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Boom or bust? Mapping out the known unknowns of global shale gas production potential

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Abstract

To assess the global production costs of shale gas, we combine global top-down data with detailed bottom-up information. Studies solely based on top-down approaches do not adequately account for the heterogeneity of shale gas deposits and hence, are unlikely to appropriately capture the extraction costs of shale gas. We design and provide an expedient bottom-up method based on publicly available US data to compute the levelized costs of shale gas extraction. Our results indicate the existence of economically attractive areas but also reveal a dramatic costs increase as lower-quality reservoirs are exploited. At the global level, our best estimate suggests that, at a cost of 6 US$/GJ, only 39% of the technically recoverable resources reported in top-down studies should be considered economically recoverable. This estimate increases to about 77% when considering an optimistic recovery of resources but could be lower than 12% when considering pessimistic ones. The current lack of information on the heterogeneity of shale gas deposits as well as on the development of future production technologies leads to significant uncertainties regarding recovery rates and production costs. Much of this uncertainty may be inherent, but for energy-system planning purposes, with or without climate change mitigation policies, it is crucial to recognize the full ranges of recoverable quantities and costs.

Keywords: shale gas, extraction cost curve, global, ERR

JEL: Q310, Q320, Q330, Q410, Q470, Q540

1. Introduction

In the 1970s growing concerns about natural gas scarcity led a number of policy makers and energy companies to direct their efforts toward extracting unconventional gas (Trembath et al., 2012). Three decades later the concurrence of technological improvements and high gas prices sparked a remarkable outcome: the recent US shale gas boom (Trembath et al., 2012; Wang and Krupnick, 2013). In fact, US shale gas production increased 12-fold in 10 years (EIA, 2012) and covered 37% of domestic gas production in 2012 (BP, 2013). Despite multiple social, environmental and economic concerns, an official best estimate scenario shows that US shale gas production could further increase and reach more than 50% of domestic gas production by 2040 while having a profound impact on global gas markets (EIA, 2014). As a result other parts of the world including Argentina, Australia, China, India, South Africa and the EU are currently assessing the potential to expand gas supply from domestic shale-gas endowments (EIA, 2011; IEA, 2011; Pearson et al., 2012; Nakano et al., 2012). In the near future and under propitious conditions one could witness the emergence of a "golden age of gas" (IEA, 2012a) during which 15% of global natural gas production could be supplied by shale gas in 2035 (IEA, 2012b; BP, 2013; IEA, 2013b). Conversely, considering more pessimistic assumptions could lead to a more moderate scenario in which US shale gas production peaks around 2030 (EIA, 2014). Even more dramatic scenarios in which production peaks between 2015-2020 have been generated and reported (Richter, 2015; Ikonnikova et al., 2015). The large uncertainty reflected in these extreme scenarios is a great burden to energy policy makers, investors, and infrastructure planners.

The challenges of energy access, energy security and climate change mitigation call for enhancing our knowledge of the role of shale gas within the global energy system and its impact on the climate system (McCollum et al., 2014). Such a study should not only consider medium-term scenarios but also include a longer term-perspective and assess uncertainty within a single framework, an approach that is lacking in the literature to date. In the present article we investigate the following research questions: What is the global and long-term economic shale gas production potential? What is the associated uncertainty range and what are the key uncertainty factors?

Assessing the potential economic production of shale gas in a global and long-term context requires information on the costs of production. This information is commonly summarized in the form of a cumulative production cost function. Constructing a global cumulative production cost function, in a scientific manner, requires a transparent methodology that accounts for both the limitations and uncertainties of publicly available data. To the best of our knowledge such a methodology has not yet been published. The present study is a first attempt to close this gap. In particular we combine global resource estimates from geological surveys with more detailed US techno-economic information to construct a cumulative extraction cost function (CECF) and we assess the implications of techno-economic data uncertainties on the global economic shale gas production potential and identify key uncertainty factors.

In a seminal study Rogner (1997) employed a methodology that divides aggregated fossil fuel endowments from global geological surveys into a few cost categories. The production costs associated with each category are based on expert judgments and ad-hoc assumptions. In 2012, new global geological surveys (USGS, 2000; BGR, 2009, 2011) and production cost data were employed to update the original study (Rogner et al., 2012). However only 5 categories were used to define shale gas endowments. Using a small number of categories neglects the heterogeneity of unconventional deposits and may misrepresent the relationship between quantities in situ and extraction costs. US shale gas CECFs derived from more detailed approaches seem to confirm this hypothesis (Petak, 2011; Jacoby et al., 2012).

In this article we present a method (section 2) that rests upon the work of

Rogner (1997); Rogner et al. (2012) but allows for a higher disaggregation of shale gas endowments using data at the shale gas play level. In section 3 we present and discuss the results and in section 4 we conclude.

2. Methodology

We first describe the overall procedure to generate a global shale gas CECF. We then provide the methodology to compute a detailed US CECF which is a prerequisite to obtaining a global one. Lastly we explain the treatment of uncertainties.

2.1. Global CECF

Constructing a global shale gas CECF is challenging because necessary public data lack systematic reporting and are exclusively or only available for the US. Despite large regional differences in below- and above-ground factors, we assume that data for the 27 US shale gas plays considered in this study provide a representative sample of shale plays. For this reason we develop a thorough and transparent method to construct a US CECF that includes the most relevant factors and their uncertainties in order to identify the key characteristics of shale gas CECFs. These characteristics are captured by normalising the CECF along the quantity dimension. Scaling the normalized CECF to regional technically recoverable resources (TRR) estimates and adjusting extraction costs to account for differences in geology and techno-economic characteristics enables us to derive a global CECF of shale gas. As such the method improves the top-down approach of Rogner (1997) by deriving assumptions on cost classes from a detailed analysis of US CECF.

2.2. US CECF

The methodology to compute a CECF is depicted in Figure 1. We start with a careful review of the grey and peer-reviewed literature that gives us an indication of the paucity of data and an overview of methods used by various communities - including academia, industry, NGO ... - to estimate shale gas extraction costs. We then design a comprehensive approach that accounts for the limits and uncertainties of available data. This enables us to compute US shale gas CECFs and importantly, include uncertainties. The main aspects of this approach are presented in the following paragraphs. For a more detailed description of methods and data, the reader is invited to consult the supplementary online material.

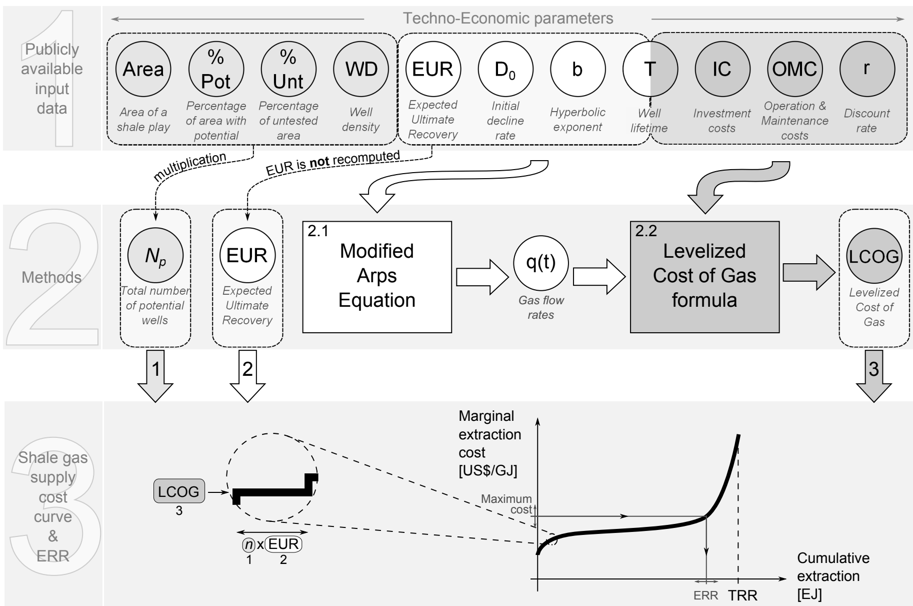

Figure 1: Flow diagram of the methodology employed in the computed tool. Note that EUR data are used in the Modified Arps' equation as well as directly in the cumulative extraction cost curve.

We first collect and harmonise data for 11 techno-economic parameters that are repeatedly reported in the literature (Block 1 in Figure 1). These parameters are divided into 3 categories corresponding to 3 methods required to obtain a CECF. The first category contains 4 parameters coloured in light grey: Area (A), percentage of area with potential[1] ($\%Pot$), percentage of untested area[2] ($\%Unt$) and well density (WD). These parameters are multiplied together to

[1]Percent of area that is expected to have technically recoverable resources (EIA, 2013a)
[2]Percent of total wells left to be drilled (EIA, 2013a)

obtain the total number of potential wells (N_p) in a shale play (p) (Equation 1 and Method 2.1 in Figure 1)).

$$N_p = A \times \%Pot \times \%Unt \times WD \tag{1}$$

The next 4 techno-economic parameters in white consist of the Estimated Ultimate Recovery (EUR), the hyperbolic factor (b), the initial decline rate (D_0) and the well lifetime (T). These are fed to an equation based on the original Arps' equation to compute gas production over time $q(t)$, which is a crucial intermediate step to calculating shale gas production costs (Method 2.2 in Figure 1).

Using empirical data, Arps devised an equation that describes oil and gas production decline over time (Arps, 1944). Owing to its simplicity, this formula is still largely employed in the oil and gas industry, including by shale gas extraction companies. Shale gas producers have observed that early gas production rates could be reasonably estimated with hyperbolic decline type curves. The hyperbolic form of the Arps equation leads however to infinitely decreasing decline rates and requires the inclusion of additional parameters such as well life time to avoid overestimating future production.

Despite continuous debate over the accuracy of the Arps equation, no alternative method has yet proven to be superior in predicting gas production. Though a promising one recently proposed by Patzek et al. (2013) might turn out to be more useful in the future[3], most published data currently relate to the Arps equation and so we use this well-established and expedient method here.

[3]Patzek et al. (2013) developed a stylized physical model of a multi-stage hydraulic fractured horizontal shale gas well. With the help of gas production data of more than 8000 US horizontal wells over 10 years, they employed their model to devise a 2-stage equation that described gas production over time. The early transient flow regime is modelled by a scaling curve that is proportional to the inverse of the square root of time. The later boundary flow regime that starts after the so-called interference time is estimated with a simple exponential decline curve.

