to reconciliation, as a proportion of the total amount of allowed revenue, over the period 2010-2012



Source: ACER

As further circumstantial evidence, Figure 15 below provides (again incomplete) data on tariff stability. The figure shows the average of the five most significant tariff changes, as well as the lowest and the highest of these 5 values, over the period 2007-2012 by member state. It indicates a significant degree of divergence in the magnitude of tariff adjustment among the member states. It should not be concluded in every instance that there is a direct cause and effect between changes in the level of tariffs and revenue under/over recovery. Volatility in tariff levels can arise as a result of other changes to charging/ cost allocation methodologies and their inputs and is not necessarily caused by under/over recovery. However the indicative data may point to the policy limits of Option 1, to the extent that the instability is caused by the revenue reconciliation approach currently applied.

Figure 15: order of magnitude of the tariff adjustments in EU over the period 2007-2012



Source: ACER

Note: for each country, the average of the 5 most significant tariff change over the 5-year period, as well as the lowest and the highest of these 5 values. Reasons for these adjustments are detailed in Annex I - .

Option 2 (Transparency and harmonisation of the reconciliation approach) provides a common approach to revenue reconciliation. This measure does not imply a common position regarding the frequency and the proportion/ magnitude of the revenue to be reconciled, but:

- Obliges NRAs/TSOs to set tariffs which seek to minimize the gap between collected and allowed revenues. (It is assumed that this is common practice, but specifying it as an objective would add focus).
- Obliges TSOs to maintain a 'regulatory account' in order to log any under/over recovery from year to year.
- Specifies that for cross border points, the network share of any under/over recovery shall lead to an adjustment of the capacity price.

This option would provide stakeholders with a better understanding of the up-coming reconciliations and allow them to anticipate the consequences of revenue reconciliation on the national tariff levels.

Option 3 (Harmonisation of the reconciliation tool and its application) goes a step further and aligns at each side of an IP the tariff adjustments resulting from revenue reconciliation. This option foresees full harmonisation at the EU level of the followings:

- The frequency over which an under/over recovery is reconciled and

- The percentages that would trigger reconciliation.

Such measures would fully harmonise adjustments under revenue reconciliation and reduce significantly the flexibility at the national level.

6.3 Reserve prices for capacity products of shorter duration and the application of multipliers, seasonal factors and pricing of interruptible services

Multipliers, if applied, modify the reserve prices for capacity products of shorter duration than the annual capacity product, which is considered to be the reference product in tariff calculations. Standard capacity products are defined in the NC CAM.

The neutral approach to determining reserve prices is to apply the reference price determined by the charging/ cost allocation methodology. This is the direct result of the cost allocation methodology plus any applied secondary adjustments. In case of capacity products of shorter duration than the annual product, this means that the reserve prices are set proportionately to the yearly product.

However, in some cases reserve prices for capacity products of shorter duration can be adjusted upwards or downwards (via the application of multipliers) for the following reasons:

- To facilitate short term gas trades;
- To facilitate revenue recovery.

The use of multipliers could be further nuanced by the application of seasonal factors to reflect differences in the seasonal costs of providing capacity. The seasonal factors on top of multipliers, if applied, improve the efficient use of the gas system, by incentivising system use in the off-peak periods.

The pricing of interruptible capacity takes into account the costs of such capacity being offered while appropriate discounts could promote efficient system use.

Three policy options for setting reserve prices for capacity products of shorter duration were considered:

- **Option 1:** *no further EU action to address the issue (baseline scenario);*
- **Option 2:** *reserve price ranges for capacity products of shorter duration and principles for interruptible products;*
- **Option 3:** *fully harmonised approach.*

The **baseline scenario** does not foresee further EU intervention. Under this option no new EU policies would be introduced and the approach to reserve price and the application of multipliers would continue to be wholly determined at national level. Under this option, any steps taken to harmonise would be on a voluntary basis between member states.

Member states follow diverse approaches concerning multipliers with some countries applying high multipliers on short term products, others, on the contrary, slightly incentivising the use of these products. This implies that member states have different strategies when it comes to balancing the objectives of revenue recovery/ reconciliation and facilitation of short term trade.

As with the approach to revenue recovery and reconciliation, the approach to reserve prices for capacity products of shorter duration and the application of multipliers could have implications for tariff level stability, predictability and, possibly, cross-subsidy between network users at both national and EU level. For instance, if short term capacity is sold at a discount to the reference price, it could mean that capacity for longer term products has to be sold at a premium in order to recover the allowed revenues, or that under recovery has to be logged in the regulatory account. Alternatively, applying a discount to short term capacity could result in a higher level of short term capacity bookings, which could potentially offset the need for adjustments elsewhere, as exemplified in the previous sentence.

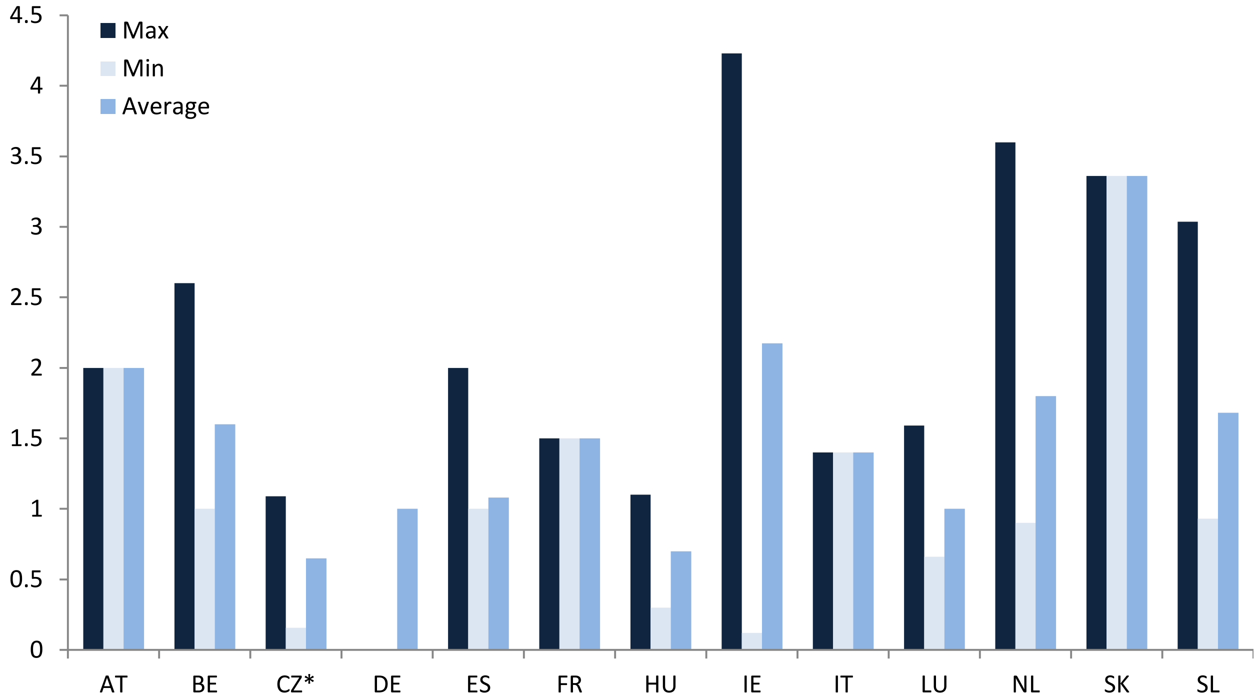
The Agency collected data on the use of multipliers in the EU (Figure 16 and Figure 17). Noticeable differences in the use of multipliers in the different member states, including large differences in the applied ranges of these multipliers indicate that without more coordinated policy options, prices will be set based on national considerations which would be likely to see the continuation of:

1. Diverse ranges in the use of multipliers, which could be difficult to follow by network users;
2. Not facilitating in a balanced way short term trading for all the IPs in the EU; and possibly hindering the development of cross-border trade in the Union;
3. Unpredictable use of high multipliers which could distort user choices and undermine the efficiency of cross-border gas trade.

The reserve price, whether or not a multiplier is applied, is the minimum tariff level for capacity sold in a capacity auction. In the future all existing capacity at entry and exit points is subject to the NC CAM and will be allocated via bundled capacity auctions. In this new situation, Option 1 could result in diverging approaches to multipliers for short term products at a given interconnection point. These diverging prices for shorter term products could be counterproductive, in particular when opposing pricing policies are applied on the two sides of an IP.

Seasonal factors could adjust product prices upwards or downwards. Non-coordinated policies or high seasonal factors would produce similarly diverging outcomes as the ones presented for the multipliers. Diverse methodologies concerning discounts on interruptible products and the lack of shared principles across member states, allowing linking the pricing of these products to the charging methodologies used and applied for other standard products, would be difficult to follow by network users.

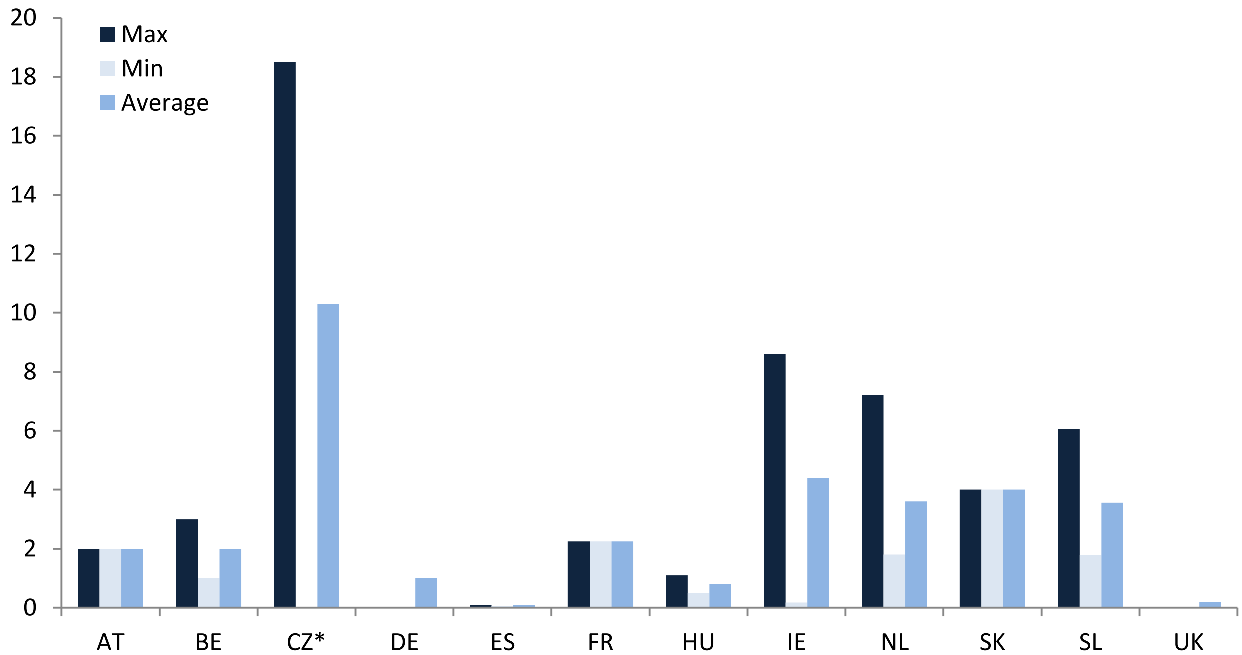
Figure 16: monthly multipliers in 2012



Source: ACER

**Note: CZ is the only country for which the variation in multipliers does not result from seasonal factors.*

Figure 17: daily multipliers in 2012



Source: ACER

**Note: CZ is the only country for which the variation in multipliers does not result from seasonal factors.*

Option 1 also permits high multipliers and seasonal factors for shorter term capacity products. Very high multipliers hinder the development of capacity products of shorter duration, which are necessary to support the development of spot markets.

Option 2 (Reserve price ranges for capacity products of shorter duration and principles for interruptible products) limits the possibility to take contradicting approaches for multipliers at IPs. Option 2 proposes ranges for multipliers, seasonal factors and shortlists methodologies applicable to interruptible products. At the same time, Option 2 would allow for some flexibility within the proposed ranges and constraints. The floor and cap on multipliers and seasonal factors, if combined with multipliers, keep the order of magnitude for multipliers controlled within a clear range, namely between an indicated floor and cap.

Option 2 would also require the coordination of neighbouring NRAs when setting multipliers, as NRAs applying multipliers would be required to take into account the opinion of their neighbouring NRA. Complex cases may rise, where the agreement of more than two NRAs is necessary, and the risk of contradicting rulings is higher in such cases.

Option 3 (Fully harmonised approach) aims at the strict harmonisation of multipliers, seasonal factors and pricing of interruptible services. Under Option 3 the same multipliers for capacity products of shorter duration would apply across the EU with no flexibility to use ranges for the reserve prices. Such a uniform measure would improve transparency, tariff predictability as well as network users' understanding concerning the calculation of transmission charges, but may not fit well in all circumstances.

6.4 Payable price at interconnection points

The payable price is the price paid for capacity at its time of use (as opposed to the prevailing price at the time of booking). The options the Agency has considered only apply to entry and exit points under the scope of the Network Code on CAM (interconnection points). However, as with the approach to revenue recovery and reconciliation, and the approach to multipliers, the approach to payable price can also have implications for tariff level stability, predictability and, potentially, cross subsidy between all network users.

The issue relates to the extent to which the price paid for capacity at the time of use should be allowed to deviate from the prevailing price at the time of booking, and the extent to which it should be protected from future increases in regulated revenues, or affected by future under/over revenue recovery. Payable price approaches which result in different tariff structures for different capacity products have the potential to concentrate revenue recovery on one group of users at the expense of another.

In the context of NC CAM, where capacity at either side of an interconnection point is required to be auctioned as bundled capacity (i.e. a single capacity product), divergent approaches to payable price could make the implementation of a single bundled capacity payable price more difficult. For example, a fixed payable price on one side of an interconnection point could require the application of a supplementary commodity based under recovery tariff. If a floating payable price was used on the other side of the interconnection point (with no commodity tariff) this could create asymmetric tariff dimensions which would cause increased complexity for network users, potentially to the detriment of competition.

The issue of payable price applies both to existing and incremental and new capacity. The assessment of the options in Chapter 7 explains why the Agency considers the same principles should apply to all types of capacity. Chapter 7 also provides an assessment of the options considered, when tariff adjustments allow incremental and new capacity to satisfy the Economic Test are necessary.

For existing and incremental and new capacity, three main policy options for payable price were considered, with the third option having two variants:

- **Option 1:** *no further EU action to address the issue (baseline scenario);*
- **Option 2:** *harmonised parameters;*
- **Option 3:** *fully harmonised approach to payable price, via*
    - *Floating price (Variant 3.a)*
    - *Fixed price (Variant 3.b)*

The baseline scenario is appropriate if there is no policy problem relating to the payable price in terms of EU market integration, or in case a problem is solved without any intervention. Given the significance of payable price to the bundled IP capacity regime, this would imply that cooperation of the member states would be sufficient to find an appropriate level of harmonisation. Taking no measures could result in increased divergence among member states, if limited voluntary action to align payable price approaches resulted. This complexity could undermine the ability of stakeholders to evaluate their costs accurately when engaging in cross-border trade and hybrid approaches to payable price could develop, which stakeholders could find difficult to keep track of. Taking no action would also avoid answering the question of the optimal approach to payable price which, given the potential impact on the distribution of tariffs between network users, may not be appropriate.

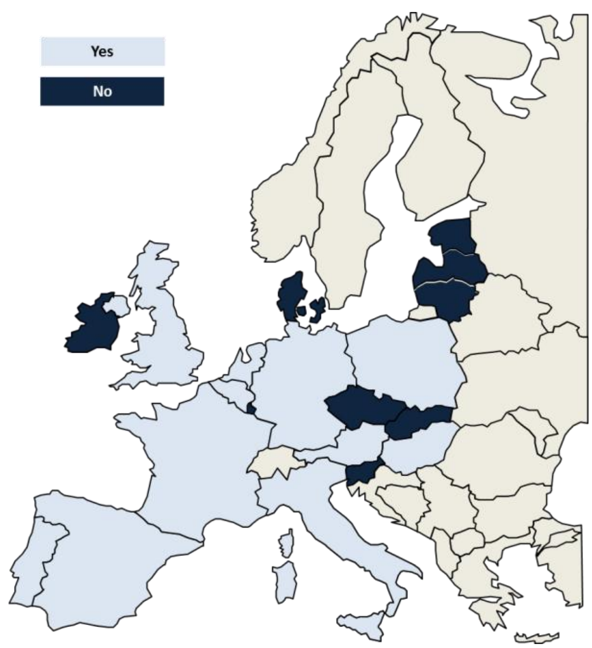
Figure 18 below shows that a significant number of countries (11) currently perform or will perform capacity auctions in a near future. For some countries, the experience may be still considered limited to a few products and very recent.

Under **Option 2** harmonised parameters would be developed to keep payable price approaches aligned and limited to a discrete set of alternatives. This option, while flexible towards alternatives, could require additional measures, to be compatible with the efficient functioning of the NC CAM: divergent approaches to payable price may not fit together with a bundled IP capacity regime. Option 2 would not seek to tackle the question of the optimal approach to payable price.

In our view **Option 3** and its variants, the fully harmonised approach, may serve best the requirements of NC CAM. NC CAM foresees the allocation of standardised bundled capacity products in capacity auctions and those would be best accompanied by a uniform payable price approach. In reaching a decision over which harmonised approach to follow, either of Options 3a (floating payable price) and 3b (fixed payable price) would address the question of the optimal approach.

