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SEASONAL FLEXIBILITY IN THE EUROPEAN NATURAL GAS MARKET

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21 August 2019

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Seasonal Flexibility in the European Natural Gas Market

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1. INTRODUCTION

Seasonal demand swing, i.e. differences between winter and summer gas consumption, is a crucial feature of the European gas market. Heating demand, which is primarily driven by temperatures, increases gas consumption in winter months but is very low during the summer months. As a result, the aggregated European gas demand in winter months is typically more than twice as high as demand in summer months.[3] European countries balance the demand variation with a mix of flexibility options such as variations in domestic gas production, variations in pipeline or liquefied natural gas (LNG) imports as well as the operation of underground gas storage facilities.

These options differ in terms of their cost and availability. Variations in domestic gas production require free production capacity. Additional imports require both free production capacity at the place of origin as well as free capacity of transport infrastructure. LNG imports are only available to some European countries (as they require regasification terminals). However, increasingly integrated European gas markets allow transferring gas across borders. Gas storages can also provide seasonal flexibility by shifting gas demand from the winter months to summer months.

In recent years, a relative abundance of flexible capacity was observed in the gas market. The main reasons included (i) low gas demand in almost all European countries in the past decade, (ii) investment in additional assets[4] and (iii) integration or European gas markets driven by optimised utilisation of existing assets. This abundance of flexible capacity was reflected by low seasonal gas price spreads on European gas hubs and low utilisation of European regasification terminals.

However, the current situation is a snapshot. In the future, several factors will put significant downward pressure on the oversupply of flexibility options. First, market forces reflect oversupply in lower price spreads between summer and winter months. Lower spreads make investments in additional flexibility less attractive and may even cause a shutdown of existing flexibility options. Second, both the Netherlands and the United Kingdom, the European Union's two largest gas producers, will provide less flexibility in the future. The Dutch government announced a series of directives to limit the maximum annual production from the Groningen field in response to seismic activity.[5] In terms of annual production, an initial cap of 42.4 bcm p.a. from January 2014 was reduced to 21.6 bcm p.a. for the 2017-2018 gas year, with the ultimate goal of completely shutting down the Groningen field by 2030 (Honoré, 2017; Snam et al., 2018). Furthermore, in 2016, the Dutch government set regulations to ensure that annual gas production is spread as evenly as possible throughout the year. In terms of monthly fluctuations, this regulation fixes gas extraction from the Groningen field to a range of plus or minus 20 % per month (Honoré, 2017). Taken together (Figure 1), this reduces seasonal flexibility from the Groningen field by around 85 % (from a swing of 4 - 5 bcm between

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[3] Over the period 2010 to 2017, natural gas consumption of EU28 in three winter months was on average 2.2 times higher than in three summer months (Eurostat, 2018).

[4] ENTSOG (2018) reports about completion of 42 infrastructure projects in period between 2015 and 2018.

[5] REEK (2014) estimates that the total European production flexibility was 213 mcm/day in 2012, out of which 163 mcm/day were supplied by the Groningen field.

winter/summer seasons in 2011 – 2013 to just 0.6 bcm in 2017/18).[6] The UK government also states a rapidly declining trend for domestic gas production.[7] The projected production volume for 2030 is 17.8 bcm p.a., which constitutes a drop of more than 50 % compared to volumes produced in 2015. Consequently, gas import dependency increases significantly – from 44 % in 2015 to 74 % in 2030 (The Oil and Gas Authority, 2016). Europe has to substitute this drop in domestic production volumes and associated flexibility with alternative options (discussed above) and find a new cost-optimal way to cover the seasonal demand swing.
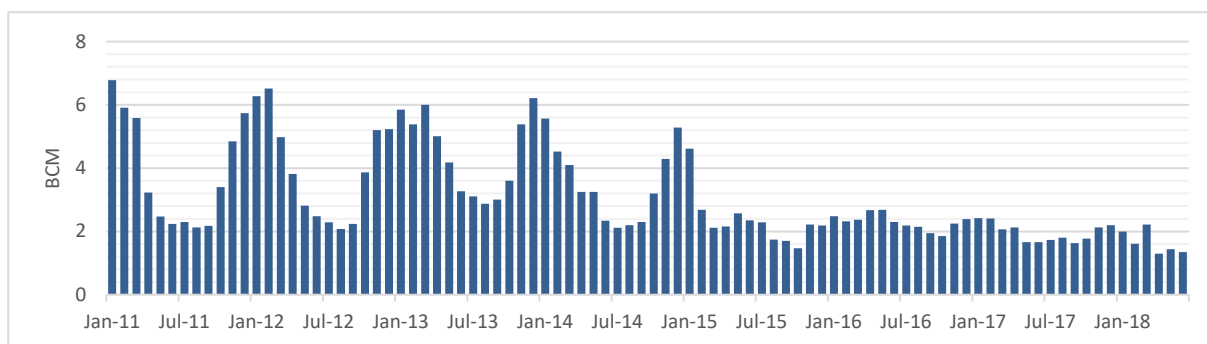

Figure 1: Natural gas monthly production from the Groningen field, Jan 2011 – June 2018. Based on NAM.[8]

On the other hand, new infrastructure projects are expected to enter the market. The TYNDP infrastructure report (2018) published by ENTSOG identifies around 120 planned transmission and compressor station projects,[9] 27 projects related to LNG terminals and 9 projects related to underground storage facilities; 46 of these projects have been approved for investment. Almost 75 % of the submitted initiatives are expected to be commissioned no later than 2022.

Taken together, the future need for seasonal flexibility (and implied scarcity as well as price signals) remains unclear. An assessment must take into account regulatory and economic changes in the gas market structure. The application of an economic modelling framework can reveal the market fundamentals and the evolving structure of market flexibility options. Furthermore, it provides quantitative results.[10]

This paper analyses seasonal gas demand swing, and the necessary flexibility covering it, with a fundamental modelling framework. We analyse the role of different flexibility options (domestic production, pipeline and LNG imports, and gas storages) in covering European demand fluctuations in monthly resolution. We contribute to the existing discussion on seasonal flexibility by addressing the problem with a mathematical gas market optimisation model. With this model, we simulate the operation of the market over a long time period (from 2018 to 2030,

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[6] 21.6 bcm p.a. / 12 = 1.8 bcm per month; 0.6 bcm = 1.8 bcm * (1 + 20 %) - 1.8 bcm * (1 - 20 %).

[7] See: https://www.gov.uk/guidance/oil-and-gas-uk-field-data

[8] See: https://www.nam.nl/gas-en-oliewinning/groningen-gasveld.html

[9] These include 46 interconnection projects between two or more countries, 21 projects related to construction of compressor or metering stations, 18 projects related to new import or production development, 21 projects concerning modernization or enhancement of a system, 9 reverse flow projects, 4 projects supporting the switch from low-calorific to high-calorific gas and 2 projects concerning methanisation of new areas.

[10] However, it should be noted that an applied mathematical model cannot (and is not intended to) show a comprehensive picture of the future. Instead, it evaluates assumption-based possible outcomes for the market players who provide supply flexibility and estimate market development trends, as well as to form a necessary background for a discussion.

combined with realised historic values for comparison). Thus, we can explore future market developments driven by changing supply and demand fundamentals. Empirically, our paper provides valuable insights with regard to declining North Western European gas production, resulting from the Groningen event (see data section for NL) and recent developments in the UK (see also data section below). Such structural breaks are optimally addressed by fundamental models. Furthermore, we differentiate between LNG and pipeline imports, which allows for the analysis of specific flexibility features of pipeline versus LNG supplies. In terms of methodology, we develop a gas market model and publish the complete source code (which is still uncommon for gas market models). Furthermore, we propose a new metric that improves the quantification of supply sources' seasonal flexibility provision. The metric extends the well-established coefficient of variation.

The remaining part of the paper is organised as follows. Section 2 describes the methodology used for this study. We present a modelling framework, a mathematical description of a market optimisation model and its associated data. Section 3 provides the modelling results and our interpretation. We begin the discussion by illustrating modelling results in the form of monthly gas demand profiles to lay out the background for the analysis. We continue with an investigation of the quantitative contributions of supply sources to cover gas demand. In the second part, we analyse which supply source offers the most flexibility in covering seasonal demand fluctuations. Finally, in Section 4, we conclude with major findings and outline our ideas for future work.

