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Sector Coupling and the Evolution of the Gas Sector: New Tariffication Principles for Gas Infrastructure?

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Executive summary

We investigate here sector coupling and the likely evolution of the European energy sector in terms of the optimal tariff methodology for its gas network

Firstly, we review a range of alternative tariffication models. Secondly, we identify the advantages and drawbacks of the current tariffication model, as compared to alternative models. Finally, we assess whether the expected evolution in the sector is likely to change the relative merits of the current tariff model *vis-à-vis* the alternatives, or even to justify its replacement.

The main results of our analysis are summarised next.

The current tariffication model

In Europe, gas transmission is framed as a regulated activity. This implies that:

- transmission development decisions are the result of a planning process;
- tariffs are not driven by competition among pipeline owners;
- instead, tariffs are set by regulators, so that, in each jurisdiction, the TSO's total costs are covered.

The certainty of a return on a TSO's prudent investments is a crucial element in the pact between TSO/investors and the regulator, acting on the consumers' behalf. Here, indeed, is the foundation for sound regulation.

In the traditional gas transmission regulatory framework , all network costs are covered by charging network users. We interpret this feature to reflect the principle, or the political decision, that gas consumption does not deserve subsidisation.

The current tariffication model relies *de-facto* on usage-based tariffs to cover fixed costs and on a zonal definition of transmission rights. This model has supported a smooth transition from a traditional organisation of the gas industry, based on separate national markets and monopoly supply, to a single liberalised market. In this respect, a unique feature of the current system is that consumers connected in the destination country pay, through their gas bills, a share of the fixed costs of the transmission networks of the countries through which their gas passes. No agreement among national authorities to share the cost of transit networks is therefore necessary.

A weakness of the current model is that it may lead to an inefficiently low use of transmission capacity, and ultimately of gas. It might also mean distortions in the selection of transmission paths.

Alternative and more efficient tariff schemes are available. However, their implementation would require an explicit international agreement to share transit network costs and an inter-TSO compensation mechanism.

Evolution of the European energy sector

The following dynamics of European energy sector's fundamentals may affect the relative merits of the current tariffication model *vis-à-vis* the alternatives.

Firstly, the role of gas is expected to change:

- gas will be increasingly used to provide temporal and locational flexibility for electricity generation, while in the past gas would meet bulk energy needs;

- gas injected into the network will come from sources other than natural wells and regasification terminals, including biomethane and hydrogen production sites;
- new types of gas consumption will be developed, including the use of hydrogen in transportation and in power generation;
- different gases will be transported by a mix of existing and new infrastructure works, either blended in the same network or in their pure form in special networks.

These changes are relevant as they affect the demand for transmission services – in terms of elasticity levels.

Secondly, end consumers will choose from a wider range of alternative technologies and energy vectors to satisfy their energy needs. The greater penetration of electricity in final uses is an established trend. Hydrogen, meanwhile, is expected to replace fossil fuels in sectors where electricity cannot be used, and in the longer term, hydrogen may compete with natural gas over a wide range of applications, including residential heating.

In that context, preventing inefficient consumption decisions may mean tighter constraints to the level or structure of transmission tariffs.

Finally, a trend of falling natural gas consumption is now established, and it is unlikely that biomethane and hydrogen will make up for a reduction in transported gas volumes.

Should gas volumes decrease but peak-usage remained unchanged, no reduction in transmission demand capacity by network users would occur. The tariff level or structure might have to be updated to ensure full cost recovery; in particular, commodity-based charges (i.e. per MWh) would be replaced by capacity-based charges.

Alternatively, the fall in transported volumes might be accompanied by a reduction in peak gas flows. This situation would lead to genuine excess capacity and stranded cost recovery issues might, then, arise. In that case, allocating excess capacity costs to a constituency other than gas consumers, for example taxpayers, might be justified on fairness grounds.

Implications for the preferred tariffication model

Changes in the composition of transmission services demand, such as those related to sector coupling, are, in themselves, unlikely to change the relative merits of the current tariff model *vis-à-vis* alternative tariff mechanisms. This is despite some of these being perhaps superior in terms of efficiency. We base this assessment on the following elements:

- demand elasticity to price for energy products is low;
- any distortions in consumption decisions must be assessed with respect to the political benchmark oriented by decarbonisation targets, rather than against the efficient benchmark in standard-economics terms;
- moving to efficient transmission tariffs would require a consensus on new arrangements to split European transmission network costs among consumers connected in different countries, which, as the experience in the electricity sector suggests, might not be easy.

However, other features of the European energy market of the future might provide the necessary motivation to update the current tariff methodology. These are:

- the contribution of gas networks to the welfare of European citizens is increasingly related to the security of supply and to energy market contestability. Therefore, an increasing part of the value created by the gas transmission network is not appropriated by flowing gas through it; in this context, usage ceases to be a fair allocation driver for fixed costs.
- Should utilisation of a transit pipeline fall, in the current system a greater share of its costs is placed on connected consumers in the country where the pipeline is located. In a small system, though, the tariff increases necessary for offsetting the missing transit revenues may be unsustainable or may raise fairness issues.

These kinds of drivers might eventually lead the gas community to agree on moving to an explicit split of the European network's costs among consumers connected in different countries. At that point, more efficient tariff structures could be implemented. These include, for example:

- charging capacity-based transmission tariffs directly to final consumers;
- articulating commodity-based tariffs based on demand elasticity of different types of gas consumers;
- charging exclusively for the entry points into the European transmission network.

Finally, part of the European gas transmission network's costs may turn-out to be stranded because of a fall in gas demand induced by decarbonisation policies. In that scenario placing the burden of stranded transmission costs on gas consumers is questionable on fairness grounds. After all, the benefits of decarbonisation are enjoyed by all citizens.

1. Introduction

The current European tariffication model for gas transmission network relies *de-facto* on usage-based tariffs. This will be even more true once the remaining long-term capacity reservations expire. Furthermore, some path-dependency elements characterise the current system, as gas crossing multiple transmission zones is exposed to pancaking transmission tariffs.

The current tariffication model has the very great merit of having supported a smooth transition from the traditional organisation of the European gas sector, based on separate national markets and monopoly suppliers, to a single liberalised European market.

However, some expected developments in the gas market, linked to European decarbonisation ambitions, may affect the performance of the current tariffication system. These developments include:

- changes in the use of gas related to the coupling of the electricity and gas sectors;
- reduction in gas demand;
- repurposing of portions of the gas networks to carry hydrogen.

Under the current tariffication system, these trends may lead to:

- the inability of transmission system owners and operators to cover costs, inclusive of a fair return on invested capital;
- unfair cost allocation among European customers.

This study investigates the implications of sector coupling, and more generally of the foreseeable evolution of the European energy sector's fundamentals, on the optimal tariff methodology for European gas networks. To this end, we, first, review a range of alternative tariffication models. Secondly, we identify the advantages and drawbacks of the current tariffication model, compared to alternative models. Finally, we assess whether the expected evolution of the sector is likely to change the relative merits of the current tariff model *vis-à-vis* the alternative ones, even to the point of justifying its replacement.

More specifically, in section 2 we provide some background information on the European gas transmission sector and we discuss its changing role. In section 3 we review the economic theory on optimal tariffs for network services, focusing on the elements relevant for gas transmission tariffs in Europe. In section 4, we refer to the results of the previous sections, highlighting the implications of sector coupling, and more generally of EU decarbonisation policies, on optimal transmission tariffs. Section 5 sets out the policy implications of our analysis.

2. The European gas transmission system[1]

In this section we provide some background information on the European gas transmission sector, including the sector's dimensions, costs, organisation and tariff regulations. Finally, we address the future role of the gas transmission network in the light of Europe's decarbonisation objectives and the coupling of the electricity and gas sectors. Our analysis is limited to the features of the European gas transmission

[1] The authors would like to thank Francesco Volpato for his important contribution to Chapter 2 of this paper.

industry that are relevant for assessing the performance of the current tariff methodology and, if appropriate, for identifying better solutions.

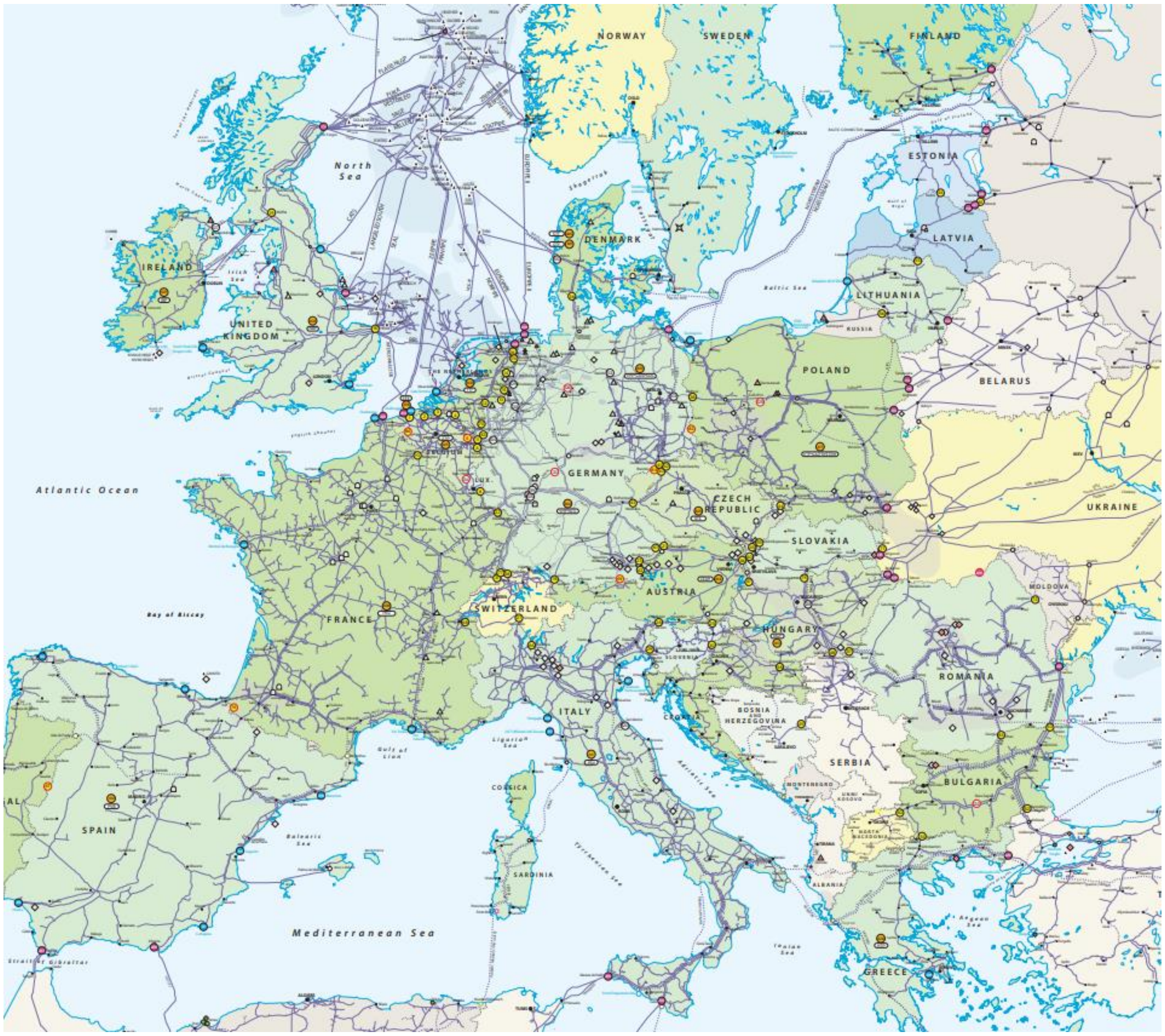
2.1. The European gas transmission network: size and cost

The European gas transmission network consists of around 190.000[2] Km of high-pressure pipelines, with 69[3] pipeline entry points in Europe and 36[4] LNG terminals.

As shown in figure 1, the European gas transmission network is highly meshed.

[2] Evaluation based on data from TSOs' websites.
[3] Source: ENTSOG transparency platform.
[4] Source: Gas Infrastructure Europe, LNG Investment database.

