ITALIAN-AUSTRIAN WHOLESALE PRICE FORMATION IN THE LIGHT OF MARKET INTEGRATION

A report prepared for ARERA and E-Control

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1 OBJECTIVE OF THIS STUDY

Background

ARERA and E-Control are evaluating the possibility of merging the Italian and Austrian gas market areas to a single trading region. The basic idea behind market merging is that two markets can gain wholesale market volumes and better efficiency by combining their demand and supply volumes into a single wholesale market. This structural reform is suggested by ACER[1] in the amended Gas Target Model (AGTM) to improve efficiency and the functioning of gas markets as it improves its liquidity.

For the currently separated market areas of Italy and Austria, the setup of a merged market is expected to have two immediate main effects:

- (a) changed wholesale gas market price, and
- (b) reduced network revenues as a result of "disappearing" bookings between formerly national market areas of Austria and Italy.

This study is analysing the aforementioned wholesale price formation (a); the aforementioned effect on networks and network operator revenues (b) is investigated by the involved regulatory authorities and network operators.

Objective of this study

In this context the objective of this study is to:

- Explain the price formation in the Austria and Italy market areas and how this price formation changes in light of the market zone merger;
- Quantify the effect of the market merger on the price formation with a model-based analysis.

Disclaimer

The decision on merging the gas markets areas / forming a trading region should be guided by a thorough investigation of benefits and costs of such a measure.

It is important to note that this study is not a full cost-benefit-analysis of the market zone merger, but rather about distributional effects through price changes. In this regard **the study is only looking at a limited set of the potentially wider effects of a market merger**. How the market merger would be assessed, requires additional analysis, e.g. on the **costs of a market integration** (e.g. because of potentially less efficient location choices for demand and supply because of a lack of geographic distinct price signals) and **benefits of market integration** (e.g. increased liquidity (lower bid-ask spreads and transaction costs), higher competition leading to more efficient market outcomes). As such this study can be seen as a prerequisite or first step for such a cost-benefit-analysis being potentially performed at a later stage.

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[1] https://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/default.aspx

Structure of this report

This report is structured as follows:

- Section 2 describes the approach to the analysis of wholesale price formation
- Section 3 describes the results of the model-based analysis on the effects of the market merger on the wholesale price formation
- Section 4 summarises our findings.

In the annex we provide additional information on the model used, the data sources for the scenarios and additional information on the results and the sensitivity analysis.

2 APPROACH TO ANALYSIS OF WHOLESALE PRICE FORMATION

In this section we describe the key drivers of price formation in the Austrian and Italian wholesale market based on historic prices and gas flows and how these drivers might change in light of future developments. The identified drivers of the wholesale price formation inform us about relevant aspects for the modelling approach in which we quantify the wholesale price formation. Further to this the key drivers inform us about important parameter variations which should be varied in different scenarios.

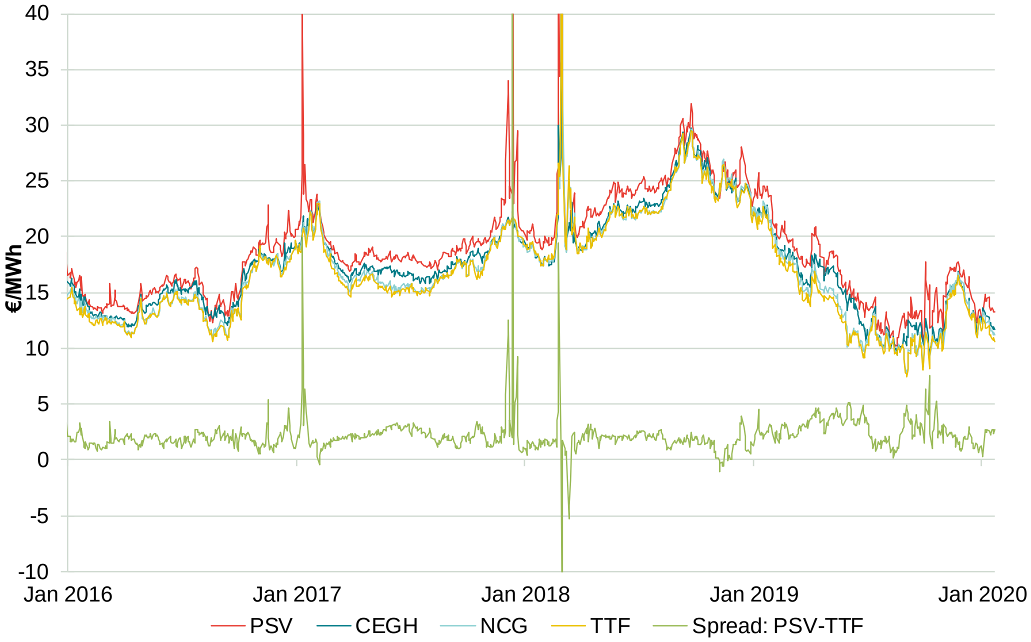
2.1 Key drivers of price formation

2.1.1 Fundamental drivers for price-formation

Wholesale prices in Europe indicates that wholesale markets are highly integrated

A comparison of historic prices (Figure 1) shows that hub prices in the core region of Europe (Austria, Italy, Germany, Netherlands, Belgium and UK) are moving in parallel. This indicates a high price integration of wholesale gas prices in Europe and further suggests that in many situations it is largely one marginal source of gas influencing the price in several EU regions. Nevertheless, we also see situations, where spreads increase massively, and the gas markets are less integrated because of transport bottlenecks. Though such situations are rare (e.g. Figure 1 shows only a few such spread-spikes between PSV and TTF over the course of 4 years) and only limited in time (typically lasting only a few days).

Figure 1 Gas prices for different hubs in Europe between 2016 and 2020



Source: DFC / Frontier Economics

The wholesale gas price for Europe is formed in an intertemporal market

Because of storability of natural gas, wholesale gas prices at each time are also driven by expectations of prices in the future. This means that gas prices at a certain time are not only linked to incremental production and transportation cost at this point in time, but also influenced by the historic supply/demand ratio ("memorised" in storage filling levels) as well as on expected supply and demand in the future. Gas forward markets therefore show a high degree of financial activity where operators develop expectations regarding the future supply structure (it is highly indicative that the TTF and NBP churn[2] rates are 16.9 times the consumption of the NWE market).

Despite this intertemporal component of the price formation there are still significant drivers of short-term price volatility. E.g., price volatility can result from:

- availability of storage and transport capacity;
- variable costs (tariffs) for storage and transport capacity usage;
- contractual obligations (e.g. take-or-pay commitments)
- fundamental changes to the supply/demand ratio (e.g. driven by weather effects, economic developments as e.g. currently seen in relation to the Corona-Pandemic, …)

[2] The churn rate measures how many times a unit of gas is exchanged in the market before being delivered physically. High churn rates thus indicate an active price-discovery activity by market participants, in what is to a good extent a "purely financial" market. Otherwise stated, participants pursue highly (or even purely) speculative strategies where they trade much more volume than they physically deliver.

- changes in the opportunity cost of gas for the market participants. For example, the announcement that in a month time a large regassification unit will be placed off-line, may impact current prices, depending on how market participants conjecture the new supply/demand balance will impact on future prices;
- changes in direct supply cost. For example, in case of major system failures, like the Baumgarten accident in December 2017, the direct cost for large market participants to fulfil their delivery commitments may change, because of a genuine scarcity conditions of either gas at certain locations or transmission capacity.
- etc.

Such short-term price volatility, being to a large degree related to fluctuating events, is not captured in a long-term simulation approach like the one developed in the context of this study.

Pricing strategy: Suppliers traditionally act as price takers – the net back pricing logic

As discussed above, because of the high degree of integration of markets a single price reference (e.g. such as the LNG price) might influence the level for the wholesale gas prices across the various market areas in Europe[3] and price differences across market areas are mainly driven by transportation costs (see also the next paragraph). In terms of pricing logic, this implies that suppliers adjust their supply prices according to this reference price, net of the transportation costs to reach the supplied region (**net back** pricing logic). This has always been the case, even before the establishment of liquid gas hubs, when gas import prices were calculated “net back” based on the costs of alternative fuels (e.g. fuel oil or coal). With the establishment of so called “gas-to-gas” competition this net-back logic has been carried on, but nowadays often with a direct price indexation to hub-prices of gas.

While the producer therefore traditionally took the “price risk”, it was the importer or down streamer, who took the “volume risk” – e.g. the obligation to market the contractual volumes (typically codified in a “take or pay” clause, i.e. the buyer had to pay the same independent of the actual volume (outside of specific flexibility corridors).

Still following this traditional net back logic, suppliers today typically in long-term contracts set targets in terms of volumes to supply, rather than implementing fixed-price contracts (which nevertheless have become a dominant part of the short-term business). The net back logic and fixed volume targets led to more long-term supply contracts being indexed to a hub price (e.g., TTF).[4]

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[3] In principle, the presence of congestions between two areas of Europe would lead to different price references for the two areas (which would be “decoupled”). However, in practice we do not observe a permanent structural congestions across the market areas analyses

[4] See for example Gazprom selling a majority of its supply volumes under hub indexed contracts: https://www.argusmedia.com/en/news/2070157-majority-of-gazproms-european-sales-hubindexed

Locational price spreads: Transmission tariffs drive price differences

The net-back-pricing logic implies that price differences between hubs are mainly driven by transmission tariffs (Figure 2). In case there is no congestion on the transport routes between hubs, competitive effects prevent the wholesale prices to differ by more than the transmission tariff. There may be points in time when prices fall apart due to congestion on transport routes. In such events price differences between countries show peaks (Figure 1). However, we note that these peaks in price differences are temporary and not structural, i.e. are not reoccurring in a regular predictable pattern.

Beside congestion and high demand leading to peaks in price differences, long-term capacity bookings and low demand might lead to price differences between countries being below published short-term transmission tariffs. With a high share of not-fully utilised long-term capacity bookings, some shippers have effective lower marginal cost of transporting additional units compared to market participants without such long-term contracts. While these long-term capacity bookings imply marginal transport costs to shippers are often close to zero, they only reduce the price difference between countries, if demand for cross market zone exchange is below long-term capacity bookings. As long-term capacity bookings are running out over the past years and will continue to do so over the next years, capacity bookings will continue to become more and more short-term. Price differences can therefore be expected to increase with the phase-out of long-term bookings.

Also, it has to be noted that various additional levies apply in various countries (e.g. for metering, balancing) which might further distort the effective costs for using Entry- and/or Exit-Capacities. In this study we abstract from such additional parameters.

Figure 2 Comparison of price spreads and tariffs on different supply routes

Supply route	Price spread 2019 €/MWh	Yearly Tariff €/MWh[5]
NCG > AT	0.79	0.76
AT > IT	1.17	1.13
TTF > NCG	0.42	0.54
TTF > BeLux > FR > ES	2.28	2.53

Source: DFC / Frontier Economics

Temporal price spreads: Seasonal price differences are limited by storage costs

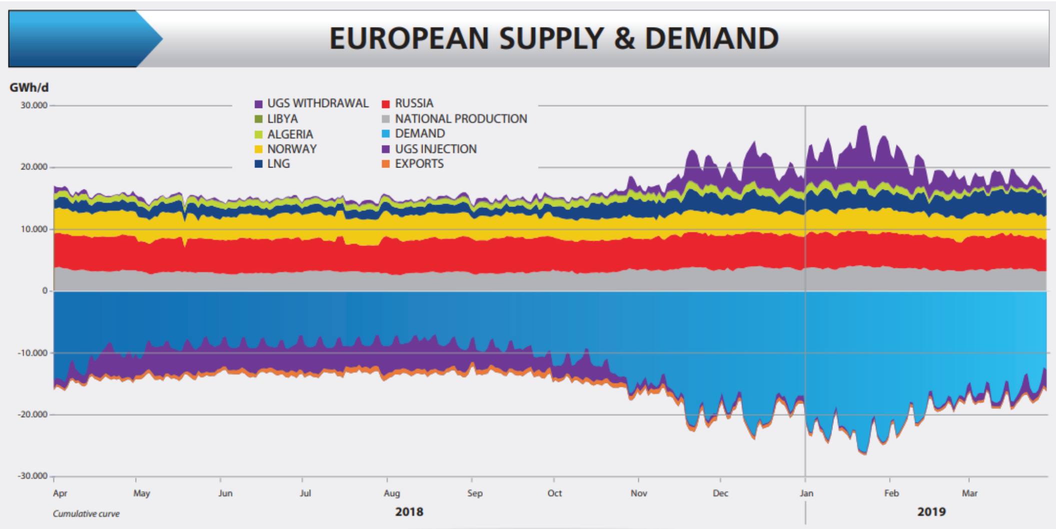
Variation in gas demand is another key driver of the gas wholesale price formation. Demand for gas can vary significantly throughout the year and might lead to temporary congestion on transport routes.

