Self-assessment and development options for the Slovenian gas wholesale market

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1 INTRODUCTION

This report assesses the current state and future development options for the Slovenian gas wholesale market. It is based on REKK's own analysis and input received form stakeholders at an internal consultation organized by the Energy Agency of Slovenia on 6th February, 2018, and during a public consultation held on 16th May, 2018. With this analysis, the Agency fulfils its commitment to a periodic self-assessment of the functioning of the market, and considering structural reforms if deemed necessary, as recommended in the ACER Gas Target Model (AGTM).

In Chapter 2, we give an overview of the characteristics of the Slovenian market from an outsider's point of view, focusing on factors that we judge important with regards to a healthy level of supply source competition and Security of Supply. We evaluate market performance by AGTM metrics, putting these figures in regional context as well as examining their likely development based on infrastructural plans and expected opportunities for future import route and supply source diversification. We show how regional import and industrial consumer prices have converged in recent years, and examine market concentration levels on the Slovenian gas wholesale and retail markets. Finally, we highlight some questions pertaining to the development of transmission tariff levels and their potential effects on transit and trade.

In Chapter 3, we assess the expected development of regional wholesale markets with a view to identify trends that may be relevant when considering options for Slovenia. We focus on major regional infrastructure projects, the functioning of the Italian and Austrian hubs, and the future of long-term commodity and capacity contracts as potential factors hindering competition on gas wholesale markets.

In Chapter 4, we identify development options for Slovenia. We first examine to what extent the current regulatory framework aiming at the implementation of 3rd package rules is likely to contribute to an integrated and competitive market. We then take a look at each of the market integration models suggested by AGTM, and analyse their relevance for Slovenia. We reflect on Security of Supply concerns raised during the stakeholder consultation, and give an overview of market integration plans already drafted in the region, with a special attention to the only one that includes Slovenia, published by E-Control in 2017.

Welfare effects of some gas market scenarios are presented in Chapter 5, based on REKK's European Gas Market Model (EGMM). We summarize our findings in Chapter 6.

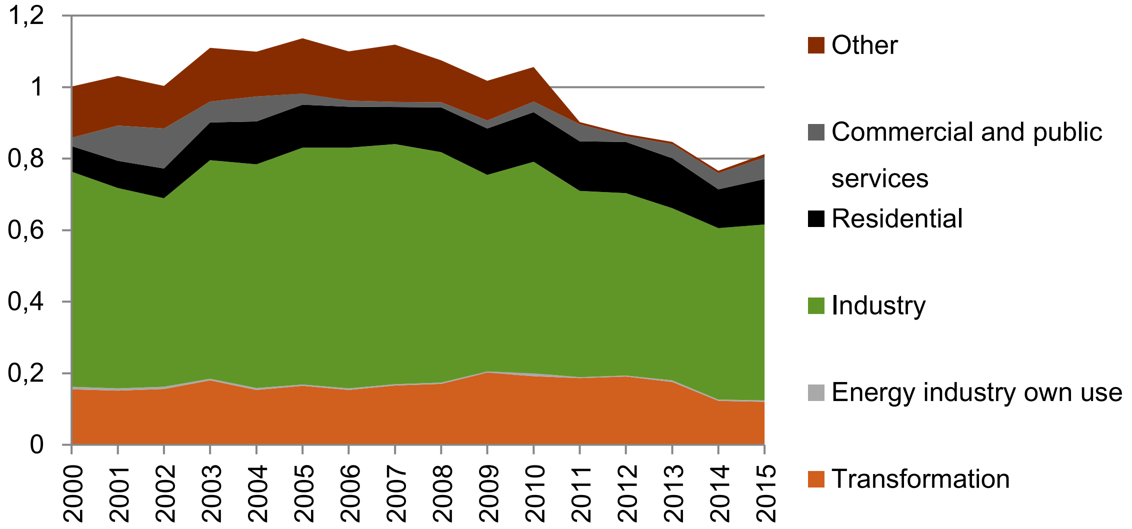
The document is supplemented by four Annexes. Three of them aim to substantiate our findings regarding regional price dynamics (Annex I); regional transmission tariffs (Annex II); and the main features of the Austrian and Italian hubs (Annex III). Annex IV presents the modelling results of a trading region comprising Austria, Italy, Slovenia and Croatia. In all cases analysed results of the cost and benefit analyses for different stakeholders are presented in table form.

2 SLOVENIAN GAS MARKET CHARACTERISTICS

2.1 DEMAND & SUPPLY

The Slovenian natural gas market is one of the smallest in Europe with an average 1 bcm yearly consumption in the last two decades. The peak yearly gas consumption of 1.13 bcm in 2005 decreased by about 30% until 2015 (0.81 bcm), in line with European demand trends.

Figure 1: Natural gas demand by sector (bcm)



Source: IEA Statistics [1]

The share of natural gas in primary energy supply was approximately 10% in recent years, about half as much as the EU28 average. Electricity generation in Slovenia is based on nuclear, hydro, domestic coal (mainly lignite, and Indonesian coal for use in Termo elektrarna Ljubljana), and renewables (some small hydro, but mainly photovoltaic). Installed capacities of gas-fired power plants currently stand at 357 MW. They are mainly used to provide flexibility for the electricity network, and their share in total power production remained below 8% in both 2015 and 2016 according Statistical Office data.

[1] International Energy Agency Statistics:
https://www.iea.org/statistics/statisticssearch/report/?country=SLOVENIA&product=NaturalGas&year=2000

Table 1: Gas-based capacities in Slovenian power production

Gas-fired power plants	Existing units in year 2018	Scheduled
Thermoelectric Power Plant Brestanica	2 X 109 MW 53 MW (in operation by March 2018)	53 MW for year 2023
Šoštanj Thermal Power Plant	2 X 43 MW	
TE-TOL Ljubljana		116 MW for year 2021 116 MW for year 2035

Source: Plinovodi

Slovenian gas consumption is quite atypical in European comparison as the share of residential consumption is very low. Households mostly use wood (as biomass), heating oil, more and more heating pumps for heating; natural gas usage is less than 10% of overall space heating, compared to an approximately 40% EU28 average.[2] The overwhelming part of gas demand comes from industrial users, covering more than 60% of total consumption. Top 10 industrial customers – mostly producers of metal, paper, construction materials and glass products – accounted for more than half (55%) of overall industrial consumption in 2016.

The low share of natural gas in the primary energy mix, and especially in household heating, indicates that the vulnerability of Slovenia in terms of natural gas is low. The share of gas, consumed by district heating systems, which use gas as the sole source, is also very low.

Slovenia lacks domestic natural gas resources, so its market is 100% import dependent. The sole gas source in Petišovci is at the moment not used for domestic consumers, although its capacity could reach 10 000 Sm^3/h. According to Energy Agency data, almost half of the imports were covered by long-term contracts in 2016. The 50.5% figure for short-term contracts was still below the 58% share of gas traded on the basis of gas-on-gas competition in Central Europe, let alone the European average of 66%.[3]

Slovenia can cover its gas needs from two physical directions: Austria and Italy. Theoretically, Slovenia can be supplied by gas from Russia, European gas hubs, Africa, as well as with LNG from terminals in Italy. At present, the connection with Croatia cannot deliver gas from Croatia to Slovenia due to technical reasons in Croatia and to its gas deficit (the country is import dependent as well with its domestic gas sources decreasing).

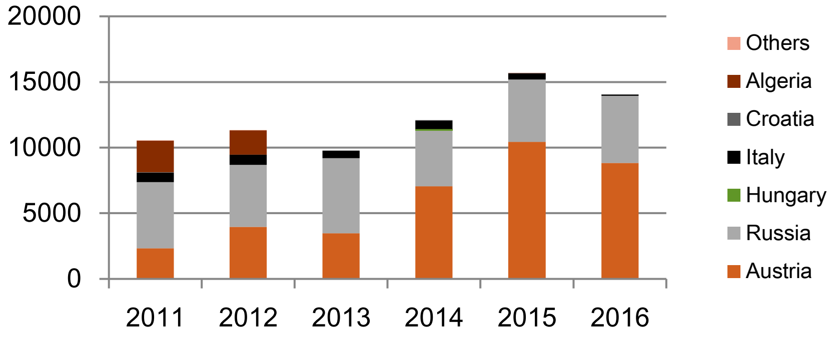
As shown in Figure 2,Figure 1 Slovenia currently fulfils its natural gas demand from three sources. The share of gas purchased from Austria increased from 22% in 2011 to 62% in 2016, while the share of oil-indexed Russian imports (based on long-term contracts) decreased from 48% to 36%. It must be noted, however, that Figure 2 shows imports by Slovenian shippers only; an additional 8,900 GWh (0.9 bcm) was imported by foreign companies in 2016. 13,650

[2] Eurostat: Electricity and Heat Statistics http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_and_heat_statistics

[3] IGU (2017): Wholesale gas price survey, 2017 edition. Although short-term contracts are generally associated with more intensive competition, we understand that in Slovenia it is not only the dominant supplier who holds long-term contracts. Smaller importers also entered into multiple-year contracts, presumably with Italian and Austrian shippers, with no oil-indexation. Long-term contracts are therefore not necessarily detrimental to competition; today, they are also increasingly based on gas-on-gas competition.

GWh (1.4 bcm) was transited to Croatia, which received its Russian import through Austria and Slovenia.

Figure 2: Import of natural gas (GWh)



Source: Energy Agency of Slovenia

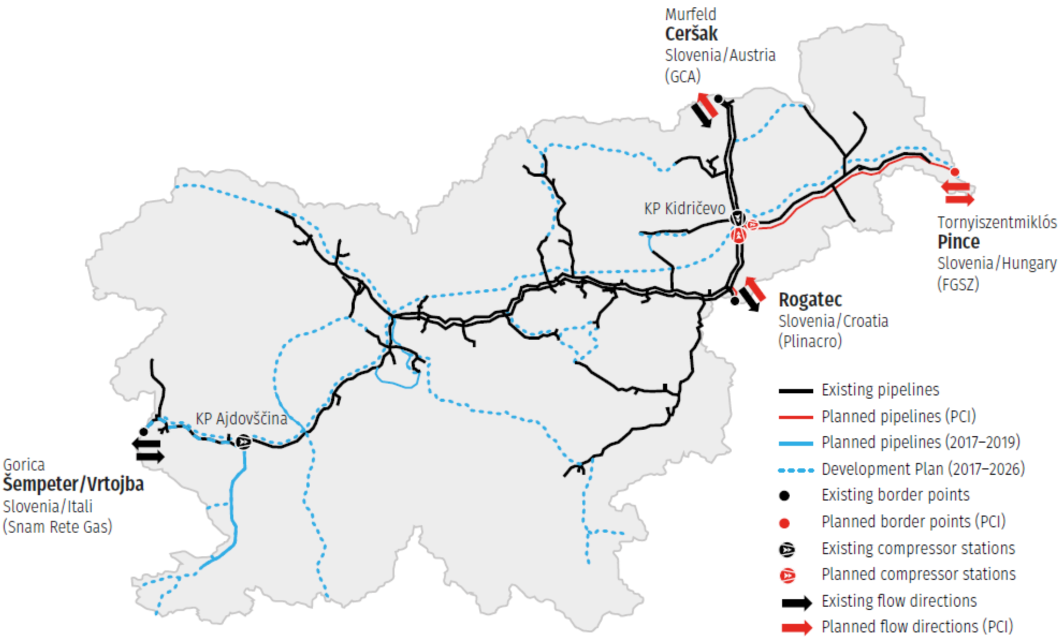
2.2 INFRASTRUCTURE

Figure 3 shows the actual state of the transmission network and some planned developments. As Slovenia does not have any gas storage facility, import capacities play a very important role in internal market operation. Technical capacity at interconnection points is the following:

- Ceršak (AT-SI): 139.4 GWh/d
- Rogatec (SI-HR): 68.4 GWh/d
- Gorica (SI-IT): 26,1 GWh/d
- Šempeter (IT-SI): 28.5 GWh/d

Slovenia has characteristically high peak loads of the system, for example in the year 2017, domestic consumption caused a peak load up to 3,300,000 kWh/h (310,000 Sm3/h). Together with cross-border transmission to Slovenia for the purpose of further transmission to Croatia, these peak loads reach almost the technical capacity of Ceršak IP. Impact of the increasingly dynamic gas market is represented also at interconnection point Šempeter. The values of the gas flows at that point reached level of a technical capacity frequently during the past year. The frequency of the short-term booking is still in progress.

Figure 3: The transmission network in December 2017



Source: Plinovodi

The country and Slovenian TSO Plinovodi d.o.o. has several development plans for the transmission system to upgrade its connectedness with neighbouring countries and to reach:

- defined reverse flows on all interconnection points;
- to increase N-1 criterion regarding security of supply;
- connection between the Slovenian and Hungarian gas markets with a new interconnector;
- gas storages in the Hungarian gas system;
- a higher degree of gas source diversity in the region with gas connections to Hungary, to existing LNG in the Italian gas market, and LNG sources in the North Adriatic sea.

The planned projects are also included in the European Union’s most recent (2017) list of Projects of Common Interest (PCI), indicating their importance from a regional perspective as well. Developments on the Croatia-Slovenia-Austria route (PCI 6.26) include the following projects on the Slovenian side:

- 6.26.2 CS Kidričevo, extension stage 2 (SI)
- 6.26.5 Upgrade of interconnection Ceršak/Murfeld (SI)
- 6.26.6 Upgrade of interconnection Rogatec (SI)

The aim of these projects is to enable reverse flows with Austria and Croatia, to increase capacities and to fulfil the infrastructure standard (N-1 criterion). The first phase of upgrade of IP Rogatec is under way, and FID for the second phase will be taken according to the development of the other PCI projects along the Austria-Slovenia-Croatia corridor.

The gas interconnector Hungary-Slovenia (PCI 6.23) is planned to be commissioned in 2020. Besides the above mentioned features, this project will also be able to contribute to supply source diversification once the Romania-to-Hungary interconnection becomes operational. The project is planned at the moment as a three-phase project with a final 1.4 bcm/y capacity.

The upgrade of interconnection Slovenia-Italy could be potentially realized with a new interconnection (San Dorligo della Valle (IT) / Osp (SI)).

2.3 PERFORMANCE BY AGTM METRICS

Metrics defined by the ACER Gas Target Model (AGTM) assess the overall performance of wholesale markets. The 'market health' metrics for Slovenia evaluate whether its gas market is structurally competitive, resilient and exhibit a sufficient degree of diversity of supply.[4]

2.3.1 Herfindhal-Hirschman Index (HHI)

The HHI shows the concentration of upstream companies selling gas for final consumption in a given market. The index does not take into account the number of traders and intermediaries, because upstream suppliers fundamentally define the level of competition. HHI can range from zero to 10,000; zero refers to a very high number of companies with small market shares, while the maximum value means that there is only one company in a monopolistic position.[5] Slovenia is in the bottom 5 in the EU with a high HHI value of 8,256 in 2016, indicating the country's heavy dependence on Russian sources coming from a single supplier (Gazprom). ACER considers a market to be 'healthy' if HHI is under 2000, but only four countries meet this criterion, while a large group of the markets performs between 2500 and 5000 (which is already a high concentration level).

Table 2: HHI for selected markets, 2016

	Country	HHI 2016
Region	Slovenia	8256
	Hungary	6347
	Austria	6303
	Croatia	4889
	Slovakia	3800
	Italy	3065
Least concentrated countries	Be-Lux	1941
	Sweden	1789
	UK	1109
Most concentrated countries	Finland	10000
	Latvia	10000
	Bulgaria	9359

Source: ACER/CEER

ACER/CEER Market Monitoring Reports show that Slovenian HHI has grown significantly in recent years: it was slightly below 8000 in 2015 and was about 5000 in 2011. Slovenia's relative position in the EU also changed, it was the 16th out of 26 European countries in 2011 and it was the 23rd in 2015.[6] It is important to note, however, that imports from Austria were assigned to Austrian domestic producers in 2011, while in later calculations they reflect the supply structure of Austria, increasing Gazprom's share in Slovenian imports. Therefore, it was methodological changes rather than an actual worsening of Slovenia's supply situation that resulted in higher HHIs.

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[4] ACER (2017): Statistical compendium of AGTM metrics for the year 2016
[5] The HHI is calculated as the sum of squared market shares for each firm supplying gas at the import level.
[6] ACER-CEER (2016): Annual Report on the Results of Monitoring the Internal Natural Gas Markets in 2015

2.3.2 *Number of supply sources*

This metric examines the number and diversity of supply sources in terms of the geographical origin of gas consumed in each Member State. The supply source refers to a gas producer country or to an EU Member State with a liquid organized market where gas can be purchased.

Slovenia at present has two relevant suppliers (Austria and Russia), but there is also a possibility to buy gas from Italy. This metric is considered satisfactory if it equals or exceeds 3, which means that Slovenia already meets the requirement of AGTM in this respect. If Slovenia becomes able to import from Croatia, this will open the way for further diversification. The Slovenian-Hungarian interconnector will grant access to new sources for the country once the Hungarian-Romanian interconnector is operational.

2.3.3 *Residual Supply Index (RSI)*

RSI quantifies whether a gas market's foundations are sound enough to support the development of a competitive gas hub. RSI measures the share of yearly natural gas demand that can be met without the largest source of supply to that Member State. It determines whether a certain supply source is pivotal, i.e. the market cannot be supplied without that specific source.

$$\text{RSI} = \frac{MS\ total\ gas\ supply\ delivery\ capapcity - largest\ supplier's\ controlled\ capacity}{MS\ gas\ consumption}$$

In 2016, there were only 5 countries in the EU that were unable to cover their gas demand in the absence of the largest supplier, and Slovenia was one of them with an RSI of 95%. After the realization of the planned infrastructure developments, however, access to new supply sources will ensure that Slovenia will meet the threshold value of this metric.

2.3.4 *Assessment & Outlook*

Although Slovenia does not meet two of the three AGTM metrics that assess 'market health', and does not have an "adequately functional transparent trading venue"[7] to even calculate 'market participants' needs' metrics, the conditions for a competitive wholesale market seems to be present. The country is directly neighbouring the region's two most mature markets, which makes it possible for Slovenian traders to supply their consumers with competitively priced gas. As we will see in the following section, price convergence is already evident, and the prospect of infrastructure developments points to a continued increase in competitive pressure.

In fact, using other metrics than those of AGTM already paints a much more favourable picture about the health of the Slovenian market. The Trilemma index of the Word Energy Council measures energy security, energy equity (accessibility and affordability) and environmental sustainability, and ranks 130 countries worldwide.[8] The Slovenian energy sector ranked 2nd in terms of energy security in 2016, and improved its score for sustainability from the previous year as well. The country showed a balanced performance and its overall score put it to the 10th place of the 2016 list.

As discussed in detail in Chapter 2.5, Geoplin has a share of around 70% on the Slovenian wholesale market. A European Commission decision of 2017,[9] however, concluded that the

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[7] ACER/CEER (2017): Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016. Gas Wholesale Markets Volume, October 2017, p. 31.

[8] World Energy Council in partnership with Olyver Wyman (2017): Word Energy Trilemma Index 2017 https://trilemma.worldenergy.org/reports/main/2017/2017%20Energy%20Trilemma%20Index.pdf. The ranking reflects the relative performance of different energy market sectors of the respective countries as a whole.

[9] Commission decision pursuant to Article 6(1)(b) of Council Regulation No 139/2004 and Article 57 of the Agreement on the European Economic Area. Case M.7936 – Petrol / Geoplin

relevant market for wholesale gas supply is not limited to Slovenia, but includes, at least, suppliers who operate on the CEGH VTP. The Commission found that there were no barriers for either foreign suppliers to serve Slovenian wholesalers/retailers or for the latter to source gas directly at CEGH VTP, *de facto* recognizing the proper functioning of the market.

Based on the Commission's decision, Geoplin's LTC with Gazprom should also be evaluated in a wider market context. Although Geoplin's portfolio amounts to a significant 1.4 bcm, only a part of it serves the Slovenian market. Around 50% of this is covered by the LTC. During the stakeholder consultation, Geoplin claimed that its LTC is not influencing the market directly: industrial customers have their own booked capacities on the Austrian-Slovenian IP, and do not face the threat of market foreclosure. Furthermore, Geoplin only has one-year supply contracts with its customers, which make it easy for them to switch supplier if the price is not competitive.

Another stakeholder, however, attributed the fact that "there is far less trading activity than would be required" on the Slovenian market due to the "extremely high market share covered through an exclusive LTC contract (i.e. limited to a single domestic supplier), which bypasses the established Slovenian VTP." Indeed, such a huge LTC can easily hinder the development of the Slovenian VTP, but if traders are free to use the CEGH VTP, a liquid national VTP is not a pre-requisite of effective competition.

Geoplin has recently entered into a new long-term contract with Gazprom covering the period up to 2022.[10] According to Geoplin's statement, the new contract will, similar to the current one, form only a part of its portfolio, which substantially exceeds the whole Slovenian consumption volume. Only a smaller portion of its portfolio is intended to supply Slovenian customers. Much more gas will be supplied to customers in other countries, including Croatia.[11]

As we will discuss in later sections, Slovenian traders are in a good position to find alternative sources and undercut the price of the LTC held by the dominant market player. Based on the European examples of how LTCs have been re-negotiated and renewed in recent years, however, we assume that the new Slovenian LTC will employ at least partial hub-indexation in its pricing formula, which means that its price cannot deviate significantly from spot gas prices. Therefore, Geoplin is unlikely to become priced out of the market, or forced to sell its long-term imports at a loss.

2.4 GAS PRICES IN SLOVENIA

2.4.1 Import prices

In this section, we briefly summarize the results of a detailed analysis on regional market prices presented in Annex I. First, the Russian LTC price for Slovenia was well above those of its neighbours in recent years, but regional LTC prices have converged since the end of 2016. Second, based on our analysis on spot markets, gas from the Austrian CEGH is clearly cheaper than the Slovenian LTC price.[12] As the Austrian-Slovenian interconnector is highly utilized but generally not congested, there seems to be room for an increase in its utilization rate when price differences exceed transportation costs and the costs of risk management. However, peak load

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[10] https://www.geoplin.si/en/news/new-contract-natural-gas-supply-slovenia-signed

[11] Croatia, however, also entered into a long-term contract with Gazprom in 2017 for the period from 1 October 2017 to 31 December 2027. The annual supply volume within the contract amounts to 1 billion cubic meters, covering 40% of Croatia's yearly demand.

[12] During the consultation, Geoplin expressed its opinion that the LTC price is in line with Austrian prices, but did not provide alternative data to those published by the European Commission, used in the analysis of Annex I.

characteristics, reaching occasionally the technical capacity level, seem to prevent further increases.

It is also important to note that daily CEGH prices may reveal that Slovenian traders are able to take advantage of price volatility and only import to Slovenia when prices are low; quarterly average prices that we have access to may hide daily arbitrage activity. Although PRISMA auction data for 2016 show that traders made short-term capacity bookings on the Austrian-Slovenian interconnection point only infrequently and in small magnitude, more recent data suggest a pick-up in spot trading activity. This is an encouraging sign of improved market efficiency. Additionally, the Austrian-Slovenian interconnection point was not listed in ACER's Annual Congestion Report in 2016, which investigated barriers to trade based on similar measures.

Third, it is not clear whether the Italian hub is a cheaper source for Slovenia compared to its actual import costs as a mix of the Russian LTC and Austrian hub purchases. At any rate, the low utilization of the Italian-Slovenian pipeline creates an opportunity for Slovenia to import natural gas through some of the Italian LNG terminals when price signals suggest to do so. Finally, Slovenia is separated from the western European natural gas markets and lower prices by physical congestions on the German-Austrian interconnector.

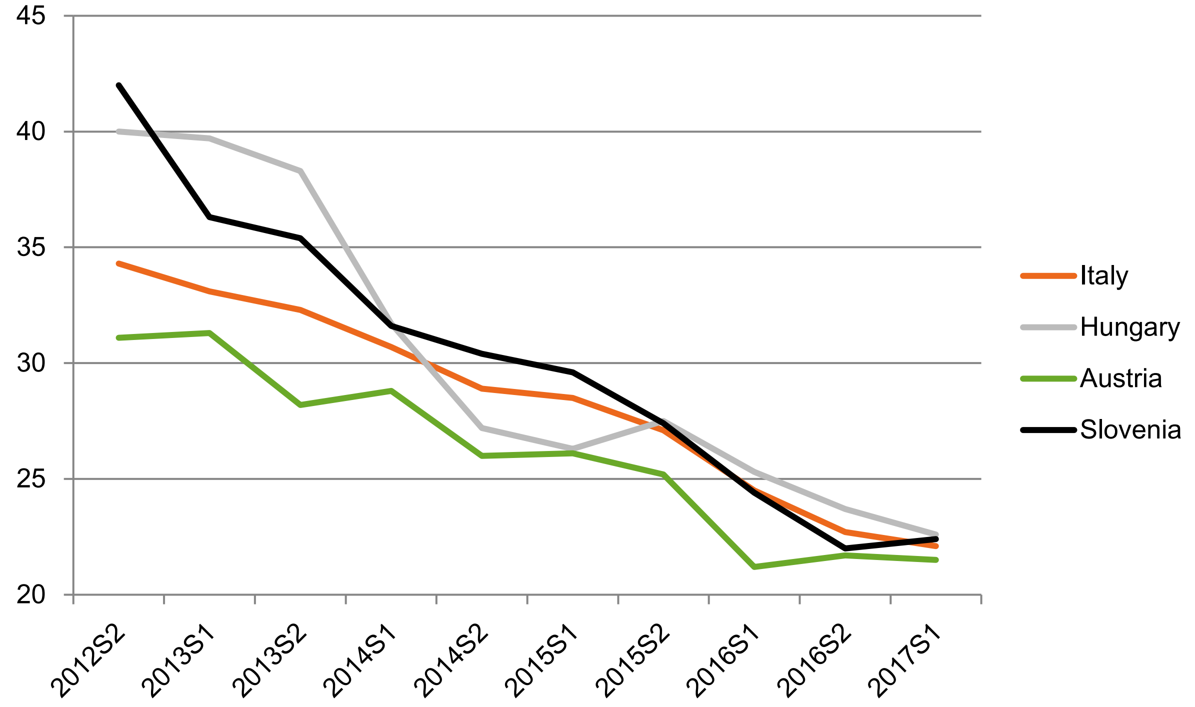
2.4.2 Prices for industrial consumers

Figure 4 shows gas prices for industrial customers in Slovenia and in neighbouring countries. The majority of the biggest Slovenian consumers belong to the "I4 category" used by Eurostat, which means that their consumption is between 100,000 and 1 million GJ annually.[13] Price differences between lower categories are much smaller than those between the highest consumption bands, and industrial customers under 100,000 GJ of yearly consumption pay approximately the same price. We assume that gas prices to be paid by the largest industrial consumers is the best approximation of wholesale gas prices; due to the high volumes they buy, they have the strongest bargaining power in relation with traders, and many of them are directly connected to the transmission network, so the prices they pay do not contain access fees to the distribution grid.

