



# Can the US shale revolution be duplicated in continental Europe? An economic analysis of European shale gas resources

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## ABSTRACT

Over the past decade, the rapid increase in shale gas and shale oil production in the United States has profoundly changed energy markets in North America, and has led to a significant decrease in American natural gas prices. The possible existence of large shale deposits in continental Europe, mainly in France, Denmark, the Netherlands and Germany, has fostered speculation on whether the U.S. shale revolution could be duplicated in Europe. However, a number of uncertainties, notably geological, technological, regulatory, and relating to public acceptance make this possibility unclear. We present a techno-economic model of shale gas production amenable to direct estimation on historical production data to analyze the main determinants of the profitability of shale wells and plays. We contribute an in-depth analysis of an extensive production dataset covering 40,000 wells and accounting for nearly 90% of shale gas production in the six main plays of the continental United States from 2004 to 2014. We combine this analysis with a discussion of the main differences between the American and European contexts to calibrate our model and conduct Monte-Carlo simulations. This enables us to estimate the distribution of breakeven prices for shale gas extraction in continental Europe. We find a median gross breakeven price before taxes and royalties of \$10.1 per MMBtu. This would make extraction unprofitable in Europe in the current natural gas price environment, with <47% of the well distribution reaching breakeven at the mean 2011–2016 price. Sensitivity analysis reveals that the breakeven price is most sensitive to initial production rate, drilling and completion costs, and decline rates. We also find that the economic outlook would be slightly better if the productivity of European shale gas plays was comparable to that of U.S. plays of similar depth, but not significantly so. We conclude that under assumptions calibrated on existing shale gas production data, it is unlikely that the U.S. shale revolution can be duplicated in continental Europe.

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## 1. Introduction

Over the past decade, the rapid increase in oil and gas production from shale deposits in the United States has profoundly changed energy markets in North America. In the early 2000s, a combination of improved horizontal drilling and hydraulic fracturing technology has considerably enhanced the economic potential of shale gas deposits. An environment of increasing natural gas prices in the first half of the last decade have made these natural gas reserves commercially exploitable.

The rapid expansion of U.S. fossil fuel production has had a number of macroeconomic impacts, notably in the form of increased activity from intensive drilling, lowered natural gas prices, and a reduction in fossil fuel imports (IHS, 2011). However, the magnitude of these impacts remains a matter of controversy. Kinnaman (2011) notes that large macroeconomic benefits estimates rest on disputable assumptions, notably concerning the redistribution of shale oil and gas royalties.

Still, the large impact of growing U.S. shale production on world energy markets (IEA, 2014) has raised the question of its reproducibility

in other regions of the world. Hilaire et al. (2015) estimate the global share of technically recoverable resources that can be considered economically recoverable using a bottom-up estimate of the levelized costs of shale gas extraction based on publicly available U.S. data. They find that under realistic assumptions, “only 39% of worldwide technical-recoverable resources” could be economically extracted.

The issue of whether shale gas can be economically produced is especially relevant in continental Europe, where the existence of potentially large shale deposits has fostered speculation on whether the oft-called “shale revolution” could be duplicated on the continent. This issue is particularly acute for natural gas, as European dependency on foreign exports has important energy security and geopolitical ramifications, notably *vis-à-vis* the Russian Federation (IEA, 2012).

The case of the United Kingdom deserves a separate treatment, as the policy environment there is more conducive to the development of shale gas extraction (Cotton et al., 2014). The first test wells were drilled in 2016, which will provide data that would allow a direct estimation of the profitability of producing shale gas in the U.K. without resorting to the methodology presented in this paper. This study will therefore focus on assessing the economic potential of the main continental shale gas plays, in France, Denmark, the Netherlands and

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Germany. Poland will not be considered, as the clay content in its shale deposits has thus far proved too high (above 40%) to make hydraulic fracturing feasible.

A number of studies have considered this topic. Gény (2010) examines the technical feasibility of shale gas extraction in Europe by identifying the key drivers of the U.S. shale boom and comparing them to the state of the existing European oil and gas industry. The author concludes that large differences in terms of onshore drilling industry maturity, ease of access to land, mineral ownership rights and environmental regulations make the U.S. operational and business model for shale gas development inapplicable to the European context. Further, absent a focus on “geological sweet spots” (locations of highest well productivity) and “new technology developments”, shale gas production would not be profitable at the \$10/MMBtu price point in Europe. Similarly, Pearson et al. (2012) estimate, using assumptions on well productivity and drilling costs derived from the literature, that European shale gas development can only be successful if “the environmental and economic boundary conditions can be fulfilled”. The report finds breakeven prices in the \$8 to \$12/MMBtu range in Germany. On the same note, Spencer et al. (2014) perform a qualitative assessment of the factors driving shale gas production projections in Europe and find that “[i]t is unlikely that the EU will repeat the US experience in terms of the scale of unconventional oil and gas production”. Vollebergh and Drissen (2014) review existing studies and also conclude that economical extraction of shale gas is unlikely in Europe, while indirect impacts on energy prices – notably through reduced coal prices – from U.S. shale production are likely to be larger on the European economy than any potential domestic shale production.

In contrast, Weijermars (2013) conducts an economic analysis of five continental European shale gas plays and concludes that two of the five plays considered could be profitably extracted at 10\$/MMBtu. However one of these was the Polish deposit, which has since been proven uneconomic. Further, this analysis is hampered by the use of a simple exponential decline model, which is not applicable to the production profile of shale gas wells (Patzek et al., 2013), and of a single sample mean over historical U.S. production data to calibrate well's EUR.

These previous analyses have been hindered by the lack of data on the geology of European shale deposits, on the productivity of shale gas wells and on drilling costs in Europe. In the present paper, we propose to compensate for this absence of data by developing a techno-economic model of shale gas production amenable to direct estimation on the full distribution of U.S. historical production data. Thus, to calibrate well performance in our model, we do not solely rely on a literature review but instead contribute an extensive dataset accounting for nearly 90% of the shale gas production in the six main U.S. plays from 2004 to 2014. This dataset of 40,571 wells covers the entire distribution of well performance across the six plays that have accounted for 93% of U.S. shale gas production over the period considered. In this respect, this analysis also extends the existing literature on U.S. shale gas plays economics (Gülen et al., 2013; Ikonnikova et al., 2015a, 2015b).

As such, even though the geology of shale plays could differ in Europe from their U.S. counterparts, the analysis of American shale gas production can provide realistic distributional assumptions for the main parameters driving well productivity. In contrast with previous European-focused analyses, our rich dataset allows us to consider the full heterogeneity of these parameters by directly estimating their distribution on U.S. historical production data. We also identify assumptions for drilling costs and operational costs, which we adapt to the specificities of the European context. These assumptions can then be used to estimate the gross breakeven price distribution of the potential shale gas resources of continental Europe. However, we do not consider potential external costs, notably environmental, that can be associated with shale gas extraction (Henriet and Schubert, 2015).

The paper is structured as follows: we first present a techno-economic model to analyze the main determinants of the profitability of shale gas wells. We then perform a detailed analysis of >40,000

shale gas wells over a decade of U.S. production data in leading shale plays, in order to calibrate the model. We also examine the particularities of the European context that have a bearing on the technical and economic assumptions used. We then present a Monte-Carlo simulation to estimate the distribution of breakeven prices for shale gas production in continental Europe based on our previous analysis of U.S. data and European specificities. Finally, after conducting an extensive sensitivity analysis, we conclude.