2. METHODOLOGY AND DATA

We develop and apply an optimisation model that covers the European gas market and its neighboring regions. The model is formulated as a linear programming problem with perfect foresight. This allows solving the large-scale optimisation model with intertemporal constraints and a high temporal granularity over the large time span. As such, decision variables (e.g. gas production, trade, and storage activities) have a time resolution of 12 consecutive months for each modelled year. We model a time period from 2018 to 2030; furthermore, we add realised historic values from 2014 to 2017 for comparison. The spatial coverage encompasses European countries and major non-European gas exporters (Norway, Russia, United States, Algeria, Libya, Nigeria, and Qatar). The dataset, including all necessary economic and technical data, is taken from publicly available sources. We discuss our assumptions on gas demand and supply structure, and transmission infrastructure elements below. The model is formulated in GAMS[11] and solved with a CPLEX solver. The applied GAMS code, associated data, and processing of the results are available online: http://bit.ly/2W98hmI

2.1 Related Work

Mathematical modelling of energy markets has a long history. Interest in model-based analyses of the European energy sector increased at the end of 1990s, when the European Commission initiated the liberalization policy measures. Several studies analysed the operation of

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[11] General Algebraic Modeling System (GAMS), more detail at: https://www.gams.com/

restructured competitive energy markets (e.g. Bohringer et al. (2002); Müsgens (2006); Neuhoff et al. (2005)). The growth of computing power and advancement of mathematical models fuelled by the challenges of the energy transition process facilitated the elaboration of more sophisticated models. A number of authors have considered the effects of electricity physical flows through the transmission grid (e.g. Kunz (2018); Schäfer et al. (2017); Tranberg et. al. (2018)). A large and growing body of literature has focused on stochastic modelling of energy markets (e.g. Mobius and Musgens (2017); Seljom and Tomasgard (2015); Su et al. (2015)). Several studies have highlighted interdependencies between electricity and gas markets (e.g. Lienert and Lochner (2012); Riepin et al. (2018); Weigt and Abrell (2016)).

Mathiesen et al. (1987) were among the first to model the European gas market. Since then, a considerable amount of research has been oriented to the economic modelling of the European gas market, such as: Abada (2012); Boots et al. (1980); Chyong and Hobbs (2014); Egging (2010); Gabriel et al. (2005); Hecking and Panke (2012); Holz (2009); Lise et al. (2008); Midthun (2007); Spiecker (2013). Although some of these studies include seasonal representation of gas market within their model formulations, an applied analysis of seasonal flexibility in the European gas market was not in focus.

Most recent studies which use a bottom-up optimisation framework to analyse flexibility in the European gas market focus on short-term flexibility (often an analysis deals with the security of supply issues, e.g. the ability of the gas system to sustain operation under shocks scenarios). REEK (2014) analyses the flexibility of the European gas market, focusing on the contribution of interconnectivity, gas storages and demand-side adjustments to the resilience of the gas system during supply shock disruptions. Tóth et al. (2017) examine the infrastructure priorities of the EU's LNG and underground gas storage strategies under different short-term supply/demand shock scenarios.

Seasonal flexibility in the European gas market has not yet been addressed with a fundamental gas market model as previous studies have relied on other methodologies. For example, Höffler and Kübler (2007) propose a simple top-down analysis to discuss supply flexibility, wherein they project the future additional demand for gas storages in North Western Europe. The Netherlands Institute of International Relations Clingendael (2011) provides an outlook on seasonal flexibility in North West Europe, addressing an issue of a supply capacity adequacy to meet gas demand over a severe winter. They propose and compare several statistical methods to evaluate the required amount of seasonal flexibility needed in the period from 2011 to 2020. A comprehensive empirical investigation of the role of gas storages in the European gas market is provided by a report issued by the European Commission (2015). The report also discusses competition between gas storages and alternative sources of flexibility and suggests using a coefficient of variation to measure the contributions of supply sources to demand swing. The analysis focuses on the years 2013 and 2014.[12] Our work complements this report with respect to seasonality with an analysis of the future situation up until 2030; furthermore, we suggest an improvement to the methodology of measuring seasonal flexibility provision (see Section 3.2).

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[12] Despite of the fact that necessary data is available for the years 2008-2014, the authors claim that consistent time series analysis is not possible due to the change of Eurostat reporting practices (for a number of countries, from January 2013, transit gas flows were included in import volumes).

To sum up, previous studies either discussed seasonal flexibility using top-down or statistical approaches or they maintained a narrow focus, dealing with the issue of short-term flexibility (mainly in the context of the security of supply). Furthermore, we can conclude that a systematic understanding of how to measure the importance of a particular supply source contributing to a seasonal demand swing is still lacking. Hence, our approach of analysing seasonal flexibility in a monthly resolution with a large-scale gas market model contributes significantly to the literature. Furthermore, we contribute to the methodological question of how to measure the contributions of different flexibility options by proposing a new metric.

2.2 Model structure

The model structure consists of a network of nodes. A node represents a country or a group of several countries from one region. For this paper, we consider a system of 27 nodes representing countries most relevant for the European gas market (Figure 2). Nodes are connected by gas transmission infrastructure, which consists of (i) cross-border interconnection pipelines within the EU, (ii) cross-border pipelines with non-EU parties (such as Nord Stream) and (iii) gas liquefaction and regasification terminals. All gas transmission infrastructure is represented via one-directional arcs.[13] To model bidirectional flows, two one-directional arcs are utilised. The model neglects friction and pressure drops in the gas network.[14]

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[13] We use entry-exit point capacities at the transmission level. Data about distribution gas networks is scarce and has not been included. Furthermore, a modelling exercise involving the representation of a detailed gas infrastructure within all the regions of a model would exceed a reasonable computational time limit.

[14] It is a common practice in existing models of this type that allows keeping optimisation problem convex. Midthun (2007) provides examples of how these issues can be addressed in optimisation models.
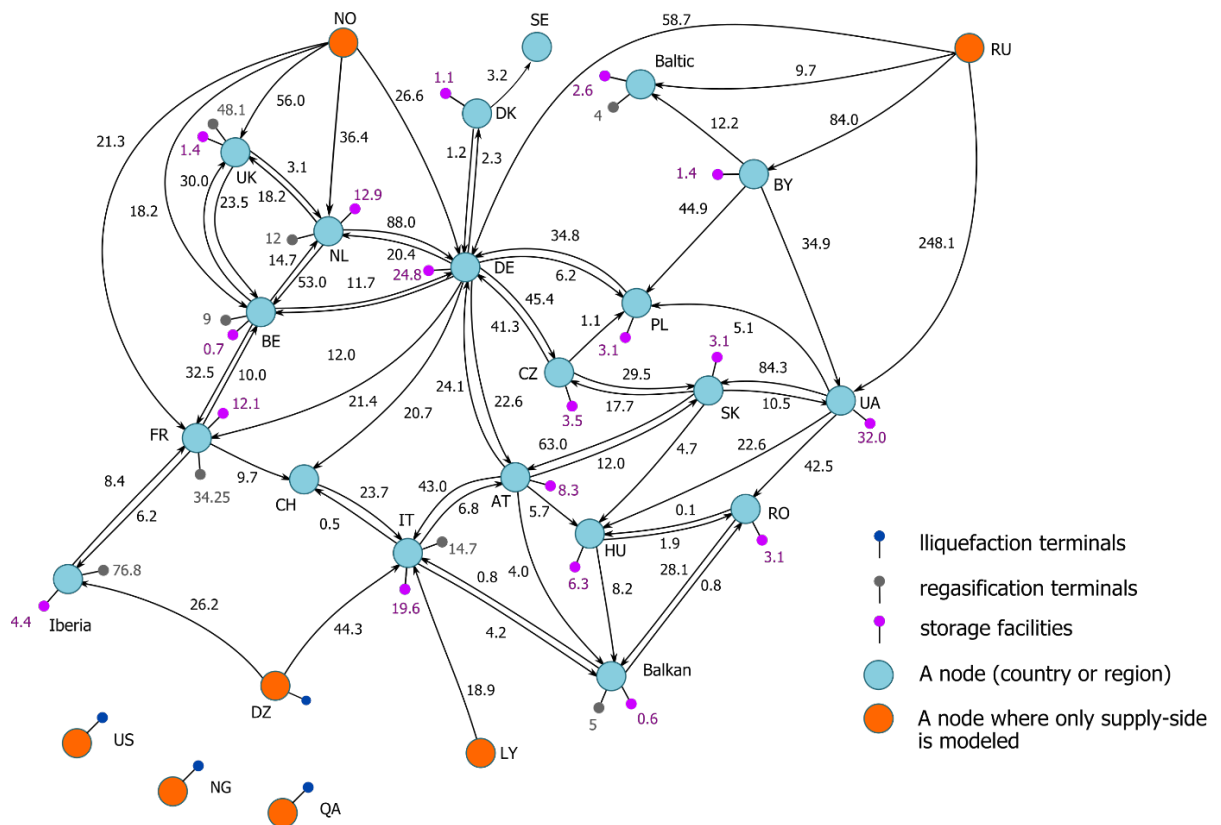
Figure 2: Nodes included in the model and capacities of gas infrastructure elements for 2017 (in bcm p.a.).[15]