A fixed payable price is based on the reference price of capacity at the time of the booking. A floating payable price is based on the reference price prevailing at the time of use. For both approaches, the price is paid at the time of use and would include any premium bid in excess of the reference price at the time of booking. Both options would provide a level of harmonisation capable of supporting an effective IP bundled capacity regime, but each one deals with the risk of future increases in allowed revenues or allowed revenue under/over recovery in different ways. The fixed approach insulates those booking capacity in advance from the risk of future increases in the allowed revenues, while the floating approach shares the risk among all network users.

Figure 18: countries having performed or planning to perform auctions in the EU by December 2013



Source: ACER

7 Assessment of the options

The previous chapter describes the main policy options considered across four of the main tariff structure components, namely: charging/ cost allocation and reference price methodology; revenue reconciliation; reserve price determination; and payable price. This chapter assesses the options for each of the components against a set of criteria and considers the approach specified in the Tariff FG against this assessment.

The criteria are as follows:

- **Effectiveness** – This is an assessment of the extent to which the option meets the objectives specified in Chapter 5, and in particular Article 1 and 13 of the Gas Regulation.
- **Feasibility** – This is an assessment of the feasibility of implementing the given policy option, including any foreseeable structural barriers.
- **Acceptability** – This is an assessment of the extent to which the option has support among industry stakeholders.

The criteria selected are intended to provide a pragmatic assessment framework. For the acceptability criteria, the Agency used responses to the 2012[38] and 2013[39] public consultations and knowledge of NRAs' points of view as expressed in the FG development process, as a proxy. Across the EU gas industry there is a significant body of expertise concerning the practical application of different tariff structure options. The Agency is of the opinion that policy options which carry a broad level of support from industry stakeholders, including NRAs, TSOs, gas shippers and gas industry organisations, have a better chance of enduring success.

7.1 Cost assessment and distributional effects

The Agency has not directly considered the cost implications of the policy options. In part, this is because the dynamic nature of the FG development process did not permit an ex-ante cost assessment of detailed policy choices. From an administrative point of view, TSOs and NRAs in all member states will incur a certain level of costs in the implementation of the Tariffs network code. These costs may be greater for those member states that need to initiate significant changes to comply with the requirements. However, because all member states are required to have an approved cost allocation and reference price methodology under each of the options, because such costs that may be incurred are likely to be one-off, and because the FG does not mandate any one particular methodology to apply, the Agency has not sought to aggregate implementation costs at this stage.

In considering cost implications, it is important to emphasise that the Tariff FG will have no direct effect on the total regulated revenues TSOs are allowed to recover. For this reason transmission charges at an aggregate level are not affected by the FG. However, in transmission networks where changes to established tariff structures are required, there is likely to be a distributional effect on the level of transmission charges within an entry-exit zone, i.e. the level of charges at some network points may increase, while the level of charges at others may decrease.

Distributional effects on the level of charges arising from implementation of the Tariff network code are likely to be the result of a need to rebalance tariff structures to better meet the requirements of the Gas Regulation. From

[38] http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/EoT_Draft%20Tariff%20FG_16_04_2013_for%20publication_TQ_clean.pdf

[39] http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/EoR_Draft%20Tariff%20FG_final.pdf

this perspective, such distributional effects could be viewed as remedying inappropriate tariff levels, or, potentially, removing prevailing cross-subsidies between network users. However, the Agency acknowledges that, from a network users' point of view, sudden and significant changes in the level of transmission charges can have commercial consequences, which may differ from country to country.

The extent of these changes will depend on the eventual NC and the choices the NRAs make when implementing it. Aside from the central decision concerning choice of cost allocation methodology, the factors which will affect eventual tariff levels following implementation of the NC include: the entry-exit split; the revenue reconciliation method; the approach to secondary adjustments; and the approach to multipliers or seasonal factors.

It would not be possible for the Agency to model the distributional effects of all possible combinations of these variables in assessing the policy options for the FG, nor to anticipate which combination of variables is likely to be applied. A full assessment of these effects will be the responsibility of individual NRAs during the methodology consultation process. However, to obtain a high level view of the possible aggregate effects at a MS level, NRAs were invited to provide the Agency with their first assessment of the distributional effects they anticipate. This assessment was performed by the following NRAs: Austria; France; Germany; Hungary; Italy; the Netherlands; and the UK. The Hungarian and Italian cases are presented below. The others are presented in Annex M and Annex N.

Case Studies: anticipated distributional effects in Hungary and Italy[40]

Disclaimer: The following cases present evolutions in tariff structures (cost allocation), and not tariff levels. The allowed revenue of the TSOs is assumed to be constant. These examples are rough anticipations of tariff evolutions, based on assumptions regarding the regulatory framework. This exercise is purely indicative and without prejudice to any regulatory decision to be taken ahead of the entry into force of the Tariff Network Code. Tariff changes are presented on an aggregated level without reflecting on individual, user level distributional effects.

Hungary

Table 4 is the result of a brief comparative analysis of the currently applied cost allocation methodology (postage stamp with an 80/20 entry-exit split) vs. postage stamp, adopting a 50/50 entry-exit split. As allowed by the FG (3.1.1. The capacity-commodity split), the volume-driven charges are treated separately – and thus are kept out of the calculation below.

The booking scenarios used are represented in the table below:

Table 3: capacity booking scenarios

Capacity booking scenarios (m3/h)			
entry	67	80	90
exit	100	100	100

The calculation is based on July 2012 charges and the applied booked capacity data relate to the entire 2012/2013 gas year. The percentage changes in the entry and exit charges are presented in the 2nd and 3rd column, in the table below. The costs of the calculated route remain under a 15% variation.

Table 4: Anticipated local Impact of the network code implementation in Hungary compared to the current situation (%variation)

	Entry	Exit	change in the route cost depending on booking scenarios		
IP	-41%	200%			
Storage	-41%	200%	**-6%**	**-11%**	**-14%**
Domestic	-41%	200%			

Source: MEKH

Italy

The current gas transport tariff regulatory framework is to a high degree compliant with the provisions set out in the FG . A possible exception to this could be the need to review the capacity/commodity split. Currently, the share of costs allocated to capacity charges is around 85% (corresponding to capital costs) while 15% is the share of costs covered by the commodity charge (corresponding to operating costs); fuel gas and gas to

[40] Similar case studies for Austria; France; Germany; the Netherlands; and the UK are available in Annex M and Annex N.

cover network losses is provided in-kind by shippers and this does not fall within the commodity charge.

The way in which the current framework may be adapted to comply with the Framework Guidelines will depend on the outcome of the consultation procedure where the alternatives will be discussed with stakeholders, following the adoption of the Network Code. Therefore, the following analysis is purely indicative, and the actual impact on shippers will depend on the specific solution that will be chosen.

The removal of the commodity charge, and the inclusion of operating costs into the amount of allowed revenues allocated via the cost allocation (matrix) methodology, results in an increase of +19% of each entry and exit charge. The impact on the overall transport cost for shippers depends on the load factor and the chosen entry/exit point. Table 5 shows the potential effect on the overall cost (based on 2014 tariffs), assuming shippers booking entry at one of the two main entry routes (from Austria and from Northern Africa), exit at the main exit point (North-Western area) and under the assumption that the same amount of capacity is booked at entry and exit.

Table 5: Potential impact of the network code implementation in Italy in comparison with the current situation (% of variation)

		Load factor		
Exit point	Entry point	0.5	0.7	0.9
North-Western area	From Austria	**-3.9%**	**-9.4%**	**-14.3%**
	From Northern Africa	**+4.1% / +4.8%**	**+0.1% / +1.0%**	**-2.6% / -3.5%**

Source: AEEG

To mitigate the downside risks arising from unexpected increases in tariff levels at individual entry or exit points as a consequence of the NC, the Agency extended the parameters on the application of mitigating measures (such as applying a glide path to new tariff levels) in the final version of the FG, from 12 months (draft FG) to 24 months following the implementation of the network code, and reduced the materiality threshold for applying such measures from a forecast change in the level of applicable charges of 25% to a forecast change of 20%. Both of these changes were in response to reactions received from industry stakeholders during the July 2013 consultation[41]. A summary of the reasons for the Agency's decision on mitigating measures, and the options considered, is contained in Annex L .

7.2 Cost allocation and reference price methodology

Table 6 below presents the assessment of the policy options for the cost allocation and reference price methodology against the assessment criteria. Each criterion is evaluated on a scale of 0 to 3, where "3" satisfies the criteria most fully, and "0" not at all.

Table 6: Cost allocation methodology options assessment

Option	Effectiveness	Feasibility	Acceptability	Total
1 No further action	0	3	1	**4**
2 Increased transparency	1.5	2.5	1.5	**5.5**
3 Harmonised parameters	2.5	2	2.5	**7**

Explanation

The Gas Directive sets explicit objectives for transmission tariffs. To consider that Option 1 was likely to be effective in furthering these objectives, the Agency would have to be content that existing tariff structures among member states avoid undue discrimination between network users, provide cost-reflective tariffs and facilitate efficient gas trade and competition between member states, or was likely to do these things in the foreseeable future. From the Agency's knowledge of the diversity of existing practice this is not the case. Table 2 indicates the divergence of current approaches. Given the extent of these differences, and the historical inertia among member states towards voluntary harmonisation, policies of no further action will most likely lead to a continuation of the status quo.

From a network users' perspective, a significant part of the tariff structure problem seems to relate to a relative lack of transparency about how tariff structures are derived, and potentially a related lack of predictability over the level of transmission charges. Both of these issues are exacerbated by the seeming complexity of charging methodology structures and the variety of approaches adopted. In the view of the Agency more explicit requirements regarding the publication of information relating to tariff methodologies, their inputs and the factors likely to affect their outputs, would mitigate this problem (Option 2). In other words, increased transparency may deliver good results for stakeholders able to process large amount of data and as such, it may improve cross-border trade in favour of large players. Smaller stakeholders may find it still challenging to collect this data and build a thorough understanding of the cost allocation methodologies applied across the EU member states.

[41] See in particular question 18 of the consultation. A majority (21 over 41) opposed the initial proposal – 14 were in favour of an amended policy. The main critic targeted the triggering level of 25%, believed to be too high by 12 respondents.

However, greater transparency around tariff structures would not of itself create greater harmony, and it would not of itself prevent instances of undue discrimination between users, facilitate competition and gas trade and provide for cost reflective tariffs, thus inefficient practice will continue to prevail. In the opinion of the Agency, only a framework where NRAs are obliged to assess their current practice against a harmonised and explicit set of parameters aligned with the objectives can fully meet this goal. This is why Option 3 is scored as 2.5 against the effectiveness criteria, but the extent to which it would be effective can be said to vary according to the degree and type of harmonisation implemented. The table and section below considers this further.

Against the feasibility criteria, at a high level, it can objectively be said that there are fewer barriers to the maintenance of the status quo than the implementation of change. As Option 3 implies the greatest change, and may face greater barriers to implementation, this option scored lower than Options 1 and 2. The same rationale has been applied to the difference between Option 1 and 2.

Against the acceptability criteria, although there are some stakeholders who would welcome no further action, the majority of respondents to the 2013 consultation[42], and most NRAs, endorse the need for greater harmonisation. Differences of opinion exist concerning the type of harmonisation necessary, but it is clear that a majority would not agree that Option 1 or Option 2 were acceptable.

7.2.1 Cost allocation and reference price methodology – types of harmonisation.

Table 7 presents the assessment of the Charging/ cost allocation methodology harmonisation options against the assessment criteria. Each criterion is evaluated on a scale of 0 to 3, where “3” satisfies the criteria most fully, and “0” not at all.

Table 7: Charging/cost allocation methodology harmonisation options

Option	Effectiveness	Feasibility	Acceptability	Total
3a Top down	1.5	2	1.5	**5.5**
3b Bottom up	2.5	2	2.5	**7**
3c Fully deterministic	3	1	1	**5**

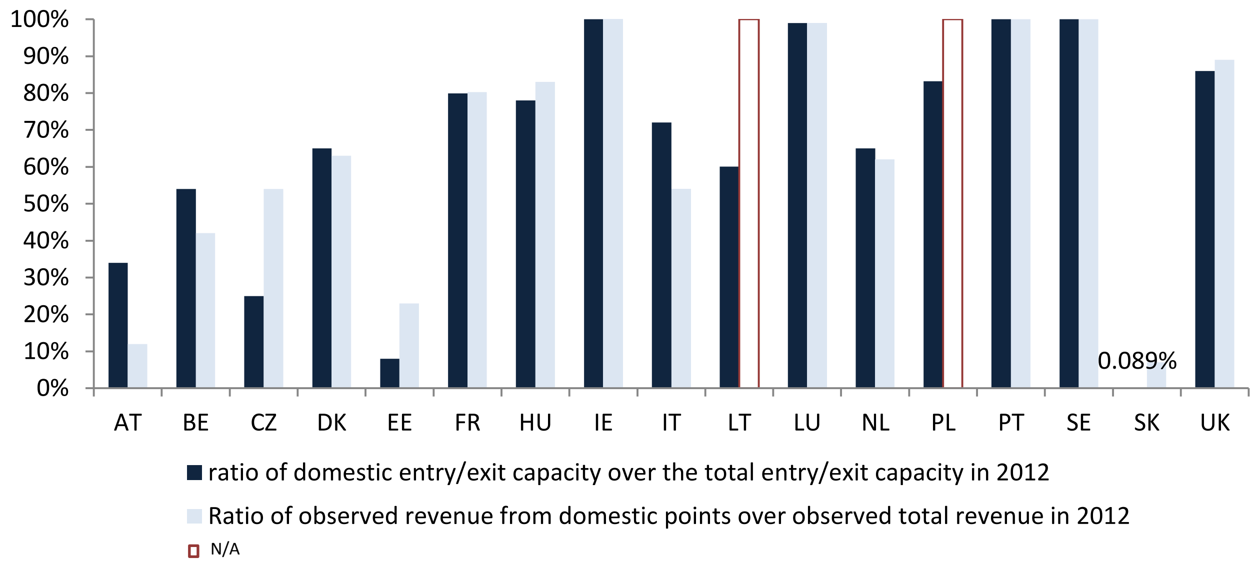
Explanation

Variant 3.a could go a significant way to minimising cross subsidies between domestic and cross border entry and exit points. Figure 19 below compares domestic capacity as a percentage of total system capacity with revenues from domestic points as a percentage of total revenues, for 17 member states. The graph illustrates that in some countries the two are closely aligned, whereas in others the two are not aligned (suggesting the possibility of an aggregate cross-subsidy of cross border by domestics or vice versa) [43].To the extent that Variant 3.a resolves this problem, it could reasonably be expected to have a positive impact on the efficiency of cross border transmission capacity signals, potentially to the benefit of hub liquidity and the efficiency of gas trades between member states.

[42] See in particular question 5 of the consultation. Out of 41 respondents, 10 supported the level of harmonisation, while 7 respondents asked for further harmonisation by reducing the number of allowed methodologies, and 8 asked for a higher level of detail. On the other hand, among the 13 respondents opposing the proposal, 6 identified a conflict with subsidiarity, suggesting excessive harmonisation.

[43] The graph does not control for non-capacity cost drivers (such as commodity and distance), and thus not present recovered revenues from non-capacity based charges. Thus conclusions are circumstantial rather than absolute.

Figure 19: comparison between domestic capacity and domestic revenue in 2012



Source: ACER

Note: European countries show a variety of consumption profiles. When comparing the revenue collected from domestic points with the influence of capacity, one of the main cost drivers, no difference is observed in 4 countries; a 10% or less difference is observed in 5 countries; a difference of more than 10% is observed in 7 countries.

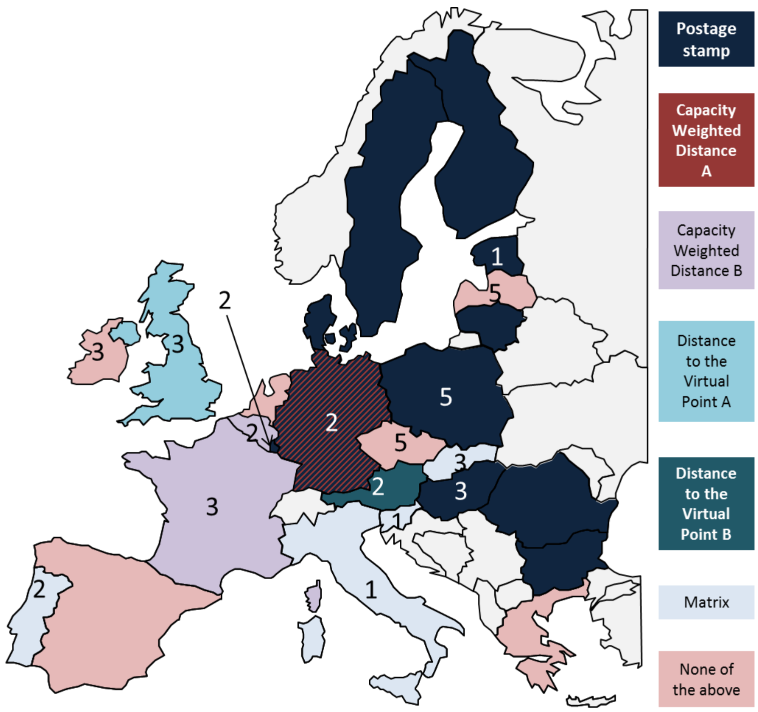
Variant 3.a, as explained in Chapter 6 does not address in full the non-discrimination between all network users and thus compromises the extent to which the option can be said to effectively achieve the objectives of the Gas Regulation. The nature of Variant 3.a can be said to be corrective rather than preventive. The limitations of this approach, that it does not address potential cross subsidy between cross border points, or between domestic points, means that the problem of non-discrimination between users remains partially solved, unless sophisticated measurement tools are developed.