## 2. Modeling shale production

In order to model shale production scenarios in Europe and identify the main parameters that determine the cost of the production flow along with its volume, we develop a techno-economic model amenable to direct estimation on U.S. historical production data. This section presents the model and specifies its equations.

### 2.1. Production profile of a single well

Oil and gas wells follow a well-identified production profile during their life cycle (Arps, 1944). Their production flow usually reaches its maximum early on, and then decreases at a decline rate that can vary over the well's lifespan.

This production profile has been characterized by Arps (1944). In its most generic formulation, the production of a well can be expressed as follows:

$$q(t) = q_0 \frac{1}{(1 + bD_0t)^{\frac{1}{b}}} \quad (1)$$

where  $q_0$  is the initial production rate,  $D_0$  the initial decline rate, and  $b(0 \leq b \leq 1)$  a parameter controlling the evolution of the decline rate over time. The parameter  $b$  notably determines the type of decline (see Fig. 1):

- *exponential* ( $b = 0$ ), where production decreases over time with a constant decline rate. If this decline rate is high, most of the production is front-loaded over the first years of exploitation;
- *hyperbolic* ( $0 < b < 1$ ), where the decline rate decreases over time. If this decrease is fast enough, the impact of high initial decline rates on the well's production can be balanced by a longer well lifespan;
- *harmonic* ( $b = 1$ ), which is a special case of hyperbolic decline. It is the slowest of all three types of declines, i.e. the one that yields the largest late-life production flows.

This equation highlights the most important parameters when estimating the expected output of a well over its entire lifespan: the well's initial production rate and the dynamic of the decline rate over the well's life cycle.

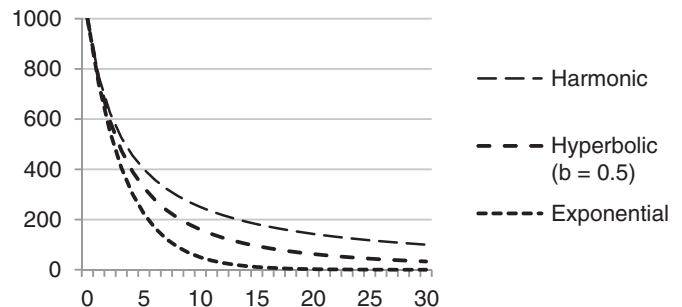


Fig. 1. Types of well production decline ( $q_0 = 1000$ ,  $D_0 = 15\%$ ).

While the trajectory of shale gas wells production over time exhibits the same initial production peak and subsequent decline observed in conventional natural gas wells production, the physics governing the evolution of the pressure in the shale gas deposit are different from that of a conventional reservoir, for which the Arps equation was originally conceived (Patzek et al., 2013). This makes using the classic Arps equation difficult, as decline rates may not evolve smoothly or strictly monotonically over time. To overcome this issue, we shall consider in this paper a discretized version of the empirical Arps equation with a varying monthly decline rate<sup>1</sup>, to estimate the monthly production of the wells that will be modeled. Discretizing Eq. (1) over time allows for the non-parametric estimation of the decline rate dynamic on historical production data. Using a decline rate with respect to the previous month's production of  $\delta_i$  in month  $i^2$ , the production for month  $n$  can be expressed as:

$$q_n = q_0 \prod_{i=0}^n (1 - \delta_i) \quad (2)$$

The total production over the well's lifetime,  $T_w$ , which amounts to its Estimated Ultimate Recovery (EUR), becomes:

$$Q_{well} = q_0 \sum_{n=0}^{T_w} \prod_{i=0}^n (1 - \delta_i) \quad (3)$$

If we then suppose that drilling costs amount to  $I$ , the operational cost per unit of production amounts to  $c$  (following the literature<sup>3</sup>, we assume that operational costs are constant over time), and the wholesale price amounts to  $p$ , the Net Present Value (NPV) of this production is, for a discount rate of  $r$ :

$$NPV_{well} = q_0(p - c) \sum_{n=0}^{T_w} \frac{\prod_{i=0}^n (1 - \delta_i)}{(1 + r)^n} - I \quad (4)$$

The gross breakeven price excluding taxes and royalties,  $p^*$ , corresponds to the price for which this NPV is zero. From Eq. (4), we find  $p^*$ , which can be split into a marginal component and a fixed costs component which amortizes the initial drilling costs:

$$p^* = c + \frac{I}{q_0 \sum_{n=0}^{T_w} \frac{\prod_{i=0}^n (1 - \delta_i)}{(1 + r)^n}} \quad (5)$$

### 3. Analysis of U.S. production data

Calibrating the equation describing the production profile of the representative well (Eq. (2)) requires detailed knowledge of the geological characteristics of the play considered. Large uncertainties remain in Europe over the actual volume of resources in place and of technically and commercially recoverable reserves (IFPEN, 2013). Besides, since only around fifty experimental wells have been drilled on the continent so far (Spencer et al., 2014), production data has yet to be made available publicly.

It is therefore necessary to calibrate our model using data from a different source. Ever since the commercial extraction of shale deposits began during the last decade, close to sixty shale gas plays have been drilled in the United States (Hughes, 2013). Thirty out

of these sixty plays have proved profitable, with only six of those accounting for 93% of the total natural gas production from shale deposits in the United States (EIA, 2015). Production data from North American plays thus covers a wide variety of distinct geological configurations. A detailed analysis of this data can provide a basis for the calibration of our model. This approach does assume that European shale deposits would be at least as amenable to extraction by hydraulic fracturing as their U.S. counterparts. This may be a strong hypothesis, as illustrated by the example of Poland—where high clay content in the shale deposits prevented their extraction. The estimates we derive in the rest of this paper should therefore be considered upper boundaries on the potential profitability of shale gas extraction in the European context.

We present here the results of analyses conducted on an extensive dataset collected from production reports provided by shale gas operators in North America's largest plays, in Barnett, Eagle Ford, Fayetteville, Haynesville, Marcellus and Woodford. The data was obtained from the Arkansas Oil and Gas Commission, the Louisiana Department of Natural Resources, the Pennsylvania Department of Environmental Protection, the Texas Railroad Commission, covers >40,000 wells and accounts for nearly 90% of the total shale gas production in the six plays considered over the period 2004–2014. This data allows deriving a very accurate picture of shale well production profiles. Using this information, we can estimate the full distribution of the key parameters of Eq. (2), initial production rate and decline rates.

#### 3.1. Initial production rate

We first estimate the mean initial production rate of wells in each play, and examine its evolution over time by vintage. Production is reported at fixed dates (usually at the beginning of each month), which introduces a potential source of bias as wells which begin extraction within the course of a reporting period would not report a full month of production in their first reporting period<sup>4</sup>. To rectify this issue, we consider initial production as the maximum production over the first two months of extraction. Results are presented in Fig. 2.

We find that the evolution of initial production over time exhibits a common pattern in five of the six plays under consideration. In a first period, which spans durations ranging from five years (2004 to 2009) in Barnett to three years (2008 to 2010) in Haynesville, average initial productions gradually increase with drilling year. Initial productions then stabilize on a plateau. Barnett, which is the oldest and most extensively drilled shale gas play in the U.S., also shows indications of a possible third phase during which initial production rates begin to progressively decline. Eagle Ford, Fayetteville and Haynesville all appear to have reached their plateau, while Marcellus is seemingly still in the first phase of this lifecycle. However, this pattern is less clear in the Woodford, where initial production rates have proven more volatile over time, with a spike in 2014. This could be explained by the smaller number of wells drilled in that year leading to a non-representative mean initial production estimate, with only 204 wells beginning production in 2014 out of a total sample size of 3015 for the Woodford play. Still, further analysis is warranted to fully explain the dynamics observed.