The model includes the following activities that can occur within every node: gas production, consumption, storage activities (injection and withdrawal), export and import via pipeline and LNG routes. The only exception to this rule is that in the case of non-EU gas exporters, we model only the supply-side by using residual supply curves, i.e. gas supply potentials available to European markets (orange in Figure 2).[16] It is important to note that the gas production for export is optimised endogenously for both the non-EU gas exporters and the European domestic gas producers. Demand-side consists of exogenous gas consumption levels. To account for seasonality, the annual consumption is broken down to monthly levels, based on historical average demand profiles for each country (or group of countries). Demand side response is not considered in our analysis because data on country specific potentials is generally not available. Furthermore, European Commission (2015) argues that the role of demand side response as a flexibility tool in European gas market is limited. We incorporate long-term contracted volumes (minimum take-or-pay levels) as lower bounds for gas deliveries between respective nodes to ensure a realistic representation of gas supply flexibility options. Also, we apply a special constraint for Dutch production to incorporate the impact of regulation on the Groningen field's flexibility.

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[15] Baltic node represents Estonia, Latvia and Lithuania; Balkan node represents Slovenia, Croatia, Serbia, Bulgaria and Greece; Iberia node represents Spain and Portugal; the European countries that are not represented in the model are Cyprus, Finland, Luxembourg and Malta.

[16] A modelling exercise incorporating the operation and development of domestic markets in these nodes would require a global gas model.

The model algorithm receives exogenous input data and searches for the decision vectors matching gas demand and supply with respect to minimising the total cost function. Optimal solution implies that all arbitrage opportunities across time and space are exhausted to the extent that infrastructure (in particular production, transportation and storage infrastructure) permit. The results of the model include spatial and temporal decisions on gas production, transportation over the pipeline or LNG arcs and gas storage. Furthermore, marginal costs for gas consumption are calculated.[17] The incorporation of gas storages in the model requires (and guarantees) intertemporal optimisation.

It is important to note that the model is designed to provide a quantitative assessment of possible future developments by capturing economic aspects of decision making in a competitive gas market.[18] The model can simulate market operation based on the concept of the supply and demand equilibrium and accounts for dynamic factors. However, the reader should remember that our modelling approach is in part based on estimates, e.g. regarding future developments as well as unavailable parameters.

2.3 Declarations

The following notations are valid for the gas market model formulation used in this paper.

2.3.1 Sets and indices

$n,m \in N$ all nodes in the network

$c \subset N$ nodes where consumption activity occurs (blue in Figure 2)

$p \in P$ gas production facilities[19]

$t \in T$ time periods (months)[20]

2.3.2 Parameters and functions

We use subscripts for indexation. For readers' convenience, we use upper case letters for exogenous variables (parameters) and lower case for endogenous variables. For example, a parameter $PROD\_CAP_{p,n,t}$ sets an upper constraint for the gas production from each facility p located in a node n for the time period t.

$PROD\_COST_{p,n}$ marginal production costs

$PROD\_CAP_{p,n,t}$ available production capacity

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[17] Marginal costs for gas consumption are derived from the dual variable of each node's gas balance constraint. An infinitely small relaxation of this constraint (i.e. one unit of gas less to be consumed) returns marginal savings from producing, transporting and (if needed) storing that unit. Thus, marginal costs can be considered as price indicators in a competitive market.

[18] We rely on the assumption of perfect competition. See, e.g., Chyong and Hobbs (2014); Hecking and Panke (2012) and Holz (2009) who discuss strategic aspects within the European gas market.

[19] Elements of set P come from linear piecewise approximation of the logarithmic production cost function per node.

[20] The temporal structure in the model consists of the sets of consecutive years and month. The tracking of the year index is not shown for clarity.

$ARC\_CAP_{n,m,t}$	transmission capacity between n and m nodes (includes LNG routes and exogenous infrastructure capacity expansions)
$TRANS\_COST_{n,m,t}$	marginal transmission costs between n and m nodes (includes LNG routes)
$CONSUM_{n,t}$	gas consumption
$WGV_{n,t}$	working gas volume of storage facilities
$INJ\_CAP_{n,t}$	storage injection capacity
$WITH\_CAP_{n,t}$	storage withdrawal capacity
INJ_COST	storage injection costs
$WITH\_COST$	storage withdrawal costs
$LOSS$	gas losses per storage cycle
$LTC_{n,m,t}$	take-or-pay levels of gas deliveries under the long-term contracts

2.3.3 Variables

$prod\_vol_{p,n,m,t}$	productions and exports of p's facility located in a node n
$\exp\_ph_{p,n,m,t}$	physical gas flows over the arc $n \to m$
$arc\_flow_{n,m,t}$	total physical gas flow over the arc $n \to m$
$level_{n,t}$	gas stock level in storage facilities located in a node n
$inj_{n,t}$	injections into gas storage facilities located in a node n
$with_{n,t}$	withdrawals from gas storage facilities located in a node n

2.4 Model formulation

The objective function (1) represents the total system cost, which consists of aggregated gas production costs (i), gas transmission costs over pipeline and LNG routes[21] (ii), and gas storage costs (iii).

$$Min\,Total\_Cost = \sum_t \left\{ \begin{array}{l} \sum_{p,n,c} \left(prod\_vol_{p,n,c,t} \cdot PROD\_COST_{p,n}\right) \quad \text{(i)} \\ \sum_{n,m \neq n} \left(arc\_flow_{n,m,t} \cdot TRANS\_COST_{n,m,t}\right) \quad \text{(ii)} \\ \left(\sum_c inj_{c,t} \cdot INJ\_COST + with_{c,t} \cdot WITH\_COST\right) \quad \text{(iii)} \end{array} \right. \quad (1)$$

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[21] The costs of liquefaction are modelled as costs of using the "virtual arc" between gas production and liquefaction activities. Similarly, the costs of regasification are modelled as costs of using the "virtual arc" between gas regasification and consumption activities.

The objective function is subject to the following set of technical and balance constraints. Equation (2) limits the quantities of gas produced and exported by each production facility to its production capacity. Equation (3) ensures that the arc capacity constrains the total gas flow over the specific arc. Equation (4) ensures that the entire quantity of gas imported and withdrawn from storage by each node equals the entire quantity consumed and injected into storage. Equations (5) ensure that the gas quantity balance in the network is maintained. Equation (6) sets a constraint on a minimal amount of gas to be produced and dispatched under long-term contracts between specific nodes. Equation (7) defines the storage level.[22] Equations (8), (9) and (10) represent storage capacity, injection capacity, and withdrawal capacity constraints respectively. Equation (11) sets a production flexibility constraint for the Netherlands. Finally, (12) specifies non-negativity constraints for decision variables.

$$PROD\_CAP_{p,n,t} - \sum_c prod\_vol_{p,n,c,t} \geq 0, \forall p, n, t \tag{2}$$

$$ARC\_CAP_{n,m,t} - arc\_flow_{n,m,t} \geq 0, \forall n, m, t$$

Where:

$$arc\_flow_{n,m,t} = \sum_p exp\_ph_{p,n,m,t} \tag{3}$$

$$\sum_{p,n} prod\_vol_{p,n,c,t} = CONSUM_{c,t} + with_{c,t} - inj_{c,t}, \forall c, t \tag{4}$$

$$\left[\sum_{m \neq n} prod\_vol_{p,n,m,t} - \sum_{m \neq n} exp\_ph_{p,n,m,t} \right] = 0, \forall p, n, t$$

$$\left[\sum_{m \neq n} exp\_ph_{p,m,n,t} - \sum_{m \neq n} prod\_vol_{p,m,n,t} \right] = 0, \forall p, n, t \tag{5}$$

$$\sum_p prod\_vol_{p,n,m,t} - LTC_{n,m,t} \geq 0, \forall n, m, t \tag{6}$$

$$level_{c,t} = level_{c,t-1} + (1 - LOSS) \cdot inj_{c,t} - with_{c,t}, \forall c, t \tag{7}$$

$$WGV_{c,t} - level_{c,t} \geq 0, \forall c, t \tag{8}$$

$$INJ\_CAP_{c,t} - inj_{c,t} \geq 0, \forall c, t \tag{9}$$

$$WITH\_CAP_{c,t} - with_{c,t} \geq 0, \forall c, t \tag{10}$$

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[22] At the start of the first month, storage levels are exogenously fixed at 60%. Reciprocally, at the end of the last month, storage levels have to reach 60%. This prevents the 'finite time horizon' problem, which means that model algorithm will tend to withdraw all gas from storage facilities by the end of the last year (to maximise profit by using value of gas stored).