By contrast, Variant 3.b would imply harmonising both the theoretical and practical approach to cost allocation while preserving a degree of choice for individual member states. The introduction of a defined and limited set of possible cost allocation methodologies, and the harmonisation of rules regarding methodology selection would be more effective in achieving the policy objectives, to the extent that it embeds cost reflectivity and non-discrimination at its heart, rather than as an add on. This approach is more likely to avoid the risks of cross subsidy within categories of user identified in Variant 3.a. Cost reflective charges for all entry and exit points in an entry-exit zone are an important way of sending efficient signals regarding the use of capacity.

Variant 3.c could be said to go further still in this regard, if it could be achieved would avoid the potential risk in Variant 3.b, namely that the flexibility offered by the variant results in the implementation of second best options.

The difficulty of specifying, in an objective way, a fully deterministic set of circumstances for the choice of cost allocation methodology is reflected in Variant 3.c’s scoring against the feasibility and acceptability criteria. In the review of the responses to the 2013 consultation[44], and from discussion with NRAs (see Figure 20 below) concerning the different network characteristics pertaining to the choice of existing methodologies, the Agency remains to be convinced that a fully deterministic set of circumstances can be specified and therefore suitable for application across the EU. Further, an attempt to mandate this would be likely to lead to resistance from most member states and stakeholders.

Figure 20: Qualitative assessment of the cost allocation methodologies to be implemented following the entry into force of the Network Code on Tariffs



Source: ACER

Note: this is a NRA qualitative assessment of the cost allocation methodologies best fitting their network specificities following the entry into force of the Framework Guidelines, as well as the impact of the implementation of these cost allocation methodologies on their current approach (the lower the number, the lower the anticipated impact on the current approach: 1 – little impact/ 5 –high impact)

The scoring of Variants 3.a and 3.b against feasibility and acceptability indicate the similarity of both options in these respects. Variant 3.a may appear less interventionist and therefore more feasible or more acceptable to some, but the extent of the adjustments, which could be necessary to adapt unconstrained cost allocation methodologies to the requirements of the cost allocation test, could be difficult to administer and could have political sensitivities. Against the acceptability criteria, the Agency considers that it received a strong mandate for harmonisation of the principles of cost allocation methodologies from the 2013 consultation[45], therefore many stakeholders may consider that Variant 3.a does not go far enough in this regard.

[44] See questions 5 to 10 of the public consultation.
[45] See question 5 of the public consultation.

7.2.2 Cost allocation and reference price methodology – impact of Framework Guidelines

The provisions in the Framework Guidelines are consistent with Variant 3.b in this area. The FG limits the choice of possible cost allocation methodologies to four (plus to variants); introduces a harmonised methodology selection process; and provides a harmonised set of parameters for potential secondary adjustments. In order to avoid second best implementation options, in determining the appropriate cost allocation methodology for its network, NRAs, or where designated by NRAs, TSOs, are obliged to publish a consultation containing the following information:

- An assessment of the proposed methodology against the methodology circumstances criteria;
- All the relevant input data necessary to determine tariffs under the proposed methodology;
- The results of the application of the cost allocation test to the proposed methodology; and
- A methodology counterfactual, consisting in providing all of the information above for at least one other of the four possible cost allocation methodologies[46].

In approving the choice of cost allocation methodology, NRAs are obliged to publish a decision which contains a detailed explanation and reasoned justification, based on the data specified above. This approach provides the most appropriate balance between effectiveness, feasibility and acceptability, as indicated in the table above.

7.3 Revenue recovery and reconciliation mechanism[47]

Table 8 below presents the assessment of the revenue reconciliation options against the assessment criteria. Each criterion is evaluated on a scale of 0 to 3, where “3” satisfies the criteria most fully, and “0” not at all.

Table 8: Revenue reconciliation options

Option	Effectiveness	Feasibility	Acceptability	Total
1 No further action	0	3	1	**4**
2 Transparency and harmonisation of reconciliation approach	2	2.5	2	**6.5**
3 Harmonisation of reconciliation tool & its application	3	2	1.5	**6.5**

Explanation

While Option 1 does clearly not, Option 2 would address the problem of inconsistent and sometimes opaque approaches to revenue recovery and revenue reconciliation due to additional obligations put on the NRAs and TSOs, as presented in Chapter 6, when describing this policy option (like small gaps, etc.).

- Obliging NRAs/TSOs to set tariffs which seek to minimize the gap between collected and allowed revenues. (It is assumed that this is common practice, but specifying it as an objective could add focus)

[46] Postage stamp, capacity-weighted distance approach, virtual point based approach, matrix approach
[47] See 27 *supra*

- Obliging TSOs to maintain a 'regulatory account' in order to log any under/over recovery from year to year.
- Specifying that for cross border points, the network share of any under/over recovery shall lead to an adjustment of the capacity price.

The level of harmonisation in Option 2 would in principle minimize the likelihood of a large under/over recovery; enable network users to anticipate the impact of under/over recovery; and ensure that revenue reconciliation does not result in cross subsidies between cross border and domestic points. Thus, Option 2 would address the issues of tariff stability, predictability and the avoidance of cross subsidy. In particular, the first instrument in conjunction with the third one would improve stability: the requirement to minimise the gap between collected and allowed revenues along with the provision to distribute any gap across all users would mitigate large tariff deviations. The second measure allows network users to predict these deviations and understand them. The third provision implies that while the under recovery does not occur at all points evenly, socialising those under recoveries across all the points of the network would imply limited cross subsidy between users. These cross subsidies would remain controlled, would be shared across all user classes and not be imposed on a limited number of captive users.

This would be consistent with the objectives of the Gas Regulation, but it would not go as far as the measures implied by Option 3 in this regard.

As well as the requirements specified in Option 2, Option 3 would mandate a harmonised approach to revenue reconciliation at all points on the network (including domestic points), and mandate a harmonised approach to the number of years over which revenue reconciliation is spread. As such, Option 3 more fully protects against inappropriate cross subsidies between all network users, provides more transparency regarding revenue reconciliation and offers greater tariff predictability, but as a uniform measure, may not fit well in all circumstances. Figures presented in Chapter 6 provide indicative data on the current level of divergence among member states on this issue.

Against the feasibility criteria, as with the charging methodology options, a reverse scoring can be observed. This is because Option 1 would require no adjustment to implement, Option 2 less and Option 3 the most. For member states obliged to change their revenue reconciliation period from alignment with the regulatory cycle to the tariff setting period for instance, the change could be significant.

This rationale is also reflected in the acceptability scoring for Option 3. However, in contrast to the high score for feasibility, the Agency has allocated Option 1 a low score for acceptability. On the basis of the 2012 consultation the Agency has a strong mandate[48] for an appropriate level of harmonisation, thus no action (Option 1) would not be consistent with this opinion.

7.3.1 Revenue recovery and the reconciliation mechanism – impact of Framework Guidelines

The provisions in the Framework Guidelines are equivalent to Option 2 in this area. The Agency has determined an equivalent total score for Options 2 and Options 3. Option 3 could be said to more fully achieve the objectives of the Gas Regulation. However, arguments and opposition from some member states, from the 2012 consultation[49]

[48] See questions 3.2.2 and 3.2.3 of the consultation. (3.2.2) Most (20 out of 43) respondents agreed with the proposed level of harmonisation and (3.2.3) a majority (29 out of 43) supported the idea that NRAs should determine or approve how often and how fast the regulatory account has to be reconciled.

on the level of harmonisation needed for domestic points on this issue, meant that the Agency was not persuaded that the benefits of full harmonisation in this area outweighed the potential feasibility and acceptability difficulties.

7.4 Determining the reserve prices for capacity products of shorter duration and the application of multipliers, seasonal factors and pricing of interruptible services

Table 9 presents the assessment of the reserve price and multipliers options against the assessment criteria. Each criterion is evaluated on a scale of 0 to 3, where "3" satisfies the criteria most fully, and "0" not at all.

Table 9: Reserve price and multipliers options

Option	Effectiveness	Feasibility	Acceptability	Total
1 No further action	1	3	1	**5**
2 Reserve price ranges	3	3	2	**8**
3 Fully harmonised approach	2	2	1	**5**

Explanation

Figure 16 and Figure 17 in Chapter 6 indicate the variety of approaches used in setting multipliers for monthly and daily capacity across a number of EU member states. The diversity of these approaches is too wide and may lead to capacity being offered at inappropriate tariff levels, putting in question cost-reflectivity of tariffs, or potentially inhibiting the short term liquidity of gas trades. No further action, Option 1, would allow this level of diversity to endure or even grow larger and thus would not be an effective policy option.

Option 2 scores higher than Option 1 against the effectiveness criteria because it harmonises the default approach to determining reserve prices (thereby preventing arbitrary applications) and harmonises the parameters within which multipliers should be set (thereby preventing inappropriately high or low multipliers). Option 2 scores higher than Option 3, because it preserves an appropriate level of flexibility for NRAs to determine the precise level of multipliers necessary to balance the trade-offs listed above, interpreted for the specific characteristics of each network. Option 2, in addition, simplifies short term price setting and improves transparency and increases the understanding of network users over price setting.

Simplification also allows for greater predictability of tariffs for stakeholders engaged in cross-border trade and may contribute to increased competition. A distinct approach between congestion and non-congestion multipliers shall facilitate the smooth application of CMPs. Light stimulation of interruptible products, within the boundaries of cost-reflectivity, is foreseen for unidirectional points, where ENTSOG building on the FG shall promote the best applicable standards in the NC, based on solid analysis. These ensure high scores for Option 2 in terms of effectiveness.[1]

In terms of feasibility, Option 3 would be the least feasible, as it would imply fixing the level of multiplier to be applied for each capacity product across the EU. Such uniform approach could hardly balance the different needs of adjacent gas markets, where specific to the maturity of the market (see Annex E), distinct measures are needed

[1] See Annex K

to facilitate short term trading in balance with long term signals for efficient investment. On the basis of the evidence available, provided there is full transparency over the level of multiplier to be adopted within a given range, the Agency is of the view that NRAs are better placed to make a national determination on this issue. The Agency also considers that Option 2 is the most acceptable, because it most closely aligns with the views of respondents to the 2012 consultation[50], and the view of NRAs: majority support for a level of harmonisation, but opposition to mandating a specific multiplier for each capacity product, which may not reflect all network and market specificities.

[50] See section 4 of the 2012 public consultation

Multipliers – a balance between short term and long term trade

A network is designed to handle flows during peak conditions. However, under average conditions, it is only partially used. Multipliers applied to tariffs for shorter term capacity products allow charging system users contributing to the peak consumptions more than system users with a flat consumption profile. In using multipliers, NRAs and TSOs must strike a balance between an efficient use of the system and revenue recovery. Low multipliers encourage users to profile their bookings according to their needs, while high multipliers have them increase their longer term bookings (yearly and beyond).

Table 10: Assessment of multipliers

	Pros	Cons
Low multipliers: system users profile their capacity booking according to their needs	• No capacity hoarding • Short term trade stimulation	• Less visibility for the TSO over revenues • Possibility of revenue shortfall in conditions where there is a high variability of consumption • Risk of cross-subsidies from users with a high load factor to users with a lower load factor
High multipliers: system users secure more long term capacity	• Good visibility over TSO revenues • Better conditions for investment and tariff stability	• Risk of capacity hoarding in the shorter term, hampering short term trade • Risk of cross-subsidies to other users from users using capacity at peak conditions

Congested IPs vs. non-congested IPs

In the course of the development of the Framework Guidelines, the Agency analysed the conditions for the use of multipliers higher than 1. The discussion focused on the risk of under recovery stemming from a change in shippers' booking behaviour (booking profiled instead of flat) due to multipliers equal or lower than 1.

The risk of under recovery is not relevant at congested IPs, as shippers would strive to secure capacity well before the day-ahead, in order to avoid paying a premium of unknown magnitude in the day-ahead auctions. A "flight to the short term" is therefore not an issue at congested IPs. Furthermore, the revenues from auction premia at congested IPs contribute to offsetting any under recovery from more profiled bookings.

The situation is different at non-congested IPs where changes in shippers' booking behaviour can lead to a significant under recovery in the presence of multipliers lower than 1.

The introduction of moderate multipliers in combination with seasonal factors reduces the probability of drastic changes in shippers' booking behaviour.

Risk of revenue shortfalls

The Agency observed that, of the 13 countries that contributed to its survey, nine apply monthly multipliers falling within the range of one to two (Figure 16). The harmonisation of multipliers around 1.5 thus seemed already a practice under which markets can function smoothly and efficiently.

During the process, stakeholders raised the issue of IPs where the variability in consumption would be such that an application of multipliers of 1.5 in combination with seasonal factors would not allow TSOs to recover their costs and would create a local revenue shortfall. The Agency observes that in such exceptional cases, the shortfalls would be fed into the revenue reconciliation mechanism and lead to an increase in all reference prices.

At that stage of the process, although deemed exceptional, this situation has not been quantified. The Agency invites ENTSOG to identify the concerned IPs in the EU, to demonstrate the extent to which the combination of multipliers and seasonal factors would not allow cost recovery, and to quantify the revenue shortfalls and the eventual tariff adjustment needed.

7.4.1 Reserve prices and the application of multipliers – impact of Framework Guidelines

The provisions in the Framework Guidelines are equivalent to Option 2 in this area, with the additional provision that NRAs must consult neighbouring NRAs when reaching decisions over the level of multipliers to adopt at cross border points. This option scores the highest against each of the criteria specified in Table 9.

7.5 Payable price

Table 11 presents the assessment of the payable price options against the assessment criteria. Each criterion is evaluated on a scale of 0 to 3, where "3" satisfies the criteria most fully, and "0" not at all.

Table 11: Payable price options

Option	Effectiveness	Feasibility	Acceptability	Total
1 No further action	0	3	1	**4**
2 Harmonised parameters	1	2	2	**5**
3.a Fully harmonised floating payable price	3	3	2	**8**
3.b Fully harmonised fixed payable price	2	3	2	**7**

Option 1 would be the least effective, principally because it would provide no controls or guidance on good practice for NRAs implementing auction mechanisms for the first time and would do nothing to address the question of the optimal approach to payable price. As highlighted in Figure 18 above, only 11 countries have experience with capacity auctions.

Among those countries, three apply a floating payable price and two apply a fixed payable price. As more member states implement capacity auctions, it is possible that they will align with these two established options, but under Option 1 it is also possible that hybrid options could be developed, leading to the further fragmentation of tariff structures among member states. By applying a set of parameters Option 2 could contain this risk; therefore it is preferable to Option 1.

However, the flexibility implied in Option 2 does not address the difficulty that the option may present of permitting different approaches to payable price on either side of a cross border point: under CAM all cross border capacity will be bundled and may be more effectively offered at a single capacity reserve price. A fixed payable price on one side of an interconnection point could require the application of a supplementary commodity based under recovery tariff. If a floating payable price was used on the other side of the interconnection point (with no commodity tariff) this could create asymmetric tariff dimensions which would cause increased complexity for network users, potentially to the detriment of competition.

Furthermore, Option 2 does not fully address the question of the optimal approach to determining the payable price. For these reasons, the Agency considers that Option 3 and its two variants are preferable to Option 2.

In the view of the Agency, both Variants 3.a and 3.b have the potential to support an effective bundled IP capacity regime: implementation of either option would mandate a harmonised and consistent approach across the EU.

However the Agency sees differences between the two options in terms of the evaluation of each against the relevant objectives and against the assessment of the implementation practicalities.

The most significant difference between the two variants relates to the different way in which each shares exposure to the risk of future increases in allowed revenues and/or the risk of future revenue under/over recovery, between network users. Under the floating payable price, this risk is shared evenly between all network users: the payable price is determined by the underlying cost allocation methodology, and the reference price of the capacity sold in following years is adjusted to meet allowed revenues or to ensure reconciliation of the regulatory account. Under the fixed payable price approach, users who book capacity in advance are protected from changes to the reference price between the time of booking and the time of use, and therefore do not have their charges scaled to meet changes in allowed revenues of the reconciliation of the regulatory account. In networks where allowed revenues grew significantly over time, the uneven protection of network users could undermine competition if higher charges are concentrated on future users or those booking shorter term.

Depending on how far and by how much capacity is booked ahead of the year of use, and depending on average changes in allowed revenues, over time, the fixed payable price has the potential to lead to a significant rebalancing of charges between existing and future network users.

Fixed vs. Floating tariffs

Contributions from various users to allowed revenues over time

For illustrative purposes, Figure 20 compares the percentage share of allowed revenues recovered in 2025 from users who booked capacity in 2015 and from users who booked capacity in the year in question (2025) under both payable price options, namely fixed versus floating tariffs. For simplicity it is assumed that 50% of capacity is booked in 2015 for a duration of 15 years and 50% is booked in 2025 on a yearly basis; that reference prices between points on the network are equal; and that allowed revenues in 2015 were 100, and grew at 5% per annum to reach 163 by 2025.

Figure 20: Floating versus Fixed payable price – revenue share 2025

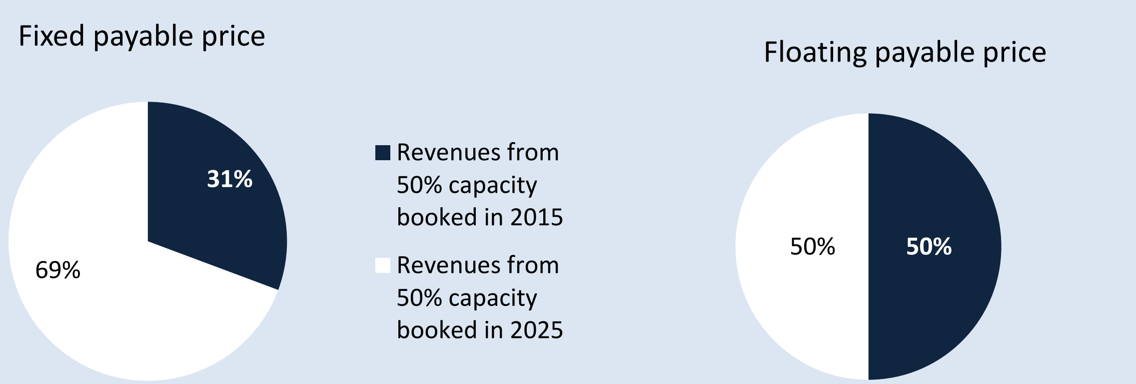


Figure 20 demonstrates the effect a fixed payable price regime, in combination with growing allowed revenues, would have on the level of charges paid by network users. Under the floating price regime all users would pay the same capacity charge, sharing the burden of paying for the increase in allowed revenues equally. Under the fixed price regime, all other things being equal, those shippers booking in 2025 would pay more than double than those booking in 2015.

