A Top-Down Approach to Evaluating Cross-Border Natural Gas Infrastructure Projects in Europe

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ABSTRACT

There is an ongoing policy debate in Europe about how to select natural gas infrastructure projects for an EU-wide investment support scheme. We contribute to this debate by introducing a model-based project evaluation method that addresses several shortcomings of the current approach and demonstrate its application on a set of shortlisted investment proposals in Central and South Eastern Europe. Importantly, our selection mechanism deals with the complementarity and the substitutability of new pipelines. We find that a small number of projects are sufficient to maximize the net gain in regional welfare, but different baseline assumptions favor different project combinations. We also explore the consequences of Russian gas permanently delivered at the EU border from northern and southern routes that bypass Ukraine and find modest negative welfare effects.

Keywords: Natural gas infrastructure development, natural gas market modeling, Market integration, Long-term contracts

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1. INTRODUCTION

Cross-border investments in electricity and natural gas transmission networks raise unusual challenges for cost-benefit analysis. Trading on a new interconnector narrows price differences across markets, making consumers better off on one side, but worse off on the other. Producer surplus moves in the opposite direction, while storage units (in case of gas) can either gain or lose profits, depending on seasonal demand-supply patterns. Market participants in directly and indirectly connected third countries are also affected. Moreover, the new infrastructure element might only be needed in case of a serious (but rare) supply disruption. These nuanced complications can forestall neighboring transmission system operators (TSOs) and governments from investing into projects that would otherwise be beneficial for the region as a whole.

Europe, with over 30 interconnected national electricity and gas markets, is ripe for divergent bilateral and regional interests over cross-border transmission investment. Aware of the threat of underinvestment in market interconnection, the European Union (EU) established a system for supporting energy infrastructure projects deemed essential for a fully integrated European market and for security of supply. These projects of common interest (PCIs) may benefit from accelerated
planning, permitting and environmental process, and they can access financial support provided by the EU.1 Yet there is no clear consensus about how PCIs should be chosen and evaluated.

In this paper, we contribute to the policy debate by providing a model-based project evaluation method for the natural gas sector and demonstrate its use on a set of currently shortlisted PCIs in Central and South Eastern Europe (CSEE). Our main tool is the European Gas Market Model (EGMM), a competitive short-run equilibrium model for the natural gas market in Europe.2

The current method for identifying projects for PCI status has been developed by the European Network of Transmission System Operators for Gas (ENTSOG), tested in two PCI selection rounds in 2013 and 2015, and is subject to continuous fine tuning (ENTSOG, 2013). Frontier Economics (2014) and ACER (2014) have, however, pointed out shortcomings of the ENTSOG methodology by—among others—(1) not providing impact estimates on stakeholders other than consumers and producers; (2) not breaking down benefits by EU member states; (3) not including non-EU members; (4) failing to adequately identify complementary and competing projects; and (5) over-simplifying transportation costs. The market-based evaluation method we propose in this paper addresses all of the above issues.

Our project evaluation mechanism unfolds in three steps. First, we establish baseline scenarios that account for expected demand, supply, and long-term contractual positions, as well as infrastructure elements (pipelines, storage units, LNG terminals) that are likely to be operational by 2020 (the year of analysis). The model is detailed enough to provide equilibrium surplus estimates for all market participants in each EU and non-EU country included. Second, we simulate market outcomes by adding all possible combinations of shortlisted PCIs in our sample to the baseline case. Third, we compare the gain in regional welfare for each pipeline combination against the joint investment costs, and provide a ranking of project sets based on our annual net social benefit measure. By considering every feasible PCI configuration, rather than single projects in a selected order, our ranking method allows for an endogenous determination of which projects are competing and which ones are complementary.

The final outcome is an illustrative set of proposed PCIs under each baseline scenario. Even though the analysis presented in this paper is not exhaustive, we can still draw some general lessons from the exercise. All baseline scenarios suggest that the central region of South Eastern Europe (roughly around the core of Serbia) is most in need of pipeline investments. In the reference case, connecting Serbia and Greece through Bulgaria (southern supply direction) brings the highest net benefits for the region. The construction of a long-planned LNG terminal on the coast of Croatia would, however, make it more beneficial to build pipelines from Croatia to Serbia and to Hungary (western supply direction). Regardless of which baseline is considered, it is never optimal to build all, or even a majority of the proposed projects. This conclusion has important policy implications: supporting too many proposals would lead to underutilized infrastructure that would have to be ultimately financed by consumers through higher regulated tariffs.

1. Regulation (EU) 347/2013 laid down rules for the PCI selection process. Regulation (EU) 913/2010 created the Connecting Europe Facility to accelerate investment into trans-European networks and to leverage funding from both the public and the private sectors. The first list of PCIs was published in 2013 comprising 248 priority energy projects, which was reduced to a number of short and mid-term key infrastructure projects in the Communication of the Commission on its Energy Security Strategy (European Commission, 2014). See the European Commission’s portal at https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest for more details.

2. The EGMM has been developed at the Regional Centre for Energy Policy Research (REKK). It was previously used to evaluate Projects for Energy Community Interest in South Eastern Europe (KEMA and REKK, 2013), and to address supply security questions (Sartor et al., 2014).
Somewhat contrary to our expectations, we also find that most of the welfare gains from new investment tend to accrue to the countries building the pipelines, in some cases even making third countries slight net losers. This reflects the limited number of scenarios considered, but it also raises questions about the exact mechanism through which the PCI scheme improves welfare for the EU itself.3

As a secondary application, we also demonstrate the advantages of the EGMM’s treatment of long-term supply contracts in conjunction with the proposed PCI evaluation mechanism. We explore a hypothetical baseline scenario in which the contract delivery points of gas arriving from Russia are moved to the member state border where the gas enters the EU, and all transit routes from the east avoid crossing Ukrainian territory.4 Although this is a large shift from the current mode of operation, we find that its negative welfare consequences for the CSEE region are modest. However, this result significantly depends on assumptions about a (not-yet-existing) southern route becoming available for Russian transit.5 The new baseline also shuffles the project combination rankings, moving a north-to-south supply route from Poland at the top of the list. Implementation of the proposed PCIs has the potential to neutralize around 30 percent of the welfare decline in the region. We also discuss other potential benefits, such as the improvement of buyer bargaining position, after modeling results are presented.

