A dynamic model of global natural gas supply

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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 forward price and/or demand signals. Industrial time series 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 shown that the modelled market share of supply by *field environment* captures very well 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.

Keywords: Energy Systems Modelling, Simulation, Natural Gas, DYNAAMO
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Highlights

- A new simulation model of global (28 regions) upstream gas supply is presented.
- Builds supply curves from production not resources 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.

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 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] and [9]). A variety of modelling techniques have been used to help answer specific questions concerning the geological [10], environmental [11] and network [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 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.

Among optimisation models 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 sume 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 ($\sim$ 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 also been widely applied to modelling international gas trade. 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. Another commercial model (for which it is hard to find detailed documentation), Nexant's World Gas Model 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, and also fail to describe 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 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 only to affect 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), and 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 5 different Integrated Assessment Models (including optimisations and simulations) to asses the climate impact of abundant cheap gas reserves.

A striking feature of many trade models discussed is the discrepancy between the sophisticated treatment of gas transportation 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-marginal-cost), and aggregating different resources types, with assumptions on the size-frequency distribution of undiscovered (or unproven) volumes [41] [42] [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 are available publicly 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 fields, Offshore fields (further broken down by water depth), Conventional (vertically drilled) fields and "associated" gas (from fields primarily developed to lift oil). Investment in a specific activity (such as drilling, or building an offshore platform) is determined from its expected profitability, using a range of investment metrics such as Net present value, Investment efficiency, Rate of return and Cumulative discounted after-tax cash flow. The main exogenous parameters are resource levels, finding-rate parameters, costs, production profiles, and tax rates. Of particular relevance to the US market is Unconventional gas, which OGSM handles at well-level by calculating production as a cumulative function of historic drill-rates. In a given time period, the clearing price for gas is set by demand, and this informs investment decisions in the following time period. The main drawback of the OGSM as a modelling environment is its complexity: over 250 independent input parameters are required to describe production in the Lower 48 onshore sub-region alone. These parameters are likely to be easiest to obtain in the USA, which has a mature and liberalised gas industry, but render the model impractical within a global energy systems model.

This paper presents a new model, DYNAAMO (the **DYN**amic Upstre**A**m G**A**s **MO**del), and its approach to the generation of dynamic gas supply curves. DYNAAMO has been developed as a sub-module of the MUSE (**M**od**U**lar energy systems **S**imulation **E**nvironment) energy systems model (see Appendix B for further details), a new global simulation of partial equilibrium across all energy vectors, but it can run independently of MUSE and produce a range of technical, emissions-related and economic outputs which are of interest in their own right.

DYNAAMO is a technology-rich, realistic, dynamic simulation of the upstream gas industry. It addresses the limitations of models based on static resources in three main ways. First, it constructs *dynamic* supply curves by aggregating forward breakeven prices on a field-by-field basis. On a "price-quantity" graph, such supply curves can move both horizontally - reflecting changes in production capacity over time - as well as vertically - reflecting the non-constant nature of expenditure among producing fields as they mature and decline. Second, DYNAAMO makes use of decades long time series from hundreds of gas fields worldwide to establish a realistic picture of both production and expenditure patterns over the life-cycle of a typical field. Third, as DYNAAMO is not an optimisation, it is able to simulate investment and operating decisions in response to current market conditions, as well as those in response to investors' expectations of future market conditions, with the level of investor foresight a tunable parameter. Constraints apply to the availability and cost of capital rather than capacity growth directly, and make use of historic industrial data.

This paper will discuss DYNAAMO, its approach to calculating capacity and corresponding activity levels for new upstream gas assets, their overall economics (i.e. capital investment, fixed operating and maintenance costs, variable operating costs) as well as the associated environmental impacts.

2. The Dynamic Upstream Gas Model

Simplicity & Scalability. DYNAAMO is a technology-rich, bottom-up, global model of natural gas production, developed in the Python programming language [52]. It builds regional supply curves for natural gas in future time periods by simulating a variety of operational and investment decisions, subject to the influence of changing price and demand expectations, the fiscal environment, the cost of capital, future technological changes and the CO_2 emissions intensities associated with different technologies. DYNAAMO uses historic expenditure and production data to determine the Net Present Value (NPV) of a large assortment of hypothetical undeveloped gas fields, and simulates future gas production by prioritising investment in those fields with greater "capital efficiency" (NPV per discounted capital dollar). A key aspect of DYNAAMO is its relative simplicity: although all major costs and technologies associated with natural gas production are included explicitly, the number of independent input parameters is less than 20 (see Table 1). This allows the underlying drivers of various correlations and trends seen in the model outputs to be identified more easily, making DYNAAMO a useful tool for studying the supply-side impact of new technologies [20].

As a simulation, rather than optimisation, based approach, DYNAAMO relies on investor expectations of future gas price and demand. When running as a "stand-alone" model (i.e. not as part of MUSE), these take the form of exogenous inputs. The number of years into the future in which investors have perfect knowledge of the future price and demand - the *foresight time horizon* - can be chosen by the user, so that DYNAAMO can be used to explore the impact of different levels of investor confidence about market conditions in the near, mid and distant future. Operational decisions such as the timing of "shut-in" (unforeseen closure) of producing gas fields also feature in the model, thus capturing the effects of, say, investor hubris or, e.g., a transient low-price environment.

Modelling assumptions & historic data. All energy systems models are based on a set of assumptions and necessary simplifications, and DYNAAMO is no different. As a bottom-up model, DYNAAMO characterises the main economic and technical drivers in the upstream gas industry and from this forecasts aggregate production as the sum of production from smaller units. It is therefore essential to model these building-block units - in our case individual gas fields - as faithfully as possible, and to this end DYNAAMO makes extensive use of historic field-level data. The development of the model structure has been significantly influenced by the kinds of field-level data which are reported and commercially available for use. In the instances where it is not possible to reconstruct a particular parameter from regression analysis on historic data (due, for example, to the scarcity of available data), we have found that the parameter can often be empirically estimated from analogous cases. An example of this would be estimating parameters for shale gas in the UK (which, at the time of writing, is not commercially developed) by using data from analogous fields in the US. Occasionally there is a genuine gap in the available historic data, or, if available, the data are so poorly correlated (due, for example, to exceptional market conditions) that industrial *rules-of-thumb* have been used. DYNAAMO has been developed in close collaboration with experts in the gas industry, making its treatment of the more discretionary aspects of the business - like operational and investment decisions - as realistic as possible.

The carbon price. A carbon price is implemented in MUSE and is paid on CO_2 (and other greenhouse gas) emissions occurring across every stage of the supply chain. This pushes up the cost of carbon-intensive energy sources and can act as a lever to control total emissions, as energy consumers switch to cheaper low-carbon suppliers. A carbon budget - a cap on total emissions in a given time period - can be enforced by raising the carbon price incrementally until emissions are contained below a prescribed level.

Within DYNAAMO the forward carbon price is an exogenous configurable which has two main effects. First, the cost impact of a given carbon price is not the same across different FEs due to their differing CO_2 emissions intensities. This can restructure supply curves and change the production technology of the marginal producer within a region. Second, the carbon price can change the technologies which investors find most lucrative. This is a longer term effect which can lead to a restructuring of the entire upstream gas industry over 10-20 years, with complex implications for the cost of gas. DYNAAMO can model both direct upstream CO_2 emissions (e.g. from flaring, own-fuel burn) and methane (CH_4) emissions associated with every sub-stage of upstream production (site preparation, drilling, hydraulic fracturing, well completions, lifting). Of particular topical interest is the potential to study the implications for stakeholders of “fugitive” methane emissions in scenarios with a future carbon price [53] [54] [55].

3. Nomenclature

3.1. Indices, Parameters & Variables

The main indices, parameters and variables used are listed in Table 1. An additional glossary in Section 10 details variables used in the Appendices of this paper. Variables in Table 1 are divided into the following types:

- Exogenous Parameter: usually found from historic data. These parameters are inputs into DYNAAMO.
- Dependent Variable: variables which are derived functions of *input variables*. These are outputs of DYNAAMO.

4. Modelling Gas Fields

This section describes the way the NPV of a stylised gas field is calculated, which in turn directly determines future gas supply curves. The two key ingredients which determine field NPV are the *expenditure profile* and the *production profile* of the field. These refer to the timing at which expenditure and production occur over the total project life-cycle. Together, the *expenditure* and *production* profiles uniquely determine the field NPV for a given discount rate.

4.1. Costs

There are 3 main factors which influence the cost of supplying natural gas:

- **Field Environment** A technologically diverse but limited portfolio of technologies accounts for almost all gas production worldwide, and large differences in their capital and operating costs directly determine both the scale of commercial reserves and the breakeven price of gas for the field. DYNAAMO incorporates this technological diversity by breaking down gas production into a small number of *field environments* (FEs) - different technologies characterised by different cost and production profiles.

  Four key FEs have been identified:

Table 1: DYNAAMO parameters

Index	Description	Units
r	MUSE region	
i	field environment	
j	asset class	
n	life-cycle year	year
t	model time period	year
Exogenous Parameter	Description	Units
$f_{i,r}$	capex per EUR	MUSD
$b_{i,r}$	opex-to-capex ratio	
$R_{0i,r}$	field EUR	BCM
$\text{tax}_{i,r}$	unit fiscal (tax)	MUSD
$\text{sub}_{i,r}$	total subsidy	MUSD
$\text{expex}_{i,r}$	Total expex	MUSD
$\bar{R}_0$	Reference Reserve	BCM
Dependent Variable	Description	Units
$v_{pi,r}$	Peak Field Production	BCM/year
$v_{n,i,r}$	Field Production	BCM/year
$N_{pi,r}$	Peak time	years
$N_{ri,r}$	Ramp-up time	years
$N_{di,r}$	Decline time	years
$N_{i,r}$	Shut-in time	years
$\text{capex}_{i,r}$	Total capex	MUSD
$\text{opex}_{i,r}$	Total opex	MUSD
$\text{GT}_{i,r}$	Government Take	MUSD
$\text{lrmc}_{i,r,t}$	long-run-marginal-cost	MUSD/BCM
$\text{meanlrmc}_{r,t}$	Volume-weighted lrmc	MUSD/BCM
$a_{n,j,r,t}$	Number of fields in a given asset class	

- *Shelf* refers to offshore fields in a water depth < 125m.
- *Deep Offshore* refers to offshore fields in a water depth > 125m.
- *Unconventional* refers to onshore fields and includes *Coal Bed Methane*, *Tight* and *Shale* gas extracted by unconventional methods.
- *Onshore Conventional* refers to onshore fields extracted by conventional methods.

Further disaggregation into a greater number of FEs (e.g. by splitting *Unconventionals*), as well as the inclusion of additional FEs, such as *Ultra-Deep* (which can involve radically different, nascent technologies), is straightforward within the DYNAAMO modelling framework.

- **Region** The geographic region determines both the abundance of gas reserves and the fiscal environment in which production and investment take place. Royalties paid on production can raise the cost of supply, whereas subsidies can promote the rapid growth of an otherwise non-commercial technology. DYNAAMO uses 28 world regions, compatible with the IEA/ETP modelling approach (see Table 3) [2]. However, all modelling of economic and technical parameters within DYNAAMO is done on a country-by-country basis, allowing the user to generate regional breakdowns "on-the-fly".