Figure 20 provides an example of the effect of a fixed payable price regime in combination with growing allowed revenues. The assumption of a 5% per annum increase in allowed revenues for networks without significant new investments may be contestable, but in some fixed price regimes, capacity prices are not indexed to inflation, whereas allowed revenues are often adjusted for underlying economic circumstances, directly through Real Price Effects (RPE) indexation, and through the determination of the rate of return. In circumstances where allowed revenues were declining, it could be argued that downside risk to future users would be reversed, that those on fixed long term contracts would not benefit from the reduction in future reference prices. In this situation, although its effects would be different, it could still have an effect on the balance or risk sharing between existing and future network users.

Contributions from various users depending on their load factor

The following example compares the contributions of domestic and industrial users to the allowed revenue, when this revenue is recovered based on fixed capacity payable prices jointly with a commodity charge, and when this revenue is recovered based on a floating capacity payable price.

- **General Assumptions**

Table 12: assumptions regarding industrial and residential consumptions

	Residential	Industrial
Consumption*	0.7	0.3
Peak demand**	0.8	0.2

**relevant cost driver to distribute the fuel costs*

*** relevant cost driver to distribute CAPEX and other OPEX*

Table 13: Budgeted costs used to determine ex-ante the allowed revenue. Year Y

	Allowed revenue (M€)	Attributable to residential consumers	Attributable to industrial consumers
Fuel costs	75	52.5	22.5
Other OPEX	325	260	65
CAPEX	600	480	120
Total	1000	792.5	207.5
Initial cost allocation		**79%**	**21%**

Table 14: Revenue actually recovered

	Allowed revenue (M€)	Attributable to residential consumers	Attributable to industrial consumers
Total	900	713.25	186.75

From Table 15, there is an under recovery of - **100 M€.**

- **Revenue recovery: Floating price (adjustment of the capacity prices)**

Table 15: revenue recovery via floating price

	Under-recovery (M€)	Allocated to residential consumers	Allocated to industrial consumers
Total	-100	-80	-20
Cross-subsidy between end-consumers in comparison with the initial allocation		**-0.75**	**0.75**

- **Revenue recovery: Fixed price with commodity charges**

Table 16: revenue recovery via commodity charges

	Under-recovery (M€)	Allocated to residential consumers	Allocated to industrial consumers
Total	-100	-70	-30
Cross-subsidy between end-consumers in comparison with the initial allocation		**9.25**	**-9.25**

The majority of transmission costs are driven by capacity. Therefore, using commodity to reconcile under recoveries would generate important cross-subsidies between the different kinds of users: for example, an industrial consumer would be more exposed to the commodity charge because of its flat load profile.

In the context of a fixed payable price, the alternative to an adjustment of the payable capacity price is the use of a separate, commodity based charge. However, the share of allowed revenue that can be cost-reflectively recovered from gas flows is limited by the share of variable costs included in the allowed revenue. These are typically below 20% (see Figure 25). In addition, this approach, as opposed to the floating one, affects differently users depending on their load factor, being detrimental to industrial users (see example above).

Since this rebalancing could not be said to arise as a result of the charging methodology itself, and would seem to arise as a by-product of the fixed payable price approach, rather than to reflect underlying network cost drivers, it could be said to promote the inefficient pricing of capacity, the potential cross subsidy of one type of network user by another and, if the effects were concentrated, detrimental to competition. For this reason the Agency considers that the fixed payable price approach would less effectively deliver against the Tariff FG objectives than the floating tariff approach.

The Agency also considered the impact a floating payable price regime could have on network users' willingness to commit to long term capacity, relative to a fixed payable price regime in its evaluation. In this regard, the Agency has not seen compelling evidence either way, but the concept of a floating payable price is not a new one for many network users, and where stable charging methodologies are implemented, short term over/under recovery issues notwithstanding, transmission charging volatility should be minimised[51].

In the view of the Agency, network users' willingness to make long term capacity commitments will reflect their own evaluation of capacity scarcity, the extent to which they value capacity certainty, and the extent to which they value or anticipate short term capacity discounts. In the UK, which is the MS with the longest experience of capacity auctions, the long term certainty users obtain from fixed capacity prices is balanced by exposure to a floating commodity charge. The Agency's views on some of the potential drawbacks of this approach are discussed above in relation to risk sharing, but to the Agency's knowledge significant infrastructure constraints as a consequence of users being unwilling to make capacity commitments, has not been a feature of the UK regime. It may be that some users prefer the flexibility that a floating commodity price offers (users only pay this when they flow gas), but if cross subsidies are to be avoided, a level of tariff uncertainty is always likely to be a feature of a regulated revenue regime: responsibility for paying for variable allowed revenues cannot be diversified away.

Against the feasibility criteria Options 1, 3.a and 3.b were considered to perform best, while Option 2 could be more difficult to implement. Option 1 would require no implementation. Variants 3.a and 3.b would deliver a fully harmonised approach which would be compatible with the bundled IP capacity regime. Option 2 could imply difficult value judgements about the best way to integrate a single payable price for bundled capacity products and could result in divergent approaches[52] on either side of IPs which could be more difficult to administer. Against the acceptability criteria, among the 2012 consultation[53] responses, and among NRAs, there is support for a level of harmonisation; therefore the Agency considers Option 1 performs the least well. Among the other options it was a difficult to discern a majority opinion, therefore the Agency has ranked each of these equally. The Agency notes that there is consistent opposition to floating payable price among some network users. The Agency also notes

[52] Strictly speaking, the Framework Guideline allows a commodity charge to be levied at IPs, to the extent that it reflects flow based costs; this will remain an insignificant issue, as only a few MS are likely to adopt this approach, and the size of the charge will be relatively small.

[53] See question 7.1.1 of the 2012 public consultation – out of 43 respondents, 18 agreed with the proposed level of harmonisation; 6 opposed; 10 had no opinion.

that the concept of a fixed payable price regime in combination with a floating commodity charge as the harmonised approach, developed limited support in the FG development process.

7.5.1 Payable price – impact of Framework Guidelines

The provisions in the Framework Guidelines are equivalent to Variant 3.a in this area. This option is considered to be the best, against the criteria specified in Table 11. The Agency observes that despite the complexity of implementation, floating tariffs already applied in capacity auctions were well understood by network users.

Tariff adjustments for incremental and new capacity: floating payable price

The development of options in the area of incremental and new capacity built on the analysis set out above concerning the generic treatment of the payable price issue. If a floating payable price carries the least risk of cross subsidy for existing capacity bookings, then the same applies for incremental capacity: offering fixed prices for incremental capacity would insulate those booking incremental capacity from future increases in regulated allowed revenues and/or from future revenue reconciliations at the expense of increases for other users, particularly where revenue reconciliation is accomplished through an adjustment to capacity charges. In our view the effect this could have on the tariffs paid by those booking short term and those booking long term could be detrimental to competition. For this reason we consider that it is appropriate for the default approach of a floating payable price to apply equally to existing, incremental and new capacity.

In our view this approach is no more likely to increase future price risk for incremental and new capacity bookings than for existing capacity bookings. Following a decision to invest for incremental or new capacity, any over-run of projected investment costs would be, subject to NRA approval, recovered by the TSO through the primary cost allocation methodology, and therefore paid for by all network users, not concentrated only on those booking the incremental capacity. Among some Member States where fixed price long term capacity is currently offered, users are not insulated from the application of a variable commodity charge, therefore the concept of transmission tariff certainty is rarely found in practice, even for incremental capacity.

By necessity, the payable price for incremental and new capacity differs from the payable price for existing capacity on the question of auction premia. In the short run, the supply of existing capacity is limited; therefore users may elect to bid a premium to secure it. For incremental capacity the reverse is true. In the long run, environmental, planning and financial considerations notwithstanding, providing it is economic to do so, incremental and new capacity can be built to meet demand.

However, it is not economic to meet all demand for new capacity regardless of price. To determine what is economic, an Economic Test (ET) can be applied. Details concerning the parameters and application of the ET are also specified in the FG. The ET can be summarised as comparing the value of the binding financial user commitments in relation to the incremental or new capacity, with the deemed costs of the investment. Where the revenues equal or exceed a pre-determined proportion of investment costs (known as the f factor), the project is deemed economic and can proceed.

The issue that arises in relation to tariff adjustments for incremental and new capacity is what should be done in the specific circumstances where selling all the incremental or new capacity offered at the prevailing reference price would not generate sufficient revenues to pass the economic test. In such circumstances, there are two questions for consideration: what form of tariff adjustment or reserve price premium (if any) should be applied to better secure the investment, and to which users should it apply.

Table 17 presents the assessment of the options in this area against the assessment criteria.

Table 17: tariff adjustments options for incremental and new capacity

Option	Effectiveness	Feasibility	Acceptability	Total
1 No further action	0	3	1	**4**
2 Premium applied to all users of the IP (including existing bookings)	1.5	2.5	2	**6**
3 Premium applied to all future users of incremental and new capacity (excluding existing bookings)	2	2	2	**6**
4 Premium applied only to those triggering the incremental and new capacity	2.5	3	2	**7.5**

Option 1 would be the least effective as it would not address the problem. This could result either in potentially efficient investment projects not going ahead (for lack of tariff adjustment mechanism) or investment projects being approved on the basis of potentially inappropriate tariff adjustment mechanisms, potentially leading to cross subsidies between categories of network users. In our view neither of these outcomes would be compatible with the overall objectives of the FG.

Options 2, 3 and 4 are superior to Option 1 against the effectiveness criteria because each of these options would provide a harmonised approach to tariff adjustments which, to varying degrees, would concentrate the tariff adjustment on those users considered to benefit from the incremental or new capacity.

However, Option 4 scores slightly higher than Option 3, and higher still against Option 2 for two reasons. Firstly, it can be said to better preserve the integrity of the ET. The determination of the f factor value for the ET will take account of a number of factors, but having been determined, it is effectively an ex-ante assessment of the proportion of costs which should be covered by those triggering the incremental or new capacity investment, and the proportion which should be covered by other users in the market (1-f), in order for the project to go ahead. Allocating contributions to satisfy f from users other than those triggering the increment, as Option 3, and, to a greater extent, Option 2 would entail, could be said to undermine this assessment, resulting in a recalibration of cost sharing between users. Option 3 would protect those users who had already booked capacity from the tariff adjustment, and therefore seems less detrimental than Option 2 in this regard. We note, however, that under Option 3, where future users do not book capacity in the volumes or at the prices anticipated, other network users would have to pick up the slack, i.e. where assumptions about future users bids included in the ET calculation did not materialise. This could also have a potential cross-subsidy effect.

The second reason relates to the economic efficiency of capacity signals. It is arguably more relevant to concentrate any necessary premium on those triggering the incremental capacity (Option 4), because it is these users who are triggering the system cost. Administering a premium on all future bookings of the incremental capacity could be considered less efficient, as at that stage some investment costs would be already sunk costs. However, in reaching this assessment we note that in some circumstances Option 4 could lead to potential 'free rider' problems which NRAs may have to address in order to mitigate competition concerns. This could be the case if, as a consequence of the investment, a substantial volume of new or incremental capacity became available to the market at a much lower price than the price the user triggering the investment had to pay in order for the project to satisfy the ET. For this reason we have not scored Option 4 full marks against effectiveness, as it may not be the optimal approach under all circumstances.

Against the feasibility criteria Options 1, 2 and 4 were considered to perform best, while Option 3 could be more difficult to implement. Option 1 would require no implementation, while Options 2 and 4 would have the advantage of relative simplicity. Because Option 4 would apply the tariff adjustment only to the reserve price premium paid by those triggering the investment, it would preserve the concept of a universal floating payable price: those who had already booked, and those who booked in the future, would be subject to the same floating reserve price as generated by the cost allocation methodology. Option 2 is a little more problematic in this regard. It would also preserve the universal floating payable price, but applying the premium to all users of the capacity at the IP would imply an ongoing administered adjustment to the reserve price generated by the cost allocation methodology for that IP, which would differentiate it from the approach adopted at other IPs. Against the feasibility criteria Option 3 could be the most difficult to implement because it could potentially result in different reserve prices applying at the same entry or exit points: to differentiate the price paid by future users from that of existing users, two floating payable prices could be required, as opposed to just the premium adjustment implied in Option 4. Option 3 could also involve subjective value judgements about the appropriate value and duration of the premium to be paid by future users, which would undermine transparency.

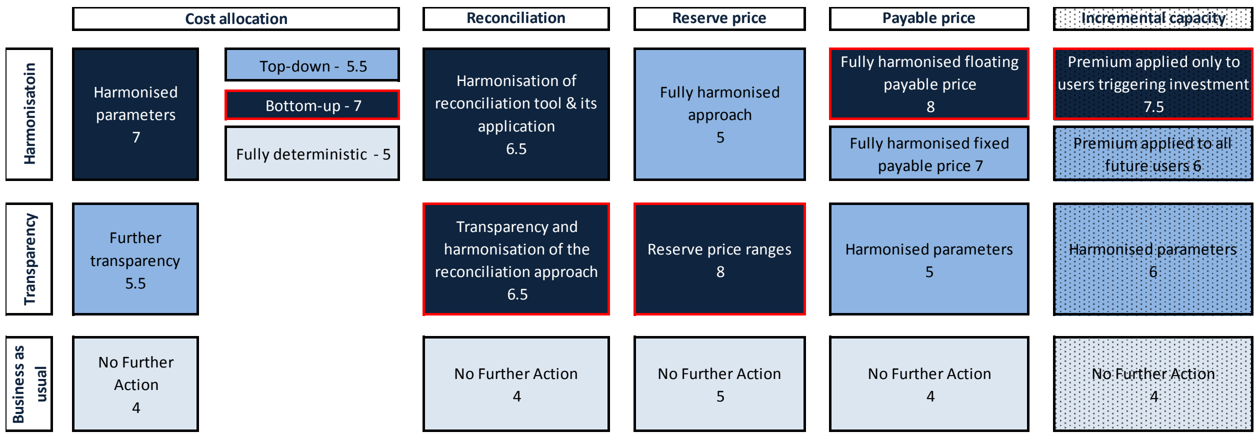
Against the acceptability criteria little difference is observed between the options. Option 1 is the least acceptable as the consultation showed that the Agency has a broad mandate towards harmonisation. Among the other options it is difficult to discern a majority view.

Conclusion

The provisions in the FG are a combination of Options 3 and 4 in this area. Option 4 is the default and should be adopted in the first instance, but the Agency also specified in the FG that in preparing the network code, ENTSOG shall consider alternative approaches, subject to a set of specified parameters. If in ENTSOG's view alternatives to Option 4, such as Option 3, satisfy these parameters, the Agency would expect ENTSOG to include them in the NC alongside a description of the circumstances under which they could be applied.

8 General conclusion: Preferred options, monitoring and evaluation

Figure 21: outcome of the assessment of the policy options



Note: Numbers represent the final assessment score (total) of Chapter 7 as in Table 6, Table 7, Table 8, Table 9, Table 11 and
Table ***17*** *– darker shades match higher scores, while selected policy options are framed in red.*

The following policies were included in the Framework Guidelines (in line with Figure 21 above):

- Cost Allocation: harmonised description of allowed methodologies, including limiting the number of methodologies to be used, and associated inputs. In addition, the methodology selection criteria include the obligation to justify the choice of methodology against circumstances criteria; the results of a cost allocation test; and a methodology counterfactual.
- Reconciliation: increased transparency and harmonisation of the tool used for revenue reconciliation (regulatory account) allowing a common approach to revenue reconciliation.
- Reserve price: harmonised parameters limiting the possibility of inconsistent approaches at IPs.
- Payable price: fully harmonised approach to payable price, via floating price

In the light of the foregoing, core indicators for monitoring the progress will be the following:

- The number of cost allocation methodologies in the EU;
- The performance of the chosen cost allocation methodologies against the cost allocation test;
- The discrepancies between reserve prices and payable prices observed at each side of EU interconnection points;
- The discrepancies between domestic capacity utilisation and domestic revenue (as in Figure 19 above)
- The proportions of revenue subject to reconciliation.

These indicators will be analysed based on the information requirements the Agency has foreseen in Section 1.4 of the FG. Additional information may be also required.