However, given the ability of gas to be stored, one can expect that seasonal price differences as a result of seasonal variation of demand, are limited by storage

[5] ENTSO Ten Year Network Development Plan 2018 – Annex D – Tariff Values

costs. The costs for using storage itself might change between short-term and long-term costs depending on the availability of storage. As long as storage capacity is available, storages manage the variation in gas demand and enable suppliers to supply gas with a constant profile (Figure 3). The seasonal variation in gas prices is therefore limited by the cost of gas storages (and related levies, e.g. entry-exit-tariffs at the storage site). We remark that storage capacity is relatively ample in Europe: in 2018 storage capacity represented about 22% of the total European consumption[6].

Figure 3 Illustration of seasonal demand variation and complementary storage supply



Source: ENTSOG – GIE System Development Map, 2018 – 2019

Summary: Price formation in the wholesale market

We established that producers mainly act as price takers on the European gas market, reflected e.g. in the trend for long-term contracts being indexed to hub prices.

The wholesale gas price for Europe is formed in an intertemporal market. Contrary to spot prices on electricity markets, the spot market clearing price for gas depends also on the development of demand and supply conditions (or the expectations of such) in a relatively long future time horizon (covering at least the storage cycle). The importance of storage thereby is potentially significant, as large storage capacities in Europe are available.

2.1.2 Outlook on future market developments

We discuss in the following sections the main market developments that might affect the price formation mechanism described above.

Supply mix is about to change but LNG likely to remain a marginal supply source

[6] Storage capacity is about 1.110 TWh (source: Gas Infrastrcture Europe, https://agsi.gie.eu/#/) *vs.* ~5.000 TWh/year of consumption in 2018 (source: Eurostat)

Until 2030 gas production within Europe is about to decline as gas fields deplete (UK) and/or production is stopped because of reduced public acceptance (NL). At the same time natural gas supply form Norway is expected to decline as well.[7] While the reduction of conventional gas production might partially be compensated by indigenous renewable gas production, a large share of reduced supply is expected to be compensated by gas from Russia and LNG.[8]

Additional infrastructure projects will open up new supply routes to Europe and increase gas flows within Europe. Most important new infrastructure to be considered in this context are:

- New LNG regasification terminals in Europe and increased liquefication capacity around the globe, particularly in the US,
- Finalisation of Nord Stream 2 pipeline, and
- Finalisation of the TAP pipeline connecting Italy, Albania and Greece to the TANAP pipeline.

With the change in gas supply, gas flow patterns within Europe will change as well and can therefore lead to a change in gas prices in Europe. At the same time, we do not expect there to be a significant change in the fundamental price formation logic. E.g. we assume future TAP suppliers to behave as price-takers following the net back logic, accordingly to the price formation mechanism described above.

Demand may decline reducing congestion in the European network

Gas demand projections for Europe show high uncertainty of demand. In several scenarios gas demand is projected to decline over the next years.[9]

Such a reduction in demand might reduce gas transport across Europe and therefore could reduce congestions, with the effect of further reducing opportunities for price “decoupling” across market areas. This implies that our finding of an already high price integration across entire European region would under such developments hold even more true in the future.

Long-term capacity bookings are expected to expire

While long-term capacity bookings potentially have an important effect on price formation by setting the marginal transmission tariff for selected shippers close to zero, we expect long-term capacity bookings to expire over time. For example, on the Tarvisio / Arnoldstein pipeline we see that long-term capacity bookings largely expire by the end of 2022 (Figure 4). As a result of this, short-term tariffs will become a more relevant driver for price differences within Europe.

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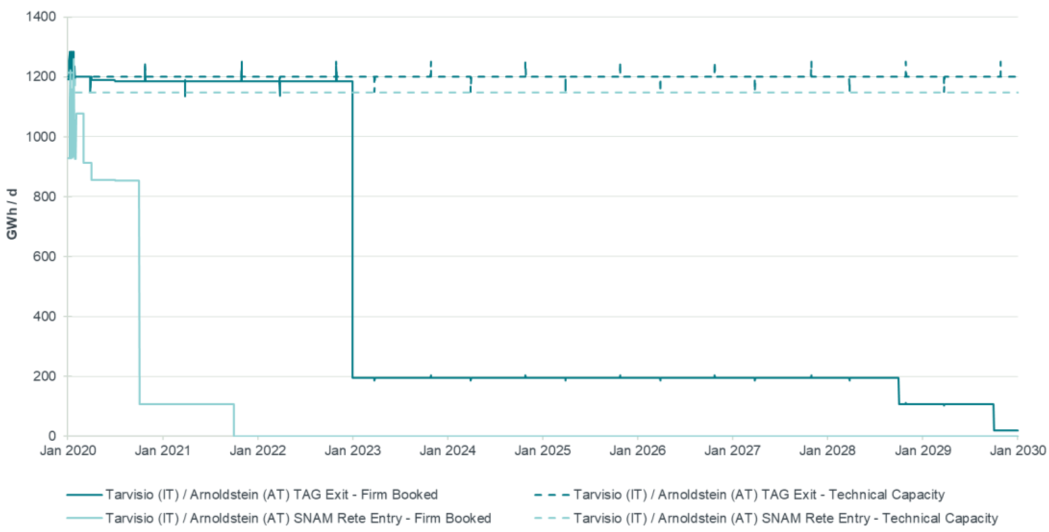
7 See remaining reserves per field: https://www.norskpetroleum.no/en/facts/remaining-reserves/#per-active-field

8 See TYNDP 2018 and 2020 projections

9 See TYNDP 2020 scenario report figure 12, p.13

Figure 4 Tarvisio / Arnoldstein capacity bookings



Source: DFC / Frontier Economics based on Entso-G

2.2 Modelling approach

Based on the discussed key drivers of the gas wholesale price formation mechanism for Europe a modelling approach suited to quantify the effects of the market zone merger has been derived.

2.2.1 Implication of the price formation mechanism on modelling approach

To quantify the effects of the market zone merger on the wholesale price formation in Austria and Italy, DFC developed a gas market model. The gas market model is a least-cost dispatch model, which minimises supply costs for the entire European area by choosing optimal supply routes for each month of the modelled years 2020, 2025 and 2030. The features of the model are aligned with our findings on the key drivers of the price formation:

- **Price formation based on a single reference price for Europe and net back logic for all other suppliers:** The model tries not to predict absolute price levels, but rather focusses on the relative price differences. This is in line with our above findings, that typically absolute price levels in all market depend on the same overall supply/demand situation in Europe, with regional prices mainly differing by transport costs. We have therefore assumed the absolute level of gas prices based on the assumption, that LNG will be of the marginal source to the European gas market in the future. The modelling approach therefore abstracts from modelling the supply function of inframarginal sources (though storage is explicitly considered). Instead it is assumed, that supply sources behave as price takers, with a volume target (following the net-back-logic). We assume the supplier's volume target to fit to the actual demand, so that a competitive equilibrium is reached among suppliers.

Our approach is tailored to the project scope, as we evaluate differences in the market outcomes between a “with-merger” scenario and a “without-merger” scenario. Being based on net-back pricing for all suppliers but LNG, the approach allows us to isolate the merger effect under a minimal set of assumptions on the price-formation mechanism.

- **Minimisation of gas transport flows and storage usage:** Within the modelling framework gas transport flows and storage usage are optimised endogenously to minimise supply costs to the EU, under the constraints given by transportation and storage capacity limitations. Gas flows are determined in such that geographic arbitrage opportunities are removed, while storage use reduces intertemporal arbitrage opportunities. As a pure endogenous optimisation of gas storages (with perfect foresight) might lead to unrealistic storage patterns, constraints are taking into account to mimic a realistic use of gas storages, based on historical information (e.g. requiring minimum filling level).
- **Flows at the entry point to Europe are allocated endogenously by the model:** Within the described competitive interactions among gas suppliers, the redistribution of the target volume from any given supplier is calculated endogenously by the model for each entry point from the supplier to Europe (if more than one exists[10]). Within the model entry flows are optimised endogenously to minimise transportation and storage costs – and thereby supply costs – to Europe.

The outcomes of the gas market model are:

- **Gas price differences** between, on the one side, Austria and Italy (in the “without merger” setting) or Austria & Italy (in the “merger” setting), and any reference node.
- **Optimal gas flows** in the EU gas network
- **Optimal usage of storage** in the EU gas network
- **Tariff revenues** for the Austria and Italy system operators (and congestion rents accruing to the auctioning of capacities in case of scarcity).

We remark that in order to assess the implication of the Austria-Italy zone merger we need to assess only the price difference in the “with merger” and “without merger” settings. Under our characterization of the price formation system prevailing in Europe, the European gas price – net of transmission costs – is independent of the market zone topology. Consequently, any gas price changes resulting from zone merger in Austria and/or Italy are entirely related to transmission and possibly storage, i.e. they are caused by changes in transmission tariffs and by corresponding changes, if any, in the optimal gas flows on the network.

More details on the model used to quantify the effects of the market zone merger can be found in Annex A.

[10] For instance, Russian gas may be allocated across the entry points to Slovakia (via Ukraine), Poland (via Belarus), or Nord Stream (to Germany). Analogously, LNG may be allocated across the different terminals in Europe

2.2.2 Price-formation model description

A detailed description of the mathematical model is given in Annex A. We present here the main features of the model in a less technical way, in order to highlight the connections with the price-formation mechanism and implications described in the above Section.

The model is a linear mathematical program that minimizes an objective function under a set of constraints. The model has monthly granularity and spans a yearly time interval.

Decision variables

The decision variables optimized by the model are the *flows* along the interconnection between European countries, as well as between suppliers (including LNG facilities) and entry points to Europe, and between EU countries and storage facilities.

Objective function

The objective function is given by the sum of:

- total transportation and storage cost for Europe, calculated with monthly granularity over a time period of one year. Storage and transportation costs are calculated by multiplying a variable cost (the "tariff"[11]) by the optimal flow calculated by the model.
- LNG supply cost, calculated by multiplying the LNG reference price (see the previous Section), time the optimal import flow from LNG facilities as calculated by the model.

Constraints

The following constraints are added to the model:

- **Energy balance**. For each month and country, the net sum of inflows and outflows in each country must be equal to the consumption
- **Transportation capacity**. For each month and interconnection, the gas flow cannot exceed a given capacity (either for transmission of regassification)
- **Storage capacity**. For each month and storage facility, the stored gas cannot exceed a certain level
- **Storage cycle**. Over the storage year (April – March), no gas can be left into storage
- **Supply constraints**. For each supplier other than LNG, and for each month, the exported gas volume must not exceed a given level.

Note that at the heart of our model lies the interaction between the "Energy balance" and the "Supply constraints". The structure of the gas market in Europe is in fact such that supplied volume from non-LNG suppliers (Russia, Norway etc)

[11] For transportation, this is given by the sum of exit and entry tariffs, in €/MWh. When no entry and exist tariffs exist buth rather a single transit tariff, such as in the case of Switzerland, the full transit tariff is used by the model

is less than the total demand in Europe. This implies that the model will select LNG suppliers to fill the remaining demand. Since the usage of LNG “switches on” a cost term in the objective function[12], given by the LNG reference price, competition among suppliers will determine their price as relative to this reference level minus the transportation costs – i.e., via the “net-back logic”.