- **Field Size** The size of a gas field influences the cost of gas supplied as well as the rate of production. Large fields tend to be cheaper by benefiting from economies of scale: fixed capital and operating costs are paid over larger volumes of gas supplied, reducing unit costs by volume. Historic expenditure data show that for every doubling in reservoir size, capital and operational costs increase by around 60% [45].

Our approach will be to break down gas production by FE and region, and then to look for simple scaling relationships or correlations between costs and field size. Using historic reported expenditure data from gas fields all over the world

[45], we can then generate a blueprint for a prototypical gas field of a given FE and size, in a given region.

Treatment of associated gas and NGLs. A significant proportion of global gas supply is obtained from fields also producing oil (so-called "associated gas") and/or natural gas liquids (NGLs), such as ethane, propane and butane. Associated gas production is driven by the economics of oil, and so the marginal cost of this segment of supply is essentially just the lifting cost. By contrast, NGLs are often of higher market value to producers than pure methane ("dry gas"), so that the NGL fraction effectively subsidises dry gas production.

DYNAAMO handles these complications by first focussing on modelling the economics of dry fields: all historic expenditure and production data used is taken from fields with a liquids-to-gas ratio < 1 bbl/MMcf. The NGL fraction can then be introduced post hoc as an independent variable, the effect of which is to augment the forward NPV of a given field. This in turn reduces the long-run-marginal-cost of dry gas from that field (see Section 6). The NGLs price historically tracks the global oil price [45] (with some variation by region), and can be taken as a configurable multiple of the clearing price for oil (when running within MUSE), or else as an additional model parameter.

DYNAAMO does not model explicitly gas production from oil fields, but this segment of supply can be inserted into the supply curve for dry gas (Section 6) at a breakeven price equal to the lifting cost (typically between $10.7 - 25.0$ MUSD/BCM [56] [57]).

Cost categories. The costs of gas production are divided into capex (capital costs), opex (operating costs) and fiscal (costs of direct taxation and royalties, as well as subsidies). Fig. 1 summarises the main costs which fall into these categories.

- **Capital costs** are the development costs related to building facilities and drilling wells and include:

– *Well capex* - costs related to drilling wells, which depend predominantly on FE and geology.

– *Facility capex* - costs related to building infrastructure for the extraction & processing of gas.

– *Exploratory capex* (or *Expex*) - costs associated with exploration for new resources.

- **Operating costs** are costs directly related to running operations (though not necessarily gas production) and include:

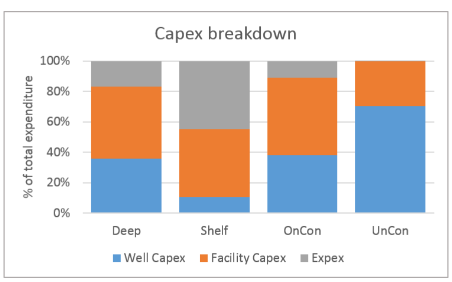
  – *Income tax* - tax paid on profits.

  – *SG&A* - fixed operating costs not related to gas production, such as administration costs, legal fees, insurance etc.

  – *Transportation* - costs of gas transportation to pricing point.

  – *Production* - costs directly related to gas production, including equipment hire, and operations-related salaries.

  – *Abandonment* - the cost of decommissioning the Gas field - plugging wells and removal of equipment.



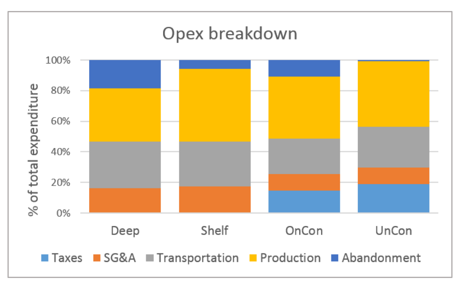


Figure 1: capex (Left) and opex (Right) breakdowns (see text) as a percentage of whole life-cycle expenditure for > 1000 currently abandoned fields in the USA since 1970.

The costs which fall into these categories are typically incurred at different stages of a field's life-cycle. The resulting expenditure profiles differ significantly by FE, as seen in Fig. 2, which shows aggregated historic data from > 4000 abandoned gas fields worldwide since 1970. The life-cycle phases are *preproduction* (corresponding to expenditure before production begins); *Early* ($< 25\%$ of initial field reserves extracted); *Early-mid* (25% to 50%); *Mid* (50% to 75%); *Late* ($> 75\%$) and *Abandonment* (expenditure after production has ceased). Fig. 2 shows, for example, that offshore FEs are relatively capex-intensive during the early stages of a project, with at least 50% of the total project capex being spent before a quarter of the initial reserves have been extracted. By contrast, onshore projects typically spend the majority of total capex later in their life-cycles.

Figure 2: Expenditure profiles (as % of total life-cycle expenditure) by field environment. Aggregate data from > 4000 abandoned fields worldwide since 1970.

Economies of scale. The total (i.e. whole life-cycle) expenditure of gas fields also depends on their size - bigger fields intuitively have larger costs. We take the 2P EUR[1] (denoted by $R_{0i,r}$) as a working proxy for the size of a field[2], and

[1]2P refers to *proved and probable* resources and is a measure of the most likely amount of commercially extractable gas. EUR means "Estimated Ultimate Recovery".

[2]When using historic production data the life-cycle production of the field is taken, rather than the EUR in the discovery year. These quantities differ in general due to reserve discoveries made during the lifetime of the field.

incorporate economies of scale by assuming that total project capex varies with field size as

$$\mathrm{capex}_{i,r} = f_{i,r}\left(\frac{R_{0i,r}}{\bar{R}_0}\right)^{\alpha} \tag{4.1}$$

with $\alpha = {}^2\!/_3$ ($\bar{R}_0$ is a reference EUR, normally taken as 1 BCM), and that total project opex[3] is expressible as a fraction of the capex;

$$\mathrm{opex}_{i,r} = b_{i,r}\mathrm{capex}_{i,r} \tag{4.2}$$

Throughout this paper we will use the subscript i to index FE, and the subscript r to index region. Subscripts are retained in most expressions as a reminder that parameters and variables in general depend on FE and region. All expenditure will be quoted in millions of 2010 US dollars (MUSD) and gas volumes in billions ($\times 10^9$) of cubic metres (BCM).

These scaling relations (Eq. (4.1) & Eq. (4.2)), albeit heuristic, are entirely consistent with industrial approaches to project expenditure estimation [58], and have the advantage of simplicity and transparency. Although considered an industrial rule-of-thumb, statistical analysis of historic data indicates that the value $\alpha = {}^2\!/_3$ for the "power-sizing" exponent in Eq. (4.1) is remarkably robust and well-founded (see Appendix C and Fig. 17).

The fiscal component of a field's expenditure - called *Government Take* - includes royalties, which are paid on production, as well as fixed costs (such as fees or subsidies), which, in net terms, can be positive or negative. We therefore assume that Government Take (denoted by $\mathrm{GT}_{i,r}$) comprises a variable and fixed component and depends on field size in the following manner,

$$\mathrm{GT}_{i,r} = \mathrm{tax}_{i,r}\left(\frac{R_{0i,r}}{\bar{R}_0}\right) + \mathrm{sub}_{i,r} \tag{4.3}$$

The 4 economic parameters $f_{i,r}$, $b_{i,r}$, $\mathrm{tax}_{i,r}$ and $\mathrm{sub}_{i,r}$ occurring in Eqs. (4.1), (4.2) and (4.3) are obtained from case studies of representative individual fields and/or regressional analysis of historic production and expenditure data. Regional differences affect fiscal regimes and may also have an indirect impact on

[3] Fixed and variable opex are not distinguished.

operating and capital expenditure (e.g. through labour costs), so the economic parameters are calculated separately for each region as well as for each FE. An illustration of the correlation between field size (in this case total life-cycle production) and total Government Take is shown in Fig. 3 (Left) for 1904 currently abandoned *Offshore Shelf* fields in the USA, giving $\text{tax}_{i,r} = 41.9$ MUSD and $\text{sub}_{i,r} = -18.8$ MUSD for this particular FE/region combination, with correlation coefficient $R^2 = 0.81$. The fact that $\text{sub}_{i,r}$ is negative means for example that small Offshore Shelf fields have historically received a net Government Take subsidy over their life-cycles in the USA, although this figure varies considerably by FE and region. In order to capture cost reductions due to efficiency improvements, these economic parameters can be adjusted appropriately over time at a rate set by the user.

Fig. 3 (Right) shows the total opex and capex of the same fields as in Fig. 3 (Left), and largely justifies the assumption that opex can be expressed as a simple fraction of capex, with $R^2 = 0.75$. It is likely that very large or very small projects cannot adequately be modelled using the same simple scaling relationships used here, and our "one-size-fits-all" approach clearly misses some of the subtleties of field operations and economics. One possible explanation of the outliers in Fig. 3 might be that these are "failed" projects: fields that were shut-in prematurely or subject to unforeseen circumstances which did not allow them to complete the stylised production and expenditure cycles dictated by our various industrial rules-of-thumb. Due to differences in the timing at which capex, opex and Government Take is spent over the field life-cycle, the expenditure of prematurely closed fields will typically be dominated by capex, thus distorting those fields' regressed economic parameters.

4.2. Gas Production

Gas production from individual gas fields tends to follow a characteristic pattern over the life-cycle of the fields. This "production profile" is the outcome of an NPV optimisation over a large number of often complex technical, geological, licensing and budgetary constraints, and an endogenous, bottom-up model of

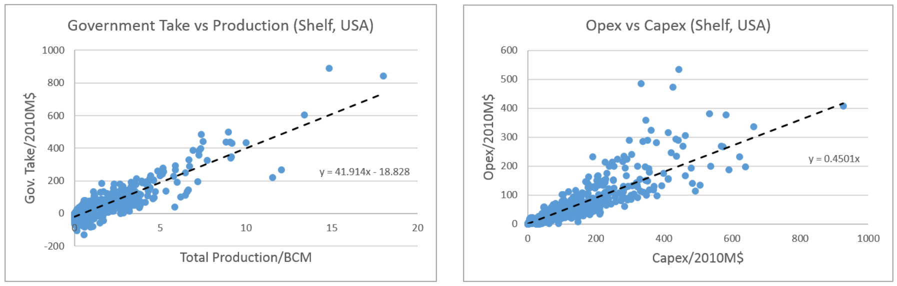


Figure 3: (Left) The total life-cycle Government Take of 1904 currently abandoned "Shelf" fields in the USA correlates with their total production. Each blue dot represents a field and the dashed line is a linear fit (see text). (Right) Total life-cycle opex and capex of the same fields as (Left), giving an opex parameter $b_{i,r} = 0.4501$ for this particular FE and region.

such a profile would be both computationally expensive and unnecessary for the purposes of DYNAAMO. We instead adopt a simplified approach to production profile modelling informed by a combination of industrial rules-of-thumb and historic field-level data. Two different production profiles (PPI & PPII) have been developed in DYNAAMO, allowing the user to choose a trade-off between greater fidelity to industrial practices (PPI) or simplicity and computational speed (PPII) (see Appendix D for details).