9 Related Documents

ACER/CEER Monitoring Report

- ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012

  http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202013.pdf

Evaluations of Responses

- Public Consultation on Scope and main policy options for Framework Guidelines on Harmonised transmission tariff structures (February 2012)

  http://www.acer.europa.eu/Official_documents/Public_consultations/PC_2012_G_14/PC_2012_G_14_ACER%20Public%20Consultation%20on%20Scope%20and%20main%20policy%20options%20for%20Framework%20Guidelines%20on%20Harmonised.pdf

- Public consultation on the draft Framework Guidelines on rules regarding harmonised transmission tariff structures for gas (5 September - 5 November 2012)

  http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/EoT_Draft%20Tariff%20FG_16_04_2013_for%20publication_TQ_clean.pdf

- Public consultation on Cost allocation methodologies and Tariffs for Incremental capacity ((18 July – 17 September 2013)

  http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/EoR_Draft%20Tariff%20FG_final.pdf

Consultancy reports

- Brattle Group's Impact Assessment for the Framework Guidelines on Harmonised transmission tariff structures – 6 August 2012
  http://www.acer.europa.eu/Media/Events/Public%20Workshop%20on%20FG%20on%20Harmonised%20Transmission%20Tariff%20Structures%20for%20Gas/Document%20Library/1/06%2008%202012_Brattle%20Draft%20FG%20tariffs%20IA%20report%20-%20Tables%20included%20v2.pdf

- Frontier Economics (February 2013) report on Impact assessment of policy options on incremental capacity for EU gas transmission.
  http://www.acer.europa.eu/Gas/Framework%20guidelines_and_network%20codes/Documents/Impact%20assessment%20of%20policy%20options%20on%20incremental%20capacity%20for%20EU%20gas%20transmission.pdf

Studies

ACER work on tariffs built on the **THINK study**, published in January 2012, and on the study on **Methodologies for Gas Transmission Network Tariffs and Gas Balancing Fees in Europe** (KEMA study) commissioned and published by the European Commission in December 2009. In addition, ACER work took account of the study on **Entry-Exit Regimes in Gas** (DNV-KEMA study) commissioned and first published by the European Commission in July 2013.

- Think Report on EU Involvement in Electricity and Natural Gas Transmission Grid Tariffication – January 2012 - http://www.eui.eu/Projects/THINK/Documents/Thinktopic/ThinkTopic6.pdf
- Both studies commissioned and published by the European commission are available following ec.europa.eu/energy/gas_electricity/studies/gas_en.htm

List of Annexes

Annex A - Ad hoc Expert Group on Harmonised Gas Tariff Structures

ACER set up an informal "Ad hoc" group of experts on harmonised gas tariff structures through an open call for interest. The goal of this group was to provide expert support to ACER during the development of the Framework Guidelines on rules regarding Harmonised transmission tariff structures. The experts were subject to confidentiality rules.

The Terms of Reference - with specific expertise criteria for the experts - and the Rules of Procedure for the expert group on harmonised gas tariff structures, on which the process for the selection of the experts was based, are provided in Annex 1 and Annex 2 of the Open Letter that was published to initiate the process[54].

As an outcome of this process, ACER decided to select 11 experts and 3 observers:

- AIMOLA Alberta, Edison
- ANGER Geoffroy, GDF Suez
- BARNES Alex, Gazprom Marketing & Trading
- DE WOLF Laurent, Fluxys
- GHIOSSO Ivan, EDF
- HAWKIN Debra, National Grid
- MEUZELAAR Dirk Jan, VEMW, IFIEC
- PEPTEA Agatha, E.ON Energie Romania
- PETROV Konstantin, KEMA
- PRESSE, Ralf, RWE[*]
- ROMAGOSA Clariana Jorge, Gas Natural Fenosa
- ASCARI Sergio, FSR (Observer)
- COLBERT Ann-Marie, ENTSOG (Observer)
- SISMAN Nigel, ENTSOG (Observer)

[*] *note: this member left the expert group in December 2012.*

[54] See http://www.acer.europa.eu/The_agency/Organisation/Expert_Groups/EG_on_Harmonised_Gas_Tariff_Structures/Pages/default.aspx

Annex B - list of the footnotes from Table 2

[1] The same transmission tariff is applied at all entry points while the tariffs at exit points are differentiated

[2] Differs among TSOs: the majority of TSOs applies postage stamp, some apply a cost allocation methodology that considers locational signals.

[3] Target split 50/50, but with market area integration of bookable points it has vanished for many TSOs

[4] Depending on TSOs methodology

[5] Some interconnection points are out of the RAB and for them an independent DFC model applies

[7] CER will implement a pricing system based on long-run marginal costs (LRMC). The revenues from entries and exits would be set at a 50/50 ratio (ignoring auction premiums).

[8] In Latvia Tariffs encompass commodity fixed price and transmission and storage service until 2014.

[9] Transmission tariffs are proportional to the consumption. For cross-border transmission a distance based component applies

[10] Transit contract to Kaliningrad (RUS)

[11] Polish part of the Yamal pipeline, named TGPS, which supplies Russian gas to Poland and Western Europe

[13] The proposal is approved after the hearing of the Tariff Council, which is composed by the stakeholders of the gas sector: regulated companies, suppliers and consumers associations.

[14] E/E system to be implemented in 2013 when a LRMC methodology will be applied

[15] No distinction between domestic and transit but Tariffs methodology does not apply to certain dedicated transmission lines

[16] P2P tariff based on distance for transmission transit and Postal Stamp for domestic exits.

[18] Revenue is calculated based on the standardised cost of the infrastructures

[19] At entry points capacity charge. At exit points capacity + commodity charge

[20] As the price for capacity will depend on the utilization, the resulting cost will correspond to a 0/100 split for zero utilization and to a 100/0 split for a full utilization.

[21] Preliminary objective, subject to auction revenues and network utilization

[22] The commodity charge is levied on both entry and exit points; the entry commodity charge is only applied if a revenue shortfall from capacity auctions is forecast.

[23] The price control mechanism consists of a revenue cap for OPEX and a rate of return for CAPEX.

[24] E/E system to be implemented in 2013 when a new methodology will be applied.

[25] Starting in February 2013, there will be separate entry/exit charges according to the New Tariff Regulation approved in 2012

[26] The Tariff Regulation was approved in 2012. The entry-exit tariffs came into force starting the 1st of February, 2013

[27] Methodology and Tariff calculation by NRA

[28] Limited to data provision

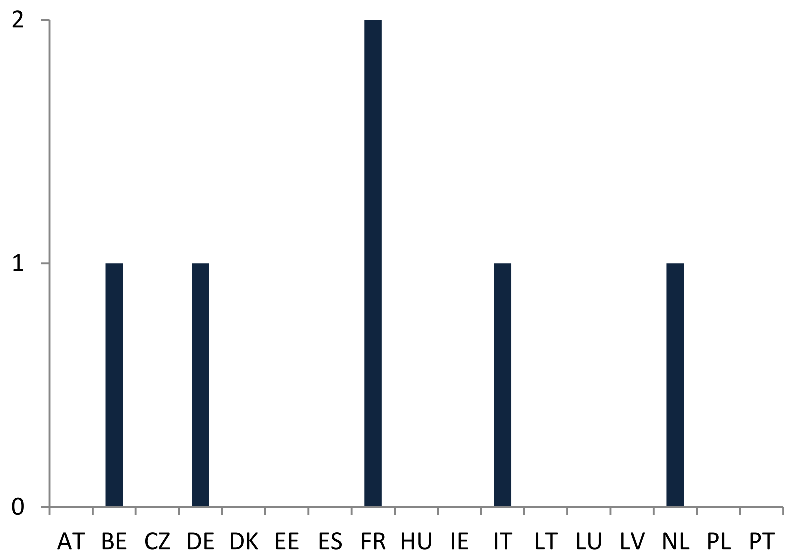
[29] From 1 January 2013

[31] Transit pipelines are not subject to special conditions; transit assets are identified for the purpose of cost allocation

[32] From 1st October 2013, capacity is being booked. The multipliers are: 1.3 for quarterly, 1.5 for 1 monthly and 2 for daily products.

Annex C – EU approaches to Tariffs

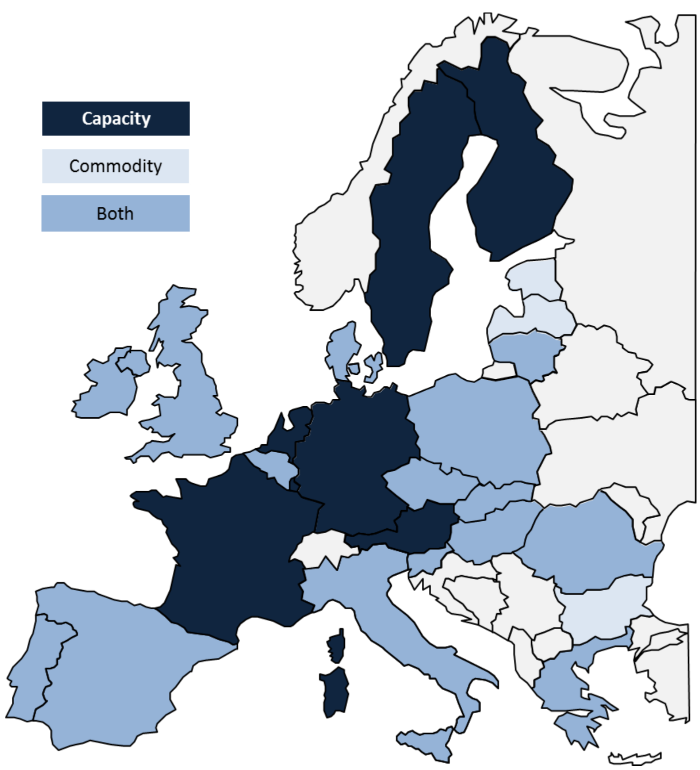
Figure 22: Total number of formal complaints* in years 2011-2012



Source: ACER

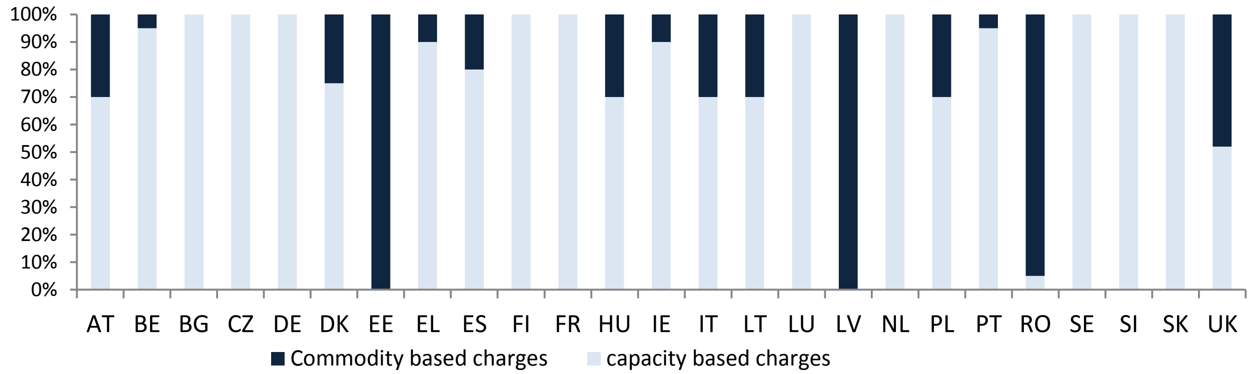
**Note: "formal complaints" mean any official, traceable (e.g. by letter or email) request for a change in the tariff structure.*

Figure 23: charges in use for revenue recovery in Europe



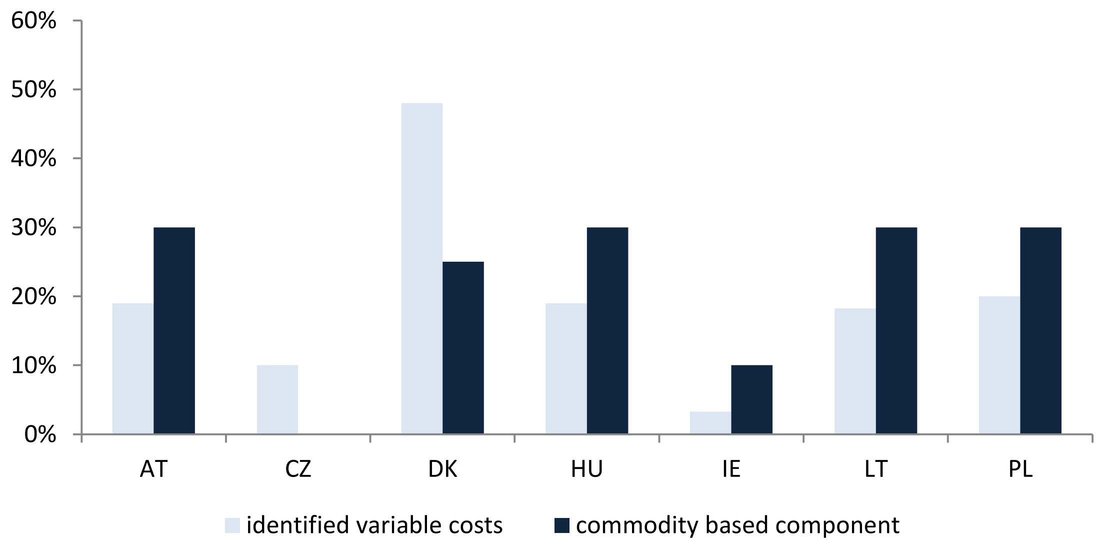
Source: Kema Entry/Exit study

Figure 24: Split between capacity- and commodity-based components in gas transmission tariffs



Source: Think, ACER country analysis

Figure 25: commodity-based components in gas transmission tariffs, compared to the observed variable costs in the system –



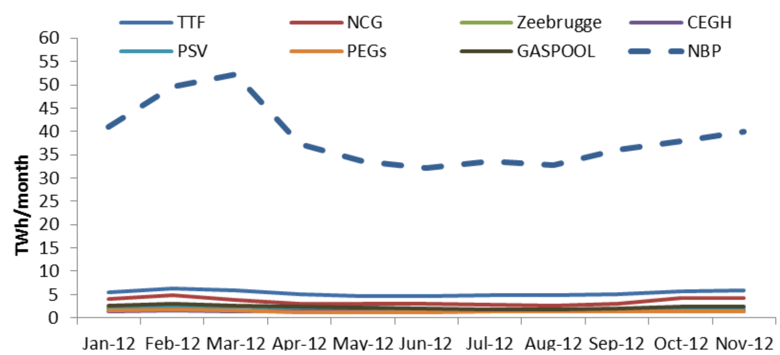
Source: Think, ACER

Annex D - Reasons For the 5 most significant average tariff evolutions over the period 2007-2012

Country	Reasons For the 5 most significant average tariff evolutions over the period 2007-2012
AT	Lower cost level accepted by E-Control
BE	(1) 2010 : Tariff decrease because of synergies in cross-border transport which became a regulated activity (2) 2011 : Socialization of compressor costs which were previously individualized (Court decision) (3) 2012 : Tariff decrease thanks to higher efficiency
CZ	(1) Setting prices according to fully implemented E/E system.
DE	(1) Merger of market zones/ Splitting of networks (2) Introducing of Karla Gas (profiled and short term booking possible) (3) shifting of bookings
DK	Auctions are defined in NC CAM and implemented at two separate stages. Emergency supply tariffs have been adjusted twice as part of the process of implementing the European SoS Regulation, changes to tariff structure reflects changes to the market (declining demand) and investments in import capacity to supplement declining national production.
ES	Annual update or extraordinary update to guarantee the revenue recovery
FR	Update of the booking assumptions, of the fuel costs and reconciliation of the regulatory account
HU	(1) Regular tariff correction during the regulatory period (2) Cost of a new investment included into the RAB
IE	(1) Reprofiling of required revenues (2) Pass through costs adjusted (3) Over-recoveries in certain years
LT	The largest reason why those adjustments took place is changing gas transportation volumes (most decreasing volumes).
NL	(1) decisions about new methodology (new x-factor) (2) cost for expansion investments (3) cost for market facilitation
PL	(1) Due to the expiry of a tariff period.
PT	(1) Reduction in forecasted demand (2) Increase in revenues to recover under recover of previous year (3) Change in the methodology of calculating the CAPEX, with impact on allowed revenues (4) ERSE only started to regulate transmission tariffs in 2007, so in the first year it was more difficult to forecast accurately
SK	50% of the average EU inflation rate
SL	(1) From 2007 to 2010 we have one year regulation period, from 2011 three years. For each regulatory period the methodology allows for tariffs change.
UK	(1) Supply/demand (possible increase in localised demand) (2) Supply/demand reduces negative long run marginal cost plus slightly larger revenue adjustment factor (to ensure revenue recovery) (3) Low price, small movements creates large percentage changes. Supply/demand changes (4) Supply/demand flows reduces negative long run marginal cost significantly (becomes positive) plus slightly smaller revenue adjustment factor compared to previous year. (5) Supply/demand flows increase negative long run marginal costs plus smaller revenue adjustment factor is applied.