In its original form the hyperbolic Arps equation states that gas production is a function of initial gas production q_0 and that it follows a hyperbolic decline over time. However, for lack of reported q_0 data, we replace q_0 by better reported parameters and effectively modify the Arps equation. In particular EUR can be obtained from integrating $q(t)$ over T so we substitute q_0 by a function of EUR, b, D_0 and T to calculate $q(t)$ (See supplementary online material for calculation details). This approach enables us to find the unique gas production rates $q(t)$ that are consistent with the parameter values of EUR, b, D_0 and T. The modified equation reads:

$$q(t) = \frac{EUR\frac{(b-1)D_0}{(1+bD_0T)^{(b-1)/b}-1}}{(1+bD_0t)^{1/b}} \tag{2}$$

Next, gas production rates $q(t)$ are combined with Investment Costs (IC), Operation and Maintenance Costs (OMC), a discount rate (r) and well lifetime (T) to compute the levelized costs of gas ($LCOG$). The LCOG formula is borrowed from the field of economics and provides the unit costs of producing shale gas over the lifetime of a well (Equation 3 and Method 2.3 in Figure 1).

$$LCOG = \frac{IC + \sum_{t=0}^{T}\frac{q(t)OMC}{(1+r)^t}}{\sum_{t=0}^{T}\frac{q(t)}{(1+r)^t}} \tag{3}$$

Finally, we combine the above equations 1, 2 and 3 to construct a CECF. For each play p, EUR probability distributions ($P_p(EUR)$) are multiplied by the total number of potential wells (N_p) to identify the number of wells (n) which will produce a certain EUR. Sorting then the $LCOG$ of all potential shale gas wells in ascending order and combining them with their associated EUR and the number of potential wells n yield a cumulative extraction cost function of shale gas (Block 3 in Figure 1). Technically Recoverable Resources (TRR), a metric common to many shale gas assessment studies, can be obtained by summing the EUR of all total potential wells across all shale plays P (Equation 4). In addition, economic recoverable resources (ERR) can be inferred from the curve for any given cost threshold.

$$TRR = \sum_{p=1}^{P} N_p \times P_p(EUR) \times EUR \tag{4}$$

2.3. Uncertainty

Techno-economic estimates bear large uncertainties. Those can be partly explained by the lack of *in situ* data but in this study they also stem from a lack of public data availability. To test the sensitivity of our results to these uncertainties we define lower, best and upper estimates for the 11 techno-economic parameters considered in this analysis. The best estimate for the EUR parameter is the result of combining the distributional data from USGS (2012) and EIA (2013a) with estimates of Area, well density in those same references. We then apply a $\pm 50\%$ change in EUR to define the lower and upper estimates[4] as in (EIA, 2013a). The lower, best and upper estimates of the other parameters including b, D_0, T, IC, OMC, r are based on our literature review (See supplementary online material for more information). When several estimates are available we define the best estimate as the mean, the lower estimate as the minimum value and the upper estimate as the maximum value. For some shale gas play data could nonetheless not be retrieved. In this case, the best estimate is simply the mean across all currently available data (See Table 1).

At the global scale, an additional level of uncertainty on TRR needs to be taken into account for the global CECF. We compile the most recent world TRR estimates from Rogner et al. (2012); Pearson et al. (2012); McGlade et al. (2013); EIA (2013b) and define best, lower and upper estimates accordingly. We also

[4]Note that these sensitivity factors are not supposed to reflect uncertainty but are used allow discussion.

Table 1: Estimates of techno-economic parameters. Estimates resulting from a literature review reflecting the heterogeneity between and across shale plays. These estimates were applied to shale gas plays with missing data. EUR are not displayed in this table since distributions are available for each shale gas play and values vary greatly.

Parameter	b	D_0	T	IC	OMC	r
Unit	-	%/yr	years	10^6 US$/well	US$/GJ	%
Best estimate	1.1	70	10	5	1.00	12
Lower estimate	0.5	50	2	3	0.50	10
Upper estimate	2.0	300	30	10	2.00	15

add a 50% cost mark-up for non-US regions (Deutsche Bank, 2011; Pearson et al., 2012).

The effect of technological change (TC) is an important parameter to consider when constructing a long-term cumulative extraction cost curve. To provide insights on the potential impacts of technological innovation, we apply a cost reduction factor on the cost component of the CECF (e.g. LCOG) and a quantity increase factor on the other component. McJeon et al. (2014) reviewed the literature and found cost reductions ranging from 20% and 45% between 2035 and 2050 (IEA, 2012a; Rogner et al., 2012; EMF, 2013; Newell and Raimi, 2014). As a result we assume a cost reduction of 33% and a TRR expansion of 44% by 2050 as in Rogner et al. (2012).

One should note that future regulations are not explicitely taken into consideration in this framework. However, the uncertainty analysis provides indications on how a decrease in investment costs or an increase in gas flow rates could shift the CECF. Additionally, the liquid content of shale gas wells and gas associated with shale oil wells are not accounted for in this study.

In the next section we first compute a best estimate cumulative extraction cost curve for the US and investigate the effect of shale play heterogeneity. We then calculate the economic recoverability of US shale gas for several gas costs and draw conclusions regarding shale gas availability at the global scale.

3. Results and discussion

3.1. US shale gas extraction costs

The CECF resulting from our methodology is shown in orange in Figure 2. Our best estimate is indicated by the orange solid line whereas the shaded area represent the techno-economic uncertainty range. One can see that extraction costs start above 1 US$/GJ and from 300 EJ on exceed 5 US$/GJ, a value close to the median well-head gas price over the period 2000-2012 (EIA, 2012). Two properties characterize our curve: convexity and asymptotic convergence towards TRR, both reflecting the large heterogeneity of shale gas deposits. Furthermore, extraction cost uncertainties exhibit a large spread which increases with cumulative extraction.

Our best estimate curve lies to the left of the bottom-up-derived ones in light blue and green (Jacoby et al., 2012; Petak, 2011). Differences between these curves can be explained by differences in input data and techno-economic assumptions that lead to various TRRs and curve shapes. Nevertheless, they all present the features described in the previous paragraph, namely low initial costs and a sharp cost increase. Conversely, the top-down curve of Rogner et al. (2012) in solid dark blue exhibits a different shape[5]. Extraction costs start at a higher value of 3 US$/GJ and increase stepwise but with a linear trend to about 5.5 US$/GJ, at which point the reserves of 1860 EJ are completely extracted. It is also interesting to look at the data reported in IEA (2013a). The authors of this study assumed a recovery factor of 40% of the original gas in place reported in Rogner (1997) and associated it with costs ranging from about 3 US$/GJ to 10 US$/GJ. Interestingly, these extraction costs did not change much from an earlier study IEA (2009). They are in stark contrast with the 5-10% estimates

[5]The resource part of the curve, in dashed dark blue, correspond to quantities assumed to become available before 2050. The underlying processes yielding this increase remain unclear and so, we discard it in this analysis.

reported in Sandrea (2012). In this analysis, 65% of shale gas resources can be economically recovered at 6 US$/GJ but this value we decreases to 19% at 3 US$/GJ. Clearly, the heterogeneity of shale gas deposits is not reflected in the outcomes of these top-down studies which could lead to a misrepresentation of extraction costs, as well as larger TRR estimates.

As expected technological change induces a shift rightward and downward of the CECFs. Nonetheless the differences observed in the previous paragraph between bottom-up and top-down studies are still present. Our best estimate becomes cheaper than the CECF in Petak (2011) for the first 600 EJ but still exhibits a steep cost increase after it. The CECF that accounts for technological change in Rogner et al. (2012) still misses cheap deposits and the steep cost increase because of the small number of categories.

As a means of harmonizing the six different results shown in Fig. 2, we normalize the cumulative extraction cost curves, thereby identifying the fraction of assumed TRR that can be economically recovered at a given cost (Fig. 3). Differences between all bottom-up curves have faded out to a large extent. Our results are more optimistic between 4.5 and 6.5 US$/GJ but our middle curve remains within a distance of 20% from the other two. On the contrary, discrepancies between bottom-up and top-down curves are emphasized on this figure. The linear assumption and small number of categories in the top-down study is clearly at odds with the exponential increase in bottom-up studies. The two curves accounting for technological change are close to each other for production costs ranging between 3-6 US$/GJ but the top-down curve does not account for the cheap deposits and the steep cost increase.

Given the relatively robust shape of bottom-up curves, we further perform a regression on our curve with a 3^{rd} order polynomial in order to facilitate the estimation of ERR and the use of the CECF in future studies. (Details are given in the supplementary online material) Not only can this equation be employed

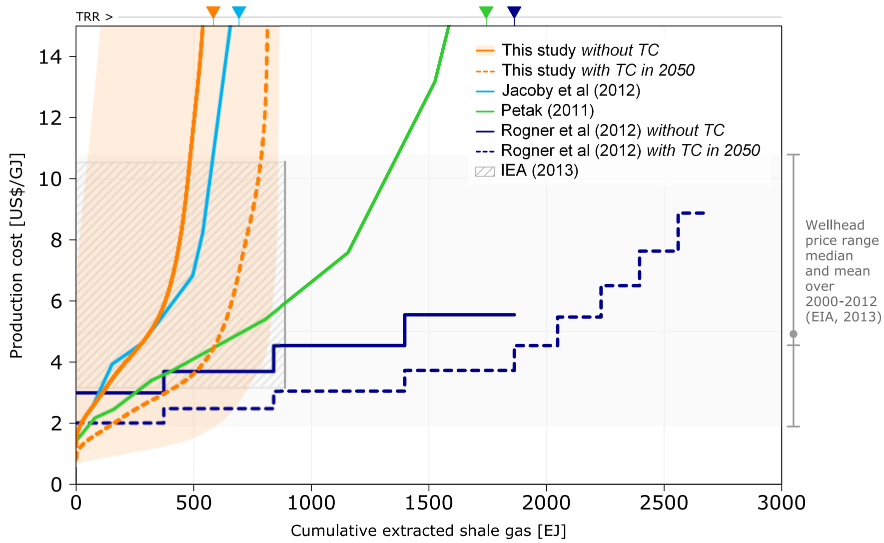

Figure 2: US shale gas cumulative extraction cost curves from bottom-up and top-down studies. The uncertainty range is displayed in light color. The hashed area in the background indicates the range of extraction costs and TRR reported in IEA (2009). This TRR results from assuming a 40% recovery factor on the original gas in place provided by Rogner (1997). TRR from bottom-up studies are indicated with a colored triangle at the top of the plot. Wellhead price range over the period 2000-2012 is indicated on the right side. The lower and upper ticks indicate the minimum and maximum prices whereas the inner tick and dot indicate the median and the mean, respectively. Note that the curve from Petak (2011) originally produced for North America was scaled down to match the US TRR given in the same study. TC stands for Technological Change

to estimate the fraction of TRR that is economically recoverable at a given cost but it also allows the calculation of the amounts of economically recoverable resource by multiplying the resulting fraction by a chosen technically recoverable resource value.