Both profiles incorporate a *preproduction* phase (following the discovery and sanction of the field), a *ramp-up* phase (during which production increases), and a *decline* phase (during which production diminishes), followed by the abandonment of the field. In PPI there is also a *plateau* phase, absent in PPII, in which production is roughly constant, as new wells are brought on stream at a rate which offsets declining production from older wells in the same field.

A schematic of both production profiles is shown in Fig. 4. Each depends on a number of parameters, which are determined from a combination of historic data and the constraint that life-cycle production be equal to the field EUR, $R_{0i,r}$. These parameters - which depend on the size of the field - describe the timing of the various production phases, as well as the "peak" or "plateau" rate of production.

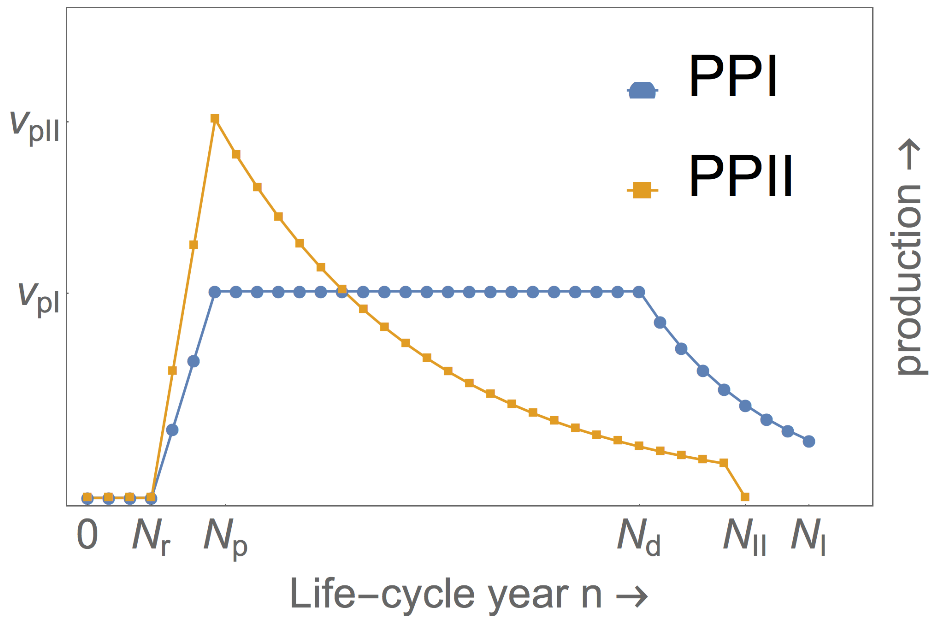


Figure 4: The alternative production profiles, PPI & PPII. After discovery of the field in year $n = 0$ there is a preproduction phase lasting N_r years before a ramp-up phase lasting $N_p - N_r$ years, during which production increases linearly, reaching a peak in year $n = N_p$. In PPI the field then produces gas "on plateau" at a constant rate v_{pI} for a further $N_d - N_p$ years, after which production declines exponentially until the field is abandoned in year N_I. PPII has the same form as PPI Eq. (D.1), except that the plateau phase is skipped: after ramp-up the field goes straight into decline. The peak/plateau rates (here denoted by v_{pI} & v_{pII}) and shut-down years (N_I & N_{II}) are in general different, as is the decline rate, although the total life-cycle production is the same for both profiles and equals the field EUR.

Abandonment. The abandonment year (N_I & N_{II} in Fig. 4) is not calculated using historic data, but instead depends on the cashflows generated by the field through its life-cycle. Cashflows depend on the timing of costs (the expenditure profile) and the timing of production (the production profile), as well as the gas price and the carbon price. Gas fields are abandoned (shut down) when their forward NPV - the NPV of future cashflows - becomes negative (see [59] for a discussion of economic limits). The forward NPV depends on a forward price assumption (normally a flat forward price from the initial year $n = 0$) which should be consistent with the forward price used to estimate the field's EUR.

4.3. Distribution of field sizes

The expenditure and production characteristics of a gas field as described in the previous section depend on a single independent variable - the 2P field EUR, $R_{0i,r}$. There is enormous variability in the sizes of gas fields, even within the same FE, and this distribution of field sizes impacts directly on the availability of gas at a given price. We examined the initial 2P reported reserves of over 17000 fields worldwide since 1970. The distribution of field sizes can be approximated very well using a log-normal distribution[4] (see Fig.5), facilitating a simple description in terms of only 2 additional parameters (the mean and variance) per FE per region. On a world level Unconventional fields have the largest mean field size of the FEs and Offshore Shelf the smallest, being approximately 60 times smaller. The mean and variance of the field size distributions by region is listed in Table 3.

Asset Classes. A knowledge of the FE, region and 2P initial reserves of a given field completely specifies the future expenditure and production of that field. In a given region, the field size distributions can be sampled discretely and fields of the same FE and a similar field size can be grouped together to create an *asset class*. All fields in the same asset class are therefore indistinguishable in DYNAAMO, but each asset class has its own initial gas reserves (apportioned using the log-normal distribution from the total 2P reserve estimates for the FE/region in question) and so is subject to depletion, *shut-in* and so forth. Asset classes are a useful concept because they acknowledge that it is a combination of technology (i.e. FE), life-cycle year (n) and the size of the field (i.e. $R_{0i,r}$) that determines the unit costs of supply. A giant, plateau-phase deepwater fields might produce cheaper gas than small, ramping-up unconventional fields, for example, although the nominal "capex-per-barrel" of deepwater technology might be higher than that of onshore unconventionals.

[4]This is intuitively reasonable given that the EUR is often constructed as a product of presumably weakly correlated, normally distributed variables, such as "gas-in-place", "recovery factor" etc. .

The number of asset classes is chosen by the user and depends on the number of FEs and on how densely or sparsely the field size distribution is sampled. This allows a choice between accuracy and speed.

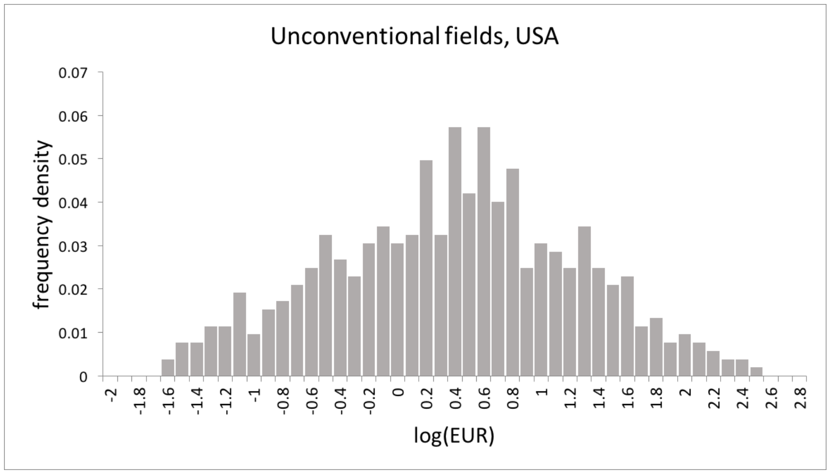


Figure 5: The frequency density (relative frequency) of the EURs (in BCM) of 553 producing and abandoned unconventional gas fields in the USA. The bin size is $0.1/\log_{10}(\mathrm{BCM})$.

5. Building new gas fields

Having described the technical and economic inputs used to calculate the NPV of potential future gas fields we turn our attention to the ultimate goal of DYNAAMO, namely the construction of future supply curves. The first step towards this end is to model investment in new fields, which is assumed to be driven by investors' expectations of the future demand for gas and its future price.

Configurable imperfect foresight. Many energy systems models are intertemporally optimised [60] [61] [62], thus requiring perfect foresight of demand and price over the whole modelling horizon, or else myopic, meaning that investment decisions are made assuming the current demand and price remains unchanging into the future. DYNAAMO offers the possibility to restrict the time horizon over which investors have expectations of future price and demand. Field

NPVs are calculated using an exogenously specified time-series of prices[5] which are in general "structured" (i.e. not constant but changing year-on-year) up to a configurable number of years known as the *foresight time horizon.* Beyond the *foresight time horizon* the price is assumed to remain constant. A similar scheme has been implemented to model expectations of future demand with DYNAAMO, and it is both future price and future demand which determine the rate at which new gas fields are built (i.e. the addition of 'capacity'), which in turn influences the costs of production.

5.1. Adding Capacity

DYNAAMO simulates building new gas fields in anticipation of future demand. This demand-driven capacity addition is modelled by considering the total aggregated production from all fields, $Q_{j,r,t}$, for a given asset class (j) and region (r) in year t (in the following we will use the letter j to index the asset class, as distinct from the FE index i encountered previously). This is given by contributions from fields at all stages in their life-cycles as follows;

$$Q_{j,r,t} = \sum_{n=0}^{N_{j,r}} a_{n,j,r,t} v_{n,j,r} \tag{5.1}$$

with $a_{n,j,r,t}$ being the number[6] of developed fields of asset class $= j$ in year n of their production cycle in region r in time period t, and $v_{n,j,r}$ the production rate per year. Given a set of known coefficients $a_{n,j,r,t}$ in period t, the newly installed capacity in period $t+1$ (i.e. the coefficients $a_{0,j,r,t+1}$) can be found by relating the change in production between consecutive periods, $\Delta Q_{j,r,t+1}$, to the "supply deficit", $S_{r,t} \equiv d_{r,t} - Q_{r,t}$ as follows,

$$\text{excess} \times S_{r,t} \geq \sum_{j=1}^{z[S_{r,t}]} \Delta Q_{j,r,t+1} \tag{5.2}$$

[5]Expectations on forward prices could be informed by a number of macro-drivers such as energy service demands and the availability of competing primary energy sources other than natural gas.

[6]For computational purposes $a_{n,i,r,t}$ is not restricted to take integer values; the actual field count should therefore be taken as the rounded value of $a_{n,j,r,t}$.

Here, $Q_{r,t} \equiv \sum_j Q_{j,r,t}$ is total production summed over asset classes, $d_{r,t}$ is the (exogenous) demand and "excess" is a configurable factor > 1 which ensures that the model targets an excess capacity margin when developing new fields. The initial coefficients, $a_{n,j,r,0}$ are determined from base year calibration (see Section 7). The production $Q_{r,t}$ includes "own-fuel" gas used to service field operations at a configurable rate, normally around 5% [63], and this should be accommodated in the "excess".

In simple terms, Eq. (5.2) says that production will increase from the building of extra capacity to fill any supply deficit (the difference between demand and production), and remain constant when the supply deficit shrinks to zero. There are, however, three features built into Eq. (5.2) designed to better simulate real-world investment practices, particularly regarding the growth and market penetration of new technologies:

- The ordering of the asset class index j in Eq. (5.2) is dictated by the capital efficiency of the associated field, with larger capital efficiencies corresponding to smaller values of j. This ensures that new capacity is built by *prioritising investment in fields with the highest capital efficiencies*. Capital efficiency is a measure of expected return on capital, in this paper taken as NPV per net present cost of capital (using only discounted capex spent over the *preproduction* lifecycle phase - see Fig. 2). Gas extraction and processing companies use multiple criteria for evaluating potential projects under a range of commodity cost stacks and forward price scenarios [64][58]. For transparency and computational speed DYNAAMO uses a single ranking metric - capital efficiency - although sensitivities can be run on the discount rate and forward gas and carbon prices, each of which affects not just the absolute capital efficiencies but the ordering of assets. The choice of capital efficiency is based on current industry practice [58][65]; there is also some evidence that this metric carries more sway in times when the industry is squeezed or capital is scarce [66].