The development of regional industrial gas prices since the second half of 2012 is in line with the decline of import prices shown in Figure 18 of Annex I. Slovenia started out with the highest prices among the countries examined; the premium the biggest Slovenian consumers had to pay was 7.7 €/MWh compared to their Italian, and 10.9 €/MWh compared to their Austrian competitors. Similarly to import prices, however, prices have shown significant convergence in recent years. According to the most recent data available on Eurostat, price premiums to Italian and Austrian industrial consumers decreased to 0.3 €/MWh and 0.9 €/MWh, respectively.

[13] The top 4 companies belong to a higher category (I5) as they consume over 1 million GJ annualy, but prices in that segment are not publicly available.

Figure 4: Gas prices for non-household consumers in the 100,000 - 1 million GJ consumption category (€/MWh)



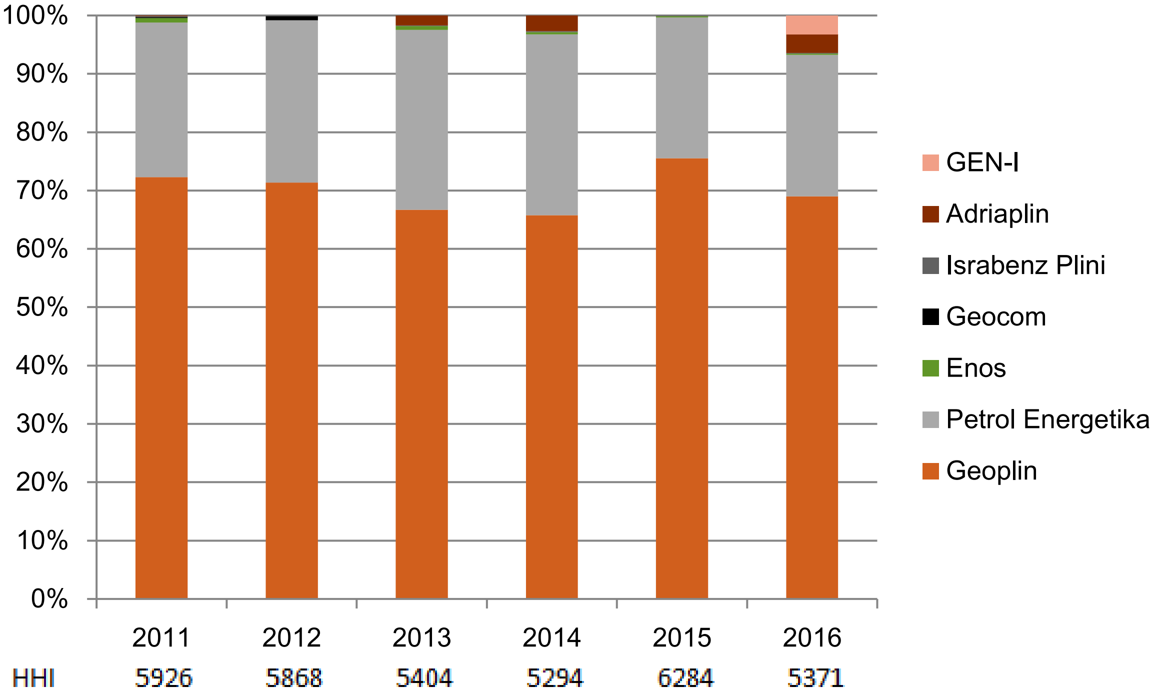
Source: Eurostat

2.5 WHOLESALE MARKET

The Slovenian gas wholesale market is dominated by two companies: Geoplin covers approximately 70% of the market, while the share of Petrol Energetika has moved in the range of 24 to 30% in recent years. The two biggest shareholders of Geoplin were the Slovenian state (41%) and Petrol (33%) until 2017, when Petrol became the majority shareholder of the company with a 65% stake, and the Republic of Slovenia retained only 25%. Petrol is mostly privately owned with only a very low share held directly by the state, but state-owned companies are also among its shareholders. The market is therefore highly concentrated; the 65% stake of Petrol in Geoplin suggests an even higher level of concentration than what is revealed by HHI values in Figure 5.

As discussed earlier, however, the European Commission identified the relevant market for the wholesale supply of gas to be wider than Slovenia, when it decided not to oppose the purchase of controlling interest in Geoplin by Petrol. The Commission concluded that the relevant market includes, "at least, Slovenia and the CEGH", based on "the lack of any significant barriers to access the CEGH, the absence of cross-border capacity limitations and the large availability of gas on the CEGH." On the basis of a market that includes Slovenia and the CEGH, Geoplin's and Petrol's combined market share was found to be consistently below 10% between 2014 and 2016. Furthermore, none of the retailers signalled to the Commission during the market investigation that they considered themselves dependent on either Geoplin or Petrol for the procurement of gas at the wholesale level. The Slovenian Competition Protection Agency investigated the market in 2016, and found no evidence of any restrictive practices or potential in dominant positions in the market.

Figure 5: Market shares on the natural gas wholesale market



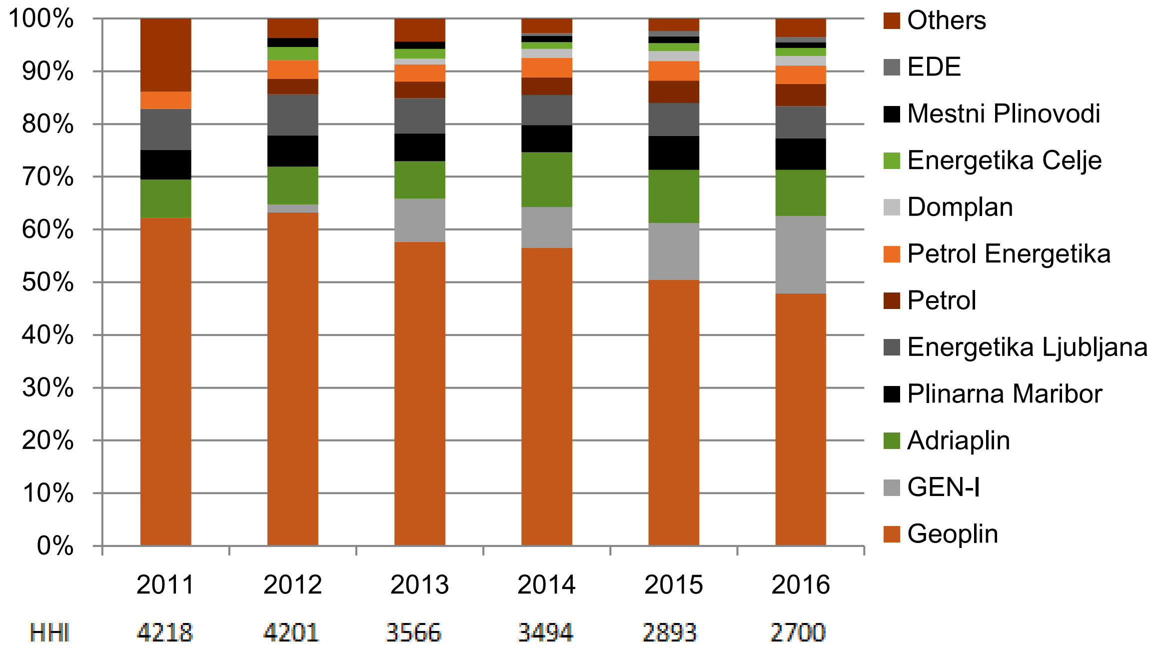
Source: Energy Agency of Slovenia

2.6 RETAIL MARKET

Figure 6 presents the most important payers in the Slovenian gas retail market. Geoplin has lost more than 15% of its market share in the last 5 years, but it still covers half of the Slovenian market. The second and fastest growing market player is GEN-I, which started its operations in 2011 and has gained a 15% market share by 2016. GEN-I is a member of GEN group with a high ratio of state ownership, and minority shareholdings by Petrol. Adriaplin is the third player owned mostly by foreign energy companies, with Geoplin holding 11% of its shares. Similarly to the structure of the wholesale market, there are ownership-overlaps with regard to the biggest suppliers, and state ownership is significant both in direct and indirect ways.

In its market investigation, the Commission concluded that Geoplin's and Petrol's non-controlling minority shareholdings in their retail competitors are unlikely to result in unilateral or coordinated effects because, inter alia, "there are numerous established suppliers in this market which would continue to exert a significant competitive constraint on the Parties and Adriaplin post-merger." Retail customers also confirmed to the Commission that they were not dependent for gas supplies on any of the companies.

Figure 6: Market shares of suppliers in the natural gas retail market



Source: Energy Agency of Slovenia

2.7 TRANSMISSION TARIFFS

In this section, we briefly summarize the results of a detailed analysis on regional tariff levels, their effects on the availability of alternative supply sources for Slovenia, and the expected changes due to the implementation of the Tariff Network Code (TAR NC) and "tariff competition" presented in Annex II.

Tariffs in the CESEC region, which includes Slovenia, are generally higher than those in the Western and Northern parts of Europe, but Slovenian shippers do not face disproportionately high tariff levels when importing gas in the country at existing IPs with Italy and Austria. With regards to the access of potential new sources, however, high tariffs on the Croatian-Hungarian and Hungarian-Romanian borders may be cause for concern. If Croatia and Romania choose to apply similarly high exit tariffs once infrastructure and (in case of Romania) upstream developments make them potential regional suppliers, gas flows from these markets may remain well below their potential levels, contributing to competition and price convergence only to a severely limited extent.

We expect that the implementation of TAR NC (prescribing cost-reflective tariff calculation) will prevent Member States with lower gas prices to erect tariff barriers that could significantly hinder trade and price convergence in the region, but tariff "pancaking", i.e. the market distortive effects of cumulative entry-exit tariffs when gas crosses several borders will remain an issue. On the other hand, the competition for transit flows – and additional revenues for TSOs – may continue to put downward pressure on cross-border tariffs.

Figure 30 in Annex II shows a substantial modification in gas flows supplying Croatia from the Baumgarten hub. Due to the lowering of Hungarian tariffs, they have been redirected through Hungary, although recent changes have made Slovenian tariffs more favourable again. If transit losses become permanent, however, it may be forced to increase tariff levels to make up for lost revenues. The need to recover investment costs of new infrastructure may have similar implications.

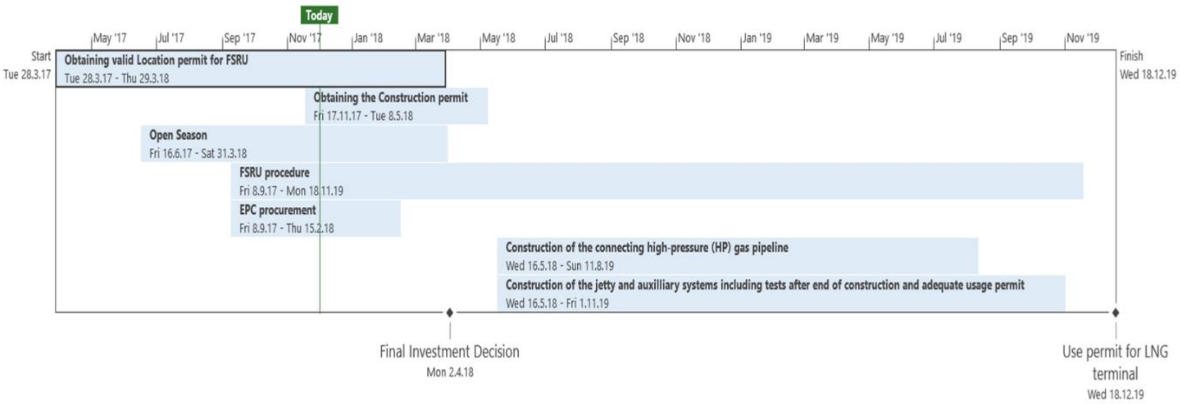
3 EXPECTED DEVELOPMENT OF REGIONAL WHOLESALE MARKETS

In this Chapter, we identify regional gas market trends that may be relevant for Slovenia to consider when analysing its own development options. We will focus on infrastructure projects which may contribute to a further diversification of sources and price convergence; we will summarize a more detailed analysis of the characteristics of the Austrian and Italian hubs presented in Annex III; and we will assess the future of long-term capacity and commodity contracts as possible factors hindering competition and a better integration of regional markets.

3.1 MAJOR REGIONAL INFRASTRUCTURE PROJECTS

Slovenia has already access to LNG in Italy and may gain access to LNG sources from Croatia once a floating terminal with an initial capacity of 2.6 bcm/year is constructed, together with the necessary evacuation pipelines. The Croatian company LNG Croatia has already received more than 100 mEUR funding from the Connecting Europe Facility (CEF) of the EU in 2017, so that the terminal can apply tariffs low enough to make the new source competitive. Further CEF-funding is expected to ensure acceptable tariff levels on the evacuation pipelines as well. As we have noted in Chapter 2.7, the implementation of TAR NC is a further guarantee that high tariffs will not prevent Croatian LNG sources to contribute to lower prices and more intensive gas-on-gas competition on a regional level.

Figure 7: Timeline of the Croatian LNG project



Source: LNG Croatia

The new terminal is expected to begin operations in 2020 according to latest LNG Croatia company information,[14] when the EU may enjoy an abundance of available LNG due to a run-up of global liquefaction capacities. This trend may result in a high utilization of the terminal, which can thus put effective competitive pressure on pipeline suppliers. The appearance of an alternative source can strengthen the bargaining position of importer countries when re-negotiating their long-term contracts with their dominant suppliers, as it was evident in case of the Baltic countries after the Klaipeda terminal was built. Hungary also managed to negotiate better prices with Gazprom after the decision to build the Hungarian-Slovakian interconnector.

Russia, on the other hand, is also active in promoting its own pipeline projects. Turkish Stream may fundamentally change gas flow patterns by shifting deliveries to the South-East European region to a Southern route. The Turkish Stream will have two strings with a throughput capacity of 15.75 bcm each. The first string is expected to be put in operation in March 2018, and the

[14] CESEC Gas plenary and working group meeting, 4th of December 2017, Brussels

second string at the end of 2019. We expect that this would somewhat decrease the benefits of the Croatian LNG terminal (if built) on a regional level. The expansion of Nord Stream may have an even more significant (negative) effect on the benefits of the project by re-routing the long-term contracts to the new pipeline and reducing the Hungarian demand for additional sources through LNG.

Another important new gas source for the region may be expected from the future start of Romanian (and Bulgarian) offshore gas production. A corridor to transport these sources West on the Romania-Hungary-Austria route is a PCI that has already received 180 mEUR CEF-funding. The fact that in 2017 the project was restructured to Romania-Hungary may increase the significance of the Hungarian-Slovenian interconnector, as Slovenia could only access new Romanian sources through Hungary.

The Italian market will also become more important for Slovenia once the infrastructure projects (listed below) are built:

- TAP (Trans-Adriatic Pipeline), which would provide the country with the option to diversify its imports with Azeri gas;
- Poseidon, which enables transmission of gas from the Eastern Mediterranean area to Southern Italy;
- Increase of transmission capacity of the North-South connections inside Italy;
- Refurbishment and capacity increase of the connections from Southern Italy to North Africa;
- Additional LNG terminals.

Italy also plans to increase its entering gas transmission volumes from new sources and transport capacities to countries North of its borders.

The appearance of additional gas volumes is likely to significantly contribute to the liquidity of the Italian hub, which would bring additional benefits to Slovenia. As we discuss in detail in Annex III, PSV is already much larger in traded volumes and has twice as many potential market players as the Austrian hub, while CEGH plays a more central role in the Austrian market with much higher liquidity if measured by the churn rate.

3.2 THE ITALIAN "LIQUIDITY CORRIDOR"

While the appearance of significant amounts of new gas sources may contribute to the development of PSV, Italy has other plans as well to increase liquidity on its market. The government's new Energy Strategy published in 2017[15] aims for the establishment of a "liquidity corridor", which should help reduce the price spread between the Dutch TTF and PSV. The price difference between these two trading points has stabilized at around 2 EUR/MWh, which is rather high compared to other more developed markets. For example, the price spread between TTF and the German virtual trading point NCG is between 0.2 and 0.3 EUR/MWh for forward transactions.

The Italian government's proposal is that the Italian TSO buys on its own behalf long-term transmission capacities between TTF and PSV and between NCG and PSV, and also possibly between PEG Nord (France) and PSV. The government expects a significant price reduction by at least half of the spread as a result of this measure. The European Commission's first reactions toward such a measure are however modestly enthusiastic, rather sceptic.

The price difference is due to tariff pancaking and contractual congestions at the German – Swiss border. As discussed in Annex I, Italian prices are higher than those in Austria. One

[15] http://www.sviluppoeconomico.gov.it/index.php/it/energia/strategia-energetica-nazionale

possible explanation for the difference is the relatively high tariff on the Austrian-Italian border. Based on quarterly market data of the European Commission, the difference between the Italian and the Austrian hub price generally did not exceed the yearly tariff (defined in Annex II) in 2016 and 2017, with the exception of 2017 Q4, when the difference was twice as big as the transmission tariff. 2017 Q4 is clearly not explainable by tariff differences.

Another possibility is that because of the high utilization – with bookings close to the technical capacity - not enough trade is possible to allow for full price convergence. We explore the possibility of barriers to trade in Annex I in more detail. It is also important to highlight, however, that ACER did not categorize the pipeline as congested in its most recent monitoring report[16].

Additionally, the Austrian market is already more expensive than the TTF and NCG as a result of physical congestions on the German-Austrian border. The possible existence of barriers to trade highlight the importance of the proper implementation of Framework Guidelines and Network Codes that form part of the Third Energy Package. We will discuss the current European regulatory framework and its potential to bring about an integrated market in Chapter 4.1 in more detail. It is important to note, however, that even if we assume that physical and contractual congestions will not be a problem in the future, market foreclosure by long-term commodity and capacity contracts is not prevented by current regulations.

3.3 THE FUTURE OF LONG-TERM CONTRACTS

Long-term commodity contracts are likely to remain part of the EU's gas wholesale trading structure, but with a contract duration of only 3-10 years as opposed to much longer periods in the past. Buyers might want to minimize their volume risk by covering only the "baseload" gas consumption of their portfolios from LTCs while covering the rest from more flexible sources. Most of the new contracts are committed to full hub indexation, or in the case of Gazprom, apply an "indirect spot pricing" regime when oil-indexed prices are only used if they remain within a pre-defined range around forward hub prices.

Although these changes make LTCs more flexible with ensuring that they follow hub prices and overall gas market dynamics, they still contain some risks related to market power issues. If the minimum take-or-pay levels in these contracts are close to the consumption or the import need of a county, then the national wholesaler have limited incentives to purchase gas from more competitive sources, and have limited ability to react to price movements. This may be a relevant concern on the Slovenian market with a dominant importer who has entered into an LTC covering more than 60% of the country's consumption, although the level and regional scope of competition seem to be sufficient to alleviate such fears.

The implementation of the Third Package in 2009 prohibited the application of destination clauses in order to relax the strict market segmentation created by legacy LTCs. Producers responded by triggering some modification of the contract terms so that long-term transmission capacity booking got a crucial role in blocking competition and preserving market foreclosure. This issue can be relevant for Slovenia, as Gazprom renegotiated the delivery point of the Italian LTC from Austria to the Italian border, contributing to the very high utilisation of the interconnector and possibly making the re-selling of gas more expensive.

A similar strategy emerges from the March 2017 European capacity auctions on the PRISMA platform in connection with the Nord Stream 2 pipeline, where Gazprom booked long-term the most important existing trading routes from Germany to the Czech Republic and Slovakia,

[16]ACER: Annual Report on Contractual Congestion at Interconnection Points - 2017

previously used by spot traders, and also contracted for new incremental capacity on this route. Although Slovenia is not directly affected by this move, reduced opportunities for spot trading may hinder the development of the Austrian hub and contribute to a sustained difference in market prices between Western and Central- South-Eastern countries.

We conclude that although Slovenia is currently much more connected to the cheaper and more liquid[17] Austrian market than to its Italian competitor, the latter may also become relevant with several factors expected to contribute to an increase of its competitiveness. As the liquidity on CEGH is mostly attributed to Russian long-term contract surpluses of European midstream companies, it is very much dependent on contract re-negotiations with Gazprom. There is a certain risk of less liquidity on CEGH once the Russian LTCs expire, which reinforces our view that the Italian market may gain importance for Slovenia in the future.

[17] Churn rate of PSV: 1.2, Churn rate of CEGH: 5.7

4 MARKET DEVELOPMENT OPTIONS FOR SLOVENIA

In this Chapter we identify and evaluate possible directions by which Slovenia could draw a strategy for developing its gas wholesale markets. We first take a look at a scenario where Slovenia does not engage in any formal integration process, but relies on the benefits that can be expected from the full regional implementation of the 3rd package rules. Next, we present integration options suggested by AGTM, and examine if and how they can be relevant for Slovenia. Finally, we give an overview of market integration plans already drafted in the region, with a special attention to the only one that includes Slovenia, published by E-Control (2017).

4.1 DEVELOPMENT IN THE CURRENT REGULATORY FRAMEWORK

The idea of integrating national gas markets into a single internal energy market goes back to 1998, when the first EU directive setting out common rules for the internal market in natural gas was published.[18] The current regulatory framework is the result of an evolutionary process consisting of successive directives and regulations, reflecting the views of various stakeholders: market participants (shippers, traders, producers, suppliers), network and storage operators, regulators and a row of European and national institutions.

The current regulatory framework is composed of a Directive and a related Regulation laying down the main principles,[19] and Guidelines and Network Codes (NCs) setting out operational rules:

- Network Code on interoperability and data exchange rules;
- Network Code on gas balancing of transmission networks;
- Network Code on capacity allocation mechanisms in gas transmission systems;
- Network Code on harmonised transmission tariff structures for gas;
- Congestion Management Procedures Guidelines.

All of the rules and provisions included in these documents fit into a big picture, making up the model of European gas market integration: separate entry-exit systems with virtual trading points, interconnected via explicit capacity auctions organised by joint booking platforms, supported by congestion management practices to maximise utilisation of cross-border capacities and increasing price convergence.

The main components of the integrated European gas market are de-coupled entry-exit systems covering a well-defined geographic region. The movement of gas within that region is unrestricted: network users can book capacity rights independently at entry and exit points, bringing gas into the system at any entry point, and making gas available at any exit point within the system. Gas can be traded freely within the region independently of its location at virtual trading points. That network access model is markedly different from the former one based on contractual paths and point-to-point relations.

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[18] Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas.

[19] DIRECTIVE 2009/73/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC; REGULATION (EC) No 715/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005

Trading within the entry-exit system takes place at a notional point, called virtual trading point (VTP).[20] The main function of a VTP is to ensure that gas can change ownership independently for its physical location within the system. As a trading platform, VTPs can serve commercial purposes, to facilitate trading gas and managing imbalance positions of shippers. A VTP is usually closely connected to the balancing responsibilities of market players: as the TSO is required to undertake balancing actions (purchase and sale of short-term products) at trading or balancing platforms, setting up a VTP may fit that purpose.

Setting up a market-based balancing regime is a key driver of short-term gas trading: network users trying to balance their portfolios and TSOs carrying out residual balancing actions rely on short-terms markets. The network code on balancing (NC BAL) states: 'This Regulation supports the development of a competitive short-term wholesale gas market…' and '…the balancing rules designed to promote a short term wholesale gas market, with trading platforms established to better facilitate gas trade…'.[21] TSOs are required to procure or offer short-term products on a trading platform meeting several criteria. In the absence of an adequate trading platform, the TSO is required to establish one (balancing platform).[22]

Slovenia introduced market-based balancing rules on 1st October 2015, which resulted in an improvement in the functioning of the balancing system. Previously, Slovenian balancing groups had the practice of planning long imbalance positions consistently, as observed by ACER.[23] Asymmetrical positions of balance groups caused an overall distortion in the balancing system. The TSO had to balance the system intensively: the TSO balancing did not only had to cover the unexpected imbalances, but also this systematic diversion.

The market-based balancing rules – including the market-based imbalance settlement system – started to resolve this phenomenon slowly. This will most likely have a beneficial effect on the balancing system and on the short-term wholesale market as well. By reducing the overall system balancing need to unexpected system cases, the balancing system will become cheaper and more efficient. Furthermore, if the balancing groups' imbalances are random, then these portfolio imbalances will have diverse directions. Moving closer to real time, imbalance positions are becoming more and more known for the network users. In response, during the renomination process, they have the possibility to exchange opposite sign imbalances with each other, and also to involve upstream sources to solve their imbalances. This way network users are becoming more and more the primary responsible parties for balancing. By this trading activity, they drive more and more liquidity to the short term market as well.