2. LITERATURE

This paper adds to an extensive literature on the numerical modeling of natural gas markets. Prominent modeling tools and applications focusing on the European consumer market include GASTALE (Boots et al., 2004; Egging and Gabriel, 2006), NATGAS (Zwart and Mulder, 2006; Zwart, 2009), TIGER (Lochner and Bothe, 2007; Lochner, 2011; Dieckhoner et al., 2013), GASMOD (Holz et al., 2008), the World Gas Model (Egging et al., 2010), the Global Gas Model (Holz et al., 2016; Richter and Holz, 2015), GaMMES (Abada et al., 2013), and the EPRG-Gas Market Model (Chyong and Hobbs, 2014). Smeers (2008) provides an in-depth discussion of the models existing before 2010.

Our approach is different from most models (except for TIGER) that allow for strategic behavior by upstream firms, and in some cases also in the downstream market, in that we assume all market participants are price takers.6 Working with a perfectly competitive equilibrium has drawbacks, as the presence of market power is an important issue in the upstream market. We remedy this shortcoming with the inclusion of a detailed representation of long-term take-or-pay supply contracts in the model. Our assumption is that most of the upstream market power is exercised through the pricing of these contracts with the market working more like the competitive benchmark in the short run. Accordingly, a single simulation run of our model encompasses one calendar year.7

3. The welfare measure is calculated as an unweighted sum of surpluses, whereas national governments might assign unequal weights to different stakeholders. In theory, favoring certain groups (consumers, for example) can decrease the willingness to build a pipeline that harms those groups, but still brings positive net benefits in aggregate.

4. The original role of long-term gas purchase contracts and the underlying fundamentals are described by Neuhoff and Hirschhausen (2005), Asche et al. (2002), Stern and Rogers (2014) and Henderson and Pirani (2014).

5. Hence our intention is not to model a supply disruption scenario, but rather a permanent shift to alternative delivery routes and destinations. Richter and Holz (2015) carry out simulations for disruptions to transits through Ukraine without assuming a new southern route, and find substantially more severe effects for a similar set of countries as we do.

6. Storage and transmission system operators have exogenously given fees that exceed marginal costs.

7. As a result, we have nothing to say about the price development of long-term supply contracts. Models with a strategic upstream sector do address producer price setting, although they tend to abstract away from the take-or-pay clauses. For a more in-depth endogenous contracting model, see Abada et al. (2014).
The price-taking assumption allows us to go into finer detail both geographically and in the temporal dimension. We aggregate demand at the country level, but not across countries. The modeling literature often lumps small neighboring markets (e.g. in South Eastern Europe) together for computational convenience, which rules out the analysis of interconnection between these markets. We also break the modeled time frame into monthly periods, whereas the cited models typically include only 1–3 seasons per year. The monthly output is especially helpful when examining market disturbances, which are typically short-lived, and the extent to which storage units can mitigate them depends on short-run gas withdrawal capacities. In terms of geographical and temporal granularity, our model is close to—but still less detailed than—the TIGER model.8 However, we do allow for price responsive demand functions and can therefore carry out a more informative welfare analysis. The detailed take-or-pay contracting structure in the EGMM also allows us to examine the effect of virtual reverse flows on market integration with limited physical connectivity.

We use a comparative static framework for our project evaluations, contrasting equilibrium outcomes with and without the investments, which could—in theory—also be carried out with other cited models that are sufficiently detailed. Some models even go beyond the static approach and allow for infrastructure changes within the time frame of the simulations. Lise and Hobbs (2008) extend the GASTALE model to automatically include new pipelines and storage units whenever the forecasted congestion rents exceed a specified threshold value.9 In the Global Gas Model, transmission and storage system operators decide about new investments based on a private cost-benefit analysis.

Making the investments of profit-oriented yet geographically limited entities in interconnected markets endogenous is not straightforward. It is not clear, for example, how the substitutability or complementarity of new pipelines can be modeled if the investment decisions are taken project-by-project by non-overlapping (or partially overlapping) sets of TSOs. In reality, policy makers with their own objectives also need to consent to the investments, which complicates a profit-based cost-benefit analysis.10 Finally, even the parties to a single pipeline can have divergent dynamic incentives, which leads to complex bargaining problems and potentially wasteful spending.11 Using the comparative statics approach, we have to make assumptions about what infrastructure will be available in the future, in exchange for a more transparent analysis that avoids the shortcomings of endogenous investment models. Since we focus on a relatively short time frame, we find this trade-off acceptable.

The remainder of the paper is organized as follows. We start with a detailed description of the EGMM, our modeling tool, followed by a section on our project evaluation methodology. We then provide the main modeling results and a ranking of the most beneficial investments for each baseline scenario. In the last part of the paper, we discuss the general lessons from our project evaluation exercise, point out potential pitfalls, and conclude.