- The rate of capacity addition in a given FE is constrained to avoid unrealistic growth levels and/or fast switching between technologies. The main real-world constraints to growth are likely to be of an economic rather than purely technical nature (such as the limited availability of capital, risk aversion to immature technologies, etc.), and so DYNAAMO implements constraints on expenditure rather than capacity *per se*. Both the expenditure growth rate (expressed as a percentage of the previous year's expenditure) and the absolute change in expenditure are constrained, with the range of values of the constraints set using historic case studies (see Figs. 8 and 10).

- Capacity is not added in FEs which have insufficient remaining gas reserves. A useful measure of the abundance of remaining reserves is the *depletion rate*, which is the production rate expressed as a percentage of the remaining (usually 2P) reserves. We analysed historic depletion rates across a wide selection of years, FEs and regions and found that almost all hover around $2-7\%$. Increases in the depletion rate are typically stabilised by new discoveries, reduced production, or both (see Figs. 6 & 7). Guided by historic precedent, capacity addition in DYNAAMO is prohibited in a given FE if the depletion rate exceeds 10% (the exact value can be configured by the user). This also avoids computational difficulties associated with the complete exhaustion of reserves, and can be seen as a form of *scarcity rent* [31].

As discussed, expenditure constraints are necessary to model technological transitions and phases of intensive investment as realistically as possible, and they implicitly determine the upper bound $z[S_{r,t}]$ in Eq. (5.2). Here, $z[S_{r,t}]$ is an integer computed self-consistently from the supply deficit, $S_{r,t}$. It indexes the "marginal" asset class in which the early-stage capex spend grows as a result of extra investment. Because asset classes in Eq. (5.2) are ranked by diminishing capital efficiency, during times of high future demand (and price), a wide portfolio of new fields will be developed across a range of available asset classes ($z[S_{r,t}]$ will be large), whereas in periods of contraction only the most profitable asset

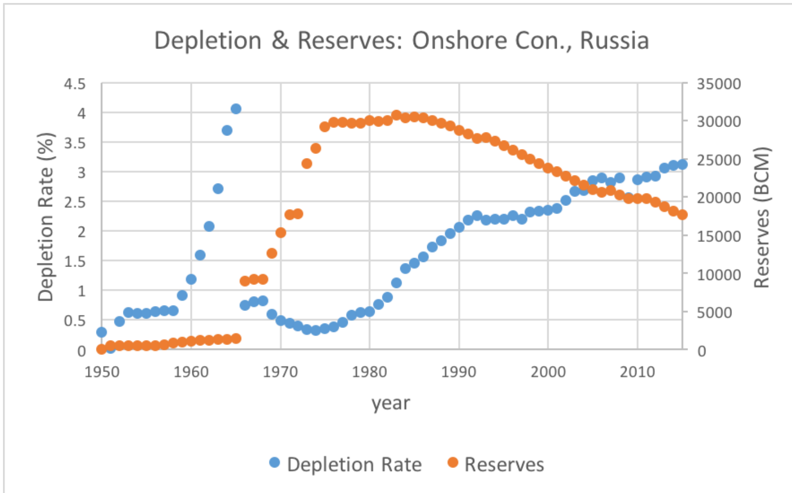


Figure 6: The depletion rate and remaining 2P reserves of Russian Onshore Conventional Gas fields in the period 1950-2015. Large discoveries in the mid 1960s stabilise the depletion rate below 5%.

classes enjoy new investment ($z[S_{r,t}]$ will be small). In cases of overproduction (i.e. when $S_{r,t}$ goes negative), the model suspends any new early-stage capital investment until supply equilibrates with demand. This does not correspond to the "shutting-in" of fields, and relies on the aggregated declining production of existing fields to reduce total supply. For further details on capacity constraints see Appendix F.

When running as part of MUSE, price and demand are not independent, but are set by the market equilibrium (see Appendix B). If supply is squeezed, the forward price naturally rises and makes it profitable to develop new reserves (the stack of asset classes with positive NPV increases). In turn, high gas prices can reduce the future demand for gas. When DYNAAMO is used as a standalone model, the forward price can be taken as the clearing price in the previous time period, which, by responding to the supply deficit, ensures that capacity is always sufficient to meet demand. An alternative treatment of capacity addition in DYNAAMO corresponds to changing the upper bound z in Eq. (5.2), by taking $z = z[pr_{r,t}]$ to index the "marginal" asset class (ranked by

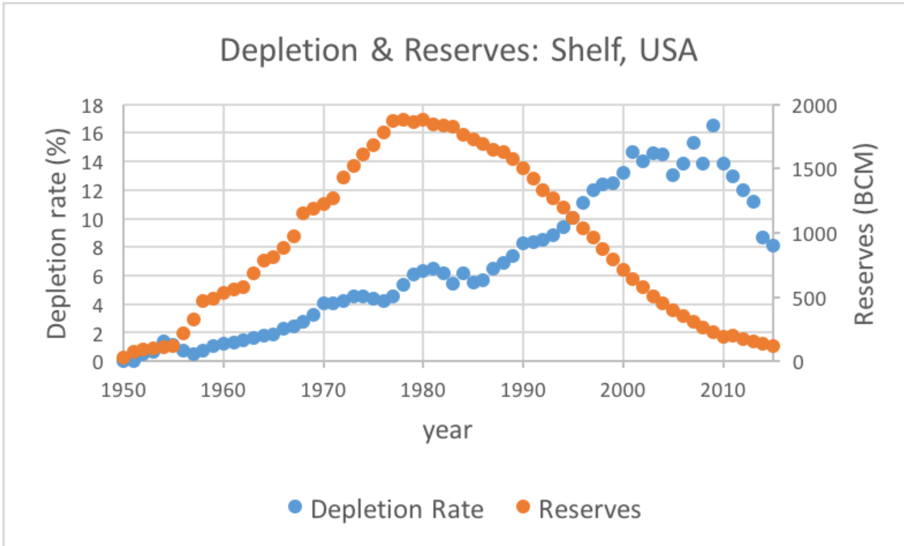


Figure 7: The depletion rate and remaining 2P reserves of US Shelf Gas fields in the period 1950-2015. The depletion rate is stabilised below 8% by cuts to production after 2000.

capital efficiency) for which NPV>0. The supply deficit is therefore modulated implicitly via the gas price. This is an appropriate strategy when running DYNAAMO independently of MUSE.

Shutting-in gas fields. Should the gas price drop lower then the breakeven price (see Section 6) of certain developed gas fields for a sustained (and configurable) number of time periods then this capacity is "shut-in" (permanently removed from the supply curve). This feature can be used in conjunction with the *foresight time horizon* to explore the effects of producers' expectations of the forward carbon price on commercial reserve volumes. Combined with a sensitivity analysis on the carbon emissions intensity of the upstream gas supply chain - e.g. most topically including likely fugitive methane emissions [54] - this offers a powerful new approach to modelling so-called "stranded assets" [3] [67].

5.2. Modelling new reserve discoveries

Whilst the underlying process of discovering new resources is clearly probabilistic in nature (and has been modelled as such [68] [67] [69]), market-driven

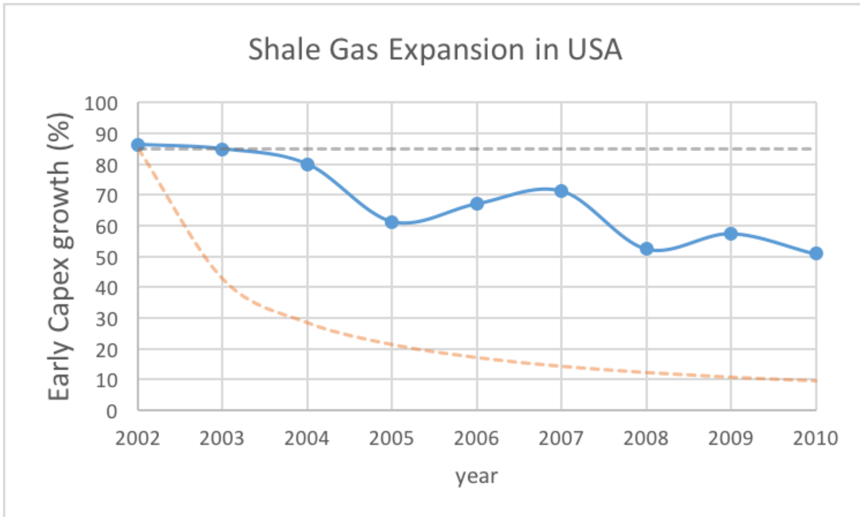


Figure 8: The % growth rate of early capital expenditure during the unconventionals boom period in the USA from 2002 - 2010. The flat dashed line illustrates *exponential* growth, whereas the orange dashed curve illustrates *fixed* growth. Actual growth appears to be somewhere in-between these scenarios.

factors, such as depletion rates and the gas price, also influence producers' *exploratory expenditure* (expex), which can be linked to expected discovered volumes using, e.g. the historic *exploration efficiency*. Reported discovery volumes show very little consistency year-on-year, notwithstanding producers' tendency to back-date new discoveries to the original discovery year of the field (a typical example is shown in Fig. 11). For the sake of modelling simplicity and solution speed, the rate at which new reserves are "discovered" is treated as an exogenous, configurable parameter in DYNAAMO, independent of *expex*. Historic discovery rates are used, averaged over an appropriate number of years which generally depends on the FE/region combination, the maturity of the sector and so on.

6. Supply curves and the cost of gas

The ultimate purpose of DYNAAMO is to build future supply curves; i.e. to calculate the cost of supplying a given quantity of gas in a given region in

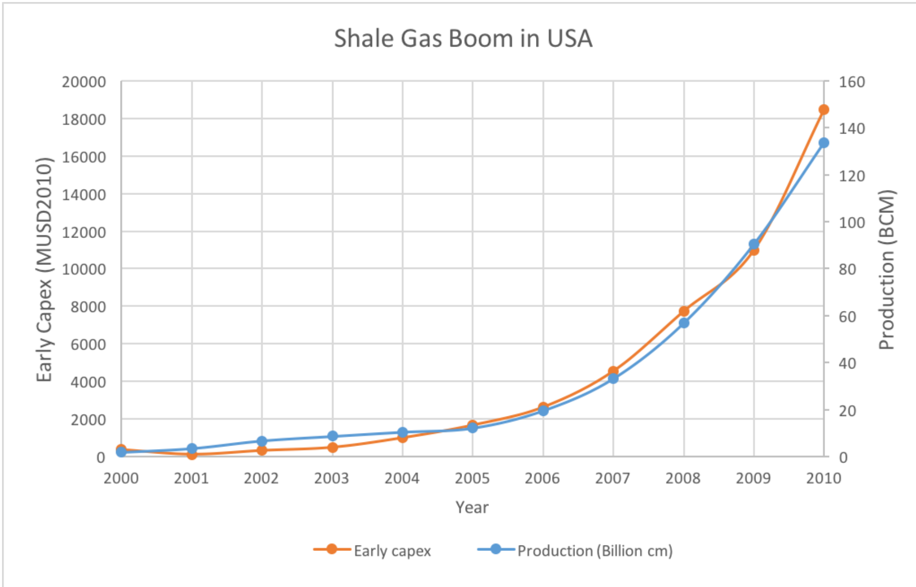


Figure 9: Early capital expenditure and production are very closely correlated during the rapid expansion in US Unconventional gas. The correlation is poorer for more mature technologies, such as US Shelf fields (see Fig. 10).

a given future time period. Supply curves can be constructed by ranking gas fields in terms of their unit *long-run-marginal-cost* ($\text{lrmc}_{n,j,r,t}$). This is the price (assumed to be flat through future years) at which the forward NPV of the field is equal to zero. This corresponds to the "breakeven price" of the field - the lowest price for which a rational producer should continue operations rather than shut-in wells (abandonment costs are included in the forward NPV). The lrmc depends on the life-cycle year of the field, n. Older fields typically need a higher gas price to justify operating, as the fall off in revenues due to declining production is not accompanied by similar opex reductions. The same is true for early-stage and pre-producing fields due to up-front capital costs which are not yet "sunk" (see Fig. 12).