The functioning of the Slovenian VTP is gaining intensity over the past years, market participants report an increasing number of transactions to the VTP. The TSO has to develop it further in order to bring it closer to its users. It is worth mentioning that liquidity of the gas market does not depend on the absolute traded volumes, but also on the proportion of these volumes to the Slovenian gas consumption.

The liberalised EU gas market consists of interconnected entry-exit systems. Gas exchange between entry-exit systems is enabled by efficient allocation of cross-border capacity, leading

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[20] Establishment of virtual trading point is not explicitly required by regulation, but is implied by the Regulation 715/2009. According to Paragraph 19 of the preamble 'To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system.'

[21] COMMISSION REGULATION (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks

[22] Article 10 (1),(2) and Article 47 of NC BAL

[23] ACER Report on the implementation of the Balancing Network Code. 16/11/2017

to price convergence in the connected entry-exit zones.[24] Transmission rights (capacity products) are allocated via explicit auctions and traded on secondary capacity markets, separately from the gas itself. Auctions are organized through capacity booking platforms. The price of the standard capacity products (yearly, quarterly, monthly, daily and within-day products) offered by TSOs is set by market forces: in case of low demand for capacity, shippers only have to pay the regulated entry-exit tariff. However, in case of high demand, shippers must pay a premium on the regulated tariffs.

Tariff calculation plays a crucial role in market integration, as high tariffs (especially for short-term capacities) make gas trading between entry-exit systems unattractive.[25] The main objective of the network code on harmonised tariff structure (TAR NC) is therefore to create cost-reflective, non-discriminatory and objective tariffs, that minimise cross-subsidization between intra-system and transit use (and between the users of different entry and exit points), and facilitate cross-border trade.[26] The TAR NC set out reference price methodology for entry/exit points, calculation of reserve prices, and pricing of bundled capacity.

Insufficient capacity and contractual congestion may impede price convergence. The regulatory framework contains an elaborated tool-kit to ease congestion and maximise available capacity: capacity increase through oversubscription and capacity buy-back, restriction of re-nomination for dominant network users through firm day-ahead use-it-or-loose-it (UIOLI) mechanism, facilitate disposal of unneeded contracted capacity by secondary capacity markets or capacity surrender scheme, and long-term UIOLI scheme to withdraw systematically underutilised contracted capacity and release it to the market should be applied to manage congestion.[27]

The above elements of the European gas market liberalisation have been put in place between 2009 and 2017. However, implementation is still incomplete, with several elements of the framework regulation functioning smoothly, others still waiting to be implemented. Implementation of the network code on capacity allocation (CAM NC) is 'well on track' on core elements: auctioning of standard capacity products via joint booking platforms (PRISMA, RBP) is well developed. However, other requirements are not yet fulfilled: bundling of capacities at interconnection points (IPs), and integrating IPs connecting neighbouring/adjacent entry-exit systems into a virtual IP (providing a single capacity service to network users) are lagging behind.[28]

Incomplete implementation is even more pressing in congestion management procedures (CMP). The most urgent issue is dynamic recalculation of technical and additional capacity to

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[24] Rules of capacity allocation is set by the COMMISSION REGULATION (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013.

[25] In a Kantor Report on barriers to gas wholesale trading across Europe, the high level of transmission tariffs, especially for short-term capacity products was identified as the biggest barrier to wholesale gas trading. According to market participants „short-term capacity products should be made as competitive as possible." For that purpose, „TSOs should not hold back in offering interruptible capacities of any duration to shippers" and „multipliers should not prevent short-term flows by being higher than annual capacity." (Barriers to gas wholesale trading. Final Report submit to ACER by Kantor Management Consultants (2017))

[26] COMMISSION REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

[27] COMMISSION DECISION of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks.

[28] ACER Implementation Monitoring Report on the Capacity Allocation Mechanisms Network Code (First Edition, 27 October 2016)

maximise technical capacity at all times of the year, implementing long-term UIOLI mechanisms, and better harmonisation/coordination of CMP applications.[29] The same is true of balancing rules; as the ACER monitoring report states: "The implementation of the Code is still patchy: some regimes are in a well-developed stage, while others have made some progress, but there is still work to be done before full implementation is achieved". 30 TSOs have to play an active role as 'market enablers' to facilitate short-term markets to develop.

Implementing the TAR NC can improve the market integration by making cross-border tariffs more transparent and cost-reflective. Application of the reference price methodology can remove some obstacles market players are facing in the European gas markets: potential overpricing of short-term capacities or pushing protectionist energy policies by distorting entry/exit tariffs are expected to become less common.

ENTSO-G reports on CAM and CMP implementation paint an overly optimistic picture of great progress,[31] but progress reports on formal implementation may be misleading.[32] Assessing the effect of CAM and CMP implementation, ACER points out that delayed, incomplete or absent implementation, and limited quality and availability of the underlying data are hindering evaluation of competition and integration effects. These problems are even more accentuated in the South-East European region: according to ACER, 'south-eastern countries still face very low compliance rates'.[33]

Insufficient application of regulations and its consequences on market integration was highlighted by the Kantor Report on barriers to gas wholesale trading across Europe.[34] Access to cross-border transmission capacities is the precondition of market integration, but it is hindered by administrative deficiencies: overpriced short-term capacities, insufficient interruptible capacities, ineffective use-it-or-lose-it (UIOLI) mechanisms, and complicated mechanisms for secondary trading of capacities. Most of the above barriers identified by market participants relate to the behaviour of transmission system operators (TSOs) and national regulatory authorities (NRAs).[35]

To sum up, there is significant room for improvement in market competition and integration as NC implementation is progressing and more elements of the framework regulation (market integration model) is put into place. Enforcing compliance with the above rules is generally regarded as a conservative approach to integrating markets: studies discussing options of gas market integration call it 'Framework Guideline driven' or 'Interconnected markets'.[36]

For the Slovenian market it is crucial to fully implement the Network Codes to ensure sufficient level of harmonisation and development of regional markets. After these requirements are fully

[29] ACER Implementation Monitoring Report on the Congestion Management Procedures (2016 Update on the First CMP Implementation Monitoring Report (2014), 16 September 2016)
[30] ACER Report on the implementation of the Balancing Network Code (Second Edition Volume I, 16 November 2017)
[31] ENTSOG CAM NC Monitoring Report 2016; ENTSOG CMP Monitoring Report 2016
[32] Although long-term UIOLI is formally implemented in all non-derogated member states, ACER points out that 'The Agency is not aware of any cases where LT UIOLI has resulted in a withdrawal of capacity.' (ACER Implementation Monitoring Report on the Congestion Management Procedures 2016, p. 26)
[33] ACER Gas Regional Initiative Status Review Report 2016 (ACER, 7 February 2017)
[34] Barriers to gas wholesale trading. Final Report submitted to ACER by Kantor Management Consultants (2017)
[35] Incomplete or bad implementation of Network Codes and lack of transparency during tariff-setting can be attributed clearly to NRAs and TSOs.
[36] Market design for natural gas: the Target Model for the Internal Market (LECG, March 2011); Study on Entry-Exit Regimes in Gas Part B: Entry-Exit Market Area Integration (KEMA DNW, July 19 - 2013)

implemented, it would be necessary to assess whether further integration, e.g. coupling of regions, are needed.

Table 3. SWOT table for the option of development in the current regulatory framework

Strengths	Weaknesses
• Priority of the European Union is to implement and enforce current regulation • Legally binding regulations and rules: non-compliance exposes Member States to trouble with the EU Commission	• Current regulation has not much to say about how to bring liquidity into small markets • Final Network Codes are the result of compromise between several stakeholders: they are far from being perfect
Opportunities	**Threats**
• Effective implementation and enforcement of current regulations has huge potential for improving markets	• Implementation may be a long journey and results are uncertain (for example long-term UIOLI)

4.2 MARKET INTEGRATION MODELS OF AGTM

This section describes and discusses market integration models as proposed by AGTM. These are, however, not the only possible forms of market integration.

4.2.1 Market merger & Trading region

A market merger entails the full merger of two or more adjacent markets by merging their virtual trading points and their balancing zones. In a trading region, end-user balancing zones remain separate, so that balancing on the level of the distribution grid continues to be done locally (by ‘end user managers’). From the perspective of traders, the creation of a joint VTP in both models means the emergence of a single price zone and the abolishment of tariffs on former Interconnection Points, i.e. at the border of former entry-exit systems. The new market area will become a single entry-exit system with a single wholesale price, with the possibility for market players to inject or withdraw gas from any point on the transmission system of the enlarged area. This facilitates trade in a number of ways:

- The merging of VTPs pools their liquidity, lowering transaction costs and enhancing price transparency;
- The abolishment of intra-zone transportation tariffs results in improved market efficiency, as gas prices are not distorted by intra-zone cross-border tariffs;
- Traders need not deal with booking capacities when moving gas from one place to another in the enlarged market area; they can buy and sell gas at a single price at the VTP, and TSOs take care of deliveries to any exit point (domestic, storage, or that of the market area);
- Portfolio management is also made easier by a better access to flexibility tools, such as short-term products on a more liquid VTP or storage.

Traders can also benefit from the bigger size of the balancing zone, which makes portfolio management easier and less costly for them as they do not need to meet balancing requirements on each - previously separate – markets, only on the level of the new, enlarged area. This is also true in a trading region, where it is the responsibility of the end user managers to physically balance the end user zones. In case of a market merger or trading region with Austria, for example, Slovenian balancing options will probably improve due to the direct availability of flexibility sources, most importantly the availability of storage flexibility services, and the direct trading possibilities on the CEGH. Currently, all these sources are available to Slovenian network users only indirectly, through the booking of border capacities. Merging of the two markets could provide a smoother and cheaper usability of these sources, therefore balancing the system would become cheaper and more efficient for both the Slovenian balancing groups and the system operator.

Achieving full market merger, however, is a slow and costly process, requiring a great deal of harmonization. A trading region is easier to implement as it saves harmonization work on metering, allocation and balancing rules, and – as ACER notes – issues of clarifying regulatory responsibilities and oversight arise to a lesser extent.[37] Both forms of market integration is also likely to create new problems, because network topologies are optimized for individual markets (countries), and not for the merged area.

As noted by LECG, large price zones may require the socialisation of significant intra-zone constraints via re-dispatch by the TSOs.[38] This allocates congestion rents earned by TSOs to shippers, and can create distorted incentives that lead to inefficient outcomes. TSOs, in turn, may be tempted to avoid costly re-dispatch by limiting capacity on the borders of the enlarged market area to reduce gas flows that are creating internal congestion (“shifting congestion to the borders”).

If more congestion costs are socialised, tariffs may increase and become less cost-reflective. Intra-zone constraints would also require TSOs to take a greater role in balancing, which is in contrast with the Balancing Network Code that gives the primary responsibility for balancing to individual network users.

TSOs, in theory, may opt for network investments to deal with intra-zone constraints, but market mergers and the creation of trading regions also bring significant changes to the financing of TSOs, making it more difficult to ensure that investment costs are recovered. Both integration models require an inter-TSO compensation mechanism, which redistributes revenues collected by TSOs participating in the enlarged market area. Such a mechanism is made necessary by the abolishment of IP-tariffs at national borders; these revenues are lost to TSOs and need to be covered by entry-exit tariffs imposed at the borders of the enlarged area, and domestic exit tariffs. To make up for lost intra-zone tariff revenues, remaining entry-exit tariffs are expected to increase, and TSOs that collect them need to compensate those whose recognized costs are not covered in the new setup (i.e. those who manage significant intra-zone transit flows, after which they can no longer collect entry and exit fees).

The creation of an inter-TSO compensation mechanism is cumbersome even if its goal is to merely guarantee that participating TSOs maintain their financial positions. It is even more difficult if NRAs want to set up a system that incentives and properly rewards investments. To begin with, signals for investment weaken because a single wholesale price covers a wider area, and price differentials that would call for incremental capacities disappear. Within the enlarged market area, traders are not faced with the direct costs of physical congestions, because they are not required to book and pay for cross-border capacities. This makes the market-based

[37] ACER (2015): European Gas Target model – review and update, Annex 6. Tools for gas market integration and connection, January 2015

[38] LECG (2011): Market design for natural gas: the Target Model for the Internal Market. A report for the Office of Gas and Electricity Markets, March 2011

financing of incremental capacities, as required by the CAM NC, impossible. TSOs would therefore need to engage in joint network development planning, and TSOs and NRAs of the enlarged market area would all need to agree on the allocation of investment costs and tariff changes that provide for their recovery.

To summarize, market mergers and the creation of trading regions may remove some market inefficiencies by facilitating trade, but at the cost of placing additional financial and – stemming from the need for increased co-operation and harmonization – administrative burden on TSOs and NRAs. It is to be noted, however, that even traders may face difficulties in the process, as their long-term supply contracts may need to be re-negotiated. This is because the delivery points of LTCs are usually set at IPs which, if they are intra-zone points of the enlarged market area, become abolished.

As TSO costs are expected to increase, there is a risk that tariffs become less transparent and cost-reflective, while investing in incremental capacities become less market-driven. An alternative to the system of inter-TSO compensations and extensive co-operation in network planning and investments may be the creation of a joint TSO for the enlarged market area, but it would only be possible with a high-level political support from all countries involved. Due to issues related to national sovereignty, especially with regards to dealing with Security of Supply situations, such commitments are unlikely to be made, as highlighted by the debates surrounding the creation of Regional Operational Centres for electricity, suggested by the European Commission in its "winter package" of 2016.

As noted by LCEG, market mergers and trading regions are best suited to solve problems related to capacity hoarding and contractual congestion. In an enlarged market area, IPs that would otherwise suffer from contractual congestion disappear in the sense that booking capacities on them is no longer necessary. Similarly, as these market integration models reduce the number of entry-exit systems that gas must cross if transited long-distance, they are an effective remedy to tariff 'pancaking'; i.e. the market distortive effects of cumulative entry and exit tariffs charged at cross-border IPs, which act as barriers to trade and price convergence. For Slovenia, however, contractual congestion does not seem to be a problem (see Figure 20), and tariff pancaking is not an issue either as the country directly connects with both Italy and Austria, the two most mature markets in the region.

On the other hand, physical congestions cannot be ruled out in the future, which may act as *de facto* barriers to full price convergence, a central element of both market integration models. In the current infrastructural setup, a market integration that allows for re-dispatch – and therefore full price convergence - in the case of physical congestion would need to involve both Italy and Austria, the two markets that can supply gas to Slovenia.

However, as shown in Annex I, wholesale price differences and available interconnection capacities between them make Italy and Austria unlikely candidates for seamless market integration that would result in full price convergence. This is implicitly acknowledged by E-Control (2017), which calculates welfare gains for market integration options including Austria and Italy by separately considering transport costs from Austria and Italy on the basis of significantly higher Italian market prices, and the important (50%) share of entry allocations in Arnoldstein compared to all entry allocations in Italy.

Slovenia could benefit from a market merger or trading region with Italy and Austria by gaining access to a more liquid hub that would emerge from the merging of the Italian and the Austrian VTP. Slovenian traders, however, are already able to take advantage of the products and services available on these hubs. As both hubs are directly neighbouring the country, the benefits they offer are easily available, and do not necessitate the application of any formal market integration tool. In our understanding, Slovenian traders face no regulatory barriers in accessing either the Italian or the Austrian VTP.

Table 4. SWOT table of market mergers and trading regions

Strengths	Weaknesses
• Better liquidity with lower transaction costs, better price transparency and access to flexibility • Improved market efficiency due to the abolishment of intra-zone tariffs • Easier and less costly portfolio management due to bigger balancing zone	• Slow and costly to establish (great deal of harmonization, inter-TSO compensation) • Price signals are lost: market-based financing of incremental capacities become impossible
Opportunities	**Threats**
• Better competition, lower prices for Slovenia	• May result in physical congestions that need to be tackled by TSOs • Re-dispatch would only be possible if both Austria and Italy participate • Tariffs may increase and become less cost-reflective • Sovereignty issues if a joint TSO is considered

4.2.2 Satellite market

It is worth noting that if Italy and Austria choose to merge their markets or create a trading region between them, Slovenia may also opt for joining them as a satellite market. This is because Slovenia can currently be supplied with gas from Italy and Austria, which – if merged - would become the only 'feeder' market for the country. In such a model, the satellite market (Slovenia) does not maintain its own VTP, but its traders use the feeder's hub and market prices. The interconnection capacity from the feeder market area into the satellite market area is booked by the 'satellite manager', who is also responsible for the transport of gas and for physically balancing the satellite market.

ACER argues that the implementation of the satellite market concept is the choice of the satellite and does not affect market organization or operation of the feeder, and there are no issues with clarifying regulatory responsibilities and oversight, since no cross-border institutions or balancing zones are established. The abolishment of cross-border tariffs between the feeder and the satellite market, however, may raise some problems that TSOs and NRAs will have to deal with.

Similarly to a full market merger or in a trading region, traders do not pay cross-border tariffs to bring gas to the satellite market, which is a necessary precondition to achieve full price convergence by the joint use of the feeder market area's hub. ACER theorizes that the cost of the booked interconnection capacity is fully allocated to the exit tariffs of the satellite, which implies that these tariffs will need to cover lost revenues of TSOs in both the feeder and the satellite market. If the satellite market has significant transit flows originating from the feeder market area, these tariffs may need to be increased disproportionately to make up for lost revenues, and the TSO of the satellite market will need to transfer some of its revenues to its counterpart in the feeder market. Alternatively, the TSO(s) of the feeder market may agree to increase their tariffs on their remaining interconnection points. In either case, an inter-TSO compensation mechanism may become necessary under this model as well.

In relation to the satellite market concept, another important consideration for Slovenia may be its ability to diversify its supply sources. Once the country is able to import significant quantities of gas from markets other than Italy and Austria, this model can be no longer applied. As we have shown in Chapter 2.2, the realization of Slovenia's infrastructure development plans may result in new import capacities from the direction of Hungary and Croatia already in the foreseeable future. The benefits of supply source diversification may well surpass those of the status of a satellite to an Italian-Austrian market area, the creation of which is uncertain anyway. If and when concrete plans for such a market area emerges, Slovenia can still decide about its participation as a "full" member, not as a satellite.

Table 5. SWOT table of satellite markets

Strengths	**Weaknesses**
• Less harmonization requirement • Improved market efficiency due to the abolishment of intra-zone tariffs	• Inter-TSO compensation may become necessary
Opportunities	**Threats**
• Better competition, lower prices for Slovenia	• Depends on an Italy-Austria market merger with no other source of supply for Slovenia

4.2.3 Market coupling

The concept of market coupling originates in the electricity sector: integrating markets via an implicit auction of cross-border capacity. Power exchanges operating the neighbouring day-ahead markets run auctions for electricity products, but clearing is performed jointly, automatically enabling supply and demand bids to be available from the other zone as well, as long as cross-border transmission capacity is available. Capacity is attached to the relevant cross-border transactions and its price is included ('implicit') in the price of electricity paid by the buyer, resulting in a single market for capacity and energy combined.

The process works as follows. Shippers place bids and offers for gas in an auction at a hub or exchange within each price zone. This information is shared by the participating hubs/exchanges, and an algorithm run by a central party determines the flow between the price zones. If there is no capacity constraint on the border, gas flows freely from the low-price zone to the high-price zone until prices are equalized across the region. If there is capacity constraint (limiting the gas flow), the prices in the two zones remain different; however, even in this case some price convergence follows. The price difference between the neighbouring markets sets the price of the cross-border capacity, varying according to the severity of congestion.

Such model, which would combine advantages of both already developed models, has not been developed so far. The optimal model has to pass price signals to the transmission system operators in case when demand exceeds available capacities. The prices of implicitly or explicitly allocated capacities should be comparable. Allocation of the capacities included in a model has to be in line with Commission Regulation (EU) 2017/459 (of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013). Such a model has to offer capacities that were not sold on explicit method to implicit auctioning. This will contribute to price convergence.

The requirements to be met before market coupling goes live are the following. Neighbouring markets must establish a trading hub/exchange with similar trading rules (harmonised trading day, products traded, balancing period), and physical interoperability of networks. A single entity should be responsible for running the algorithm which determines the flow between the relevant markets. Lack of liquidity of infant gas hubs/exchanges should not be a barrier: experiences with market coupling in electricity sector suggest that market coupling may itself lead to greater liquidity in small markets.

Market coupling has several benefits. First of all, it ensures efficient use of cross-border capacity and increases price convergence between the zones. Price convergence across coupled markets eliminates the arbitrage gain from the price difference, resulting in huge benefits for consumers. Newberry (2016) estimates the EU-wide gains from electricity day-ahead market coupling at above 1 bnEUR/year. Additional benefits of integrating intra-day and balancing markets increase these gains up to 3 bnEUR/year.[39]

It should be noted that during the process of developing a target model for market integration in the electricity sector, there was a clear preference toward day-ahead market coupling. Merging smaller market areas into bigger ones was not considered by stakeholders at all. On the contrary: as artificially large prices zones with internal congestions are giving rise to unscheduled flows and high costs to system operators, splitting these market areas into smaller bidding zones is the preferred solution.[40]

As price for cross-border capacity is set in an auction (in time of no congestion the price of the cross-border capacity is zero), it gives transparent price signals for TSOs to invest in congested cross-border capacity, and congestion rents provide financial sources to (partly) fund the investment. This is considered as a dynamic market integration tool, “where market areas ‘couple’ and prices converge when there is sufficient interconnection capacity and markets ‘split’ and separate prices are formed when there is insufficient interconnection capacity”.[41] Market coupling is “dynamic” in another sense, too: insufficient cross-border capacities and congestions give rise to congestion rent accruing to the TSO and contribute to infrastructural investments easing congestions and increasing market integration.

The main limit to market coupling is the amount of short-term cross-border capacities put into the market coupling mechanism. Without significant capacities available for short-term allocation, the benefits (first of all: price convergence) brought about by implicit allocation remain limited.

There are marked differences between electricity and gas markets. For that reason, the above concept of market coupling applied in the electricity markets cannot be easily adapted to the gas market, resulting in several deviations from the original concept.

[39] Reducing cost of unscheduled flows with moving toward nodal pricing can add around 1 bnEUR/year to the potential benefits. See D. Newberry et all (2016): The benefits of integrating European electricity markets (Energy Policy 94 (2016))

[40] As insufficient transmission capacities within Germany and on the German-Austrian border result in unscheduled (loop) flows, ACER suggested the German-Austrian market zone to be split. See Decision of the Agency for the Cooperation of Energy Regulators No 06/2016 of 17 November 2016 on the Electricity Transmission System Operators’ Proposal for the Determination of Capacity Calculation Regions

[41] LECG (2011): Market design for natural gas: the Target Model for the Internal Market. A report for the Office of Gas and Electricity Markets, March 2011

First of all, gas supply is more flexible than electricity as it is storable. Electricity network operators have to balance the system every minute as opposed to gas systems, which can cope with differences in supply and demand over hours. Gate closure and daily auctions are the norm in the electricity sector; however, in the gas sector re-nomination and trading can continue through the gas day (continuous trading).

The pricing of cross-border capacities in the gas sector results in another difference. Cross-border trade in the gas sector is based on entry-exit tariffs set by the regulator in a cost-reflective manner. In the electricity sector, cross-border capacities are auctioned by the TSOs and they are exclusively priced by market forces: there are no fixed entry and exit tariffs. In case of congestion, traders face high prices, but in low-demand situations, the price of the capacity is zero. For that reason, there is more room for price convergence in the electricity sector.

The above characteristics of the gas sector led ACER to present a markedly different version of the original market coupling model. (1) The neighbouring spot markets connected via market coupling are operated on the basis of continuous trading (re-nomination is not restricted). (2) Available short-term cross-border capacities are allocated on a first-come-first-served basis, not by an auction. (3) Price of the allocated capacities is fixed by regulators, therefore all market participants have to pay the same price for capacities, irrespective of the level of congestion.[42]

The above features of the ACER vision preserve some benefits of the original market coupling model, and also bring some new ones. Implicit allocation results in price convergence, and continuous trading minimises transaction costs for shippers. The most remarkable benefit is the elimination of the co-ordination problem inherent in the system of explicit capacity allocation and continuous trading. When trading of capacities is separated from that of gas, traders could be 'short' or 'long' on cross border capacities, which may act as a barrier to trade and reduce liquidity.[43] In market coupling, capacities are automatically (implicitly) allocated to market participants who conclude contracts on the spot market, avoiding the need of 'parallel trading' of commodity and capacity, therefore excluding the risk of shippers having gas without the necessary cross-border capacity or vice versa.

The benefits of implicit allocation as opposed to explicit capacity auctions are summarised by EuroPEX, the Association of European Energy Exchanges: "*As real time approaches, it becomes increasingly difficult for market participants to coordinate their gas and capacity positions if these are defined on separate markets, as it is the case with explicit auctions. …. By integrating capacity allocation and gas trading, implicit auctions overcome these inefficiencies, provide consistent price signals and ensure that the available transfer capability is fully used, subject to demand*."[44]

On the other hand, some attractive features of the original market coupling model are lost in the gas target model. As shippers have to pay regulated entry-exit tariffs, price signals on the existence and on the level of congestion are missing. Tariffs must be paid even in the absence of congestion, preventing full price convergence between the coupled markets. In case of congestion, no extra revenue accrues to the TSO; the benefits of using a congested capacity is

[42] European Gas Target Model – review and update. Annex 6: Tools for gas market integration and connection (ACER, January 2015)
[43] The Brattle Group (2012): Gas market integration via implicit allocation: Feasibility from the North-West European gas market perspective (23 April 2012, written by Dan Harris and Carlos Lapuerta)
[44] EuroPEX response to ERGEG Call For Evidence On Gas Target Model (31 December 2010)

kept by the shipper (first mover).[45] The risk of holding unused capacities by the trader is shifted to the TSO, who may realize less revenue from capacity sales.