Note that in months of high demand (winter), storage may be used to satisfy demand, reduce congestions and lower system costs. However, due to the “Storage cycle” constraint this implies that additional demand is created in the summer months, to fill the storages.

2.3 Scenarios modelled

To quantify the effects of the market zone merger we define a base scenario and three variations of that scenario. The scenarios are all largely based on information from the TYNDP and cover the years 2020, 2025 and 2030. In the following we will briefly describe the scenarios used.

2.3.1 Description of base scenario

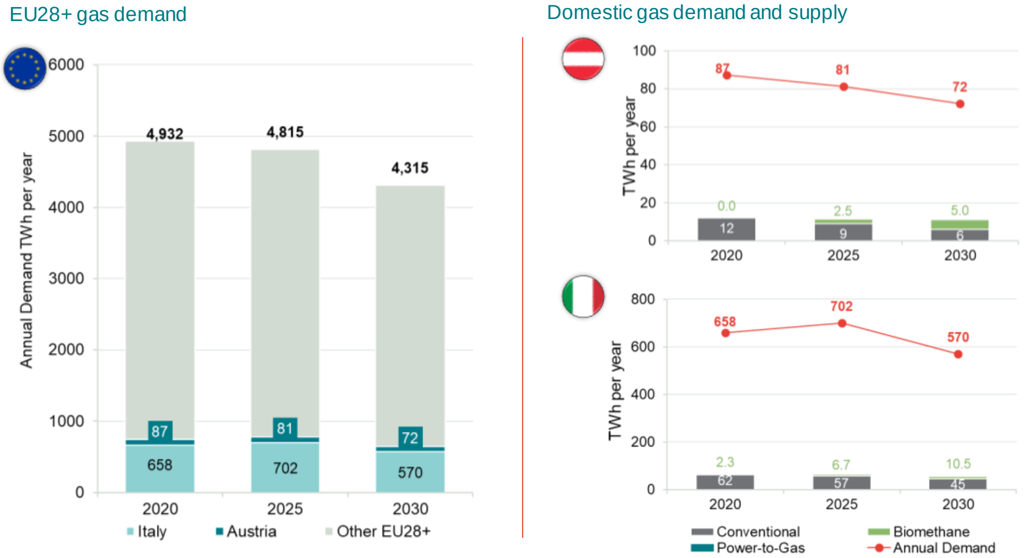
The base scenario relies on information from the TYNDP 2020 and the TYNDP 2018, where newer data is not yet available.

Gas demand based on TYNDP 2020 National Trends scenario

Gas demand and indigenous gas production in the base scenario follows the National Trends scenario of the TYNDP 2020. For Austria additional biomethane production of 2.5 TWh in 2025 and 5 TWh in 2030 were added to reflect ambitions for carbon emission reduction plans of the Austrian government which were not yet covered in the TYNDP 2020.

[12] We stress that non-LNG suppliers implicitly have zero-cost in the objective function, i.e. we make no assumptions on the cost structure of non-LNG suppliers. Suppliers prices are determined as “shadow prices”

Figure 5 Gas demand and indigenous production



Source: DFC/Frontier Economics based on TYNDP 2020 National Trends

Note: No Power to gas production expected in National Trends, gas before coal; Not all countries in EU28+ included. Malta & Cyprus not modelled

Supply scenario assumes pipeline gas supply within TYNDP 2020 range

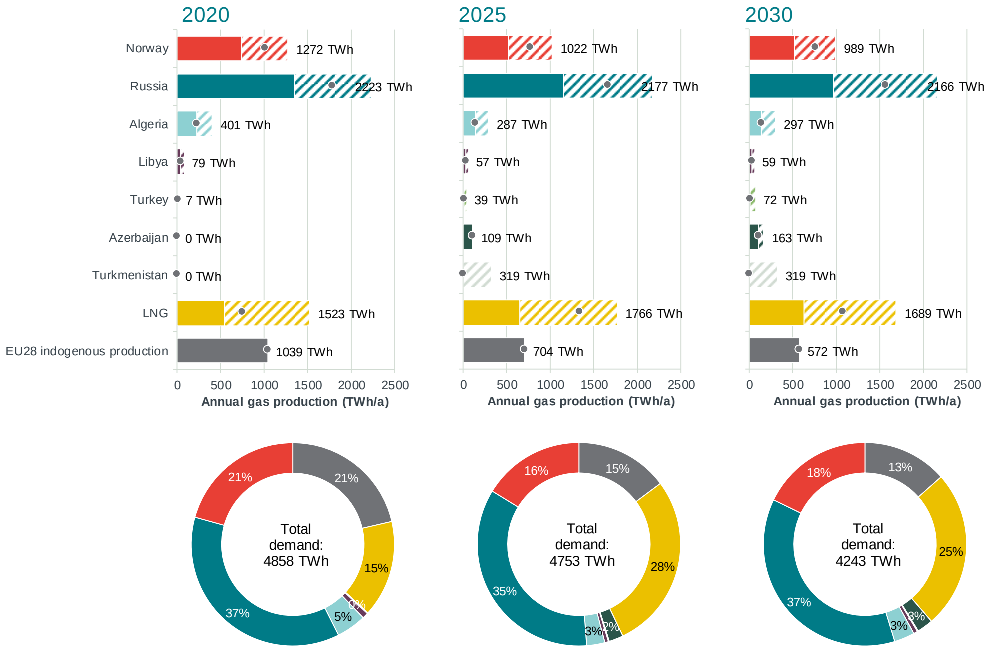
As the model to quantify the price effects of the market merger derives supply prices based on a netback-logic from the marginal supply source and fix supply volumes, the scenario definition only includes assumptions on these supply volumes.

For the base scenario supply volumes have been derived from the TYNDP 2020. TYNDP 2020 provides minimum and maximum supply volumes for each supply source and thereby defines a supply range for each source. (Figure 6) For these scenarios we assume:

- Indigenous production in line with TYNDP 2020 (no range),
- Gas supply from Norway and Russia equal to the average of the minimum and maximum supply volumes of the TYNDP 2020.
- Gas supply from Algeria, Libya, Turkey, Azerbaijan and Turkmenistan equal to the minimum supply volume of the TYNDP 2020, and
- Gas supply from LNG equal to the residual of demand and before mentioned supply sources.

The scenario thereby reflects how indigenous production and gas supply from Norway is declining over time, while gas supply from LNG is increasing.

Figure 6 Gas supply over time



Source: DFC/Frontier Economics based on TYNDP 2020

Note: Supply and demand volumes reflect modelled region, i.e. excl. Malta and Cyprus. Filled bars in chart indicated minimum supply volumes assumed in TYNDP 2020. Striped bars and number indicate maximum supply volumes assumed in TYNDP 2020.

Infrastructure and regulation

With regard to infrastructure and regulation the scenario relies on information from TYNDP 2018 (TYNDP 2020 data was not available at the time of definition of the scenarios). For the scenario all infrastructure projects with a final investment decision have been taken into account. In addition to this we assume Nord Stream 2 and the TAP pipeline to be commissioned after 2020.

Similar to the infrastructure, we apply tariffs as assumed in the TYNDP 2018[13] and assume them to remain constant over time. One exception from this are transmission tariffs of interconnections with Germany. Here we assume that the tariffs will increase from 2025 onwards as a result of the market zone merger of NCG and Gaspool and the accompanied loss in tariff income from gas transport between both regions.

In contrast to this we assume the reduced tariff income from the market zone merger of Austria and Italy not to be compensated by higher tariffs on interconnection pipelines. Instead we implicitly assume that these revenues will be recovered by increasing exit tariffs to end customers.

2.3.2 Description of alternative scenarios

In addition to the base scenario three additional scenarios have been explored (Figure 7):

[13] TYNDP 2018 transforms capacity tariffs (€/MWh) into tariffs per unit of commodity by applying a load factor. See TYNDP 2018 Annex D, p.8

- **Scenario 2** explores the impact of an increase in transmission capacity of the TAP. Additional investment into compressors could double the TAP capacity. As we assume the capacity in TAP to be backed-up with long-term supply contracts[14], these additional supply volumes would reduce supply to Europe from other sources. For this scenario we explore two options in this regard: (i) LNG supply is reduced, (ii) supply from Russia via continental pipelines is reduced.
- **Scenario 3** explores the impact of the BACI pipeline which would provide a direct connection from the Czech Republic to Baumgarten and thereby the option to bypass Slovakia when transporting gas from Germany to Austria.
- **Scenario 4** looks at the effect of the market zone merger when Slovakia cannot be supplied via Ukraine. As such a scenario would mean that a significant amount of gas from Russia is not supplied via this route, gas needs to be supplied via another route. Here we look at two alternative supply options: (i) where gas transits via Slovakia are replaced by additional LNG imports and (ii) where gas is rerouted via the northern continental pipelines from Russia (Yamal).

Figure 7 Overview of scenarios modelled

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Demand Side	National Trends demand scenario	National Trends demand scenario	National Trends demand scenario	National Trends demand scenario
Supply Side	TYNDP 2020 supply scenario	Increased TAP supply and reduction in LNG or RU supply	TYNDP 2020 supply scenario	Disruption of supply via Ukraine (no transits via Slovakia)
Infrastructure	TYNDP 2018 FID projects	TYNDP 2018 FID projects + TAP expansion	TYNDP 2018 FID projects + Baczi & Hungarian	TYNDP 2018 FID projects
Regulation	Default tariffs	Default tariffs	Default tariffs	Default tariffs

Source: DFC / Frontier Economics

[14] See TPA exemption for the TAP pipeline: https://ec.europa.eu/energy/sites/ener/files/documents/2013_tap_decision_en.pdf

3 RESULTS OF MODEL-BASED ANALYSIS

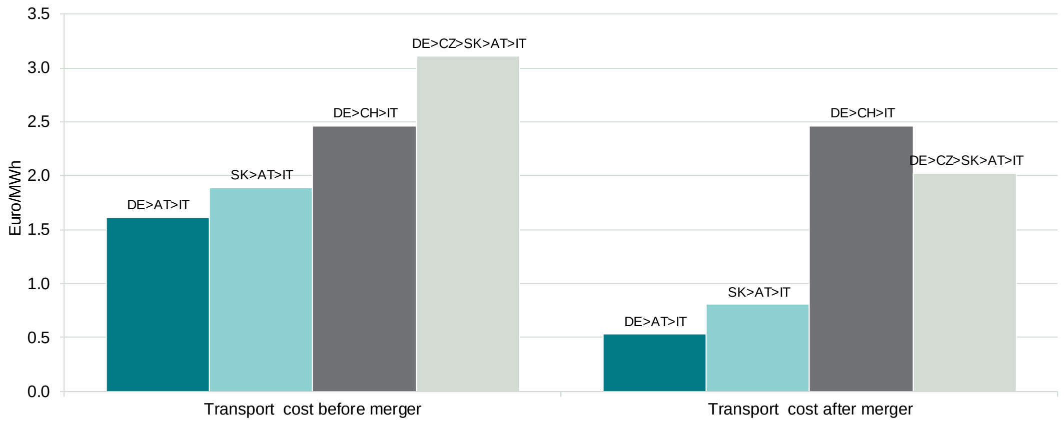
The Central European gas market is highly integrated and is supplied with gas through different transport routes. As gas gets distributed through the highly connected pipeline network across Europe, several supply routes may lead to the same destination. Assuming perfect competition, the cheapest transport route will be used more extensively compared to more expensive routes. A merger of market zones eliminates entry- and exit fees at the borders and, therefore, effectively reduces the costs of transport for certain routes (we abstract for the time being from potential 2nd round effects if reduced revenues are compensated through increased tariffs at the remaining point). Consequently, the merger of the Italian and Austrian market zone might affect the utilisation of supply routes.