Supply curves constructed using this high level of granularity (i.e. segmented by asset class and lifecycle year) do not necessarily best reflect real-world gas pricing. In heavily regulated markets, such as China or Russia, the price to

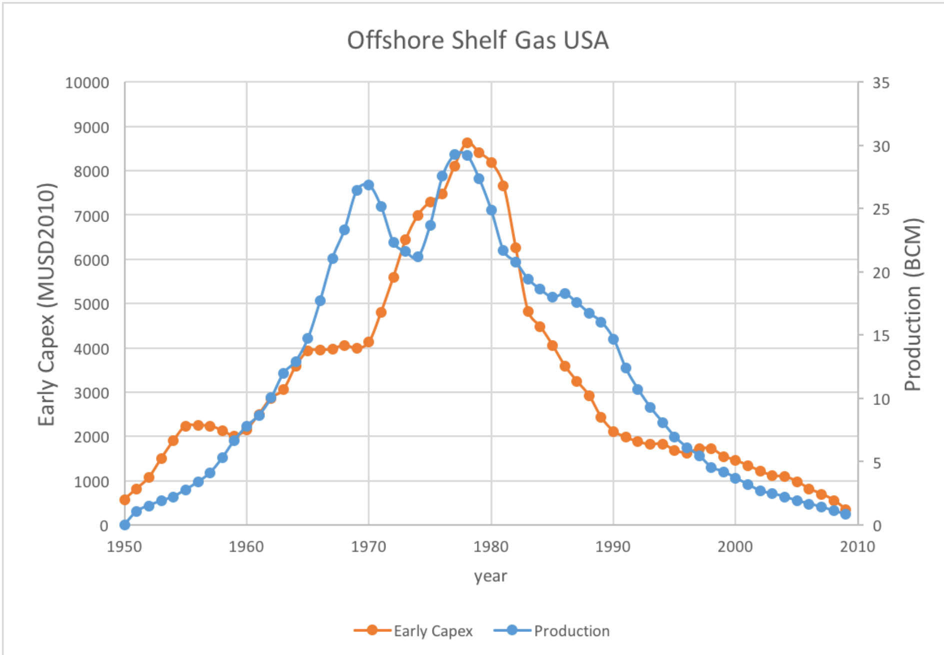


Figure 10: The capital expenditure and production of Offshore Shelf fields in the USA. Over the period 1950 - 2010 the sector expanded, peaked and contracted.

consumers is often modulated by reference to the volume weighted cost of gas purchased or produced [70] [71], given by,

$$\text{meanlrmc}_{j,r,t} = \frac{\sum_{n=0}^{N_j} a_{n,j,r,t} v_{n,j,r} \times \text{lrmc}_{n,j,r,t}}{Q_{j,r,t}} \tag{6.1}$$

In this case the highest lrmc among producers influences the gas price only incrementally through its contribution to the total cost, thus sheltering consumers from high cost gas. Eq. 6.1 also has the advantage of cutting down the size of the cost stack to the number of asset classes, making DYNAAMO run faster.

The clearing price for a given demand is found by equating demand and supply:

$$d_{r,t} = \sum_{j=1}^{x[d_{r,t}]} Q'_{j,r,t} \tag{6.2}$$

This equation can be solved self-consistently, as in Eq. (5.2), to find the “marginal” producer, indexed by asset class $j = x \equiv x[d_{r,t}]$. The prime in Eq. (6.2) indi-

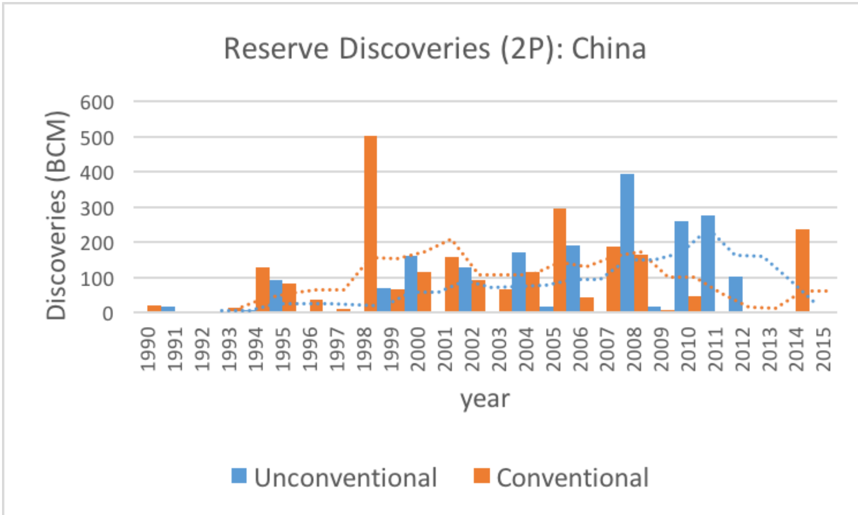


Figure 11: An example of the apparent randomness of exploration for natural gas: discovered volumes of Onshore Conventional and Onshore Unconventional 2P reserves by year in China. The dashed lines correspond to 4 year moving averages.

cates that asset classes in the summation have been ranked by cost (i.e. the asset class with $j = 1$ is the cheapest). The equilibrium gas price then follows from Eq. (6.2) as $\mathrm{lrmc}_{\mathrm{x[q],r,t}}$, and the set of quantity-price pairs $\left(q_{r,t}, \mathrm{lrmc}_{\mathrm{x[q],r,t}}\right)$ generates the supply curve in region r at time t. By construction $\mathrm{lrmc}_{\mathrm{x,r,t}}$ is the highest lrmc among all the producing asset classes needed to satisfy demand, and this sets the equilibrium price of gas.

6.1. Other Outputs

In addition to calculating supply curves, DYNAAMO generates a number of other economic and technical outputs which are relevant to emissions targets, remaining gas reserves and so forth. These outputs include (per time period and region):

- Total emissions
- Total quantity of gas supplied
- The total cashflow

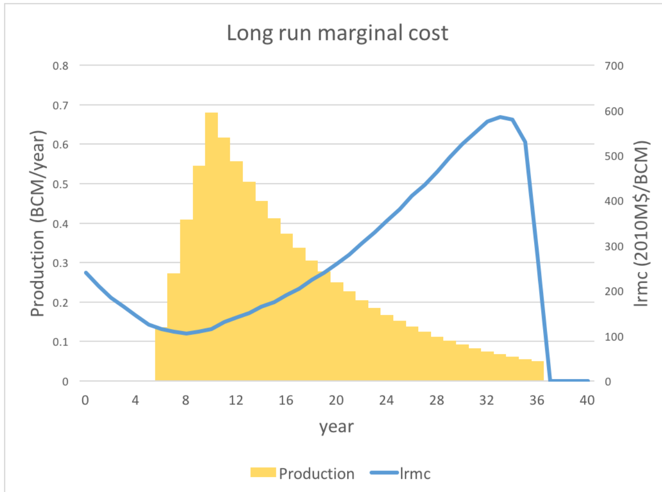


Figure 12: The long-run-marginal-cost of a typical gas field changes over its life-cycle due to changes in production and revenue. The production-weighted average lrmc in the above example is 214.4 MUSD/BCM - similar to its value after roughly half of initial reserves have been extracted. The planned abandonment year is based on a high forward price scenario of 600.0 MUSD/BCM. The discount rate is 10%.

- The total NPV of developed fields
- The remaining reserves (yet-to-extract) of developed fields
- 2P reserves by FE
- Investment and capacity growth by FE
- Capacity that has been "shut-in" (i.e. stranded assets) by FE

7. Calibration

DYNAAMO is calibrated to base year (normally taken as 2010) *activity* and *capacity* using reported figures for base year production and 2P reserves, broken down by FE and region. In the context of upstream gas, *activity* refers to gas production and *capacity* refers to the number of developed (i.e. economically active) gas fields. In practice, calibration involves picking a set of coefficients $a_{n,i,r,0}$ in Eq.(5.1) which determine the initial state of the model. Because fields produce at different rates over their life-cycles, the age of the initial stock is tuned so that production and reserve volumes can be matched to their base year values separately.

Calibration on the base year price of gas is hard to achieve, and, to our knowledge, is not a feature of other bottom-up energy systems models. Note, however, that the user has some discretion in setting the excess capacity factor, as well as the discount rate, which both affect the equilibrium gas price (see Eq. (5.2) and Section 6).

8. Model Validation

To illustrate the model in action we run a demand scenario corresponding to the historic gas consumption in the USA during the period 2000 - 2015. The base year is taken as 1995, with a discount rate of 10% and an excess capacity margin in the base year of 18%. Figs. 13 and 14 show the historic (i.e. actual) and modelled market share of production, respectively, broken down by field environment. DYNAAMO captures very well the major trend during this period, namely the rapid development of Unconventional[7] resources accompanied by an increasingly smaller market share for Onshore Conventionals. The change arises in DYNAAMO because asset classes associated with Unconventionals are ranked highest in terms of capital efficiency. This means that even during periods of flat demand (see the demand profile in Fig. 15) the model installs capacity predominantly in Unconventionals to maintain existing levels of production, so generating a slow upward trend in the market share for Unconventionals. The effect is more pronounced when the forward demand is rising (after $\sim$ 2006), as well as during later stages of growth (2008 and after), when capacity expansion limits are less tight (see Appendix E).

Fig. 15 shows the breakeven price and historical consumption, which is used

[7]NB: "tight" gas is included in the Unconventionals FE. The market share of Unconventionals in 2000 - before the "shale boom" - is therefore larger than would be expected for shale gas alone.