These features, as well as the remarkable degree of price convergence already evident among national gas markets in Europe, are limiting the potential gains to be realized from any market coupling. According to a report prepared by the Brattle Group for the former Dutch competition authority (NMa):[46] "*The estimated welfare benefits per year on both the Dutch-German and Dutch-Belgian borders are in the range of €15-25 million per year – a relatively small number considering that the total value of gas consumed in the Netherlands is about €10 billion*."[47]

Revenue and risk re-allocation, and limited possible gains shed light on the problem of incentives to encourage market coupling. In the electricity sector, power exchanges that operate liquid day-ahead markets initiated and promoted the market coupling model, which they regarded as an effective instrument to bring more trading activity on the exchanges. Power exchanges along with TSOs (usually owning and operating exchanges) developed all the processes and software needed to bring the market coupling idea into life. The European Commission and national regulators supported the model as it was regarded as a building block of integrated electricity markets.

This kind of support may be lacking in the gas sector. Traders may be interested in the re-allocation of congestion rents and risks, but are afraid of revolutionary movements in regulation proposed by CEER and ACER. They are interested in "avoiding the risk of unintended consequences of regulation" and prefer "evolutionary arrangements which build on existing practice" carrying less complexity and risks.[48] The top-down process of developing the Gas Target Model by regulators with the goal of overcoming insufficient regulation is in a sharp contrast to the bottom-up process that were driven by stakeholders in the electricity sector.

The first market coupling scheme in the gas market was implemented in France. The project was launched in 2011 by GRTgas (the TSO operating the French gas transmission network) and Powernext (the French gas exchange).[49] After years of merging small regional transmission zones within the country, two entry-exit zones emerged: PEG North and PEG South. Limited transmission capacities between the two zones prevented further integration of the French gas market. Market coupling was considered as an interim step towards a full North-South market merging until infrastructural investments eliminate congestion between the two zones. The integration is expected to be finalised in 2018 in a France-wide trading region model:[50] on 1st November, 2018, the North-South IP tariff will disappear.[51]

[45] The magnitude of lost revenue may be limited as long as short-term capacities „represent a relatively small residual after the forward capacity allocation process". See: Frontier Economics & Stratorg-Ylios (2011): Target Model for the European Natural Gas Market (A report prepared for GDF SUEZ Brache Infrastructures, June 2011)

[46] The Netherlands Consumer Authority, the Netherlands Competition Authority (NMa) and the Netherlands Independent Post and Telecommunications Authority (OPTA) joined forces on April 1st 2013, creating a new regulator: the Netherlands Authority for Consumers and Markets. www.acm.nl

[47] The Brattle Group (2012): Gas market integration via implicit allocation: Feasibility from the North-West European gas market perspective (23 April 2012, written by Dan Harris and Carlos Lapuerta)

[48] See Frontier Economics & Stratorg-Ylios (2011): Target Model for the European Natural Gas Market (A report prepared for GDF SUEZ Brache Infrastructures, June 2011)

[49] Market coupling between the zones North and South (GRTgas, 29 March 2013); Pilot Project on Market Coupling PEG Nord / PEG South (Powernext and GRTgas; 3rd Workshop on Gas Target Model, London, 11 April 2011)

[50] Trading region model enable the merger of the neighbouring zones while retaining the GRTgaz and TIGF balancing region. See TIGF Activity Report 2015

[51] See CRE Public Consultation of 27 July 2017 Nº 2017-012 relating to the Creation of a Single Gas Market Area in France on 1st November 2018

The market coupling initiative aimed at reinforcing liquidity on the PEG South spot market by linking it up with the more liquid PEG Nord market, and fostering price convergence. The chosen method differed from the one suggested by ACER and the one applied in the electricity sector. Capacity allocation was integrated within continuous trading: GRTgas allocated capacities on a day-ahead basis through a spread product on the Powernext screen, offering to meet PEG South / PEG North spread ask/bid requests. Two years later Powernext and EEX integrated their natural gas products on one trading platform, called PEGAS (Pan-European Gas), and introduced location spread products between its Belgian, Dutch, French, German, Italian and UK market areas (ZEE, TTF, PED Nord, GASPOOL, NCG, PSV and NBP).

Table 6. SWOT table of market coupling

Strengths	Weaknesses
• MC improves liquidity of spot markets in smaller zones and brings about price convergence • Easier and less costly implementation (compared to market merger) • No more risk for traders of having gas without cross-border capacity	• Limited amount of day-ahead capacities restricts price convergence • Regulated tariff for capacities limits price convergence and kills price signals indicating congestions • MC mechanism in gas markets doesn't have long track record • Not much improvement compared to explicit capacity allocation
Opportunities	**Threats**
• Multilateral market coupling can lead to price convergence within a bigger region • Full implementation of long-term UIOLI may increase the amount of short-term capacities and the effects of MC	• TSO may lost revenues on congested borders (restricting investment)

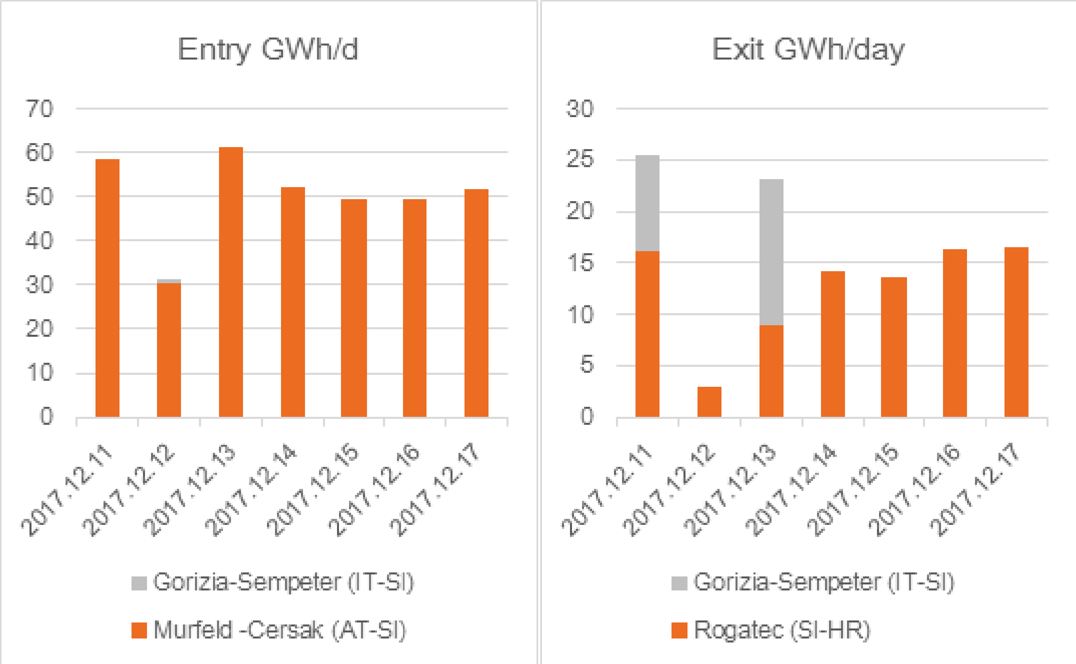
4.3 SECURITY OF SUPPLY CONSIDERATIONS

Considerations regarding Security of Supply (SoS) were raised during the stakeholder consultation process in the wake of the Baumgarten incident.

The Baumgarten gas hub was closed for a day due to an explosion from 9 a.m. until midnight on 12th December, 2017. One third of the Russian gas transferred to Western Europe passes through Baumgarten, so the explosion caused confusion on the market with significant price hikes. Gas Connect Austria announced that Austria's gas supply was not endangered by the explosion, but transit to Italy and Slovenia was hindered.

In the absence of storage facilities, Slovenia's gas supply is largely dependent on the volumes transferred from Austria through the Murfeld/Cersak interconnector. On the day of the explosion, the volume of natural gas transferred through Baumgarten dropped to 16 mcm (which is 100 mcm less than the usual daily amount), and the amount entering Slovenia halved to 3 mcm (30 GWh). Slovenia reacted by importing gas from Italy, although the volume was very small (1.25 GWh). On the day after the explosion, enhanced imports from Austria were observed. Almost one third of natural gas arriving from Austria is transferred to Croatia; this flow also dropped on the day of the explosion and was restored only gradually.

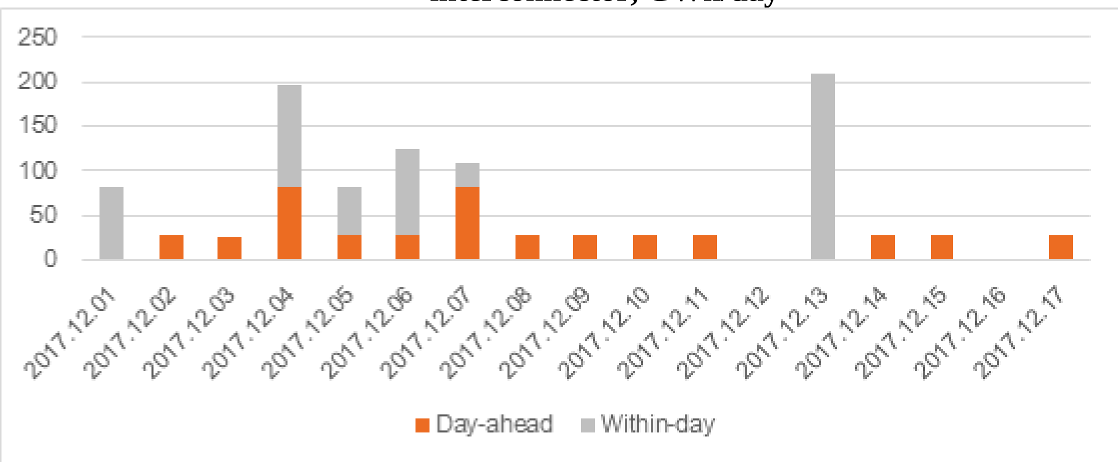
Figure 8: Gas flows to and from Slovenia in the week of the Baumgarten incident



Source: Plinovodi

To meet regular daily demand, huge amount of within-day capacities were offered the day after the explosion. 27 GWh/day, or 13% of the published within-day capacities were sold on 13th December, which means that 43% of gas imports from Austria was shipped using the shortest-term capacity product available.

Figure 9: Published day-ahead and within-day capacities on the Austrian-Slovenian interconnector, GWh/day



Source: PRISMA

Prices on CEGH, TTF, NCG and GPL increased by 7- 10% on 12th December. Italy, which is dependent on Russian flows for almost one third of its demand, faced almost twice as high prices as on the previous or the following days, and declared a state of emergency. The incident increased Slovenian import costs by the combined effect of higher priced imports from Italy on the day of the explosion, and the need to buy more expensive within-day capacities on the AT-SI interconnector the day after; we estimate the extra cost to be around EUR 120,000.

Cross-border capacity curtailment in times of crises is clearly prohibited by Regulation 2017/1938,[52] Article 11, §6 of which stating that:

The Member States and, in particular, the competent authorities shall ensure that: (a) no measures are introduced which unduly restrict the flow of gas within the internal market at any time; (b) no measures are introduced that are likely seriously to endanger the gas supply situation in another Member State; and (c) cross-border access to infrastructure in accordance with Regulation (EC) No 715/2009 is maintained as far as technically and safely possible, in accordance with the emergency plan.

This requirement is irrespective of any possible market integration tool applied by Member States, and a market merger would not help if the maintaining of gas flows becomes impossible due to technical reasons (such as an explosion), or the physical absence of gas (due to a supply cut made by a 3rd country exporter or transit country).

When two adjacent gas markets are merged, traders do not need to nominate gas flows on former interconnection points, only on domestic exit points. For example, Slovenian traders who buy gas on the joint VTP, can directly nominate flows on domestic exit points in Slovenia. One could argue that it is easier to falsely claim *force majeure* to restrict the flow of gas at a cross-border point than at a domestic exit point, but this would imply the assumption that the TSO of the country where the joint VTP is located may be inclined to act in bad faith in crises situations. As current regulations clearly prohibit such a behaviour, it is not necessary to pursue market merger as a tool to prevent the restriction of gas flows.

Slovenia largely depends on gas flows from Austria, which makes it inevitable that a SoS situation in Austria will hurt Slovenia as well, whether they are in a single entry-exit system or not. Both countries are part of the Eastern gas supply risk group involving Ukrainian transit pursuant to Annex I of Regulation 2017/1938. Therefore, they are required to co-operate in assessing supply risks and drafting their preventive action plans and emergency plans. Making arrangements to maintain gas flows “as far as technically and safely possible” in situations when state of emergency is declared, should be made in the framework of this co-operation mechanism.

As we have shown in previous Chapters, Slovenia stands a good chance of decreasing its dependence on the Austrian supply route. When that happens, it will have better opportunities to mitigate the effects of a situation when state of emergency is declared in Austria. Under such improved circumstances, Slovenia may even face less sharp price increases in case of a supply crises in Austria provided that they are not in a single price zone.

4.4 MARKET INTEGRATION PLANS IN THE REGION

Regional gas market integration plans are discussed by energy regulators, transmission system operators, the European Commission, national governments, energy companies and other relevant stakeholders in the framework of Regional Initiatives. Slovenia, together with 11 other

[52] REGULATION (EU) 2017/1938 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010

EU Member States[53] and 8 Energy Community Contracting Parties,[54] is part of the South South-East (SSE) region. Although Regional Initiatives focus on completing the implementation of the third package and the Network Codes, the current work plan of the South South-East Gas Regional Initiative (GRI SSE) covering the 2015-2018 period[55] includes a market integration pilot project as well. The project has been developed by the NRAs and TSOs of Austria and the Czech Republic, with the aim of implementing a "small-scale" market integration according to the concept of a "Trading Region Upgrade (TRU)".

Austria and the Czech Republic are not directly interconnected on transmission level, therefore integration via merging of markets or implementing a functional trading region is currently not feasible. In May 2015 the two TSOs launched a market survey to receive feedback from the market whether the incremental capacities should be offered on a new interconnection point or through a new concept reflecting the principles of market integration. The result of the market survey was a preference for market integration.[56]

The TRU concept would offer the possibility to upgrade booked entry capacity at each entry point in the transmission grids of Austria and the Czech Republic. TRU options could be purchased and used by anyone who has such capacities, and enable them to access the Austrian, the Czech, or even both VTPs at the same time. In other words, this upgrade of entry capacities would enable gas entering one market to be traded on the other, even if they do not form a single entry-exit system, and are not even directly connected. The first TRU options were planned to be offered at the annual yearly capacity auctions in July 2017 for use from 1 October 2017, but there has been no public updates about the state of the project since June 2017.

E-Control, Austria's NRA commissioned a study from WECOM to assess further market integration options, which was published in January 2017.[57] The study analyzed six market integration options for Austria's Eastern market area, including market mergers between Austria and the German NCG market area; Austria and Italy; Austria, Italy, Slovenia and Croatia; Austria and the Czech Republic; Austria, the German GPL market area and the Czech Republic; and Austria, the German NCG market area and the Czech Republic. As opposed to the starting point of the TRU concept, the Bi-directional Austrian-Czech Interconnector (BACI) is considered as existing interconnection capacity in the market integration options that comprise the Czech Republic and Austria.

The cost-benefit analysis presented in the study is based on the premise of a full market merger, and concludes that it is the option comprising Austria, Italy, Slovenia and Croatia that results in the highest overall welfare gain for the participants considered. The calculated welfare gain was particularly high for both options that included Italy, with an explanation referring to the large size of the Italian market and the relatively small capacity restrictions between Austria and Italy.

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[53] Austria, Bulgaria, the Czech Republic, Croatia, Cyprus, Greece, Hungary, Italy, Poland, Romania and Slovakia.

[54] Albania, Bosnia and Herzegovina, Montenegro, former Rep. of Macedonia, Serbia, Moldova, Ukraine and Kosovo.

[55] ACER (2016): South South-East Gas Regional Initiative Work Plan 2015-2018. Version updated and revised in July 2016

[56] Consultation on the integration of gas markets of Czech Republic and Austria. https://www.e-control.at/documents/20903/443907/2016-03-29_AT-CZ_Consultation_Document_final_clean_EN.pdf/e9a45dcf-a5dd-45e2-8f83-2b08f6d50915

[57] E-Control (2017): Assessment of market integration options and simplified cost-benefit analysis. Non-binding English version of a study conducted by Wagner, Elbling & Company (WECOM) for E-Control Austria. Vienna, 31 January 2017

Capacity restrictions refer to potential interconnection deficits, i.e. to situations where market demand for interconnection capacity surpasses available levels. The study calculates "theoretical interconnection deficits" on interconnection points based on scenarios that would result in the highest imaginable level of demand for capacity.[58] The resulting theoretical capacity restriction rates were used to correct calculated theoretical welfare gains to account for welfare gains not to be realized because of interconnection deficits.

As the expected price decrease in Italy accounts for the bulk of the welfare gains, the inclusion of Slovenia and Croatia in the market integration scenario covering Austria and Italy adds only 3 mEUR, i.e. 0.6% to overall gains. However, both Slovenia and Croatia lack functional wholesale markets, while it is the characteristics of national wholesale markets that would otherwise serve as a basis for calculating those gains.

Therefore, when calculating the benefits of price convergence (based on spot wholesale prices), the study takes welfare gains that are calculated for the merger of the Austrian and Italian markets, and scales it to Slovenian and Croatian market volumes. Welfare gains resulting from the reduction of the bid-ask spread is assumed to be negligible for both countries. Finally, welfare gains resulting from retail market efficiency are based on regulated supplier margins in case of Croatia, and on Austrian prices plus transport costs in the case of Slovenia.

Even if we endorse the chosen methodology for calculating welfare gains, those presented for Croatia and Slovenia can therefore be regarded as rough approximations at best. Benefits are only presented on the level of the integrated market, and they only account for those of consumers and traders in the form of price convergence and reduced bid-ask spreads. The effects of the elimination of IP tariffs are not considered, although this is one of the most important feature of the market merger model.

In fact, as we have seen earlier, the study explicitly adds transport costs from Austria to Italy on the basis of significantly higher Italian market prices, and the important (50%) share of entry allocations in Arnoldstein compared to all entry allocations in Italy. This also raises questions about the study's assumption that when merging the higher-priced Italian and the lower-priced Austrian markets, the lower prices would prevail, even if the higher-priced market is much larger.[59] We also see some inconsistency in the claim about relatively small capacity restrictions between Austria and Italy on the one hand, and the need for adding transport costs between merged markets on the other. As we have seen in Figure 26, congestion is already an issue on the Austrian-Italian interconnector.

As the elimination of IP tariffs is not considered, the problem of possible internal congestions is not considered either; "interconnection deficits" are not based on expected changes in gas flow patterns that may result from the elimination of tariffs. Furthermore, they are not treated as cost items, but they reduce welfare gains. As a result, no full price convergence is assumed, which would be another central element of the market merger model.

Apart from the TRU concept and the market integration options put forward in the E-Control study reviewed above, there seems to be no other regional plan that could still be considered

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[58] Country A may need to import all its gas needs (including transit) from country B, and country B may need to export all its gas entering its market and not consumed there to country A.
[59] E-Control, however, reiterated this view in its „Summary of responses to the consultation and reaction", available at https://www.e-control.at/documents/20903/443907/Zusammenfassung+Auswertung+Konsultation+Marktintegration+170609+EN.pdf/774d0dc3-729a-f686-90f1-f679fa79311c

relevant.[60] In 2012, WECOM drafted another concept (commissioned by E-Control, CEGH, Eustream and NET4GAS) about a trading region covering Austria, the Czech Republic and Slovakia (CEE Trading Region).[61] Also in 2012, E-Bridge presented a study (again for E-Control) on cross-border market integration covering Austria, Slovakia, the Czech Republic and Italy.[62] The study came to the conclusion that social welfare gains resulting from the integration of the Italian and the Austrian markets would be substantially higher than those involving Austria, Slovakia, and the Czech Republic. It is interesting to note that E-Bridge did expect a significant price increase in Austria in case its market is integrated with that of Italy.

Finally, V4 countries adopted a road map towards a regional gas market in 2013.[63] The document envisioned a market coupling study by 2014, but it was not completed.

[60] We understand that Italy is in preparation of its self-assessment study.

[61] http://www.acer.europa.eu/en/Gas/Regional_%20Intiatives/South_South-East_GRI/Documents/CEETR%20Basic%20Model,%20Part%20I%20-%20Principles%20of%20the%20CEE%20Trading%20Region,%20121105_.pdf

[62] E-Bridge (2012): Study on cross-border market integration. Macroeconomic Analysis of the CEE region. Final Report, June 28, 2012. The study focused on the economic effects of market integration and did not provide any recommendation or guidance on the conceptual design of market integration.

[63] http://www.visegradgroup.eu/calendar/2013/v4-road-map-eng

5 ASSESSMENT OF GAS MARKET SCENARIOS FOR 2021

The aim of this Chapter is to analyze the potential effects of changes in the market environment on the Slovenian gas market and to identify associated risks. Based on the findings of an interim report and on an internal stakeholder consultation organized by the Energy Agency of Slovenia on 6thFebruary, 2018, the following risks were identified: significant changes of gas demand; any congestion or SoS situation on the Austrian-Slovenian interconnector; and the need for Slovenia to increase its transmission tariffs as a result of new investments or changing regional gas flow patterns. Based on these factors, the following scenarios were modelled:

1. impact of Slovenian gas demand changes;
2. impact of the non-availability of the AT-SI interconnector;
3. impact of the Krk LNG terminal with reverse flows on the SI-HR interconnector;
4. increase of Slovenian tariffs;
5. impact of the SI-HU interconnector (first phase).

Modelling was carried out for the year 2021.

Before the detailed presentation of modelling results, we give a brief description of the modelling tool, summarize the main assumptions and introduce the reference scenario to which the modelling results will be compared.

5.1 SHORT DESCRIPTION OF THE MODELLING TOOL

Modelling was carried out using the European Gas Market Model (EGMM) developed by REKK. EGMM is a competitive, dynamic, multi-market equilibrium model that simulates the operation of the wholesale natural gas market across the whole of Europe. It includes a supply-demand representation of 35 European countries, including gas storage and transportation linkages. Large external markets, including Russia, Turkey, Libya, Algeria and LNG exporters are represented exogenously with market prices, long-term supply contracts and physical connections to Europe.

The timeframe of the model covers 12 consecutive months, starting in April. Market participants have perfect foresight over this period. Dynamic connections between months are introduced by the operation of gas storages and ToP constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

There are four decision-making players incorporated into the model: consumers, local producers, importers, and traders.[64] Consumers in each market within the region are represented by a linear monthly gas demand function that only depends on the contemporaneous local wholesale price of gas. Local producers have piecewise linear short-run cost functions, with upper and lower limits on monthly production and a separate upper constraint on yearly output. Importers own long-term take-or-pay (ToP) contracts that are sourced from gas exporters in outside markets: Russia, Norway, Algeria, Azerbaijan and several LNG exporting countries. Each contract specifies a price, delivery route, and minimum and maximum delivered quantity per month and per year. Traders decide about spot trade according to transportation infrastructure (cross-border pipelines and LNG) and injection to and withdrawal from gas storages based on price spreads between countries and time periods.

A crucial assumption in the EGMM is that producers, importers, and traders are all price-takers. Given the input data, the model calculates a dynamic competitive market equilibrium for the modelled countries, where all arbitrage opportunities across time and space are therefore

[64] Storage operators and TSOs do not make decisions on tariffs as their fees are set exogenously and quantities are determined by the traders.

exhausted to the extent that storage facilities, transportation, infrastructure, and contractual conditions permit. As a result, the competitive equilibrium yields an efficient, welfare-maximizing outcome.

The modelling results reveal the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions and long-term contract deliveries. Based on these outputs the model also calculates the social welfare components of all market participants:

- **consumer surplus**: the difference between what consumers are willing to pay for natural gas, and what they actually pay on the wholesale gas market;
- **producer surplus**: the difference between the market price (what producers receive for natural gas) and what it costs them to extract the gas in the short run;
- **profit of LTC holders** on long-term take-or-pay (ToP) contracts: the difference between the wholesale market price (at which importers sell the gas), and the contract price set for the gas, multiplied by the delivered quantity;
- **profit of storage operators**: the difference between the storage tariffs and costs, multiplied by the amount of gas stored;
- **storage arbitrage profit**: if there is sufficient wholesale gas price difference in excess of storage fees between periods, then traders realize profit from the use of storage;
- profit of TSOs consists of
    - congestion revenues: total auction revenue from an interconnector is split in 50-50% between the concerned countries, and
    - operational profit from transmission and storage: the difference between tariffs and costs,[65] multiplied by the shipped or stored quantity;
- **profit of LNG operators**: congestion revenues and operational profit, i.e. the difference between regasification tariffs and costs, multiplied by the regasified quantity.

[65] Transmission cost is assumed to be 0.1 €/MWh in all IP entry and exit points.

5.2 Main assumptions of modelling

Sources of input data and most important assumptions are summarized in Table 7.

Table 7: Summary of input data sources and main assumptions

Input data	Unit	Source	Comment
Yearly gas demand	TWh/year	Primes ref 2016	Data for Energy Community CPs are collected from national sources
Monthly demand	% of annual	Eurostat	Based on fact data from 2013-15
Production	TWh/year	Primes ref 2016	Data for Energy Community CPs are collected from national sources
Pipeline Capacity	GWh/day	ENTSOG capacity map 2016	For future projects ENTSOG TYNDP 2017
Pipeline Tariff on IP	€/MWh	REKK calculation; regulators' websites as of 2017	Except for UA, where 2020 tariffs are used based on Naftogas data
Storage capacity	Working gas: TWh, Inj., Withdr.: GWh/day	GSE	Data on storage sites is aggregated on a country level
Storage tariff	€/MWh	Storage operators' websites, Jan 2017	1 €/MWh cap is used
LNG regas capacity	GWh/day	GIE	Aggregated on a country level
LNG regas tariff	GWh/day	Operators' websites	Entry into pipeline network is taken into account
LNG liquefaction	GWh/day	GIIGNL 2016	Flow is constrained by liquefaction capacity
LNG transport cost	€/MWh	REKK calculation	Distance-based; takes into account ship rates and boil-off cost
Long-term contracts	Annual contracted quantity (ACQ): TWh/year Daily contracted quantity (DCQ): GWh/day	REKK collection from press + Cedigaz	- ToP flexibility is assumed except for gas islands - Delivery points are on borders - Pricing is based on foreign trade statistics published by Eurostat, with forecasts based on oil price forecast of Primes 2016 - Delivery routes are predefined

One of the most important parameters are the infrastructure developments assumed in the reference scenario. In our analyses we include existing infrastructure plus new projects that have reached a Final Investment Decision (FID) status according to TYNDP 2017. Table 8 summarizes new infrastructure elements included in the reference scenario for 2021 and the analysed scenarios. The use of new transmission infrastructure is modelled with a uniform 1.5 €/MWh tariff.