Figure 1. European gas transmission network



Source: ENTSO-G https://www.entsog.eu/, 2019 European gas network (extract)

The current European gas transmission infrastructure appears adequate for meeting the security of supply standards and gas market contestability objectives adopted by the EU[5]. The existing EU gas infrastructure:

1) is sufficiently capable of meeting a variety of future gas demand scenarios in the EU28[6];

2) is resilient to a wide range of potential extreme supply disruptions[7];

[5] EU security of supply and market contestability objectives as stated in, respectively, Regulation (EU) 2017/1938 and Directive 2009/73/EC.
[6] Artelys on behalf of the European Climate Foundation, *An updated analysis on gas supply security in the EU energy transition – Final report*, 2020.
[7] ENTSOG, *Union-Wide Security of Supply Simulation Report,* 2017; and Artelys on behalf of the European Climate Foundation, *An updated analysis on gas supply security in the EU energy transition – Final report*, 2020.

3) allows the internal market to function reasonably well: around 75% of gas in the European Union is consumed within a competitive liquid market, one in which gas can be flexibly redirected across borders to areas experiencing spikes in demand or shortages in supply[8].

The EU's Projects of Common Interest (PCI) and the full transposition of internal gas market directives will help resolve the few remaining interconnection issues.

The European gas transmission network is operated by 52 transmission system operators. Generally, a TSO operates the entire network serving a Member State, with some exceptions: for example, Germany counts 16 TSOs, the UK 4, Italy 3 and France 2.

The total annual cost of the European transmission network can be estimated, for the year 2017, at around 10 billion euros[9], of which only around 5% is represented by variable costs (i.e., compression cost).

The total cost of the transmission network is in the range of 6-8% of the total gas bill, before taxes and levies, paid by European gas consumers.

2.2. Industry organisation

The cost structure of gas transmission networks features some economies of scale, in that it is cheaper to build a single pipeline than to build multiple smaller pipelines to transport a given amount of gas from one location to another.

In fact, in Europe gas can be moved between most locations across multiple alternative routes. This might suggest that a competitive organisation of gas transmission activity is feasible, given European demand.

However, in Europe, gas transmission is framed as a regulated activity. This means, *inter alia*, that:

- gas transmission developments are subject to a planning process, as opposed to the merchant approach operating in the United States;
- tariffs are not driven by competition among pipeline owners wishing to attract shippers to their networks[10];
- instead, tariffs are set by regulators, in such a way that the TSO's total costs are covered.

In this setting, a for-profit company is granted a monopoly to provide services in exchange for commitments around service availability, supply and price. Certainty of a return on investments is crucial for the pact between investors and regulators, on the consumers' behalf, the "regulatory compact"[11] on

[8] IEA, *A long-term view of natural gas security in the European Union*, 2019.

[9] European network total revenue requirement as the product of: 2017 booked capacity and applicable unitary tariff for firm capacity, for each entry and exit point at EU level. Data source: ENTSO's Transparency Platform and the Transmission System Operators' websites.

[10] Issues related to competition among alternative transmission paths may be addressed by each European regulator by departing from the reference tariff-setting methodology applied to all nodes within its jurisdiction, according to Article 6 of the Tariff Network Code (Commission Regulation (EU) 2017/460). However, the Tariff Network Code provides no guidance on the conditions that may trigger this kind of intervention and on the limits of the regulators' discretion in this area.

[11] Davis, *Regulatory Principles and Regulatory Regimes*, 2009.

which industry regulation is built. That certainty in necessary to attract capital accumulation in the industry (and in the country) at relatively low costs.

This holds true, in particular, for demand-risk. Placing responsibility for the network's total cost on gas consumers, irrespective of the network's utilisation level, is a necessary feature of an institutional framework in which transmission owners are prevented from charging tariffs in excess of cost. It would be impossible to attract capital to an industry in which, when demand is high, revenues cannot exceed costs and, when demand is low, costs cannot be covered.

2.3. Transmission right definition and tariff regulation

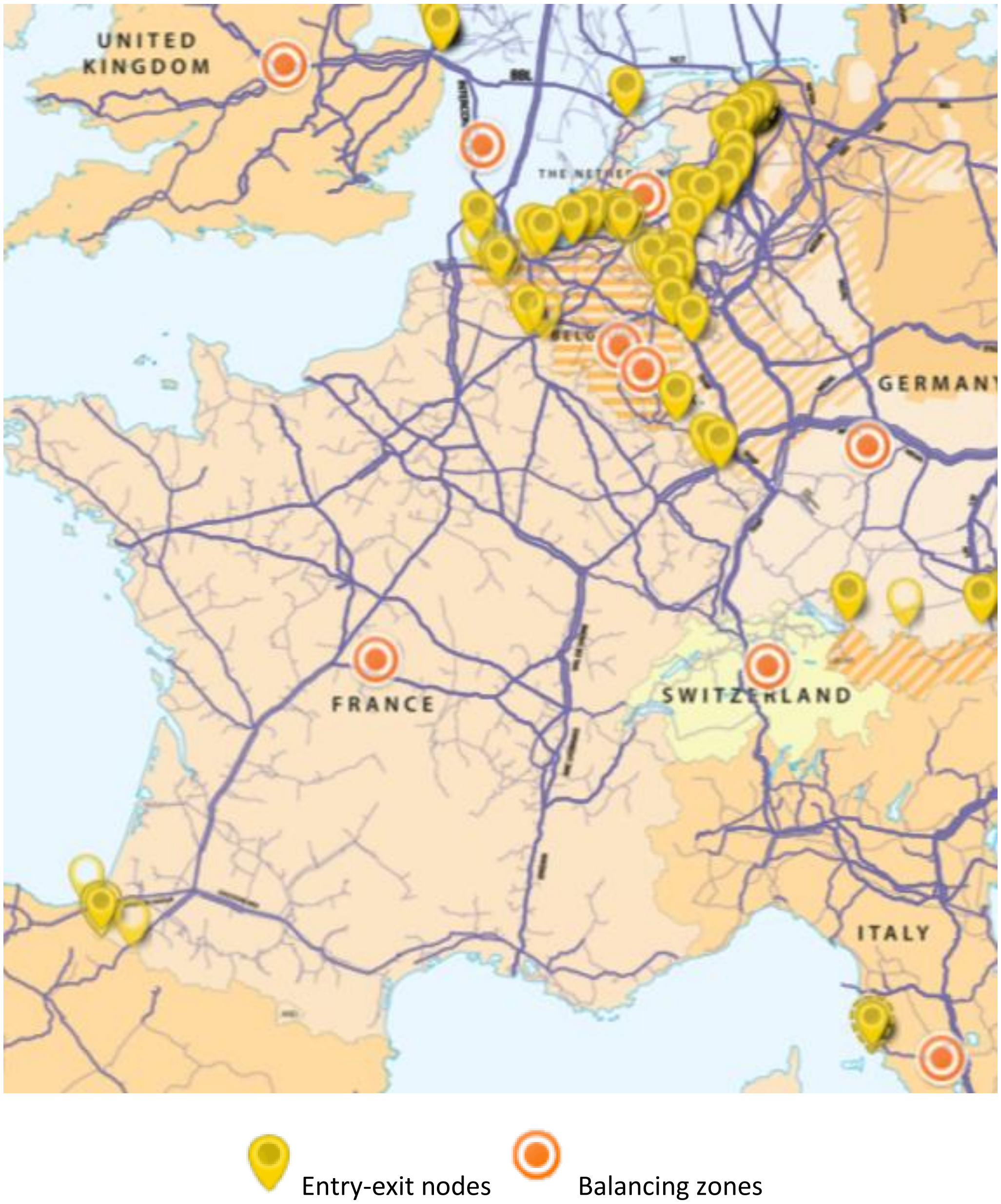
In the European system, shippers are responsible for procuring the transmission services necessary to move gas from entry points into the European transmission network to exit points. There gas is handed over to a distribution service provider or directly delivered to large consumers.

Non-discriminatory third-party access to EU transmission network is mandatory, and should demand exceed available capacity, allocation of transmission rights takes place via auctions.

Transmission rights are defined in terms of options for gas to flow through certain entry and exit nodes, i.e., of *capacity reservations*. Entry/exit nodes mark the boundaries between transmission zones, as shown in the following figure for a portion of the EU transmission network. Currently the European transmission network is divided into 31 transmission zones[12].

[12] ENTSOG Transparency Platform (https://transparency.entsog.eu/#/map).

Figure 2: Entry/exit nodes and balancing zones in a portion of the EU



Source: ENTSOG Transparency Platform (https://transparency.entsog.eu)

Should the entry point in the European network and the exit point to the destination network selected by the shipper belong to different tariff zones, multiple entry and exit rights must be procured; in this way, consumers connected in the destination country pay a share of transmission network costs of the countries which their gas crosses.

Capacity reservations may be acquired by shippers from system operators or traded in a secondary market. Capacity reservations can be purchased from system operators years ahead of use, to the same day in which the gas is delivered. The allocation mechanism is based on auctions; in case capacity at an entry or exit point falls below demand, the auction clearing price rises[13]. Furthermore, capacity reservations are traded on a secondary market.

The tariffs charged at the entry/exit nodes of a transmission zone are meant to meet an allowed revenue target equal to the recognised transmission costs in the zone. The tariff component based on capacity is due irrespective of actual use; this component covers the bulk of transmission costs. Should reserved capacity be used, an additional tariff component or an in-kind payment is charged to shippers, to cover variable transportation costs.

The current model can be interpreted as a way of transposing into the pan-European market the traditional arrangements, developed when national monopolies were in force, to allocate pipeline costs to consumers in different countries.

Recall that in the pre-liberalisation era:

- in each country, a monopoly gas retailer would procure the volume of natural gas necessary to meet national demand and the corresponding transmission services, in some cases investing in transmission pipelines across multiple countries;
- procurement of gas, as well as of transmission services, was based on often decades-long contracts, basically hedging total investment cost in transport infrastructures;
- the transmission product being designed in terms of right to have gas flow down specific pipelines, the transmission cost paid by consumers in the destination country was intrinsically path dependent.

Through such long-term transmission capacity reservation contracts, consumers connected in the destination country would pay part of the cost of supplying pipelines located in other counties.

Purchasing long-term transmission rights was a way for national monopolists to split the common cost and risk of building common infrastructures, irrespective of actual use.

In the current model, the price of gas at the border of the destination zone, where end-consumers are connected, reflects charges paid by the shippers for carrying gas through transit transmission zones. In this way, end-consumers pay some of the cost of the transit network.

The European entry-exit model has the great merit of having supported a smooth transition from the traditional organisation of the gas industry, based on separate national markets and monopoly supply, to a single liberalised market. However, because of the tariff structure and because of the zonal definition of transmission rights, resulting in tariff pancaking, the current tariffication model may lead to inefficiently low use of transmission capacity – something we will discuss in section 4.3. There are distortions in the selection of transmission paths, since fixed cost are recovered via variable tariffs [14].

As existing long-term capacity rights expire, there is evidence that European market participants will resort to short-term capacity purchasing. In fact, the European Commission acknowledges as much: "*contractual congestion is expected to lose significance due to the gradual dismantling of legacy commodity and capacity contracts and to the unwillingness of midstreamers to contract new capacity long*

[13] The auction price takes the form of a price component paid by shippers in addition to transmission tariffs.

[14] These features are investigated in: Cervigni, Conti, Glanchant et al., *Towards an efficient and sustainable tariff methodology for the European gas transmission network*, 2019.

term. EU midstreamers' appetite for future LT capacity contracts is fading away. Capacity bookings by them have become more and more short term. Over-contracting and related low-cost cross-border shipping will disappear, and locational spreads adjusted to short-term cross-border tariffs will return. The competitive situation of midstreamers in a liberalised market is very different from what it used to be." [15].

This, as well as increased reliance on short-term commitments for gas procurement, is a consequence of gas retail liberalisation. If consumers can freely change retailer when they find a cheaper one, the possibility for a retailer to hedge long-term purchases of gas and transmission capacity against its customer base is limited. Therefore, the gas market moves from long- to short-term commitments.