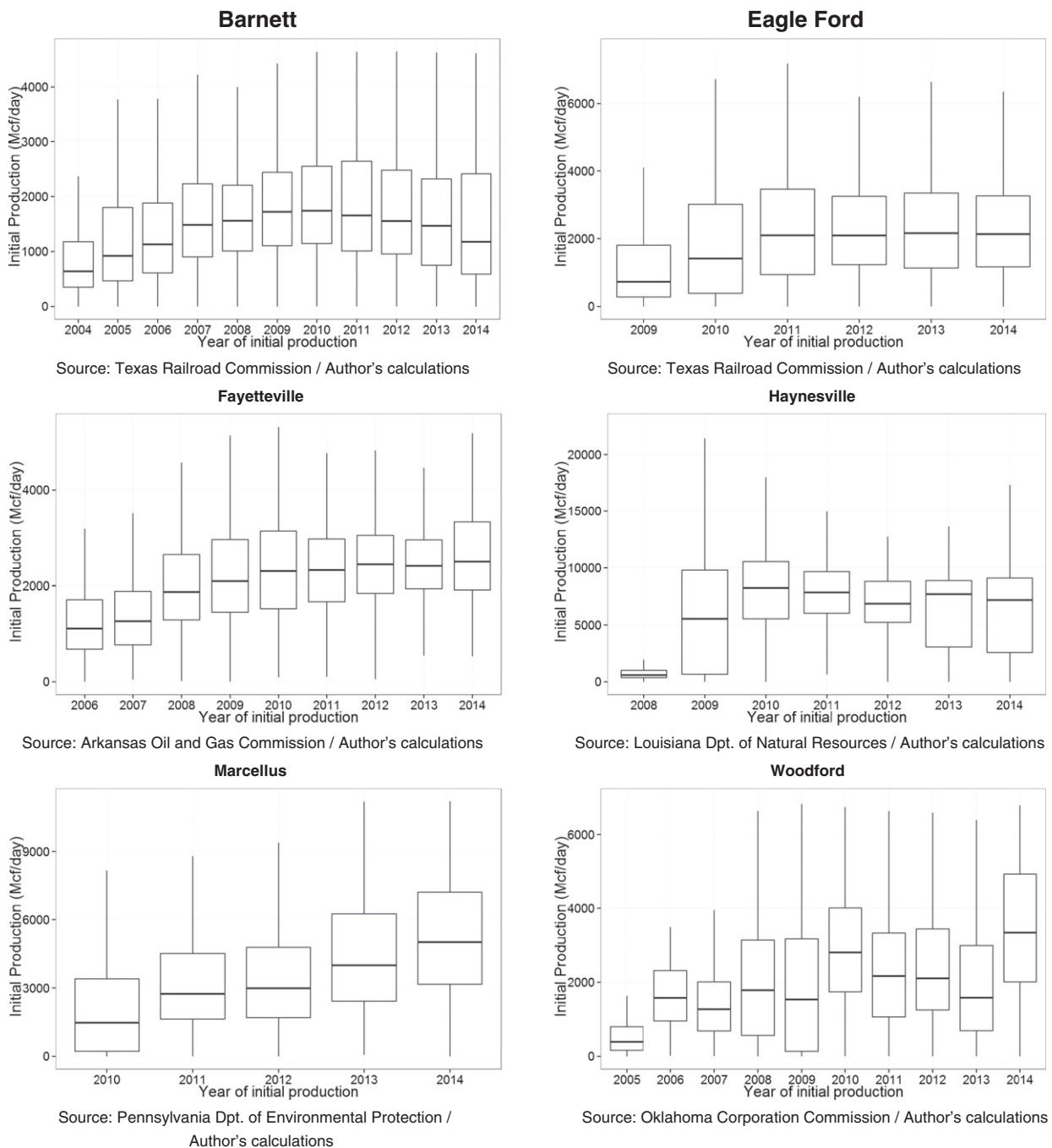
An increase in initial production rates leads to improved well productivity, provided that decline rates remain constant across drilling years (see next section). Indeed, a simultaneous increase of decline

<sup>1</sup> The derivation of the discretized Eq. (2) is available in the Supplementary Online Material.

<sup>2</sup> In Eqs. (2) through (5),  $\delta_0 = 0$ .

<sup>3</sup> See in particular Hilaire et al. (2015), Gülen et al. (2013) and Ikonnikova et al. (2015a, 2015b).

<sup>4</sup> In the case of the Marcellus play, the Pennsylvania Department of Environmental Protection only enforces biannual reporting of production. For this particular play, we calculate initial production rate as the production in the first reporting period observed divided by the number of production days. This may introduce a small downward bias, as the decline rate observed.



**Fig. 2.** Initial production rate by well vintage. In each chart, the lower side of the box corresponds to the 25th percentile, the upper side to 75th, and the bold middle line to the median. The whisker extends to the lowest and highest values comprised within one and half time the interquartile range (p75–p25).

rates over time could cancel out the impact of improved initial productions over the well's total lifecycle production.

Increasing initial production can be driven by at least two causes: an improvement in extraction and fracturing technologies, which leads to an increase in recovery rates of natural gas from the shale resource (EIA, 2015); and a better knowledge of the field's geology, notably the identification of so-called “sweet spots” – regions of the play where well productivity tends to be optimal – which once found concentrate the drilling activity, thereby increasing average well productivity in the play (EIA, 2011). In both cases, this first period of increasing well productivity can be understood as a learning phase, either at the play

level – during which operators increase their geological knowledge of the shale play, – or at the industry level – whereby technologies used to extract shale deposits are improved simultaneously across all plays. Further research will be needed to distinguish the relative contributions of each of these factors in the observed overall increase in well productivity over time.

In four of the six plays under consideration, once the learning phase is over, mean initial production rate reaches a stable level that has been roughly maintained to the present, although the variance of initial production rates has varied over time in each play. This process is still under way in the Marcellus, which exhibited strong year-on-year



**Table 1**

Mean initial production rate of a well in the six largest shale gas plays in the U.S. by vintage (2010–2014, in Mcf/day).