Table 8: Summary of new infrastructure assumptions

Transmission	Maximum flow (GWh/d)	Date of commissioning	Basis to include into reference for 2021
Infrastructure included in the reference scenario for 2021			
New pipelines:			
IT-CH	368	2018	FID
CH-FR	100	2018	FID
CH-DE	240	2018	FID
TR-GR_TAP	317	2019	FID
GE-TR_TANAP	485	2018	FID
GR-BG	90	2018	FID
GR-IT_TAP	334	2019	FID
GR-AL_TAP	40	2019	FID (source for Albania)
IT-AT	189	2018	FID
FI-EE	79	2020	FID according to project site
EE-FI	79	2020	FID according to project site
New LNG:			
GR-LNG expansion	156	2020	FID
PL-LNG exp	67	2020	FID
ES-LNG exp	192	2020	FID
New infrastructure in analysed scenarios:			
HR_LNG	108	2020	Under binding OS
SI-HR2	165	2019[66]	FID
HR-SI	7.75/165 (depending on the scenario)	2019	FID
SI-HU	8 (first phase)	2021	

[66] According to TYNDP 2017 ANNEX A this project is planned to have FID by 2019

HU-SI	8 (first phase)	2021	

In line with including TAP and TANAP in the reference, we assume new LTCs from Azerbaijan: 1 bcm to Bulgaria, 1 bcm to Greece, and 8 bcm to Italy.[67] The long-term contracted gas arriving through TAP to Italy is priced competitively to the Russian contract price, and is cheaper than Algerian gas contracted to Italy.

5.3 Assumptions for Slovenia in the reference scenario

Concerning Slovenia, we used the following input data for the year 2021:

- Slovenian consumption: 11.9 TWh
- Slovenian production: 0.7 TWh
- 0.6 TWh/year Russian long-term contract into Slovenia (current contract of 4 TWh/year expires and is replaced by short-term trade[68])

Table 9 summarizes the assumed capacity and tariff data in case of Slovenian interconnectors.

Table 9: Summary of capacities and tariffs in case of Slovenian gas interconnectors

Pipeline	From market	To market	Maximum flow	Transmission fee		Cost on IP
				Exit	Entry	
			GWh/d	€/MWh	€/MWh	€/MWh
AT-SI	AT	SI	113	0.68	0.55	1.23
IT-SI	IT	SI	28	0.78	0.40	1.18
SI-IT	SI	IT	21	0.61	0.73	1.33
HR-SI	HR	SI	165	0.75*	0.41	1.16
SI-HR	SI	HR	53	0.47	1.77	2.24
SI-HR2	SI	HR	165	0.47	1.77	2.24
SI-HU	SI	HU	5.08	0.55**	0.36**	0.91
HU-SI	HU	SI	5.08	0.25**	0.33**	0.58

*Assuming the regional average tariff level on HR-SI flows; the currently published tariff on interconnector exit points of Plinacro is 4.72 €/MWh, but to enable flows we assumed a regional average exit tariff from Croatia

**HU-SI tariff data is approved by Plinovodi and FGSZ

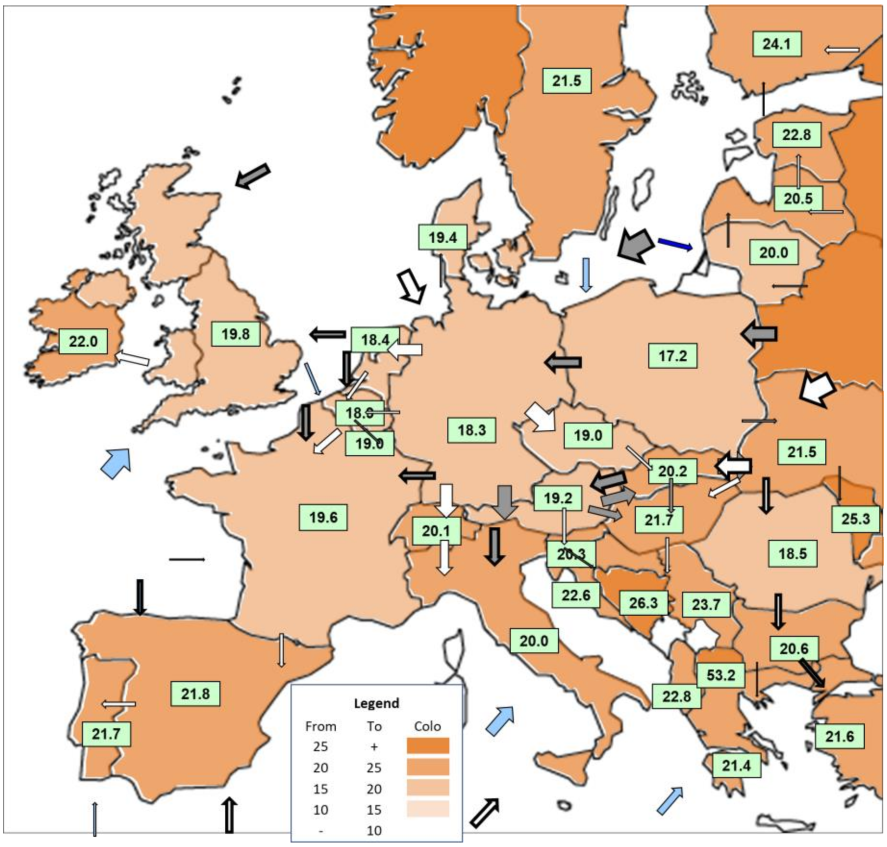
5.4 Introduction of the reference scenario for 2021

Before analysing the impact of different scenarios, it is important to view the main outputs in the reference scenario.

[67] These flows require the extension of the South Caucasus Pipeline as well, but as EGMM primarily focuses on Europe, this investment is beyond the scope of the model.

[68] We use this assumption for modelling purposes only. The rationale is that even if there is a new LTC with Russia, it is likely to follow hub-based pricing, so the contract will behave much like spot trading.

Figure 10: Yearly average wholesale gas prices (€/MWh) in 2021



Blue arrows indicate LNG flows, white arrows indicate modelled gas flow on interconnectors, dark blue and grey indicate congestion in at least one month

Decreasing domestic production in Europe leads to increased import dependence, resulting in higher prices compared to the current (2017) situation. Forecasted yearly average Slovenian market price in 2021 is 20.3 €/MWh, which is higher than both Italian and Austrian prices. As Austrian prices are still below the Italian ones in this reference, the Slovenian market is served through the AT-SI interconnector, which is utilized up to 52% on a yearly basis. The highest utilization (87%) of this pipeline can be seen in February (monthly utilization data is presented in Table 14).

Table 10: Yearly average utilization of Slovenian interconnectors

Pipeline	Yearly utilization
AT-SI	52%
IT-SI	0%
SI-HR	54%
SI-IT	0%

5.5 RESULTS OF MODELLING SCENARIOS

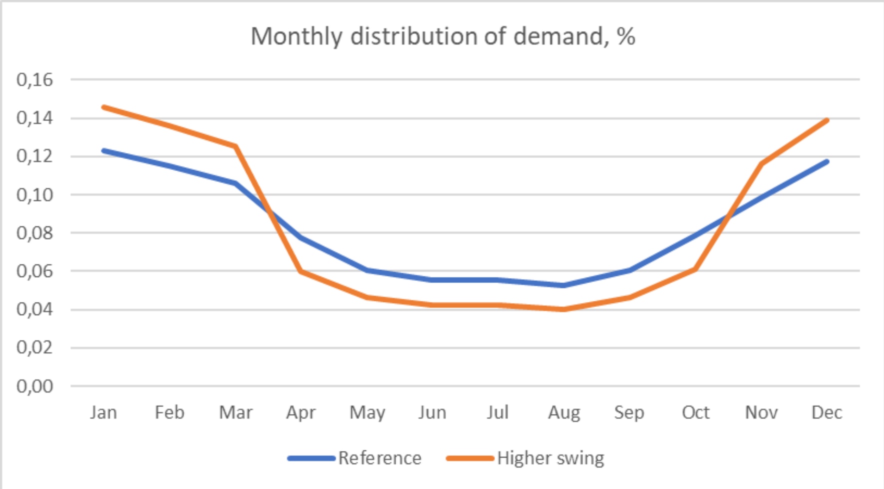
5.5.1 Impact of Slovenian gas demand changes

The following demand scenarios were analysed:

- 10% increase of Slovenian demand;

- 10% decrease of Slovenian demand;
- 20% increase of Slovenian demand;
- 20% decrease of Slovenian demand;
- 20% increase of Slovenian demand accompanied with a higher seasonal demand swing (see Figure 11).

Figure 11: Monthly distribution of demand in the reference and in case of higher seasonal swing



As it can be seen in Table 11 and Table 12, the price effect of demand changes is negligible. Even if a 20% demand increase is accompanied by higher seasonal swing, the price increase does not reach 1%. The highest monthly Slovenian price increase, which can be seen in February, is not more than 0.031 €/MWh.

Table 11: Consumption weighted yearly average price change compared to the reference due to demand change (€/MWh)

	+10%	-10%	+20%	-20%	+20%+higher swing*
SI	0.001	-0.004	0.019	-0.005	0.185
AT	0.001	-0.004	0.019	-0.005	0.019
HR	0.001	-0.004	0.019	-0.005	0.019
HU	0.001	-0.004	0.020	-0.004	0.020
IT	0.000	0.000	0.000	0.000	0.000

*Monthly consumptions assuming higher seasonal swing are used during weighted average calculation

Table 12: Price change in February compared to the reference due to demand change (€/MWh)

	+10%	-10%	+20%	-20%	+20%+higher swing
SI	0.001	-0.004	0.019	-0.004	0.031
AT	0.001	-0.004	0.019	-0.004	0.019
HR	0.001	-0.004	0.019	-0.004	0.019
HU	0.001	-0.004	0.019	-0.004	0.019
IT	0.000	0.000	0.000	0.000	0.000

Results of pipeline utilization show that demand changes affect the flows through the AT-SI interconnector, but Croatian transit remains unchanged, and the SI-IT interconnector unused.

Table 13: Yearly average pipeline utilization due to demand change in different scenarios

	Reference	+10%	-10%	+20%	-20%	+20%+higher swing
AT-SI	52%	55%	49%	57%	47%	57%
IT-SI	0%	0%	0%	0%	0%	0%
SI-HR	54%	54%	54%	54%	54%	54%
SI-IT	0%	0%	0%	0%	0%	0%

Monthly distribution of pipeline utilization shows that the AT-SI interconnector becomes congested only in the last scenario where 20% demand increase is accompanied by a higher seasonal swing, and only in February.

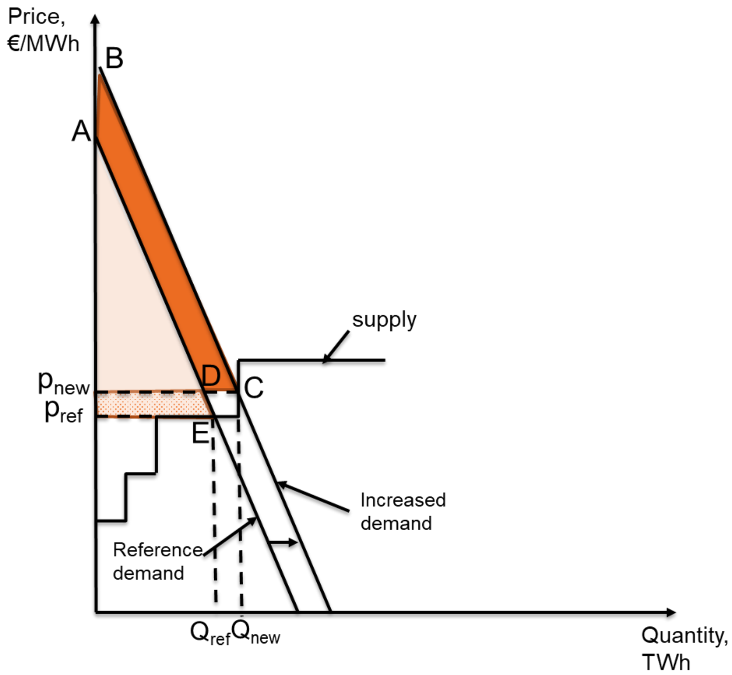
Table 14: Monthly distribution of pipeline utilization due to demand change

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Year
	Reference												
AT-SI	43%	31%	36%	57%	52%	56%	72%	32%	44%	47%	87%	69%	52%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	18%	100%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	+10%												
AT-SI	46%	33%	38%	59%	54%	58%	75%	35%	47%	51%	91%	72%	55%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	18%	100%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-10%												
AT-SI	41%	29%	34%	55%	51%	54%	70%	29%	40%	43%	83%	65%	49%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	18%	100%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	+20%												
AT-SI	48%	35%	40%	61%	56%	60%	77%	38%	51%	55%	95%	75%	57%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	18%	100%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-20%												
AT-SI	38%	27%	32%	54%	49%	52%	67%	25%	36%	39%	79%	62%	47%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	18%	100%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	+20% + higher seasonal swing												
AT-SI	42%	30%	35%	56%	51%	55%	70%	45%	59%	66%	100%	82%	57%
IT-SI	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SI-HR	38%	25%	38%	84%	75%	78%	100%	0%	15%	25%	92%	75%	54%
SI-IT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 15 presents the welfare change of different market participants in the last scenario – assuming 20% demand increase and higher seasonal swing – when Slovenian price-change is the largest. Total welfare increases by 131.1 mEUR per year, primarily due to the increase of consumers' welfare. Change of consumer surplus consists of two parts when demand increases: first, consumers who already consumed gas suffer welfare losses due to higher prices caused by higher demand; on the other hand, new consumers realize welfare gains on additional quantities. In cases when demand is not very price elastic in short-term (and this is usually true for gas demand), the second part is bigger and total consumer surplus increases despite higher prices.

This change of consumer surplus is illustrated in Figure 12. In the reference, consumer surplus equals the area of the p_{ref}AE triangle. Demand increase brings higher equilibrium price and quantity, with a new consumer surplus represented by the p_{new}CB triangle. Although some of the original consumer surplus is lost (represented by the $p_{new}p_{ref}$ED dotted area), it is compensated by an increase equivalent to the ABCD dark orange area. This additional gain is bigger than the loss if the demand curve is steep enough, i.e. consumed quantities are independent from price changes to a large extent, or, in other words, demand is characterised by low price-elasticity. We assume that gas demand has low price-elasticity in the short run because switching between gas and other fuels would require time and investment.

Figure 12: The change of consumer surplus due to increased demand



The other – but smaller – part of welfare increase is the increase of TSO-profit. The main part of this profit change comes from the change of operational profit due to larger flows on interconnectors. Change of auction revenues is negligible (0.01 mEUR), because pipelines generally do not become more congested than before: although the AT-SI interconnector becomes congested in February, congestions in that month (seen in the reference) cease to exist on the SI-HR interconnector.

Table 15: Welfare change in the +20% demand and higher seasonal swing scenario:

Welfare change m €/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO profit	LNG operator profit	Total Welfare
SI	124.8	0.0	0.0	0.0	0.0	6.2	0.0	131.1
AT	-1.7	0.3	0.0	0.0	1.4	1.5	0.0	1.4
HR	-0.6	0.4	0.0	0.0	0.0	0.0	0.0	-0.2
HU	-2.0	0.3	0.0	-0.2	0.7	0.1	0.0	-1.1
IT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total region	120.6	0.9	0.0	-0.2	2.1	7.8	0.0	131.1

5.5.2 Impact of the non-availability of the AT-SI interconnector

As Slovenia depends on gas imports from Austria under normal market circumstances, it is worth examining what happens if the AT-SI interconnector is not available for a given period. In the scenarios presented below, we assume that this interconnector is unavailable in the whole of January. First, we examine market outcomes in this case, then we analyze some changes in the market environment that can mitigate the negative effects. During this modelling exercise it is assumed that reverse flow on the SI-HR interconnector is partly enabled: available capacity from Croatia to Slovenia is 7.75 GWh/day.

Figure 13 and Table 16 present market outcomes in January if delivery on the AT-SI interconnector is not possible. Flows are re-routed to the IT-SI and HR-SI interconnectors, but their monthly capacity of 1.12 TWh is not enough to prevent a serious price increase. The January price in Slovenia increases by almost 100% (by 20.2 €/MWh). January price in Croatia also increases slightly due to the loss of flows on the SI-HR interconnector.

Figure 13: Price increase in January if the AT-SI interconnector is not available (€/MWh)

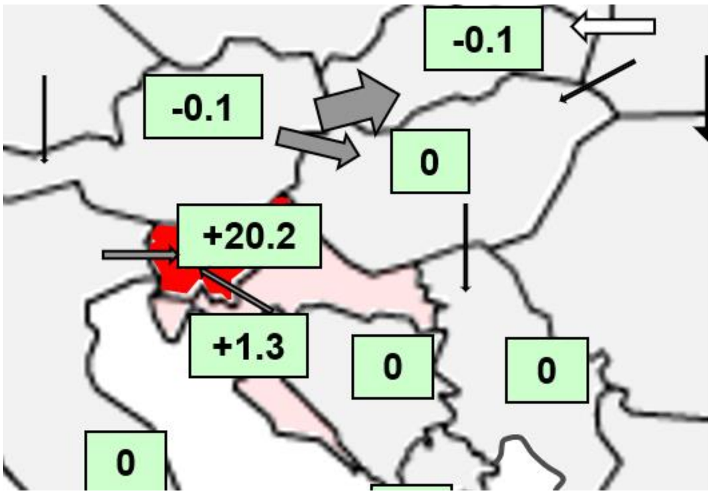


Table 16: Utilization of Slovenian interconnectors if the AT-SI interconnector is unavailable

Infra	Utilization in January	
	Reference	no AT-SI
AT-SI	47%	0%
IT-SI	0%	100%
HR-SI	0%	100%
SI-HR	18%	0%
SI-IT	0%	0%

As it can be seen in Table 17, total social welfare in Slovenia decreases significantly (by 13.6 mEUR per year) if the AT-SI interconnector is not available in January. Consumer welfare decreases by 23.7 mEUR, which is partly compensated by the TSO-profit increase due to auction revenues realized on the congested IT-SI and HR-SI interconnectors.

Table 17: Welfare change due to the unavailability of the AT-SI interconnector

Welfare change mEUR/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO profit	LNG operator profit	Total Welfare
SI	-23.7	0.0	0.0	0.0	0.0	10.1	0.0	-13.6
AT	5.0	-0.6	0.0	-4.1	-1.8	1.1	0.0	-0.3
HR	-6.9	3.5	0.2	1.8	0.0	3.1	0.0	1.7
HU	-1.6	0.1	0.0	1.0	0.0	1.3	0.0	0.8
IT	4.3	-0.4	0.0	0.0	-3.8	9.5	0.0	9.6
Total region	-22.9	2.7	0.2	-1.4	-5.6	25.1	0.0	-1.9

In order to analyze some factors which may mitigate these negative effects, the following scenarios will be examined:

- Construction of SI-HR reverse flow (165 GWh/day is available in both direction);
- Construction of SI-HR reverse flow and the Krk LNG terminal – assuming high (3 €/MWh) and low (1.5 €/MWh) regasification tariff;
  Capacity enlargement on the IT-SI interconnector up to 47 GWh/day;
- Construction of the first phase of the HU-SI bidirectional interconnector (8 GWh/day).

Figure 14 shows the price effects of different scenarios in January, assuming that the AT-SI interconnector is unavailable in the whole month. Compared to the reference case presented above (+20.2 €/MWh), the price increase is significantly lower in all scenarios. The two figures on the top show that the new HR-SI interconnector can by itself mitigate the price increase to a large extent, because additional flows from Hungary can reach Slovenia through Croatia. The Croatian LNG terminal is not used when we assume high regasification tariffs, thus this scenario comes to the same results as the reverse flow only scenario. With low regasification tariffs, Croatia and Slovenia receive gas from the LNG terminal instead of Hungary. In this case, 0.43 TWh of gas is supplied to Slovenia from Croatia, and 0.88 TWh from Italy, allowing for a more moderate price increase on the Slovenian market.

The third figure shows that capacity extension on the IT-SI interconnector can almost totally mitigate the price increase effect. If the first phase of the HU-SI interconnector is built, the IT-SI, the HR-SI, and the HU-SI interconnectors are fully used in January, but the wholesale gas price increase is still significant (+7.1 €/MWh) due to capacity constraints.

Figure 14: January price effect of different scenarios when the AT-SI interconnector is unavailable (€/MWh)

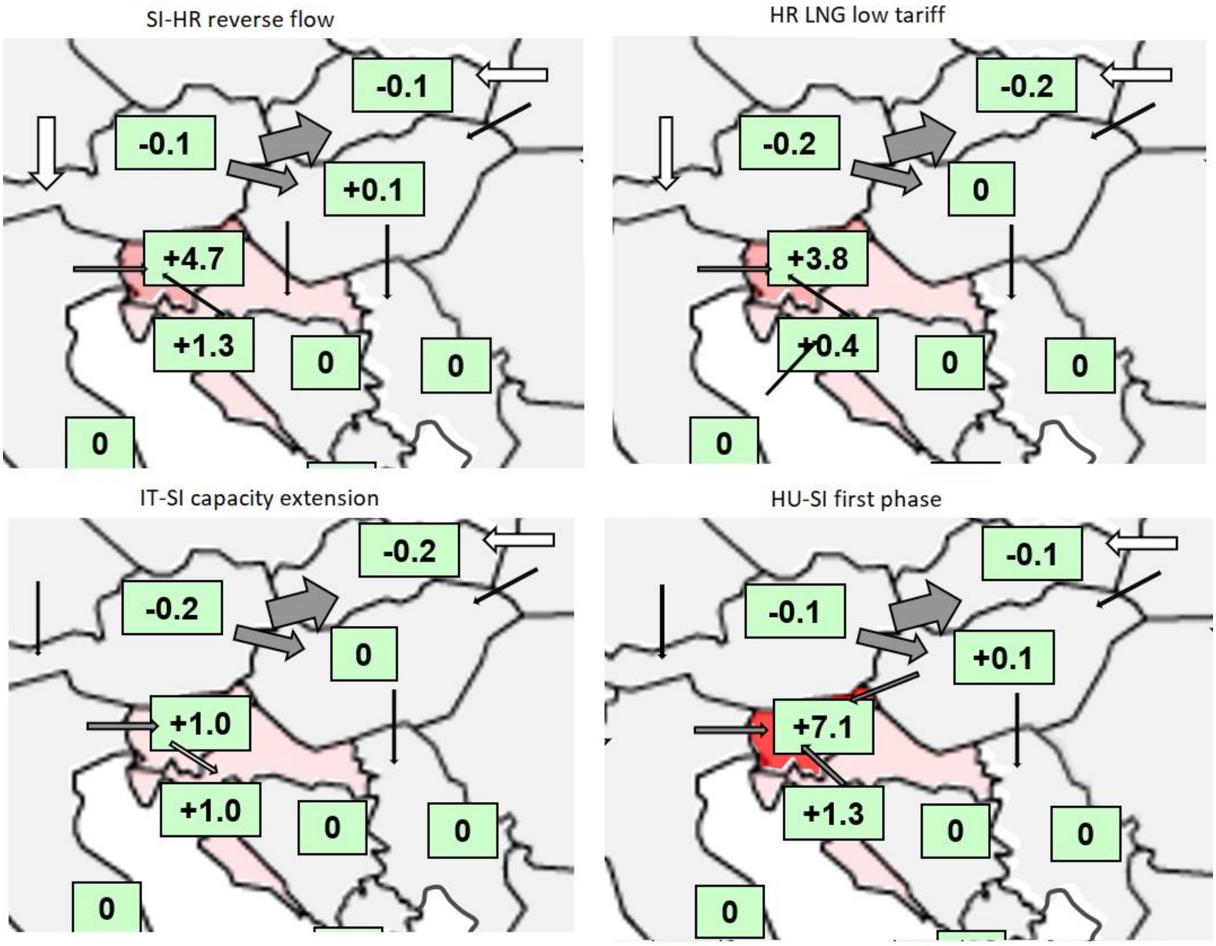


Table 18: Pipeline utilization in the different scenarios in January

Infra	Utilization in January				
	no AT-SI	no AT-SI + SI-HR reverse flow	no AT-SI + SI-HR reverse flow + HR LNG low tariff	no AT-SI + IT-SI extension	no AT-SI + HU-SI
AT-SI	0%	0%	0%	0%	0%
IT-SI	100%	100%	100%	90%	100%
SI-HR	0%	0%	0%	15%	0%
SI-IT	0%	0%	0%	0%	0%
SI-HR2		0%	0%		
HR-SI	100%*	8%**	8%**	100%*	100%*
HR LNG		0%	11%		
HU-HR	6%	13%	0%	0%	6%
SI-HU					0%
HU-SI					100%

*With a capacity of 7.75 GWh/day

**With a capacity of 165 GWh/day

5.5.3 Impact of the Krk LNG terminal with reverse flows enabled on the SI-HR interconnector

In this scenario, we analyze the effects of the planned LNG terminal in Croatia, and the associated HR-SI interconnector under normal market circumstances. The scenario was modelled with a high (3 €/MWh) and a low (1.5 €/MWh) regasification fee. Infrastructure assumptions are the same as above (see Table 8). In case of the higher tariff, there is no flow from the LNG terminal into the gas system, which yields the same output as in the reference scenario.