The move towards shorter term capacity reservations is contrasted, in most countries, by tariff structures. These heavily penalise capacity reservations that take place closer to usage time[16].

2.4. Governance of network development

While in Western Europe, the gas transmission system is well developed and largely adequate for meeting current and foreseeable demand, in Eastern Europe the scope for gas transmission upgrades is larger.

Multiple legal/regulatory frameworks have governed gas transmission network development in Europe in the last decade. These include: the Incremental capacity process under the Capacity Allocation Mechanisms Network Code (CAM NC) in force since 2017[17]; the Exemption regime under the Second and Third gas Directives[18]; the Project of Common Interest status under the Trans-European Network for Energy Regulation[19]; the open season procedure, under the GGPOS (Guidelines for Good Practice on Open Season Procedures)[20]; and various Intergovernmental agreements.

An analysis of those frameworks is beyond the remit of this paper[21]. We limit ourselves to presenting some CAM NC provisions – CAM NC is the relevant framework for future investment decisions – in order to assess the role of planning and the market as drivers of investment decisions in the European gas transmission network. According to the CAM NC:

- receiving non-binding demand indications for incremental capacity is not sufficient for a TSO to start an incremental capacity process. This would be subject to a broader market demand

[15] European Commission – DG Energy, *Quo vadis EU gas market regulatory framework – Study on a Gas Market Design for Europe*, 2018.

[16] The Tariff Network Code (Commission Regulation (EU) 2017/460) sets the criteria to calculate reserve prices for different capacity products. The reserve prices for firm non-yearly capacity products (quarterly, monthly, daily and within-day products) involve the application of formulas with multipliers. The range for quarterly and monthly multipliers is between 1 and 1.5; the range for daily and within-day multipliers is between 1 and 3.

[17] Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems.

[18] Directives 98/30/EC ("Second gas Directive") and 2009/73/EC ("Third gas Directive") of the European Parliament and of the Council concerning common rules for the internal market in natural gas.

[19] Regulation (EU) No 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure.

[20] European Regulators' Group for Electricity and Gas, Guidelines for Good Practice on Open Season Procedures, 21 May 2007

[21] We refer the interested reader to Katja Yafimava, *Building New Gas Transportation Infrastructure in the EU – what are the rules of the game?*, Oxford Institute for Energy Studies 2018, on which this section is largely based.

assessment, carried out by the TSO. The assessment would takes multiple elements into account, including: (i) physical capacity gaps identified in the EU Ten-Year Network Development Plan (TYNDP), or National plans; and (ii) alternative economically efficient means to meet any demand for transmission services. As such the TSO has much discretion over if and when the incremental capacity project is initiated;

- once binding commitments of network users for contracting incremental capacity are received, a given TSO must perform an economic test to assess the viability of the incremental capacity project. However, national regulators have a significant degree of discretion over the minimum share of the investment cost that should be covered by such commitments (the f-factor) for the investment to pass the economic test;
- should a TSO demands assessment identify demand for incremental capacity, the design stage starts. At this point, the TSO must assess, and publish for consultation information on, among other things, the likelihood that incremental capacity results in a material and sustained reduction in the utilisation of non-depreciated gas infrastructures;
- once the design stage is concluded, a TSO(s) must submit an incremental capacity project proposal to the relevant regulators for approval. The regulator's approval decision considers the views of the other national regulators whose networks are affected by the project; furthermore, the decision must take into account any detrimental effects on competition or the effective functioning of the internal gas market associated with the proposed incremental capacity project.

This summary of the governance model for European gas network development shows that decisions in this area are typically based on centralised planning. Adequacy of expected incremental tariff revenues to cover investment costs is one, but not the only driver of the investment decision, as it would be in a merchant-leaning model, such as the one employed in the United States. In fact, European authorities have powers and tools to:

- attract capital in welfare-enhancing network assets, even if the incremental tariff revenues obtained by allocating the additional capacity would not, by themselves, cover the corresponding cost. This may happen, for example, with upgrades that relieve congestion in other portions of the network or that improve supply security and service reliability;
- disallow investment in assets that, though profitable and based on expected revenues from selling the capacity they make available, are not welfare enhancing. This may happen for example, if existing tariffs would make it profitable for investors to build a pipeline whose only effect would be to displace the capacity of an existing one. In this case, building said new pipeline would increase total transmission revenue requirements[22]: these would ultimately fall on consumers, without delivering any benefits.

2.5. The future role of gas transmission in in Europe's energy sector

In order to achieve the EU's 2030 climate targets as well as the EU's commitments under the Paris Agreement, the EU energy system is expected to change dramatically in the coming decades.

While total final energy demand is expected to reduce significantly - through energy efficiency measures in all end-use sectors - demand for electricity will continue to increase. In power production, the most

[22] Because the displaced asset would still have to be paid for, despite its reduced utilisation.

carbon intensive fossil fuels (coal, lignite, oil) are to be phased out and the growth in renewables (much of which will be from intermittent sources, such as solar PV and wind) means that additional flexibility in the electricity system will be required.

Hence, the flexibility requirement of the electricity grid is expected to be achieved by a combination of demand side management/response, energy storage and peak gas power plants. In order to allow this transition without incurring unsustainable costs for EU citizens, natural gas, with increasing shares of renewable or low-carbon gases (biomethane, hydrogen and/or methane from renewable electricity) will, it is thought, play a major role in the transition to full decarbonisation.

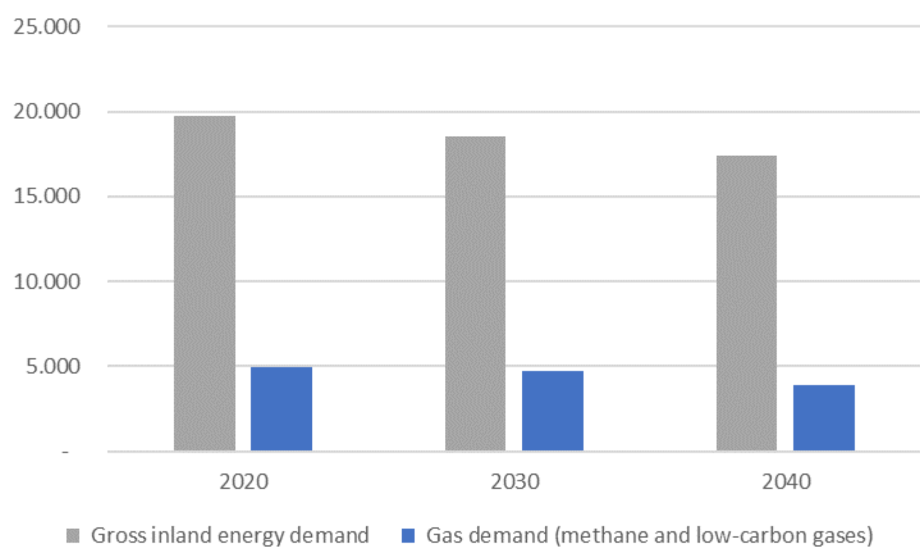
Therefore, an efficient and effective path to decarbonisation in Europe requires:

- use of natural gas during the transition; and
- greater integration between the different sectors producing, transporting and consuming energy; we refer to the arrangements supporting or implementing such integration as “sector coupling”.

There is a wide consensus on the assessment that natural gas will continue to play an important role in Europe in the next decades[23].

The TYNDPs, that ENTSO-E and ENTSOG have recently published, present multiple gas demand scenarios for the next 10 to 20 years. All scenarios feature a large share of gas in Europe’s energy mix[24]. As shown in figure 3, even in the Distributed Energy scenario, the one in which the decline of gas demand is the largest, gas will account for a material share of total energy demand up to 2040.

Figure 3. Gross inland energy demand (European Commission, *EU Reference Scenario*, 2016) and gas demand (TYNDP, Distributed Energy scenario) – TWh (GVC)



[23] On these themes see for example: European Commission, *EU Reference Scenario*, 2016; CEER, *Study on the Future Role of Gas from a Regulatory Perspective*, 2018; COWI consortium for the European Commission, *Potentials of sector coupling for decarbonisation – Assessing regulatory barriers in linking the gas and electricity sectors in the EU*, 2019.

[24] Entso-e and Entsog, TYNDP 2020 – Scenario report, 2020, available at: https://www.entsog.eu/tyndp

Among the 'renewable and decarbonised' gases, hydrogen is certainly going to play a primary role. Given the 2030 target set by the European Commission[25], and based on current conversion rates of hydrogen production facilities, the total production of hydrogen will reach around 300 TWh per year by 2030.

The impact of hydrogen sector development on the existing natural gas networks is still uncertain. However, gas infrastructure may end up playing an important role in moving hydrogen across Europe and bringing it to Europe from producers outside the EU[26].

In this scenario, falling demand puts pressure on the transmission tariff system. The gas transmission network will remain, though, indispensable for a long time, as:

- natural gas is expected to cover a material share of European energy needs at least for the next 20 years;
- even after the electricity industry is largely decarbonised, the availability of gas will be crucial for keeping the lights on in case the wind goes down and the sky gets cloudy at the same time.

This raises the issue of how to ensure transmission cost recovery at minimum cost for society in the future.

Finally, the number of "users" and "uses" of the gas transmission network will expand because:

- the ability to move and store gas provides geographical and time flexibility to electricity generation from renewable sources;
- the ability to move gas supports the development of biogas production;
- of the need to move hydrogen, subject to the required retrofitting.

3. From the old to the new system: the challenges to the existing EU gas market posed by Sector Coupling

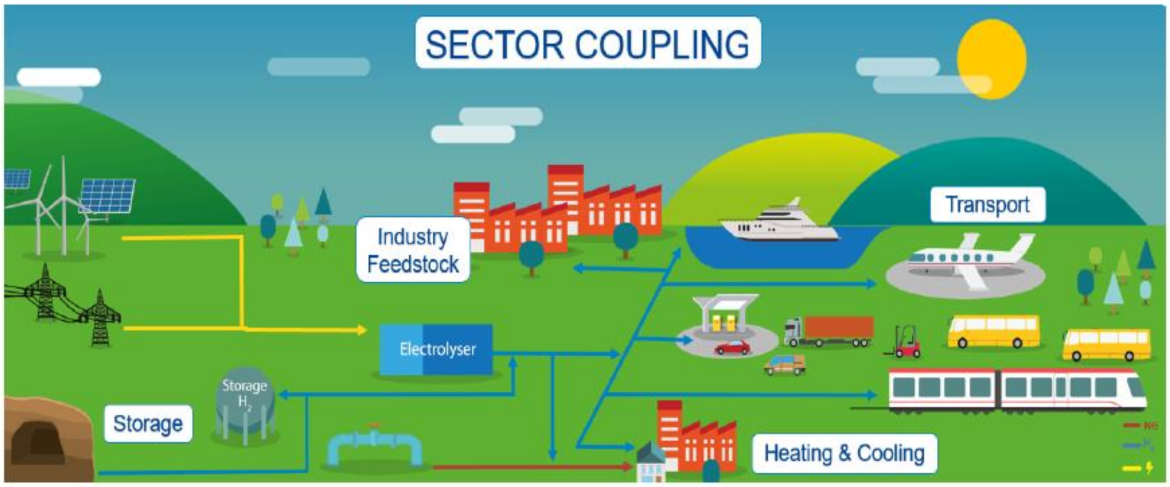
3.1. Sector Coupling and Sector Integration

Despite having been one of the most debated topics in EU energy policy in the last two-three years, there is, as yet, no universal or agreed definition of "Sector coupling" (SC).

A number of academic authors have, in the last few years, attempted to provide the right definition and the main features of Sector Coupling [27].

[25] EU COM(2020) 301, A hydrogen strategy for a climate-neutral Europe, 8th July 2020.
[26] See for example: Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, *European Hydrogen Backbone*, 2020.
27 Cf: T. Brown et al., Synergies of sector coupling and transmission extension in a cost-optimised, highly renewable European energy system, 2018. Martin Robinius et al., Linking the Power and Transport Sectors—Part 1: The Principle of Sector Coupling, 2017. Katrin Schabe et al., Managing Temporary Oversupply from Renewables Efficiently: Electricity Storage Versus Energy Sector Coupling in Germany, 2013.