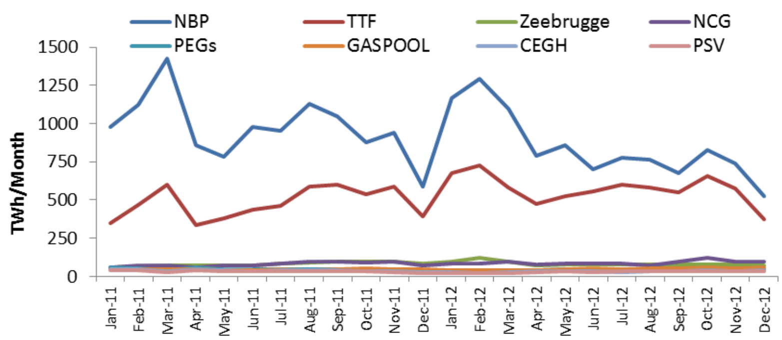
Annex E – Markets characteristics in EU (source: ICIS)

Figure 26: average volumes traded at HUBs (TWh/month) – 2012



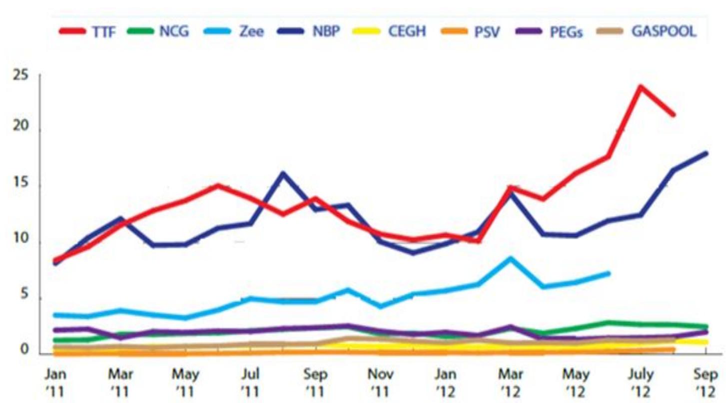
Source: ICIS

Figure 27: average volumes traded OTC (TWh/month) – 2012



Source: ICIS

Figure 28: churn ratios at hubs in Europe in 2012

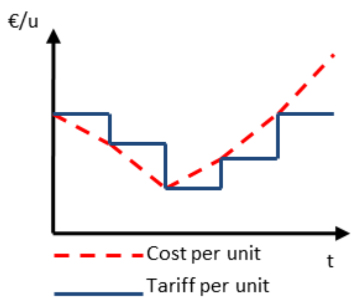
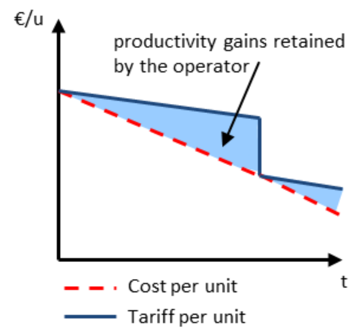


Source: ICIS

Annex F - Cost-plus vs. Price (or Revenue) cap

There are two main theoretical approaches to regulated gas transmission tariffs:

- "Cost-plus" consists of tariffs which are designed **to cover the observed costs** of the operators. Since the approach is based on actual cost, there is no incentive for the system operator to lower its cost.
- "Price-cap" or "revenue cap" consists in covering **the efficient costs of the operators**, by establishing a trajectory for the evolution of the tariffs (price cap) or the revenues to be recovered, for a longer period of time. In that context, the operator is incentivised to "beat" the objectives defined by the regulator, as it can retain all or a part of the productivity gains. Under a price-cap regime, the risk associated with the volume of sales is borne by the operators. Under a revenue cap regime, it is borne by the system users.

Approach	Cost-plus	Price/Revenue Cap
Objective	The overarching goal is the minimisation of the regulatory rent, i.e. minimising the risk that the operator is able to set a price higher than its long-term production cost.	The overarching goal is efficiency, i.e. encouraging the operator to achieve productivity gains thus to provide the service at a lower price for the desired level of quality.
Tariff evolution over time		
Advantages	· Limits the possibility for operators to extract long-term rents; · Increases financial visibility and limits financial risk for the operator who is insured to recover its costs; · Allows a faster integration of the effects of depreciation in the tariff level.	· Incentivises productivity; · With longer tariff periods, provides increased visibility to shippers and operators.
Drawbacks	· Does not provide incentives for the operators to be cost efficient and business oriented; · As a consequence, might not address or generate inefficiencies; · Requires frequent tariff adjustments.	· Is a more rigid framework in which regulatory adjustments may not be easily performed; · As a consequence, an inappropriate of price or revenue could trigger losses for the operator (cap too low) or excessive rent ("windfall profits"- cap too high). · In addition, operators seeking productivity gains could be exposed to decreases in quality and level of investment.

The relationship regulator-operator can be seen as a principal-agent relationship, where the regulator (principal) should control the operator (agent). The main difficulties for the regulator are: (1) that regulator and operator have different objectives and (2) the regulator is in a situation of information asymmetry vis-à-vis the operator (the operator knows better the system it runs).

To overcome information asymmetry, the regulator may conduct audits, or design a tariff structure that would encourage the operator to reveal information about cost efficiency levels. The latter is the objective pursued with price or revenue cap systems, within which an operator willing to maximise its profit must improve productivity, thereby revealing its cost efficiency levels.

In practice, neither “cost-plus” nor “price” or “revenue cap” is applied in its pure form. In general, price regulations applied by NRAs show both features. Regulators fragment the allowed revenue in various components (for example OPEX / CAPEX) to which they apply a given approach based on certain criteria.

Annex G - Theoretical analysis of the Impact of Cost allocation methodologies on Tariff levels

In this analysis, for a given network, costs are allocated using the following methodologies:

- Postage stamp;
- Variant A of Capacity-weighted distance;
- Variant B of Distance to the virtual point;
- Matrix.

Note: Variant B of capacity-weighted distance and variant A of Distance to the virtual point were not developed here. Capacity-weighted distance (variant B) only differs from variant A by initially restricting possible combinations of entry and exit points. An analysis of the possible impact of such assumption could be assessed at a later stage. The necessary information and tools to run Distance to the Virtual Point (variant A) were not made available to ACER.

Inputs

Table 18 below lists the inputs that were used in association with the cost allocation methodologies.

Table 18: Input overview

Inputs	Postage Stamp	Capacity-weighted	Distance to the Virtual	Matrix
Revenue				
Allowed revenue	X	X	X	X
% revenue to be collected from Entries	X	X		X
Capacity				
Booked capacity	X	X	X	X
Technical capacity		X	X	X
Standard investment costs				X
Network representation				
geodesical distance		X		
topological distance				X
Consumption points geographical coordinates			X	

- **Revenue hypotheses**
  - Allowed revenue: 100 000€;
  - Revenue to be collected from Entries: 50%.
- **Network representation**

  Figure 29 below is the map of a simple unmeshed network consisting of 3 entry points and 4 exit points. Table 19 provides the coordinates for these points. Table 20 provides both geodesic distance (shortest distance between two points) and topological (along the pipeline) distances.

Figure 29: Network representation

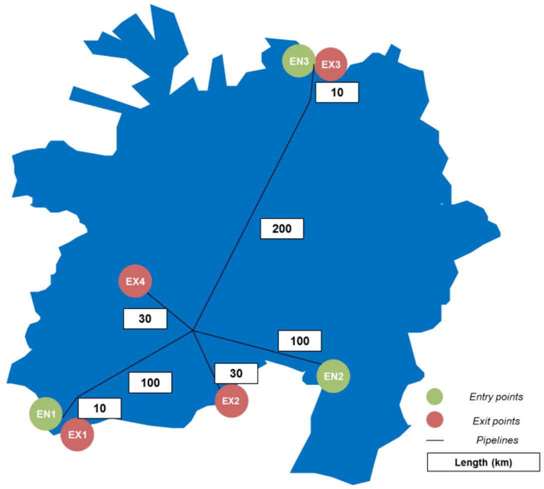


Table 19: Network point coordinates

Network point	X (km)	Y (km)
Entry point 1	0	0
Entry point 2	197	55
Entry point 3	185	241
Exit point 1	0	0
Exit point 2	115	26
Exit point 3	185	241
Exit point 4	67	60

Table 20: network distances (km)

	Geodesic	Topological
En1 to Ex1	0.00	0
En1 to Ex2	117.90	140
En1 to Ex3	303.82	320
En1 to Ex4	89.94	140
En2 to Ex1	204.53	210
En2 to Ex2	86.98	130
En2 to Ex3	186.39	310
En2 to Ex4	130.10	130
En3 to Ex1	303.82	320
En3 to Ex2	226.11	240
En3 to Ex3	0.00	0
En3 to Ex4	216.07	240

- **Capacity**

Table 21 below lists values used for capacity-related inputs.

Table 21: network capacity (GWh/h)

Network point	Technical capacity (GWh/h)	Booked capacity (GWh/h)
Entry point 1	400	350
Entry point 2	300	290
Entry point 3	100	100
Exit point 1	400	340
Exit point 2	100	90
Exit point 3	50	50
Exit point 4	50	50

In addition to booked and technical capacity, the matrix methodology requires the association of a cost to each path from one entry to one exit in the system.

In this example, this was done as follows:

- each segments' capacity was calculated:

$$C_{En_iEx_j} = \frac{TC_{En_i} \times TC_{En_j}}{Max(\sum TC_{En}, \sum TC_{Ex})}$$

Where
$C_{En_iEx_j}$ is the segment technical capacity from Entry point i to Exit point j (GWh/h);
TC_{En_i} (respectively TC_{En_j}) is the technical capacity at entry point i (respectively exit point j) (GWh/h).

- the following formula was used for the standard investment costs:

$$SIC_{En_iEx_j} = 0.0502 * C_{En_iEx_j} + 0.278$$

Where
$SIC_{En_iEx_j}$ is the standard investment cost from Entry point i to Exit point j (€*GWh/h/Km)

- The unit distance costs are derived from the previous values

$$UDC_{En_iEx_j} = \frac{SIC_{En_iEx_j}}{C_{En_iEx_j}}$$

Where
$UDC_{En_iEx_j}$ is the unit distance cost from Entry point i to Exit point j (€/Km)

Finally, costs associated with each segment were obtained by multiplying the unit distance costs by the length of each segment (see Table 20).

Table 22: segment costs calculation steps

	Segment capacity	Standard investment costs	Unit distance costs	Segments costs
En1 to Ex1	200.00	10.32	0.05	**0.00**
En1 to Ex2	50.00	2.79	0.06	**7.81**
En1 to Ex3	25.00	1.53	0.06	**19.62**
En1 to Ex4	25.00	1.53	0.06	**8.58**
En2 to Ex1	150.00	7.81	0.05	**10.93**
En2 to Ex2	37.50	2.16	0.06	**7.49**
En2 to Ex3	18.75	1.22	0.07	**20.16**
En2 to Ex4	18.75	1.22	0.07	**8.45**
En3 to Ex1	50.00	2.79	0.06	**17.84**
En3 to Ex2	12.50	0.91	0.07	**17.39**
En3 to Ex3	6.25	0.59	0.09	**0.00**
En3 to Ex4	25.00	1.53	0.06	**14.72**

Cost allocation methodology

Each methodology followed the steps described in the Tariff Framework Guidelines.

For Distance to the Virtual point (variant B), it is necessary to arbitrary select a reference entry point, and a reference exit point for the determination of tariffs. For this example, Entry point 1 and Exit point 1 were selected.

Secondary adjustments

For the matrix methodology, a rescaling was performed, in order to recover the allowed revenue, while respecting the entry/exit split. Table 23 shows the outcomes of successive rescaling, in €/GWh/h.

Table 23: Matrix rescalings

	Tariffs (before rescaling)	Tariffs scaled for revenues	Tariffs scaled for E/E split
En1	4.32	67.51	50.21
En2	6.93	108.18	80.45
En3	7.84	122.32	90.97
Ex1	3.30	51.46	78.53
Ex2	4.65	72.52	110.66
Ex3	6.90	107.69	164.33
Ex4	4.30	67.16	102.48

Outcome and first conclusions

As shown in Table 24, Figure 30 and Figure 32 below, depending on the approach, the outcome of the cost allocation methodologies can widely differ at a given point. The modelling of the level of tariff variance arising from applying four of the methodologies currently in use in certain member states to a simplified network shows that variations up to 95% compared to the average value per entry/exit point are possible, depending on the chosen allocation methodology.

These variations may result from the inputs, the cost allocation methodologies and their associated assumptions, and the secondary adjustments. These results reinforce the importance of a proper selection of the applicable cost allocation methodology at national level, something which has been enshrined within the FG.

In interpreting such results, it is important to note that the analysis is based on a simplified network, and does not take account of the network characteristics that may make one methodology more suitable than another for a given entry-exit zone. The issue of network characteristic and circumstantial effects of cost allocation methodologies will be developed in detail during the Network code process. Nevertheless, given the divergence of possible tariff outcomes, the results of the analysis on a simplified network indicate the importance of harmonised, objective and transparent methodology selection criteria.

Table 24: annual capacity tariffs for a given network, applying various cost allocation methodologies (€/GWh/h/a)

Output	Postage Stamp	CWDA	DVPB	Matrix
Entry point 1	67.57	29.99	77.93	50.21
Entry point 2	67.57	91.69	39.66	80.45
Entry point 3	67.57	129.15	59.80	90.97
Exit point 1	94.34	89.96	107.17	78.53
Exit point 2	94.34	88.78	96.91	110.66
Exit point 3	94.34	147.90	94.50	164.33
Exit point 4	94.34	80.53	107.17	102.48

Figure 30: tariff comparison depending on the cost allocation methodology (tariffs expressed in €/GWh/h/a)

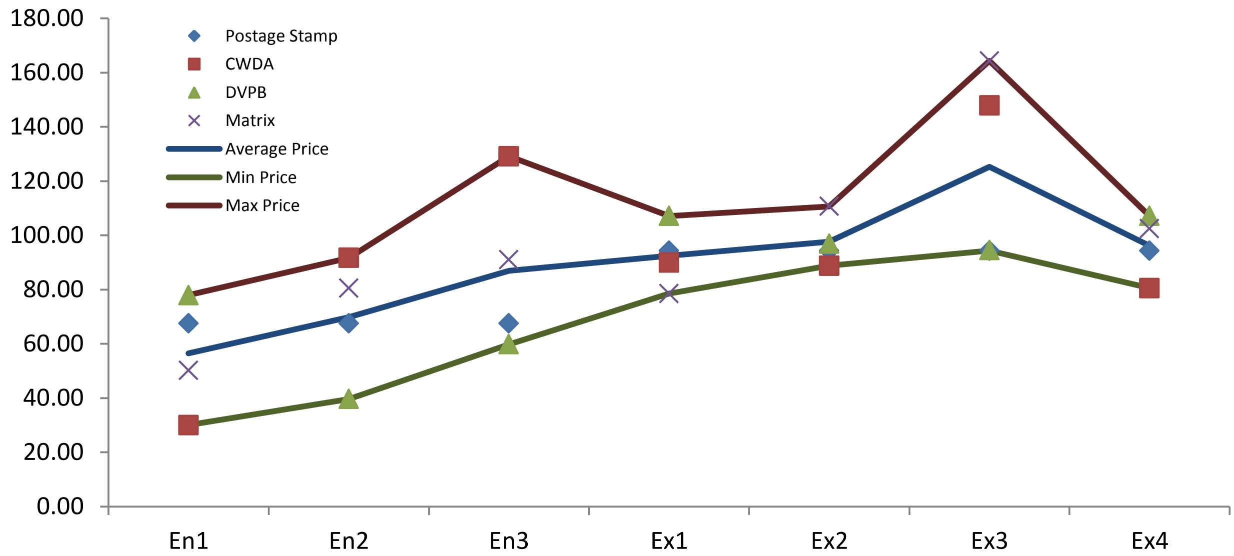
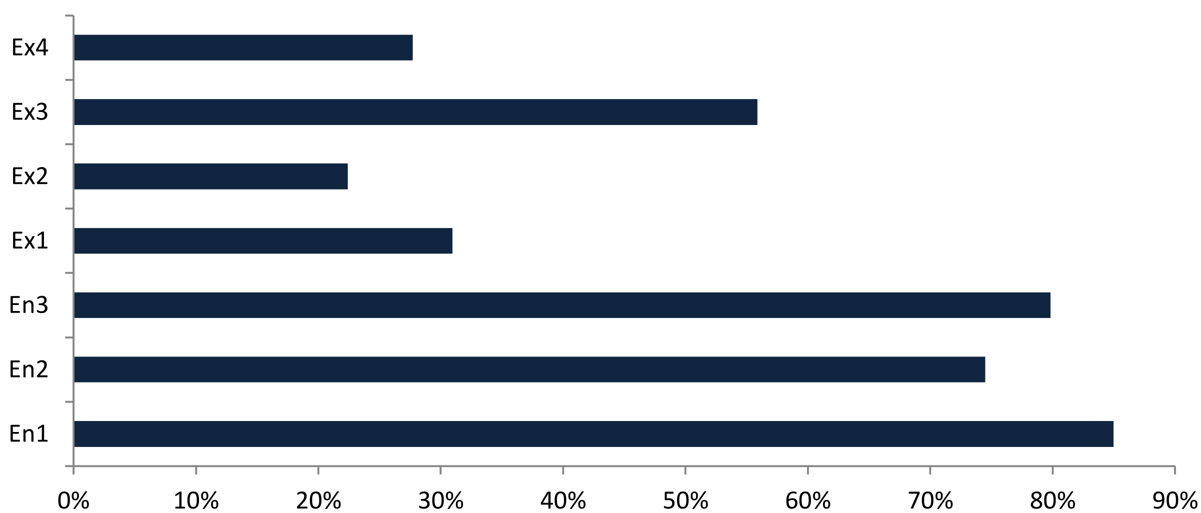


Figure 31: amplitude of the tariff variations as a proportion of the average tariff



Influence of the Entry/Exit split

The influence of the Entry/Exit split is further studied here.

Note: the influence of other inputs should be further studied while developing the Network Code.

Two possible impacts of the Entry/Exit split were studied:

- For a given split at a given point, how the minimum, average and maximum tariffs react (as in Figure 31)?

- Considering all possible splits and all possible tariff values, would the range between the lowest and the highest possible tariff change?

The postage stamp, capacity weighted distance (A) and Matrix methodologies were run, with variations of the revenue to be collected from entries from 0 to 100%, by increments of 10%.

Table 25: amplitude of the tariff variations depending on the Entry/Exit splits

Amplitude	0-100	10-90	20-80	30-70	40-60	50-50	60-40	70-30	80-20	90-10	100-0
En1		76%	76%	76%	76%	76%	76%	76%	76%	76%	76%
En2		30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
En3		64%	64%	64%	64%	64%	64%	64%	64%	64%	64%
Ex1	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	
Ex2	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	
Ex3	52%	52%	52%	52%	52%	52%	52%	52%	52%	52%	
Ex4	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%	

Table 25 confirms that, except for values of 0% and 100% of revenue to be recovered from Entry points, the tariff variations to the average tariff observed in Table 24 are not influenced by the Entry/Exit splits, as while tariff levels will change, variations around the tariff average remain unchanged.