3. MODEL

The EGMM is a competitive, dynamic, multi-market equilibrium model for natural gas production, trade, storage, and consumption in Europe. It explicitly includes a supply-demand

8. See Dieckhoner (2010) for a supply security application exploiting the granularity of TIGER.
9. For further applications, see Lise and Hobbs (2009) and Lise et al. (2008).
10. Joskow and Tirole (2005) and Bruneckreft et al. (2005) describe similar tensions between the social benefits and the private profitability of “merchant” investment in electricity transmission capacity.
11. Hubert and Suleymanova (2008) examine extensions to the Eurasian gas transmission network through a dynamic bargaining model, and conclude that the absence of international contract enforcement results in inefficient investments relative to the cooperative outcome (the default assumption in an endogenous cost-benefit analysis).

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representation of 33 European countries, as well as their gas storages and transportation links to each other and to the outside world. The time frame of the model is 12 consecutive months, starting in April. Market participants have perfect foresight over this period.

3.1 Market Participants

There are four kinds of players within the model: consumers, local producers, importers, and traders. 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. For outside markets, we use perfectly elastic demand functions at exogenously given prices.

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, most importantly from Russia, Norway, Algeria, and a number of LNG exporting countries. Each contract specifies a price, a delivery route, and a minimum and maximum delivered quantity per month and per year. The monthly minimum delivery constraint alone is flexible: it can be violated, but most of the undelivered gas must be paid for according to the TOP rules.

The function of traders is to move gas between markets using cross-border pipelines and LNG shipments, and between time periods using storages.

3.2 Infrastructure

Transportation

Transportation links between two markets consist of cross-border pipelines and LNG routes. From a modeling perspective, they operate similarly. Each link is unidirectional and has a maximum transportation capacity. Pipelines have entry and exit tariffs, and LNG connections have shipping costs, regasification prices, and network injection fees.

Transportation infrastructure can be used for delivering gas into the target market through long-term contracts or spot trade, and into the source market via virtual reverse flow (“backhaul”). Virtual reverse flow can only be carried out if there is already a pre-contracted gas flow in the default direction. Even then, its availability may be limited by the legal environment, which is captured as an additional constraint in the model.

Formally, physical flows on a piece of transportation infrastructure are given by:

\[ x_{fs}^c = t_{fs}^c - b_{fs}^c + \sum_{e} \Omega_{es}^c \cdot (d_{es}^c + D_{es}^c) \]  

(1)

where \( f \) indexes the infrastructure, \( s \) the time period (month), and \( c \) the long-term contracts. \( t_{fs}^c \) is the amount of spot trade and \( b_{fs}^c \) is the amount of backhaul shipment on infrastructure \( f \). \( d_{es}^c + D_{es}^c \) is
the total delivered quantity on contract \( c \), and \( \Omega^c_{jc} \) specifies what portion (typically 0 or 1) of contract \( c \) flows through infrastructure \( f \) in month \( s \).

We also include in the model upper constraints on linear combinations of physical flows to separately account for the regasification capacity of LNG terminals and the total shipment capacity of LNG exporters.\(^{15}\)

**Storage**

Storage units reside within 23 out of the 33 markets we explicitly model. Each has a monthly injection and withdrawal capacity and associated fees. In addition, storages have a working gas capacity and exogenously given starting and year-end inventory levels. Traders can decide in each month how much gas they want to inject into, or withdraw from, a storage unit. Inventory levels can never fall below zero or rise above the working gas capacity of a facility. Storages must eventually be reloaded to the specified year-end inventory level (usually equal to the starting inventory).

**3.3 Decision Variables**

Local producers determine production levels \( (e_p^m) \), importers determine the quantity of delivered gas up to \( (d_f^m) \) and above \( (D_f^m) \) the monthly TOP quantities, and traders determine spot trade \( (t_f^g) \) and backhaul \( (b_f^g) \) on transportation infrastructure, and injection \( (i_f^g) \) to and withdrawal \( (w_f^g) \) from gas storages \( (p \) indexes the producers and \( g \) the storages). Although consumers are listed as participants in the model, their consumption is derived from the other decision variables as:

\[
Q_m = \sum_p \Pi_{mp} \cdot e_p^m + \sum_f \Phi_{mf} \cdot x_f^m + \sum_g \Gamma_{mg} \cdot (w_g^m - i_g^m) \tag{2}
\]

where \( m \) indexes markets, and \( \Pi_{mp} \) and \( \Gamma_{mg} \) are zero-one parameters indicating whether producer \( p \) and storage \( g \) are in market \( m \). \( \Phi_{mf} \) is also an indicator: it equals 1 if market \( m \) is the target of transportation infrastructure \( f \), \(-1 \) if it is the source, and \( 0 \) otherwise.

**3.4 Equilibrium**

A crucial assumption in the EGMM is that producers, importers, and traders are all price-takers. In equilibrium, all arbitrage opportunities across time and space are therefore exhausted to the extent that storage facilities, transportation infrastructure, and contractual conditions permit. As a result, the competitive equilibrium yields an efficient outcome and can equivalently be computed as the solution to a constrained welfare maximization problem with the following multi-period objective function:

\[
W = \sum_s \beta_s \left\{ \sum_m \left[ \int_0^{Q_m}(Q)dQ - \sum_p C_{ep} \cdot e_p^m - \sum_g C_{ig} \cdot i_g^m - \sum_g C_{wg} \cdot w_g^m - \sum_f C_{df} \cdot (d_f^m + D_f^m) + t_f^m \right] - \sum_f C_{df} \cdot b_f^m - \sum_f P_{dt} \cdot (t_f^m - b_f^m) \right\} 
\]

\[
- \sum_c P_d^c \cdot d_c^m - \sum_c P_D^c \cdot D_c^m \tag{3}
\]

15. These constraints allow for an endogenous determination of which LNG exporter will ship to which LNG terminal in equilibrium.
In the welfare expression, \( \beta \) is the month-to-month discount factor, \( P_{m,s}(Q) \) is the (linear) inverse demand function in market \( m \) and period \( s \), and the (quadratic, concave) integral term measures gross consumer surplus.