In the EU debate, the term appeared for the first time in the agenda of the 31st EU Gas Regulatory Forum[28], also known as the Madrid Forum. There the European Commission announced a study on "Smart sector coupling", launched to explore possible options for the role of gas in the future EU energy sector[29]. Since then, the concept is generally understood as the progressive integration of the electricity and gas sectors, at various stages in the energy chain.



Source: European Commission, November 2019

The ultimate scope of coupling or integrating the sectors consists in the achievement of EU climate objectives and of the EU Green Deal's vision for a carbon-neutral EU economy by 2050, through the creation of a decarbonized and hybrid EU energy system. An efficient and effective path to decarbonisation in Europe requires, *inter alia*, much greater integration between the different sectors producing, transporting and consuming energy. In IRENA's words this would take in "co-production, combined use, conversion and substitution of different energy supply and demand forms"[30]. In this scenario, gases will have a role alongside greater electrification in the economy.

The concept of "sector coupling" therefore involves the optimisation of the existing synergies in the generation, transport, and distribution of electricity and gas. It can represent the first step in a wider integration process, which would involve other sectors – such as heating, transport, industrial processes.

The resulting system will be an Integrated Energy System[31], where the increasing electrification of various economic sectors (with a rising share of intermittent renewable electricity) will need to be supported by

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28 https://ec.europa.eu/info/sites/info/files/agenda_madrid_31_updated.pdf.

29 Indeed, "Smart sector coupling" was listed as an agenda item under "Role of gases in the decarbonisation of the EU energy sector", Day 2.

30 "Global Energy Transformation: A Roadmap to 2050". IRENA, 2018, p. 70.

31 This concept is developed in the recent Communication on a Energy System integration Strategy: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0299&from=EN .

a substantial share of 'clean molecules'. These would include hydrogen, biogas, biomethane and synthetic methane.

Therefore, at least in the medium term, it is safe to assume that three energy vectors will coexist as part of a least-cost solution for decarbonisation: electricity, natural gas/methane and hydrogen.

3.2. The role of gas and gas infrastructure in an integrated energy system

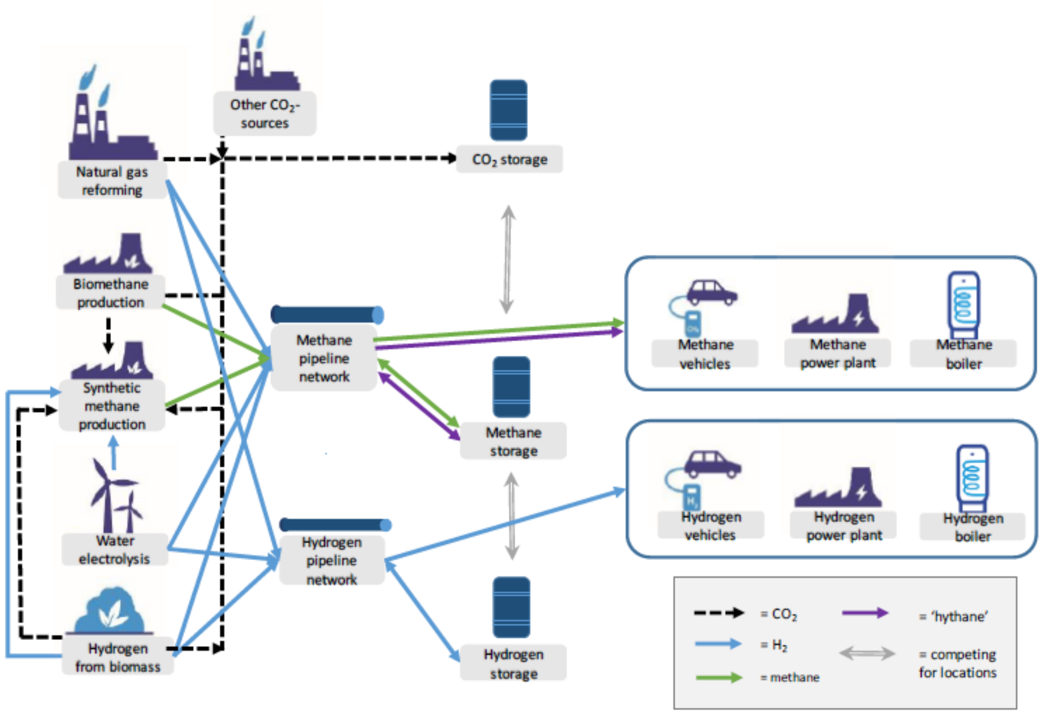
The EU decarbonisation strategy centres on massive renewable energy penetration. In the electricity sector, this requires the system to become more flexible, to accommodate the greater variability of renewable-based generation. Technological development is enabling new sources of flexibility – such as, for example, demand response and electricity storage; however, as already mentioned in section 2.5, there is no doubt that the gas sector will contribute to the decarbonisation process and will play an important role in it. Yes, the importance of natural gas, as a fossil fuel and at least in its non-decarbonised form, is bound to shrink[32]. But in the short and medium term gas-based generation could still represent an important source of much-needed flexibility for the electric system.

Moreover, renewable and decarbonised gases will be called on to provide the "clean molecules" needed in the future EU energy system. Their contribution to the current system is limited. But most of these gases will gain importance over the next decades – particularly where their usage is compatible with pre-existing infrastructure.

Biogas, for instance, is still produced in very limited volumes in the EU (approximately 5% of total EU demand for gas). But biogas can easily be upgraded into "biomethane", whose use and physics do not differ much from those of natural gas.

Hydrogen, probably the most versatile of these new "green gases", can be produced by renewable electricity via electrolysis (green hydrogen) or from natural gas (grey and blue hydrogen) with the release or capture/sequestration of CO2.

32 Cfr. the recent IEA World Energy Outlook 2020 (https://www.iea.org/reports/world-energy-outlook-2020/overview-and-key-findings) and BP Energy Outlook (https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/introduction/overview.html).



Linking different gases for energy use. Source: EU Commission, 2019

Hydrogen can also be blended, up to a certain extent, with natural gasses and thus can be used in the existing gas infrastructure. Technological development is likely to change the landscape here as well, with greater percentages of hydrogen blending being permissible in gas infrastructure and in many applications of gas. This would include electricity generation in existing power plants. Blending hydrogen with methane does not appear to be a sustainable option in the long-term, as it prevents the full exploitation of hydrogen's calorific and economic value. Nevertheless, all these developments appoint towards a future in which different types of gases will co-exist, to a greater extent than today.

In our view, the contribution of gas and gas infrastructure to the EU's welfare will be increasingly related to their value in:

- security of supply;
- diversification;
- increased renewable penetration in electricity production;
- electricity system flexibility.

Security of supply has several dimensions, including the ability of the gas system to withstand the geo-political risks of the loss of one or more suppliers, or catastrophic events that might undermine the ability to serve consumers in certain areas. Gas is easier to store and cheaper to transport over long distances. Therefore, gas and gas infrastructure can also play a role in providing an alternative to electricity storage and transmission.

Diversification means that the infrastructure endowment must support, and not constrain, market selection of the optimal mix of the three vectors (electricity, gas and hydrogen) and conversion technologies. This selection has to serve future energy needs (and, for the molecular vectors, the feedstock needs), as well as optimal timing for the commercial-grade deployment of new technologies.

Finally, power and gas sector integration offers an upgraded role for the gas infrastructures. The use of gas infrastructure – existing and new – might allow the gas sector to support the greater penetration of renewables in the energy sector. It would do so by using power-to-gas or other technologies aimed at producing (renewable) gas, for example from excess renewable-based electricity generation. It would also use the resulting molecules to store energy over longer periods or to transport them over longer distances than what is possible or economically efficient with electricity. The combination of power-to-gas technologies and adequate gas transportation infrastructures is likely to be, at least in the medium term, among the most efficient and reliable sources of flexibility for the electricity system.

All these features point to a major change in the nature of the contribution of gas networks to the EU. In the context of decarbonised and integrated electricity and gas sectors, the value of gas networks will be increasingly related to optionality, or insurance, especially in areas such as security of supply and flexibility. The relative value of the gas network's ability to transport large volumes of natural gas to meet the EU baseload's energy requirements, at least for some portions of the network, might instead decrease.

3.3. Infrastructure challenges

Nevertheless, the integration of power generation with end-use sectors would require significant changes in the energy system and would pose new challenges, in terms of infrastructure planning and system and in terms, too, of market operation. Such challenges will certainly require a fundamental change in the traditional "silos-structured" approach to energy system management. It would also require considerable support from innovative regulation and research.

Regarding the first point, some steps forward have already been taken in the last two years, with a number of electricity and gas TSOs having started a dialogue on joint infrastructure planning. In this light, the publication of ENTSOs Scenario Development starting with the TYNDP2018 (Ten Year Network Development Plan) should be welcomed as a positive development. Since then, the associations representing TSOs for electricity (ENTSO-E) and gas (ENTSOG) have worked together on a document providing anoverview of potential developments in the European energy system up to 2040.

From a system operation perspective, one of the main questions are: to what extent these different gases will be able to use the same (existing) infrastructure; or whether they would need to be segregated in different networks. For instance, each EU country has set its own limitations and regulatory provisions for the injection of hydrogen and these can differ significantly from country to country, including between close neighbours.

For this reason, and depending on the opportunities and costs relating to the energy infrastructure of each country, there might be different "pathways" to 2050. ENTSOG proposes this in its "Roadmap for gas grids"[33]: with a Methane pathway, a (pure) Hydrogen pathway or a Blending Hydrogen and Methane pathway.

Finally, additional gas quality considerations might prevent higher ratios of hydrogen and synthetic methane from being injected into the gas pipelines and transported to final consumers. Even where blending is technically possible, technical and regulatory problems arise with higher hydrogen content. Studies show that a higher content of hydrogen may be harmful to: transmission and distribution pipelines; compressors, and storage facilities; gas metering (currently used chromatographs are not suitable to measure hydrogen); and end consumers. Gas turbines, note, have not been designed to operate on hydrogen-rich fuels.

4. Optimal tariffs for gas transmission services

In this section we review requirements for the gas transmission tariff structures that are commonly touted in policy discussions, survey the economic theory on optimal tariffs and draw out the implications for the design of tariff methodologies for gas transmission in Europe.

In section 4.1 we discuss the requirements for gas transmission tariffs. In sections 4.2 to 4.4 we present the tariff methodologies whose properties have been investigated by mainstream economic theory; these are marginal cost pricing, two-part tariffs and Ramsey pricing. In section 4.5 we focus on optimal pricing for a utility facing competition in some of its products, and we introduce the concept of sustainability. In section 4.6 we address tariffs based on forward-looking costs. This, note, is a methodology frequently implemented in the telecommunications industry that, while rooted in the same theoretical framework as sustainability, has over time gained a methodological standing of its own.

4.1. Requirements for gas transmission tariffs

In this section we review requirements for the desirable structure of gas transmission tariffs that are commonly put forward in policy discussions. We investigate how they relate to each other and highlight the main trade-offs among them. In doing so, we refer to properties of alternative tariff schemes that are presented in greater detail in the following sections.

Efficiency

A tariff system is efficient if it:

- induces efficient use of the existing transmission capacity; an efficient tariff system leads network users to purchase the optimal level and mix of transmission services[34]. We refer to this feature as *short-term* efficiency. Note that, as transmission is an input to supply of natural gas, suboptimal use of transmission services reflects suboptimal gas consumption[35];
- provides correct economic signals for the merits of network upgrades; an efficient tariff system makes it attractive, for the party that appropriates tariff revenues, to invest capital in

33 https://www.entsog.eu/entsog-roadmap-2050.

[34] Including the optimal choice among alternative routes connecting entry points in the European network.
[35] Gas consumption decisions are affected by total supply price, and transmission prices might not be the most important. We do not address here other sources of retail gas price distortions.

transmission assets yielding additional positive welfare, while discouraging investment in assets yielding negative welfare effects. We refer to this feature as *long-term* efficiency.

Efficient tariffs equal marginal or short-run incremental costs. In case additional demand-rationing tariff components are charged at times of scarcity, these kinds of tariff models correctly signal the value of capacity upgrades[36].