Figure 8 illustrates the transport costs of gas to the Italian market for four exemplarily supply routes before and after the merger. Before the merger, supply via Austria to Italy is the cheapest, whether from Germany or Slovakia. It follows transport from Germany through Switzerland, only surpassed by supply from Germany through the Czech Republic, Slovakia and Austria. With a merger of the Austrian and Italian market zones, the transmission fee at the border will be omitted, resulting in (ceteris paribus) lower transport costs for pipelines transiting Austria. In contrast, the costs of transport through Switzerland will remain unchanged. Consequently, those altered cost structures might result in modified gas flows. Supply routes which have become cheaper might be used more, on the other hand transportation of gas through Switzerland might diminish. As a result, congestion that occurs under the setting of separated market zones may be resolved, while new congestion in other places could possibly appear.

It has been outlined previously that producers of gas operate typically according to a net-back logic, i.e. prices of gas are based on the price in the target market (typically reflecting the cost of the marginal supply source) and transport costs. Hence, the differences between gas hubs of different countries usually reflect the costs of transport, which are to a large part determined by the transmission tariffs. In the case of congestions, gas cannot be transferred sufficiently to balance prices and the difference in hub prices would increase, reflecting the value of additional capacity for such events (congestion rent). As a result, altered flows and lower transportation costs might systematically influence relative gas hub prices. Due to the increased usage of transport routes through Austria, higher flows at the interconnector might cause congestions, which will impact the price structure at the gas hubs. Those effects are examined in the following chapter.

In this section we quantify the price effects described qualitatively above by applying the described gas market model. Note that the analysis focuses on the 1st round price effects of the market zone merger. Additional effects of the market zone merger, such as potential 2nd round effects through a changed tariff system or increased liquidity and competition are not addressed in the analysis but should be considered as part of a full cost-benefit analysis of the market zone merger.

Figure 8 Comparison of transport costs for different selected supply routes to Italy before and after the market zone merger



Source: DFC/Frontier Economics

3.1 Results of base scenario

In this section we describe the effects of the market zone merger in the base scenario.

3.1.1 Impact of market zone merger on gas flows

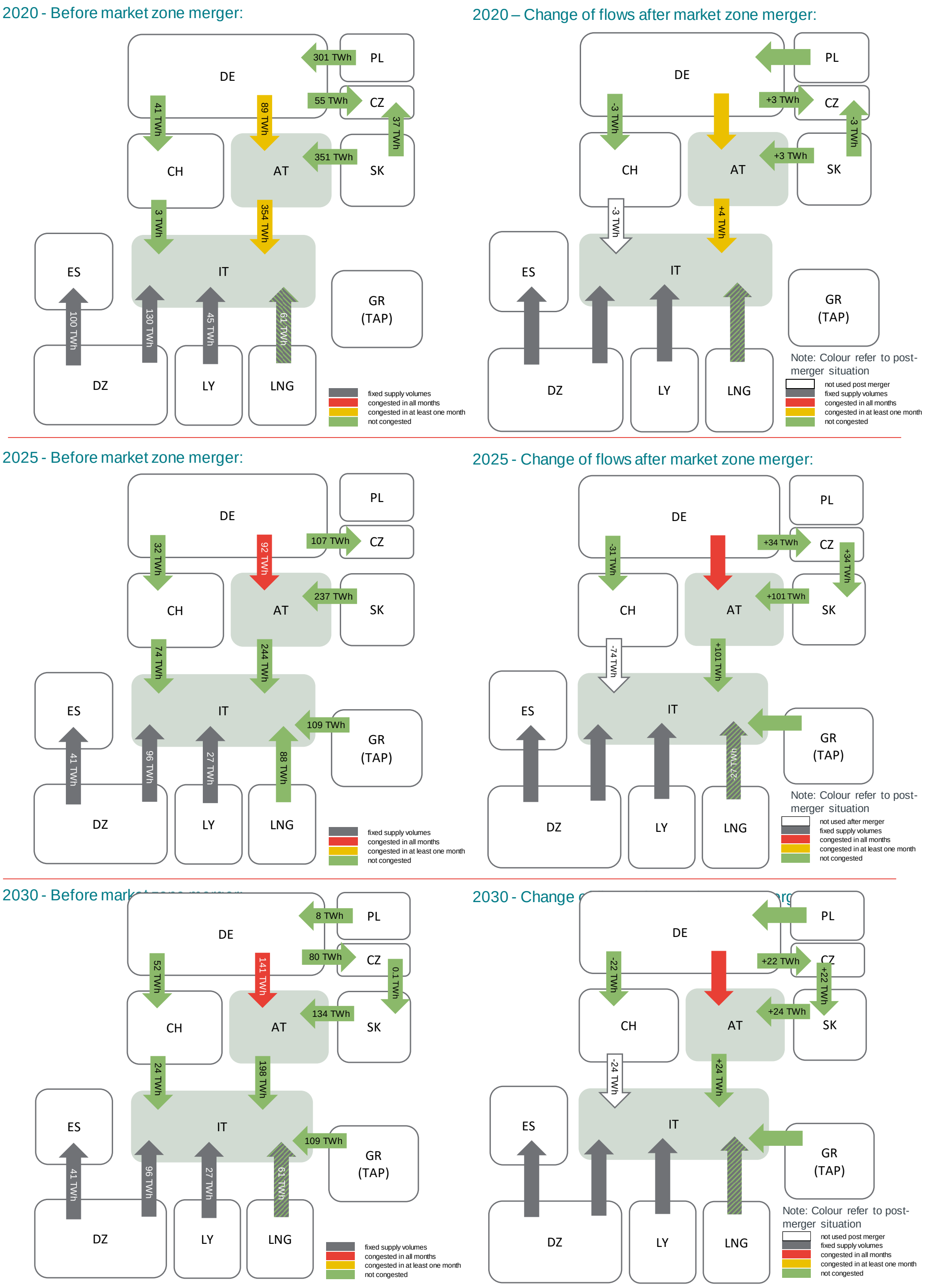
Market zone merger results in temporarily replacement of Switzerland transits and LNG

Before the market zone merger, Austria is supplied via Germany and Slovakia. While the route from Germany to Austria is congested in most months on 2020 and throughout the year in 2025 and 2030, the route from Slovakia to Austria is not fully utilised. Before the market zone merger, the Italian market is supplied via Algeria, Libya, Switzerland, Austria and by LNG. After 2020 TAP provides an additional supply route. From these supply routes, the route through Switzerland is only used to a lower extend. The route from Austria to Italy on the other hand shows a higher utilisation and is congested in some months in 2020 (but not anymore after 2020 as gas is also supplied via TAP to Italy).

Removing the tariff on the Tarvisio/Arnoldstein interconnection by merging the market areas makes supplying Italy via Austria ceteris paribus more attractive relative to other supply routes.

In the modelled years we therefore observe a change of gas flows, as transit from Germany to Italy through Switzerland ceases and is substituted by transit via Czech Republic, Slovakia and Austria and additional supply from Russia via Slovakia. Also some LNG imports are substituted by pipeline gas coming via Slovakia (Figure 9). Across the years modelled we observe that this effect is strongest in 2025.

Figure 9 Change in regional annual gas flows



Source: *DFC/Frontier Economics*

Note: *Flows through Slovenia not illustrated. LNG supply route marked as fixed and not congested in case fixed lower supply bound is reached. Blank arrows on the right-hand side indicate no change of flows because of the market zone merger*

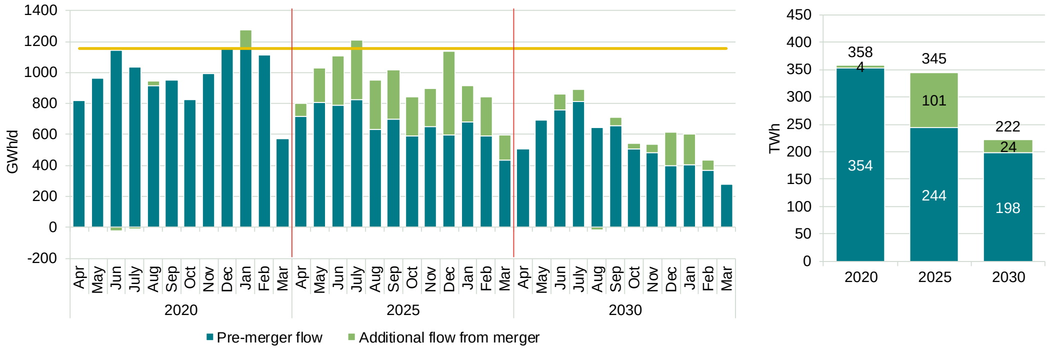
Market zone merger increases gas flows on Tarvisio-Arnoldstein pipeline, however no significant congestion

Looking more closely on the effects of the market zone merger on the Tarvisio-Arnoldstein pipeline gas flows we observe that the before the merger the pipeline is expected to be congested in two months (December and January) in 2020. After the merger flows increase and some congestion also occurs in 2025. No congestion can be observed in 2030. Congestion volumes after the market zone merger are:

- 3.9 TWh in 2020, and
- 1.7 TWh in 2025.

Overall decreasing demand in Italy and the commissioning of the TAP after 2020, lead to a reduction of gas flows on the Tarvisio-Arnoldstein pipeline over time making congestion less likely in the future.

Figure 10 Flows on the Tarvisio-Arnoldstein Pipeline before and after the market zone merger



Source: DFC/Frontier Economics

3.1.2 Impact of market zone merger price formation

The market zone merger only leads to a change of gas flows between Austria and Italy and the wider region. While LNG still remains the marginal supply source for Europe, the change of gas flows and potentially congestions, have an impact on the market zone prices (which are based on the marginal supply cost).

Post-merger we expect an alignment of prices of the Austrian and the Italian market area. As before the merger prices in Italy were higher than in Austria, this can be achieved by a price increase in Austria or by a price reduction in Italy, depending on the marginal supply route in the respective markets. The price increase in Austria or the price reduction in Italy is therefore determined by the marginal supplier in the merged markets. In extreme situations

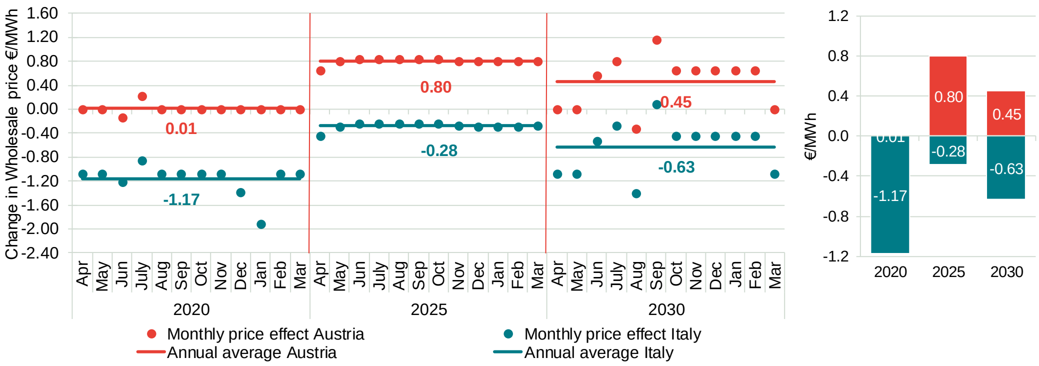
- the former Italian marginal supplier might become the marginal supplier to the merged market, resulting in a market price post-merger on the Italian level;
- or the former marginal supplier to Austria has enough volume to supply both markets, resulting in a price on Austrian level.

- In between these extremes there is the possibility for a situation, where the marginal supplier to the whole market is a route, which is inframarginal in Italy pre-merger, resulting in a price level for the whole market between the former two prices in both areas (i.e. AT becoming slightly more expensive, IT becoming slightly cheaper).