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$$0.8 \leq \frac{\sum_{p,m} prod\_vol_{p,n,m,t}}{\sum_{p,m} prod\_vol_{p,n,m,t-1}} \leq 1.2, \forall t \geq Jan16, n = NL \tag{11}$$

$$prod\_vol_{p,n,m,t}, exp\_ph_{p,n,m,t} \geq 0,$$

$$level_{n,t}, inj_{n,t}, with_{n,t} \geq 0 \tag{12}$$

2.5 Data

Data for the existing cross-border interconnection pipelines is based on the ENTSOG (2017) capacity map. Data for LNG liquefaction and regasification terminals was acquired from the GIE transparency platform[23] and GIIGNL (2016). The model also incorporates exogenous capacity expansions of gas infrastructure (including transmission network, storages and regasification terminals). The structure of the system's development is harmonised with the ENTSOG TYNDP (2018) report. Only units with final investment decision status are included in the dataset.[24] In this study, we do not include endogenous capacity expansions.

We also use the ENTSOG TYNDP (2018) report for data on gas supply potentials.[25] Gas demand projections for European countries are based on the EUCO30 demand scenario from the same source.[26] The annual gas demand levels are broken down to a monthly structure for each node. Monthly demand profiles are calculated based on historical average monthly gas consumption data from Eurostat (2018).

We analysed numerous public information portals, open-source literature, and relevant academic papers to parametrise the cost structure of gas production, transmission and storage. Production costs are calculated as linear piecewise approximations to logarithmic cost functions, which are calibrated based on Chyong and Hobbs (2014).[27] Transmission costs are calculated as a linear function of pipeline lengths. Following the natural gas modelling literature (Chyong and Hobbs, 2014; Fodstad et al., 2016) and publicly available estimates (ACER, 2018) transmission costs are assumed to be 1.2 €/MWh per 1000 km. For all underwater transmission routes transmission costs are 2.0 €/MWh per 1000 km. Liquefaction and regasification costs are assumed to be 3.7 €/MWh and 0.7 €/MWh respectively (Fodstad et al., 2016; Team Consult, 2017). LNG shipping costs are calculated as a function of the distance between nodes,[28] average vessel speed (18 knots), average vessel capacity (150.000 m³) and charter rates (69.000 €/day) based on GIIGNL (2016) and Rogers (2018). Information about average vessel speed and capacity combined with the charter costs allows for computing costs per voyage (0.19 €/MWh

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[23] See: http://www.gie.eu/index.php/maps-data

[24] New infrastructure is typically being added to the model dataset each January (i.e. all units that are planned to be commissioned in 2020, will be 'launched' by the model in Jan 2020).

[25] Supply potential is defined as '*the capability of a supply source to supply the European gas system in terms of volume availability*'. We take the maximum supply potential for each supplier. For more detail see: https://www.entsog.eu/public/uploads/files/publications/TYNDP/2018/entsos_tyndp_2018_Final_Scenario_Report.pdf

[26] EUCO30 is a core policy scenario produced by the European Commission. The scenario models the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014, but including an energy efficiency target of 30%.

[27] For more detail, see Appendix A.

[28] We use https://sea-distances.org/.

per 1000 km). This data, combined with the distance between nodes gives shipping costs in €/MWh per route. For example, the shipping costs between the Qatar and the UK nodes (distance is approx. 9875 km) are accordingly estimated to be 1.95 €/MWh. Hence, the delivery costs (including liquefaction, regasification and shipping) of one MWh via the LNG route for these two nodes amount to €6.35.[29] Due to limited information available concerning the actual price paid by storage users, we assume variable costs to be uniform and equal to 2.0 €/MWh for all storage nodes in the model. According to European Commission (2015), this cost level should represent the minimum price to cover storage marginal operation costs and transport fees between storage sites and virtual trading points.

Data about national storage capacities, as well as about maximum monthly injection and withdrawal rates are based on the GIE transparency platform. This data was aggregated on the node level (i.e. each region has one representative storage node). We assume storage losses to be 1.5 % per cycle.[30] Also, we incorporate European strategic storage requirements based on data from CEER (2014) and European Commission (2015).[31] Thus, country-specific shares of storage capacities, which are booked for strategic storage, are exogenously fixed and not included in the model's decision space. Storage obligations, in turn, are not included in the model.[32] Thus, in our modelling framework, gas storage utilisation is driven by price signals only.[33]

Our model incorporates existing long term contracts based on data from a study by Neumann et al. (2015), which contains a literature survey on existing global long-term contracts covering both pipeline and LNG deliveries.[34] In particular, we use information on contracting parties, annual contracted gas volumes and contract expiration dates. As information about Take-Or-Pay levels is not disclosed, we assume a level of 70 %. This data is used in the model as an exogenous constraint specifying the minimum bound on a trade variable between respective nodes.[35] This constrains diversification of supplies by importing countries that would not have been captured if the long-term obligations had been omitted.

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[29] We use a conversion rate of 1 bcm = 10760000 MWh to report quantities with a more convenient metric.

[30] This assumption follows Egging (2010) who finds storage losses to vary between 1 % and 1.5 % depending on storage operator information and local characteristics.

[31] *Strategic storage* refers to a mechanism under which a part of storage capacities is removed from the market, mainly by the TSO, for use only in extreme circumstances.

[32] *Storage obligations* require market participants (mainly gas suppliers) to secure storage capacity and ensure that a certain amount of gas is stored and available at a specified time.

[33] Gas storages have multiple functions apart from covering seasonal flexibility needs, e.g. covering short-term flexibility needs and system security needs. In this paper, we focus exclusively on seasonal flexibility. Note that we do not deduct storage capacities that are used for short-term flexibility needs. Thus, we establish an upper limit of flexibility available for seasonal needs from gas storages. However, benchmarking our results with the historical data (see Figure 3) suggests that modelled injection and withdrawal gas volumes are in line with the history for the European and country-specific cases.

[34] The data covers 426 long-term (five years and more) gas supply contracts, of which 127 cover pipeline deliveries and 299 cover LNG shipments.

[35] An example of endogenous modelling of the long-term contractual aspects (both the price formation and volumes) can be found in Abada (2012).

3. RESULTS

The following sections discuss the numerical results of our model setup. The first section investigates the quantitative contributions of supply sources to cover gas demand. We focus on competition between different flexibility options to cover seasonal demand swing. The second section introduces a novel quantitative metric that measures the contribution of different flexibility options to meet seasonal demand swing. We also apply this metric to quantify which supply source offers the most flexibility in covering seasonal demand fluctuations and how it changes over time.

3.1 Quantitative supply contributions by source

The gas supply profiles follow the seasonal structure of demand. A certain "base load" has to be covered throughout the year. In addition, heating demand increases gas consumption in winter months. We distinguish four options for providing natural gas to European consumers during any particular month: domestic gas production, pipeline imports, LNG imports and storage withdrawals.[36]

Since our modelling set-up implies the market clearing mechanism that minimises total cost, the simulated supply mix at every node in every month is formed based on a "merit order" principle (based on ascending order of marginal costs). A strength of our approach is that while doing so, it also takes intertemporal constraints, in particular with respect to storages, into account. As a result, supply sources with the lowest value-chain costs are the first to be dispatched to meet gas demand. More expensive supply sources are used to satisfy the "peak load". However, intertemporal optimisation may change this picture, e.g. saving (free) domestic production in a summer month to increase production during a winter month.