Revenue adequacy

Certainty of investment cost recovery is an important pillar in the regulatory framework of the European gas transmission industry. This holds true, in particular, when the value of regulated assets is reduced as a consequence of a reduction in demand for their services.

In the pre-liberalization environment, supply monopoly made placing demand risk on consumers straightforward:

- the national monopolist would commit to paying for transmission capacity along the entire route from source to destination country on a long-term basis, irrespective of its use; and
- in cases where gas demand fell consumers would pay higher unit retail prices to make the monopolist whole.

The trade-off between efficiency and revenue adequacy is central to tariff design in industries, like gas transmission, which feature decreasing average cost. As we will discuss in detail in section 4.1, with decreasing average cost, efficient linear tariffs, i.e. tariffs equal to marginal/incremental cost, will generally not allow for the revenue adequacy requirement to be respected. Two part-tariffs allow the transmission operators' revenue requirements to be met with minimal or no distortion in consumer decisions.

Fairness

The fairness requirement assumes different meanings in different contexts. Fairness is often associated with affordability – the ability of a consumer to pay for his energy needs – and with non-discrimination – equal treatment of network users with the same characteristics.

In European countries, affordability issues are commonly addressed via *ad hoc* policy measures[37]. In some cases, measures specifically targeting energy poverty are implemented. Such measures operate on gas retail tariffs. For this reason, fairness, in terms of affordability, does not appear to constraint the design of gas transmission tariffs.

The connection between fairness and non-discrimination is discussed below.

Cost-reflectivity

The requirement that the tariff system be cost-reflective can hardly be justified *per se*; it may though be related to other requirements, in particular efficiency, revenue adequacy and fairness.

[36] Section 4.1.

[37] Along these lines, see also the proposal to target CEF-E funding to address affordability issues, in https://fsr.eui.eu/publications/?handle=1814/67673.

As far as efficiency is concerned, since efficient tariffs equal marginal or short-run incremental cost[38], they are cost-reflective. However, second best tariffs, i.e. tariffs that achieve a given revenue requirement while minimising welfare loss, are not cost-reflective. They, after all, also depend on the demand characteristics of the different network users[39].

Transmission tariffs reflective of some measure of forward-looking costs of meeting additional demand have been advocated on long-term efficiency grounds. As such tariffs signal to network users the cost of increasing capacity along the different routes. This approach is hard to reconcile with the efficiency objective, to the extent that prices based on forward-looking costs may distort decisions on the use of existing transmission assets[40].

Cost-reflectivity might also be interpreted as requiring that total gas transmission costs be recovered. In this sense, cost-reflectivity overlaps with revenue adequacy.

Finally, with respect to the relationship between cost reflectivity and fairness, a tariff model that makes each gas consumer, or each network user, pay for its use of the network would be appealing from a fairness perspective. In fact, since most of the gas transmission cost is fixed and sunk, assessing a user's cost responsibility is, both logically and practically, impossible[41].

Based on our analysis, then, it appears that cost reflectivity has little merit as a stand-alone requirement for gas transmission tariffs.

Non-discrimination

Non-discrimination refers to applying the same network access conditions, and in particular tariff treatment in identical situations. ACER, for example, considers that discrimination would occur if company A and company B were charged different tariffs for the same capacity product at the same Interconnection Point[42]. For this definition of non-discrimination, two situations are identical if the same transportation product is sold.

No trade-off between non-discrimination and efficiency exists if efficient linear prices are implemented. After all, consumers requiring the same service would be charged the same tariff, a tariff equal to a marginal or short-term incremental cost. However, should prices depart from marginal costs in order to meet the revenue adequacy constraint, the welfare-maximising price structure would not satisfy an intuitive definition of non-discrimination. This happens because second-best optimal prices also depend on the characteristics of demand[43], which would ideally mean that different consumers buying the same service pay different prices.

[38] Sections 4.1.
[39] In particular, price-elasticity (section 4.3 and 4.4) and availability to pay for service (section 4.3).
[40] As we discuss in Section 4.6.
[41] Only compression costs, that account only for a small part of total transmission costs, can, to some extent, be directly related to consumers connected at different locations. With meshed networks and multiple supply sources, even compression costs may cease to be allocated among consumers on a cost-causation basis.
[42] See, for example: ACER, Agency Report - Analysis of the Consultation Document on the Gas Transmission Tariff Structure for the Netherlands, 2018.
[43] In particular, price-elasticity (section 4.3 and 4.4) and availability to pay for service (section 4.3).

In the next section we review economic theory on optimal tariffs and draw its implications for the design of gas transmission tariff methodologies for Europe.

4.2. Marginal cost pricing

The marginal, or short-term incremental transmission cost is the cost caused by a small increase in the usage of the transmission network. In the current European model, incremental usage consists in a unit increase in gas injections (or withdrawals) at a certain entry (exit) node; in the traditional model, based on point-to-point transmission products, incremental usage of the route from node A to node B would be defined as a simultaneous unit increase in gas injections at node A and withdrawals at node B.

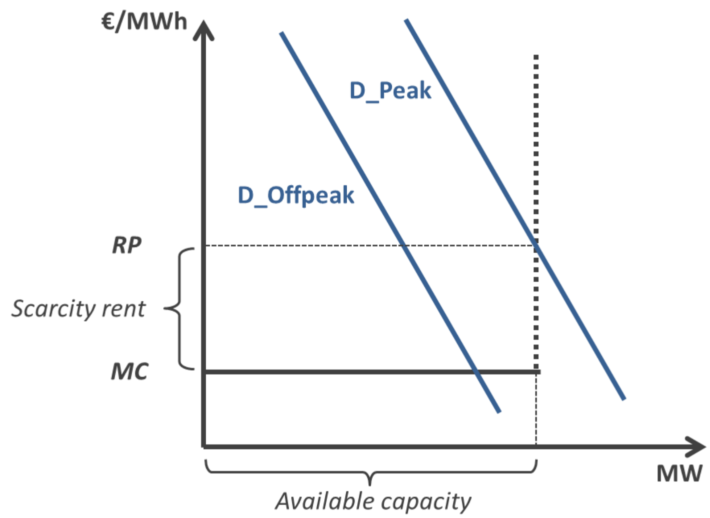
Mainstream economic theory suggests that setting prices equal to marginal costs results in the efficient allocation of resources, i.e. in the efficient volume of gas transported and consumed. We refer to such outcome as *first best*.

Marginal cost pricing requires that the tariff be levied on the volume of gas flows (i.e. it is expressed in €/sm3, or €/MWh) and be differentiated according to the capacity utilisation rate. In this respect:

- at times in which capacity is not fully employed, the transmission price equals the marginal transportation cost, basically the compression cost;
- at times in which capacity is fully utilised, a demand rationing component is added to the marginal cost, to obtain the price level at which the demand for transmission services equals the available capacity. Marginal cost pricing, inclusive of a rationing price add-on in scarcity situations, is known as *peak-load pricing*[44].

Peak-load pricing is illustrated in the following figure.

Figure 4: Peak-load pricing



[44] PANZAR J. C., *A neoclassical approach to peak load pricing*, in "Bell Journal of Economics", 1976.

The figure shows that, under the assumption that marginal costs (i.e. incremental compression costs) are independent of volume, transmission revenues help cover fixed costs only during peak hours. In those hours, the price that rations demand is higher than marginal costs; therefore, rent accrues to the transmission operator. When available capacity adjusts to the welfare maximising level – the "long-run equilibrium" – scarcity rent collected during all peak-hours equals the transmission operator's fixed costs[45].

Marginal cost tariff is a form of *linear* tariff, since the total transportation cost borne by network users increases linearly with the volume of transmission service consumed or, the equivalent, the average transportation cost does not vary with consumption level.

For a given pattern of demand, peak-load pricing, over time, yields transmission revenues:

- above total transmission cost, when installed capacity is inefficiently small;
- equal to total transmission cost, when installed capacity is efficient;
- below total transmission cost, when installed capacity is inefficiently large.

Because of this feature, peak-load pricing provides correct signals for the opportunity to upgrade the network. It, therefore, meets the long-term efficiency requirement.

However, since marginal transmission costs account for a small share of total unit cost, a small share of total cost is covered in non-scarcity periods. Therefore, should scarcity events be rare, as is currently the case in Europe, peak-load pricing is likely to result in large tariff deficits. In other terms there will be large gaps between tariff revenues and allowed costs. Note also that excess capacity conditions cannot be regarded as being temporary in Europe, because:

- redundancy of transportation capacity is structurally pursued by public authorities to ensure security of supply and to support competition among alternative suppliers;
- a falling trend in gas demand is expected in Europe, as a result of Europe's decarbonisation commitments;
- transmission infrastructures are lumpy and have long economic lives. Therefore, the downsizing process of the gas transmission network could take many years and create much friction.

Note, incidentally, that the nature of the services delivered by the transmission network in the context of sector coupling is not different from the ones currently provided; in particular, the marginal/incremental cost of services related to sector coupling are as small as the usual gas transportation services. Therefore, the critical issues related to marginal cost pricing are not affected by the possibility of delivering additional services to support energy transition.

For the same reason, the relative merits of the tariff methodologies presented in the rest of the section are not affected by the possibility of delivering, through the gas network, additional services to support the energy transition.

[45] Including fixed operating cost, asset depreciation and the return on invested capital required by the market.

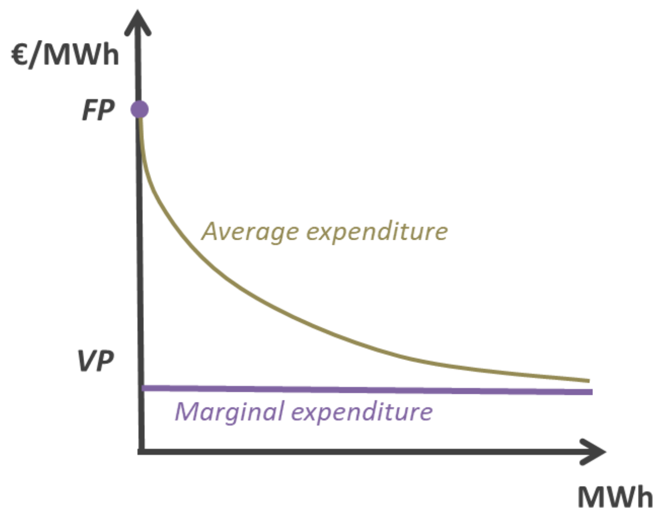
4.3. Two-part tariffs

With two-part tariffs transmission network costs are covered by:

- a tariff component equal to marginal costs, based on the use of the network, i.e. on gas flows. This is known as the *variable part* of the tariff. It is typically expressed in €/sm3, or €/MWh[46];
- a fixed component, independent of the use of the network, set at a level that ensures full cost recovery. This is known as the *fixed part* of the tariff.

Two-part tariffication is illustrated in the following figure.

Figure 5: Average and marginal expenditure with two-part tariffs



With two-part tariffs, the average expenditure for the user of transmission services declines with the purchased volume[47].

This tariff scheme leads to efficient network use. The tariff charged on the marginal unit of service consumed by each user equals the marginal transmission cost and the fixed part does not affect the choice of transportation paths. This is the case, provided the fixed part of the tariff is not large enough to discourage some consumers from purchasing gas services, a question we examine below, unless otherwise indicated.

Furthermore, to the extent that competition among shippers and among suppliers leads to one-to-one variable costs being passed-on to retail prices, efficient gas consumption follows[48].

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[46] Since we present two-part tariffs as a possible way to address revenue-deficit issues expected with peak-load pricing (because of too few scarcity events), we assume in this section a setting in which scarcity-events do not occur for simplicity of exposition. In this setting the network's total non-variable cost must be covered through the tariff's fixed component.

[47] The two-part tariff is an instance of non-linear pricing, since the total transportation cost borne by network user increases less than linearly with the volume of transmission service consumed. We do not present more general forms of non-linear tariffs here, as this would not add to our general results.

[48] We discuss later the inefficiency that obtains if too-high fixed part discourages some consumers to connect.

Finally, two-part tariffs allow full cost recovery, without distorting consumption decisions[49].

Relations between current tariffication system and the two-part tariff model

In the following section we discuss the features that distinguish the current tariff system from the two - part model.