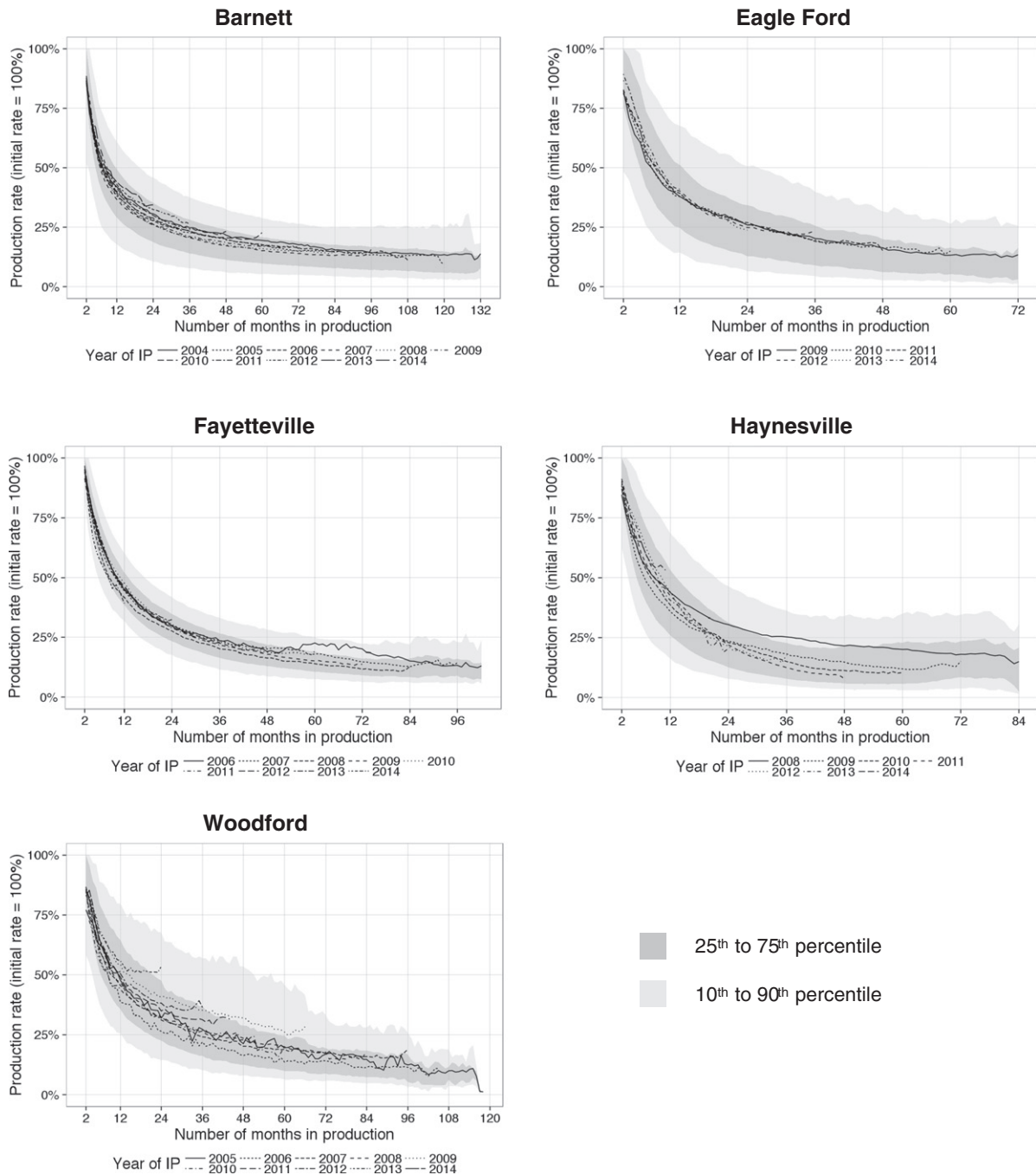
Year of IP	Haynesville	Barnett	Marcellus	Fayetteville	Eagle Ford	Woodford
2010	8632	2093	2272	2385	2461	3542
2011	8076	2138	3720	2361	2641	2436
2012	6977	1849	3815	2479	2596	2561
2013	7082	1801	5754	2540	2538	2253
2014	6939	1675	6560	2777	2554	4032

growth in initial production rates over the entire period. Table 1 provides the mean initial production observed in each of the six largest U.S. shale gas plays for the five most recent well vintages, from 2010 to 2014.

3.2. Decline rates

Monthly production data allows us to estimate well decline profiles. Fig. 3 shows the evolution over time of mean production rates normalized by the initial production rate, for each well vintage. Decline profiles are provided for every play considered except Marcellus, where no monthly data was available, as the Pennsylvania Department of Environmental Protection only mandates that production data be reported twice a year.

Decline profiles are characterized by high decline rates in the first years of production in all of the plays: after one year, the mean production of a shale gas well has declined between 47% and 59%. Second and third year year-on-year decline rates remain high, ranging from 23% to 39% and 17% to 30% respectively.



**Fig. 3.** Mean ratio of current to initial production rate over time, by vintage.

**Table 2**  
Mean year-on-year decline rates.

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Barnett	58%	28%	19%	17%	12%	12%	10%	10%	6%	3%
Eagle Ford	58%	31%	28%	16%	16%	–	–	–	–	–
Fayetteville	57%	33%	24%	18%	13%	16%	12%	3%	–	–
Haynesville	59%	39%	30%	18%	14%	10%	–	–	–	–
Woodford	47%	23%	17%	14%	9%	3%	10%	19%	7%	–

In addition to these trajectories, we also perform a non-parametric estimate<sup>5</sup> of monthly decline rates  $\delta_n$  (see Eq. (2)). Table 2 presents annualized year-on-year decline rates resulting from this estimate in each of the plays:

While decline rates do exhibit some heterogeneity between plays, the variance in mean decline profiles across shale gas producing regions is significantly smaller than that of initial productions. However, the variance within a single play can be substantial, as illustrated by the interquartile spread observed in the Eagle Ford, Haynesville and Woodford plays. Yet, the mean decline trend over time is stable across drilling years. This indicates that unlike initial production rates, the average well's production profile does not exhibit a learning phase after which observed decline rates would be reduced. It can therefore be assumed that the decline rates distribution estimated over the whole lifespan of a given play is also applicable to its most recent wells.

We also find that in general, the decline of production cannot be described as either exponential, since the annual decline rate varies over the well's lifespan, nor hyperbolic, since decline rates are neither constant nor do they decrease strictly monotonically over time.

Finally our separate estimates of initial production rates and decline rates have thus far assumed that these two parameters were independent. We verify this assumption by plotting initial production rate by vintage against first-year decline rate by vintage (see Fig. 4), and performing a Hoeffding  $\mathcal{D}$  test (Hoeffding, 1948) on these two variables. With a  $\mathcal{D}$  statistic of  $-0.008$ , we can conclude that initial productions and decline rates are indeed independent.

## 4. Specificities of the European context

### 4.1. Gas price formation

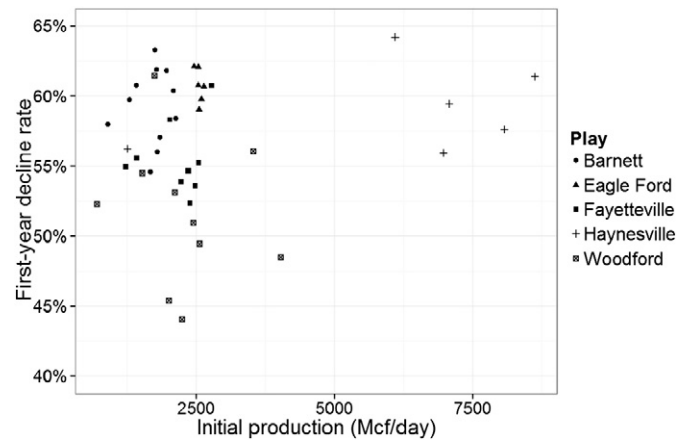
The large drop in natural gas prices over the past decade, from a weekly average high of 14.49\$/MMBtu in December 2005 to a low of 1.86\$/MMBtu in April 2012<sup>6</sup>, has been one of the more significant consequences of the large increase in domestic gas production in the United States.

Unlike other energy commodities, crude oil in particular, the market for natural gas is still fragmented into several regional markets. The price of natural gas is therefore different in the United States, Europe and East Asia (IEA, 2012). Hence, the decrease in gas price resulting from the growth of shale gas production has remained localized in the United States.

This is due in large part to the difficulty of transporting natural gas. Across oceans, where pipelines cannot be used, natural gas must be liquefied and transported in LNG tankers. This entails building very expensive processing facilities to liquefy the gas on departure, and gasify it back on arrival - taking into account liquefaction, shipping costs and regasification, LNG transportation adds upwards of \$2 per Mcf to

<sup>5</sup> In production month  $n$ , the mean decline rate  $\delta_n$  in a given play is estimated as the mean of decline rates between production months  $n$  and  $n-1$  over all the wells that produced at least until production month  $n$ . This estimation procedure ensures that  $\delta_n$  is estimated over wells that were producing both in month  $n$  and in month  $n-1$ . Taking a simple mean production profile to estimate decline rates would result in calculating a decline between all wells that produced in months  $n$  or  $n-1$ , even when some wells in month  $n-1$  were no longer active in month  $n$  - and would therefore be inconsistent.