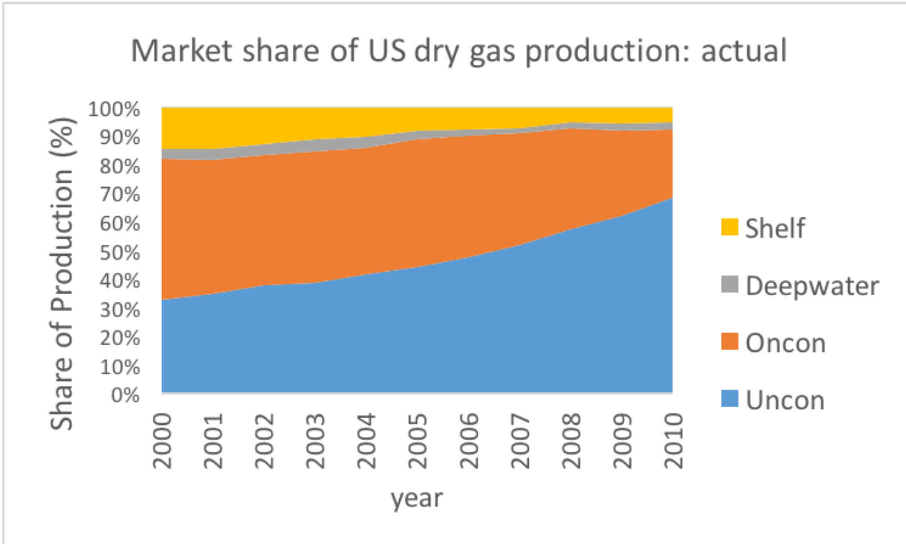


Figure 13: The market share of natural gas production by field environment in the USA.

as the demand in this scenario. The foresight time horizon is 8 years. Although the main focus of DYNAAMO is not price formation - which depends on a host of external factors, ranging from severe weather events to political actions - the model price response to demand in Fig. 15 is entirely consistent with expected market behaviour. The slight easing of demand from 2000 - 2006 is accompanied by a modest downward trend in price. The subsequent price spike from 2006 - 2011 is caused by two factors. First, demand initially rises more quickly than production, the supply gap gets squeezed and prices go up. Second, large amount of capital expenditure on new Unconventional fields raises the average breakeven price (see Fig. 12) (which subsequently falls because these capital costs have become "sunk").

9. Conclusions

This paper has described a novel modelling framework, DYNAAMO, to simulate investments and operations in the upstream gas industry. The model can be used either as a self-contained "stand-alone", or as a supply module inter-

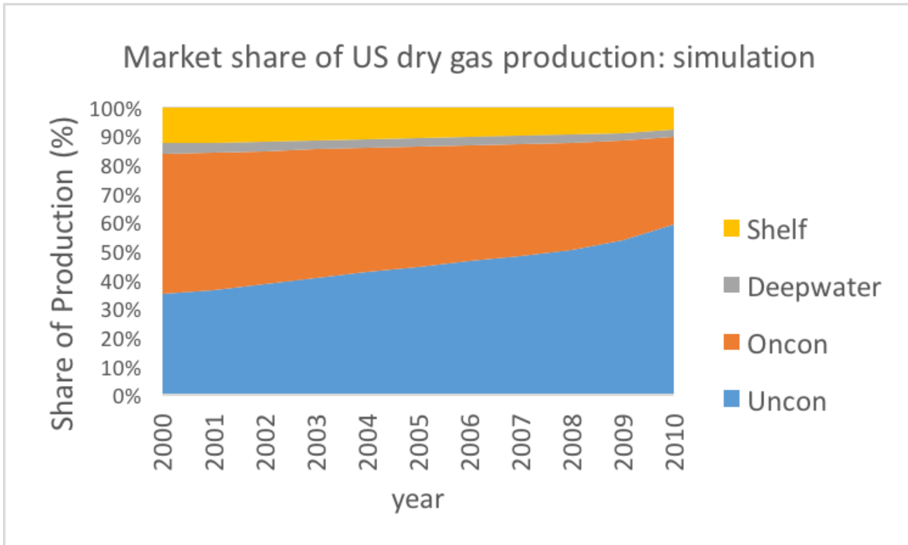


Figure 14: DYNAAMO simulated market share of natural gas production by field environment in the USA.

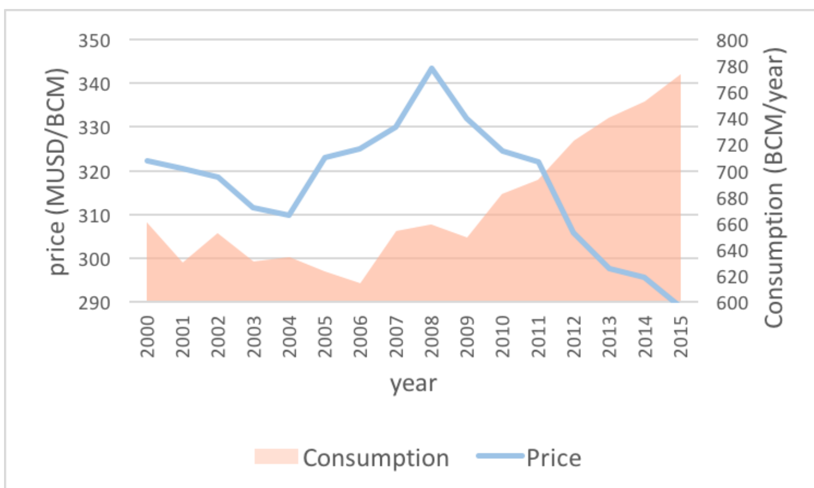


Figure 15: The model price and historic gas consumption for the USA.

acting with an integrated energy systems model. DYNAAMO, developed in collaboration with industry, simulates global investment in the upstream gas industry using a real-world representation of investment decisions. Unlike the majority of the supply sectors used in energy systems models, DYNAAMO generates dynamic gas supply curves where new investments are triggered in anticipation of a forward gas price and demand. Using historic trends, capacity growth is constrained by limiting both the availability of capital and the rate at which remaining reserves are depleted. Breakeven prices are calculated using a regional break-down of supply by field size, field life-cycle year and field environment. Uncertainties in future demand and price projections are taken into account using a foresight time horizon - a time period beyond which investors' knowledge of future market trends becomes progressively more vague. Operational procedures, such as the "shut-in" of capacity, are also modelled as a strategy to reduce investors' exposures to the risks of market fluctuations.

DYNAAMO uses a bottom-up approach to technology characterisation with a high resolution cost breakdown, in which capital investment, fixed operating and maintenance costs, subsidies, exploration costs, taxation and carbon prices are disaggregated. The environmental performance of different stages of the upstream supply chain is also characterised in terms of energy intensity (own-use fuel) and CO_2/CH_4 emissions. In this way, the model can be applied to investigate policy effects on new technology diffusion, paving the way for low-carbon energy systems.

DYNAAMO has been validated using the growth of unconventionals in USA during the 2000s as a case study and is able to capture very well historic trends in terms of market share of upstream technologies, as well as producing plausible gas price trajectories.

Future research will address uncertainty in the availability of resources, focussing on the interplay between producer surplus, exploratory expenditure and the profitability and volumes of new discoveries.

10. Glossary of additional terms

A glossary of variables occurring in the Appendices of this paper and not covered in Table 1 is given in Table 2. In addition to *dependent variables*, parameters can be sub-divided into:

- Configurable Parameter: can be chosen by the user. Multiple interrogations using a range of different values can help to map out space of model outputs. The values of these parameters are sometimes set from industrial "rules-of-thumb" (e.g. in the case of α) or other data sources.
- Input Variable: input from the MUSE *Market Clearing Algorithm* (or else exogenous inputs when DYNAAMO is running as a stand alone model. See Appendix B).

Table 2: DYNAAMO parameters

Configurable Parameter	Description	Units
$Q_{i,r,0}$	base year production	BCM/year
$R_{i,r,0}$	base year reserves	BCM
$D_{i,r}$	Decline Rate	years^{-1}
$r_{i,r}$	Discount Rate	years^{-1}
$y_{i,r}$	Plateau Exponent	
$\text{capad}_{i,r}$	Capacity addition limit	
α	Capex Exponent	
cit_i	Carbon (emissions) intensity	tonnesCO_2/BCM
$\text{discover}_{i,r}$	Discovery rate of reserves	BCM/year

Table 2: DYNAAMO variables

Input Variable	Description	Units
$p_{r,t}$	forward price	MUSD/BCM
$cpr_{r,t}$	forward carbon price	MUSD/tonneCO_2
$d_{r,t}$	forward demand	BCM/year
$\Delta d_{r,t}$	change in demand between periods t and $t-1$	BCM/year

Table 2 Contd.

Dependent Variable	Description	Units
$R_{i,r,t}$	reserves in time period $t > 0$	BCM
$Q_{i,r,t}$	production in period $t > 0$	BCM/year
$\mathrm{cap}_{i,r,0}$	base year capacity	
$\Delta Q_{i,r,t}$	change in production between periods t and $t-1$	BCM/year
$\Delta \bar{d}_{r,t}$	excess change in demand between periods t and $t-1$	BCM/year
$A_{i,r}$	peak production coefficient	BCM/year
z	marginal developed asset index	
x	marginal producing asset index	

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Appendices

A. Reserve Volumes & Field EUR Parameters

Table 3 shows 2P reserve volumes ($R_{i,r,0}$) and field size distribution parameters for the model base year (2010) by region. The mean log is $< \log R_{0i,r} >$, with standard deviation $\sqrt{< \log(R_{0i,r})^2 > - < \log(R_{0i,r}) >^2}$. For details of the regional breakdown (compatible with that used in the MUSE model) see [2].

Table 3: The mean and standard deviation of the log-normal distribution (base 10) field EUR (BCM) & base year (2010) 2P reserves (BCM) of non-associated natural gas by field environment.

Region		Shelf	Deep	OnCon	UnCon
	mean	-0.46	0.05	-0.14	0.34
USA	s.d.	0.70	0.60	1.05	0.96
	reserves	195.30	100.70	2099.80	7613.80
	mean	1.03	-	-0.66	-0.22
Canada	s.d.	0.20	-	1.11	1.01
	reserves	33.50	0.50	1140.10	1191.40
	mean	-0.45	-	-0.25	-
Mexico	s.d.	0.86	-	0.96	-
	reserves	2.30	19.30	153.40	10.10
	mean	0.72	-	-0.79	-
Chile	s.d.	0.59	-	0.96	-
	reserves	86.10	-	10.10	-
	mean	0.71	1.72	-0.68	0.17
AUS	s.d.	0.79	0.74	0.86	1.31
	reserves	893.40	3338.80	191.90	706.10
	mean	-	-	-	-
Iceland	s.d.	-	-	-	-
	reserves	11.90	305.10	0.10	-

Table 3 Contd.

Region		Shelf	Deep	OnCon	UnCon
	mean	1.09	1.44	-	-
Norway	s.d.	0.65	0.79	-	-
	reserves	137.60	2103.70	-	-
	mean	1.47	-	-	-
Denmark	s.d.	0.27	-	-	-
	reserves	66.80	-	-	-
	mean	-	-	-	-
Finland	s.d.	-	-	-	-
	reserves	-	-	-	-
	mean	-	-	-	-
Sweden	s.d.	-	-	-	-
	reserves	-	-	-	-
	mean	0.38	0.79	-0.45	-0.86
EU18	s.d.	0.67	0.69	0.88	0.79
	reserves	964.90	222.30	1569.90	84.10
	mean	0.32	-	0.05	-
EU7	s.d.	0.27	-	0.71	-
	reserves	35.30	52.80	201.60	0.30
	mean	0.74	-	0.26	-
OETE	s.d.	0.40	-	0.86	-
	reserves	19.40	1.60	349.90	19.70
	mean	2.31	-	0.74	-
RUS	s.d.	0.40	-	1.24	-
	reserves	733.60	245.60	20263.90	3.60
	mean	1.05	2.15	0.86	-
ATE	s.d.	0.61	0.86	0.89	-
	reserves	147.90	700.14	6042.50	0.10
	mean	0.72	1.22	1.25	1.05
CHN	s.d.	0.53	0.70	0.60	0.81
	reserves	183.50	100.70	1945.70	1139.80
	mean	-	-	0.26	0.57
ODA	s.d.	-	-	0.83	0.25
	reserves	98.20	3.80	1857.50	2.30

Table 3 Contd.