Overall the exact price effects will therefore depend on the specific supply situation. For the years analysed here we observe that (Figure 11):

- For the scenario year 2020 the market zone merger leads to a reduction in gas prices in Italy up to a level of the Austrian price levels, i.e. prices in Austria remain largely the same.
- For the scenario year 2025 the price in Italy decreases again, however this time to a lesser extent. Further to this we observe a price increase in Austria.
- For the scenario year 2030 the price effect is again split between a price reduction in Italy and a price increase in Austria.

Figure 11 Base scenario price effects



Source: DFC / Frontier Economics

3.1.3 Distributional effects of market zone merger

The change in prices leads to a range of distributional effects which we show in below for Europe (Figure 12) and specifically for Austria and Italy (Figure 13).

The distributional effects for Europe show how the price changes as a result of the market zone merger changes consumer rent, supplier rent, income of storages and TSO income consisting of tariff income and congestion rents[15]:

- For 2020 we observe that the price effects lead to an increase in consumer rent as only prices in Italy are reduced and prices in other market areas remain almost the same. This rent is sourced by lower supply prices (i.e. supply price

[15] Change in consumer rent is calculated as the difference in the value of gas consumption (volume x price) before and after the merger. A positive value indicates a consumer benefit (i.e. gas has become cheaper).

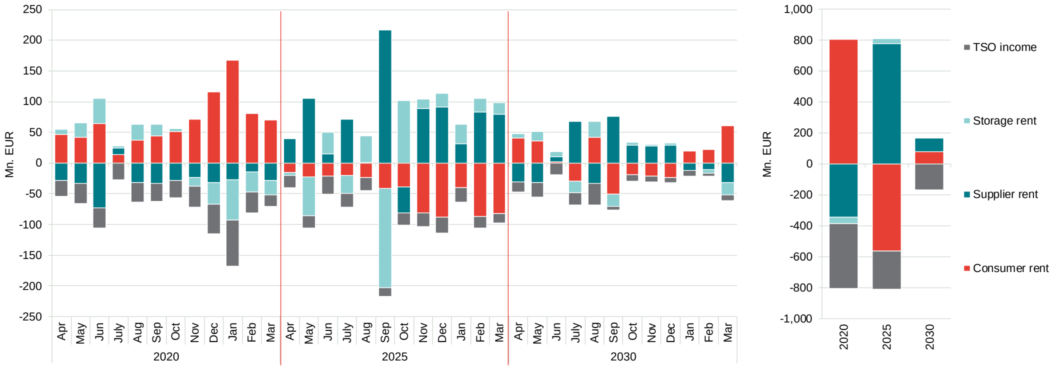
Similarly a change in producer rent is calculated as the difference in the value of gas supply (volume x price) before and after the merger. A positive value indicates a supplier benefit (i.e. gas has become more expensive). Like for pipeline and LNG supply, the change in storage income is negative if income is reduced.

The change in TSO income comprises the change in tariff income (product of tariff and transmission volume) and congestion income (product of congestion rent and transmission volume). A negative value indicates that TSO income has fallen as a result of the merger.

of gas from LNG, Algeria and Libya to Italy is reduced) and by a reduction in tariff and congestion rent income (largely at Tarvisio-Arnoldstein).

- For 2025 we observe the market equilibrium to lead to a price increase in Austria and also in other markets in NWE. As a result, the consumer rent in the European market area is negative, i.e. the price reduction for consumers in Italy cannot outweigh the price increase for consumers in Austria and the NWE market. Like in 2020 we also observe a reduction in TSO income, again largely because of the reduced tariff at Tarvisio-Arnoldstein. In contrast to reduced consumer rent and TSO income, supplier rent increases. This is largely explained by pipeline suppliers from Norway and Russia profiting from higher prices based on more expensive marginal suppliers in the markets.
- In 2030 the price increase in Austria is lower and the increase in consumer rent in Italy is higher than the reduction in consumer rent in Austria and the NWE market. This benefit largely comes from a reduction in TSO income, again driven by reduced tariff income at Tarvisio Arnoldstein.

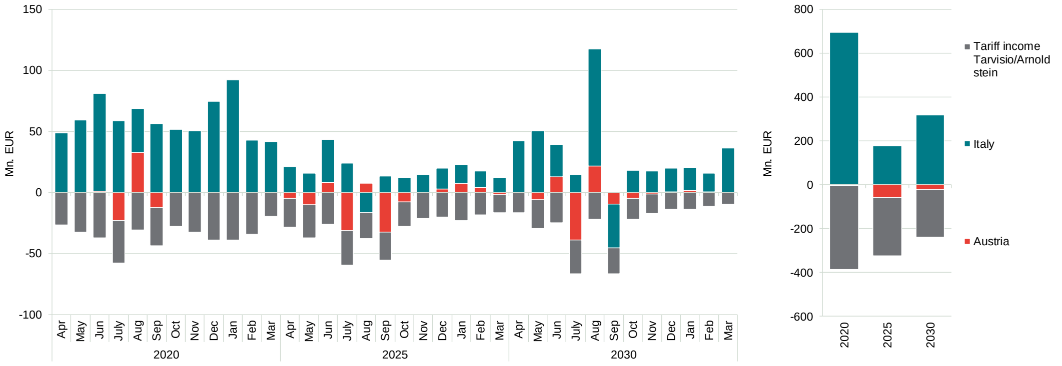
Figure 12 Base scenario distributional effects in modelled region.



Source: DFC / Frontier Economics

Looking more closely to the distributional effects between Austria and Italy we observe a more consistent picture. Italy largely benefits from price reductions: consumer benefit while indigenous gas producers receive a lower price. In contrast to this we observe no positive distributional effects for Austria as price increases for consumer outweigh the benefit of the price increase for indigenous producers. Further to this, tariff income on the Tarvisio-Arnoldstein pipeline is reduced by the merger. As TSOs will be allowed to increase other tariffs to compensate for that, this could further reduce any consumer benefits in Austria and reduce the potential gain to consumers in Italy. However, as demand in Italy is falling over time and new supply options to Italy emerge, tariff income on the Tarvisio-Arnoldstein pipeline is falling in general (and irrespective of market integration).

Figure 13 Base scenario distributional effects between Austria and Italy



Source: DFC / Frontier Economics

Note: Distributional effects for Austria and Italy include national consumer effects, indigenous producer effects and changes in national storage rent.

3.2 Results of alternative scenarios

Below we summarise our findings for the alternative scenarios. Figure 14 shows gas flows on the Tarvisio-Arnoldstein pipeline and how they change as a result of the market zone merger. Further we show how this results in price effects in Austria and Italy. Figure 15 illustrated the distributional effects of the market zone merger for the whole European market and for Austria and Italy specifically.

Scenario 2 – TAP expansion reduces flows on Tarvisio-Arnoldstein pipeline and prevents prices in Austria to increase after merger

The TAP pipeline is expected to be operational at the end of 2020.[16] Doubling the capacity of TAP is therefore also assumed to be effective from 2025 onwards. Modelling results for 2020 are therefore the same as in the base scenario. For the years 2025 and 2030 two options have been explored to which supply is reduced in order make room for additional supply via TAP:

- In one LNG supply is reduced,
- in the other supply from Russia is reduced.

In the variation where global LNG supply is reduced, we see overall gas flows from Austria to Italy being reduced (Italy is already well supplied with the extended TAP supply). Utilisation of the Tarvisio-Arnoldstein pipeline is therefore low in years 2025 and 2030 (in 2025 212 TWh instead of 244 TWh and in 2030 114 TWh instead of 198 TWh). The merger leads to additional gas flows from Austria to Italy in 2025, which supplied via the routes Germany-Slovakia and Russia-Slovakia. Due to relatively low demand in 2030 we do not see significant additional flows from Austria to Italy as a result of the merger.

In the case where Russian supply is reduced, we see again relatively low gas flows from Austria to Italy in the pre-merger situation (in 2025 137 TWh instead of 244 TWh and in 2030 73 TWh instead of 198 TWh). The reason for this is again that

[16] See report by TAP AG: "First gas deliveries to Europe via TAP will start by the end of 2020." https://www.tap-ag.com/news/news-stories/trans-adriatic-pipeline-completes-offshore-section

Italy is already well supplied by the TAP pipeline. However, in case Russian supply is adjusted, the relatively higher LNG supply levels provide more flexibility to move LNG supply between different LNG facilities. LNG supply to Italy can therefore effectively be reduced to make room for additional supply from Russia to Austria. Hence the merger effect on gas flows we observe is slightly larger.

Scenario 3 – BACI pipeline provides cheaper supply option to Austria enabling additional imports from Germany and limiting price the price increase after the merger.

The BACI pipeline will provide a connection between the Czech Republic and Baumgarten and thereby provide an option to bypass Slovakia when transporting gas from Germany via the Czech Republic to Austria. Overall this reduces transport cost for additional supply from Germany to Austria and Italy.

For 2020 we see that the introduction of the BACI pipeline does not have a significant impact on the pre- and post-merger situation. This is because in 2020 other routes present cheaper supply options (i.e. the Czech Republic is supplied via both, Germany and Slovakia). The reduction in transport costs to Italy as a result of the merger does therefore not lead to additional supply from Germany to Austria and Italy. Instead additional gas to supply Italy is sourced via Slovakia (like in the base scenario)

With the introduction of Nordstream 2 after 2020 we see an increase in supply volumes in the NWE market. Hence in the years 2025 and 2030 we see the BACI pipeline being used to transport Gas from Germany via the Czech Republic to Austria and onwards to Italy. As a result, pre-merger flows on the Tarvisio-Arnoldstein pipeline are higher for those years (268 TWh compared to 244 TWh in the base case). As Italy is already well supplied, removing the market zone merger leads to little additional flows. The result of this is that prices cannot increase after the merger as much as in the base case.

Scenario 4 – Ukraine Transit disruption

In this scenario where no gas is supplied from Russia to Slovakia via Ukraine transits, we look at two options which could replace volumes from this supply source:

- One is that global LNG effectively increased,
- the other one is that Russia will reroute gas supply from Transgas to Yamal pipeline.

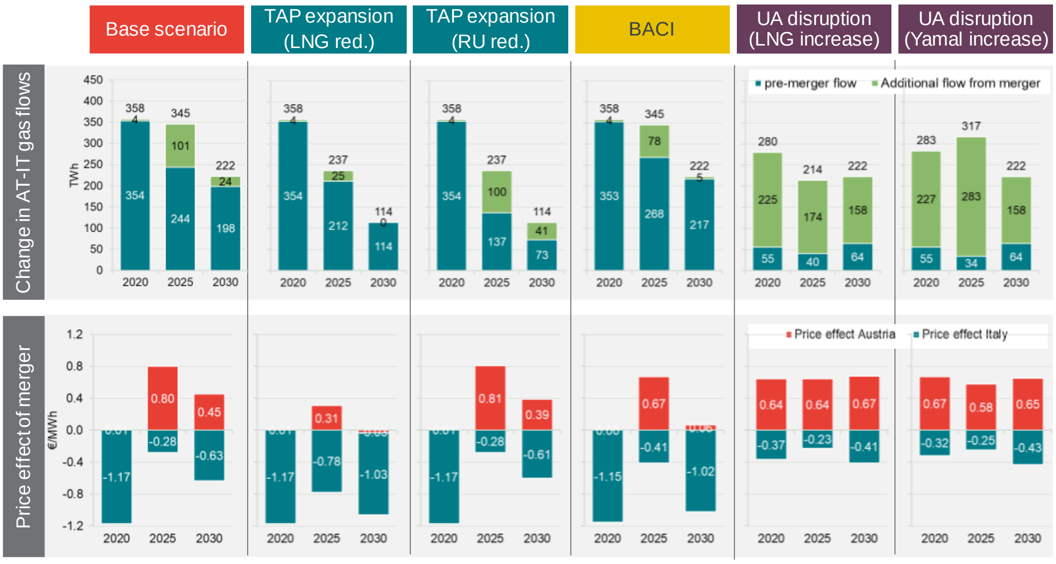
In both cases we observe low gas flows from Austria to Italy prior to the merger, i.e. gas supply:

- in 2020 is 55 TWh instead of 354 TWh,
- in 2025 is 34 TWh instead of 244 TWh, and
- in 2030 is 64 TWh instead of 198 TWh.