Figure 15 and Table 19 show the market outputs assuming low regasification tariffs. It can be seen that although the LNG terminal is used (yearly utilization is 20%), LNG does not leave Croatia, and prices decrease only marginally even in Croatia. However, the LNG terminal has a significant effect on the utilization of Slovenian pipelines. Due to the LNG flows to Croatia, Croatian transit through Slovenia decreases, which leads to lower utilization of both the AT-SI and the SI-HR interconnectors compared to the reference scenario.

Figure 15: Yearly average price change due to HR LNG and SI-HR interconnector (€/MWh)

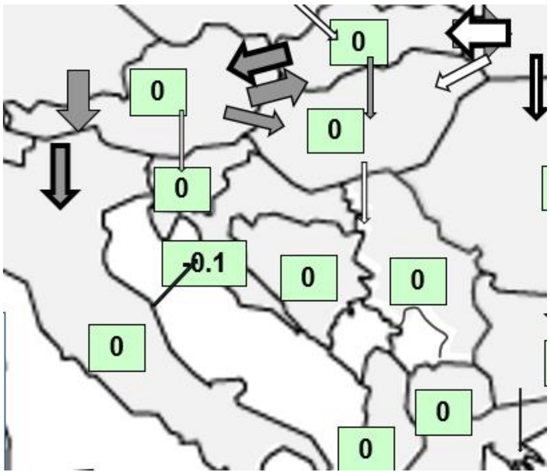


Table 19: Infrastructure utilization with the Krk LNG terminal and SI-HR reverse flows

Infra	Yearly utilization in the reference	Yearly utilization in the analysed scenario
AT-SI	52%	33%
IT-SI	0%	0%
SI-HR	54%	13%
SI-IT	0%	0%
SI-HR2		0%
HR-SI		0%
HR LNG		20%

As LNG from the Croatian terminal does not reach the Slovenian market, welfare effects are not significant. The only measurable welfare change concerning Slovenia is the decrease of TSO profit due to the lost Croatian transit, which is substituted by gas coming from LNG terminal.

Table 20: Welfare effect of Croatian LNG and HR-SI reverse flow

Welfare change mEUR/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO profit	LNG operator profit	Total Welfare
SI	0.2	0.0	0.0	0.0	0.0	-6.4	0.0	-6.2
AT	1.4	-0.2	0.0	0.0	-1.1	-11.5	0.0	-11.4
HR	3.8	-2.5	0.0	0.7	0.0	-9.4	11.2	3.9
HU	1.6	-0.2	0.0	0.1	-0.5	0.0	0.0	0.9
IT	0.0	0.0	0.0	0.0	-3.2	-5.1	0.0	-8.3
Total region	6.9	-2.9	0.0	0.8	-4.8	-32.5	11.2	-21.2

5.5.4 Impact of Slovenian tariff increase

In this section, the impacts of Slovenian tariff increases will be analyzed. All other tariffs remain the same as in the reference, but Slovenian entry and exit transmission tariffs are increased by 10% and 20% from the levels shown in Table 9.

Figure 16 and Table 21 reveal that not even a 20% tariff increase has a significant effect on market outcomes. A slight decrease of pipeline utilization is accompanied by a marginal increase of market prices. Because of the low elasticity of gas demand, transit flows are not materially affected by the tariff increase either: Croatian imports from Slovenia are estimated to decrease by 0.5% only.

Figure 16: Price effect of tariff increase

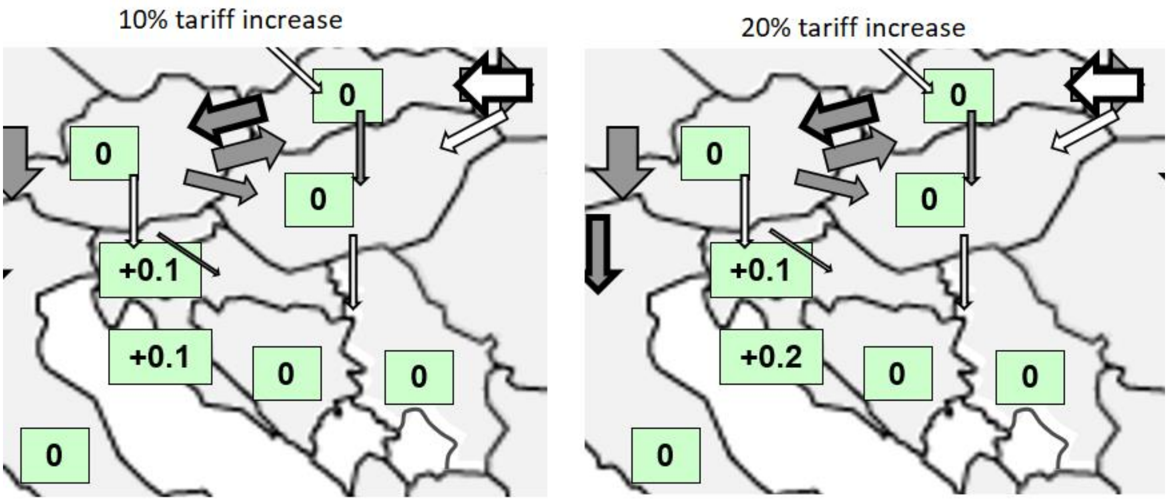


Table 21: Change of IP utilization due to tariff increase

Infra	Yearly utilization		
	Reference	+10%	+20%
AT-SI	52.0%	51.9%	51.9%
IT-SI	0.0%	0.0%	0.0%
SI-HR	53.6%	53.5%	53.3%
SI-IT	0.0%	0.0%	0.0%

Welfare change in this scenario is also negligible (see Table 22). In line with the change of price and utilization, the welfare of Slovenian consumers decreases a bit, while TSO profit slightly increases due to higher tariffs.

Table 22: Welfare change due to 20% tariff increase

Welfare change m €/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO profit	LNG operator profit	Total Welfare
SI	-1.2	0.0	0.0	0.0	0.1	3.2	0.0	2.1
AT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HR	-6.1	4.0	0.0	0.0	0.0	-0.1	0.0	-2.2
HU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total region	-7.3	4.0	0.0	0.0	0.1	3.1	0.0	-0.2

5.5.5 Impact of SI-HU interconnector (first phase)

In this scenario we examine the potential effect of the first phase of the bi-directional HU-SI interconnector (infrastructure assumptions are summarized in Table 9). As in the reference scenario the price difference between Hungary and Slovenia is higher than the assumed tariff on the interconnector, the pipeline is expected to be utilized in the SI-HU direction. Results are presented in Figure 17 and Table 23. Although the interconnector is fully utilized, the shipped quantity of only 1.9 TWh is not enough to measurably alter prices. Utilization of the AT-SI interconnector slightly increases due to transit flows toward Hungary. Consequently, consumer surplus does not change significantly in the effected countries, welfare change is due to changes of TSO-profit only.

Figure 17: Price effect of the SI-HU interconnector

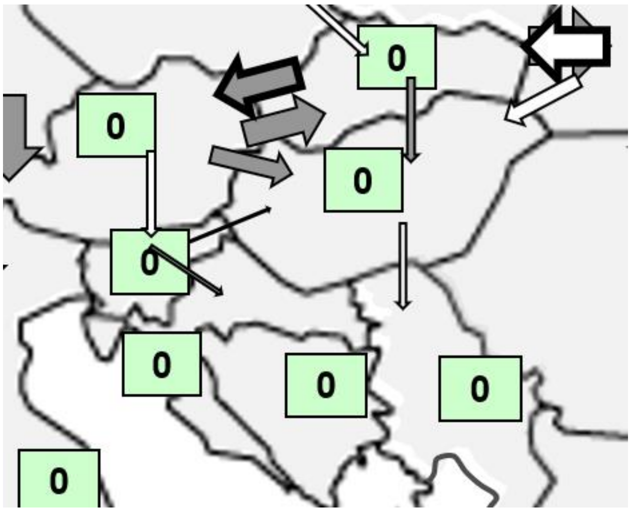


Table 23: Pipeline utilization if the SI-HU interconnector is constructed

Infra	Yearly utilization	Yearly utilization
AT-SI	52%	57%
IT-SI	0%	0%
SI-HR	54%	54%
SI-IT	0%	0%
SI-HU		100%
HU-SI		0%

Table 24: Welfare change due to the SI-HU interconnector

Welfare change m €/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO profit	LNG operator profit	Total Welfare
SI	0.0	0.0	0.0	0.0	0.0	2.0	0.0	2.0
AT	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.8
HR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HU	0.0	0.0	-0.4	0.0	0.0	-0.8	0.0	-1.1
IT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total region	0.0	0.0	-0.4	0.0	0.0	2.1	0.0	1.7

6 CONCLUSIONS

In Slovenia the conditions for a competitive wholesale market are present. The country is directly neighbouring the region's two most mature markets, which makes it possible for Slovenian traders to supply their consumers with competitively priced gas, and price convergence is already evident. This is true despite the fact that Slovenia performs poorly if measured by AGTM metrics and does not have a functional transparent trading venue. If Slovenia becomes able to import from Croatia, this will open the way for further diversification. The Slovenian-Hungarian interconnector will grant access to new sources for the country once the Hungarian-Romanian interconnector is operational. The success or failure of these projects, not fully in Slovenia's control, will largely influence the outlook of its wholesale market.

The country's wholesale market is highly concentrated, and the dominant market player has entered into a new long-term contract with Russia. Stakeholders, however, did not raise any concern about possible trade barriers to compete with the LTC holder. Although Geoplin holds a large LTC portfolio compared to Slovenian consumption, it is a regional player and faces competitive pressure. Under today's market circumstances, large LTC quantities are not an obvious sign of market power that may result in unduly high prices for consumers, because the LTC holder may easily lose its customers if it is not able to react to price movements.

Our analysis concludes that Slovenian shippers do not pay disproportionately high transmission tariffs for gas import at interconnection points to Italy and Austria. Still, tariff issues are important, as there is a "tariff competition" between regional TSOs for transit flows. It is expected that modified physical gas flows between countries will, during the implementation of TAR NC, lead to adaptations of tariffs in neighbouring EU countries.

Although Slovenia is currently much more connected to the cheaper Austrian market than to its Italian competitor, the latter may also become relevant with several factors expected to contribute to an increase of its attractiveness. Building of the TAP pipeline will not only provide Slovenia with the option to diversify its imports with Azeri gas through the currently unutilized Italian-Slovenian interconnector, but the appearance of an additional 10 bcm of gas is likely to contribute to the liquidity of the Italian hub, which would bring additional benefits. Furthermore, the already existing LNG regasification terminals provide the option for Italy to host surplus LNG volumes if those might be available, depending on the future supply-demand gap in the spot LNG market.

Russia's market foreclosure strategy may result in reduced opportunities for spot trading on the Austrian hub and contribute to a sustained difference in market prices between Western and Central- South-Eastern countries. Furthermore, there is a certain risk of less liquidity on CEGH once the Russian LTCs expire, which reinforces our view that the Italian market may gain importance for Slovenia in the future.

A key question for Slovenia is whether it needs any additional market integration tool to better benefit from the regional implementation of 3rd package rules and its favourable geographical location. We argue that the implementation of the Third Energy package is the only market integration tool that is needed for Slovenia. We argue that there is significant room for improvement in market competition and integration as Network Code implementation is progressing and more elements of the current framework regulation is put into place.

Our market modelling analysis investigated the option of a full market merger, targeted in the only regional market integration study that includes Slovenia, published by E-Control. We found that the full market merger may remove some market inefficiencies by facilitating trade, but at the cost of placing additional financial and – stemming from the need for increased co-operation and harmonization – administrative burden on TSOs and NRAs. As TSO costs are expected to increase, there is a risk that tariffs become less transparent and cost-reflective, while investing in incremental capacities become less market-driven. An alternative to the system of inter-TSO compensations and extensive co-operation in network planning and investments may be the creation of a joint TSO for the enlarged market area, but it would only be possible with a high-level political support from all countries involved.

Slovenia could benefit from a market merger or trading region with Italy and Austria by gaining access to a more liquid hub that would emerge from the merging of the Italian and the Austrian VTP. Slovenian traders, however, are already able to take advantage of the products and services available on these hubs.

Capacity hoarding, contractual congestion, and tariff pancaking, problems that market mergers and trading regions are best suited to tackle, are not issues for Slovenia at present. If physical congestions do occur in the future, a market integration that allows for re-dispatch – and therefore full price convergence - would need to involve both Italy and Austria, the two markets that can supply gas to Slovenia. Wholesale price differences and available interconnection capacities between them make Italy and Austria, however, unlikely candidates for seamless market integration that would result in full price convergence.

Should it happen anyway, Slovenia may consider joining them as a satellite, but once the country is able to import significant quantities of gas from markets other than Italy and Austria, this model could be no longer applied. The benefits of supply source diversification may well surpass those of the status of a satellite to an Italian-Austrian market area.

Market coupling may be worth considering, as it may increase the liquidity of the market. Cost and complexity of implementation of spread products is limited, but as capacity hoarding and contractual congestion is not prevalent on Slovenian interconnection points, the potential benefits are also limited.

Full implementation of network codes, especially those related to capacity allocation and congestion management, require huge efforts from TSOs and regulators, limiting their capacity to elaborate and introduce additional measures to improve market functioning. Efficient use of limited regulatory capacities requires prioritization of different policies. In theory, market coupling may increase the efficiency of market operation, but explicit capacity allocation with sufficient amount of short-term capacity may bring roughly the same benefits in terms of price convergence and market integration, without the risks implied in the lack of experience with implicit allocation in gas markets.

Based on these findings and consultations with stakeholders, we do not deem it necessary for Slovenia to apply any formal market integration tool described by the ACER Gas Target Model. Instead, the regulator should make sure that Network Codes are properly implemented, and Slovenian traders continue to benefit from easy access to the Austrian hub. The availability of competitively priced short-term cross-border capacities is of key importance in this regard. Furthermore, the regulator and the TSO should help the realization of supply source diversification projects, with the strengthening of links to Italy as a priority. The need for diversification was highlighted by the Baumgarten incident of December 2017, which pointed to security of supply risks of import dependence from the direction of Austria.

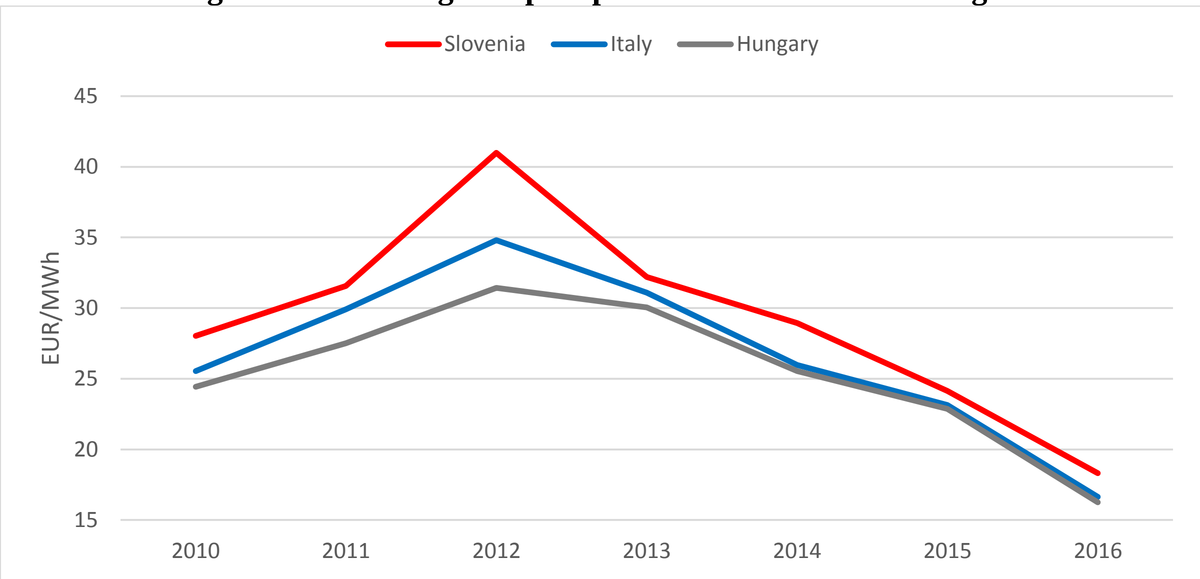
ANNEX I: REGIONAL GAS PRICE DYNAMICS

In this Annex we identify natural gas price dynamics in the last couple of years with respect to Slovenia and its neighbours. As far as import prices are concerned, we base our analysis on the European Commission's quarterly natural gas report (EU quarterly), which shows the unit price of different gas sources for a given country. In the case of Slovenia, only the price of the Russian long-term contract is available. For the Italian and the Austrian market, hub prices are also given in these reports, but for the sake of consistency, we will generally compare LTC prices across the region.

6.1 Comparison of regional LTC prices

Figure 18 shows that Slovenian LTC prices were the highest in the region between 2010 and 2016. In 2010, there was an approximately 5 EUR/MWh spread between Hungary and Slovenia, which increased to almost 10 EUR/MWh in 2012. Since 2012, LTC prices have converged, resulting in a very significant price decrease for Slovenia.

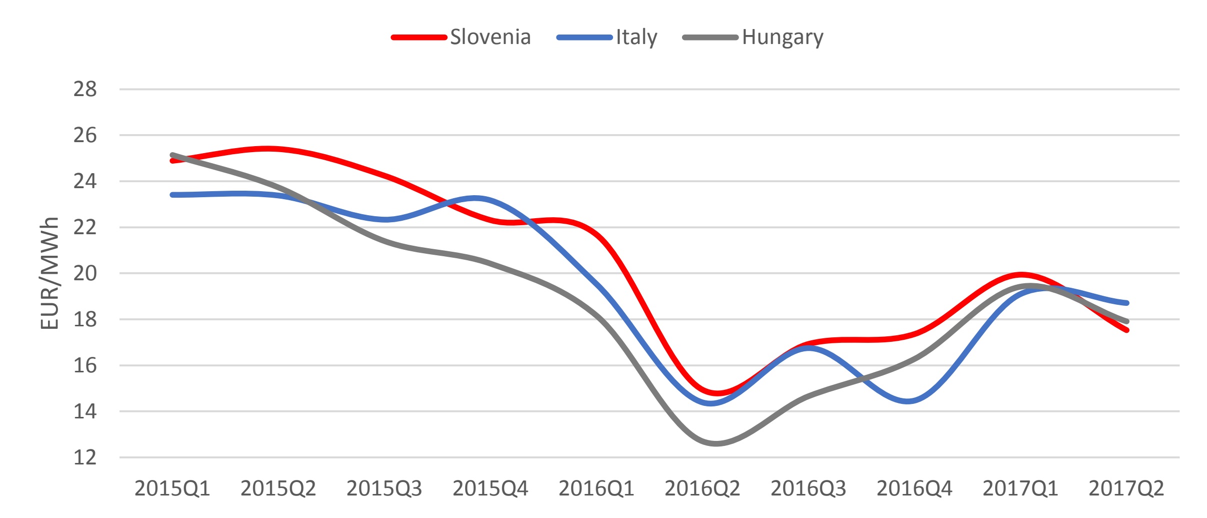
Figure 18: Annual gas import prices under LTCs in the region



Source: EU Quarterly Report, Eurostat

For a more detailed analysis, we present the evolution of quarterly LTC prices between Q1 2015 and Q2 2017 in Figure 19. Slovenian gas imports have continued to become cheaper in 2017. While in almost all quarters between Q1 2015 and Q4 2016 the Slovenian price was the highest, in Q1 2017 it was at a similar level that that of Hungary and Italy. In the following quarter, the long-term contract of Slovenia was already the cheapest in the region.

Figure 19: Quarterly gas import prices under LTCs in the region



Source: EU Quarterly Report

As mentioned earlier, the proximity of the Austrian CEGH and the Italian PSV may provide the Slovenian market with alternative, and potentially cheaper sources. Furthermore, as an important portion of Italy's LNG regasification capacity is unused, it is possible to import gas through either long-term contracts or spot trades originating from these terminals. It is also possible to buy natural gas on the most liquid European hub, the TTF, and transport it to Slovenia. We investigated the competitiveness of all these sources relative to the Slovenian LTC price of 2016.

In 2016, the yearly average LTC price in Slovenia was 18.30 EUR/MWh based on EU quarterly data. We used EU quarterly price data for alternative sources as well, and REKK's own assessment of entry-exit tariffs on relevant interconnectors to calculate transport costs. Table 25 shows the price of gas available from different sources, including transport costs.

Table 25: Estimated cost of alternative gas sources

Source	Relevant route	Calculated price in 2016 (EUR/MWh)
Slovenian LTC	n.a. (cost is given at border)	18.30[69]
CEGH (Austrian hub)	AT-SI	15.84
PSV (Italian hub)	IT-SI	17.13
Italian LNG	IT-SI	15.30
TTF	NL-DE-AT-SI	17.40

Source: REKK calculation

In 2016, the Russian LTC was clearly the most expensive source for Slovenia; it was 1 EUR/MWh costlier than the most expensive alternative source[70]. According to the table, the

[69] The real price of gas in this commercial LTC is a business secret and cannot be disclosed. The price listed in this table stems from a statistical source (the European Commission's quarterly natural gas report) and is based on a statistical methodology which gives, as a rule, somewhat higher prices than those in reality. This was confirmed also by Geoplin during the project workshop 16 May 2018. Yet, for the purpose of this assessment we use the statistical value and consider it maximal.

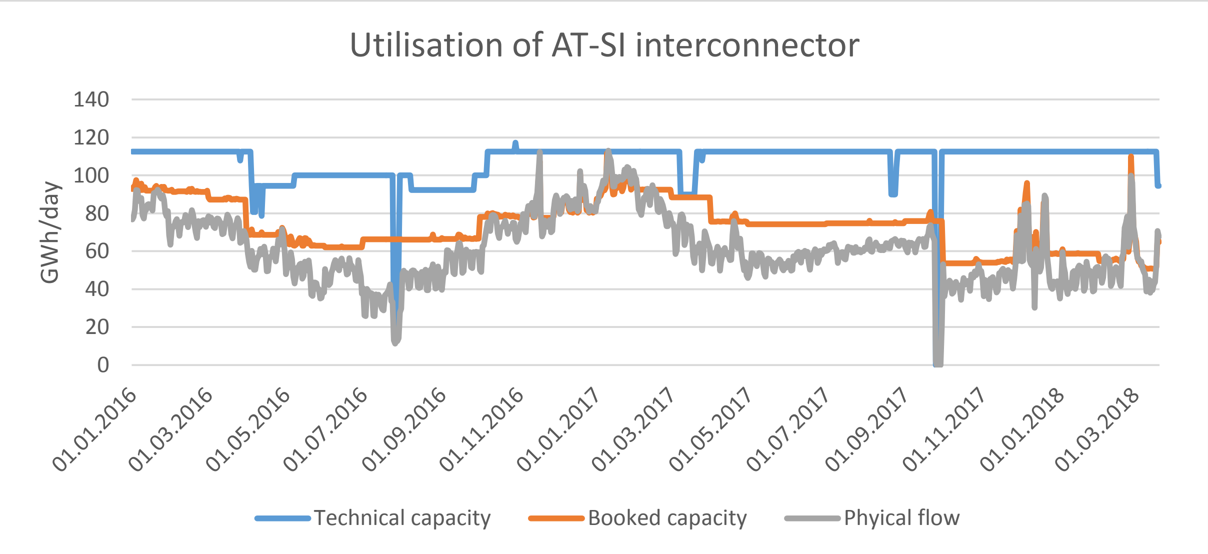
[70] In reality, this difference is believed to be smaller, see note 69.

cheapest option would be importing LNG through the Italian terminals at a cost of 15.30 EUR/MWh in 2016. This is followed by buying gas on the two neighbouring hubs, CEGH and PSV. It is interesting to see that buying spot gas on the TTF was also a cheaper alternative than the existing Russian LTC, considering the Netherlands-Germany-Austria-Slovenia route. The German-Austrian pipeline is usually congested, however, so it is not a viable option. In the next sub-section, we will assess the feasibility and the competitiveness of buying gas from the Austrian and Italian hubs or through the Italian LNG terminals in more detail.

6.2 The utilization of the AT-SI interconnector

In 2016, the average CEGH price was 15.84 EUR/MWh, compared to the 18.30 EUR/MWh Slovenian LTC price. As Austria is connected with Slovenia, it is easily possible to buy gas from the Austrian market. However, the Russian long-term contract route runs through the Austria-Slovenia interconnector, which theoretically can result in barriers to trade. First, physical congestions may occur, so that the transportation of ToP quantities leaves not enough free capacity to achieve wholesale price convergence between the two markets. Second, contractual congestions may occur if there is significant amount of booked but unused capacity on the pipeline. To investigate these issues, Figure 20 shows the technical capacity, booked capacities and physical flows between 1st January 2016, and 20th March 2018.