On the cost side, \( C_{e_p} \) is the marginal cost of local production. \( C_{I_p} \) and \( C_{W_p} \) denote the storage fees for injection and withdrawal. \( C_{I_f} \) is the transportation fee on infrastructure \( f \) for gas flows in the default direction, and \( C_{b_f} \) is the fee payable for virtual reverse flows. If infrastructure \( f \) originates (ends) in an outside market, then \( P_{t_f} \) is \((-1)\) times the exogenously given price in that market. \( \sum_f P_{t_f} \cdot (t_f - b_f) \) therefore measures the total cost of net spot imports from outside markets. Finally, \( P_{d_f} \) and \( PD_{d_f} \) are the marginal prices of gas below and above the minimum monthly delivery limit of long-term contracts.16

The objective function is continuous and weakly concave with a non-empty, closed and convex domain, ensuring the existence of an equilibrium. With minor additional assumptions, the equilibrium also becomes a unique one.17 We find it by solving the first-order linear complementarity conditions of the constrained optimization problem using standard pivoting techniques (Gabriel et al., 2013).18

### 3.5 Welfare

We use storage and transportation fees in our objective function (3) as if they were the marginal costs of these activities, even though the fees typically exceed the marginal costs to ensure a sufficient return on capital invested into the infrastructure. Similarly, using a low marginal price for the gas bought below the monthly delivery limit in a long-term contract does not reflect the full cost of the gas, because the take-or-pay delivery limit creates a large fixed cost element as well. Despite these qualifications, the welfare formulation in expression (3) is the one that allows us to replicate the competitive equilibrium.

In our ex post welfare calculations, we adjust the maximized value of our objective function to properly account for actual welfare in the market. We add the operating profit of transmission and storage system operators using estimates for their marginal costs, and increase the expenditure on import contracts by the take-or-pay fixed cost element. The augmented welfare used for evaluating the benefit of new infrastructure is therefore given by:

\[
\hat{W} = W + \sum_i \beta^i \left[ \sum_g (C_{I_g} - \hat{C}_{I_g}) \cdot i_g + \sum_g (C_{W_g} - \hat{C}_{W_g}) \cdot w_g \right. \\
+ \sum_f (C_{I_f} - \hat{C}_{I_f}) \cdot \sum_c \Omega_{c_i} \cdot (d_i + D_i) + t_f \right] + \sum_f (C_{b_f} - \hat{C}_{b_f}) \cdot b_f \\
+ \sum_c (PD_{d_c} - Pd_{d_c}) \cdot Kd_c \tag{4}
\]

16. Because of the financial penalties associated with take-or-pay obligations, \( Pd_{d_f} \) tends to be 70–90% lower than \( PD_{d_f} \).

17. Uniqueness might not hold, for example, if there is more than one unconstrained marginal producer in the same location. Since marginal production costs are assumed to be constant, any feasible distribution of the joint output across the equal-cost producers is part of an equilibrium outcome, even though all such equilibria lead to the same market price. This multiplicity is not an issue in practice, however.

18. The full set of complementarity conditions are available from the authors upon request.
where $\hat{C}_i$, $\hat{C}_w$, $\hat{C}_t$, and $\hat{C}_L$ are the (constant) marginal costs of storage injection, storage withdrawal, pipeline/LNG transportation in the default direction, and backhaul. $Kd_c$ is the minimum monthly take-or-pay obligation, and $(PD_c^d - PD_c^a) \cdot Kd_c$ is the monthly fixed cost component of a long-term contract. All numerical welfare values in the paper are the result of evaluating expression (4) at the competitive equilibrium with given input parameters.

We assign all welfare components to regional and outside markets based on location. For consumer and local producer surplus, long-term contract profit, storage operating income and congestion rent, the assignment is straightforward. Pipeline operating income is shared in the ratio of entry and exit fees and pipeline congestion rent is shared equally by the neighboring markets. LNG-related welfare components are assigned to the market hosting the terminal.

### 4. METHODOLOGY

We evaluate the social benefit of new cross-border pipelines by running market simulations with and without the new infrastructure and comparing aggregate welfare in the two equilibria. All simulations are for the year 2020 using forecasted values for demand, indigenous production, and long-term contracts in place. In our baseline (“before investment”) scenarios, we include all existing infrastructure, as well as all current projects that already have final investment decisions and are planned to be commissioned before 2020. Most important among these for our analysis is the Trans Adriatic and the Trans Anatolian Pipeline (TAP/TANAP) connecting Turkey with Italy through Greece and Albania.

We use three baseline scenarios for our evaluations. The first one is a business-as-usual case (Reference) with no additional assumptions. The second baseline scenario explores the market consequences of Russian gas being delivered at the border of the EU on routes that avoid Ukraine (No Ukraine transit). Finally, we examine the effects of a new LNG terminal in Croatia on the usefulness of cross-border pipeline investments in the region (Croatia LNG).

In each case, we proceed by adding to the baseline setup all possible combinations of cross-border pipelines, chosen from a shortlist of proposed projects of common interest in the North-South Gas Corridor in the CSEE region, and comparing the changes in our welfare measure relative to its baseline value. Evaluating the benefit of all project combinations, as opposed to single projects in a selected order, allows us to capture both the complementarity and the substitutability between pipelines. The shortlisted projects are shown in Table 1.

Our main result is a list of the most beneficial project combinations based on welfare improvement net of annualized investment costs. We estimate investment costs using publicly available information on the projects (pipeline length and diameter) and benchmark unit investment costs published recently by the European Agency for the Cooperation of Energy Regulators.