<sup>6</sup> Henry Hub Natural Gas Spot Price, weekly averages. Source: U.S. EIA.



**Fig. 4.** First-year decline rate as a function of initial production rate by play and vintage.

the cost of supplying natural gas (Mokhatab et al., 2014). In addition, processing plants used for liquefaction cannot be used for gasification without costly retrofitting (IGU, 2012).

Besides, gas price formation mechanisms are distinct in each of the major markets. In the United States, the price of natural gas is set through gas-on-gas competition. Natural gas is traded over a variety of time frames (e.g. daily, monthly or annually) at a number of physical hubs - Louisiana's Henry Hub being the largest, - and the interplay of supply and demand determines the price. In such a market, changes in the balance between supply and demand have an immediate impact on prices. The United States, which until the late 2000s expected domestic natural gas production to decline, had built LNG plants to import gas, but not to export it (EIA, 2011). When shale gas extraction rapidly grew, the newfound domestic production of natural gas changed the local balance of supply and demand immediately. From 2008 to 2012, domestic production grew at a rate of 3.6% per annum, outpacing consumption, which only grew at 2.3% per annum<sup>7</sup>: this led to the large drop in prices.

In Europe, gas price formation follows a different mechanism. Traditionally, European natural gas supplies have been priced through a mix of long-term contracts with producing countries and spot market pricing. Long-term contracts are mostly priced using a mechanism known as oil price escalation, whereby gas prices are linked, usually through a base price and an escalation clause, to the price of competing fuels - typically crude oil (IGU, 2012). Oil price escalation used to dominate natural gas price formation in Europe. However, since the late 2000s, oil indexation of natural gas contracts has been decreasing: as of 2012, 51% of European gas consumption was priced through an oil price escalation clause, down from 59% in 2010. Meanwhile, from 2007 to 2012, spot-priced natural gas volumes have doubled, to reach 44% of consumption (EC, 2013).

This pricing structure makes European wholesale gas prices less elastic to changes in the balance of supply and demand. While an increase in domestic production could improve the bargaining power of European countries with their suppliers, the impact of introducing small volumes of domestic shale gas production in the European supply mix on gas prices is unclear.

### 4.2. Drilling costs

Public data on drilling costs is scarce, which makes their calibration difficult. According to the U.S. EIA, drilling costs per well in the leading shale plays of Marcellus, Bakken and Eagle Ford are comprised between

<sup>7</sup> Source: U.S. EIA Natural Gas statistics.

**Table 3**

Average drilling costs and depth of the main U.S. shale plays.

	Fayetteville	Marcellus	Barnett	Haynesville	Woodford
Average drilling costs (million USD)	2.8	5.3	3.5	9.9	8.5
Average depth (ft)	3600	6200	7900	12,100	13,100

Source: Kaiser and Yu (2015), Nickelson (2013), Berman and Pittinger (2011).

\$6.5 and \$9 million, including both horizontal drilling and hydraulic fracturing (EIA, 2012).

However, these estimates cannot be used directly in the European context. Notably, one of the main drivers of drilling costs is the depth of the well and the length of its lateral (Pulsipher, 2007). Table 3 presents average drilling costs and average depth in the main U.S. shale plays.

As shown in the above table, the most expensive wells are located in the deepest shale deposits, between 10,000 and 13,000 ft. on average, indicating a relationship between drilling costs and average deposit depth. Most continental European deposits have been identified in geological strata located at comparable depth: the majority of the French resources would be found between 10,000 and 14,000 ft., between 10,000 and 12,500 ft. in Poland, between 11,500 and 14,500 ft. in Germany, between 11,000 and 12,500 ft. in the Netherlands, and around 11,000 ft. in Spain; only British shale deposits would be located at a shallower depth of 8000 ft. (EIA, 2013).

These elements lead us to estimate that drilling costs will on average be higher in Europe than in the United States. This is indeed the conclusion of Wood Mackenzie (2012) on the economic potential of shale gas resources in the United Kingdom, which estimated that should the British shale resources be developed, the average drilling costs would reach \$17 million. This would amount to more than one and a half times the average well cost in the Haynesville, where drilling costs are the highest of any American play. Oil services company Schlumberger also estimated in 2011 that drilling costs in Poland could turn out to be three times higher than in the United States<sup>8</sup>.

Finally, it should be noted that the availability of drilling equipment is much higher in the United States than in Europe. In the first quarter of 2014, >1700 drilling rigs were being operated in the United States, including both oil and gas plays of the conventional and unconventional varieties (EIA, 2014). This is to be contrasted with less than a hundred rigs available across the entire European continent in 2011 (Hsieh, 2011). Further, only a small fraction of these rigs can be used to drill shale gas wells: for example, in 2011, out of 15 drilling rigs available in Poland, only 5 were suitable to shale gas extraction<sup>9</sup>. An important component of drilling and completion costs, the day rate for drilling equipment rental, is a function of the demand for drilling rigs: with the rapid fall of oil prices in the second semester of 2014, drilling rates fell quickly across the U.S., reducing the day rates for U.S. land rig suitable for use in shale plays by 31% between November 2014 and July 2015<sup>10</sup>. Capacity constraints could thus make well drilling costlier and limit the drilling rate in European countries, at least in the first years of production.

#### 4.3. Regulatory environment

In addition to the improvements made to hydraulic fracturing and horizontal drilling technologies, the expansion of commercial shale gas extraction was also accompanied by changes made to the regulatory

framework governing oil and gas production - especially regarding environmental regulations.

Indeed, the Energy Policy Act of 2005 (Pub.L. 109-58, 2005) brought some significant modifications to the environmental legislations regulating oil and gas drilling in the United States. Passed at a time when conventional gas plays were exhibiting signs of depletion (EIA, 2005), the Energy Policy Act defined new core principles for American energy policy, with a particular emphasis on reducing future dependency on fossil fuel imports. The Act included a number of measures aiming to increase domestic fossil fuel production. Notably, two existing environmental laws were amended to facilitate the use of hydraulic fracturing - and thus the extraction of oil and gas from shale deposits:

- the Safe Drinking Water Act (Pub. L. 93-523, 1974), which regulates the public drinking water supply, and ensures its quality and suitability for human consumption. Originally, this Act banned any drilling in the vicinity of underground water reservoirs. Section 322 of the Energy Policy Act of 2005 lifts this ban for oil and gas drilling.
- The Clean Water Act (Pub. L. 92-500, 1972), which governs water pollution. This Act notably defines what constitutes a water pollutant. Through an amendment to section 502 of the Clean Water Act, the Energy Policy Act of 2005 excludes from this definition "water, gas, or other material which is injected into a well to facilitate production of oil or gas".

These changes, made to two pillars of the environmental regulatory framework of the United States, have facilitated the widespread use of hydraulic fracturing, and thus the shale revolution. Without the chemical additives that were formerly listed as pollutants by the Clean Water Act, hydraulic fracturing would be less effective, and well productivity would be lower.