3.2. Sensitivity analysis of the normalized CECF

To test the sensitivity of our model to variations of input parameters, we vary best estimates across all shale plays by +/- 20%. This method allows us to identify which individual input parameters as well as combinations of input parameters are key in explaining changes in $LCOG$. It is important to recall that this sensitivity analysis only applies to $LCOG$ since EUR is an input parameter

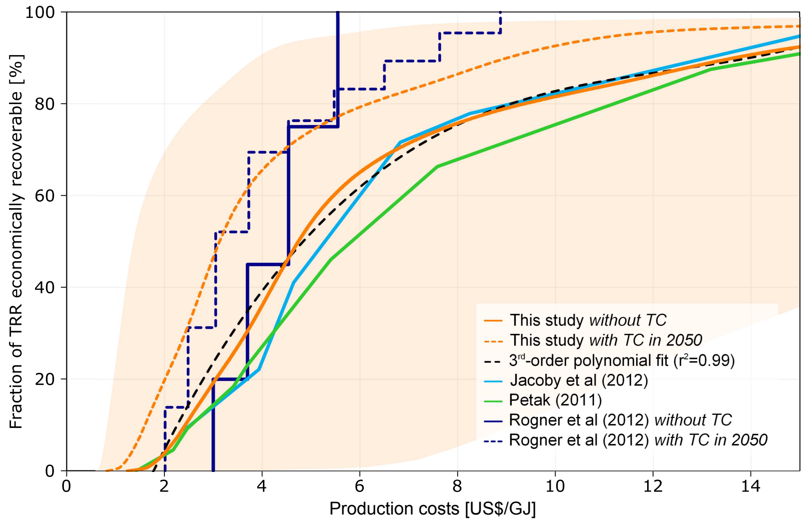

Figure 3: Economically recoverable fraction of TRR. Same as for Fig. 2.

in our framework. Changes in $LCOG$ are defined as the ratio between $LCOGs$ resulting from a change in input parameters and $LCOGs$ resulting from the best-estimate case. These changes are summarised in box plots and shown on Figure 4. Regarding individual parameters, it turns out that EUR, IC and OMC have the largest effects on $LCOG$, though they mostly remain below +/- 20%. As for combinations of input parameters, the effect of economic parameters is larger than 20% and dominates over that of Arps parameters. Nonetheless combining all input parameter sensitivities result in $LCOG$ changes ranging between -20% and +80%, far greater than the effects of economic parameters alone. It is also important to note that these effects vary along the CECF as indicated by the box plots. In particular, the effect of OMC is reduced at higher costs. Given the relatively small effect of b, $D0$ and T, the results suggest that q_0 has a large impact on $LCOG$.

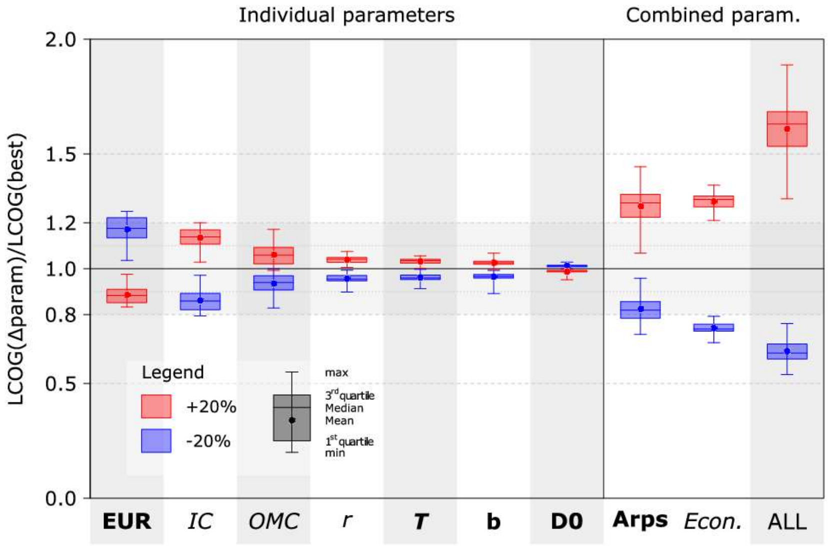

Figure 4: Sensitivity analysis of the normalized CECF. Economic parameters are in italic letters whereas non-economic parameters are in bold letters. The effect of single parameters is shown in the left panel. Combinations of parameters are displayed on the right panel.

3.3. Global shale gas extraction costs

Since shale gas activities outside the US are still in their infancy, detailed techno-economic data are not yet publicly available. As an alternative, one may gain insights at the global scale by scaling up the US shale gas CECF using global TRR estimates. Global TRRs have been estimated and recently compiled by Pearson et al. (2012) and McGlade et al. (2013). In the present study we complete this dataset with other recent estimates from Rogner et al. (2012) and EIA (2013b). We compute a best estimate of about 6500 EJ and lower and upper estimates of about 2600 EJ and 12100 EJ, respectively (Details on these calculations can be found in the supplementary online material).

In this last result section, we apply the previously computed normalized US curve to TRR estimates to obtain a global cumulative extraction cost curve. To make this extrapolation a bit more realistic, we apply a 50% cost mark-up to

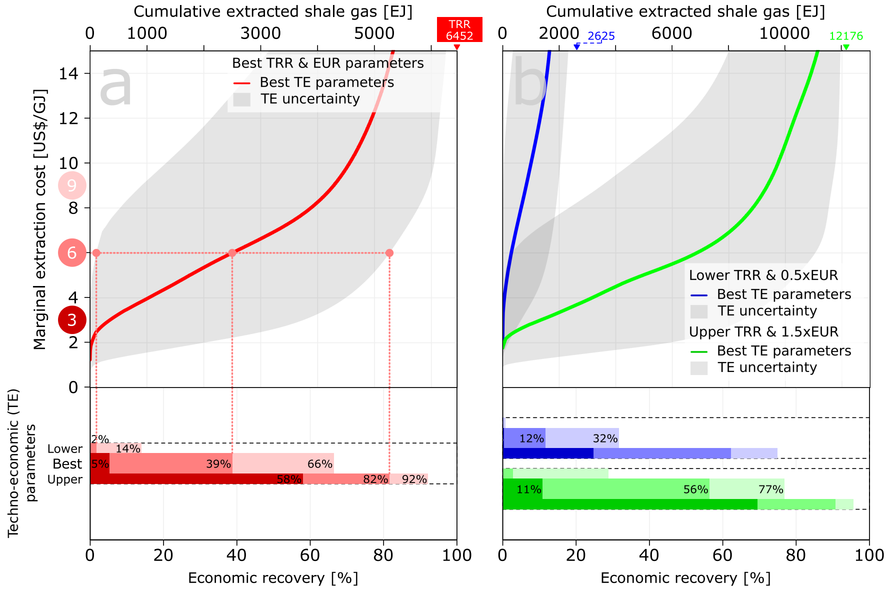

Figure 5: Global shale gas cumulative extraction cost curves, TRR and ERR for the (a) best as well as (b) lower and upper global TRR estimates. Grey-shaded areas represent techno-economic uncertainties. ERRs are given for 3 cost thresholds highlighted in red on the vertical axis.

investment costs in order to reflect the less favourable infrastructure, market conditions and regulations in non-US regions (Deutsche Bank, 2011; Pearson et al., 2012). The on-going development of shale gas extraction in regions outside the US will provide a clearer picture in the future but as for now we have to resort to such methods to derive first order information and assess the related uncertainty.

We compute global CECFs for the best, lower and upper TRR estimates and assume that differences in these estimates can be primarily explained by differences in EURs. More precisely we assume that an increase or a decrease in EURs lead to a respective increase or decrease in global TRR as in EIA (2012, 2013a). Since similar relationships cannot be established between EUR and other parameters (See methodological section), we cluster the remaining techno-economic parameters and analyse their effect on CECFs by defining 3 parameter combinations best, lower and upper cases that span the range of possibilities (See online supplementary online material). In addition, for each of the three global CECFs, we provide estimates of economic recoverability[6] at three different cost thresholds that pertain to the range of US wellhead prices between 2000 and 2012[7]: 3, 6, and 9US$/GJ. To sum up, we perform an extensive sensitivity analysis of economic recoverability along three dimensions: TRR and EUR, techno-economic parameters and costs.

Let us first focus on the global CECF corresponding to the best TRR estimate and indicated by a red line on Figure 5(a). The associated economic recoverability is shown in the lower panel. At 6 US$/GJ, 39% of the TRR is economically recoverable which contrasts with the entire shale gas reserves that can be extracted in Rogner et al. (2012). The large uncertainties in input techno-economic data (grey area) change the recoverability at a cost of US$6/GJ to 2% and 82% in the lower and upper cases respectively, highlighting the need for better reporting of these parameters. Sensitivity to costs is also substantial. At 3 US$/GJ economic recoverability decreases to 5% whereas at 9 US$/GJ it increases to 66%, emphasizing the large impact of future gas prices on economic recovery.