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19. By long-term contract profit, we always mean the profit that the importer earns by selling the delivered gas into the local wholesale market. As we take the contract prices as given, the profit of the exporter (e.g. Gazprom) is outside of both of our model, and our welfare measure of interest.

20. We assume that the long-term supply contracts expiring before 2020 are not renewed.

21. Our main data source is the capacity maps and the 2015 edition of the Ten-Year Network Development Plan of the European Network of Transmission System Operators for Gas (ENTSOG, 2015).

22. Other infrastructure to be operational by 2020 include interconnectors between Slovakia and Hungary, France and Spain, and the LNG terminal in Poland.

23. We have added another pipeline (Croatia-Serbia) to our analysis, because it features high on a similar shortlist of the Energy Community in South Eastern Europe (Energy Community, 2013).
### Table 1: Potential Pipeline Projects of Common Interest in the North-South Gas Corridor in Central and South Eastern Europe

| From     | To       | Short name | Capacity (bcm/year) | Length (km) | Diameter (inch) | Investment cost (million €/year) |
|----------|----------|------------|--------------------|-------------|-----------------|----------------------------------|
| Bulgaria | Serbia   | BG-RS      | 1.8                | 150         | 28              | 12.6                             |
| Croatia  | Hungary  | HR-HU      | 2.8                | 0/308       | 39              | 2.4/31.2†                        |
| Croatia  | Serbia   | HR-RS      | 6.0                | 102         | 31              | 9.4                              |
| Greece   | Bulgaria | GR-BG      | 3.0                | 185         | 32              | 15.0                             |
| Poland   | Czech Rep.| PL-CZ     | 5.0                | 108         | 39              | 12.5                             |
| Poland   | Slovakia | PL-SK      | 5.4                | 164         | 39              | 17.7                             |
| Romania  | Hungary  | RO-HU      | 1.7                | 6           | 28              | 2.8                              |

† A pipeline currently operates from Hungary to Croatia, which could be physically reversed with a single compressor station on the Croatian side. A new 308 km internal pipeline may, however, be necessary to transport larger quantities of gas from the coast to Hungary if the LNG terminal in Croatia is built. We therefore calculate assuming this higher investment cost in the Croatia LNG scenario, but not otherwise.

Our cost figures are only imprecise estimates, since there is considerable (typically ±30%) variation around the mean benchmark values in the cited dataset. In an actual policy application, the numbers can be substituted by the cost estimates of the project promoter, for example.

Belarus, Kosovo, and Montenegro are not included in the model.

(ACER). For example, the average unit investment cost is 1.06 million €/km for a pipeline with diameter 28”–35” (Table 8 in ACER, 2015), and 2.1 million €/MW for a new compressor station (Table 11 in ACER, 2015). Calculating with a length of 185 km and a single 18 MW compressor station (a typical size in the ACER database), the Greece-Bulgaria pipeline has a total investment cost of €234 million. This is equivalent to €15 million annually, assuming a 25-year lifetime and a 4% yearly discount rate (recommended parameters by ACER, 2014). Table 1 lists our estimates of the annualized investment costs for all the projects we include in the analysis.**

### 5. RESULTS

#### 5.1 Reference Scenario

The stylized map of Europe in Figure 1 provides an overview of market prices in the Reference baseline scenario. It shows the modeled markets with a shaded background and the exogenously-priced outside markets (Norway, Russia, and Turkey) in white.** Consumption-weighted yearly average wholesale gas prices (in €/MWh) are displayed for a selected set of countries. Darker shaded areas indicate higher prices.

Markets in South Eastern Europe, including even Croatia and Hungary, have the most problematic supply-demand situations. The region lacks sufficient interconnection to Western Europe for cheaper gas to enter and push down prices. Greece is an exception, due to access to LNG and the Trans Adriatic Pipeline, but markets to its north see little of these benefits. Surveying the potential projects in Table 1, we would therefore expect the GR-BG, BG-RS, and HR-RS pipelines to allow for the largest increase in welfare as a result of increased trading and price equalization.

Starting from the baseline scenario depicted in Figure 1, we add all 127 possible pipeline combinations from Table 1 and find the competitive equilibrium in each case. We then aggregate social welfare (as measured by equation (4)) across all Central and South Eastern European markets,

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24. Our cost figures are only imprecise estimates, since there is considerable (typically ±30%) variation around the mean benchmark values in the cited dataset. In an actual policy application, the numbers can be substituted by the cost estimates of the project promoter, for example.

25. Belarus, Kosovo, and Montenegro are not included in the model.
and calculate the annual net social benefit (ANSB) of an investment by subtracting the estimated annualized investment cost from the change in our welfare measure between the baseline and the after-investment scenario. We rank all pipeline combinations in decreasing ANSB order, and drop the ones that are dominated by another investment with a subset of the pipelines.26

Table 2 shows the main result of our simulations for the Reference baseline. Each column lists the pipelines included in the investment scenario, followed by the social cost-benefit balance.

26. If building Pipelines A and B has a positive ANSB, but building Pipeline A by itself has an even higher ANSB, then we drop the two-element combination, because it is more costly and less valuable than the single pipeline investment. In the reverse case (when B adds value to A), we keep both pipeline combinations in the list, because financial constraints might, for example, prevent the A + B investment, but allow for the less costly A investment to proceed.
Table 2: Ranking of Investments in the Reference Baseline

| From    | To       | Rank | 1 | 2 | 3 | 4 | 5 |
|---------|----------|------|---|---|---|---|---|
| Bulgaria| Serbia   | ×    | × | × |   |   |   |
| Croatia | Hungary  |      |   |   |   |   |   |
| Croatia | Serbia   |      |   |   |   |   |   |
| Greece  | Bulgaria | ×    | × |   |   |   |   |
| Poland  | Czech Rep.|   |   |   |   |   |   |
| Poland  | Slovakia |      |   |   |   |   |   |
| Romania | Hungary  | ×    |   |   |   |   |   |

Welfare increase | 60.3  | 19.2  | 0.9  | 0.0  | 0.0  |
Investment cost  | 27.6  | 15.0  | 2.8  | 2.4  | 12.5 |
Net social benefit | 32.7  | 4.2   | –1.9 | –2.4 | –12.5 |

All values are in million €/year. Welfare changes and net social benefits are valid for the CSEE region.