This is because supply to Italy via LNG or via Switzerland represents a cheaper supply route than gas supply from Germany via the Czech Republic and Slovakia. Removing the tariff between Austria and Italy however changes this and increases supply via Germany, the Czech Republic and Slovakia drastically to the detriment of Northern Europe to Italy transits via Switzerland and LNG imports in Italy.

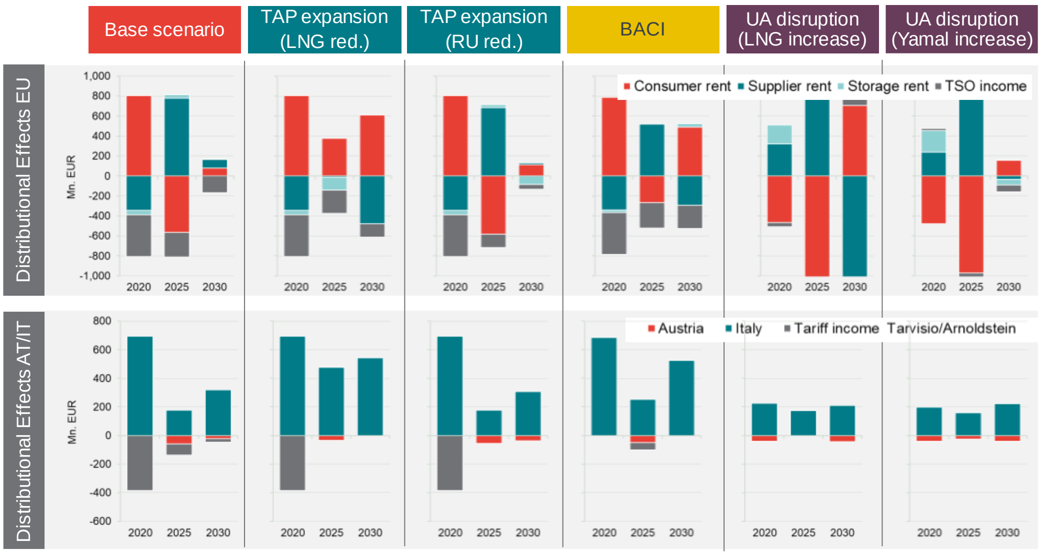
As a result, the gas price in Austria increases to the net-back price from Germany but is limited by the transmission tariff of the Switzerland route.

Figure 14 Effect of merger on gas flows on Tarvisio-Arnoldstein pipeline and price effects of merger on Austria and Italy



Source: DFC/Frontier Economics

Figure 15 Distributional Effects for complete modelled region and Austria/Italy



Source: DFC/Frontier Economics

3.3 Sensitivity Analysis

The gas market model optimises gas transportation costs, gas storage costs, LNG terminal costs by choosing cost minimising gas flows and entry flows, while assuming fixed supply volumes per source. In this scenario suppliers are assumed to be price takers. We have therefore undertaken two sensitivity analysis, in which we

- change Russian supply volumes in order to see whether the results are sensitive to the fixed supply volume assumption, and
- remove the endogenous entry flow optimisation for Russian supply and replace it with a fixed entry flow split between Transgas and Yamal.

The sensitivity analysis has been conducted for the base scenario.

Model results are not sensitive towards higher Russian supply shares

The sensitivity analysis shows that distributional effects of the market zone merger do not change significantly (less than 1%) when increasing or decreasing the Russian supply share by up to 10%.

Model results are sensitive towards alternative entry flow splits of Russian gas supply

With regard to the sensitivity on endogenous entry flows of Russian supply we observe that allowing for a price differentiation between Transgas and Yamal can lead to significant variations in the distributional effects of the market zone merger.

We would like to comment that this finding should be interpreted with caution, as:

- the sensitivity only changes the option for price differentiation at Russian entry points,
- total supply volumes in the model are still fixed, and
- the behaviour of other suppliers is assumed to stay the same, which might not necessarily be true in reality.

However, the sensitivity shows that in case the assumption underlying the gas market model of a competitive European gas market is not valid, the distributional effects of the market zone merger might be different.

4 SUMMARY OF FINDINGS

European gas market is characterised by a high degree of integration

We have established that the European gas market is well integrated and that prices between countries usually only differ by transport costs. While price differences can increase due to congestion and can be lower due to long-term capacity bookings these effects are overall neglectable because of the few congestions in the European gas network and due to the expiring long-term capacity bookings. In this framework the whole European market has a marginal supplier and prices in countries are derived based on this marginal supplier and the network tariffs for gas flows within Europe. It can be assumed that LNG is this marginal supplier in typical situations (i.e. most or all of the time).

Additionally, we find that Europe is well endowed with gas storage capacity. Gas storage facilities take advantage of intertemporal arbitrage opportunities (i.e. price difference) and thereby modulate fluctuating gas demand over the year. This allows for gas suppliers to supply gas with a flat production profile. It also means prices are well integrated over the year and temporal price differences (as e.g. observed in forward markets[17]) are driven by the cost of storage.

Modelling approach is based on key features of the gas market

Taking into account these key features of the gas market, we quantify the effects of the market zone merger based on a model with fixed supply volumes where market and supply prices are derived on a net-back-logic to the marginal gas price to Europe (LNG). The model minimises gas transport and gas storage costs by choosing optimal storage volumes and gas transport flows. Resulting gas flows thereby reduce geographic and intertemporal arbitrage as we would expect it to happen under perfect competition.

The market zone merger is modelled by removing the tariff from the Tarvisio-Arnoldstein pipeline and by removing any capacity restriction from this pipeline. For the purpose of this study, it has been assumed that the missing tariff income is recovered by increasing exit tariffs to end customers.

Market zone merger increases gas flows from Austria to Italy but only leads to limited congestion

The market zone merger makes gas flows from Austria to Italy cheaper. As a result, gas flows on this route increase. The additional gas flows are sourced indirectly from Germany (via the Czech Republic and Slovakia) and replace gas supply to Italy from Switzerland and from LNG.

While the market zone merger increases gas flows on the Tarvisio-Arnoldstein pipeline physical congestion only occurs in a few months (3.9 TWh in 2020 and 1.7 TWh in 2025). As the commissioning of TAP after 2020 provides an additional supply route to Italy and overall gas demand in Italy is declining, gas flows on the

[17] Day-ahead prices in the course of the year may also differ for other reasons such as changes in expectations regarding supply and demand of gas.

Tarvisio-Arnoldstein pipeline decline over time and we expect no congestion in 2030.

After merger prices in Austria and Italy align by Austrian prices increasing and Italian prices decreasing

As there will be only one wholesale price after market integration, the gas market wholesale price in Austria and Italy will align as a result of the merger. This happens by Austrian prices increasing and/or Italian prices decreasing. How exactly the price difference before the merger is translated into price increases or decreases for each of the countries depends on the supply situation in each year and the marginal supplier. While for 2020 we find that price is only reduced in Italy to the level of Austrian prices, the results for 2025 and 2030 show a mixed picture of price increases in Austria and price reductions in Italy.

The distributional effects of the merger therefore show, that Italian consumers can benefit from the market zone merger. If prices are however increasing in Austria it is likely that prices in other parts of NWE will increase as well, which can quickly result in a negative effect of the market zone merger on consumer rent in Austrian and also Europe more widely.[18] In this event suppliers benefit from the increased prices and reduced tariff income.

Tariff increase at Baumgarten might prevent transfer of rent to suppliers but will lead to increase of prices in Austria

For the analysis we assumed that the forgone tariff income from Tarvisio-Arnoldstein will be recovered by higher exit tariffs to end costumers (i.e. payed by consumers). Another option would be to recover the missing tariffs by increasing entry tariffs at Baumgarten and thereby preventing suppliers to extract the rent from the market zone merger. However, as the model indicates that supply from Slovakia is often the marginal supply route to Austria, we expect this to lead to a price increase in Austria. The exact effects of such a tariff increase would need to be quantified by additional analysis.

More generally, the tariff design after market integration has a significant impact on the distributional effects outlined in this study. This means tariff design can be used to reduce or adjust distributional effects; it also means the findings of this study need to be interpreted in the context of the tariff assumptions made.

[18] This general finding is irrespective of the fact that TSO will levy the forgone Tarvisio-Arnoldstein revenue onto other grid users in Austria and Italy (which reduces net-benefits to consumers in both countries but not the overall conclusion in this section).

ANNEX A DESCRIPTION OF GAS MARKET MODEL

This Annex presents a detailed description of the model used to analyse the AT/IT market merger. The model implemented is a least-cost dispatch model for natural gas across the European network, which assumes that suppliers pursue targets in terms of supply volumes to EU and implement net back pricing. The "cost" being minimized is the total supply cost (i.e., including transportation, storage and regassification) for the entire Europe.

In order to describe the functioning of the model we introduce a stylized representation of the gas network, based on the TYNDP 2018 transmission capacities, gas storages and LNG regasification capacities. We then discuss the objective function for the model and discuss how net back pricing is ensured in the determination of the equilibrium prices. Finally, we present the additional technical constraints for the model and presents the full mathematical formulation of the model.

Nodes

Nodes represent either consumer market areas (e.g. Austria or Italy), or supplier countries (such as Russia and Norway). Additional supply nodes are introduced to model indigenous production in each EU country, and LNG facilities across Europe. LNG nodes are somewhat "special" in the model formulation, as discussed below, so we keep them separate from "pipeline" supply nodes. Finally, storage facilities are also modelled via additional nodes:

- N_C: Consumer market areas,
- N_P: "Pipeline" supply countries and indigenous production nodes,
- N_{LNG}: LNG facilities,
- N_S: storage facilities.

We remark that LNG and storage facilities are aggregated into one single node per country. For instance, the three regassification facilities present in Italy (OLT Offshore, Panigaglia and Porto Levante) are grouped into one single node for simplicity. Similarly, production facilities are grouped into one indigenous production node per country.

Edges

Edges represent the interconnections between nodes in the network, i.e. they model an abstract representation of the physical gas network. This representation is clearly simplified with respect to the physical one, but it is correct for the problem at hand as it provides the correct representation of transportation under the entry-exit tariff mechanism. Every interconnection (every *edge*) in the network is in fact associated to:

- A transportation capacity in GWh/day,
- A transportation tariff in €/MWh,

- A regassification tariff in €/MWh, and
- A storage injection/withdrawal tariff in €/MWh.

Interconnection points across Europe are mapped into edges connecting the various nodes, the tariffs being given by the sum of the exit and the entry tariffs to move gas from market area A to market area B[19]. The transmission capacity is expressed in GWh/day, so that the day is the minimum granularity that can be implemented via the model, although in practice a monthly granularity is used in this study. Capacities and tariffs are assumed constant through the simulation period (12 months).

Tariffs thus correspond to the cost of moving gas from a given node to another node in the stylized representation of the network. As such, tariffs are added to represent more than the transportation (exit+entry) costs:

- For indigenous production nodes, the tariff is set to zero. This models the fact that as gas is produced in a given country, it can be consumed in the same country at no additional transportation cost
- For regassification facilities, the tariff associated to the edge that connects the LNG node includes transportation and regassification costs
- For storage facilities, two edges are added that connect any given country to its associated (consumer) market area. These two edges model injection (from the market area to the storage node) and withdrawal (from the storage node to the market area). A tariff is associated to the gas flows on both edges, in order to model variable injection/withdrawal costs.

We remark that the network is modelled as a “directional” graph, i.e. gas flows along each edge are positive variables. Counter-flows, or injection/withdrawal flows to/from storage nodes, are implemented by adding additional edges connecting the same two nodes in opposite directions.

In the following we refer to the set of all the edges comprising the gas network with the symbol K.