When the TRR and EUR uncertainty is accounted for economic recoverability is further impacted (Fig. 5(b)). One may first notice the important gap of about 10 ZJ between the blue and green curves that correspond to the lower and upper TRR and EUR cases. This reflects the lack of knowledge about shale gas plays inside and outside the US. The two curves exhibit the same insights gathered in the best TRR and EUR case. An additional interesting result is the decreasing incremental quantity available from moving from 3 US$/GJ to

[6]defined as ERR/TRR

[7]Wellhead price throughout the 1980s and 1990s was about $2. This was followed by a large upward swing from 2000-2007 and then a downward trend. `http://www.eia.gov/dnav/ng/hist/n9190us3a.htm`

6 US$/GJ and from 6 US$/GJ to 9 US$/GJ. This diminishing returns effect is the result of the shape of the CECFs.

It is interesting to put these estimates into perspective. On the one hand, Henry Hub natural gas prices are currently around 4 US$/GJ and are projected to increase in the future (EIA, 2014). On the other hand, the US had produced about 50 EJ of shale gas by the end of 2013 (EIA, 2014). These facts invalidate some of the CECFS. In particular those resting from lower techno-economic estimates and especially in the lower TRR & 0.5xEUR case. It is however worthwhile to note that all best techno-economic estimates at 6 US$/GJ which range between 300 EJ and 6800 EJ are in agreement with current shale gas production.

4. Conclusion

In this study, we developed a method based on publicly available data that enables us to compute cumulative extraction cost curves of shale gas, derive economic recoverability and identify key uncertainties. We offer this method in the form of a computing tool[8] and also provide 3^{rd} order polynomial fitting curves that can be applied to estimates of technically recoverable resources to quickly approximate shale gas extraction costs. Our results are found to be in good agreement with previous bottom-up studies and highlight the importance of accounting for the heterogeneity of shale gas deposits in estimating extraction costs. Crucially, our results show that extraction costs are likely not adequately represented in previously published top-down studies. More importantly we identified initial production, iunvestment costs, and operation and maintenance costs as key parameters driving differences in estimates of the levelized costs of gas. It is also interesting to note that Arps parameters describing gas flow over time have a lesser impact on overall costs than economic ones (e.g. investment costs, operation and maintenance costs, and discount rate).

[8]Please send an e-mail to hilaire@pik-potsdam.de

For the US, we calculated that about 400 EJ or two thirds of technically recoverable resources could be economically recovered at a cost of 6 US$/GJ in the best estimate case. This estimate decreases dramatically to 100 EJ at 3 US$/GJ, a result that is still in agreement with current production. At the global level and at 6 US$/GJ, we obtain economically recoverable resources ranging between 300 EJ and 6800 EJ in the case of best techno-economic estimates. It is worthwhile to note that the extrapolation of detailed US data to the global level, even when including a +50% mark-up on investment costs, cannot fully account for the different techno-economic characteristics of other regions. As drilling activity starts to take place outside the US and new data will become available, estimates could be refined.

Since data availability is an important factor that determines the outcome of such analysis, it is necessary to address its scarcity to refine estimates in the future. Although the results from this analysis can only be as accurate as the information and the assumptions upon which it draws, they suggest that analyses at the global level and over the 21$^{\text{st}}$ century using estimates reported in top-down studies could overestimate the future of gas production. This could have important repercussions on both climate change mitigation strategies and energy security and access.

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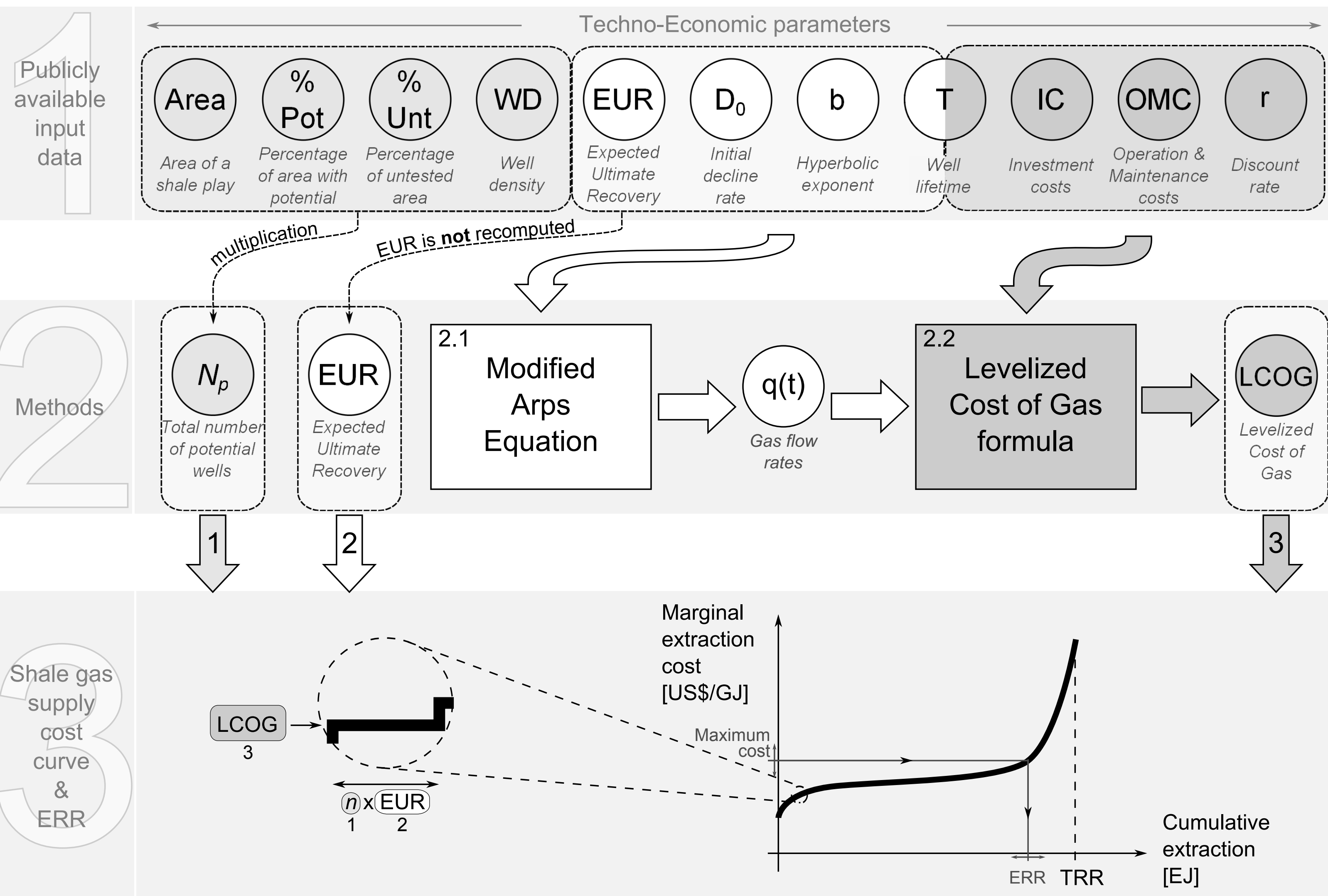
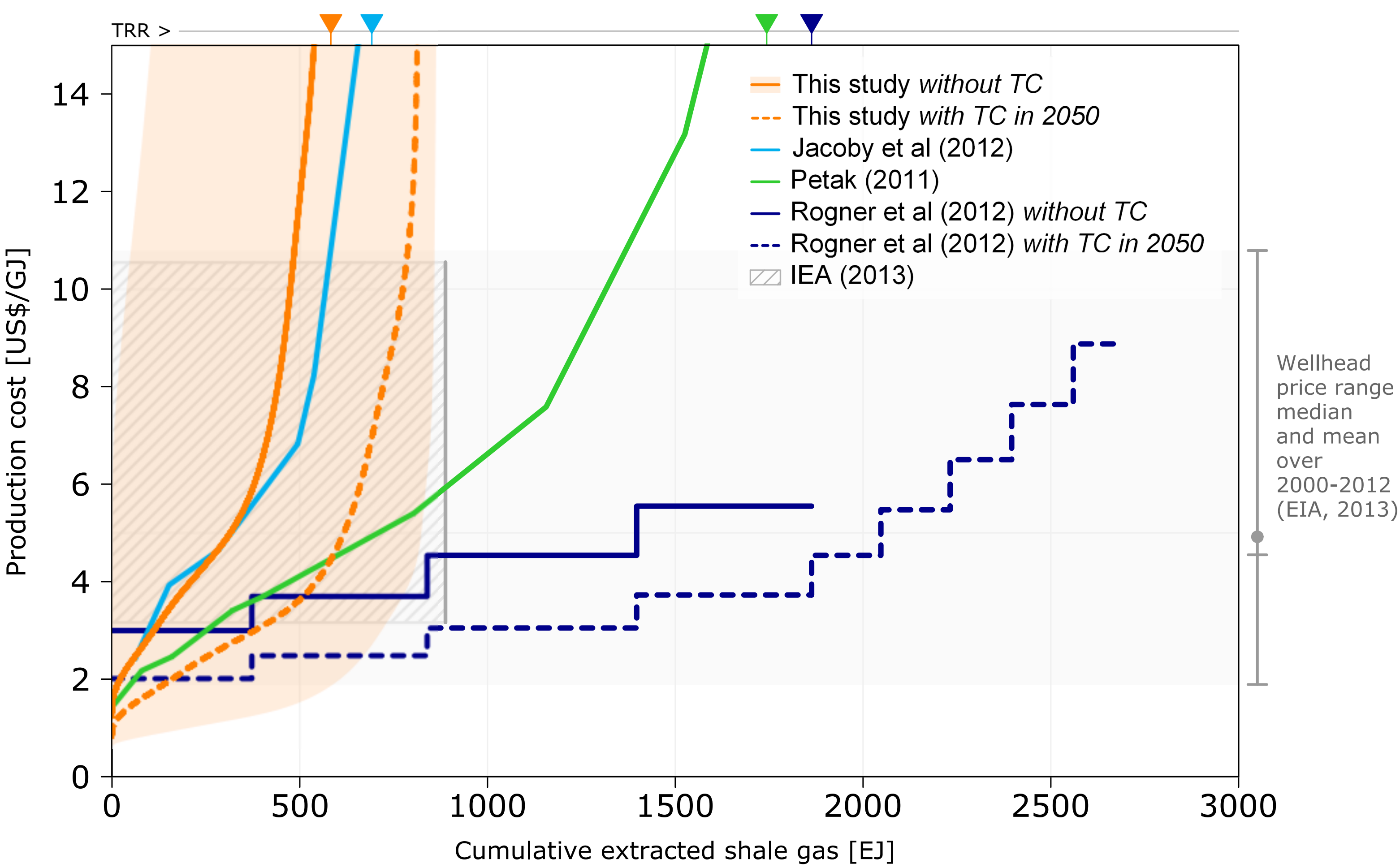
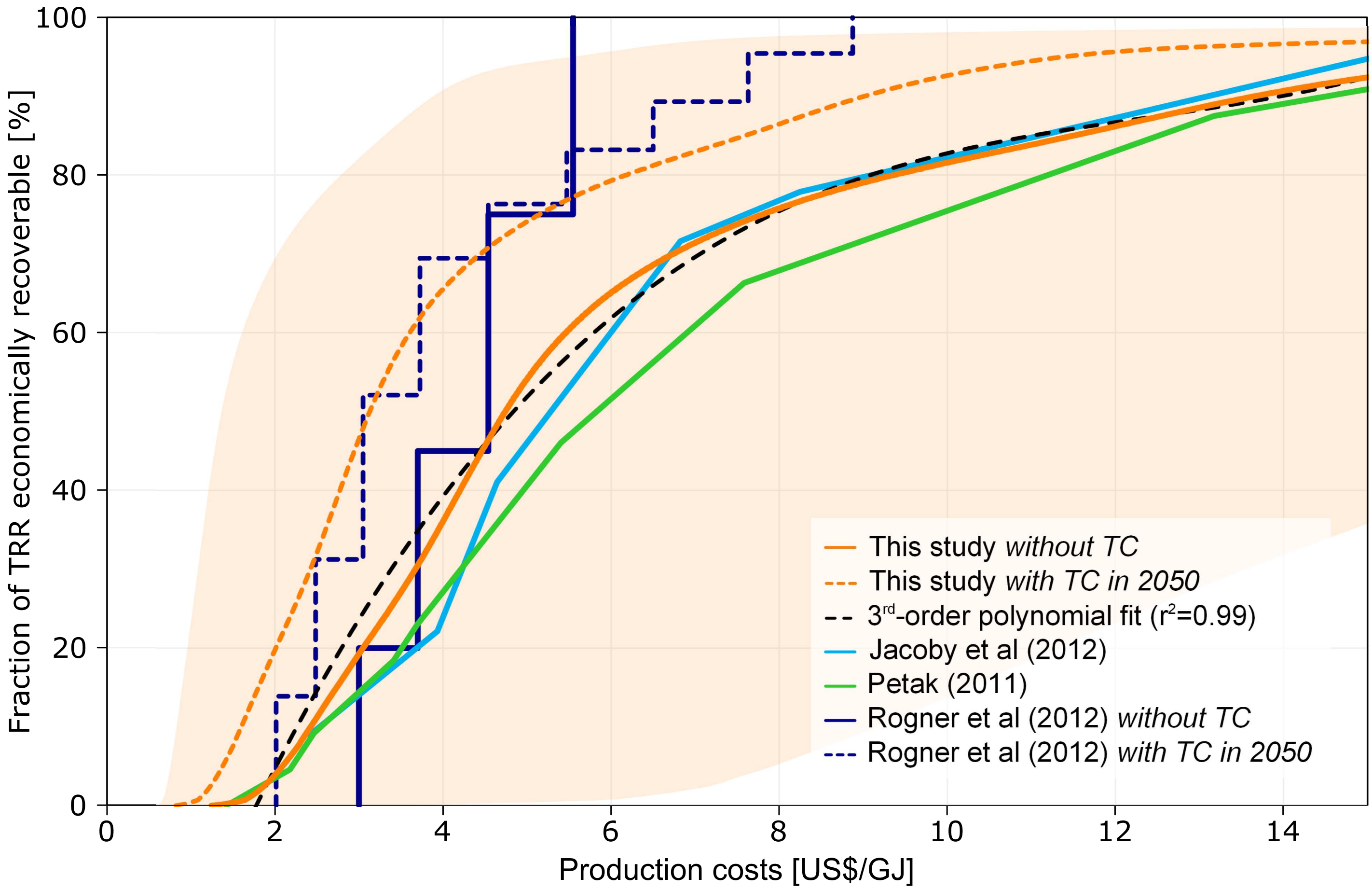