Figure 3 illustrates modelling results for quantitative gas supply contributions to cover monthly gas demand. We show the European aggregated demand profile, as well as three selected nodes: the two countries with highest gas consumption in Europe (Germany and the UK) and the Netherlands (due to significant expected changes in production). For the historical outlook, we plot data from Eurostat[37] (to the left of the separation line) next to the model simulation results (to the right of the separation line). It is important to note that the data from Eurostat does not differentiate between pipeline imports and LNG imports. However, in our model, we are able to differentiate. Hence, Eurostat's aggregated net imports (i.e. imports minus exports) should be compared to the sum of pipeline imports and LNG imports. In addition, Dutch domestic production includes gas volumes used for exports (therefore, for the period of 2014 – 2017, domestic production exceeds Dutch consumption levels).[38]

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[36] Note that withdrawals from storages can be a supply source for one month but the gas has to be injected in the form of increased consumption in another, prior month, first. In aggregate, gas storage is a net consumer (due to losses) but an important source for flexibility.

[37] This data is available at: https://ec.europa.eu/eurostat/web/energy/data/database

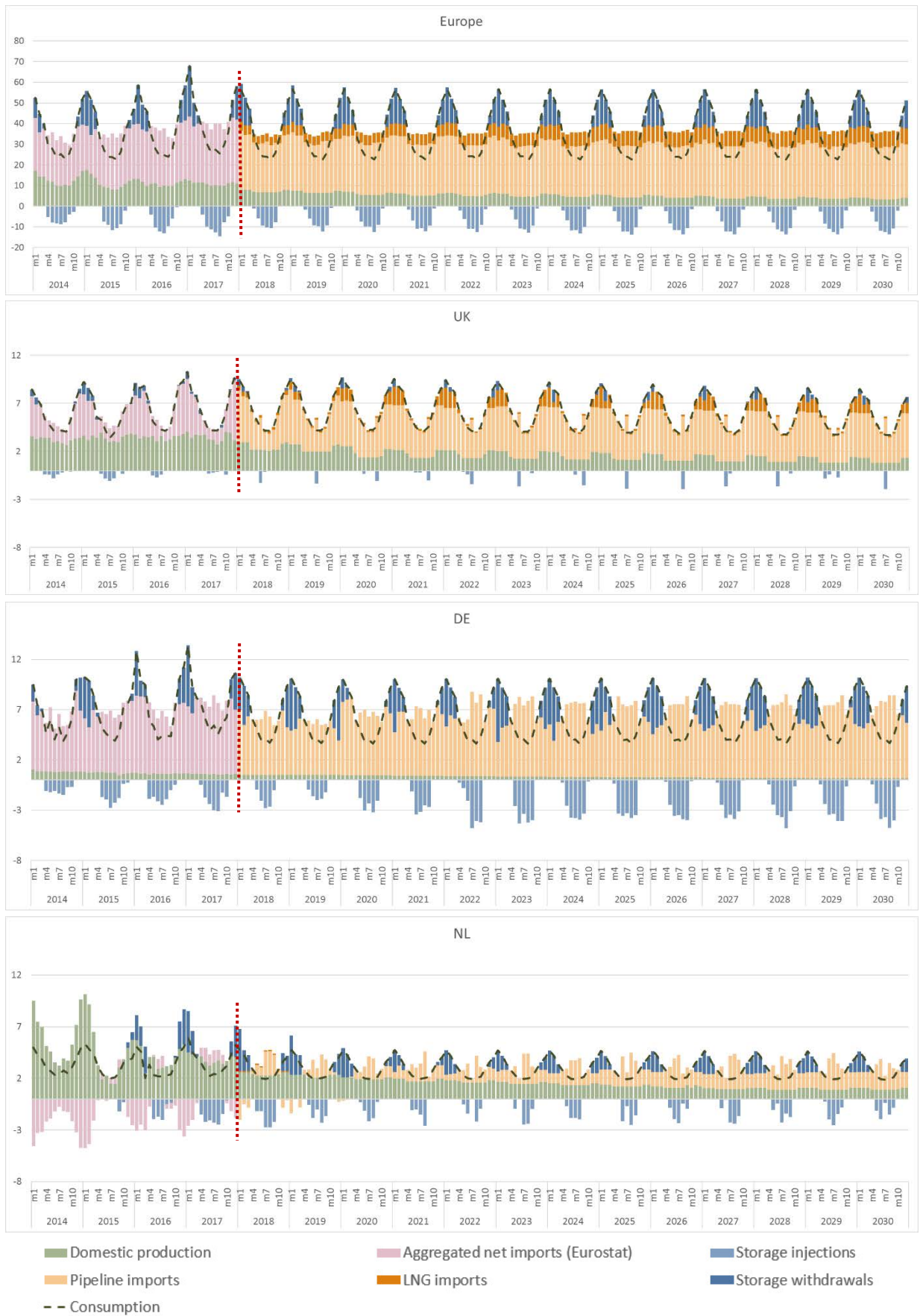[38] No data is available for Dutch gas stock changes for year 2014 in Eurostat.

Figure 3: Quantitative Gas supply contributions for selected countries in bcm per month.

It can be seen that base load during the year is mostly covered either by domestic production (e.g. the Netherlands until 2018), pipeline imports (e.g. Germany) or a combination of these two (e.g. the UK). Seasonal demand swing is covered by country-specific combinations of all four sources. Combinations depend on geographical position, domestic production volumes, and flexibility, as well as on the availability of transmission infrastructure (including pipeline and LNG routes) and production capacities of gas exporters.

Figure 3 also illustrates how the two major European domestic producers UK and NL compensate their respective decrease in production volumes. The Netherlands, which became a net gas importer in 2017, increasingly relies on pipeline imports and storages to cover seasonal flexibility. The picture for the UK is different: while domestic annual production decreases in the future, it still provides seasonal flexibility. The latter is partially driven by a relative lack of alternative flexibility sources (in particular storage facilities, see Figure 4 below for detailed discussion).

To further improve the visualisation of seasonal flexibility options' utilisation further, we also present monthly demand levels in descending order of magnitude, forming load duration curves.[39] Figure 4 presents load duration curves for selected nodes on a monthly resolution, starting with the highest demand month on the left, for the years 2020, 2025 and 2030. The figure provides several insights into the utilisation levels of gas supply sources, its seasonality and the future role of gas storages.

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[39] While the term is mostly used in the context of electricity markets, the underlying idea is also useful to visualise the use of gas market flexibility sources.
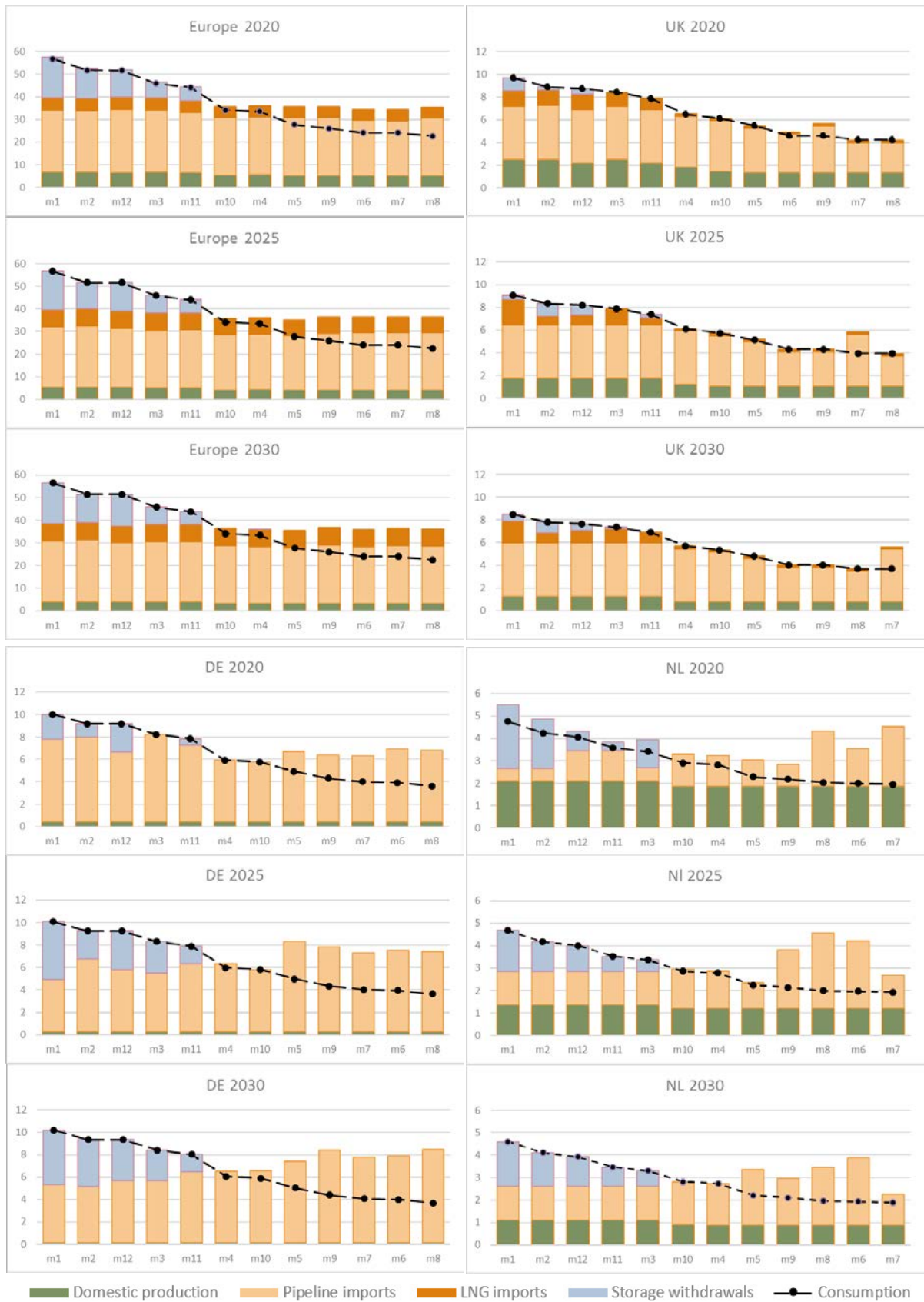
Figure 4: Annual load duration curves for selected countries in bcm per month.