Table 3: Major Price and Surplus Changes from Best Investment in the Reference Baseline (GR-BG, BG-RS)

| Market   | Prices | Surplus gains and losses | Total |
|----------|--------|--------------------------|-------|
|          | Before | After | Consumers | Producers | Contracts | Infrastructure |       |
| Bulgaria | 30.5   | 26.2  | 182       | –51       | –121      | 32             | 41    |
| Greece   | 24.4   | 24.4  | –4        | 0         | 2         | 32             | 30    |
| Hungary  | 28.0   | 27.6  | 35        | –3        | 0         | –32            | –1    |
| Romania  | 27.0   | 26.9  | 16        | –15       | –1        | 0              | 1     |
| Serbia   | 30.1   | 29.4  | 25        | –1        | –9        | 1              | 16    |
| Slovakia | 24.5   | 24.4  | 4         | 0         | –3        | –18             | –17   |
| Other CSEE | 9   | –1   | –6        | –12       | 2         | 60             |
| Total    | 267    | –71   | –139      | 2         | 60        |

Prices are in €/MWh, all other values in million €/year.

There are only two pipeline combinations with a positive net social benefit. The route from Greece to Serbia through Bulgaria is the most valuable investment, followed by a single pipeline from Greece to Bulgaria. The Romania-Hungary pipeline also yields some additional welfare for the region, but not enough to justify its cost. The pipelines in the 4th and 5th place do not increase welfare at all, because they connect markets with a price difference smaller than the cost of transportation.

In Table 3, we take a closer look at price and surplus changes resulting from the Greece-Bulgaria-Serbia pipeline investment. The first two columns show the before-after market prices, followed by changes in consumer surplus, producer surplus, net profit from long-term contracts, and infrastructure income. The latter category includes operating income and congestion rent on pipelines, LNG terminals, and storage units. We list the markets that are substantially affected in some dimension in separate rows, and add an Other CSEE line for the total welfare change in the region to match with the value in Table 2.

The largest price decrease is in Bulgaria, closest to the low-priced Greek market. Consumers in Hungary, Romania, and Serbia also benefit to some extent, while the rest of the region remains largely unaffected. Overall, consumers gain about €270 million, which is partially mirrored by losses on the producer and long-term contract holder side. The net effect on infrastructure income...
is neutral, although the area gets more of its gas from the south, which redistributes transportation profits from Hungary and Slovakia to Bulgaria and Greece. In the end, the countries benefitting most from the investment are the ones with jurisdiction over the territory where the pipelines run.

5.2 Change of Russian Long-term Contract Delivery Points

In this section, we explore hypothetical baseline and investment scenarios in which the contract delivery points of gas arriving from Russia are moved to the country where the gas enters the European Union. We will further assume that all transit routes from the east avoid crossing the territory of Ukraine. Instead, three other routes will be used: the Nord Stream pipeline with its current capacity under the Baltic Sea to Germany, the Yamal pipeline through Belarus to Poland, and a not-yet-existing pipeline through Turkey to Bulgaria. For simplicity, we will refer to this set of scenarios as No Ukraine transit.27

We assume that all re-routed Russian long-term contracts are delivered to Germany, Poland, or Bulgaria. Specifically, the gas currently destined to Austria, France, Hungary, and Italy will first be sold in Germany, the Czech, Dutch, and Slovakian contract will be sold in Poland, and the gas transported through the Trans-Balkan pipeline will instead arrive through Turkey in Bulgaria. We calculate the revenues of contract holders as if they sold all the deliveries in these three countries, and allow traders in the spot market to profit from distributing the gas across the continent.28

In the spirit of a fair contract renegotiation, we assume that the (implied) wellhead prices of contracts are changed to reflect the difference in transportation fees between the new and the old delivery routes. As a result, if the gas found its way to its former target market, its border price (wellhead price + transportation cost) would be the same as before.

Figure 2 shows the equilibrium outcome of the No Ukraine transit baseline scenario. It uses a map of Europe similar to Figure 1, but the displayed numbers now represent differences in yearly average prices relative to the Reference baseline. Lighter shaded areas experience price decreases, darker shaded ones see their prices rise.

Changing contract delivery points does change market prices across the continent, although only mildly. Prices in Italy and most of Central and South Eastern Europe rise, while consumers in Western Europe become slightly better off. Prices in the smaller designated delivery countries, Poland and Bulgaria, are especially depressed. Overall, Figure 2 suggests that a lack of cross-border capacity prevents some of the gas from reaching its nominal destination.

Taking the No Ukraine transit baseline as a starting point, Table 4 shows the pipeline combinations from Table 1 that are most beneficial to the CSEE region. Connecting Bulgaria to Serbia and Poland to the Czech Republic and Slovakia is the most valuable investment with an ANSB of €195 million. All other projects in the top 5 list are variations on the same idea: letting surplus gas “trapped” in Poland and Bulgaria find its way towards the markets that have previously been supplied through Ukraine.