Comparing the ranges of possible tariff choices at each point, for each of the three methodologies and the various Entry/Exit splits, Table 24 becomes:

Table 26: annual capacity tariffs for a given network, applying various cost allocation methodologies, for various E/E splits (€/GWh/h/a)

	Postage Stamp		CWDA		Matrix	
Output	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
En1	135.14	0.00	59.97	0.00	100.42	0.00
En2	135.14	0.00	183.38	0.00	160.90	0.00
En3	135.14	0.00	258.30	0.00	181.94	0.00
Ex1	188.68	0.00	179.93	0.00	157.06	0.00
Ex2	188.68	0.00	177.57	0.00	221.32	0.00
Ex3	188.68	0.00	295.81	0.00	328.66	0.00
Ex4	188.68	0.00	161.06	0.00	204.96	0.00

Figure 32: tariff comparison depending on the cost allocation methodology, for various E/E splits (tariffs expressed in €/GWh/h/a)

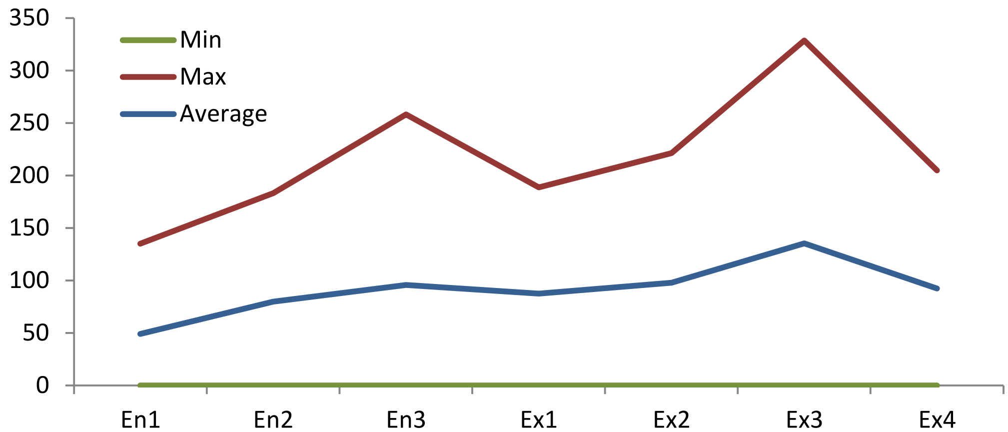


Figure 33: amplitude of the tariff variations as a proportion of the average tariff, for various Entry/Exit splits

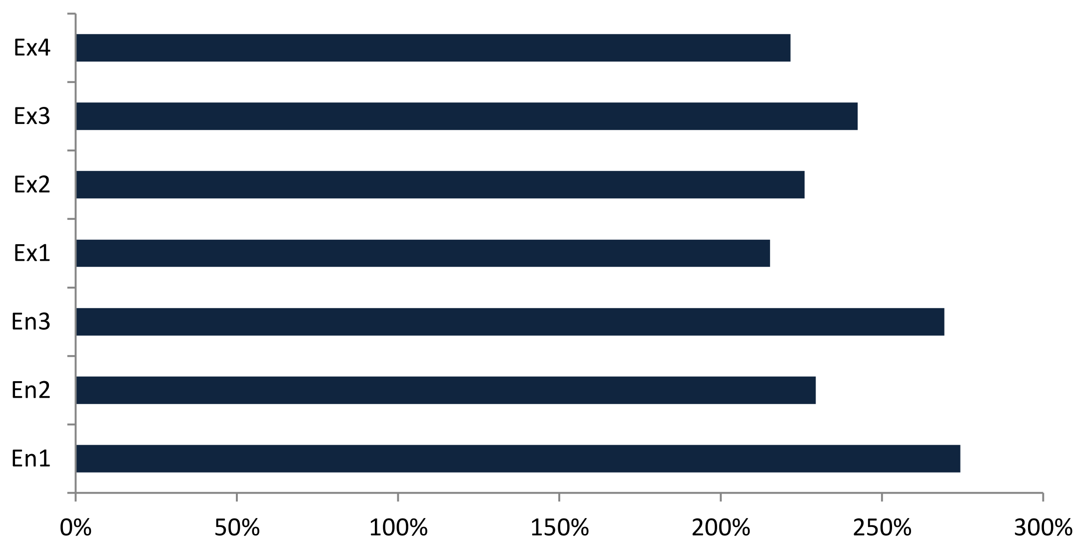


Figure 32 and Figure 33 show that at a given point, considering all possible splits and all possible tariff values, the range between the lowest and the highest possible tariff increased.

Annex H - Impact of different capacity commodity splits *(source: Brattle)*

In the following example, two operators were considered (called TSO B and TSO C). Both had the same underlying costs, but adopted different approaches to recoveries via capacity and commodity charges. While TSO B recovered all of its revenues via a capacity charge (see relevant countries in Table 2), TSO C recovered only 70% through a capacity charge. Given the choice, a user with a low load-factor would prefer the route through TSO C, since it ships a relatively low level of commodity. A user with a high load-factor would prefer the route through TSO B.

Table 27: capacity/commodity splits

			TSO_B		TSO_C	
			cross-border route	domestic route	cross-border route	domestic route
Total capacity booked	[1]	Assumed	1	1	1	1
Total volumes transported	[2]	Assumed	6,000	4,000	6,000	4,000
Cost allocated to entry	[3]	Assumed	5.0	2.5	5.0	2.5
Costs allocated to exit	[4]	Assumed	5.0	2.5	5.0	2.5
% costs allocated to capacity	[5]	Assumed	100%	100%	70%	70%
% costs allocated to commodity	[6]	Assumed	0%	0%	30%	30%
Cost allocated to entry (capacity component)	[7]	[3]x[5]	5.0	2.5	3.5	1.8
Cost allocated to entry (commodity component)	[8]	[3]x[6]	0.0	0.0	1.5	0.8
Costs allocated to exit (capacity component)	[9]	[4]x[5]	5.0	2.5	3.5	1.8
Costs allocated to exit (commodity component)	[10]	[4]x[6]	0.0	0.0	1.5	0.8
Entry capacity tariff	[11]	See note	3.8	3.8	2.6	2.6
Entry cammodity tariff	[12]	See note	0.00000	0.00000	0.00023	0.00023
Exit capacity tariff	[13]	[9]/[1]	5.0	2.5	3.5	1.8
Exit commodity tariff	[14]	[10]/[2]	0.00000	0.00000	0.00025	0.00019
User 1 - low load factor						
Load factor	[15]	Assumed	3,000		3,000	
Tariff per unit volume	[16]	([11]/[15]+[12]+[13]/[15]+[14])x1,000	**2.9**		**2.5**	
User 2 - high load factor						
Load factor	[17]	Assumed	8,000		8,000	
Tariff per unit volume	[18]	([11]/[17]+[12]+[13]/[17]+[14])x1,000	**1.1**		**1.2**	

Notes and sources:
[11]: Sum of [7] for domestic and cross-border routes divided by the sum of [1] for domestic and cross-border routes.
[12]: Sum of [8] for domestic and cross-border routes divided by the sum of [2] for domestic and cross-border routes.
[16]: ([11]/[15]+[12]+[13]/[15]+[14])x1,000
[18]: ([11]/[17]+[12]+[13]/[17]+[14])x1,000

Source: Brattle

Annex I - Cross-subsidies between domestic and transit users (from the THINK study)

In entry-exit systems of network tariffication there is often a systematic bias in the form of a cross-subsidization between short distance transmission and long distance (cross-border) transportation (GTE, 2005; Kronfuss, 2009; CIEP, 2009).

Tariffs at a specific entry point are equal for all network users, independent on whether the gas is transported only a few km to the next local consumption centre or a few hundred km across the whole entry-exit zone.

Thus, domestic consumers tend to cross-subsidize transit flows, and transmission over some hundreds of km can even be cheaper than transmission over 50km depending on the pricing at individual exit points.

Table 28: Entry/Exit split for distances 60 km, 110 km, 260 km and 350 km

		60 Km	110 Km	260 Km	350 Km
France	GRTgaz	83/17	73/27	63/37	59/41
France	TIGF	34/66	34/66	32/68	33/67
Belgium	Fluxys	19/81	19/81	19/81	19/81
Denmark	Energinet.dk	50/50	50/50	50/50	50/50
Hungary	MOL	77/23	77/23	77/23	77/23
The Netherlands	GTS	59/41	54/46	38/62	26/74 (1) 50/50 (2)

Source: Brattle

The optimal size of market areas, due to economic inefficiencies, should be taken into consideration when evaluating mergers. Some countries (e.g. Italy, France, or the UK) have introduced so called 'short-haul tariffs' in order to adjust tariffs for short distance transportation and to mitigate this effect and potential distortions in competition (see also Kema/Rekk, 2009). In Italy, for example, there is a discount for gas transportation over distances of less than 15km; shippers pay 1/15 times the distance in km times the standard tariff.

Annex J – Gas Storage

Gas storage can generally be used in two ways[55]: to meet base load and foreseeable seasonal swing requirements, and to meet short run peak requirements, including unforeseen supply disruptions. Storage installations can react to price changes, depending on their technical characteristics and on the availability of a transparent wholesale price reference in the market concerned.

Decision making over the extent to which storage is used is based on commercial and economic considerations. Whether storage flexibility can compete with other flexibility tools depends on the price difference between storage price and the price of the competing flexibility tool, on the development of the summer – winter gas price spread and on transmission costs.

Two regulatory approaches can be applied to gas storage based on the Third package: regulated access and negotiated access. Regulated access to storage sets regulated prices as well as ensures regulated access to the sites, thus creating greater transparency to users, while less flexibility to the operator is provided, compared to negotiated access to storages. GSE referenced 8 EU countries, where negotiated access to storages is allowed and 10 offering regulated access to storages, in July 2013[56].

The different regulatory approaches result in different approaches to transmission tariffs for gas storage in different EU countries. The Agency is of the view that the basic principles adopted in setting transmission tariffs for gas storage should be harmonised. These principles should ensure that NRAs take into account the underlying economic benefits gas storage may provide to the network when setting or approving the level of transmission tariffs that gas storage facilities face, including whether a tariff discount for storage would be appropriate.

The benefits brought by gas storage to a system are relative to that system. The benefit storage can bring to a system, depends:

- On the local access to other sources of flexibility; and
- On the distance the system has from its gas supply sources.

For producing countries, flexibility can be obtained from producers directly. For importing/ consuming countries, the more distant the system is from the gas production site, whose gas it consumes, the more the flexibility it needs has to be addressed via downstream sources, such as storage sites, line-pack or LNG terminals etc.

The principles should also ensure that transmission tariffs for storage are not priced in such a way as to arbitrarily affect the efficiency of cross border gas flows. Where the benefits of gas storage are not appropriately evaluated there is a risk that tariffs result in distortions to the gas market potentially attracting storage developers to markets where the tariffs are cheaper (discounted), rather than to markets where storage is needed the most, or potentially, incentivising gas flows contrary to gas hub price differentials. These potential distortions can occur between competing gas storage facilities, where stakeholders are able to buy and use the storage flexibility in

[55] This summary of gas storage utilisation appears in the relevant section of the ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011.

[56] http://www.gie.eu.com/index.php/maps-data/gse-storage-map

different (usually adjacent) member states and those storage facilities are subject to different tariff structures. The potential for this effect has been observed specifically[57]:

- At the border between Germany and the Netherlands;
- At the border between Germany and Austria;
- Between Ireland and Great Britain.

Evidence/stakeholder support

During ACER's public consultation on the scope of the FG, only two out of thirty-eight respondents suggested including gas storage tariffs[58]. Following ACER's public consultation on cost allocation methodologies and the determination of the reference price launched in July 2013, only one out of forty-one respondents listed this issue as one of the most important to be tackled by the FG[59].

Conclusions

For the reasons set out above, the Agency considers that it is important that the principles for setting gas storage tariffs are subject to harmonisation. For this reason the Agency adopted the approach that offers flexibility to NRAs to determine the storage tariffs appropriate to the characteristics of the national network. The FG specifies that in setting or approving gas storage tariffs the following should be taken into account: the benefits which storage facilities may provide to the transmission system; the need to promote efficient investments in networks; and in addition, the FG specifies that NRAs shall also minimize any adverse effect on cross-border flows.

The Agency has no evidence to support a more specific provision for gas storage tariffs, or an approach which, given the potentially divergent nature of different storage facilities within different countries, could have a universal application[60]. In the absence of such evidence, mandating a specific harmonised approach would have potentially been contrary to the subsidiarity principle.

Furthermore, the imposition of harmonised storage discounts on an EU level, overlooking the complexity and the heterogeneity of the benefits storages offer, could have triggered distortions in the functioning of the gas market and cross-border trade, with the potential that other users subsidise storage. The Agency is of the view that this would have been contrary to the objectives of the FG.

[57] See Section 3.5.1 of the Poyry report sent by VNG in addition to their contribution to the 2012 public consultation http://www.acer.europa.eu/Official_documents/Public_consultations/PC_2012_G_14_responses/Annexes%20to%20some%20responses/Gas%20Storage%20Netherlands%20-%20600_VGN_Transportation_tariff_report%20v2_0.pdf

[58] See question 5 of ACER consultation on scoping http://www.acer.europa.eu/Official_documents/Public_consultations/PC_2012_G_14/PC_2012_G_14_ACER%20Public%20Consultation%20on%20Scope%20and%20main%20policy%20options%20for%20Framework%20Guidelines%20on%20Harmonised.pdf

[59] See question 32 of the 2013 Public Consultation - See section 9 *supra* for full reference

[60] The lack of underpinning evidence is, in particular, true for the statements contained in the Brattle report. No further supporting evidence resulted from the consultation processes that followed the publication of these conclusions.

Annex K - Pricing of non-physical backhaul capacity and interruptible products (Source: ACER, Brattle)

Article 14 (1)(b) of the Gas Regulation requires that TSOs shall provide both "firm and interruptible third-party access services"; it clearly sets out that the price of interruptible capacity shall "reflect the probability of interruption". In addition, Article 16(1) of the Gas Regulation requires a Transmission System Operator (TSO) to make maximum capacity on its system available to market participants.

The probability of a backhaul product to be interrupted depends on the forward flow nominations. It can thus be considered either interruptible or firm, when combined with relevant CMP measures. Firm backhaul is currently being offered in the Netherlands.

At unidirectional interconnection points, where technical capacity is offered only in one direction, transmission system operators shall offer backhaul as a daily product for interruptible capacity in the other direction.

The THINK study reports that as of 2011, "[n]on-physical backhaul capacity is only offered by the minority of TSOs."[61] Accordingly, the key problem in the context of this study is the lack of consistency in the pricing of interruptible capacity and backhaul capacity, and an inconsistency in the availability of the latter.[62]

Table 29: assessment of the current offer of backhaul at EU IPs

	2010	2013
Number of Unidirectional IPs	55	56
Where backhaul not offered	13	19
Where no data on backhaul offers	2	14

Source: ENTSOG[63]

If backhaul is offered as an interruptible product, it will differ from interruptible products offered in the flow direction in three aspects:

- Other interruptible capacity is offered on top of firm capacity, whereas backhaul is offered against a physical flow: the latter enables new transaction paths. Non-physical backhaul capacity thus enhances cross-border trade by providing players with access to markets that they otherwise would not reach. Market players can take advantage of arbitrage opportunities which will improve liquidity and help develop competition.
- The availability of other interruptible capacity mainly depends on physical network parameters such as consumption and network configuration. These can to some extent be anticipated or programmed by the TSO. To the contrary, without the forward flow nomination – a commercial parameter which is outside of the TSOs control – the TSO cannot program a non-physical backhaul flow.
- It has been argued that backhaul flows have the potential to reduce network variable and perhaps fixed costs - through postponing network expansion, by relieving congestion in the direction of the physical flow.

The Agency submitted to public consultation[64] two possible approaches to the pricing of backhaul capacity:

[61] THINK report p.39.
[62] See THINK report, p. 40.
[63] http://www.entsog.eu/public/uploads/files/maps/transmissioncapacity/2013/ENTSOG_130724_Map-Data_CAP.zip
[64] See section 4.4 of the 2012 Public Consultation - See section 9 *supra* for full reference

- **'service view':** non-physical backhaul should be priced like any other interruptible product based on the probability of interruption, reflecting the market value of an interruptible product for its user; or
- **'incentives approach':** interruptible backhaul flows have the potential to reduce network costs and should follow a marginal cost pricing, a pricing that remains within the perimeters of cost-reflectivity, reflecting the costs of offering such product.

The outcome was balanced, with 16 respondents supporting each approach.

In its final drafting of the framework guidelines, the Agency considered the KEMA/REKK study on Methodologies for Gas Transmission Networks, where it is reported that backhaul capacity prices that are well above its 'costs' would prevent efficient arbitrage between neighbouring markets and may contribute to a sub-optimal use of the network.[65]

The Agency thus favoured the 'incentive approach', based on marginal costs disallowing zero or negative prices for interruptible backhaul, as the best balance between the objectives of cost-reflectivity, non-discrimination and promotion of competition and efficient network use.

[65] See KEMA/REKK report, p. VI.

Annex L – Mitigating measures

The FG specifies that the provisions in the NC on Tariffs shall apply to all contracts from 1 October 2017 at the latest. However, in order to mitigate the impact of applying the new tariff levels that full implementation of the Tariff NC by 1 October 2017 may require, consideration within the FG has been given to the scope and eligibility criteria for applying ‘mitigating measures’. The effect of applying mitigating measures would be to delay the application of new tariff levels at one or more entry or exit points on an entry-exit system where the relevant criteria were met.

