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A dynamic model of global natural gas supply

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HIGHLIGHTS

- A new simulation model of global (28 regions) upstream gas supply is presented.
- Builds supply curves from field breakeven prices using extensive industrial data.
- The spatial resolution is individual gas fields; the temporal resolution is yearly.
- Realistic investment and operating decisions in response to price & demand signals.
- A validation is performed using the US Shale gas boom as a historic case study.

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ABSTRACT

This paper presents the *Dynamic Upstream Gas Model* (DYNAAMO); a new, global, bottom-up model of natural gas supply. In contrast to most "static" supply-side models, which bracket resources by average cost, DYNAAMO creates a range of dynamic outputs by simulating investment and operating decisions in the upstream gas industry triggered in response to investors' expectations of future gas prices. Industrial data from thousands of gas fields is analysed and used to build production and expenditure profiles which drive the economics of supply at field level. Using these profiles, a novel methodology for estimating supply curves is developed which incorporates the size, age and operating environment of gas fields, and treats explicitly the fiscal, abandonment, exploration and emissions costs of production. The model is validated using the US shale gas boom in the 2000s as a historic case study. It is found that the modelled market share of supply by field environment replicates the observed trend during the period 2000–2010, and that the model price response during the same period – due to lower capacity margins and the financing of new projects – is consistent with market behaviour.

1. Introduction

1.1. Background

In the quest for a more sustainable energy system, the natural gas market is at a critical stage. On the one hand, the availability of new and cheap sources of natural gas has created renewed appeal for this resource and driven new discoveries, often in remote regions [1]. On the other, although natural gas is the least carbon intensive fossil fuel, its future consumption may be jeopardised by the imposition of more stringent targets on emissions reductions [2]. This would ultimately have a dramatic impact on the value of many upstream companies whose assets may become stranded due to the implementation of climate policies [3].

Energy systems models [4,5] are powerful tools for studying long-term transitions of the energy system and provide stakeholders with valuable information to inform decision-making about investments in new assets (in terms of capacity, type and geographical context), technological R&D, and the likely impact of future climate change mitigation policies. In attempting to give a comprehensive representation of the global energy system and capture the complex interactions among multiple factors such as technological breakthroughs and changes in policy, energy systems models unavoidably have an inherent level of uncertainty. A key source of this uncertainty arises from the definition of fossil fuel supply curves and their long-term evolution, both in terms of the availability of resources and the cost of bringing these to market [6,7]. To help address this uncertainty a number of models have been developed, both commercially and non-commercially, with a specific focus on natural gas (for a review of approaches see [8,9]).

1.2. Existing models

A diverse variety of modelling techniques have been used to help

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answer specific questions concerning the geological [10], environmental [11] or network-related [12] aspects of the natural gas industry, but in the context of techno-economic modelling there are two main approaches which underpin most efforts to date. In the first, the model represents economic agents which are assumed to have perfect foresight of future demand and price changes over the model time horizon. These agents act to maximise their economic utility, and the model solution is "optimal" in the sense that some global objective function representing producer surplus or total cost is extremised. In the second approach, model agents have imperfect knowledge of future market conditions and decision making is often based on criteria intended to replicate the behaviour of real-world stakeholders. Simulation models of this type have no global objective function, and can generate outputs which are sub-optimal.

One example of an optimisation model is the International Natural Gas Model (INGM) [9], which covers natural gas production and trade in the US Energy Information Agency's (EIA) World Energy Projection System Plus (WEPS+) [13]. INGM treats upstream activities, processing, shipping and storage across 61 regions, endogenously building new capacity to service demand in a way that maximises the sum of producer and consumer surplus. Although there is some evidence to suggest that cost optimal paths are approximately followed in some markets [14,15], projects horizons in upstream gas are often extended (20–35 years), and capital spending high (~ 500 MUSD (2010) for a large deepwater field), making inter-temporal optimisation ill-suited for this kind of study. A possible approach to softening perfect foresight is to reduce the time horizon over which the system is optimised before patching together the locally optimised solutions [9,16].

Optimisation methods have been widely applied to modelling the international trade in natural gas. Gas is transported from "supply" regions (typically found in North and South America, the Middle East, Russia and Africa) to "demand" regions (typically found in Europe, Asia and Oceania) via pipelines or Liquid Natural Gas (LNG) ships. Short term models, such as Wood Mackensie's Global Gas Model [17], enforce static constraints on infrastructure (pipeline capacity, liquefaction terminals, storage facilities), and solve an LP which minimises total cost over a short time horizon. Nexant's World Gas Model (another commercial model for which it is hard to find detailed documentation) has sub-country level resolution, and includes endogenous capacity expansion as part of the LP framework [18]. Key outputs include spot prices, production and consumption, trade flows and infrastructure utilisation.