Welfare calculations show that changing the long-term contract delivery point results in a welfare loss of about €1.5 billion/year relative to the Reference baseline for all modeled countries together.29 Two-thirds of the loss is borne by Ukraine because of the re-routed transits. Contract

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27. In the past, natural gas disputes between Russia and Ukraine have led to supply disruptions to consumers in Central and South Eastern Europe. The aborted South Stream and Turkish Stream projects have both sought to displace Ukraine as a transit country. In this scenario, we assume that a similar project in the south might eventually be completed, although recent political tensions between Russia and Turkey make this unlikely to happen until 2020.
28. In the welfare expression, trading profit is actually turned into congestion rent collected by TSOs and SSOs.
29. Detailed welfare results are available in the Online Appendix which can be accessed at http://bit.ly/2eNMpLw.
holders also have to forgo about €1 bn/year by selling gas in areas with depressed prices. Consumers, on the other hand, end up being better off across the continent on average, even if the gains are unevenly distributed. Specifically, Italy, Ukraine, Romania, Hungary, and Austria are among the countries whose consumers lose most from the change, although this is more than offset by gains in Poland, Bulgaria, Germany, the Netherlands, and France. The overall losses in the CSEE region amount to €680 million/year. Around 30% of this amount can be avoided by carrying out the most beneficial pipeline investment indicated in Table 4.  

30. One might argue that a change in contract delivery points affects the entire European continent to some extent, which will likely spark new investment projects other than the ones listed in Table 1. In this case, the rearrangement of transit routes will likely result in even smaller welfare losses for gas importing countries (although not for Ukraine).
Table 4: Ranking of Investments in the No Ukraine transit and the Croatia LNG Baseline

| From     | To      | No Ukraine transit | Croatia LNG |
|----------|---------|--------------------|-------------|
|          |         | 1 2 3 4 5          | 1 2 3 4 5   |
| Bulgaria | Serbia  | × × ×              | ×           |
| Croatia  | Hungary | ×                  | × ×         |
| Croatia  | Serbia  | ×                  | × ×         |
| Greece   | Bulgaria| ×                  | × ×         |
| Poland   | Czech Rep. | × × × ×         |            |
| Poland   | Slovakia| × × ×             |            |
| Romania  | Hungary | ×                  |            |

| Welfare increase | 237 | 184 | 150 | 144 | 97 | 164 | 113 | 96 | 140 | 98 |
| Investment cost  | 43  | 30  | 25  | 30  | 13 | 41  | 24  | 9  | 59  | 46 |
| Net social benefit | 195 | 154 | 125 | 114 | 85 | 124 | 89  | 86 | 81  | 51 |

All values are in million €/year. Welfare changes and net social benefits are valid for the CSEE region.

Table 5: Major Price and Surplus Changes from Best Investment in the Croatia LNG Baseline (HR-HU, HR-RS)

| Market          | Prices Before | Prices After | Consumers | Producers | Contracts | Infrastructure | Total |
|-----------------|---------------|--------------|-----------|-----------|-----------|----------------|-------|
| Austria         | 24.2          | 24.1         | 10        | −2        | −7        | −19            | −17   |
| Croatia         | 23.2          | 24.4         | −31       | 10        | 0         | 173            | 153   |
| Czech Rep.      | 23.6          | 23.5         | 5         | 0         | −3        | −17            | −15   |
| Hungary         | 27.9          | 27.0         | 94        | −9        | 0         | −55            | 30    |
| Serbia          | 30.0          | 26.2         | 136       | −4        | −48       | −17            | 67    |
| Slovakia        | 24.4          | 24.2         | 11        | 0         | −14       | −38            | −41   |
| Other CSEE      | 47            | −41          | −6        | −12       | −12       |                |       |
| Total           | 273           | −46          | −79       | 17        | 164       |                |       |

Prices are in €/MWh, all other values in million €/year.

5.3 LNG terminal in Croatia

The third baseline scenario simulates the completion of a long-planned LNG regasification terminal with a capacity of 6.5 bcm/year on the Adriatic coast of Croatia. By itself, the LNG terminal has a modest effect on the CSEE region. Average prices decrease by €4.8/MWh in Croatia relative to the Reference baseline (welfare increase of €80 million/year), but almost none of it flows over to neighboring markets due to the lack of interconnectivity. As a secondary effect, competition for LNG sources results in a loss of €20 million/year for Greece. Overall, the LNG terminal in Croatia brings a surplus of €48 million/year to the CSEE region without additional investments.

The right-hand side of Table 4 shows the investments with the highest social return in the Croatia LNG baseline. By far the most valuable project combination is the pair of pipelines from Croatia to Hungary and Serbia, which would increase regional welfare by €124 million/year, net of investment costs. Table 5 shows a breakdown of surplus changes in the countries most affected by the new infrastructure.

Croatia benefits most from the two new export pipelines. Its income from the LNG terminal and the cross-border infrastructure rises by €173 million/year, largely consisting of profits from LNG imports. Consumers in Serbia and Hungary also derive massive benefits from indirect access.
to the LNG market. At the same time, producers and (especially) contract holders suffer some losses due to decreased prices. Pipelines carrying gas from the north towards Hungary and Serbia are also less heavily utilized. Similarly to the Reference baseline, the countries that derive most of the benefits from the projects are the ones involved in the investment decision.

6. DISCUSSION

In this section, we discuss the lessons from our modeling exercise and point out potential pitfalls.

6.1 Welfare-based Regional Project Evaluation

Our starting point was a Reference baseline scenario for 2020, depicted in Figure 1. In our model runs, the central areas of South Eastern Europe have the highest prices. Thus pipelines bringing gas into this region from lower-priced markets have the highest potential for welfare improvement.

The projects on the shortlist in Table 1 offer three distinct directions in which the region, roughly around the core of Serbia, could be supplied. The first one is from the north using expanded capacity from Poland to the Czech Republic and Slovakia; connections from Austria and Slovakia to Hungary already exist. Our simulations suggest that this direction would not yield welfare improvements, because the three countries to be connected already have similar prices.