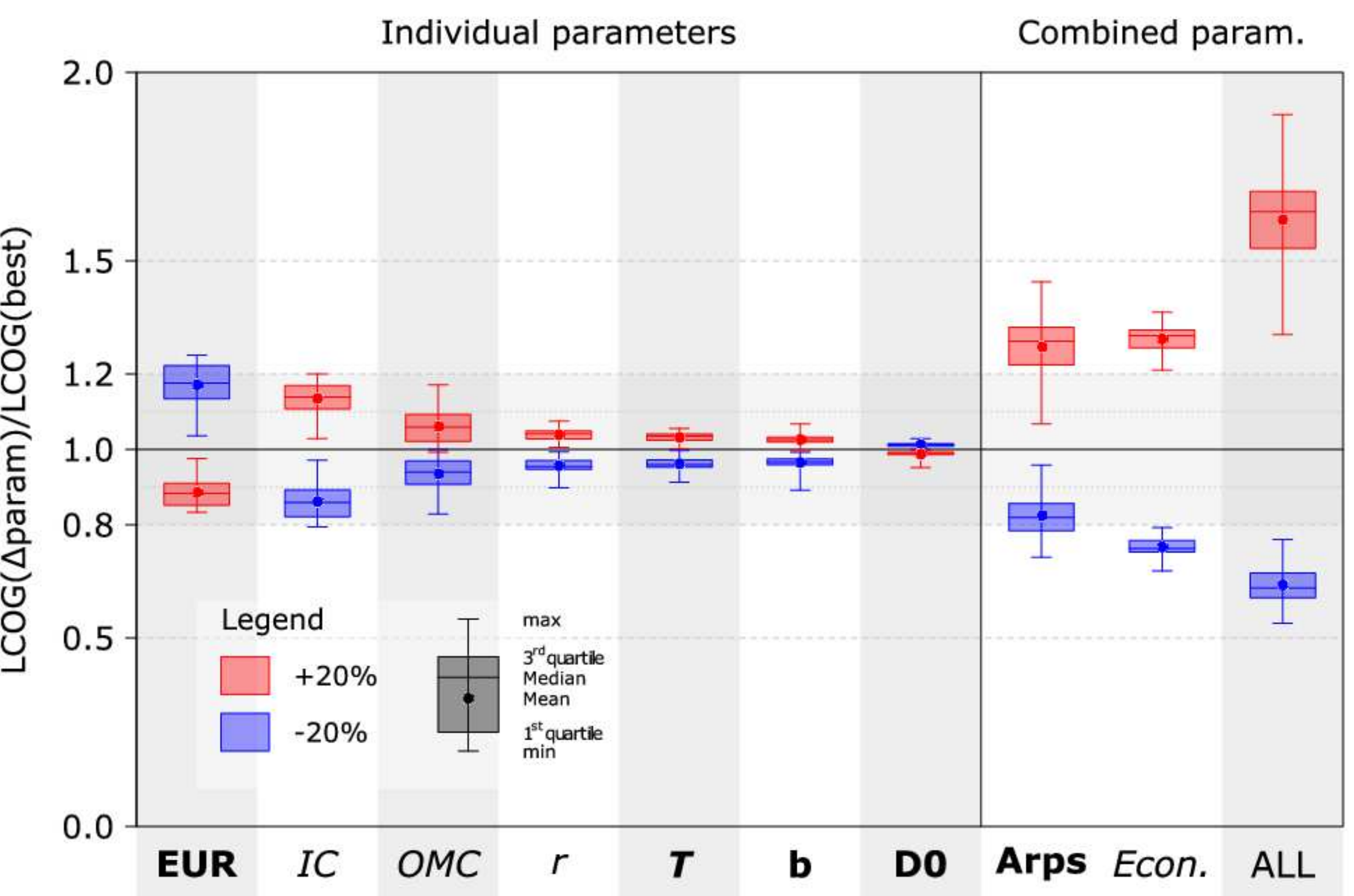
Techno-Economic parameters
1
Publicly available input data
Area
Area of a shale play
% Pot
Percentage of area with potential
% Unt
Percentage of untested area
WD
Well density
EUR
Expected Ultimate Recovery
D_0
Initial decline rate
b
Hyperbolic exponent
T
Well lifetime
IC
Investment costs
OMC
Operation & Maintenance costs
r
Discount rate
multiplication
EUR is **not** recomputed
2
Methods
N_p
Total number of potential wells
EUR
Expected Ultimate Recovery
2.1
Modified Arps Equation
q(t)
Gas flow rates
2.2
Levelized Cost of Gas formula
LCOG
Levelized Cost of Gas
1
2
3
3
Shale gas supply cost curve & ERR
LCOG
3
n x EUR
1
2
Marginal extraction cost [US$/GJ]
Maximum cost
Cumulative extraction [EJ]
ERR
TRR