Definition of the objective function

The model is a linear programming (LP) model which minimizes the supply cost for Europe, while ensuring competitive equilibrium among suppliers (via the net back pricing logic), and subject to a number of technical constraints (described in the next section).

The objective function for the system is the total transmission, storage and regassification cost, plus the cost of gas supplied via LNG:

$$C = \sum_{k \in K} T_k \cdot f_{k,t} + \sum_{k \in K_{LNG}} P_{ref} \cdot f_{k,t} \qquad \text{Eq. 1}$$

[19] We do not model separate exit and entry tariffs because the tariff split between the two market areas on each side of the interconnection point is not relevant in the determination of total transmission cost for Europe (it is purely a redistribution effect)

where

- T_k denotes the tariff associated to edge *k*,
- $f_{k,t}$ the gas flowing along edge *k* in month *t*
- P_{ref} is the "reference" price for Europe, set by LNG (see the discussion in Section 2),
- K_{LNG} represents the subset of the edges *K* that connects a LNG node to any given country.

Note that the objective function does not include the supply cost from pipeline suppliers or indigenous production nodes. In this sense, the model does aim at finding – directly via the optimization of the cost function above – the total supply, transmission and storage costs for Europe. These can be obtained as a by-product of the model, as described later, but the focus of the model is specifically on the determination of equilibrium prices.

A relevant point for the discussion below is that gas from pipeline suppliers is essentially "free", while LNG is supplied at a price *Pref*. This holds exactly because the only supply costs made explicit in the objective function is relative to LNG supply. We therefore need to limit the amount of "free" gas that can be taken from pipeline suppliers, which is exactly what is achieved with the specification of target volumes per supplier (see below). The idea underlying this approach is that suppliers express target volumes that allow them to sell their gas at a sufficiently high supply price, "inherited" from the LNG reference level via net back pricing.

Implementing net back pricing: target volumes for pipeline supplier

The model assumes that LNG can provide an infinite supply of gas at the reference price P_{ref}. All other suppliers, on the other hand, pursue volume targets which are represented as follows: for each supplier $\mathrm{n} \in \mathrm{N_p}$, a constraint is placed in the form

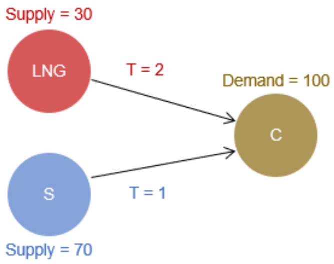
$$\sum_{k \in K_{out}(n)} f_{k,t} \leq Q_{n,t} \qquad \text{Eq. 2}$$

where:

- $Q_{n,t}$ is the volume target in TWh for supplier *n* in month *t*
- $K_{out}(n)$ is the set of edges exiting node n

The constraints above implement the fact that no more than $Q_{n,t}$ can be supplied by supplier *n* in month *t*. Since additional flows $f_{k,t}$ from pipeline suppliers do not affect the objective function while LNG flows do, the optimization algorithm ensures that all $Q_{n,t}$ are imported into the system. Otherwise stated, the optimal solution for the system is always such that the inequality above holds with the equality sign[20].

[20] Note that "oversupply" of pipeline gas into the system would lead to the constraint being fulfilled with a strict "<" sign for at least one supplier, whose gas would have zero value. When defining the simulation scenario, one must therefore ensure that $\sum_n Q_{n,t} < D_t$ where D_t is the total European demand, and the remaining quota of the demand is met via LNG. This is true in all realistic scenarios, where a given non-zero supply of LNG is assumed.



In order to make the above arguments concrete, consider the simple network depicted on the left, constituted by one supplier node *S*, one LNG node and one consumer node *C*.

Let us assume a demand in node *C* equal to 100, and a target volume from supplier *C* equal to 70. This imply that 30 units of gas will be imported via the *LNG* node. Let us assume a reference price of 10, and tariffs as shown in the figure. The value of the objective function will be:

- **Total cost = 430**, constructed as follows
  - Transportation and regassification costs = 70 × 1 + 30 × 2 = **130**
  - LNG supply cost: 30 × 10 = **300**

In order to determine the equilibrium price for supplier *S*, consider that should *S* dispose of an additional unit of gas to sell, it could sell it replacing a unit of LNG at a price not higher than 11. The supply price is in fact determined as the total price in node C (12), minus the tariff from S to C (net back logic). This is a simple implementation of what is called a **non-arbitrage** (or *equilibrium*) condition: market equilibrium requires that if two routes supply the same node, the total (supply + transportation and regassification) cost along the two routes must be equal:

$$P_C = P_{LNG} + 2 = P_S + 1 \quad which\ implies \quad P_S = P_{LNG} + 1$$

In mathematical terms, the supply price is determined within the model as the Lagrange multiplier of the target volume constraint of Eq. (2). The Lagrange multiplier is a mathematical quantity that captures the saving in the objective function that can be obtained by "relaxing" the constraint by a unit in the good served (in this case, the supplied gas $Q_{n,t}$). As having an extra-unit of $Q_{n,t}$ allows the system to:

- save on a unit of LNG supply
- save the regassification and transmission costs needed to bring LNG gas into Europe,
- pay the transmission costs needed to bring the additional unit of gas from node *n* into Europe,

the Lagrange multiplier automatically answers the complex question:

Should supplier n have an additional unit of gas at month t, what is the maximum saving that the system can achieve by replacing LNG with gas from the given supplier?

The answer to this question represents the supply price for supplier *n* in month *t*, and already fulfils all the non-arbitrage conditions imposed by the network structure.

Note that in a complex network, intuitively visualizing the price formation mechanism is by no means immediate. LNG supply might in fact be reduced in any given country, with knock-on effects on multiple gas routes across Europe, so that the additional unit of gas is supplied somewhere else. The structure of the problem, however, makes the mathematical determination of the prices operationally simple, as the extraction of Lagrange multipliers is a standard technique in LP problems.

Other constraints imposed in the model

Besides the target volume constraints described above, additional constraints are imposed in the model to ensure that:

- Transportation capacities in each month are not exceeded
- Regassification capacities in each month are not exceeded
- Storage capacities in each month are not exceeded
- LNG geographical distribution is plausible, i.e. the utilisation rate is above a given minimum in each country
- Storage patterns (injection/profiles though the months) are plausible:
  - In terms of injection/withdrawal rates
  - In terms of geographical redistribution of the storage capacity

Transportation and regassification capacity constraints

The transmission capacity constraints require that for each interconnection (*edge*) k in the network, for each month *t*, the flow does not exceed the technical capacity F_k:

$$f_{k,t} \leq F_{k,t} \qquad \text{Eq. 3}$$

Note that this constraint applies to every edge *k* represented in the network, including the ones connecting LNG nodes to European countries. These latter set of constraint thus limits the amount of LNG supply that can be supplied by each LNG node.

Storage constraints

Optimizing storage utilisation ensures that congestions between countries A and B in a given month *t* can be avoided by storing more gas in country B in a previous month (of lower demand), and withdrawing the gas at month *t*. This has the effect of reducing the flow when demand is high, de-congesting the interconnection A > B. The effect is the reduction of transmission congestions, and thus of overall system costs.

In the context of the dispatch model, injections and withdrawals into/from the storages are modelled as flows $f_{k,t}$ between the storage node and the corresponding European country[21]. The **storage filling level** σ_s, t is then defined for each storage *s* and month *t* as the cumulate sum of (injections – withdrawals) until time *t*. A constraint imposed into the final solution of the problem is that no gas is left in storage at the end of the simulation period (month of March): $\sigma_{s,March} = 0$ for all storages *s*.

In order to ensure that plausible storage patterns are reached in the solution, additional constraints are imposed to the injection/withdrawal rates and the maximum filling levels reached in storage. Specifically, the model requires that the final solution does not deviate by more than +/- 5% from the historical benchmark relative to each country for:

- Maximum storage filling level, reached at the end of October

[21] For countries with no storage facilities, storage nodes are defined with a storage capacity of **0 TWh**

- Injection/withdrawal rate, defined as the amount of gas injected/withdrawn into/from the storage relative the maximum storage filling level

The historically benchmarks are calculated as the five-year averages calculated over the period April 2014 – October 2019.

The reason for these additional definitions and constraints lies in the fact that since the observed solution (in all scenarios analysed) display a low level of congestions, different geographical distributions of storage levels across Europe lead to the same result in terms of total system cost. In other words, the solution to the gas dispatch problem is indifferent to where gas should be stored and might therefore chooses an arbitrary solution resulting in potentially extreme storage patterns. . On the other hand, analysing the market outcome in the past years we can observe consistent and stable storage patterns in which:

- Storage injection and withdrawal rates are "smooth". For instance, we do not observe a higher-than-usual injection in Italy compensated by a lower-than-usual injection in Austria.
- The maximum storage filling level is i) always reached at summer-end (month of October), in all countries, and ii) is distributed similarly in all years analysed. We do not observe, for instance, a low utilisation of the Italian storage compensated by a higher utilisation in other facilities (say, in Germany)

The observations above derive from the fact that storage use is regulated, and injection/withdrawal profiles cannot be determined arbitrarily by market participants for technical reasons. Also, regulatory reasons might lead to the storage patterns in the market: in Italy, for instance, auctions for storage capacity are held annually with zero reserve price. As a consequence, the Italian storage capacity is used almost to its full extent every year.

ANNEX B DATA USED IN GAS MARKET MODEL

This Annex documents the data used to deploy the gas market model.

Gas demand

For the annual gas consumption used in the gas market model we have relied on the TYNDP 2020 National Trends scenario data. With respect to the year 2025, the coal before gas scenario has been used.

To structure the annual gas demand into a monthly demand series we have derived a consumption pattern based on the historic gas consumption between 2016 and 2020 as published by Eurostat. The consumption pattern used is shown in Figure 16.

Figure 16 Distribution of annual gas consumption

node	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Jan	Feb	Mar
AT	7%	6%	4%	5%	5%	6%	8%	11%	13%	14%	11%	10%
BeLux	8%	6%	5%	5%	5%	6%	8%	11%	11%	13%	11%	10%
BG	8%	7%	6%	6%	5%	6%	8%	10%	12%	13%	10%	10%
HR	7%	6%	5%	5%	6%	6%	9%	11%	13%	12%	11%	10%
CH	7%	6%	5%	5%	5%	6%	8%	11%	11%	14%	12%	11%
CZ	7%	5%	4%	4%	4%	5%	8%	11%	13%	15%	12%	11%
DK	8%	6%	5%	4%	5%	6%	8%	11%	11%	14%	12%	11%
EE	8%	5%	4%	4%	4%	4%	9%	10%	12%	15%	13%	12%
FI	8%	6%	5%	6%	6%	6%	7%	9%	10%	14%	12%	11%
FR	7%	5%	4%	4%	4%	5%	8%	11%	13%	14%	13%	11%
DE	7%	6%	5%	5%	5%	6%	8%	11%	11%	14%	12%	11%
GR	6%	6%	7%	9%	8%	7%	9%	9%	12%	11%	9%	7%
HU	7%	5%	4%	4%	4%	5%	8%	11%	14%	16%	12%	10%
IE	9%	8%	7%	8%	7%	8%	8%	9%	9%	9%	9%	9%
IT	7%	6%	6%	6%	5%	6%	7%	10%	13%	13%	11%	10%
LV	7%	4%	4%	5%	6%	5%	9%	11%	12%	15%	12%	11%
LT	8%	7%	6%	5%	5%	8%	9%	10%	11%	12%	10%	10%
NL	8%	6%	5%	6%	6%	6%	8%	10%	11%	13%	11%	9%
PO	8%	7%	6%	6%	6%	6%	8%	10%	11%	12%	10%	10%
PT	7%	8%	9%	10%	9%	9%	8%	9%	8%	9%	7%	7%
RO	7%	5%	5%	5%	5%	6%	8%	10%	13%	13%	12%	10%
SK	7%	4%	3%	4%	5%	5%	8%	11%	13%	16%	12%	12%
SI	7%	6%	6%	5%	5%	6%	8%	10%	12%	13%	11%	10%
ES	7%	7%	7%	8%	7%	7%	8%	10%	10%	10%	9%	9%
SE	7%	6%	5%	5%	5%	5%	7%	10%	11%	12%	11%	16%
UK	8%	7%	6%	5%	5%	6%	8%	10%	11%	12%	11%	11%

Source: Frontier / DFC based on Eurostat

Gas supply

In the gas market model, the annual gas supply volumes are assumed to be fixed. The annual supply volumes have been derived from the TYNDP 2020. For some supply sources TYNDP 2020 provides a range of likely supply volumes. The supply scenario modelled here is based on the minimum range for Algeria, Libya, Azerbaijan and Turkmenistan. For Norway and Russia, we have selected the mid-point of the range. LNG is assumed to be a residual supplier and supply volumes are equal to the difference in demand and supply volumes from all other sources. The annual supply volumes are shown in Figure 17.