Figure 20: Utilisation of the Austria to Slovenia interconnector in 2016-2018



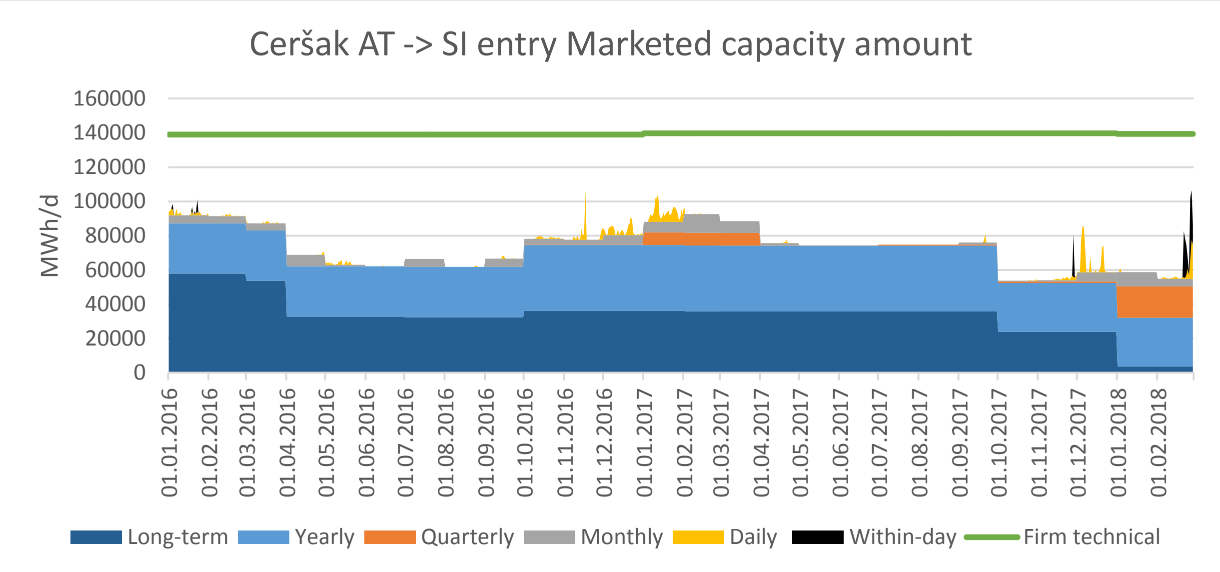
Source: ENTSO-G transparency platform

The results are somewhat surprising, considering the fact that the Austrian hub price was much lower than the LTC price in Slovenia.[71] The Austrian-Slovenian interconnector is neither physically nor contractually congested in the investigated timeframe. Although the pipeline is generally heavily utilized with a utilization rate of around 60%, it only happened in Q1 2017 that physical flows reached the technical constraint, and only for a couple of days. There were several longer periods when the level of booked capacities were higher than the utilization rate, but remained significantly below the technical capacity. This means that contractual congestions did not hinder the use of the pipeline.

[71] As mentioned in Chapter 2.4.1, Geoplin did not agree with this statement during the stakeholder consultation.

To get a better picture of the wholesale competition in supplying gas from Austria, we analyzed the share of yearly, monthly, daily and within-day capacity bookings, based on daily PRISMA data, between 2016 January and 2018 February. The rationale of this analysis is that when traders spot arbitrage opportunities arising from price movements on the CEGH, they can profit from short-term imports using available capacities. The booking levels of the period are summarized in Figure 21. It is important to note that there is no available data on bookings for periods longer than one year on PRISMA, so we made a rough estimation of these capacities using Plinovodi data.[72] The share of long-term booked capacities have decreased to a marginal level by 2018: from the 1st of January, 2018, the transition from long-term bookings to shorter-term products is evident.[73]

Figure 21: Capacity bookings on the Austrian-Slovenian interconnector, 2016 January - 2018 February



Source: PRISMA, Plinovodi

In the following analysis, we disregard from existing long-term capacity bookings, and focus on the booking structure of published available capacities. More than 90% of all bookings in the period was made for yearly products, and only 2% of them were related to daily or within-day products. The use of short-term[74] capacities was highly seasonal, as these bookings were concentrated in the winter periods. For daily and within-day capacities, almost all bookings were made in winter, and most of the monthly and quarterly bookings were concentrated around winter months, too. This suggests that market participants book short-term capacities only when there is excess demand for natural gas, but do not consider them for baseload consumption. The high share of yearly bookings is in line with the structure of the Slovenian market, where industrial consumers with a baseload consumption profile dominate demand.

In Figure 22, we can identify an increase in the share of short-term bookings from 2016 (13.3%) to 2017 (16.0%). Figure 23 confirms that short-term bookings had a more significant role in the winter months of 2016/17 with a share of 32%. The share of the most flexible products, i.e.

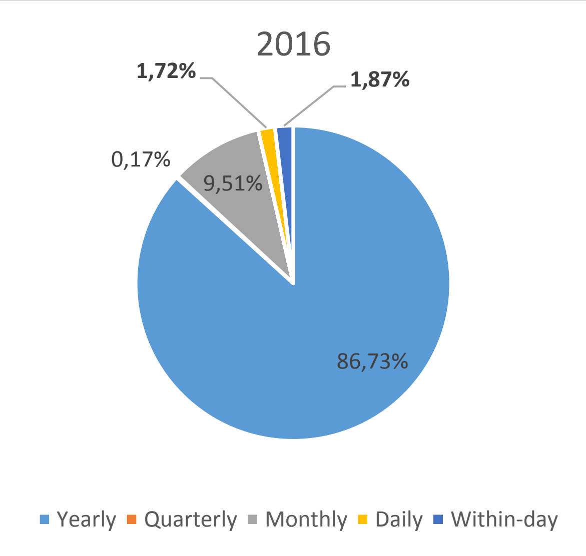
[72] Long-term bookings = Technical capacity (Plinovodi data) – Bookings on PRISMA – Available capacity (Plinovodi data)

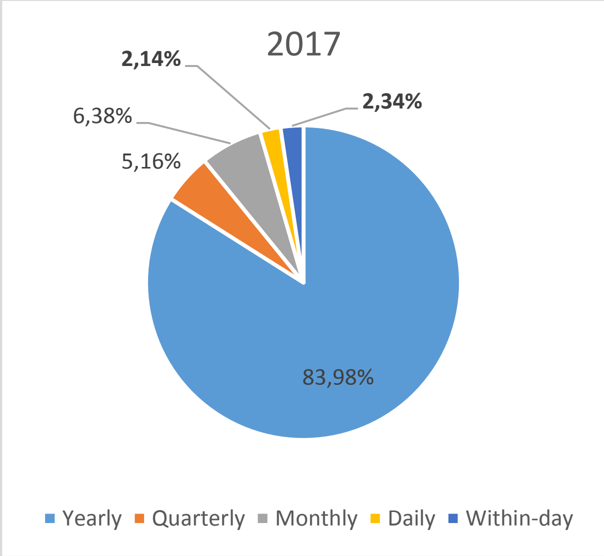
[73] Although it is possible that a new long-term supply contract with Russia will be accompanied by the re-emergence of long-term bookings.

[74] Quarterly, monthly, daily and within-day bookings.

daily and within-day bookings was still marginal in 2017, approximately 4.5% in the whole year, and 9% percent in the winter months.

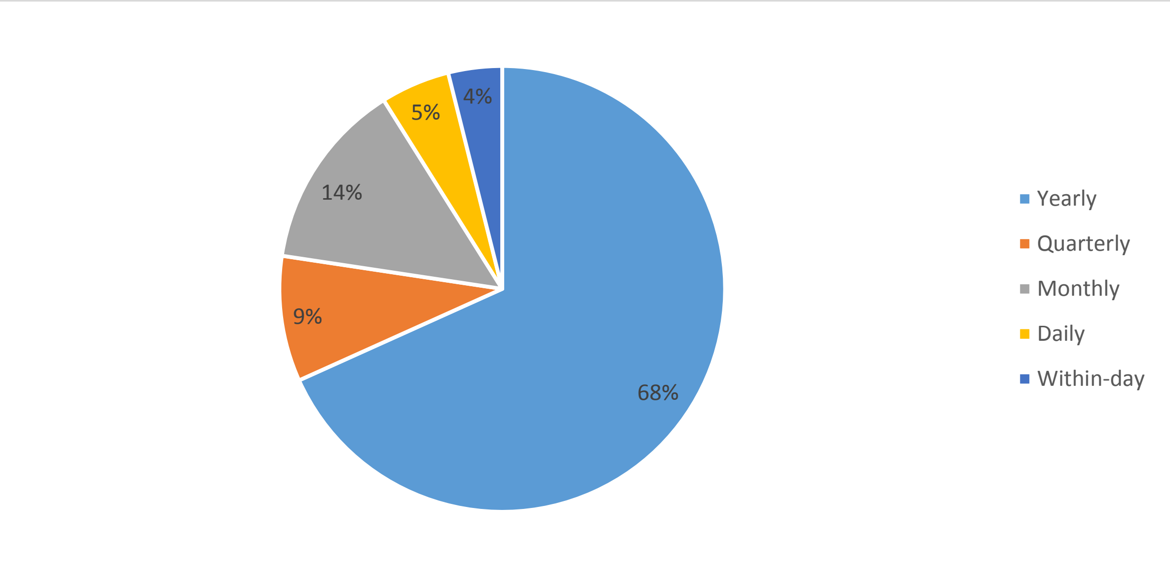
Figure 22: The relative share of different types of capacity bookings in 2016 and 2017





Source: PRISMA

Figure 23: The relative share of different types of capacity bookings in winter 2016/17*



*December 2016 – February 2017

Source: PRISMA

Despite the low relative levels, however, we can see a sharp increase in the absolute volume of booked short-term capacities. As short-term bookings are more common in winter, we present their evolution in this period in Table 26. Table 27 shows the contribution of daily and within-day bookings to the overall increase.

Table 26: Total short-term booked capacities (MWh/d)

Winter 2015/16	Winter 2016/17	Winter 2017/18

337,835	1,535,966	2,207,214

Source: PRISMA

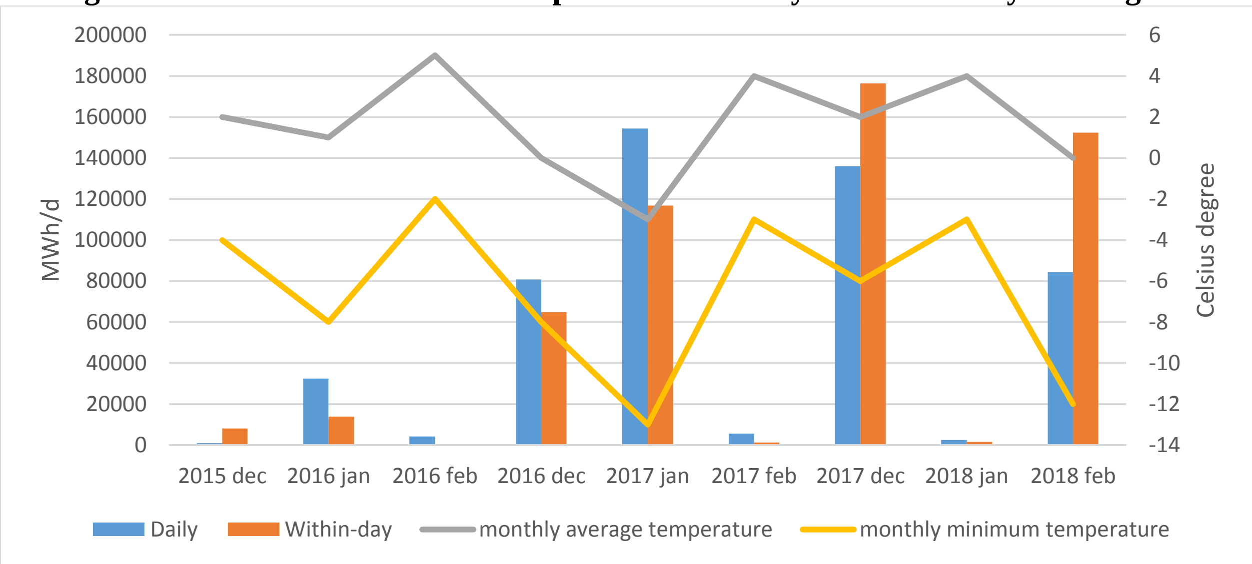
Table 27: Booked daily and within-day capacities (kWh/h)

Winter 2015/16		Winter 2016/17		Winter 2017/18	
Daily	Within-day	Daily	Within-day	Daily	Within-day
37,515	22,213	240,808	182,936	222,727	330,203

Source: PRISMA

While there is a clear increasing trend, the use of daily and within-day bookings seems to be heavily dependent on weather. In December 2017 and in February 2018, for example, vast amount of daily and within-day bookings were made, while in the milder January booked values were much lower. It is also interesting to note that only within-day capacity bookings increased from winter 2016/7 to 2017/8, and daily bookings decreased slightly. Figure 24 shows the relation between the average and minimum temperature in Ljubljana for the given month, and the amount of bookings.

Figure 24: The relation between temperature and daily and within-day bookings



Source: PRISMA, timeanddate.com

A possible explanation for the capacity booking structure may be found in transmission tariff levels. In most countries short-term tariffs are higher than yearly tariffs, so that a given amount of capacity for the whole year is cheaper to cover with a yearly product than buying quarterly/monthly/daily products. However, if capacity is only needed for a shorter time-period, it might be cheaper to buy a more expensive short-term product than booking the needed capacity for the whole year. Optimisation depends on the precision of gas demand forecasts and also on the level of short-term multipliers.

To make different tariff systems comparable, we calculated short-term multipliers for different products for every month as the ratio of the price of the product in the given month, and the 1/12th (for the monthly product) or 1/365th (for the daily product) of the price of the yearly product.[75] This way it can be measured how much the use of yearly products is incentivised over the use of short-term products.

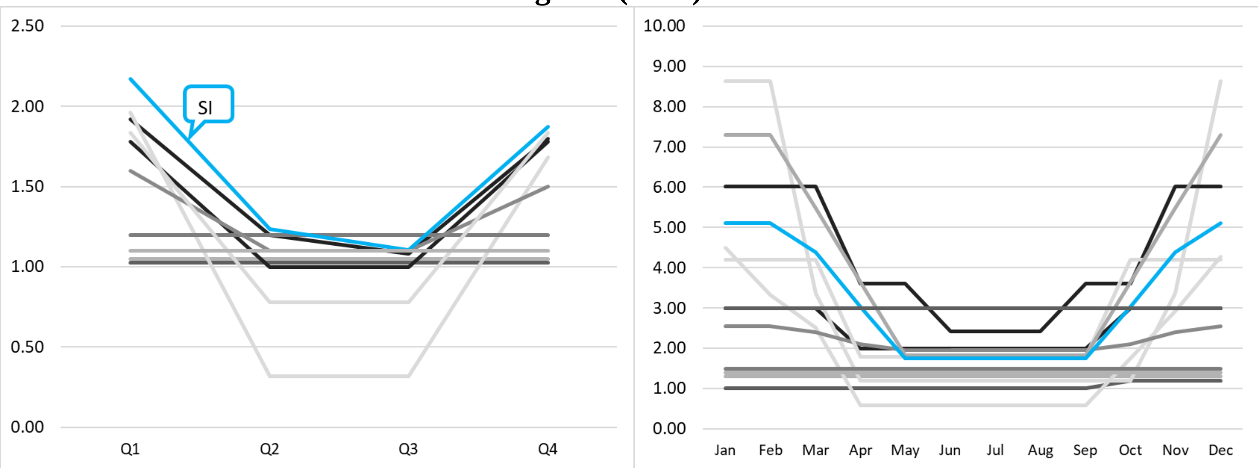
There are two typical ways of short-term product pricing: some countries apply one multiplier per product-length (there is one quarterly, one monthly, and one daily multiplier), while others apply seasonally different multipliers, higher ones in the winter period and lower ones in the summer period. In some countries (e.g. Hungary and Romania) summer products are even cheaper than the yearly product (the multiplier is smaller than 1), basically to incentivise storage use.

Slovenia applies the same short-term multipliers since 2015, and as discussed in Annex II, tariff levels for the yearly product have not changed significantly (except for the change in the Croatian exit point from October 2017). This means that the change in traders' behaviour is not the result of changing tariff conditions in Slovenia – neither for yearly, nor for short-term products.

Slovenian monthly and daily multiplier levels can be considered typical for the region. The highest multipliers in the region are 4.8 and 8.64 for monthly and daily products, respectively, applied in the winter months in the Czech Republic, while the lowest ones are 0.36 and 0.58 for the summer months in Hungary. In Slovenia, monthly multipliers vary between 1.1 and 2.52, while daily multipliers are in the range between 1.75 and 5.11. Quarterly multipliers in Slovenia, however, are the highest in the region in 3 out of 4 quarters, being in the range between 1.1 and 2.17.

[75] In case of quarterly products, one third of the price of the product is compared with the 1/12th of the yearly product, and the multiplier is the same for each month in the same quarter.

Figure 25: Multipliers for quarterly (on the left) and daily products (on the right) in the region* (2018)



* countries included on the figures: AT, BG, CZ, DE, HR, HU, IT, PL, RO, RS, SI, SK

Source: TSO and NRA websites

We can conclude that even though the relative cost of quarterly products compared to the yearly tariff is high in Slovenia in a regional comparison, the use of this and other short-term products is gaining importance. This is a positive sign of traders reacting to short-term gas price signals on the CEGH, confirming the existence of a competitive market environment. The situation will improve further when the Tariff Network Code is fully implemented. The Energy Agency intends to do this and also lower short term tariffs after 2019.

The lack of a liquid secondary market, however, can be identified as a possible trade barrier; according to PRISMA data, there are very few such offers with 1.5-2 times higher prices than the reserve price of the given product, i.e. the starting price of the capacity auctions.[76] The issue was also raised by a market participant during the stakeholder consultation, suggesting that "a more liquid capacity market would enable more flexibility and thereby better utilisation/benefits from Slovenia's proximity to the Austrian Hub."

6.3 THE UTILIZATION OF THE AT-IT-SI ROUTE

In 2016, there was an approximately 1 EUR/MWh spread between the Italian hub price and the Slovenian LTC price; Slovenian traders could buy and ship gas to Slovenia from the PSV at a cost of 17.13 EUR/MWh, compared to the 18.30 EUR/MWh Slovenian LTC price. Interestingly, however, there were almost no flows on the pipeline in 2016 and 2017. According to ENTSO-G data, there were minimal flows in Q1 and Q3 2017 from Italy to Slovenia, with some reverse flow as well in Q1 2017, but these were marginal compared to the pipeline's technical capacity.[77] There were very few bookings on the pipeline as well, so the possibility of contractual congestions can be excluded.

A possible explanation is that there is no actual price difference between the two countries. As we highlighted at the beginning of this Annex, only the price of the Russian LTC is available

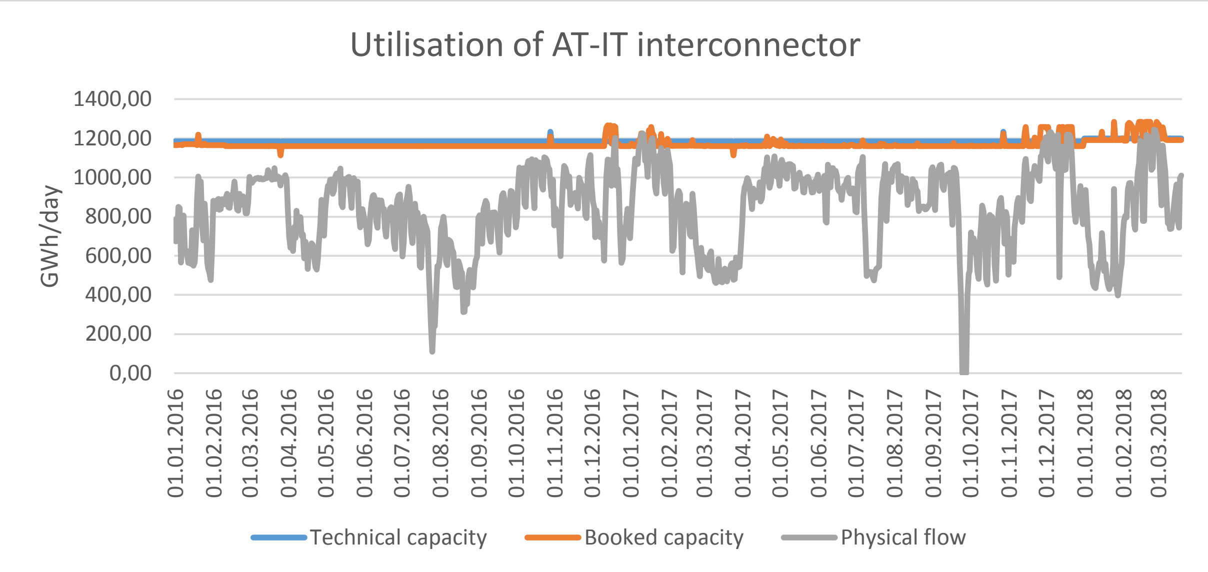
[76] Source: PRISMA (https://platform.prisma-capacity.eu/#/network-point/details/1277954; https://platform.prisma-capacity.eu/#/network-point/details/4784128; https://platform.prisma-capacity.eu/#/network-point/details/4423689; https://platform.prisma-capacity.eu/#/network-point/details/1277955; https://platform.prisma-capacity.eu/#/network-point/details/4751365).

[77] In case of congestion on the Austrian-Italian interconnector and high gas demand in Italy (especially in the winter period), there are gas flows on the Austrian-Slovenian-Italian route. They may even reach technical capacities for a duration of a few days.

for Slovenia, which covers only part of the country's natural gas trade. If we assume that only half of Slovenian imports originate from the Russian LTC, with the other half purchased on the CEGH, we get an average price of 17.07 EUR/MWh. This is almost identical to the average PSV price (17.13 EUR/MWh with transportation cost) for 2016. The idea that in spite of the more expensive LTC, Slovenian imports were not more expensive than the Italian market in 2016, is also strengthened by our finding that industrial prices were already similar in the two countries (see Figure 4).

Another reason for the low utilization of the Italian-Slovenian pipeline might come from the fact that Austria is a main gas source for the Italian market as well. The daily utilization of the Austrian-Italian interconnector between 1st January 2016 and 20th March 2018 is presented in Figure 26.

Figure 26: Utilisation of the Austria to Italy interconnector in 2016-2018



Source: ENTSO-G transparency platform

The pipeline seems to be very heavily utilised in some time periods, as the utilization of the interconnector is at the technical capacity. Additionally, the booking rate of the pipeline is also very high. As almost all capacity is booked, it is worth investigating the possibility of contractual congestion. It is possible that market players would like to bring more gas to Italy, but it is not possible because of barriers to trade, which can be one possible explanation of why Italian prices remain higher than those in Austria (see also Annex III for a comparative analysis of the Italian and Austrian hubs). Slovenian traders are therefore better off buying in Austria as long as the Austrian-Slovenian pipeline is not congested.

As the Italian-Slovenian pipeline is not utilized, Slovenia may also import natural gas through the Italian LNG terminals. In Table 28, we collected all regasification terminals and their utilization rates in 2016 in Italy. The table shows the regasification capacity, the average yearly utilization, and peak-month utilization.

Table 28: Italian regasification terminal utilisation in 2016

Name	Technical capacity (bcm)	Average utilization 2016	Peak month utilization 2016
Panigaglia	3.40	0.06	0.29

Porto Levante	7.58	0.75	0.99
FSRU OLT	3.75	0.14	0.58

Source: IEA Gas Trade Flows in Europe

The Porto Levante terminal was almost fully utilized in 2016 by Qatar, but there was great amount of unused capacities on the Panigaglia and OLT FSRU terminals. Even if we calculate with the most pessimistic scenario (peak month utilization for a whole year), 70% of Panigaglia and 40% of OLT is available, totalling to almost 4 bcm of available regasification capacity. The Italian-Slovenian interconnector's technical capacity is approximately 1 bcm, which means that theoretically Slovenia could cover all its gas needs from this direction. The cost of this option is difficult to tell, but it is most likely higher than the Italian LNG price reported in the EU quarterly (15.30 EUR/MWh with transportation tariffs).

ANNEX II: ANALYSIS OF REGIONAL TRANSMISSION TARIFFS

Figure 27 summarises August 2017 cross-border tariffs in Europe. The highest and the lowest 25% of IP tariffs (the sum of exit and entry tariffs at the given point in the given direction) are indicated with orange and green boxes, respectively. The tariff calculation methodology is explained in the box below. Benchmarking is applied in order to get comparable tariffs in the same measurement unit.

Transmission tariff benchmarking methodology applied in this study

Transmission fees are estimated as a standardized transportation service for each relevant cross-border point and expressed in a common measurement unit (€/MWh).