Environmental regulations in Europe are much stricter on these points. In particular, the use of chemical additives in the fracturing fluid, the transportation and storage of flowback water and drilling mud from well fracturing, or the drilling of wells within proximity to water reservoirs or inhabitations would all be very difficult or outright forbidden under the current European environmental legislation, both at the Union and Member State level (Gény, 2010). Other measures targeting both safety and environmental protection, such as standards of safety valves and the compulsoriness of multiple casings around the well's body, would have a direct impact on drilling costs.

At this stage, it is impossible to know whether the European Union or some of its Member States will amend their existing legislations to lift some of the restrictions currently limiting the use of hydraulic fracturing. Fostering shale gas production on their territory would entail rescinding part of their environmental protection framework to favor domestic on shore drilling, as the Energy Policy Act did in the United States in 2005. Currently, compliance with the local legislation would lead to significantly higher drilling costs in Europe than in the United States (Gény, 2010).

#### 5. Estimating breakeven prices in Europe

In this section, we determine whether shale gas could be profitably produced in continental Europe by estimating the distribution of breakeven prices for shale gas extraction. We consider the potential shale gas reserves of France (unproved technically recoverable resources of 137 Tcf), Denmark (32 Tcf), Netherlands (26 Tcf) and Germany (17 Tcf) in the aggregate (EIA, 2013). We exclude Poland, the largest potential holder of shale gas resources in Europe, as high clay content (above 40%) in the shale deposits make extraction impractical using current technology. Besides, these scenarios assume that the current regulatory obstacles preventing shale gas production in France, Germany and the Netherlands could be lifted.

<sup>8</sup> "Shale-Gas Drilling Cost in Poland Triple U.S., Schlumberger Says", *Bloomberg*, 29 November 2011.

<sup>9</sup> *Ibid.*

<sup>10</sup> Source: Bloomberg Intelligence, July 2015.

## 5.1. Assumptions

According to Eq. (5), the breakeven price of a shale gas well is determined by initial production rate, decline rates over time, and drilling and completion costs. The U.S. shale gas plays analyzed in the previous sections exhibited significant variance in all three of these determinants both within and between plays.

To account for this heterogeneity, we derive distributional assumptions for each model parameter from the statistical analysis performed in Section 3 and the discussion conducted in Section 4. Following Ikonnikova et al. (2015a, 2015b) and Hilaire et al. (2015), we then perform a Monte-Carlo simulation to estimate the distribution of shale gas wells breakeven prices under these assumptions. Values are drawn from the distribution of each model parameter using Sobol low-discrepancy quasi-random sequences to simulate 50,000 wells. The resulting distribution of breakeven prices is then derived from these simulations.

### 5.1.1. Initial production rate

Using the dataset analyzed in Section 3, we can estimate the full distribution of initial well production rates in the six largest commercially developed plays in the U.S. However, by construction, this distribution excludes all wells drilled in plays that performed more poorly than the top six - this hypothesis is therefore equivalent to considering that the distribution of wells drilled in continental Europe will be on par with the performance recorded in the six best U.S. shale gas plays.

We also observed that initial production rate was initially increasing on average with each well generation, until it stabilized - which could result from improving technology and/or better knowledge of the plays' geology. It is likely that shale gas extraction in continental Europe would benefit from most of this technological improvement. Estimating the distribution over our full sample - including earlier wells drilled with less advanced technology - would therefore lead to a downward bias on the well performance. Besides, we noted that four of the six plays considered (which account for 70% of the shale gas produced from 2010 to 2014) had reached the stabilization phase by 2010. To reduce the risk of downward bias while maintaining a large sample size, we thus use the probability distribution of initial production rates over wells that started producing from 2010 to 2014.

### 5.1.2. Decline rates

We found in Section 3 that decline rates were stable across drilling years. We thus calibrate the decline rates used in Eq. (2) on the distribution of decline profiles observed in our entire dataset, using the same non-parametric estimation used for individual plays.

The mean decline rates derived from this distribution are presented in Table 4 for illustration purposes. While monthly decline rates are used in the model, annualized year-on-year decline rates are provided for clarity. Decline rates beyond the tenth year of production are drawn from the distribution of year 10.

### 5.1.3. Drilling and completion costs

We noted in our analysis of drilling and completion costs that potential shale deposits in continental Europe were located at a depth comparable - or deeper - to that of the Haynesville, Eagle Ford and Woodford plays, and that drilling costs were linked to the depth of the deposit. A number of other factors, such as the geometry of the rock formation or the type of fracturing fluid to be used, are important drivers of drilling and completion costs. However, given the current

lack of experimental drilling in potential shale gas fields in continental Europe, it is impossible for now to calibrate these other factors.

We therefore assume a minimum for drilling costs in Europe of \$10 million, comparable to that observed in the Haynesville (Kaiser and Yu, 2015). Yet, the specificities of the continental European context, namely its lack of well-developed on-shore drilling infrastructure and its more stringent environmental regulations could increase this cost. In particular, there is a large uncertainty on the level of compliance costs necessary to meet the requirements of the body of environmental rules enforced at the European Union level. We therefore consider a mean cost hypothesis 50% higher (\$15 million per well). It should be noted that this assumption is still below Wood Mackenzie's (2012) \$17 million average cost per well estimate for the United Kingdom. To account for the uncertainty on this important parameter, we assume that drilling and completion costs are distributed following a normal distribution left truncated at 10 million, with mean 15 million and standard deviation of 2 million.

### 5.1.4. Productive lifetime of a well

Given that the overwhelming majority of shale gas wells have been drilled for less than ten years, their ultimate lifetime is not currently observable. Assumptions in the literature vary significantly: Hilaire et al. (2015) considered a mean expected productive lifetime of 10 years, while other studies have considered 14-year (Weijermars, 2013) and up to 20-year wells (Ikonnikova et al., 2015a, 2015b). Recognizing the uncertainty on this parameter, we model it following a normal distribution left truncated at 10 years with mean 15 years and standard deviation of 5 years.

### 5.1.5. Other parameters

Operating costs,  $c_m$ , have been estimated by Moniz et al. (2011) between \$0.5 et \$1 per MMBtu. We therefore model them using a truncated normal distribution comprised between these two boundaries, with mean 0.75\$ per MMBtu. Finally, we calibrate the discount rate  $r$  at 7%, as is common in the economic literature on resource economics (Arrow et al., 1996).

## 5.2. Results

Using this set of assumptions for initial productions, decline rates and drilling and completion costs, Eq.(5) can estimate breakeven prices for shale gas extraction. We then conduct a Monte-Carlo simulation to estimate the probability distribution of breakeven prices of shale gas production in continental Europe. The resulting cumulative distribution is presented in Fig. 5. Percentiles at the 10%, 25%, 50%, 75% and 90% levels are also reported in Table 5.

We find that, under our given set of hypotheses, 50% of the wells drilled in continental Europe would reach gross breakeven (before taxes and royalties) for a natural gas price of 10.1\$/MMBtu. However, our results also illustrate the large heterogeneity in shale gas well profitability. Indeed, we could expect 10% of all wells to reach breakeven under 3.5\$/MMBtu, while 25% would need natural gas prices above 19.8\$/MMBtu to recoup their drilling and operational costs.

To assess the profitability of shale gas extraction along this distribution of breakeven price points, we confront our results with historical natural gas price in Europe since 2001 (Fig. 6). We assume that shale gas producers in continental Europe would not produce enough natural gas to impact wholesale natural gas price (see Section 4). Natural gas price has been volatile on the European market over the past 15 years, varying between a low of 3.6\$/MMBtu in May 2002 to a spike of 17.2\$/MMBtu in November 2008<sup>11</sup>. If we only consider the past half-decade, from 2011 to 2016, the average natural gas price in Europe was 9.4\$/MMBtu.