Figure 17 Annual Gas supply by supplier

	2020	2025	2030
Norway	1005 TWh	772 TWh	756 TWh
Russia	1785 TWh	1662 TWh	1566 TWh
Algeria	230 TWh	138 TWh	138 TWh
Libya	45 TWh	27 TWh	27 TWh
Azerbaijan	0 TWh	109 TWh	109 TWh
Turkmenistan	7 TWh	7 TWh	7 TWh
LNG	748 TWh	1335 TWh	1069 TWh
Indigenous production	1039 TWh	704 TWh	572 TWh

Source: Frontier / DFC based on TYNDP 2020

Infrastructure

The model makes assumptions on gas storage capacity, LNG regasification capacity and transmission capacity.

As the TYNDP 2020 was not finalised at the time of conducting this study, infrastructure data has been derived from the TYNDP 2018. Here all projects which have a FID status have been considered. Further to the we assume Nord Stream II and TAP to be commissioned before the model year 2025.

Regulation

In terms of regulation the model assumes storage costs, LNG regasification costs and transmission tariffs in line with the TYNDP 2018. To reflect the upcoming market merger in Germany a change in transmission tariffs from and to Germany has been included from 2025 onwards. The change in transmission tariffs reflects the tariff income from gas transport between NCG and Gaspool before the merger.

ANNEX C RESULTS OF ALTERNATIVE SCENARIOS AND ENTRY FLOW SENSITIVITY

In this Annex we provide an overview of the scenario results and the findings of the sensitivity analysis.

C.1 Overview on scenario results

Below we show aggregated scenario results on gas flows on Tarvisio-Arnoldstein, price-effects for Austria and Italy and distributional effects.

Impact of market zone merger on gas flows

Figure 18 Impact of market merger on gas flows at Tarvisio-Arnoldstein

	Before merger	After merger	Delta
Base Case			
2020	354 TWh	358 TWh	4 TWh
2025	244 TWh	345 TWh	101 TWh
2030	198 TWh	222 TWh	24 TWh
Scenario 2 - TAP LNG Reduction			
2020	354 TWh	358 TWh	4 TWh
2025	212 TWh	237 TWh	25 TWh
2030	114 TWh	114 TWh	0 TWh
Scenario 2 - TAP Expansion and RU Reduction			
2020	354 TWh	358 TWh	4 TWh
2025	137 TWh	237 TWh	100 TWh
2030	73 TWh	114 TWh	41 TWh
Scenario 3 – BACI pipeline			
2020	353 TWh	358 TWh	4 TWh
2025	268 TWh	345 TWh	78 TWh
2030	217 TWh	222 TWh	5 TWh
Scenario 4 – Ukraine disruption and LNG increase			
2020	55 TWh	280 TWh	225 TWh
2025	40 TWh	214 TWh	174 TWh
2030	64 TWh	222 TWh	158 TWh
Scenario 4 – Ukraine disruption and Yamal increase			
2020	55 TWh	283 TWh	227 TWh
2025	34 TWh	317 TWh	283 TWh
2030	64 TWh	222 TWh	158 TWh

Source: DFC/Frontier economics

Impact of market zone merger on gas prices

Figure 19 Price effect of market zone merger on Austria and Italy

	Price effect AT	Price effect IT
Base Case		
2020	0.01 €/MWh	-1.17 €/MWh
2025	0.80 €/MWh	-0.28 €/MWh
2030	0.45 €/MWh	-0.63 €/MWh
Scenario 2 - TAP LNG Reduction		
2020	0.01 €/MWh	-1.17 €/MWh
2025	0.31 €/MWh	-0.78 €/MWh
2030	-0.03 €/MWh	-1.03 €/MWh
Scenario 2 - TAP Expansion and RU Reduction		
2020	0.01 €/MWh	-1.17 €/MWh
2025	0.81 €/MWh	-0.28 €/MWh
2030	0.39 €/MWh	-0.61 €/MWh
Scenario 3 – BACI pipeline		
2020	0.00 €/MWh	-1.15 €/MWh
2025	0.67 €/MWh	-0.41 €/MWh
2030	0.06 €/MWh	-1.02 €/MWh
Scenario 4 – Ukraine disruption and LNG increase		
2020	0.64 €/MWh	-0.37 €/MWh
2025	0.64 €/MWh	-0.23 €/MWh
2030	0.67 €/MWh	-0.41 €/MWh
Scenario 4 – Ukraine disruption and Yamal increase		
2020	0.67 €/MWh	-0.32 €/MWh
2025	0.58 €/MWh	-0.25 €/MWh
2030	0.65 €/MWh	-0.43 €/MWh

Source: DFC/Frontier economics

Distributional effects of market zone merger

Figure 20 Distributional effects of market zone merger on model region (left) and Austria and Italy (right) in Mio. €

	Cons. rent	Sup. rent	Storage income	TSO income	Austria	Italy	Tariff income Tarvisio /Arnoldstein
Base Case							
2020	807	-343	-44	-420	-1	695	-384
2025	-563	781	31	-249	-57	178	-265
2030	79	87	3	-170	-22	319	-215
Scenario 2 - TAP LNG Reduction							
2020	807	-343	-44	-420	-1	695	-384
2025	376	-12	-128	-236	-34	478	-229
2030	611	-477	-3	-131	0	542	-124
Scenario 2 - TAP Expansion and RU Reduction							
2020	807	-343	-44	-420	-1	695	-384
2025	-582	684	31	-133	-57	176	-148
2030	112	21	-84	-49	-38	306	-79
Scenario 3 – BACI pipeline							
2020	787	-338	-27	-421	0	685	-383
2025	-265	520	1	-255	-48	252	-290
2030	490	-295	35	-230	0	526	-236
Scenario 4 – Ukraine disruption and LNG increase							
2020	-468	321	190	-43	-41	226	-60
2025	-1183	823	387	-28	-2	174	-43
2030	705	-1133	-54	482	-43	211	-69
Scenario 4 – Ukraine disruption and Yamal increase							
2020	-477	240	214	23	-41	199	-60
2025	-972	1640	0	-668	-26	159	-37
2030	158	-31	-57	-70	-42	221	-69

Source: DFC/Frontier economics

C.2 Results of sensitivity analysis

The gas market model optimises gas transportation costs, gas storage costs, LNG terminal costs by choosing cost minimising gas flows and entry flows, while assuming fixed supply volumes per source. In this scenario suppliers are assumed to be price takers. We have therefore undertaken two sensitivity analysis, in which we

- change Russian supply volumes in order to see whether the results are sensitive to the fixed supply volume assumption, and

- remove the endogenous entry flow optimisation for Russian supply and replace it with a fixed entry flow split between Transgas and Yamal.

The sensitivity analysis has been conducted for the base scenario.

Model results are not sensitive towards higher Russian supply shares

To analyse how the effects of the market merger on the price formation change with alternative supply volumes from Russia, the gas price model was run with a higher and a lower Russian supply share via continental supply routes. The change in gas supply from Russia is compensated by a modulation of gas supply from LNG. In the sensitivity analysis a change of gas supply from Russia of 10% corresponds to a volume of 117 TWh in 2020, 75 TWh in 2025 and 66 TWh in 2030.

The results of the sensitivity analysis are summarised in Figure 21. The results show:

- For 2020, with alternative supply volumes, the market merger still leads to a positive net transfer to EU consumers. Measured as share of the total system costs, the share of net transfer changes only slightly.
- For 2025, with alternative supply volumes, the market merger still leads to a negative net transfer to EU consumers. Measured as share of the total system costs, the share of net transfer changes only slightly.
- For 2030, the net transfer to consumers is negative in the base scenario. Looking at alternative supply volumes we see that increasing Russian supply volumes has a positive impact on the net transfer to EU consumers, while decreasing Russian supply volumes has a negative impact. Measured as share of total system costs, the net transfer to EU consumers resulting from the market zone merger changes only slightly.

Overall the sensitivity analysis shows that distributional effects of the market zone merger do not change significantly (less than 1% of system costs) when increasing or decreasing the Russian supply share by up to 10%.

Figure 21 EU consumer benefits of market merger and sensitivity towards alternative Russian supply volumes

	Net Transfer to EU consumer	Net Transfer as share of total system cost
2020		
Base Scenario	343 Mio €	0.36%
+ 10% supply from Russia	222 Mio €	0.24%
- 10% supply from Russia	330 Mio €	0.35%
2025		
Base Scenario	-781 Mio €	-0.82%
+ 10% supply from Russia	-324 Mio €	-0.34%
- 10% supply from Russia	-753 Mio €	-0.79%
2030		
Base Scenario	-87 Mio €	-0.11%
+ 10% supply from Russia	18 Mio €	0.02%
- 10% supply from Russia	-395 Mio €	-0.49%

Source: DFC/Frontier economics

Note: Net Transfer to consumer comprises consumer rent, storage income and TSO income. System costs comprise all transport, storage and supply costs.

Model results are sensitive towards alternative entry flow splits of Russian gas supply

The gas price model endogenously choses which continental pipeline to use to supply Europe with gas from Russia. The underlying assumption of this is, that the market is perfectly competitive and supply prices for gas cannot be differentiated between different supply routes (for the same source).

As a sensitivity to this assumption we have analysed the market results with an alternative supply split. This supply split assumes that, compared to the endogenous split, additional 60 TWh are supplied via Yamal instead of Transgas. This fix split allows gas supply prices sourced via Yamal and Transgas to be different.

With regard to the sensitivity on endogenous entry flows of Russian supply we observe that allowing for a price differentiation between Transgas and Yamal can lead to significant variations in the distributional effects of the market zone merger:

- In 2020 we observe that the net consumer benefits of the merger are significantly lower.
- In 2025 the sensitivity shows that the alternative split also leads to a more negative impact of the merger on net consumer benefits.
- Similarly, for 2030 we observe that an alternative supply split reduces the net benefits of the merger for consumers.

We would like to comment that this finding should be interpreted with caution, as:

- the sensitivity only changes the option for price differentiation at Russian entry points,
- total supply volumes in the model are still fixed, and

- the behaviour of other suppliers is assumed to stay the same, which might not necessarily be true in reality.

This means that important competitive follow up effects which would follow to such a price differentiation have not been considered in this sensitivity.

However, the sensitivity shows that in case the assumption underlying the gas market model of a competitive European gas market is not valid, the distributional effects of the market zone merger might be different.

Figure 22 EU consumer benefits of market merger and sensitivity towards alternative Russian supply splits

	Net Transfer to EU consumer	Net Transfer as share of total system cost
2020		
Base Scenario	343 Mio €	0.36%
Alternative Split	59 Mio €	0.06%
2025		
Base Scenario	-781 Mio €	-0.82%
Alternative Split	-811 Mio €	-0.81%
2030		
Base Scenario	-87 Mio €	-0.11%
Alternative Split	-100 Mio €	-0.11%

Source: DFC/Frontier economics

Note: Net Transfer to consumer comprises consumer rent, storage income and TSO income. System costs comprise all transport, storage and supply costs.