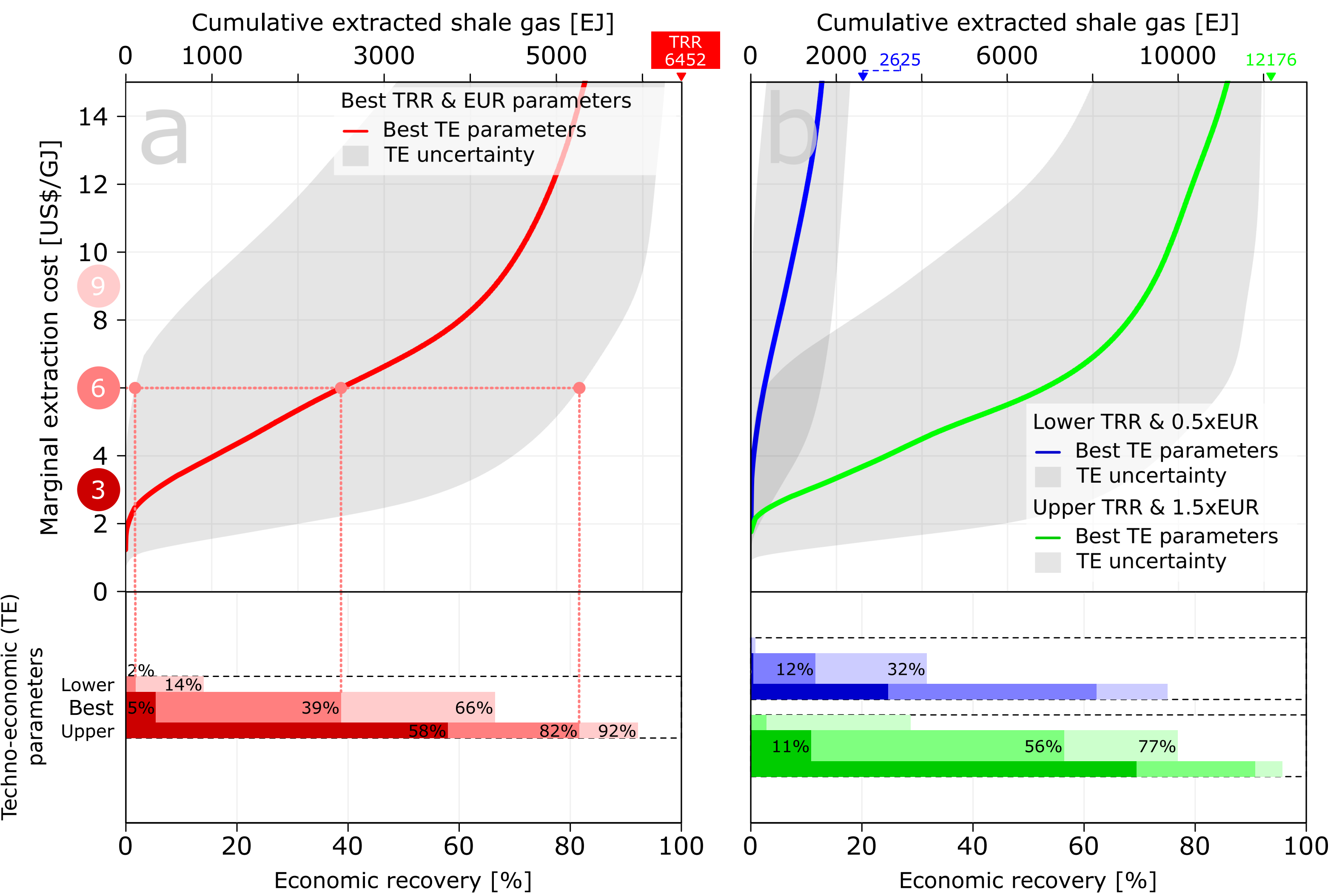
TRR >
This study without TC
This study with TC in 2050
Jacoby et al (2012)
Petak (2011)
Rogner et al (2012) without TC
Rogner et al (2012) with TC in 2050
IEA (2013)
Production cost [US$/GJ]
0
2
4
6
8
10
12
14
0
500
1000
1500
2000
2500
3000
Cumulative extracted shale gas [EJ]
Wellhead price range median and mean over 2000-2012 (EIA, 2013)



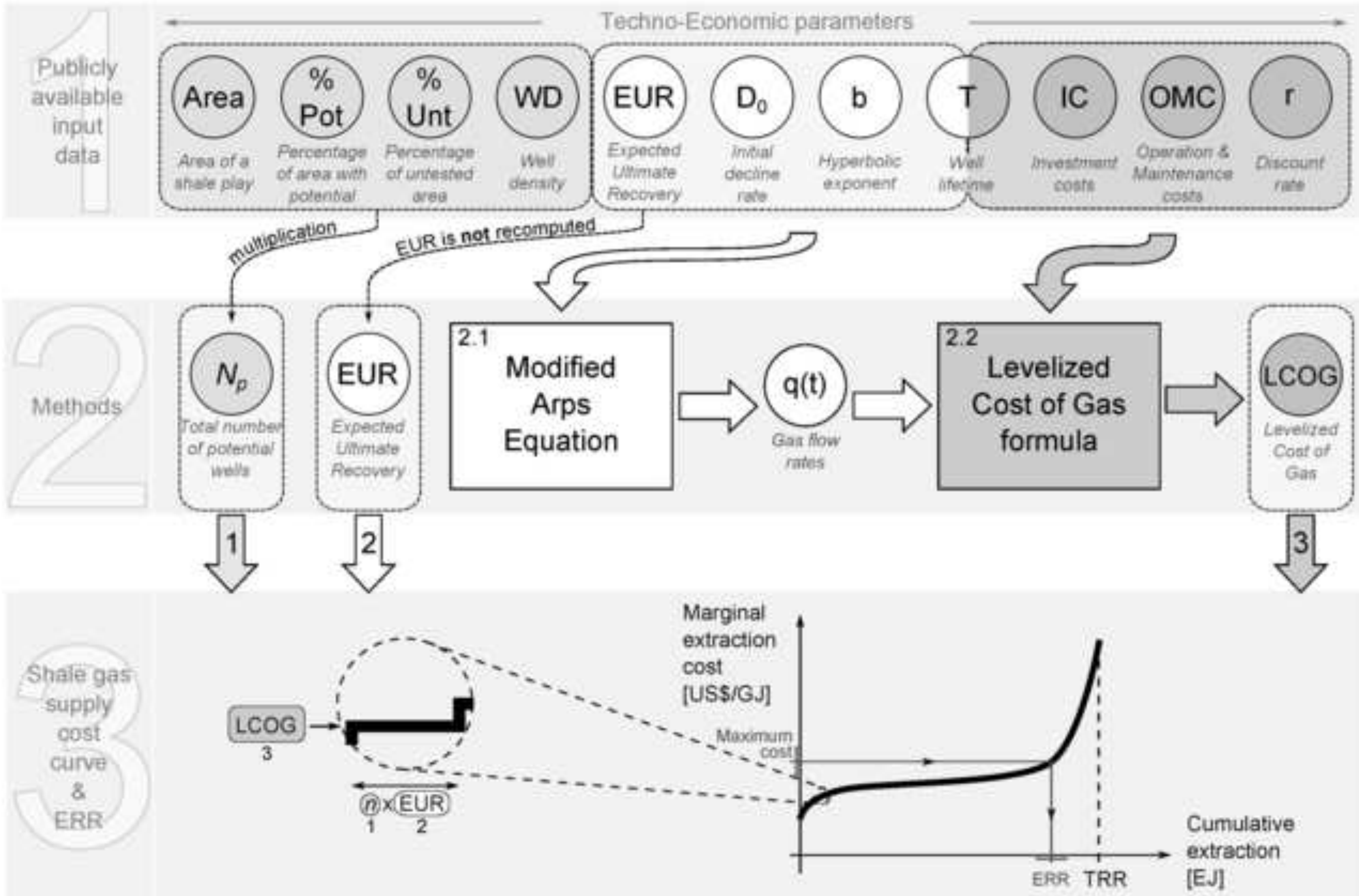
Fraction of TRR economically recoverable [%]
0
20
40
60
80
100
0
2
4
6
8
10
12
14
Production costs [US$/GJ]
This study *without TC*
This study *with TC in 2050*
3rd-order polynomial fit (r2=0.99)
Jacoby et al (2012)
Petak (2011)
Rogner et al (2012) *without TC*
Rogner et al (2012) *with TC in 2050*



Individual parameters
Combined param.
LCOG(Δparam)/LCOG(best)
2.0
1.5
1.2
1.0
0.8
0.5
0.0
Legend
+20%
-20%
max
3rd quartile
Median
Mean
1st quartile
min
EUR
IC
OMC
r
T
b
D0
Arps
Econ.
ALL



Cumulative extracted shale gas [EJ]
0
1000
3000
5000
TRR
6452
a
Best TRR & EUR parameters
Best TE parameters
TE uncertainty
Marginal extraction cost [US$/GJ]
14
12
10
9
8
6
4
3
2
0
Techno-economic (TE) parameters
Lower
Best
Upper
2%
14%
5%
39%
66%
58%
82%
92%
20
40
60
80
100
Economic recovery [%]
Cumulative extracted shale gas [EJ]
2000
2625
6000
10000
12176
b
Lower TRR & 0.5xEUR
Best TE parameters
TE uncertainty
Upper TRR & 1.5xEUR
Best TE parameters
TE uncertainty
12%
32%
11%
56%
77%
Economic recovery [%]