The effect of the April 2013 draft FG was that mitigating measures could be applied for a period of 12 months following October 1, 2017, where moving to the new tariff level by 1 October 2017 would imply a change in the level of the prevailing tariff of greater than 25% at a given entry or exit point. In determining these parameters, a level of protection against higher than expected tariff increases was considered appropriate in implementing the NC, but it was important to limit the scope and duration of applied mitigating measures to avoid delaying the impact of the FG. Industry responses to the 2013 consultation on the draft FG confirmed support for the concept of mitigating measures, but a majority of those who commented on this issue considered that the threshold for applying mitigating measures should be lower than the 25% tariff level change.

In determining the final FG text the following broad policy options were considered for mitigating measures:

1. Specify no mitigating measures permitted: full implementation at all points by October 2017;
2. Maintain the draft FG option;
3. Amend the draft FG option;
4. Specify that users with existing capacity contracts whose tariff levels are affected by implementation of the Tariff NC have the right to cancel their contracts;
5. No harmonised parameters on mitigating measures: NRAs may apply such mitigating measures as they determine fit for as long as they determine necessary.

Implementation of the Tariff NC forms an important part of the 3rd package. For the benefits of the NC to be realised it is important that its effects are implemented as early as possible. However, implementation of the Tariff NC could result in significant changes in the level of tariffs faced by some users. The extent of these changes (the distributional effects) will not be known fully until NRAs have the opportunity to assess the extent of the changes to tariff structures they propose to implement. This will take place during the consultation stage of the methodology selection procedure. For this reason Option 1 above is discounted. Depending on the timing of the methodology selection procedure ahead of the implementation of the NC, mandating full implementation of the NC by 2017, regardless of the tariff level changes proposed, could provide network users facing large tariff level increases little more than a year to adjust. This could be too short an adjustment period for some users.

At the other end of the spectrum, and for different reasons, Options 4 and 5 are also discounted. Harmonised EU tariff structures have been in development since at least 2012. Unless large tariff increases are forecasted, implementation by 2017 provides a reasonable time horizon over which to adapt, particularly if the transition to the new tariff level is anticipated ahead of 2017. Allowing NRAs a free hand over the application and duration of mitigating measures as proposed under Option 5 would disregard this and could result in the inconsistent implementation of the NC across the EU. Option 4 has been discounted primarily because the termination of capacity contracts relates to the way in which contract law is applied in the member states. Further, issues concerning capacity contracting more appropriately reside in the NC CAM. In addition, implementing Option 4 could have a detrimental effect on revenue recovery, and could exacerbate the distributional effects of the NC: the unilateral right to cancel capacity contracts could increase the likelihood of a revenue under recovery, and would concentrate responsibility for revenue recovery on a smaller number of network users.

In choosing between the remaining options (two and three) industry responses to the 2013 consultation were taken into account, and the views of NRAs who participated in the FG development process. Given the relative uncertainty over the extent of the tariff changes which could result from implementation of the NC, it was decided that where one or more of the mitigating measures criterion is met, it would be appropriate to extend the period over which mitigating measures can be applied from twelve months to twenty four months. This change is more in line with Option 3 than Option 2. For those users facing the largest tariff increases, this would effectively allow at least three annual tariff setting periods over which the transition to the new tariff level could be smoothened. In cases where the new tariff level was anticipated before 2017, the transition period could be longer. A longer mitigation period was supported among some consultation responses, and this revision to the text was supported by a majority of NRAs.

The three criteria for applying mitigating measures are where the transition to the new tariff level by 1 October 2017 would:

- Affect the execution of specific contracts; or
- Not coincide with the commencement of the gas year, tariff setting cycle or regulatory period; or
- Where tariffs at individual entry or exit points would increase by more than 20% from one year to the next due to the application of the provisions in the Network Code on Tariffs.

The criteria are substantively the same as the draft FG, aside from the reduction in the tariff level change threshold from 25% to 20%. The reduction is in response to consultation responses[66] which called for a lower threshold and is supported by NRAs. In finalising the FG we also considered whether, if one of the mitigating measures criteria was satisfied, the application of mitigating measures should be mandatory rather than elective. The decision to specify that NRAs 'may' apply mitigating measures is primarily intended to allow NRAs to take account of specific national or regional circumstances on this issue. In particular, where that tariff level change threshold is concerned, it should be noted that for users currently on very low tariffs, relatively small material increases in the level of tariffs, could already breach the 20% threshold. It may be more appropriate for NRAs to take a proper decision in such circumstances.[67]

[66] See question 18 of the 2013 Public Consultation - See section 9 *supra* for full reference
[67] See, for example, contributions from German stakeholders to ACER's 2013 Open-House - http://www.acer.europa.eu/Media/Events/Open_House_Gas_Tariff/default.aspx

Annex M - Case studies on the Cost Allocation Methodology

The first section of this annex explored the theoretically possible variations in local tariff levels (at individual network points) depending on the choice of a cost allocation methodology, represented in Figure 33.

This section presents indicative estimates of the potential impact on local network points of the implementation of the Tariff Framework Guidelines, for the following countries:

- Austria;
- France;
- The Netherlands;
- The UK.

In addition, the Hungarian and Italian cases are presented in section 7.1, and the German case is presented in Annex N.

The case studies were provided by the respective NRAs. When relevant, an assumption was made on the methodology to be adopted once the network code enters into force. Otherwise, the impacts of several methodologies were compared.

Disclaimer: The following cases present evolutions in tariff structures (cost allocation), and not tariff levels. The allowed revenue of TSOs is assumed constant. These examples are rough anticipations of tariff evolutions, based on assumptions on the regulatory framework. This exercise is purely indicative and without prejudice to any regulatory decision to be taken ahead of the entry into force of the Tariff Network Code. Tariff changes are presented on an aggregated level without reflecting on individual, user level distributional effects.

Austria

Figure 34: Anticipated local Impact of the network code implementation in Austria in comparison with the current situation (% of variation)

	Entry	Exit
IP	+29%	-11%
Storage	0%	0%
Domestic	n.a.	-24%

Source: E-Control

France

Table 30 evaluates the potential impact of the Capacity weighted distance methodology as described in the network code in comparison with the current situation. This simulation uses capacity subscriptions of 2012 and the current market structure (3 entry-exit zones: GRTgaz Nord, GRTgaz Sud and TIGF). A rough estimate was made of flow distances and locations of the consumers. Further network studies will be required to refine the data.

Furthermore, the merger of the three French market zones is in progress and is planned to be completed by 2018. Therefore, the tariff fees at the interconnection points between these zones should gradually decrease and will minimize tariff instability elsewhere in the network. Then, potential equalizations of some tariffs fees (domestic delivery points, entry IPs, storages,…) might be considered nationally.

Table 30: Anticipated local Impact in France of the Capacity weighted distance methodology as descibred in the network code implementation in France in comparison with the current situation (% of variation)

	Entry	Exit
GRTgaz Nord		
LNG	9%	n.a.
STORAGE	10%	
IP	3%	-13%
Domestic	n.a.	7%
Link N-S	1.20%	
GRTgaz South		
LNG	9%	n.a.
STORAGE	0%	
IP	n.a.	n.a.
Domestic	n.a.	7%
Link S-TIGF	-1.73%	
TIGF		
LNG	n.a.	n.a.
STORAGE	-4%	
IP	29.18%	4.05%
Domestic	n.a.	-12%

Source: CRE

Netherlands

Table 31 below shows the effect of the network code implementation in the Netherlands, moving from the currently applied methodology, to Postage Stamp, Distance to the Virtual point or Capacity-Weighted Distance.

All the methods are based on a 40/60 split except for the Distance to the Virtual point, where the split is a result of the methodology.

The calculation is based on data from 2013.

Table 31: Anticipated local Impact of the network code implementation in the Netherlands in comparison with the current situation (% of variation)

	POSTAGE STAMP		DTVP		CWD	
	Entry	Exit	Entry	Exit	Entry	Exit
LNG	5%	21%	-1%	-11%	-18%	-100%
IP	5%	-2%	71%	-16%	2%	8%
STORAGE	-8%	65%	21%	65%	-18%	-13%
Domestic	4%	-5%	35%	-43%	10%	-8%

Source: ACM

Note: the results above have neither been verified by nor agreed with GTS

United Kingdom

Table 32 shows a preliminary assessment of the possible effect of having flow based commodity charges at IPs in GB, as required under the Tariff FG. Data from 2012/13 was used. The purpose of this assessment is to provide a simplified indication of the possible impact of the introduction of flow based commodity charges at National Grid Gas's IPs.

Significant assumptions have been made about how much revenue should be recovered at IPs and also on the size of the future flow based commodity charge. The main assumption is that IPs are not allowed to recover revenue from the standard GB commodity charge. To facilitate this, the followings have been considered:

- The revenue to recover at the GB IPs is mainly based on revenue recovered from capacity sales and commodity charge at the GB IPs in 2012/13; and
- The new commodity charge is based on the cost of the energy required for running the transmission network.

Capacity bookings were then uplifted to recover revenue, which resulted in the values in Table 32.

These assumptions have a significant impact on the possible tariff changes.

These changes only reflect tariff changes on the GB gas transmission network owned and operated by National Grid Gas and do not reflect tariff changes in other affected TSOs, such as Interconnector UK.

Table 32: Anticipated local Impact of the network code implementation in the Netherlands in comparison with the current situation (% of variation)

	Entry		Exit	
	Capacity	Commodity	Capacity	Commodity
IP	+18%	-88%	+71%	-80%
LNG	0%	0%	0%	0%
Storage	0%	0%	0%	0%
Domestic	0%	0%	0%	0%

This graph shows the transfer of commodity charges to capacity charge, in order to comply with the Tariff FG. While commodity charges currently represent about 50% of the charges collected, variable costs typically represent less than 20% of the costs in the system (see Figure 24 and Figure 25).

Annex N - Germany - Application of a single Entry/Exit split and a single cost allocation methodology per Entry/Exit zone

The FG requires that *"One and the same primary cost allocation methodology shall apply to all entry and exit points on an entry-exit system."* It further specifies that "*This rule shall equally apply to entry-exit-zones including several TSO networks."*

This implies that the allowed revenues of all TSOs active in the E/E zone are added up to one single allowed revenue. The single cost allocation methodology is applied to that allowed revenue, thereby ensuring that no cross-subsidy will occur between the different network users.

The outcome of this cost allocation methodology provides collected payments for each TSO in the zone, which could be completed by Inter TSO Compensation, ensuring the recovery of the allowed revenue of each single TSO.

This provision is particularly relevant in the German context.

German context

The German market consists of two entry/exit zones in which several TSOs operate their networks. These TSOs are private, independent and autonomous companies. They are regulated by the National Regulatory Authority, Bundesnetzagentur. Each of these TSOs submits to BNetzA for approval its tariff setting methodology, based on its individual allowed revenue.

In addition, TSOs are legally provided with the possibility to claim the existence of pipe-to-pipe competition in the German market. Several claims have been studied and rejected in 2008 by Ruling Chamber No 4 of BNetzA[68]. In 2009 and 2010, the Higher Regional Court confirmed those decisions.[69]

The Tariff Framework Guidelines aim at providing adequate solutions to pan-European problems. The current situation regarding tariffs in Europe has been documented in the Agency's latest Market Monitoring Report. The lack of transparency and convergence in the approaches to cost allocation, as well as their potential negative impact on trade, has been discussed during the process of drafting the Framework Guidelines, and in particular in the contributions to the successive public consultations .

The policies set in the framework guideline follow the principle that shippers who want to deliver a customer within one entry-exit-zone or who want to transit gas across the entry/exit zone can freely combine entry and exit points independently of the TSOs that operate in the zone. Therefore, the reference point for tariff setting should be the entry-exit-zone.

---

[68] See Bundesnetzagentur, Beschlusskammer 4 (2008): http://beschlussdatenbank.bundesnetzagentur.de/index.php?lr=view_bk_overview&year=2008&group=53&filter_reset=1&page=0 (Geschäftszeichen: BK4 07-100 to BK4 07-102, BK4 07-104 to BK4 07-111)

[69] See Oberlandesgericht Düsseldorf (2009/2010): http://www.justiz.nrw.de/Bibliothek/nrwe2/index.php (Aktenzeichen: VI-3 Kart 72/08 (V), VI-3 Kart 67/08 (V), VI-3 Kart 73/08 (V), VI-3 Kart 58/08 (V), VI-3 Kart 59/08 (V), VI-3 Kart, 63/08 (V), VI-3 Kart 57/08 (V), VI-3 Kart 74/08 (V), VI-3 Kart 48/08 (V))

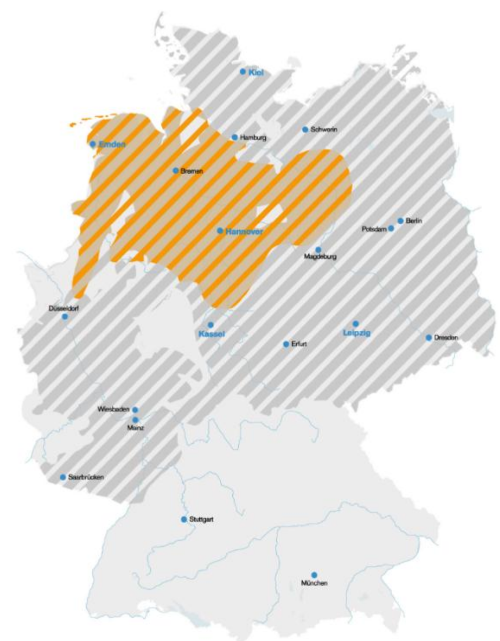
Consistent with that principle and taking account of entry-exit zones with several TSOs, the Framework Guidelines allow inter-TSO-compensation mechanisms in a multi-TSO environment. This would allow TSOs to retain a certain degree of freedom to take business decisions and run networks efficiently.

Impact analysis: Gaspool 2013 based on price sheets

Disclaimer: In conducting the following analysis the Agency was only provided with partial data. In order to increase the relevance of the analysis, missing information (on capacity) was completed with probably outdated data from the Transparency Platform used as a proxy, to make the necessary assumptions. The Agency encourages ENTSOG to complete this analysis based on more actual and complete data.

The Gaspool market area comprises 5 major TSOs: GASCADE Gastransport GmbH, Gastransport Nord GmbH, Gasunie Deutschland Transport Services GmbH, Nowega GmbH and ONTRAS Gastransport GmbH. The Gaspool market area incorporates overall 11 TSOs and approx. 350 downstream natural gas transport networks. The following analysis focuses on the major players.

Figure 35: Gaspool market area



Source: Gaspool

Table 33: TSO Characteristics

	Entry (GWh/d)	Exit (GWh/d)	Network lenght (Km)
GASCADE Gastransport GmbH	1,083	957	2300
Gasunie Deutschland	357	175	3201
GTG Nord	76	71	321
Nowega	211	3	700
Ontras	1,020	578	7200

Source: Transparency Platform

Table 34: Split between Domestic and IP capacity

	IP Entry (GWh/d)	IP Exit (GWh/d)	Non-Ip Entry (GWh/d)	Non-IP Exit (GWh/d)
GASCADE Gastransport GmbH	2.18	128.26	1080.58	828.70
Gasunie Deutschland	0.00	122.68	356.68	52.77
GTG Nord	76.18	0.00	0.02	71.40
Nowega	0.00	36.00	211.20	-33.09
Ontras	34.41	66.60	985.17	511.61

Source: Transparency Platform

The Agency encourages ENTSOG to update the data in Table 34. Beyond the individual TSO by TSO analysis, the ENTSOG data update should provide for an appropriate analysis at the level of the entry/exit zone, which is currently absent from this review.

Current tariffs

The following table shows the tariffs of the different TSOs in the GASPOOL Market Zone as they currently are. Each TSO applies its own entry-exit-split and its own methodology (mostly postage stamp).

Table 35: 2013 tariffs in the Gaspool market area (simplified)

	Entries (€/kwh/h/a)	Exits (€/kwh/h/a)
GASCADE Gastransport GmbH	2.65	2.56
Gasunie Deutschland	2.87	3.44
GTG Nord	0.98	0.20
Nowega	1.69	1.69
Ontras	3.32	3.10

Application of the framework guidelines

The following assumptions were made:

- The same entry/exit split is applied to the whole entry/exit system, to the aggregated allowed revenue of all TSOs in the market zone, i.e. entry/exit system;
- One and the same cost allocation methodology (Postage stamp) is applied to the whole entry/exit system, to the aggregated allowed revenue of all TSOs in the market zone, i.e. entry/exit system;
- Revenue cap and booked capacities are constant;
- No distinction is made between different types of capacities;
- Tariff changes are only indicative as capacities of the other TSOs are only estimated, tariffs are drawn from the price sheets.

The results are shown in the following table, for each TSO:

Table 36: Anticipated tariff evolution per TSO

	New tariffs		Tariffs evolution	
	Entries (€/kwh/h/a)	Exits (€/kwh/h/a)	Entries	Exits
GASCADE Gastransport GmbH	2.3	2.20	-13%	-14%
Gasunie Deutschland	2.3	2.20	-20%	-36%
GTG Nord	2.3	2.20	136%	976%
Nowega	2.3	2.20	36%	30%
Ontras	2.3	2.20	-31%	-29%

The Agency encourages ENTSOG, on the basis of Table 34 and data updates, to deliver the aggregated distributional effects triggered by the application of the Framework Guidelines at domestic points and IPs.

Apart for GTG-Nord, these percentages are of the same order of magnitude as observed recently in Europe (see Figure 15). In the previous years, tariff changes for single TSOs were quite significant (up to 30-50%). The reasons were changes of booking behaviour as a consequence of a new capacity allocation and congestion management in Germany, low temperatures, the economic downturn after 2008 and the higher tariffs.

Another important effect of the Framework Guidelines is the distributional effect in share of revenues to be collected from IPs and domestic points. Data on the current situation was not provided for Germany (see Figure 19). **The Agency would welcome a detailed analysis from ENTSOG, containing data on the share of domestic revenues over domestic capacity, both before and after application of the tariff methodology, the same share per TSO as well as over the whole zone.**