Some characteristics of the current tariff system make it appear like two-part tariffs:

- the tariff component for reserved capacity is due irrespective of actual use; it may therefore be interpreted as the fixed part of a two-part tariff;
- in case reserved capacity is used, an additional tariff component or in-kind payment is charged, covering variable transportation costs; this charge can be interpreted as the variable part of a two-part tariff.

Assume, without losing generality, the following stylised representation of the current capacity allocation system:

(i) The market for capacity reservations takes place in only two sessions:
   - a forward stage, the *primary market* for yearly products, in which shippers purchase capacity reservations from the system operators based on their expected use. This stage is meant to represent the allocation of yearly products by system operators;
   - a spot stage, in which shorter-term products are traded. At the spot stage, shippers may trade transmission rights purchased in the forward stage (the *secondary market*); they can also buy additional transmission rights from the system operators at a tariff.

(ii) The spot stage takes place close to the time of usage. At the spot stage, gas demand and supply conditions at all locations, and therefore minimum cost usage pattern of transmission capacity, are known precisely. From now on we refer to that usage pattern as *real-time demand* for transmission services.

(iii) The tariff charged for capacity allocated at the forward stage is materially lower than the tariff charged for capacity allocated at the spot stage. This assumption is in line with the inter-temporal tariff structure implemented by most European TSOs.

(iv) The secondary market for transmission capacity is perfectly competitive and frictionless.

We can now identify the conditions needed for the current tariffication model, in our stylised representation, to deliver the same (efficient) outcome as a two-part tariff model. This would happen if transmission capacity allocated at the forward stage were larger than *real-time demand* for transmission services. The clearing price of the secondary market, at the spot stage, would be zero. In this case, the spot-price for capacity is not set by the spot-tariff; therefore, no distortion in capacity usage decisions occurs; hence, the *first best* outcome is achieved, as it would be with a two-part tariff.

Note that, when this happens, shippers that had bought capacity in the forward market in excess of their real time use would face a (speculative) loss, equal to the forward tariff. Therefore, a scenario in which the market is over-hedged – i.e. more capacity is sold in the forward stage than the volume actually used

[49] Two-part tariffs require setting up a rationing system in case of scarcity, like the current auction-based allocation mechanism.

– cannot be expected to recur systematically. It might, though, have featured in Europe for some time as a result of long-term capacity contracts signed before liberalization.

Indeed, buying in the forward stage exposes the shipper to the risk that its capacity portfolio turns out to be different from its *real-time demand* for transmission. Note also that the excess capacity conditions, prevailing in most European networks, make speculative arbitrage between forward and spot capacity pricing unprofitable, further reducing incentives to forward purchases. As such one can reasonably rule out the possibility that a shipper's optimal hedging strategy consistently entails anything near full hedging (save for the effects of intertemporal tariff structure, which we discuss below).

On that basis, we can focus on the situation in which the transmission market is not over-hedged, i.e. when forward purchased volume matches or is less then *real-time demand* for transmission services. In this situation:

- the forward tariff level determines the volume of transmission services purchased at the forward stage;
- if it turns out that forward purchases are below *real-time demand* for transmission services, then it is the spot-tariff, that determines additional capacity purchased and used;
- this means that the either the forward tariff level affects the shippers' choices of how much capacity to purchase, or the spot tariff level does;
- therefore, either the forward or the spot tariff level acts as the *variable* component of a two-part tariff;
- if the capacity tariff is greater than the variable cost, distortive effects on capacity usage will result, even if the decision to flow gas is taken after the decision on the volume of reserved capacity.

Therefore, departures from marginal forward or spot tariffs result in an inefficiently low use of transmission capacity[50]. Forward contracting cannot be expected to deliver the same (efficient) consumption decisions as two-part tariffs[51].

Consider, finally, the impact on the shippers' decisions of the intertemporal structure of transmission tariffs implemented by most European system operators: since spot tariffs are materially higher than forward tariffs, all things being equal, it would be optimal for shippers to hedge more volumes in the forward stage. However, this feature does not mitigate the distortive effects of forward tariffs being higher than the corresponding marginal cost. In addition, artificially high spot-tariffs distort capacity purchase decisions in the spot timeframe. Therefore, the current intertemporal structure of transmission tariffs has no efficiency justification.

To wrap up, a "capacity charge" – as such – does not act as the fixed component of a two-part tariff.

Implementation of two-part transmission tariffs in the European gas system

Implementing two-part tariffs in the current organisation of gas transmission in Europe is not straightforward. As shippers – and not gas consumers – are charged for transmission services, there is no

[50] And gas consumption.

[51] Recall that two-part tariffs deliver the efficient outcome, provided the variable part is set equal to marginal costs, precisely because the fixed part of the tariff does not affect consumption decisions.

obvious non-distortive charging base for the *fixed part* of the tariff. Consider for example a scheme in which all shippers pay the same annual *fixed part* of the unit tariff to be able to reserve and to use capacity, independently of the type and volume of transmission services purchased.

It is worth recalling here that efficiency requires that the fixed part of the tariff covers fixed costs, most of the total transmission cost. Given the current number of gas shippers[52], then, the uniform *fixed part* could turn out to be so large as to induce small shippers to leave the market. The resulting increase in market concentration for shipping services is not justified by the economic fundamentals of the industry and would be detrimental to competition.

To overcome this problem, the fixed part could be differentiated according to the same indicator of the shipper's readiness to pay, typically the shipper's size; for example, the level of capacity used in the past could be a reasonably non-distortive measure of the shipper's size, for the purpose of setting the fixed charge. This could, however, distort competition between historically smaller and larger shippers and induce strategic behaviour.

An effective way to implement two-part tariffs is by charging the *fixed part* directly to consumers, as a uniform charge or differentiate the same based, for example, on the size of the consumer's connection[53]. This could be achieved by charging the fixed part to the consumer's retailer, who would then pass this cost on to consumers as part of their gas bill; this solution is already employed for electricity transmission and electricity and gas distribution costs in many countries.

The scheme rules out any distortions caused by transmission tariffs in network use. Further, no distortion in total gas consumptions results, if the fixed part is not so large as to make it worthwhile for some consumers to give up buying gas. Should the inefficient exit of consumers be a concern, the fixed price component might be differentiated according to some features of the consumers that are related to the value they assign to gas services. This form of price discrimination would be justified by the efficiency objective.

Note finally that, in this scheme, the *fixed part* of the tariff is fully independent of the transmission network nodes that are used to supply customers, as well as of shipped gas volume. This implies that the split of total transmission cost among consumers, for example those connected in different European countries, is not determined by gas flows. Therefore, sharing part of the transit network's fixed cost, with consumers connected in different tariff zones, requires collecting the corresponding revenues through the fixed parts of the tariff charged to those consumers. This means, in turn, implementing monetary transfers among system operators, known as inter-TSO compensation.

Inter-TSO compensation marks an important point of departure for two-part tariffs, as well for other efficient tariff schemes, as compared to the system currently employed in Europe. With the current scheme, multiple entry/exit charges are paid should gas be transported across multiple European tariff zones. Per MWh tariffs are set above marginal costs, with tariff pancaking consumers in the destination country paying a share of the fixed costs of the transmission networks of other countries which the

[52] In August 2020 the total number of registered shippers on Prisma platform – the joint capacity booking platform of major European Transmission System Operators – was 707 (https://app.prisma-capacity.eu/market-information/players/shipper).

[53] Or the value of the property, or any other indicator of the consumer's availability to pay.

purchased gas crosses. For example, the wholesale price of Russian gas delivered to Italy embeds the transmission tariffs paid to transport gas through the Austrian network[54].

In other terms, with the current tariff mechanism the cost of the European transmission network is split among the different countries as a result of suppliers' decisions on the source of gas and the transmission path to the destination country. Furthermore, since entry/exit tariff levels are set in such a way as to cover total transmission costs borne in the tariff zone, no inter-TSO compensation mechanism is necessary.

4.4. Ramsey prices

In section 4.2, we argue that transmission tariffs based on marginal network usage cost are efficient. But they are unlikely to generate enough revenues to meet the transmission company's revenue target set by the regulator based on the company's cost. Two-part tariffs, discussed in section 4.3, are a way to address the revenue adequacy problem.

Ramsey tariffs, based on linear prices, are an alternative solution to this revenue gap[55]. Ramsey tariffs are linear tariffs that maximise the economic surplus generated by gas transmission, asking that the transmission operator covers its total costs via tariff revenues. Should the transmission operator sell just one product, the budget constraint uniquely determines the problem's solution and the single Ramsey tariff equals the operator's average cost.

Should the operator sell multiple products, Ramsey tariffs minimise the loss of surplus – compared to marginal cost tariffs – that must be borne to meet the operator 's revenue requirement. Ramsey tariffs are governed by the so-called "inverse elasticity rule": for each product provided for by the operator, the tariff's mark-up over marginal cost is inversely proportional to the price elasticity of demand for that product.

The same holds true if the operator can identify consumers with different price elasticity of gas demand and charge them differently. In this case, the Ramsey rule requires that consumers with higher price demand elasticity be charged lower prices than consumers with lower elasticity[56].

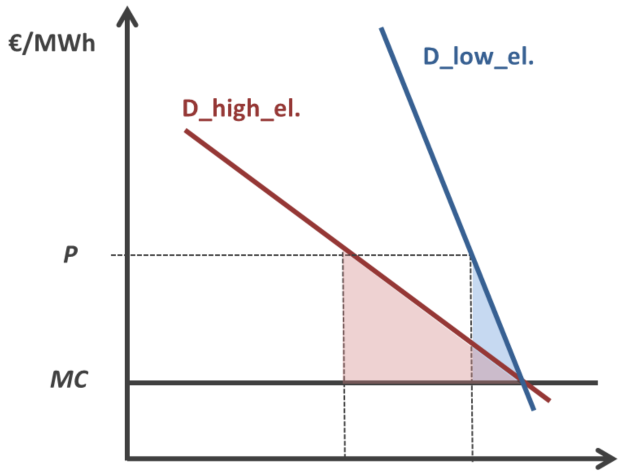
The intuition underlying Ramsey tariffication is illustrated in the following figure.

[54] More precisely, transportation costs of the marginal source of gas to a country is reflected in the country's wholesale gas price.

[55] A tariff scheme is linear if it is based on a fixed price per unit sold. Two-part tariffs are not linear. The current tariff scheme for gas transmission is linear.

[56] An instance of price-discrimination motivated by the efficiency objective.

Figure 3: Intuition underlying Ramsey pricing



The figure shows the welfare effect of setting prices above marginal costs, to cover fixed costs. The effect of a price increase of the same magnitude is shown for elastic and inelastic demand. The shadowed triangles represent the loss of welfare caused by the price departure from marginal costs (known as *deadweight loss*) caused by price increases. This is the difference between the value to consumers and the incremental costs of the units of goods that are not provided because price is higher than marginal costs. The higher the elasticity of demand the higher the welfare loss caused by the price departing from the marginal costs. Ramsey prices depart from marginal costs in the way that minimises the sum of welfare losses, subject to achieving the operator's revenue requirement.

Ramsey tariffs and price discrimination

Ramsey optimality provides an efficiency argument supporting price discrimination, i.e. of a tariff system that charges different prices for the same product or service sold to different consumers.

Price discrimination has been implemented in the gas and electricity industry in the past. This, though, has not necessarily been done in connection with efficiency objectives and has, therefore, been based on demand elasticity. For example, different electricity and gas unit prices have been charged to consumers using energy for different ends, or with different consumption levels. For example, both electricity and gas tariffs have been differentiated for residential, commercial or industrial users; transmission tariffs have been differentiated for gas used in electricity generation and for other purposes.

As discussed in section 5, in the future, gas networks will be used by an increasing number of parties and for different purposes. This might create the opportunity for efficiency-enhancing price-discrimination in gas transmission.

Implementation of Ramsey tariffs in gas transmission

Implementing Ramsey tariffs in the current organisational framework for gas transmission in Europe presents similar challenges as the two-part tariffs discussed in the previous section. After all, the shipper's demand for entry/exit rights does not reflect their clients' demand elasticity. Rather, it reflects the relative cost of alternative transportation routes.