Techno-Economic parameters
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% Unt
Percentage of untested area
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EUR
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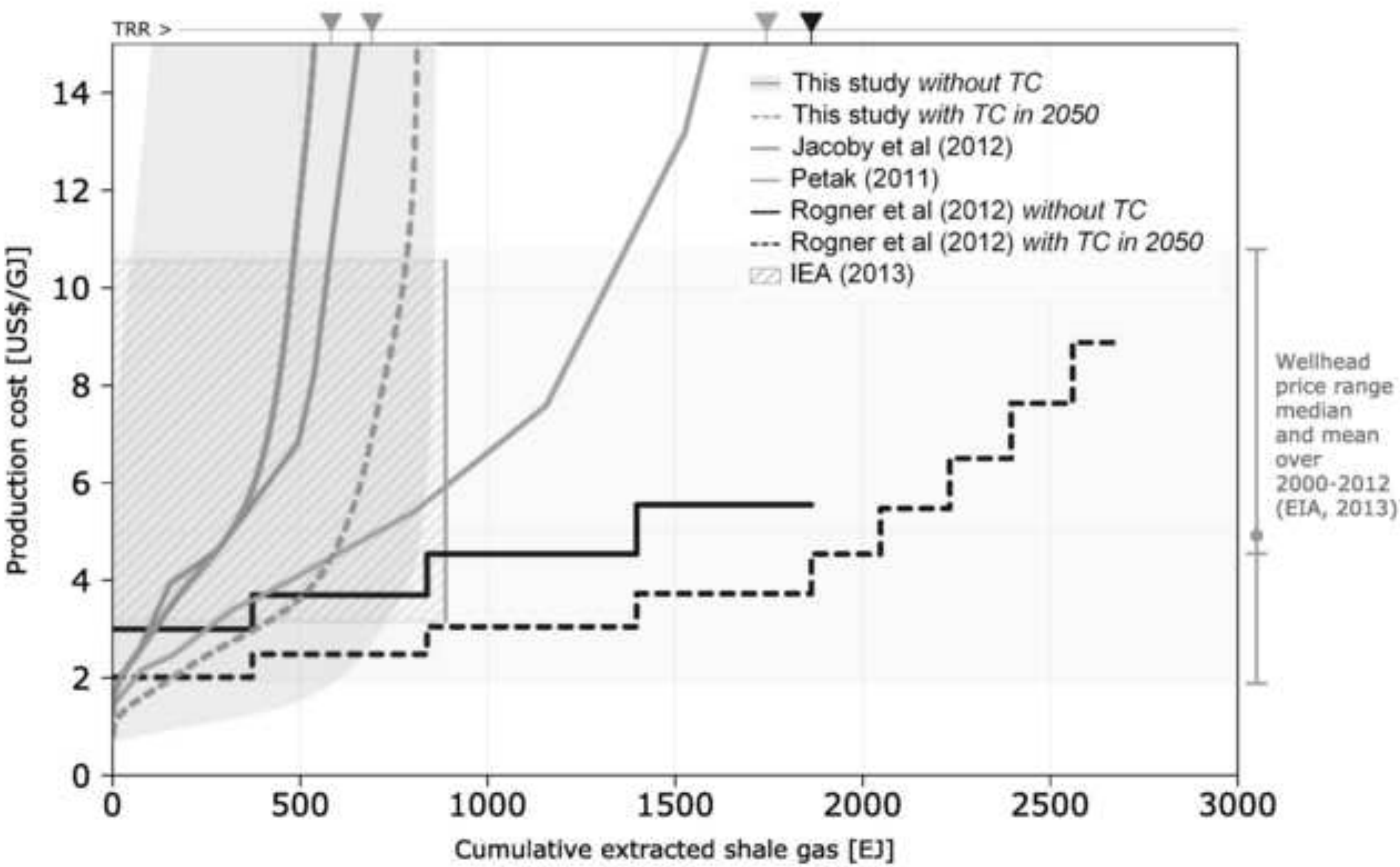
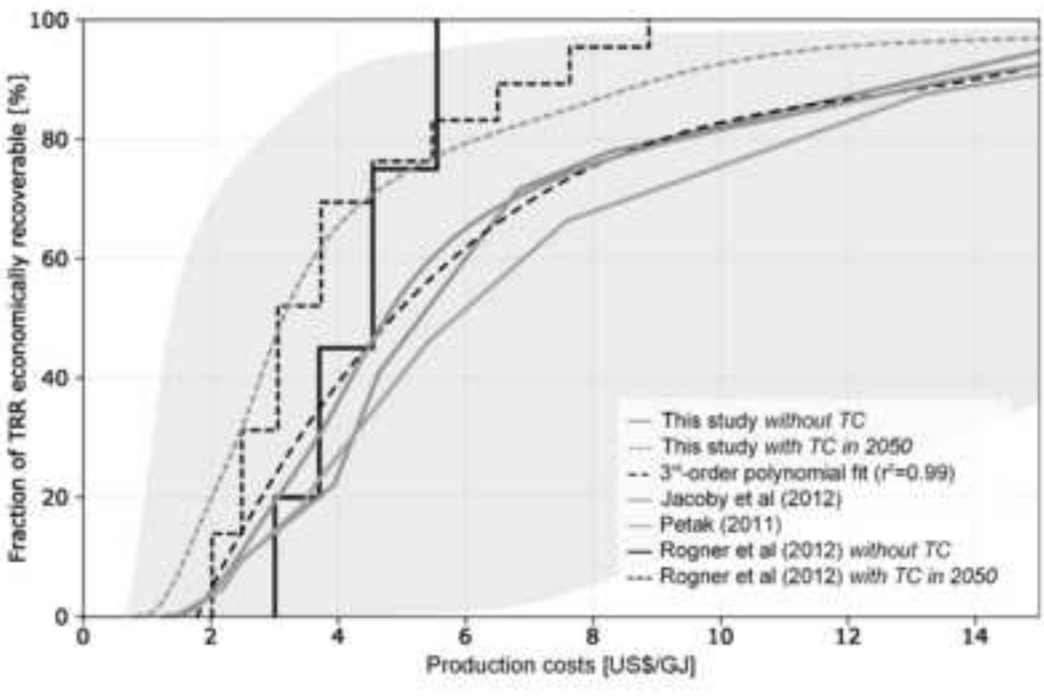
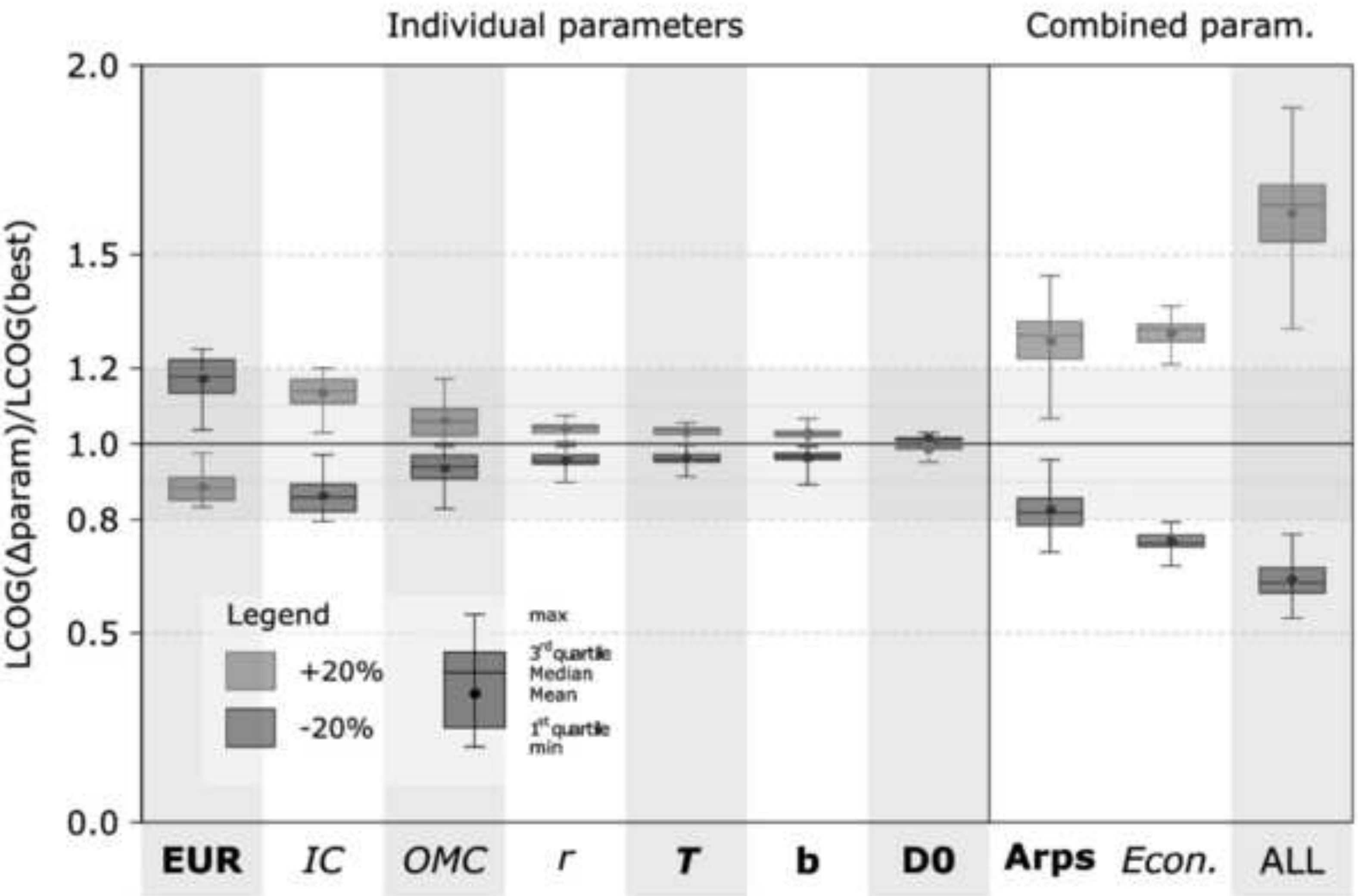
D0
Initial decline rate
b
Hyperbolic exponent
T
Well lifetime
IC
Investment costs
OMC
Operation & Maintenance costs
r
Discount rate
multiplication
EUR is not recomputed
2
Methods
Np
Total number of potential wells
EUR
Expected Ultimate Recovery
2.1
Modified Arps Equation
q(t)
Gas flow rates
2.2
Levelized Cost of Gas formula
LCOG
Levelized Cost of Gas
1
2
3
3
Shale gas supply cost curve & ERR
LCOG
3
n x EUR
1
2
Marginal extraction cost [US$/GJ]
Maximum cost
Cumulative extraction [EJ]
ERR
TRR



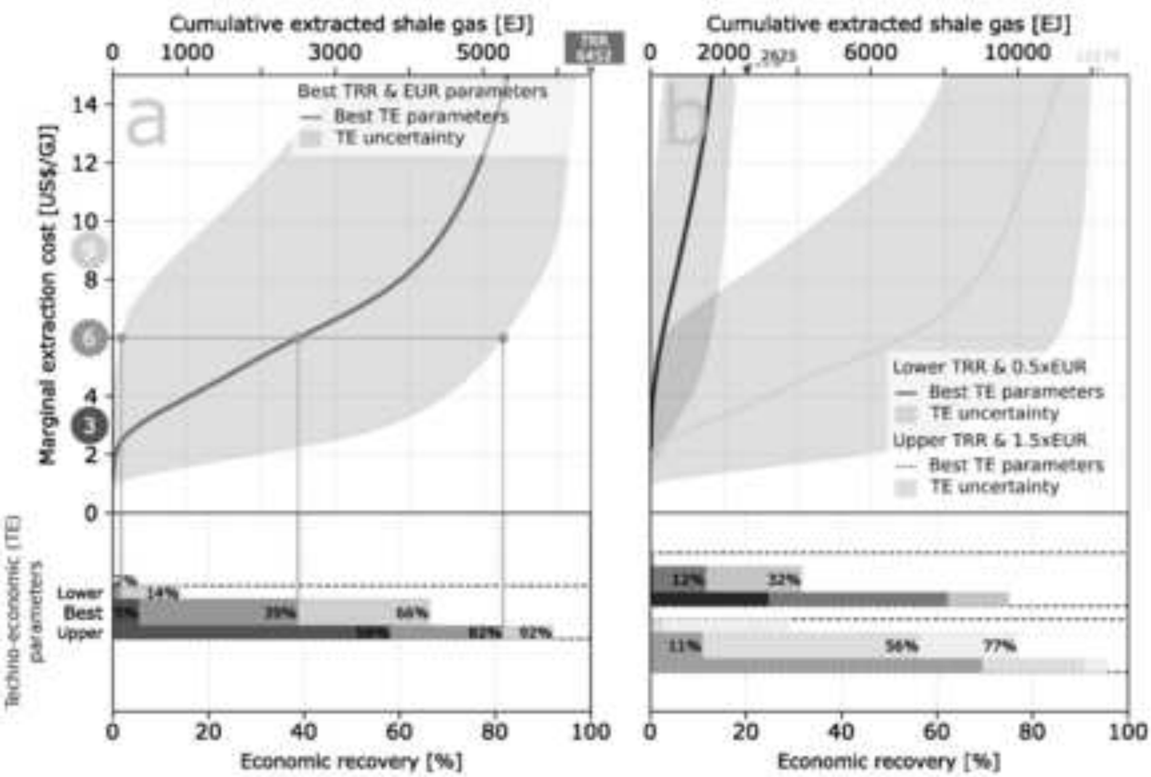
TRR >
This study without TC
This study with TC in 2050
Jacoby et al (2012)
Petak (2011)
Rogner et al (2012) without TC
Rogner et al (2012) with TC in 2050
IEA (2013)
Wellhead price range median and mean over 2000-2012 (EIA, 2013)
Production cost [US$/GJ]
Cumulative extracted shale gas [EJ]
0
2
4
6
8
10
12
14
0
500
1000
1500
2000
2500
3000