The assumed standard transportation service has the following characteristics:

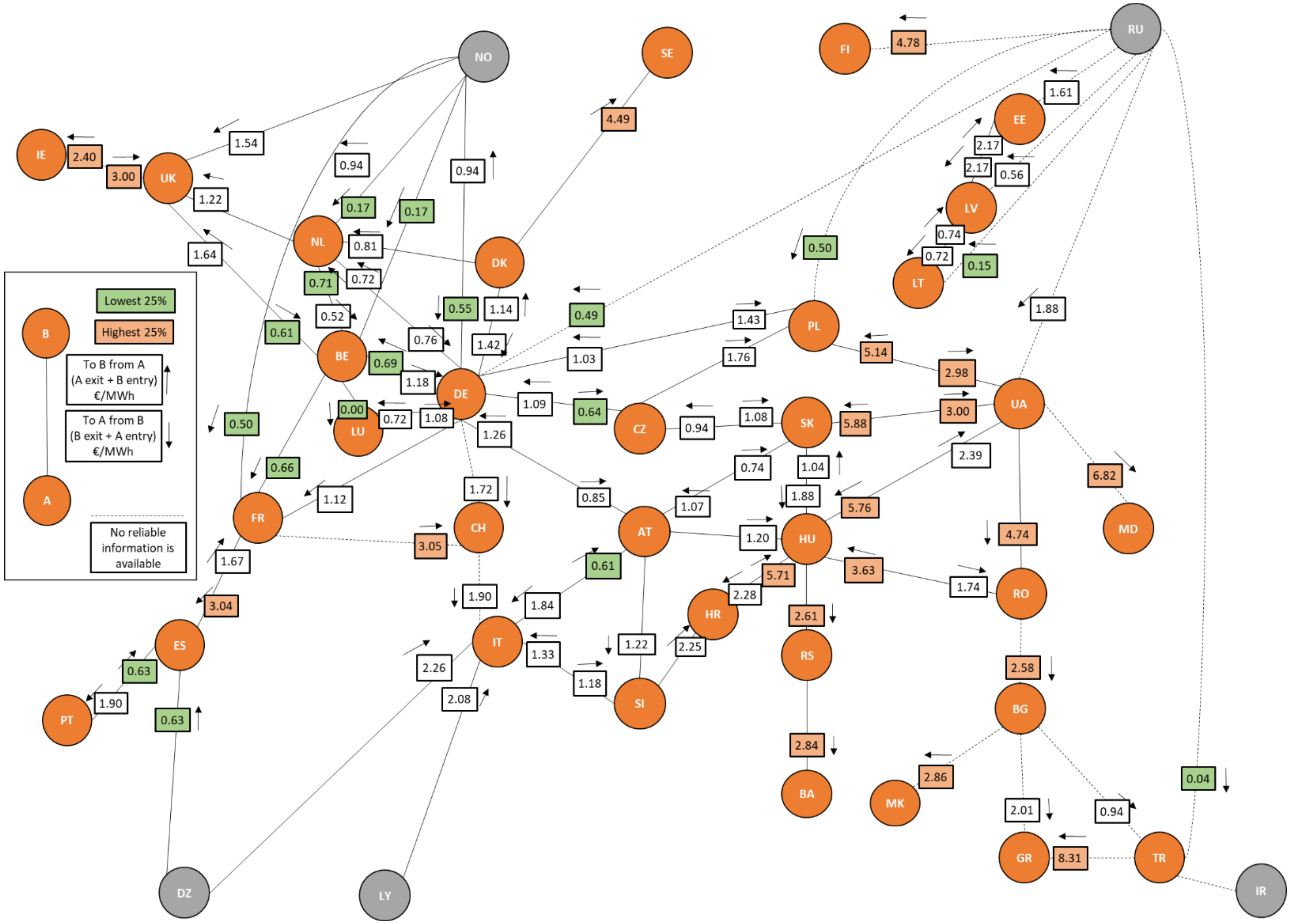
- The duration of transmission contracts is one year
- Contracts refer to firm transportation services
- The product offers an hourly capacity of 10000 kWh (/h/y)
- Applied booked capacity usage ratio is 56.2% [1]
- Tariffs are expressed in €/MWh

Using our assumed capacity reservation level of 10 000 kWh/h for the yearly firm transmission service contract, we calculate the overall transportation fee (in €) that would be incurred by a shipper at each interconnection point (IP), making all the necessary conversions regarding gas reference conditions and currency units.

Once we have arrived at the total fee corresponding to the standardized service, tariffs can be determined on a per MWh basis (€/MWh), dividing total payments by the yearly transported volume (using the booked capacity usage ratio (56.2%)). The fee consists of the relevant exit plus entry fees due at the two sides of the border (including the commodity fee at the relevant point).

[1] calculated as: (Average flow)/(Average booked capacity). Average booked capacity utilization in Europe is reported in the CEER/ACER Market Monitoring Report 2015, pp. 251-252.

Figure 27: Transmission tariffs in Europe



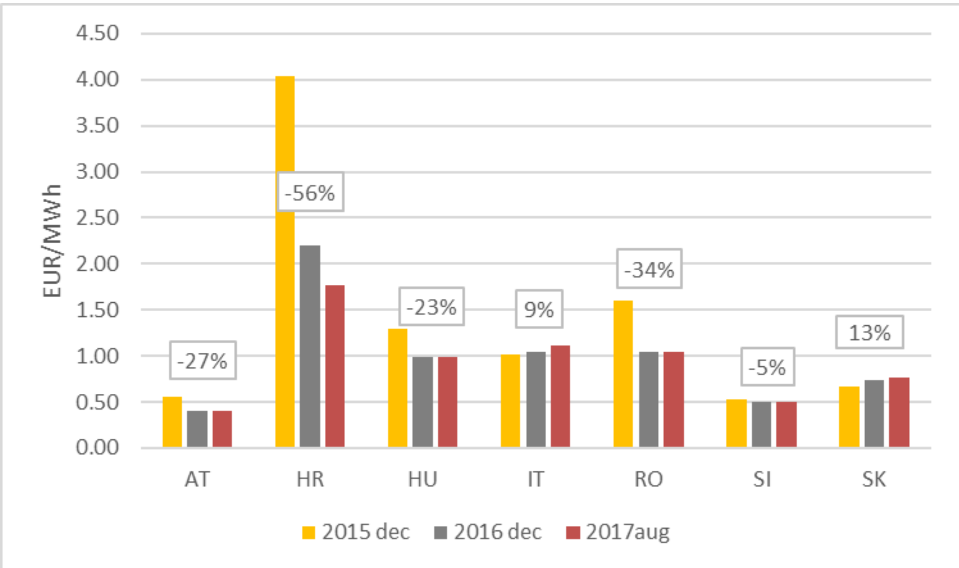
Source: REKK calculation based on TSO and NRA data

There may be several reasons behind individual border- and regional-level tariff differences, such as differences in the age and capacity of the pipelines, market functioning, IP related capacity booking and flow levels. However, a potential explanation can also be tariff distortions (e.g. through cross-subsidisation, or market power related issues). TAR NC tries to solve this latter problem through the introduction of detailed rules for transmission tariff calculation. These might imply cost-reflective, non-discriminatory and objective transmission tariffs that minimise cross-subsidization and facilitate cross-border trade.

Although there is a detailed guidance regarding transmission tariff calculation methodology in TAR NC, NRAs have significant discretion over several components. TAR NC provides only ranges for short-term multipliers and seasonal factors, although the expected distribution of bookings should be considered. Exclusive discounts are granted to storage facilities, and tariffs at other network points relevant for increased security of supply can also be discounted – such as entry points from LNG regasification terminals, or the only entry point to isolated countries. NRAs can make further adjustments: benchmarking (in order to reach a competitive tariff level), equalisation and rescaling.

Taking into account all these factors, it is hard to forecast precise tariff levels as a result of TAR NC implementation. Many countries, however, have already started to apply the new rules (even if the implementation deadline is 2019), and at the same time a "tariff competition" started to emerge in the region. These two effects would probably lead to the equalisation of tariffs, and the cut-back of outliers. As it is shown on Figure 28, we already see an adjustment process in case of outlier tariffs, including Romania and Croatia.

Figure 28: Evolution of IP tariffs in the CESEC region and in some other European countries (shown as a benchmark) *

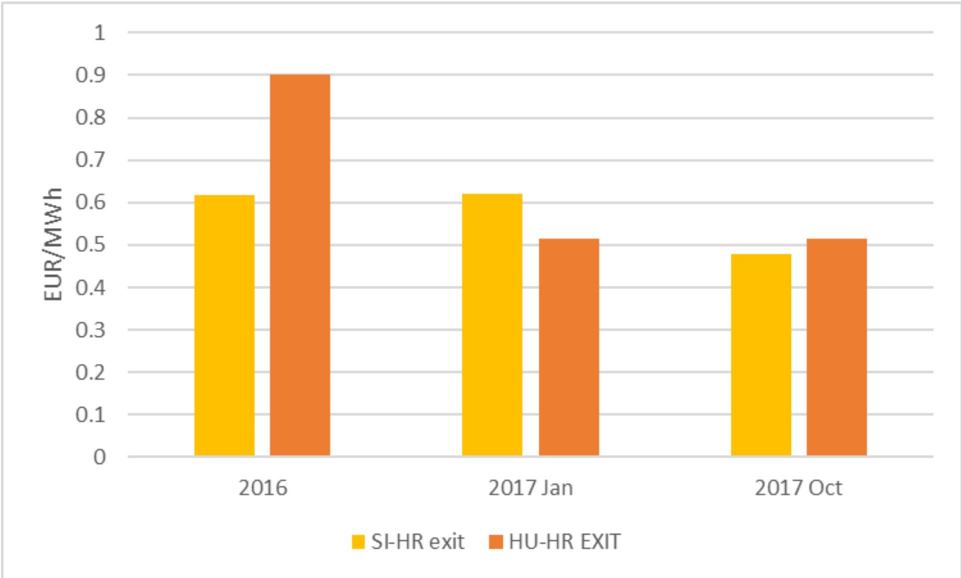


*percentages refer to the change from December 2015 to August 2017

Source: REKK calculation based on TSO and NRA data

A typical example of tariff competition can be observed in case of the Slovenian-Croatian and Hungarian-Croatian exit points. After a cost and asset revision, tariff levels were lowered at most Hungarian IPs from 2017 January. Before this cut, bringing Russian gas to Croatia was cheaper on the Austria-Slovenia than on the Austria-Hungary route.[78] After the cut, transit through Hungary became cheaper, but then Slovenia also decreased its Croatian exit tariff from October 2017. As a result, Slovenian transit is again cheaper for Croatia than using the Hungarian system.

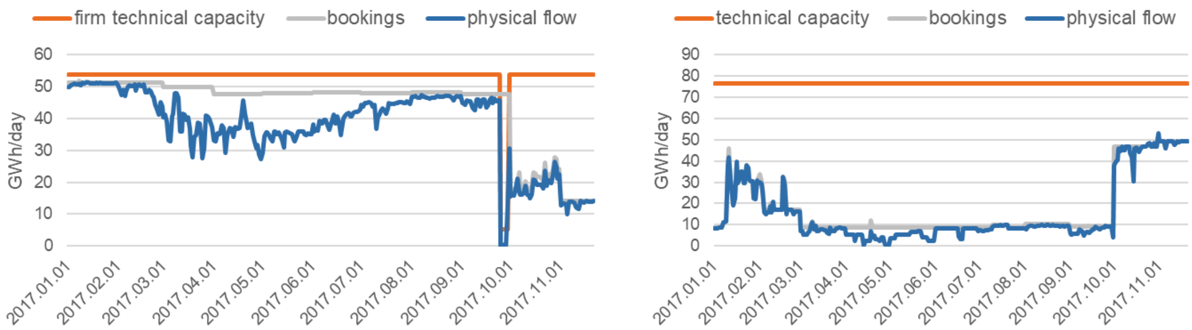
Figure 29: Tariff evolution on SI-HR and HU-HR exit points, 2016-2017



Source: REKK calculation based on TSO and NRA data

We assume that the shift in gas flows from one border to the other, seen in Figure 30, could be the result of the lowering of the Hungarian tariffs. As the gas year begins in October, bookings from October 2017 on the SI-HR and HU-HR interconnectors are likely to reflect January tariff levels advantageous to Hungarian transit, and not the changes introduced in Slovenia effective from that date.[79] The effect of Slovenia's answer to the Hungarian tariff decrease may become observable later, depending on the timing and the duration of bookings.

Figure 30: Utilisation of SI-HR and HU-HR interconnector points in 2017 (booking and physical flow)



Source: ENTSO-G transparency platform

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[78] HR entry tariffs are the same for all interconnection points, and the difference between the sum of entry and exit tariffs on the AT→HU and the AT→SI points is less than 2%.

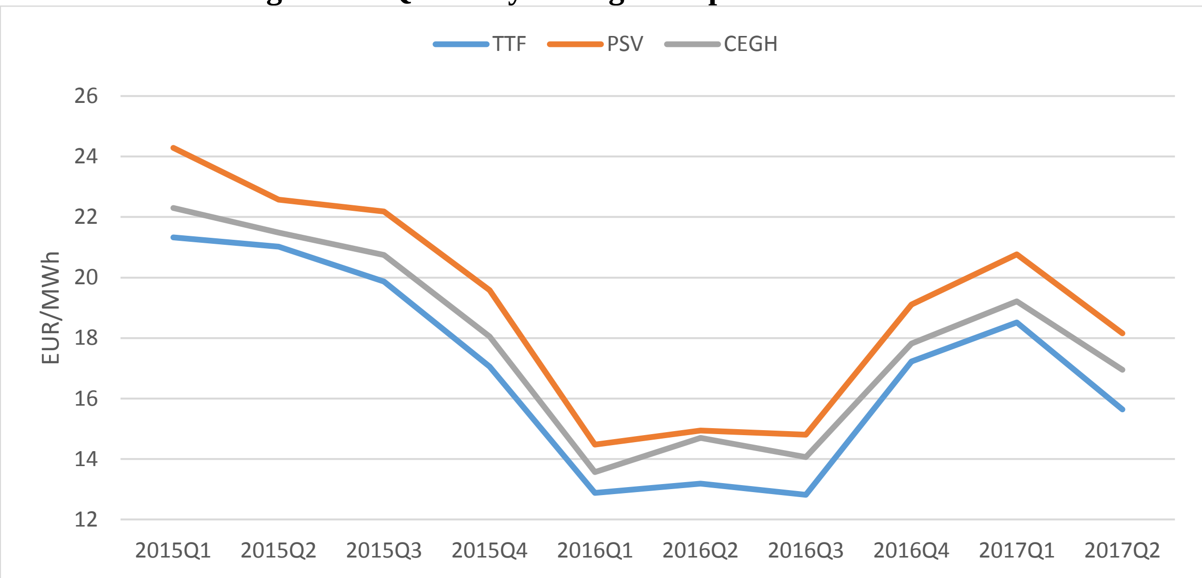
[79] Data is not available on the date when bookings were made, only on their overall level at a given time.

ANNEX III: THE MAIN FEATURES OF THE AUSTRIAN AND THE ITALIAN HUBS

Slovenia can import natural gas from two neighbouring hubs, from the CEGH in Austria and the PSV in Italy. In order to assess the potential of these markets for Slovenia, we examined their liquidity and prices in more detail.

Figure 31 shows the quarterly average price of CEGH, PSV and TTF based on the European Commission's quarterly natural gas market report between Q1 2015 and Q2 2017. As the TTF is the most liquid hub in continental Europe, it can be used as a good benchmark to compare the Italian and Austrian prices with.

Figure 31: Quarterly average hub prices in 2015-2017



Source: EU Quarterly Report

There is a clear hierarchy between the hub prices in the investigated period. In every quarter TTF is cheaper than CEGH, while the prices on the Austrian hub are always lower than PSV market price. On average, there is a 1 EUR/MWh spread between CEGH and TTF, while around 2 EUR/MWh between TTF and PSV. It is interesting to see, however, that while the price premium of the Italian market relative to the Dutch is basically constant, there is a bigger volatility in the Austrian hub price; in some quarters it is closer to TTF, while in others to PSV. It is also evident that there is a strong correlation between the three market prices.

The difference between the hub prices can be traced back to two main sources. First, potential barriers to trade can hinder price convergence even between hubs (see Annex I). Second, European gas hubs are on different maturity levels, and more mature hubs generally produce prices, which reflect actual market conditions better. For this reason, based on the results of a paper by Heather and Petrovich (2017)[80], we will evaluate briefly the maturity of CEGH and PSV relative to each other and other European gas hubs.

The paper investigated the maturity of gas hubs based on several measures. We present the most important ones in Table 29 for TTF, PSV and CEGH based on 2016 market data.

[80] P Heather, B Petrovich (2017): European Traded Gas Hubs- an updated analysis on liquidity, maturity and barriers to market integration. Oxford Institute for Energy Studies

Table 29: Assessment of hub maturity

Hub name	TTF (Netherlands)	PSV (Italy)	CEGH (Austria)
Market participants (active)	130 (40+)	118 (18)	53 (15)
Traded volumes (TWh)	22230	885	553
Churn rate	57.1	1.2	5.7
Maturity- index (out of 15)	15	7	7

Source: Heather and Petrovich (2017)

We highlighted three main dimensions, the number of market participants, total traded volumes in a year and the churn rate. We also presented the maturity index that was given by the authors. TTF in all dimension archived better results than the other two hubs. Interestingly, the total number of market participants is very similar between TTF and PSV with 130 and 118 players respectively, but the number of active market participants shows the real difference. While at TTF there are more than 40 active market participants, at PSV and CEGH these numbers are 18 and 15, respectively. Based on these figures given by Heather and Petrovich (2017), only 15% percent of all participants is actively trading at PSV, while this value is 28% percent in the case of Austria. This means that in Austria the role of the hub in natural gas trade seems to be relatively more important than in Italy.

When analysing total traded volumes, the differences become even larger compared to TTF: they were at least 25 times bigger at TTF than at any of the other two hubs. It this respect, PSV performs better than CEGH with 1.6 times bigger traded volumes. In terms of churn rate, however, CEGH is a more liquid hub with a value of 5.7 compared to 1.2 at PSV. The churn rate is the number of times a unit of gas is traded and re-traded between its initial sale by the producer and the final purchase by the consumer.

These values highlight the different characteristics of CEGH and PSV. The Italian hub is much larger in volume and has twice as many potential market players as the Austrian hub. However, the relative importance of PSV is probably smaller as the large majority of its market players are inactive. CEGH is a smaller exchange but plays a more central role in the Austrian market with much higher liquidity.[81] These differences balance each other out in the assessment of Heather and Petrovich (2017), as both hubs qualify for a maturity index of 7 in a 15 points scale, and they are thus labelled "poor".

[81] CEGH's churn rate is in effect the third highest in Europe after that of TTF and Britain's NBP. Even at the German NCG, which is the third most mature hub after TTF and NBP according to Heather and Petrovich, the churn rate is only 4.0.

Figure 32: An assessment of European gas hubs

Source: Heather and Petrovich (2017)

ANNEX IV: WELFARE EFFECTS OF A MARKET MERGER INVOLVING ITALY, AUSTRIA, SLOVENIA, AND CROATIA

In this Annex we assess the welfare effects of a potential market merger of Italy, Austria, Slovenia and Croatia, in line with Option 3 of the WECOM study commissioned by E-Control.

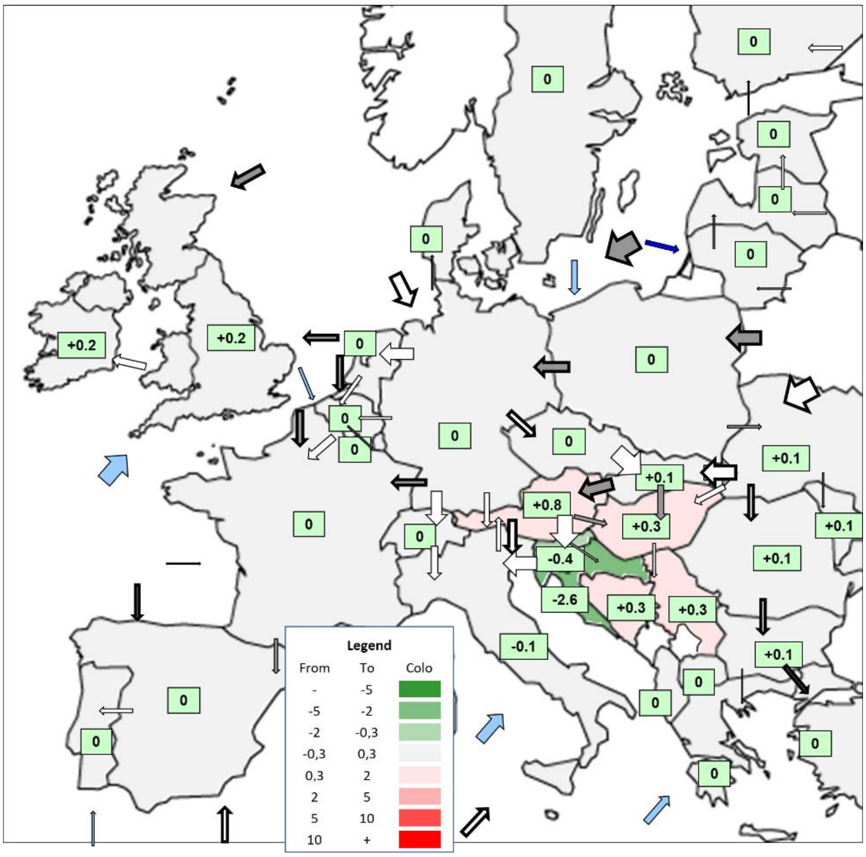
Based upon a market modelling approach, we analyse market changes in an integrated way, and quantify the social welfare change of all market participants by countries. Modelling was carried out for the year 2021, with the same reference conditions that were presented in the main text.

In the first step of modelling, we assume a full market merger, meaning that tariffs are assumed to be zero inside the tariff region, and congestions no longer apply among the merged markets (i.e. capacities are assumed to be not constrained). These assumptions, however, lead to a situation where TSOs suffer significant profit losses due to the decrease of within-zone tariffs.[82] In order to compensate for these profit losses, we increase entry and exit tariffs at the borders of the region with the same increment in a second step, so that we reach the same level of total operational income for the TSOs from transmission as in the reference scenario. Modelling results show that the necessary increment of entry and exit tariffs is 0.85 €/MWh, which results in a total revenue difference of only 0.1% compared to the reference. Figure 33 shows the change of gas wholesale prices in the region due to the market merger.

Equalization of the prices in the region is triggered by increased flows from Austria to Italy: 27 TWh of additional gas is delivered compared to the reference scenario. It is important to note that since the AT-IT interconnector is already congested in the reference scenario in several months, this additional gas must be delivered partly through Slovenia. This change of delivery route might cause additional costs to TSOs which is not paid for by traders because of zero within-zone tariffs.

[82] Modelling results show that the sum of profit loss of the four TSOs is approximately 600 mEUR/year.

Figure 33: Changes of yearly average wholesale gas prices due to market merger (€/MWh)



Blue arrows indicate LNG flows, white arrows indicate modelled gas flow on interconnectors, dark blue and grey indicate congestion in at least one month

Table 30 below illustrates the change of flows into and from the region. Because of increased Italian demand and increased tariffs on the borders of the region, there are no flows from Austria to Slovakia. Instead, Slovakia is supplied through the Czech Republic, explaining the decrease of flows on the Germany-Austria interconnector as well. For the same reasons, flows from Austria to Hungary decrease significantly, which are compensated through the SK-HU interconnector. This change in flow patterns result in a slight price increase in Hungary.

Table 30: Utilization of pipelines in a market merger scenario

	Reference	Market merger
DE-AT	73%	28%
CH-IT	25%	21%
SK-AT	66%	66%
HU-HR	0%	0%
DZ-IT	60%	60%
TAP-IT	0%	0%
CZ-SK	9%	45%
DE-CZ	15%	30%
SK-HU	48%	90%
AT-DE	0%	0%
AT-SK	80%	0%
AT-HU	100%	57%
HR-HU	0%	0%
IT-CH	0%	0%

Table 31 and Table 32 show the welfare effects of the market merger in the participating and in the neighbouring countries. Total welfare change in the merged zone is 19.2 mEUR/year. Consumers' benefit increase by 52.8 mEUR/year due to the price decrease in Italy, Croatia and Slovenia. This gain is reduced by the decrease of producer surplus in Italy and Croatia. With the help of the increase of entry and exit tariffs on the zone-borders, the change of operational profit of TSOs is approximately zero. All TSOs within the zone realize almost the same profit from transmission as in the reference scenario if a compensation mechanism is introduced.

The decrease of Slovenian TSO profit consists of two parts: 16 mEUR is lost due to abolished entry tariff on the AT-SI IP, and exit tariff on the SI-HR IP. An additional profit decrease of 18 mEUR derives from the increased transmission costs[83] arising from higher flows on the AT-SI-IT delivery route. Of course, these losses can be compensated in the framework of an inter-TSO compensation mechanism. TSO auction revenues decrease in Austria due to less flows on the DE-AT, AT-SK and AT-HU interconnectors; in theory, this could also be compensated by some additional increase of entry and exit tariffs on the zone-borders. This loss, however, is less than 2% of total TSO profit in the region and would cause a negligible increase in marginal tariffs.

[83] Transmission costs is assumed to be 0.1 €/MW in the case of all entry and exit points.

Table 31: Welfare change due to market merger in the region

Welfare change m €/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO operational profit*	TSO auction revenues	LNG operator profit	Total Welfare
SI	4.2	0.0	0.0	0.0	-0.2	-33.8	0.0	0.0	-29.9
AT	-76.1	11.2	0.2	0.0	72.7	63.4	-24.3	0.0	47.0
HR	77.3	-49.9	0.0	0.3	0.0	-17.5	0.0	0.0	10.1
IT	47.4	-4.5	-0.1	-5.1	-35.3	-10.6	0.1	0.0	-8.0
Total	52.8	-43.2	0.1	-4.9	37.2	1.5	-24.3	0.0	19.2

*TSO operational profit consists of revenues from transmission entry and exit, storage entry and exit, consumption exit and production entry fees

Table 32 shows that the market merger brings welfare changes in neighbouring countries as well. Prices in some of these countries increase due to higher prices in Austria and higher zone-border tariffs, resulting in a decrease of consumer surplus. Czech and Slovak TSOs, on the other hand, realize significant benefits due to higher transit flows, as presented in Table 30.

Table 32: Welfare change due to market merger in the neighbouring countries

Welfare change m €/year	Net consumer surplus	Producer surplus	SSO operating profit	Storage arbitrage profit	Net profit of LTC buyers	TSO operational profit*	TSO auction revenues	LNG operator profit	Total Welfare
BA	-0.6	0.0	0.0	0.0	0.5	0.0	0.0	0.0	-0.1
CZ	-0.5	0.0	0.0	-0.9	-1.2	45.2	0.0	0.0	42.5
DE	4.5	-0.1	0.3	0.0	-0.5	-8.2	-0.2	0.0	-4.2
FR	3.0	0.0	-0.1	0.0	-0.4	1.4	0.0	0.0	3.9
HU	-30.6	3.6	1.4	3.0	7.7	-0.2	-19.8	0.0	-34.9
RS	-7.0	1.5	0.0	0.0	5.4	-0.1	0.0	0.0	-0.2
SK	-3.9	0.1	0.0	0.0	8.8	22.6	1.3	0.0	28.9
Total	-35.1	5.0	1.6	2.1	20.2	60.6	-18.8	0.0	35.8