Finally, note an fairness-based objection to Ramsey tariffs: to the extent that energy is a necessary good, if consumers with less price-elastic demand turn out to be the poorer citizens, Ramsey prices produce the effects of regressive charging[57].

4.5. Sustainable prices

An analysis of sustainability should focus on efficient prices for a utility facing competition in some of its products. In that framework, multiple concepts have been developed to characterise the prices that a natural monopoly-holder can charge without inducing a subset of consumers, a *coalition*, to give up the monopolist's service and satisfy their needs in an alternative way, such that:

- the coalition's welfare increases;
- total welfare generated in the industry falls.

We call *sustainable*[58] a set of prices that, in a frictionless market without any entry or exit barriers, does not result in inefficient self-provision by any coalition.

The constraints on tariffs placed by the sustainability requirement may be intuitively presented by considering a multi-product natural monopoly[59], charging the usual linear tariffs. In this setting the following *necessary* conditions for sustainability hold:

- each product's tariff must be below the corresponding average *stand-alone* cost, i.e. the cost of supplying only the product with the cheapest technology available at the time in which tariffs are computed; this holds since if the tariff yields revenue in excess of the product's *stand-alone cost*, consumers of that product would find it convenient to replace the monopoly supplier with one producing that product only, with stand-alone technology[60]. In that case, fixed cost recovery would be impossible for the monopoly-holder and an inefficient industry would result, because several producers would operate in a market, while production cost would be minimized by just one;
- total revenues cannot be greater than total cost; if that does happen, an inefficient entry by a producer with identical technology becomes possible.
- each product's tariff must be above the corresponding *avoidable cost*, i.e. the cost that the producer saves if it stopped producing the product, while continuing the production of all the

[57] The same happens with two-part tariffs should the poor consume less gas than the rich.

[58] We use the term "sustainable" in an informal way, in order to provide an intuitive presentation of the concept. For a rigorous presentation of the results of theory of contestability, see for example D. Spulberg, Regulation and markets, MIT Press, 1989, chapter 6 and the references therein.

[59] Technically, with sub-additive cost function (Baumol, William J., Panzar, John C., and Willig, Robert D, *Contestable Markets and the Theory of Industry Structure*, 1982). This feature of the cost function ensures that it optimal that one firm only supplies all products.

[60] In the terms of section 4.5 prices in excess of stand-alone costs violate a necessary condition for sustainability.

others[61]. For the producer's budget to balance, if one of its product is priced below avoidable cost, another product at least must be priced above the cost necessary to produce it alone[62], i.e. without supplying the under-priced product; consumers of that product would then find it convenient to replace the monopoly supplier with a firm supplying that product only.

Consider that, in the case of gas transmission, the set of tariffs meeting those conditions is very large, because avoidable costs are negligible and stand-alone costs to deliver gas to certain point are high. In addition, the European regulatory framework governing transmission network development can be relied upon to prevent inefficient entry. This is despite it being profitable given current tariffs. For these reasons, we would suggest that sustainability constraints to transmission tariffs, related to pipeline-to-pipeline competition, have, in Europe, a limited or have no role.

However, in Europe, sustainability constraints may depend on other things, as the following highly stylised example shows. Consider two countries A and B consuming natural gas; assume gas is highly valued by consumers in both countries, so that they would pay any price for the service. Countries A and B are connected to gas supplier GS1. The following figure illustrates the setting.

Figure 5: Setting for the sustainability example

Consumers in Country B have access to an alternative technology (PS2) to meet their energy needs; say for example that in Country B full electrification of energy consumption is heavily subsidised.

In order to focus on transmission tariffs, let us assume that the variable cost of the alternative "non-gas" technology and the price of gas are identical. The consumers' choice between gas and the alternative technology (PS2) depends only on the comparison between transmission cost and the fixed cost of the alternative technology. The total cost of the available energy supply options is:

- if country A and country B consume gas, total (transmission) cost is 150;
- if only country A consumes gas, while country B adopts the alternative technology, total (transmission) costs would be 120 for country A, and total (fixed) costs for the new technology would be 80 for country B

Observe firstly, that efficient allocation requires that gas is supplied to both countries. This solution is cost minimising. The alternative solution, in which country A consumes gas and country B adopts the alternative technology would cost 200.

Consider now a tariffication system that splits total transportation costs, 150, between B and A, in such a way that country B pays 100 and country A pays 50. This kind of cost allocation might be regarded as fair, in that gas consumed in country B travels twice as far as gas consumed in country A.

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[61] The avoidable cost is also known as *short-run incremental costs*, i.e. the additional cost of supplying the product given that all other products are supplied.

[62] i.e. the stand-alone costs.

Those tariffs are however *not sustainable* because it would be cheaper for the coalition of consumers connected in country B to move to the alternative technology. If that happened, consumers in country A would bear the entire cost of the pipeline *connecting* the country to the gas supplier, 120.

In this example, the availability of an alternative technology caps the share of total cost that a tariff system implementing the efficient technology mix can allocate to consumers in country B.

This simplified scenario highlights how European policies for decarbonisation are strongly connected to transmission tariff setting. In Europe, the selection of primary sources and transformation technologies is not market driven. On the contrary, it is heavily dependent on political and regulatory decisions, since:

- European energy policy relies on a politically selected mix of primary sources and energy transformation technologies for meeting ambitious decarbonisation targets;
- multiple incentive schemes for low-carbon technologies are in place or are being developed; these schemes interact in a complex way in shaping the consumers' preferences and the suppliers' cost;
- consumers are free to choose how they satisfy their energy-related needs and there is free entry in the markets for alternative energy solutions.

In this context, policy measures aimed at pursuing the decarbonisation targets may prevent some gas transmission operators from covering costs through tariff revenues. As a result, stranded-cost issues would arise.

4.6. Long-term incremental cost pricing

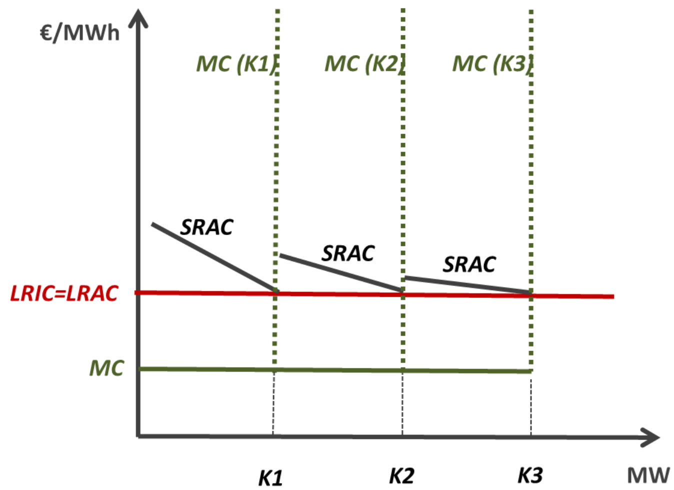
In some implementations in the telecommunications and in the electricity industry, network tariffs are based on the incremental unit cost necessary for serving demand with an optimised network, based on the technology and cost available at the time in which tariffs are set. These kinds of cost are called long-run incremental cost (LRIC)[63]; it is a forward-looking notion since it refers to hypothetical efficiency costs, as opposed to actual, or historic-costs.

For a single-product firm, LRIC pricing boils down to average-cost pricing, with a twist: instead of charging customers the actual *average cost*, LRIC pricing charges consumers the average cost of an optimal network, reflecting current technology and cost. The following figure illustrates LRIC for a natural monopoly[64].

[63] Baumol W. J., G. Sidak, *The Pricing of Inputs Sold to Competitors*, 1994.

[64] The natural monopoly attribute is given by the fact that long-run average costs decline with demand.

Figure 6: Short- and long-term incremental cost



The figure represents a technology such that any level of demand can be supplied at the same average cost, the LRAC (for long-run average cost), once production capacity is optimally dimensioned[65]. This assumption is acceptable if the demand for transmission services is large enough, but we make the assumption here only to simplify the exposition.

At any time, given the installed capacity, in which we show only three possible levels (K1, K2 and K3), average cost decreases with utilisation[66], until capacity is fully reached. This is the SRAC (for short run average cost), the usual notion of average cost.

In section 4.4 we discussed *average cost* pricing. We showed that average cost pricing has the merit of producing tariff revenues covering recognised costs, but that it induces inefficient network use. LRIC presents the same drawback for average cost pricing in terms of the inefficient allocation of resources. In addition, it does not ensure full cost recovery, because LRIC refers to the ideal network at the time in which tariffs are being set.

The merit of LRIC pricing, according to its advocates, is that it induces optimal consumers' decisions about <u>future</u> consumption, by sending signals on service costs in an ideal future setting. This view is hard to reconcile with the efficiency objective. As shown in section 4.2, efficiency requires that consumers receive price signals leading them to consumption decisions that are optimal in the <u>current</u> situation. This is desirable also in a forward-looking perspective, since a by-product of this kind of pricing policy is that investors, or the regulator, receive signals, in the form of losses or extra-profits, that drive production capacity to its optimal[67] level.

LRIC pricing, on the contrary, produce inefficient price signals. As shown in Figure 5, when capacity is not enough to meet demand, LRIC is too low to ration demand[68]. When capacity is redundant, LRIC tariffs

[65] When it comes to gas transmission this means assuming that unit transportation costs at full capacity are constant, independently of the pipeline's diameter.
[66] As we assume that marginal cost (compression) is constant.
[67] Or long-term, in economic jargon.
[68] Because the value of energy for consumers is typically greater than average production cost.

exacerbates excess capacity, by reducing consumption, compared to the optimal tariff level, equal to marginal cost, for no reason.

LRIC cost pricing could be advocated for on the grounds that sending correct short-time signals by varying tariffs according to capacity utilisation is difficult to implement[69]. However, in this case, two-part tariffs are a better substitute for peak-load pricing than LRIC, because by charging marginal costs they do not distort network use decisions.

In a multi-product monopoly setting[70], a product's LRIC is defined as the incremental cost that the producer would bear to satisfy product demand, compared to a situation in which the producer does not supply that product[71]. In gas transmission in Europe, different entry and exit points are different products. Therefore, LRIC tariffs would constrain the entry/exit tariff at each node to be no greater than the average cost of the capacity of that node, with a fully optimised network. The efficiency properties of LRIC tariffs in a multi-product setting are the same as in the single product setting.

Finally, long run incremental cost estimates dramatically depend, for example, on assumptions on:

- the reference network model, which in real world implementations[72] range from the actual network, to a green-field optimal network;
- where the gas necessary to meet incremental demand at a certain node will be sourced.

The large dependence on modelling assumptions further calls into question the value of the cost signals that tariffs based on LRIC convey to consumers.

5. The impact of sector coupling on gas transmission tariffs

In this section we investigate if and to what extent sector coupling and, more generally, the European Union's policies for decarbonisation justify a revision of the current transmission methodologies. We organise the presentation around three "trends" that may be expected to affect the gas transmission business:

- Gas is used for different purposes / new types of gas are transported in the network;
- The range of options available to consumers to meet their energy needs expands;

[69] These kinds of infeasibility arguments certainly do not hold for gas transmission, since the current allocation mechanism of transmission capacity between transmission areas implements price-rationing of demand in cases of scarcity.

[70] Technically, with sub-additive cost function (Baumol, William J., Panzar, John C., and Willig, Robert D, *Contestable Markets and the Theory of Industry Structure*, 1982). This feature of the cost function implies that minimum supply cost is achieved when one firm supplies all products.

[71] Both LRIC and stand-alone costs, introduced in section 4.5, are forward-looking and long-term notions (i.e. they include fixed and variable cost); however, they differ in the assumption about what other products are supplied by the firm: a product's LRIC is computed assuming that the firms supplies also all other products; on the contrary, a product's stand-alone cost is computed assuming that the firm produces that product only.

[72] See for example the presentation of tariff setting methodology based on forward looking incremental costs implanted in Great Britain, provided in Leonardo Meeus, Niels Govaerts, and Tim Schittekatte, *Cost-reflective network tariffs: experiences with forward looking cost models to design electricity distribution charges*, Robert Schuman Centre for Advanced Studies Policy Paper n. 04/2020, Florence School of Regulation.