The second direction is from the south, exploiting the backhaul capabilities of the newly built Trans Adriatic Pipeline and low-priced LNG imports to Greece. In the Reference scenario, this is the most promising alternative, suggesting that the Greece-Bulgaria and Bulgaria-Serbia interconnectors could bring reasonable net welfare improvements across the region, especially in these three markets.

The third direction is from the west, using cross-border pipelines from Croatia to Hungary and Serbia. These projects could substantially increase welfare in the region, but only in connection with a (long-planned) LNG regasification terminal in Croatia that brings in new gas sources. Otherwise, prices in the three markets set to be connected are too similar for the new infrastructure to be worth building.

The welfare analysis in Tables 3 and 5 also illustrates the advantages of a model-based project evaluation. By comparing equilibrium outcomes with and without the new infrastructure, we can provide a nuanced picture of which market participants are likely to gain and lose from the investments across the greater interconnected system. It is possible, for example, that third countries receive indirect positive effects from an investment that would not bring enough direct benefits to its sponsors otherwise. In this case, regional subsidies can be welfare-improving. The opposite outcome, where direct effects are large enough but indirect effects are negative, can also occur. In fact, many of our results fall into the second category, questioning the exact rationale for subsidizing the investments in Table 1.

We have also analyzed the net social benefits of PCIs inclusive of all modeled European countries in our welfare measurement, rather than the CSEE region alone. It turns out that some of the welfare gains in CSEE are actually a redistribution from other EU countries, tilting the cost-benefit analysis against the new investments. In the Reference baseline, all investments yield net welfare reductions (the Greece-Bulgaria pipeline is only marginally unprofitable). The most beneficial project combinations in the other two baselines are also worthwhile investments from an EU point of view.
To check for robustness, we have performed the analysis assuming lower demand for natural gas in 2020. (Tóh et al., 2014) A low-demand baseline leads to more uniform prices across the continent, decreasing the potential benefit of additional pipelines. Accordingly, we find that no project combinations result in a positive ANSB in the Reference baseline, although both the Croatia-Hungary and the Romania-Hungary pipelines are on the verge of profitability for the region. In the Croatia LNG scenario, the Croatia-Serbia interconnector proves to be a robust project.

Our investment analysis is not without a number of caveats. In an actual policy application, one would extend the analysis for several years (possibly decades) after 2020, and examine alternative assumptions about our exogenous parameters (e.g., LNG prices, long-distance transportation infrastructure, contract characteristics). Ideally, there would be some feedback over time from short-run model outcomes into the assumptions driving the results in subsequent years. Such an analysis is beyond the purposes of this paper, however.

The competitive nature of our modeling approach does not allow us to analyze the effects of new investment on the market power of upstream, downstream, and infrastructure firms either. Such effects might be relevant, especially at the time of long-term contract negotiation. We also omit the analysis of short-run disruption scenarios, even though some of the cross-border pipelines could bring considerable benefits in extreme supply shortages. Our results should therefore be taken as an illustration of a regional welfare-based investment (or subsidy) decision method, rather than a definitive list of recommended projects.

6.2 Modified Delivery Routes for Long-term Contracts

The second contribution of this paper is the analysis of a large-scale change in the delivery routes and destinations of long-term contracts from Russia. In our hypothetical (but not entirely unrealistic) situation, no gas arrives via Ukraine, resulting in a large loss of transit income for the country. The effect on welfare in the European gas sector is less drastic. The redistribution of welfare from Eastern to Western Europe is more noticeable than the overall loss resulting from the increased geographic mismatch of supply and demand. A substantial part of the negative effect can even be mitigated by north-to-south pipeline investments within the European Union.

Again, our conclusions are derived from a single baseline scenario, and a more nuanced picture would emerge from the use of a multitude of alternative assumptions. The necessary renegotiation of contract terms could, for example, lead to somewhat different outcomes in terms of contract prices and/or delivery locations.

There are two additional aspects worth discussing. Contrary to our assumptions about the border (destination) prices of contracts remaining the same as before, one could imagine that the current system of price discrimination by destination country would disappear if all contracts were to be delivered at an EU entry point. Although the CSEE region loses welfare when transits through Ukraine stop, it would benefit from having its long-term supply contracts priced according to the market realities in Germany, for example.

With the change in delivery points to the EU border, the long-term capacity bookings on intra-EU pipelines (such as the Poland-Germany, Slovakia-Austria, or Austria-Italy pipeline) could also be freed up and made available for spot trade. These pipelines could even carry gas in the reverse direction with moderate additional investment, further contributing to the emergence of an integrated European gas market.

7. CONCLUSION

In this paper, we have introduced a competitive dynamic natural gas market model for Europe and applied it to evaluate infrastructure projects in Central and South Eastern Europe. Project
rankings are based on the resulting net increase in regional welfare, taking into account all possible combinations of pipelines to be built from the shortlist of proposed PCIs. In a separate baseline case, we also used the EGMM to explore the consequences of changing the delivery points of long-term gas supply contracts from Russia to bypass the territory of Ukraine.

The goal of the paper is to outline an alternative project selection methodology, and not to provide an exhaustive analysis of costs and benefits. For reasons of conciseness, we have for example omitted the simulation of actual supply disruption scenarios.

One important element missing from our paper is the feedback from infrastructure investment into the pricing of long-term contracts. The destination-based price discrimination currently seen in take-or-pay contracts is largely consistent with the lack of alternative supply sources in countries that receive Russian gas at higher prices. As new pipelines bring gas from lower-priced regions, the bargaining position of these countries will also improve. Accounting for these effects in contract pricing is an important area for additional work on our modeling approach.

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