**Table 4**  
Annualized year-on-year mean decline rates.

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
58%	30%	22%	17%	12%	11%	10%	10%	6.1%	3.3%

<sup>11</sup> All prices expressed in 2015 dollars.



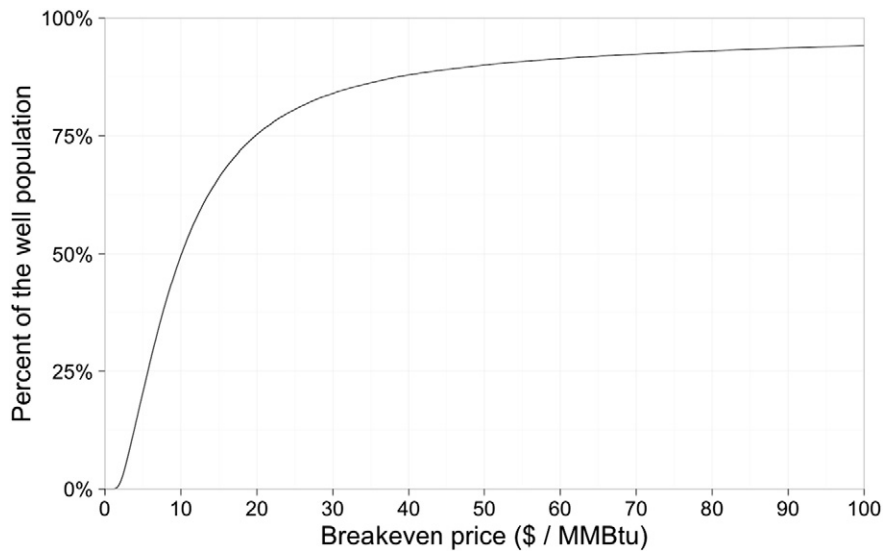


Fig. 5. Cumulative breakeven price distribution (Monte-Carlo simulation).

At that price point, the median well in our simulations would not reach gross breakeven: we could instead expect 53% of all wells drilled to not be profitable before taxes and royalties. The distribution also exhibits a long tail of significantly unprofitable wells, with 29% of the well population requiring natural gas prices above the historical maximum to achieve gross breakeven.

Further, it should be noted that the 2011–2016 period was characterized by higher than average natural gas prices when compared with previous decades and the most recent year at the time of writing. Indeed, European natural gas prices averaged 4.6\$/MMBtu from November 2015 to November 2016, 7.6\$/MMBtu between 2000 and 2009 and 3.8\$/MMBtu between 1990 and 1999. In each of these periods respectively, we could have expected >82%, 63% and 88% of all wells drilled to not reach breakeven on average.

Importantly, there has not been any continuous 15-year period over the past 25 years when natural gas prices in Europe have averaged >10.1\$/MMBtu. Therefore, assuming a mean shale gas well lifespan of 15 years, at no point over the past 25 years could more than half of shale gas wells drilled in continental Europe have reached gross breakeven.

### 5.3. Sensitivity analysis

To assess the robustness of our results, we estimate the sensitivity of the breakeven price to the physical and economic parameters considered. Specifically, we observe the impact on the median breakeven price of a 10% variation of initial production rates, decline rates, well lifespan, drilling and completion costs, operating costs and discount rate around their respective median values. The results of this sensitivity analysis are presented in Fig. 7.

We find that the breakeven price is significantly sensitive to geological parameters - specifically the initial production volume and the decline rate. Increasing the initial production rate by 10% reduces the breakeven by 9% whereas decreasing it by the same amount increases the breakeven by 10%. Similarly, wells that deplete 10% faster would have a breakeven price 7% higher, while slowing the decline rate by 10% would reduce the breakeven price by 7%.

**Table 5**  
Breakeven price percentiles.

Percentile	10th	25th	50th	75th	90th
Breakeven price (\$/MMBtu)	3.5	5.7	10.1	19.8	50.1

This is expected, as these two geological parameters determine the total amount of natural gas ultimately extracted (EUR), over which drilling and completion costs can be amortized. However, interestingly, increasing the well lifespan only reduces the breakeven price marginally. Under our median assumptions of decline rate and discount rate, a shale gas well operated for 10% longer<sup>12</sup> would only achieve breakeven at a 1% lower price point. This stems from the large initial decline rates: most of a well's EUR is produced in the first two to three years of operation.

The next most important hypothesis is drilling and completion costs, with a sensitivity of breakeven price of  $\pm 9\%$  for a  $\pm 10\%$  variation. The remaining economic parameters, discount rate and operational cost, bear comparatively little impact on the profitability of a shale gas well, with sensitivities to a  $\pm 10\%$  variation confined in the  $\pm 2\%$  range.

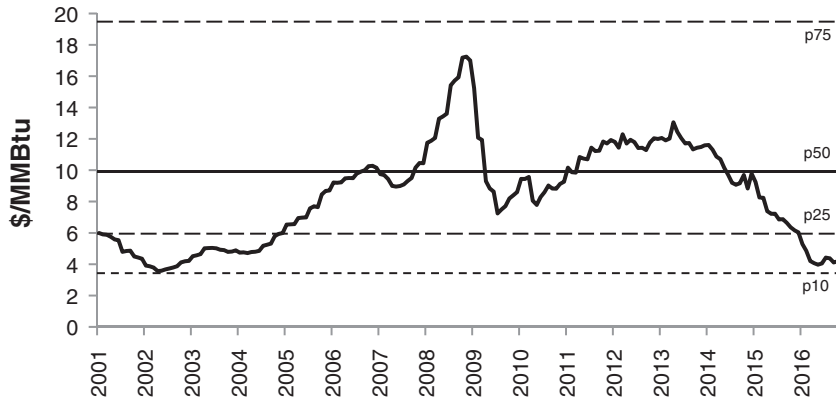
Finally, we also consider the impact of a simultaneous  $\pm 10\%$  variation of all physical parameters, initial production, decline rates and well lifespan; of all economic parameters, drilling costs, discount rate and operating costs; and finally of all parameters simultaneously. This complementary analysis confirms that the breakeven price is more sensitive to physical parameters, with a sensitivity of  $-15\%/+21\%$ , than to economic parameters whose impact is limited to a  $\pm 12\%$  variation. Finally the joint variation of all parameters yields a sensitivity of  $-25\%/+35\%$ . This magnitude is comparable to the results found by Hilaire et al. (2015).

This sensitivity analysis reiterates the central importance of the three main parameters identified in our model, initial production, decline rates and drilling and completion costs. The robustness of decline rate profiles across U.S. shale gas plays suggests that a similar production profile could be expected in continental Europe. However, it appears necessary to resolve the uncertainties concerning initial production rates and drilling and completion costs in Europe if shale gas is to be extracted commercially on the continent.

### 5.4. Sensitivity to a correlation between shale depth and well productivity

The analysis conducted in this section assumes that shale gas wells drilled in continental Europe would exhibit characteristics comparable to that of the six most productive shale gas plays in the United States. However, as illustrated in Section 4, three of these plays (Fayetteville, Marcellus and Barnett) are found at shallower depths than the potential

<sup>12</sup> This is equivalent to adding 1.6 years of operation to a median well lifespan of 16 years.



Source: World Bank, author

Fig. 6. Natural gas prices in Europe vs shale gas breakeven (2001–2016, \$2015) Source: World Bank, author.