Region		Shelf	Deep	OnCon	UnCon
	mean	0.49	0.99	-0.45	-
Brazil	s.d.	0.93	0.51	0.88	-
	reserves	47.50	152.70	50.80	0.20
	mean	0.53	1.03	0.05	0.36
India	s.d.	0.61	0.73	0.68	1.26
	reserves	261.50	229.70	96.80	27.70
	mean	-	0.68	-	-
Israel	s.d.	-	1.46	-	-
	reserves	-	180.10	-	-
	mean	-0.17	-	-0.57	-
OE2	s.d.	0.42	-	0.66	-
	reserves	5.70	1.40	8.10	0.25
	mean	1.03	0.96	0.03	-
Japan	s.d.	-	0.08	1.11	-
	reserves	8.90	8.90	15.70	0.10
	mean	-	-	-	-
Korea	s.d.	-	-	-	-
	reserves	0.20	4.30	-	-
	mean	0.93	1.22	0.33	-0.26
ASEAN	s.d.	0.68	0.60	0.84	0.23
	reserves	2750.70	849.50	612.10	4.10
	mean	1.28	1.28	0.15	-0.16
OCSA	s.d.	0.56	0.57	0.94	1.24
	reserves	742.90	267.10	1734.90	49.80
	mean	-0.15	1.22	-	-
South Africa	s.d.	0.97	-	-	-
	reserves	26.70	40.30	0.60	0.90
	mean	0.97	0.96	0.40	-
OAFR	s.d.	0.56	0.50	1.03	-
	reserves	1062.80	1758.70	4363.40	92.30
	mean	2.21	-	1.31	0.89
MEA	s.d.	0.84	-	0.82	0.49
	reserves	28092.30	17.50	6583.60	104.60

B. The MUSE model

MUSE (**M**od**U**lar energy systems **S**imulation **E**nvironment) aims to bring engineering reality to energy systems modelling using a bottom-up approach to technology characterisation. This primarily implies that, compared to traditional global models, a new perspective to the modelling of decision making in upstream gas is adopted rather than static supply curves, allowing better insight into the role of gas in future energy systems. While the vast majority of global energy systems models are based on optimisation approaches and define normative trajectories to meet predefined targets (e.g. cost minimisation), MUSE is a simulation model. As such, it aims to simulate the real decision-making processes occurring in each sector of the energy system. In doing so, a limited foresight approach can be used in modelling the knowledge of future energy commodity prices and demand trajectories.

MUSE is a partial equilibrium model of the global energy system with microeconomic foundations. It applies a modular approach to the modelling of the energy system where the specific drivers to investments and operations (i.e. production and emissions levels) are tailored to represent each specific energy sector. Fig. 16 shows the structure of the MUSE modelling environment. In its modular architecture, MUSE includes supply sectors (*upstream oil*, *upstream gas*, *coal extraction*, *renewables uptake*, *uranium uptake*); conversion sectors (*power sector*, *refinery*, *bio-refinery*) as well as demand sectors (*agriculture*, *buildings*, *industry*, *transport*). The modular structure of MUSE allows flexibility as each module represents a specific sector of the energy system and it is characterised by a methodology for investments in asset capacity addition and operation which is sector-specific. Macroeconomic links are also included for energy service demand projections. As shown in Fig. 16, every sector module exchanges information with a market clearing algorithm (*MCA*), which iterates across all sectors and all energy commodities until a market equilibrium is reached. In particular, in each single period of the simulation, DYNAAMO iteratively receives from the *MCA* the forward gas demand, the forward gas price and the forward carbon price. As such, these represent exogenous inputs to DYNAAMO for the dynamic calculation of forward gas supply curves, which are returned to the *MCA* in MUSE as price-quantity pairs.

MUSE enables the generation of multiple scenarios of long-term energy technology transitions (from 2010 to 2100) on a global scale with a disaggregation into 28 regions where the effects of technological breakthroughs and policies can be explicitly modelled. It is designed to inform stakeholders about the value and role of technologies in a low carbon world as well as to enable robust development strategies, business models and R&D investment prioritisation. It can be also used to produce climate change mitigation pathways. In order to guarantee transparency in the modelling approach the modelling framework of MUSE will be released as open access.

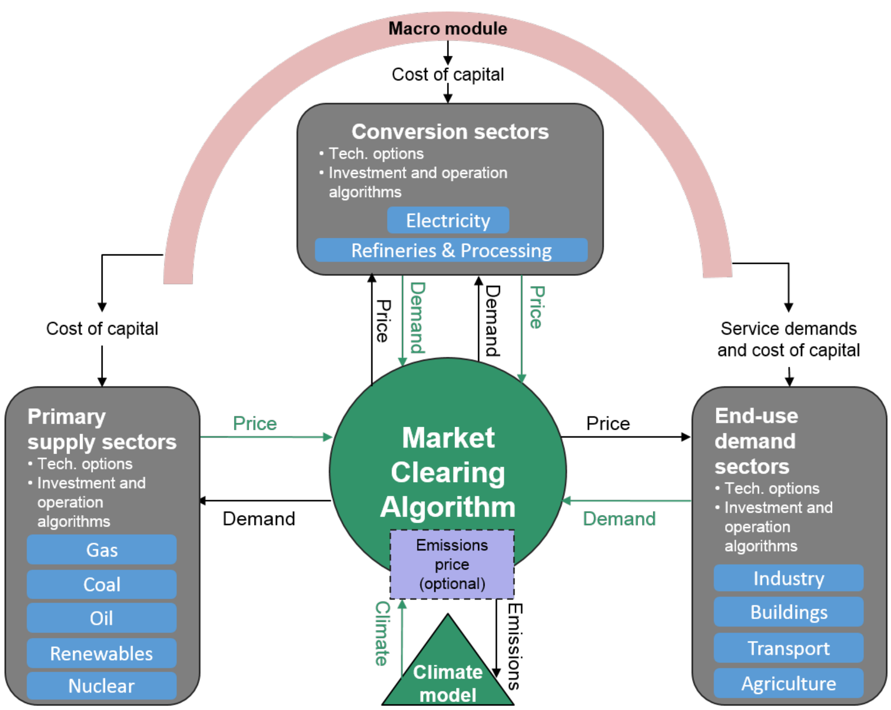

Figure 16: MUSE: the model architecture and main dynamic interactions across the sector modules.

C. Economies of Scale

Larger gas fields typically benefit from economies of scale, as captured in DYNAAMO by the power sizing exponent, α, which dictates how a field's capex scales with its EUR. Historic data from 237 currently abandoned Onshore Conventional fields discovered after 1960 worldwide are shown in Fig. 17, giving a regressed value $\alpha = 0.671$. A similar plot focussing exclusively on 346 Offshore Shelf fields in the USA gives $\alpha = 0.670$, with - as expected given the choice of a single region and FE - a far tighter correlation. A comparable value of $\alpha = 0.652$ and $\alpha = 0.841$ is found for Unconventional and Deep Offshore fields respectively, albeit less well correlated given the relative scarcity of fields which have completed their life-cycle expenditure and production.

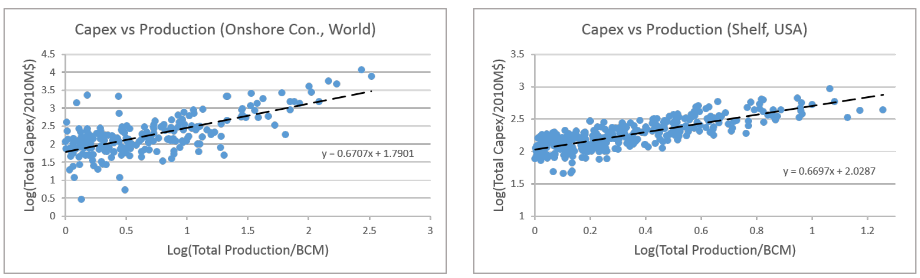

Figure 17: (Left) A Log-Log plot (base 10) showing the total (i.e. whole life-cycle) capex and production of 237 Onshore Conventional gas fields discovered since 1960, worldwide. Each blue dot represents a field, and the black dashed line is a linear best fit with correlation coefficient $R^2 = 0.64$. (Right) The same figure focussing on 346 Offshore Shelf fields in the USA shows a better line of best fit, with $R^2 = 0.71$. The slope of the fitted lines corresponds to the "power-sizing" exponent α, and is remarkably close to value $\alpha = {}^2/_3$ in both cases.

D. Field Production Profiles

Quantitatively, the production of a field $v_{n,i,r}$ can be written as a function of the *life-cycle* year of the field, denoted by n in the following. Note that the life-cycle year refers to the "age" of the field, and is distinct from the time period index, t. DYNAAMO offers the user 2 production profiles (see Section 4.2). In

PPI the production rate $v_{n,i,r}$ is a piecewise function;

$$v_{n,i,r} = \begin{cases} 0 & n \leq N_{ri,r} \\ \frac{v_{pi,r}}{N_{pi,r}-N_{ri,r}}(n - N_{ri,r}) & N_{ri,r} < n \leq N_{pi,r} \\ v_{pi,r} & N_{pi,r} < n \leq N_{di,r} \\ v_{pi,r}e^{-D_{i,r}(n-N_{pi,r})} & N_{di,r} < n \leq N_{i,r} \end{cases} \tag{D.1}$$

After discovery of the field in year $n = 0$ there is a preproduction phase lasting $N_{ri,r}$ years before a ramp-up phase lasting $N_{pi,r} - N_{ri,r}$ years, during which production increases linearly, reaching a peak in year $n = N_{pi,r}$. The field then produces gas "on plateau" at a constant rate $v_{pi,r}$ for a further $N_{di,r} - N_{pi,r}$ years, after which production declines exponentially with decline rate $D_{i,r}$ until the field is abandoned in year $N_{i,r}$.

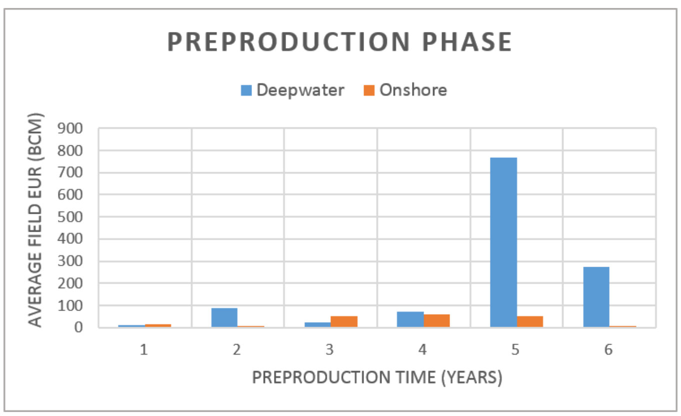

Figure 18: Gas fields developed between 1970 and 2015 are sorted by Preproduction time, and the average of the fields' EUR is shown.