An academic model, EUGAS [19] is a linear optimization analysis of long-term supply into Europe out to 2030. It has a detailed representation of existing pipelines both within Europe and entering Europe, and also integrates domestic production within the LP. However, demand is treated exogenously, and production costs – i.e. a representation of the upstream side of the industry – are static, with reserve additions and upstream activity decoupled from price. A global extension of EUGAS is the MAGELAN model (used in [20]).

The "normative" approaches described above can provide a characterisation of global gas trade in perfect market conditions, but can be over-sensitive to often arbitrary constraints and assumptions regarding the availability of resources and infrastructure. They can also fail to describe adequately the response of investors, producers and shippers to price. A number of methods have been developed which go beyond the "least-cost" paradigm, but still retain some features of constrained optimisation. The World Gas Model [21] uses a Mixed Complementarity Problem (MCP) formulation [22] to simulate market behaviour out to 2030. A variety of agents, including producers, traders, pipeline operators, LNG companies and end-users (residential, commercial and power-sector), compete to maximise their individual discounted profit, subject to constraints on infrastructure and assumptions regarding the power of different individual agents to swing the market. A crucial difference between MCP and LP models is that in the former producers and shippers can choose to withhold supply in a given region to increase price, or else flood a market to gain long term market share. As regional gas prices are influenced by the balance between volumes supplied in long-term contracts and those traded on the spot market [23], MCP models are arguably better suited to describing price formation. Agent-based approaches which rely on profit maximisation have also been developed commercially [24,25], but few details about how they work are publicly available. In spite of its sophisticated approach to trade, the World Gas Model treats production relatively simply by using a generic convex production cost function containing a number of parameters estimated from reference values in the base year. Producers (as agents) make decisions about how much gas to produce, but the marginal cost of production is essentially exogenous.

Based on Deloitte's MarketBuilder software [26], Rice University's World Gas Trade Model [27,28] is a dynamic spatial equilibrium model which uses agent-based profit maximisation. This shares features of the MCP method but is less constrained, and, as an ABM, has the potential to better represent outcomes caused by interactions between agents and imperfect competition [29,30]. As in other models, infrastructure capacity expansion is endogenous, but long term LNG contracts are treated with some sophistication, in that they are assumed to affect only the risks borne by different parties (affecting agents' propensity to trade), but not the flow of gas, so that contracted trades can be swapped with alternatives if cost effective. Production is modelled at basin level using static resource curves. However, there is some accounting for depletion effects [31] (which raise long run costs), as well as technology gains (which reduce long run costs).

In addition to global gas trade models, a number of studies have addressed specific (and regional) techno-economic questions relating to the gas industry, such as optimal water management in shale plays [32,33], or the allocation of mobile plants to monetise associated gas [34], or the prospects for gas supply and usage in the southern cone of Latin America [35]. Of relevance when modelling future production costs, a comprehensive technical assessment of US Shale gas [36] emphasises the importance of "learning-by-doing" in terms of extraction efficiencies. Detailed scenarios of Shale gas production out to 2025 using a discounted cashflow model [37] of rig roll-out rates is given in [38]. A long term perspective on the role for gas in the energy mix in [39] uses five different integrated assessment models (including optimisations and simulations) to assess the climate impact of abundant cheap gas reserves.

A striking feature of many of the trade models discussed is the discrepancy between the sophisticated treatment of international trading and the simplistic representation of the upstream industry, which controls domestic supply and the cost of gas entering the international trade market. A common approach uses cumulative resource curves [40,7], which estimate how total resource volumes vary over time with price. These are normally constructed by bracketing natural gas resources by the price at which they become commercial to develop (for example their average long-run-cost), and aggregating different resource types, with assumptions on the size-frequency distribution of undiscovered (or unproven) volumes [41–43]. Supply curves are often constructed from resource curves by assuming that some fixed fraction of each resource type can be offered to the market at any given time. Apart from the effects of efficiency gains over time [44], supply curves constructed in this way are essentially static because they are insensitive to short term market behaviour. More sophisticated treatments have been developed commercially [45,46] but few details can be found on how they work. Other upstream models focus on a single region [47], or optimised production scheduling [48]. Perhaps the most detailed supply model in the public domain has been developed as part of the EIA's National Energy Modeling System (NEMS) model [49], used to create the Annual Energy Outlook [50]. The Oil and Gas Supply Module (OGSM) [51] is a high resolution simulation of partial equilibrium in the US oil and gas market. It comprises 4 main supply subcategories – Lower 48 onshore, Lower 48 offshore, Alaska, and Oil shale – and within these distinguishes production from Shale plays, Coalbed