On the European level, the results show even more prominently what we already pointed out in the discussion of Figure 3:

- First, what stands out in Figure 4 is that storage utilisation provides most flexibility on a European level. Storage withdrawals during peak demand remain high over the modelling horizon.

- Second, the share of pipeline gas imported (relative to gross consumption) does not change significantly over the modelling period. LNG has an increasing role in the European consumption mix replacing the drop of domestic European production. Compared to 42 bcm of LNG imported by Europe in 2014 and 60 bcm in 2017, the volume of LNG imported in our model simulation is 61 bcm in 2020 and 91 bcm in 2030. Thus, LNG does not become the game changer some expect (see, e.g. Wilfried Martens Centre for European Strategy (2016)). Potential LNG imports are available to Europe at larger quantities. The hypothetical maximum of LNG supply available to Europe assumed in the model is 103.2 bcm in 2020 and up to 158.3 bcm in 2030. However, the share of LNG in European imports depends not only on 'free' world liquefaction capacities and an LNG costs chain, but also on the availability and costs of alternative supply sources and the European gas demand.

- Third, the model forecasts significant free seasonal flexibility remaining in the European system over the modelled period. With regard to storage capacities (and injection/withdrawal volumes), only 49 – 60 bcm (out of approx. 110 bcm of working gas capacity) is withdrawn annually.[40] With regard to LNG, annual utilisation of LNG terminals increases from 29 % in 2020 to 43 % in 2030. This implies significant available but unused LNG import capacity (however, country-level utilisation rates of regasification terminals vary widely). Nonetheless, events not analysed in this paper (e.g. supply interruptions, exceptionally cold and long winter periods) require additional flexibility and a more detailed analysis.

An analysis of country specific results reveals further insights.

The UK historically had a relatively low amount of gas storage facilities (for more detail see Fevre (2013)). The working capacity became even lower in 2017 after the permanent stop of Rough storage operations with 3.3 bcm of working capacity (approx. 70 % of all storage capacity in the UK). As a result, the working capacity of gas storages in the UK was reduced to 1.4 bcm p.a., which can be compared to a gross national consumption of 77.6 bcm in 2017 (Eurostat, 2018). The remaining storage capacity is utilised at 100% according to the modelling results. Additional flexibility in the UK is provided by LNG, which covers primarily winter demand, thus taking the role of a seasonal peak supplier. The importance of LNG for the UK gas supply increases over time. Furthermore, it is noteworthy that even declining national production will contribute to flexibility. Figure 4 shows this clearly for the UK.

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[40] This observation reconfirms that reserving a certain share of storages for short-term flexibility need would most likely not affect results in a context of our analysis.

The results in Germany and the Netherlands are substantially influenced by Russian gas. In the case of Germany, the Nord Stream 2 pipeline project, which is included in our model from January 2020, influences storage utilisation immediately. Figure 4 reveals that pipeline imports partially substitute storage withdrawals for the first half of the calendar year 2020. This substitution drives fewer storage injections in the preceding summer season. However, more injections occur in the following summer season;[41] as a result, storage utilisation recovers in winter 2020/2021. In the medium term, the effect of Nord Stream 2 project on the utilisation of German storages is limited. More detail is provided in the Appendix B.

The development in the Netherlands is also influenced by Russia (mostly via transits through Germany). This can be highlighted based on a more detailed presentation of the origins of gas supply in the Netherlands (Figure 5).[42] Russian exports receive a significant share in the Dutch gas demand mix from 2021 onwards, substituting the drop in domestic production volumes. Norwegian imports are used to fill storage facilities in summer periods.[43] Norwegian export volumes decrease over time reflecting our assumptions on decreasing production capacity (based on Norwegian petroleum web and ENTSOG (2018). Our results are in line with the argument of Honoré (2017) that the only possibility of increasing the delivery of Norwegian gas to the Netherlands would be to re-direct some volumes there at the expenses of other European importers. The take-away message is that Norwegian exports cannot be seen as a possible solution to substitute the drop in Dutch production gas volumes and associated flexibility.
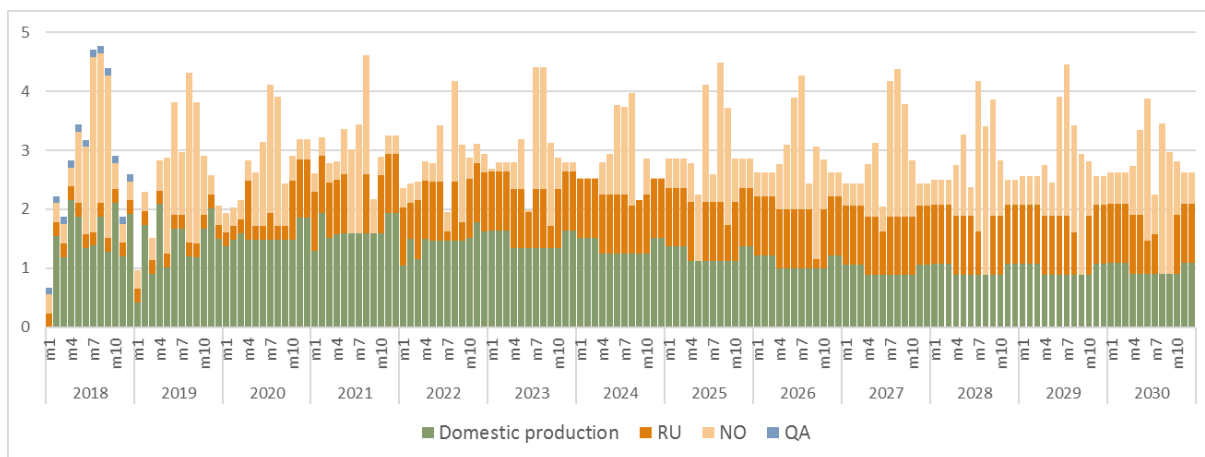

Figure 5: Dutch domestic production and imports by point of origin. All values are model output in bcm per month.

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[41] This effect is possible because Nord Stream 1 capacity is utilised at full capacity (transport costs via Ukrainian route are higher). The actual Nord Stream 1 utilisation was near to 93 % in 2017 (source NS webpage).

[42] Tracing of gas flow follows Egging (2010); Hecking and Panke (2012); Holz (2009).

[43] Gas imports peaking in summer periods may look somewhat counterintuitive; however, these results should be seen through the prism of a cost minimisation problem that takes into account a complex set of interdependencies over space and time. In this case, Norway exports natural gas to many European countries, e.g. Germany, France, Italy, Czech Republic, Belgium, Austria and the UK. The UK is the largest consumer

3.2 Measuring seasonal flexibility

In this section, we analyse different flexibility options' contributions to seasonal flexibility both on the country-specific and on the European level. Flexibility in our paper is analysed on a monthly level and both monthly and seasonal conclusions are derived.[44] Consequently, all our input data is in monthly resolution to be consistent. Furthermore, our gas market model is optimized to analyse seasonal flexibility and it also has monthly time resolution. A key metric to measure and compare technologies' flexibility contribution should thus also be optimized for the research question and be set-up in monthly resolution.