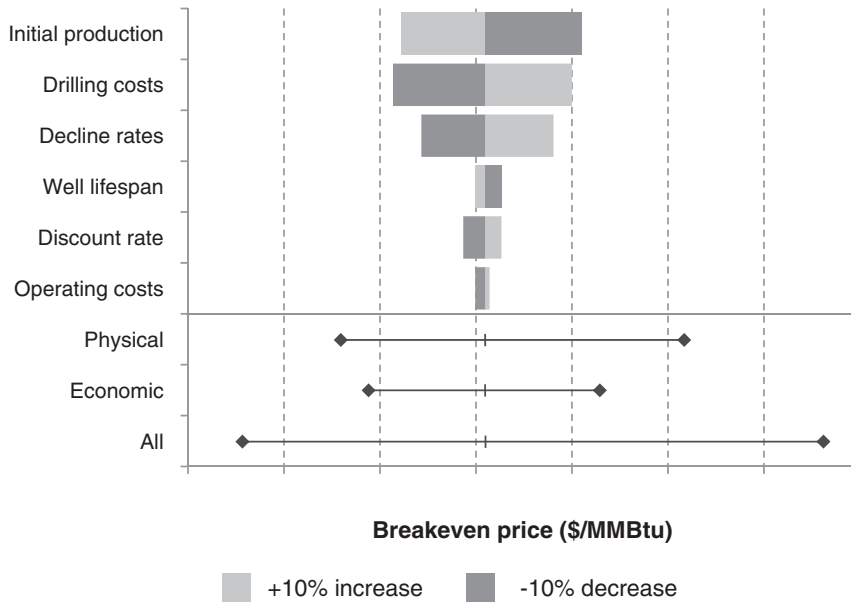


Fig. 7. Sensitivity of the median breakeven price to a 10% variation of each parameter.

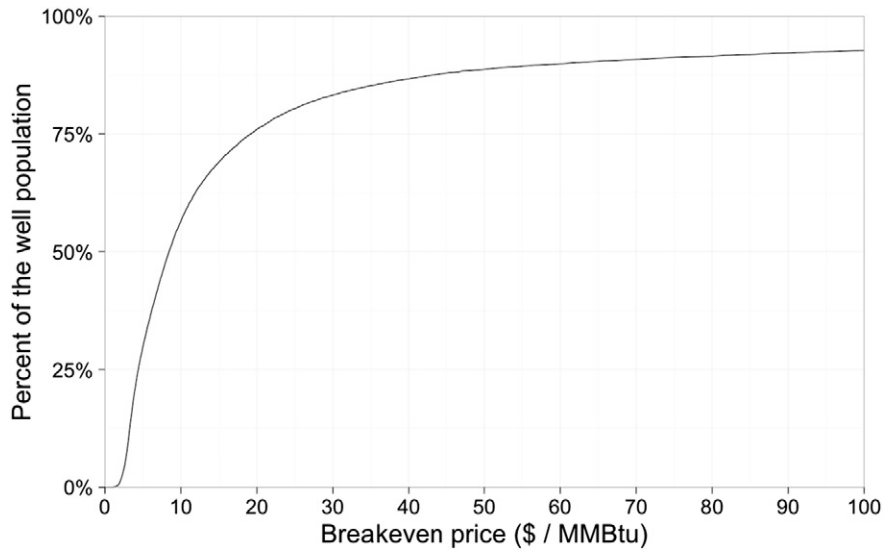


Fig. 8. Cumulative breakeven price distribution (calibration on deep shale gas plays only).

**Table 6**  
Breakeven price percentiles (calibration on deep shale gas plays only).

Percentile	10th	25th	50th	75th	90th
Breakeven price (\$/MMBtu)	3.1	4.4	8.4	19.2	61.1

shale gas deposits of France, Denmark, Netherlands and Germany. Still, all six plays are included in the calibration of the model's geological parameters - most importantly initial production rates.

Conversely, drilling and completion costs assumptions were mainly calibrated on the most comparable plays by depth, the Haynesville, Eagle Ford and Woodford. This in turn rests on the hypothesis that the initial production rate of a well is uncorrelated with its depth. This assumption seems to be supported by the fact that while located at comparable average depth, Eagle Ford (10,000 ft), Haynesville (12,100 ft) and Woodford (13,100 ft) have very different initial production rate distributions.

Yet, Brown et al. (2016) report a positive correlation between average well EUR and average shale depth at the county level. Ikonnikova et al. (2015a, 2015b) also observe a positive link between well depth and EUR. This correlation could result from the fact that deeper wells are more expensive to drill and are thus preferentially drilled in the more promising parts of a play, or it could stem from geological mechanisms. Regardless of its root cause, a similar correlation could be observed in continental European shale gas plays.

To test the sensitivity of our results to this last hypothesis, we conduct a second Monte-Carlo simulation using a subset of the initial production distribution calibrated on the sole Haynesville, Eagle Ford and Woodford plays. Results are presented in Fig. 8 and Table 6.

We find that the median breakeven price is reduced by 15% compared with our main results, but that the variance is higher. In particular, the 90th percentile breakeven price is 35% higher. When calibrating the initial production distribution on the deepest U.S. plays only, 54% of the well distribution reaches gross profitability at the 2011–2016 mean natural gas price, 7 percentage points higher than in the main simulation. Thus, while marginally improving the profitability outlook, assuming that European shale gas plays would share the same initial production rate distribution as American plays of similar depth does not modify our main finding.

## 6. Conclusion

To assess whether the American shale gas revolution can be duplicated in Europe, we have determined the main drivers of shale gas extraction profitability. To this end, we have presented a techno-economic model of shale gas production that allowed us to identify the following key parameters: well productivity, as described by initial production and decline rates, and drilling and completion costs.

The volume and geological characteristics of shale gas resources in Europe remain speculative. Besides, experimental drilling has remained very scarce. It is therefore not possible to assess well productivity in the potential European shale gas plays. At this stage, we cannot directly calibrate our model on European production data.

To remedy this lack of data, we contribute a detailed statistical analysis of an extensive dataset of 40,000 wells, which accounts for nearly 90% of the production of the six largest American shale gas plays over the period 2004–2014. We then analyze the specificities of the European context, notably in terms of gas price formation, drilling costs and environmental regulations.

Based on these analyses, we estimate the distribution of initial production rates and decline rates, and derive assumptions for drilling and completion costs in continental Europe- under the premise that the geology of the corresponding shale deposits proves conducive to the commercial extraction of shale gas. Using our model, we find a median gross breakeven price before taxes and royalties of 10.1\$/MMBtu. This is higher than the mean European natural gas price over the period

2011–2016. Further, 29% of the well distribution requires a breakeven price higher than the maximum historical natural gas price in Europe. The assessment is worse considering the most recent price trends, with 82% of the distribution unprofitable at the mean 2016 price.

Thus, considering both recent and historical natural gas prices on the continent, shale gas production does not appear profitable. A sensitivity analysis on the model's parameters reveals that the breakeven price is most sensitive to initial production rate, drilling and completion costs and decline rates. Median breakeven price decreases by 15% when assuming that European shale gas plays would have productivity characteristics similar to that of U.S. plays of comparable depth. Still, even under this hypothesis, only 54% the well distribution would be grossly profitable before royalties and taxes at the 2011–2016 mean price.

Thus, it appears that an expansion of shale gas production on a scale comparable to the American experience over the past decade cannot be reproduced in Europe at present. Only under the most favorable geological configurations could shale gas extraction prove significantly profitable in Europe.

Absent extreme well productivity, or a technological improvement that would lower drilling costs or increase recovery rates while complying with local environmental regulations, it appears very difficult for shale gas extraction to have a significant impact on European energy markets.

## Appendix A. Online appendix

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.eneco.2017.10.002>.

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