- Smaller gas volumes are transported.

Trend 1: Gas is used for different purposes / new types of gas are transported in the network

The role of gas in the European energy sector of the future is expected to be different from today. In particular:

- gas will be increasingly used to provide temporal and locational flexibility to electricity supply and demand, while in the past gas was used to meet the bulk of energy needs;
- gas injected into the network will come from sources other than natural wells and regasification terminals, including biomethane or hydrogen production sites;
- new types of gas consumption will develop, including the use of hydrogen in transportation and in power generation;
- different gases will be transported by a mix of existing and new infrastructures, being either blended in the same network or in their pure form in special networks.

These changes are relevant as they affect transmission services demand – in terms of level and/or elasticity. However, the structure of transmission cost is, to a large extent, unaffected by developments in the gas sector; in particular, fixed costs will continue to account for a large share of total transmission infrastructure costs.

This means that the inability of first-best tariffs (i.e. tariffs equal to marginal cost) to ensure full cost recovery remains the central issue in tariff setting. In this respect, the changes in the demand for transmission services that come with sector coupling matter because they affect second-best optimal tariffs.

Consider, for example, Ramsey pricing. If the (price elasticities of) demand for the different gas transmission services or users change, the price structure that ensures cost recovery with minimum distortion changes. However, the obstacles to the implementation of Ramsey tariffs identified in section 4.3 would not be lessened by sector-coupling.

Further, since hydrogen's development may be subsidised, any mark-up of transmission tariffs on variable cost might just add to the subsidy needed to achieve the policy objectives in the hydrogen sector. This might lead to questioning higher than average tariff-cost mark-ups for hydrogen transmission services on fairness grounds.

For these reasons, we assess that changes in the demand for transmission services related to sector coupling alone are, in themselves, unlikely to tilt the balance of pros and cons of the current tariff methodology or of the optimal methodology in the standard-economics sense. In other terms, it is unlikely that, even in a mature sector-coupling scenario, the efficiency benefits of an alternative tariff methodology would outweigh the costs of giving up the desirable features of the current methodology.

However, as we discuss later in the section, the trend of falling gas transportation service demand may provide the necessary motivation to move away from the current tariff methodology.

Trend 2: A wider range of technologies and energy vectors available to consumers

End consumers will choose among a wider range of alternative technologies and energy vectors to satisfy their energy needs. Greater penetration of electricity in final uses is an established trend; hydrogen is expected to replace fossil fuels in sectors where electricity cannot be used, such as maritime transport, aviation and some highly energy-intensive processes. Biomethane production is expected, too, to grow.

In that context, the constraints on transmission tariffs related to the multi-product nature of the industry – discussed in section 4.5 – may become increasingly relevant, in case different levels of transmission tariffs cause inefficient consumption decisions.

In this respect, we note that:

- transmission tariffs typically account for a relatively modest share of the total supply cost of the different energy vectors, and – more importantly – of the total cost of the products or services which energy is an input for; this would suggest that transmission costs have a modest impact on the selection of energy vectors by consumers;
- in identifying the "optimal" mix of energy vectors we must take into account the role of energy policies; this means that distortions in consumption decisions must be assessed with respect to a political benchmark, rather than to the standard-economics efficiency benchmark;
- moving to non-distortive transmission tariffs would require developing a new mechanism to split the cost of the EU transmission network among consumers in different countries. This might prove to be a politically-sensitive matter[73].

In conclusion, we assess that the availability of more energy vectors for consumers is unlikely to tilt the relative merits of the current tariff methodology and of the one that is optimal in standard-economics meaning.

Trend 3: Smaller gas volumes are transported

A trend of falling natural gas consumption is now established, and it is unlikely that biomethane and hydrogen will make up for the reduction in transported volumes.

Smaller volumes of gas transported may or may not be accompanied by a reduction in the network's capacity usage, i.e. of gas flowing at peak. Consider, firstly, a scenario in which peak-usage of network capacity is unchanged. This happens, for example, if gas fired power generators are displaced by renewable generators in most hours of the year, while still being necessary for meeting load in some hours. In this case, the demand for gas transmission capacity by the generators is unchanged.

In this scenario, a reduction in a TSO's revenues caused by lower consumption, would signal a flaw in the tariff methodology. This is the case since peak-usage[74] should be the basis for efficient transmission tariffs[75]; in other terms, for a given peak level, a user's transmission bill should be independent of the overall volume of gas flows[76].

[73] See section 4.3.
[74] To be precise "usage at system peak".
[75] See section 3.1.
[76] Indeed, we understand that under the current tariff methodology most European TSOs' revenues would not fall in our example, since power generators are (commonly) required to reserve and pay for capacity equal to their peak withdrawal over a year.

Consider, secondly, a scenario in which the fall in gas consumption were accompanied by a fall in peak flows. In this case, part of the existing transmission capacity would be redundant. Under first- and second-best tariff methodologies, tariff revenues should fall. This does not happen with the existing tariff methodology, that offsets volume reduction with unit-tariff increases, in order to ensure TSO cost recovery. This might exacerbate the fall in gas demand.

Moving to two-part tariffs might mitigate this demand reduction[77], by making payments for transmission costs partially independent of consumption levels.

Alternatively, part of network costs may be covered by the public budget, recognising that they correspond to prudently incurred investments stranded by decarbonisation policies. The two options differ substantially in their wealth redistribution effects.

Finally, one may ask why allocating a share of network's cost to parties other than network users is a relevant option only if gas sector's dynamics result in excess transmission capacity. This assessment is based on the observation that the current tariff system – that places all network cost on transmission users – reflects a political decision that gas consumers should pay for the entire supply cost. Put in other terms there is a political decision that gas consumption should not be subsidised.
This political decision is not presumably connected with the characteristics of the transmission product supplied to consumers, in particular the energy/peak-load ratio. Therefore, it is hard to justify a different allocation, between gas consumers and other parties, of the cost of necessary network infrastructures with changes in transmission service characteristics.
The same does not hold if case-sector dynamics make some transmission capacity redundant. This is even truer if excess capacity results from political decisions whose benefits are to be enjoyed also by parties other than gas consumers. Under these conditions, a different allocation of network costs, between gas consumers and other parties, may be justified, both on efficiency and on fairness grounds.

6. Policy implications

In this section we present the implications of our analysis in terms of the best design for European gas transmission tariffs.

The current tariffication model is unlikely to distort network development decisions

The governance framework for network development in Europe can be effectively expected to control investment in additional capacity. In this way transmission tariffs do not have the task of preventing inefficient investments and inducing efficient ones.

Given that the investment selection is not driven by tariffs, any limits to the tariffication scheme in terms of the ability to send scarcity signals to would-be investors is likely to cause little or no distortion in network investment decisions.

Removing inefficiencies in the current tariffication model may lead to greater gas consumption, but may be politically difficult to implement

[77] See section 3.3.

The current tariffication model may induce some inefficient network use and inefficient gas consumption; in particular, marginal tariffs in excess of marginal cost inefficiently reduce gas demand and, consequently, the demand for transmission services[78].

However, the benefits of removing this kind of inefficiency may be outweighed by political costs.

As far the benefits are concerned, the price elasticity of demand for energy products is low and transmission costs account for a small part of total end-user prices; therefore, these kinds of distortions in gas consumption are likely to be limited.

As to political costs, note, firstly, that multiple policy measures are being implemented to promote: decarbonisation and the penetration of renewable energy vectors, including incentives for renewable primary energy sources; penalties on CO2 emissions; support for the development of low-emission technologies and energy conservation. These measures deliberately promote lower gas consumption, in order to internalise its environmental implications. Moving to a more efficient tariffication model, which would, if anything, incentivise higher gas consumption, might not be regarded, then, as politically desirable.

Secondly, our analysis of optimal tariff schemes suggest that the inefficiency of the current methodology might be overcome by loosening the link between transmission bills and network usage: usage should be charged at marginal cost and the bulk of transmission revenue requirement would be raised via usage-independent tariff components. Usage independent tariff components, though, should be charged directly to final consumers or their retailers, as generally happens, for example, with the fixed components of distribution charges[79].

Implementing this kind of tariff scheme, though, would mean abandoning a feature of the current system that might have been crucial to attracting political consensus towards the integration of European gas markets: namely that the cost of the European gas transmission network is split among European consumers endogenously. As such the negotiation among countries belonging to different transmission zones takes place within the zonal topology of the European transmission network and, above all, thinking of constraints to each country's discretion in setting entry/exit tariffs at different connection points.[80] Then, gas flows determine the transmission cost burden borne by each country and no compensation between the transmission operators of different zones is necessary.

This mechanism cannot operate if the cross-zonal tariff is set to corresponding marginal costs, since in that case, consumers in the destination country would not contribute to covering the fixed costs of the

[78] The current tariff scheme may also distort the optimal choice of gas transportation routes within Europe and result in unwanted wealth transfers from European consumers to gas suppliers. This feature is investigated in: Cervigni, Conti, Glanchant et al., *Towards an efficient and sustainable tariff methodology for the European gas transmission network*, 2019.

[79] By charging final consumers, or their retailers, the most inelastic tariff basis should be used, thus minimising distortions. Furthermore, fixed tariff components could be differentiated based, for example, on the size of the consumer's connection, to mitigate unwanted wealth redistribution implications and to ensure that usage-independent tariff components do not lead some small consumers to give up gas consumption.

[80] This could lead to disputes between member states regarding the correct allocation of transmission costs. See, for example, the complaint raised by the Italian regulator against the transmission tariffs reform in Germany (https://www.euractiv.com/section/energy/news/italy-squeals-on-german-gas-tariff-reform-eu-ready-to-step-in/) and the discussion surrounding the recent transmission tariff review in France.

transit country's network. Moving to variable tariffs based on marginal costs, then, would require a re-thinking of current governance; for example, an inter-TSO compensation mechanism, whose criteria and implementation system would be agreed upon by EU member states, could be set-up to allocate the fixed cost of transit pipelines. This would be similar to the inter-TSO compensation mechanism in the electricity sector. Note that there the values involved are much lower than they would be for gas

Cost recovery issues and fairness of cost allocation among countries may make the case for upgrading the current tariffication model compelling

Our analysis highlights that changes in the gas industry associated with sector coupling may somewhat change the structure of optimal transmission tariffs. This would be as a result of the emergence of new types of network uses, such as hydrogen producers and users, and of changes in the capacity/energy mix in the transportation services for some users, like peaking power generators. However, sector coupling alone is unlikely to tilt the relative merits of the current tariff methodology or of the optimal methodology in pure economic terms.

Instead, a reduction in the demand for transmission services may ultimately provide the necessary impetus for a redesign of the EU transmission tariff system.

The current tariff system makes revenues raised in each transmission zone dependent on the volume of gas flowing through the zone's entry and exit points. When demand falls, unit transmission charges must be increased to meet the same revenue target, which, in turn, reduces gas demand and, therefore, demand for transmission services. In the long run, recovering transmission operators' allowed revenues might prove difficult.

More importantly, gas demand reduction may differently affect the demand for transmission services in different zones. With the current tariff scheme, the share of transit network costs falling on consumers connected in a different transmission zone would then change. For example, if transit gas flows through a zone decline, the unit tariff increase necessary for meeting the total revenue requirement would end up placing a larger cost share on consumers connected within the transit zone.

If this kind of cost reallocation among countries were material, the current tariffication model might be called into question on fairness grounds. This would be particularly the case if some of the zone's capacity was specifically built to allow gas transits. As such the move to alternative, more efficient schemes might be facilitated.

Fairness issues in the allocation of transmission cost among gas consumers and citizens

The contribution of gas networks to European citizens' welfare is increasingly related to supply security and energy market contestability. Therefore, an increasing part of the value created by the transmission network is not appropriated by beneficiaries and the gas flowing through it; in this context, usage ceases to be a fair allocation driver for fixed costs.

A more general question is whether part of the European transmission network's cost turn-out might not be stranded by a fall in gas demand induced by the pursuit of decarbonisation objectives. In this case, placing the burden of stranded transmission costs on gas consumers becomes questionable on fairness grounds. After all, the benefits of decarbonisation are enjoyed by all citizens.

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