With this aim, we develop a new metric extending the coefficient of variation (CV) used in a report issued by the European Commission (2015). The authors introduce the CV to measure which supply source provides the most swing required to meet demand fluctuations.[45] The coefficient of variation is defined as a variable's standard deviation in relation to its mean (13):

$$CV = \frac{\sqrt{\frac{1}{n}\sum_1^n(x_i - \bar{x})^2}}{\bar{x}} \tag{13}$$

We propose an adjustment that removes two potential pitfalls of applying the CV in the context of gas markets' seasonal flexibility analysis. First, problems likely arise when the mean value is close to zero. With the mean in the denominator, the CV becomes sensitive to small changes of the mean around zero. For example, a small volume of LNG imported by country with a little LNG in its import mix in a specific year may cause the CV parameter to approach a relatively high number for that year. Second, the importance of a supply source in the provision of seasonal flexibility cannot be measured based on CV alone. Following our earlier example, a small volume of LNG imported by a country in a month of peak demand may have a high CV value (in case the imported volumes in other month are low), however the actual contribution of LNG imports to cover seasonal demand may be very small compared to, for example, a high volume of flexible pipeline imports. Hence, we propose to scale the CV with an annual share of a specific supply source in covering gas demand, fixing both mentioned problems (14).

$$SCV_i = CV_i \cdot AS_i = \frac{\sqrt{\frac{1}{12}\sum_{m1}^{m12}\left(S_{i,m} - \bar{S}_\iota\right)^2}}{\bar{S}_\iota} \cdot \frac{\sum_m S_{i,m}}{\sum_{i,m} S_{i,m}} \tag{14}$$

Where:

CV_i Annual coefficient of variation for flexibility option i

AS_i Annual share of gas demand covered by flexibility option i

$S_{i,m}$ Gas quantity supplied by flexibility option i in month m

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of Norwegian gas, which is driven by economical (in particular geographical proximity) and technical (available infrastructure, decrease of domestic production) factors. Furthermore, we already discussed the low capacity of gas storages in UK, which drives high volumes of Norwegian gas imported by the UK in winter periods. Therefore, the Netherlands covers a bulk of gas demand via (almost constant) imports from Russia and can benefit from Norwegian imports by injecting gas into storages in summer periods.

[44] An analysis of e.g. short term flexibility on the diurnal or weekly level requires a different set-up.

[45] Coefficient of variation is also known as relative standard deviation.

The intuition for this scaled coefficient of variation (SCV) metric can be derived from its components. The CV is zero when supply is constant throughout the year (i.e. standard deviation is zero). The CV will increase once the supply pattern gets a seasonal structure. AS, as specified in Equation (14), reflects a supply source's annually aggregated contribution to demand and has an interval of [0, 1]. Therefore, the CV's first problem discussed above does not apply to the SCV metric, because a low value of AS will compensate the CV's tendency to spike in cases where the mean is close to zero. The second problem is also treated, because a supply source with even a small-to-moderate seasonal variation will be noted by the SCV metric if it has a relatively high AS value. Alternatively, a supply source with a high seasonal variation but a small AS value will have a small SCV value. Altogether, the SCV provides a measure for the contributions of different flexibility options to cover seasonal demand swing.

We calculate SCVs based on our modelling results for the representative nodes and aggregated Europe on an annual basis (Figure 6).[46] On the European level, the results show that compared to other flexibility sources, gas storages contribute most to the European seasonal flexibility. Furthermore, we find no evidence that gas storage facilities may be displaced by pipeline or LNG imports from this position in a long-term perspective.
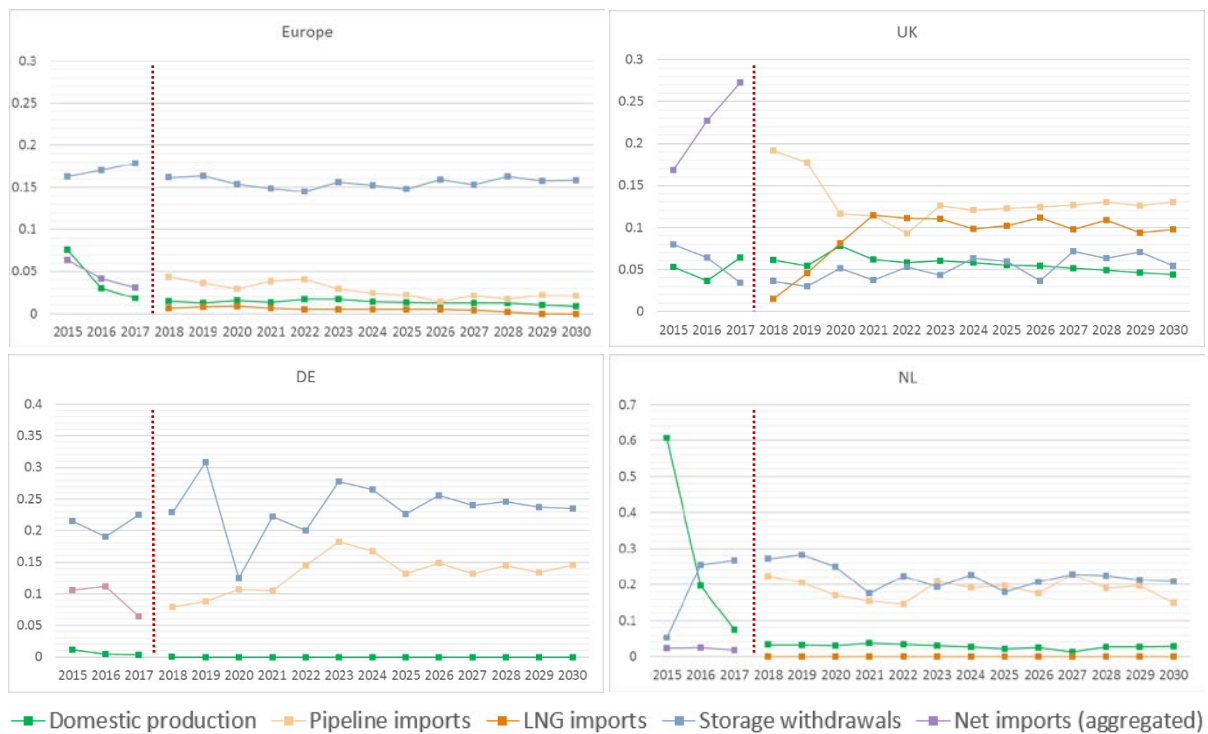

Figure 6: Annual SCVs for selected countries.

Regarding country-specific results, Figure 6 again shows the relative lack of storages in the UK market: in all other regions presented in the figure, storages are the most significant provider of flexibility based on the SCV. In the UK, storages have the lowest contribution on average over the period of observation. Furthermore, the contribution of domestic production to seasonal flexibility decreases over the modelling horizon. This is driven by declining domestic production volumes. The low volume of storage working capacity and the decreasing trend of

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[46] As before, we include historic values based on Eurostat data for comparison.

domestic production can be potentially compensated by pipeline interconnections with Continental Europe, a direct pipeline interconnection with Norway and high capacities of regasification terminals. The sharp increase of seasonal flexibility provided by LNG between 2018 and 2022 is driven by increasing LNG volumes in winter periods.

In Germany, the SCV for domestic production is low. This can be explained by its low volumes and a constant production pattern. Gas storages, in contrast, provide the bulk of seasonal demand swing. The SCV metric also captures the above mentioned (see section 3.1) short-term effect of Nord Stream 2 displacing German storages as key provider of seasonal flexibility, in particular in the year 2020. The results also highlight that the role of pipeline imports in providing German seasonal demand swing increases after 2021, which can be explained by a higher volume of gas imports via the Nord Stream 2 once the project is completed. The abundant volume of German working gas storage capacity permits storing additional gas imports in summer periods. Therefore, it should be noted that seasonal flexibility provided by storages requires sufficient capacity of pipeline interconnectors.

The SCVs in the bottom right chart of Figure 6 quantify the drop in seasonal supply flexibility provided by domestic production in the Netherlands. Since 2017, Dutch domestic production has played a minor role in fulfilling demand swing, delivering a nearly constant amount of gas over time (see Section 3.1). Increasing SCVs for gas storages and pipeline imports, both based on historic as well as model generated values, quantifies their role as replacements for flexibility of domestic production.