PPII has the same form as PPI Eq. (D.1), except that the plateau phase is skipped: after ramp-up the field goes straight into decline. Both production profiles (PPI & PPII) are constrained by the requirement that the total life-cycle production (in other words $\sum_{n=0}^{N_{i,r}} v_{n,i,r}$) be equal to the field EUR, $R_{0i,r}$,

$$R_{0i,r} = \sum_{n=0}^{N_{i,r}} v_{n,i,r} \tag{D.2}$$

so that for a given EUR the peak production rate using PPII would be larger than that using PPI. The durations of the various life-cycle phases which characterise the production profile (i.e. the $N_{ri,r}$, $N_{pi,r}$, $N_{di,r}$ & $N_{i,r}$ in Eq. (D.1)) depend on the field EUR and the FE. The preproduction phase is normally longer for offshore than onshore fields, and also shows some positive correlation with field size. Fig. 18 shows the duration of the preproduction phase for 1452 Onshore conventional and 93 Deepwater gas fields developed worldwide between 1970 and 2015. As is consistent with other approaches [72], for Offshore fields DYNAAMO uses a preproduction time of 5 years for large fields (EUR $>$ 200BCM) and 3 years otherwise. For Onshore fields the preproduction time is 4 years (EUR $>$ 50BCM) or 2 years otherwise.

The duration of the ramp-up phase is typically longer for larger fields, and is set equal to the Preproduction time, so that $N_{pi,r} = 2N_{ri,r}$. As mentioned previously, the remaining part of the production profile during which gas is produced is configured differently in PPI and PPII. PPII is more straightforward to describe and we discuss this first.

D.1. Production Profile II

Cashflow & Abandonment. In order to specify the details of the plateau and decline phases of production it is first necessary to calculate the abandonment year of the field. This depends on the cashflow generated by the field. Cashflow depends on production, expenditure, the gas price ($p_{r,t}$) and the carbon price ($cpr_{r,t}$), as given by,

$$\text{cashflow}_{n,i,r,t} = (p_{r,t} - cpr_{r,t}cit_i - \text{tax}_{i,r})v_{n,i,r} - \text{ysub}_{n,i,r} - \text{ycapex}_{n,i,r} - \text{yopex}_{n,i,r} \tag{D.3}$$

where the carbon price $cpr_{r,t}$ is multiplied by the emissions intensity cit_i and plays the role of a tax on CO_2 outputs associated with gas production. Expenditure in Eq. D.3 is contained within $\text{ysub}_{n,i,r}$, $\text{ycapex}_{n,i,r}$ and $\text{yopex}_{n,i,r}$, which denote the annual subsidy, capex and opex respectively, and result from combining the expenditure profiles (i.e. the timing of costs) described in Section 4.1 with the total life-cycle expenditure of the field.

Gas fields are abandoned (shut down) when their forward NPV - the NPV of remaining future cashflows - becomes negative. The forward NPV in life-cycle year n in time period t is,

$$NPV_{n,i,r,t} = \sum_{\ell=n}^{N_{i,r}} \frac{\text{cashflow}_{\ell,i,r,t+\ell-n}}{(1+r_{i,r})^{\ell-n}} \tag{D.4}$$

where $r_{i,r}$ is the discount rate, so that the abandonment year ($N_{i,r}$) is the solution to the equation,

$$NPV_{N_{i,r},i,r,t} = 0 \tag{D.5}$$

The planned abandonment year of a field depends on the future gas price as well as the initial 2P reserves, $R_{0i,r}$. Although these reserve estimates in principle also depend on the current and future gas price, we will assume a reasonably uniform distribution of the unit cost of the gas-in-place within a field, so that for a commercially viable field $R_{0i,r}$ is taken as a working proxy for the reservoir volume, and plays the role of a physical, rather than an economic, quantity in DYNAAMO.

Large fields tend to produce gas at a higher rate than small fields, so the peak rate of production, $v_{pi,r}$, is assumed to be proportional to $R_{0i,r}$,

$$v_{pi,r} = A_{i,r}\left(\frac{R_{0i,r}}{\bar{R}_0}\right) \tag{D.6}$$

where $\bar{R}_0$ is a reference EUR (normally taken as 1BCM). However, due to the constraint on total life-cycle production, Eq. (D.2), the parameter $A_{i,r}$ is not independent and is given by,

$$A_{i,r} = \frac{2D_{i,r}\bar{R}_0}{2(1-e^{-D_{i,r}(N_{i,r}-N_{pi,r})}) + D_{i,r}(N_{pi,r}-N_{ri,r})} \tag{D.7}$$

so that the abandonment year implicitly determines the peak rate of production. As we are taking the reserves as being fixed, Eqs. (D.6) and (D.7) imply that, given a falling price environment, producers would be expected to increase peak production rates to extract the maximum amount of gas before rapidly declining revenues necessitate abandoning their fields. This might reflect real industrial practice to a degree; an alternative strategy would be to accept a reduction in commercial volumes and maintain the current drill-rate, thus leaving the peak production rate unchanged. In PPII the decline rate $D_{i,r}$ is an independent parameter that can be chosen by the user. Decline rates are affected by geological and technical considerations and are normally in the range $5-15\%$ per year.

D.2. Production Profile I

In contrast to PPII, in PPI there is a plateau phase of production between life-cycle years $n = N_{pi,r}$ and $n = N_{di,r}$. This introduces another variable into the model, $N_{di,r}$ (the year in which the field comes off plateau and goes into decline), and as a consequence the plateau production rate $v_{pi,r}$ is no longer uniquely fixed by the abandonment year and the constraint on total life-cycle production, Eq. (D.2). The plateau rate can instead be modelled more realistically using a combination of historic field data and industrial rules-of-thumb. It is well-known that larger fields produce a smaller fraction of their EUR per year in the plateau phase than smaller fields. This empirical observation can be captured most simply by modifying Eq. (D.6) and setting,

$$v_{pi,r} = A_{i,r} \left(\frac{R_{0i,r}}{\bar{R}_0} \right)^{y_{i,r}} \tag{D.8}$$

with $0 \leq y_{i,r} < 1$ and $A_{i,r}$ a constant to be determined[8]. Industrial practice assumes recovery rates corresponding to $y_{i,r} \approx 0.75$ (irrespective of FE) [58], and similar figures have been reported in the literature [72] based on a study of 15 mature gas fields in Russia, the USA and the UK. In DYNAAMO we have taken historic production data from 2883 offshore fields and 3482 onshore fields which had already extracted $25-50\%$ of their original EUR, normally corresponding to the plateau phase of their production profiles. Regression analysis on these data gives $y_{i,r} = 0.75$ and $y_{i,r} = 0.76$ for Deep and Shelf FEs respectively, and $y_{i,r} = 0.83$ and $y_{i,r} = 0.86$ for Onshore Conventional and Unconventional FEs

[8]For clarity the same notation will be used for various parameters in both PPI and PPII, although the definition of these parameters and their inter-relationships is not in general the same in PPI & PPII.

respectively. The parameter $A_{i,r}$ can also be regressed against $R_{0i,r}$, so that $v_{pi,r}$ is fully specified for a given field EUR $R_{0i,r}$.

One other industrial rule-of-thumb is needed to specify the duration of the plateau phase: roughly 60% of EUR is extracted on plateau. As in PPII, abandonment occurs in PPI after a decline phase when the forward NPV of the field goes to zero. However, in PPI the decline rate is determined *endogenously* using the constraint on total life-cycle production Eq. (D.2). It follows that both $D_{i,r}$ and $N_{di,r}$ are determined from the pair of equations,

$$\overbrace{\sum_{n=0}^{N_{pi,r}} \frac{v_{pi,r}}{N_{pi,r} - N_{ri,r}}(n - N_{ri,r})}^{ramp-up} + \overbrace{0.6R_{0i,r}}^{plateau} + \overbrace{\sum_{n=N_{di,r}}^{N_{i,r}} v_{pi,r} e^{-D_{i,r}(n - N_{di,r})}}^{decline} = R_{0i,r}$$

$$v_{pi,r}(N_{di,r} - N_{pi,r}) = 0.6R_{0i,r} \tag{D.9}$$

where the production during the plateau phase has been re-written as 60% of EUR using the aforementioned rule-of-thumb.

E. Capacity Addition

For a known set of coefficients $a_{n,j,r,t}$ in time period t (base year coefficients $a_{n,j,r,0}$ are matched to production and reserves), we calculate the coefficients in the next time period $t+1$ by first considering the change in aggregate production between the 2 consecutive time periods as given by,

$$\Delta Q_{j,r,t+1} \equiv Q_{j,r,t+1} - Q_{j,r,t} = \sum_{k=0}^{N_{j,r}} (a_{k,j,r,t+1} - a_{k,j,r,t}) v_{k,j,r} \tag{E.1}$$

Noting that the number of fields in year n of their production cycle at time t is equal to the number of fields in year $n+1$ of their production cycle at time $t+1$ we can re-write $\Delta Q_{j,r,t+1}$ as,

$$\Delta Q_{j,r,t+1} = a_{0,j,r,t+1} v_{0,j,r} + \sum_{k=0}^{N_{j,r}-1} (v_{k+1,j,r} - v_{k,j,r}) a_{k,j,r,t} - a_{N_{j,r},j,r,t} v_{N_{j,r},j,r} \tag{E.2}$$

The unknown coefficients $a_{0,j,r,t+1}$ in Eq. (E.2) (i.e. the new capacity which gets built in period $t+1$) are then found by relating the change in production, $\Delta Q_{j,r,t+1}$, to the "supply deficit", $S_{r,t} \equiv d_{r,t} - Q_{r,t}$ as described in Section 5.1.

F. Growth Constraints

Early capex. In cases where a new technology undergoes rapid growth from a low starting point there is some evidence that capital becomes progressively more available as previously developed fields come on stream and cashflows are generated. This was seen in the case of shale gas in the USA in the period 2000 - 2010, when total expenditure in the "early" phase of a field's production profile (when $< 25\%$ of initial EUR has been extracted) grew rapidly over the decade (see Fig. 9 (right)). The accompanying growth rate (in percentage terms), however, was not quite constant[9] (see Fig. 8), suggesting that both a relative and an absolute constraint should play a role in modelling capacity expansion. Configurable limits to both the *rate of increase* and the *absolute amount* of early-stage capex are implemented in DYNAAMO, the former typically set between[10] $50\% - 80\%$ and the latter strongly dependent on region and FE. These economic constraints obviously indirectly constrain the building of new capacity in the model. Fig. 9 shows that, at least for an immature technology, the early-stage capex is closely correlated with production, and this appears to hold approximately true during periods of technological maturity, and even decline (see Fig. 10).

[9]Similar expenditure trends were seen in the USA during the 1950s and 60s during the boom in offshore shelf fields.

[10]DYNAAMO does not model the development of fields in FEs in which no 2P reserves have been reported. The existence of reserves is always associated with some (exploratory) expenditure and so the obvious problems associated with growth rate limits in completely undeveloped FEs are circumvented.