4. CONCLUSIONS

This paper compares and quantifies the role of different flexibility options in the European gas market using a fundamental modelling framework. We contribute to the ongoing discussion of this topic (i) with a thorough analysis of seasonal flexibility and (ii) addressing the problem using an optimisation model to simulate the operation of the market over a long period. This allows us to explore structural trends in market development, which are driven by changing supply and demand fundamentals. Furthermore, we propose a new metric to analyse a provision of seasonal flexibility.

Our findings provide several insights into the development of gas supply sources' utilisation. In particular, the results illustrate that (i) European domestic production is facing a dramatic decrease in production volumes; (ii) LNG has a growing share in the European import mix, but it does not become a game changer; (iii) Europe continues to rely heavily on pipeline imports from Russia. Norwegian export volumes will not fill the gap as production is expected to decrease steadily in the next decades. Russia, in turn, has enough free production and transportation capacity to increase its exports to Europe substantially. In the details, our findings show that the bulk volumes of the Dutch production drop are substituted by pipeline imports from Russia, while Norwegian gas is imported to cover a seasonal demand swing; (iv) storage utilisation at peak demand levels is forecasted to remain high on both the national and European level.

We show that our methodologically improved coefficient of variation (a "scaled coefficient of variation") allows for better understanding of how market dynamics effects on seasonal flexibility. SCV captures the effects caused by e.g. the drop of Dutch domestic production volume and flexibility, the closure of the Rough storage facility in UK, and the completion of new transmission infrastructure projects (e.g. Nord Stream 2). Our results suggest that gas storages contribute most to European seasonal flexibility in all years included in the modelling horizon. Even with increased import pipeline capacities after the completion of Nord Stream 2, pipeline imports rarely displace storage facilities in meeting seasonal gas demand swing. Instead, additional interconnection is utilised with relatively low variations over the year. The contribution of LNG to seasonal flexibility on the European level is small; however, it may play a role of the important seasonal supplier on a national scale (e.g. the UK). Taken together, our findings suggest that there is no observable evidence that gas storage facilities may be displaced by pipeline or LNG imports from the position of a key seasonality provider from a long-term perspective.

Several questions remain for further research activity in the context of our analysis. In terms of the methodology, the new SCV metric was computed and interpreted exclusively with monthly data in this paper. It will be interesting to see to what extent the underlying considerations hold for other time resolutions (e.g. diurnal seasonality) as well as other product markets (e.g. electricity). Furthermore, future investigations might differentiate between types of storage facilities (e.g. seasonal storage and fast-cycle storage). Furthermore, time resolution can be increased even further to introduce short-term market dynamics (e.g. weekly seasonality). These features will allow capturing both the intrinsic and extrinsic storage values. A further study with more focus on the gas market in North Western Europe may include data on L-gas and H-gas production fields and transmission infrastructure. Increasing geographical scope of the model would allow for studying impacts of trends in global LNG supply and demand on the European gas market. This can facilitate a more thorough analysis of the competition between LNG supplies and alternative seasonal flexibility options. Further modelling work might explore the potentials of flexibility on the demand side. While price elasticities of natural gas demand are hard to estimate,[47] sector demands could be analysed in more detail coupling sector models. Thus, an integrated electricity and gas sector model could be used to analyse the potential role of demand response by gas-fired power generation.

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[47] See, e.g., Arora (2014) and Chai et al. (2018).

APPENDIX A

Production costs are determined by a logarithmic function related to capacity utilisation as proposed by Golombek et al. (1995). The increasing marginal cost function can be expressed as follows:

$$TPC'(q) = \alpha + \beta \cdot q + \gamma \cdot ln(1 - \frac{q}{Cap})$$

$$\alpha, \beta \geq 0, \gamma \leq 0, q < Cap$$

(15)

In equation (15), q is a production quantity, Cap is available production capacity, α is the minimum marginal unit cost term, β is the per unit linearly increasing cost term, and a term γ ensures that production costs increase sharply when production is close to full capacity.

To keep the model formulation linear, we use piecewise approximations to logarithmic cost functions. Thus, we obtain a merit-order type linear production costs function for each node. Figure 7 illustrates our approach.
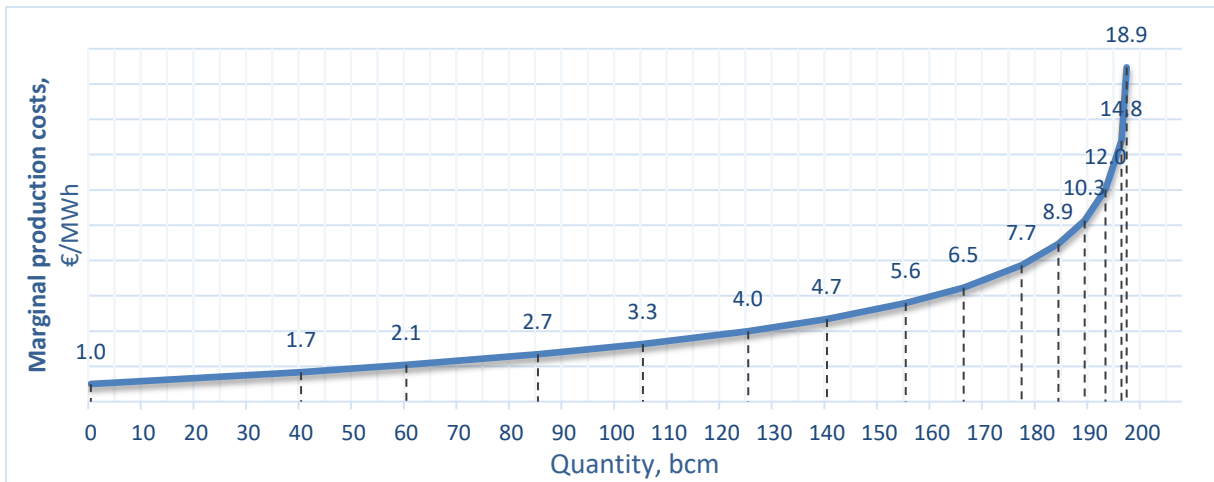

Figure 7: Russian marginal production cost function (supply potential for 2015).

APPENDIX B

Figure 8 illustrates net annual storage injections and withdrawals in Germany for the reference scenario (left) and for a scenario with an assumption that Nord Stream 2 is not realised and all other market settings remain the same (right). The results suggest that the effect of gas imports via the Nord Stream 2 pipeline substituting storage withdrawals in 2020 has a short-term nature – storage utilisation recovers in the next calendar year. Furthermore, the fact that injection/withdrawal volumes in preceding years are affected to a great extent can be explained by the perfect information assumption in a cost minimisation problem.
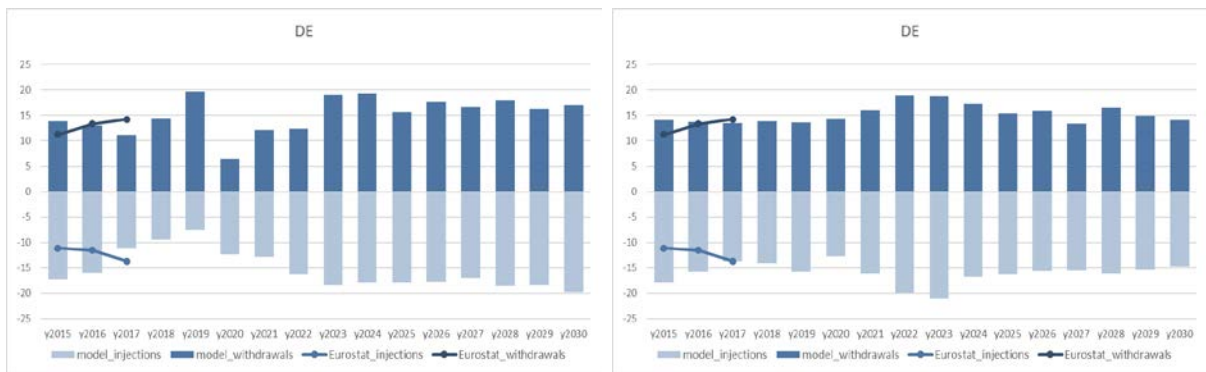

Figure 8: Utilisation of German gas storages under different market settings – Nord Stream 2 project is completed by 2020 (left) and Nord Stream 2 project is not completed (right). All values are in bcm per year.

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