Fraction of TRR economically recoverable [%]
Production costs [US$/GJ]
0
20
40
60
80
100
0
2
4
6
8
10
12
14
This study without TC
This study with TC in 2050
3rd-order polynomial fit (r²=0.99)
Jacoby et al (2012)
Petak (2011)
Rogner et al (2012) without TC
Rogner et al (2012) with TC in 2050



Individual parameters
Combined param.
LCOG(Δparam)/LCOG(best)
2.0
1.5
1.2
1.0
0.8
0.5
0.0
Legend
+20%
-20%
max
3rd quartile
Median
Mean
1st quartile
min
EUR
IC
OMC
r
T
b
D0
Arps
Econ.
ALL



Cumulative extracted shale gas [EJ]
0
1000
3000
5000
a
Best TRR & EUR parameters
Best TE parameters
TE uncertainty
Marginal extraction cost [US$/GJ]
14
12
10
8
6
4
3
2
0
Techno-economic (TE) parameters
Lower
Best
Upper
14%
39%
66%
58%
82%
92%
Economic recovery [%]
20
40
60
80
100
Cumulative extracted shale gas [EJ]
2000
6000
10000
b
Lower TRR & 0.5xEUR
Best TE parameters
TE uncertainty
Upper TRR & 1.5xEUR
Best TE parameters
TE uncertainty
12%
32%
11%
56%
77%
Economic recovery [%]

Boom or Bust? Mapping out the known unknowns of global shale gas production potential

Supplementary material

Jérôme Hilaire, Nico Bauer and Robert J. Brecha

Contents

Modified Arps equation

In this section we show how we derive the numerator of the modified Arps equation.

$$EUR = \int_0^T q(t)dt = \int_0^T \frac{q_0}{(1 + bD_0t)^{1/b}} dt = q_0 \int_0^T \frac{1}{(1 + bD_0t)^{1/b}} dt$$

We pose $x = 1 + bD_0t$. As a result we obtain $dt = \frac{1}{bD_0} dx$.

The equation then becomes:

$$EUR = \frac{q_0}{bD_0} \int_1^{1+bD_0T} \frac{1}{x^{1/b}} dx$$

We know that $\int x^n \, dx = \frac{x^{n+1}}{n+1} + C$, if $n \neq 1$. Thus we obtain the following equation:

$$EUR = \frac{q_0}{bD_0} \left[\frac{x^{(b-1)/b}}{(b-1)/b} \right]_1^{1+bD_0T} = q_0 \frac{(1 + bD_0T)^{(b-1)/b} - 1}{(b-1)D_0}$$

Hence

$$q_0 = EUR \frac{(b-1)D_0}{(1 + bD_0T)^{(b-1)/b} - 1}$$

Data, input parameters and assumptions

In this section, we provide further information about data used and assumptions made in our methodology. All data, algorithms and code are available from the authors upon request. The equations presented in our study are repeated here:

$$N_p = A \times \%Pot \times \%Unt \times WD \quad (1)$$

$$q(t) = \frac{EUR \frac{(b-1)D_0}{(1 + bD_0T)^{(b-1)/b} - 1}}{(1 + bD_0t)^{1/b}} \quad (2)$$

$$LCOG = \frac{\sum_{t=0}^{T} \frac{IC\delta + q(t)OMC}{(1+r)^t}}{\sum_{t=0}^{T} \frac{q(t)}{(1+r)^t}} \quad (3)$$

$$TRR = \sum_{p=1}^{P} N_p \times P_p(EUR) \times EUR \quad (4)$$

Technically recoverable resources (TRR)

TRR can be calculated over different geographical areas and is mainly reported for countries. For instance US estimates range between 509 EJ and 1863 EJ (see Table 1). The best-estimate taken in this study result from the sum of all shale plays TRR reported in ARI (2011) and USGS (2012) (see attached dataset).

Table 1 US shale gas TRR estimates

Study	US TRR (EJ)
Petak, 2010	1472
EIA, 2011	791
Medlock et al, 2011	672
Petak, 2011	1743
BGR, 2012	888
EIA, 2012	509
Rogner et al, 2012	1863
Jacoby et al, 2012	691
EIA, 2013	573
EIA, 2014	611
This study (best-estimate)	**582**

For the whole world, Pearson et al (2012) and McGlade et al (2013) compiled the most recent estimates. We further complete their dataset with estimates from Rogner et al (2012) and ARI (2013) (see Table 2).

Table 2 Global shale gas TRR

World regions and countries	Technically Recoverable Resources (EJ) Low	Best	High	Sources
Africa (sub-saharan)*	411	457	512	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Australia	149	341	461	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Canada	133	412	1047	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
China	241	917	1336	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Central and South America**	149	1183	2084	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Eastern Europe	159	193	228	Pearson et al (2012), Rogner et al (2012) and ARI (2013)
Former Soviet Union	429	1034	2235	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
India	67	81	101	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Middle East and North Africa	104	665	1062	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Other developing Asia	48	271	818	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
USA	511	582	1863	McGlade et al (2013), Rogner et al (2012) and ARI (2013)
Western Europe	224	316	429	Pearson et al (2012), Rogner et al (2012) and ARI (2013)
TOTAL	**2624**	**6454**	**12175**	

* In McGlade et al (2013), Africa included North Africa which was also accounted in Middle East. This is why we discard this estimate.

** In this study, Mexico belongs to the Central and South America region.

The estimate taken from Rogner et al (2012) includes 20% of gas in place that are deemed to become recoverable by 2050.

All estimates provided in this section are in exajoules (EJ) and have been converted (when required) by using the unit conversion table in Rogner et al (2012) (Table 7.3, page 437).

Africa (sub-saharan)

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	ARI (2011)		512		
Rogner et al (2012)	Several		448	*671*	we include the East African region (EAF), the Western African region (WCA) and the South African region (SAF)
ARI (2013)			411		"Reduced area due to igneous intrusions."
This study	ARI (2011), Rogner et al (2012), ARI (2013)	**411**	**457**	**512**	

We calculate the Best estimate as the mean of Rogner et al (2012), McGlade et al (2013) and ARI (2013). We also take as High estimate the value reported by McGlade et al (2013) and take the value of ARI (2013) as Low estimate. Compared to McGlade et al (2013), we do not include Algeria, Lybia, Tunisia and Morocco in this region because they are already considered in the reference used to assess the Middle East region.

Australia

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	ARI (2011)		414		
Rogner et al (2012)	Several		149	*224*	The region contains also New Zealand
ARI (2013)			461		
This study	ARI (2011), ARI (2013)	**149**	**341**	**461**	

We calculate the Best estimate as the mean of Rogner et al (2012), McGlade et al (2013) and ARI (2013). We also take the value in Rogner et al (2012) as Low estimate and we take the value of ARI (2013) as High estimate.

Canada

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several	133	444	1047	
Rogner et al (2012)	Several		186	261	
ARI (2013)			605		"7 basins vs. 12 basins"
This study	ARI (2011), Rogner et al (2012), ARI (2013)	**133**	**412**	**1047**	

We calculate the Best estimate as the mean of Rogner et al (2012), McGlade et al (2013) and ARI (2013). We keep the Low and High estimates as defined in McGlade et al (2013).

China

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several	241	659	1336	
Rogner et al (2012)	Several		75	*112*	
ARI (2013)			1176		“Better data; higher TOC criterion”
This study	ARI (2011), Rogner et al (2012), ARI (2013)	**241**	**917**	**1336**	**We discard Rogner (2012) estimates which do not reflect results from recent assessments.**

We calculate the Best estimate as the mean of McGlade et al (2013) and ARI (2013). We exclude the estimate from Rogner et al (2012) which appears as an outlier. We keep the Low and High estimates defined by McGlade et al (2013).

Central and South America

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several		1317		Contains the Central and South America region and Mexico
Rogner et al (2012)	Several		149	*224*	
ARI (2013)			2084		Argentina. “Improved dry and wet gas areal definitions.” Brazil: “New dedicated chapter” Venezuela: “Included associated gas; better data.” Mexico: “Better data on areal extent.”
This study	ARI (2011), Rogner et al (2012), ARI (2013)	**149**	**1183**	**2084**	

We calculate the Best estimate as the mean of McGlade et al (2013), Rogner et al (2012) and ARI (2013). We use the value in Rogner et al (2012) as Low estimate. We defined as High estimates the value reported in ARI (2013). For consistency with Rogner et al (2012) we include Mexico in the region “Central and South America”.

Eastern Europe

Study	Sources	Low	Best	High	Comment
Pearson et al (2012)	Several		159		
Rogner et al (2012)	Several		224	336	
ARI (2013)			228		Poland: “Higher TOC criterion,

					better data on Ro."
This study	Pearson et al (2012), Rogner et al (2012), ARI (2013)	**159**	**193**	**228**	

We calculate the Best estimate as the mean of Pearson et al (2012), Rogner et al (2012) and ARI (2013). We take the estimate from ARI (2013) as High estimate and that from Pearson et al (2012) as Low estimate.

Former Soviet Union

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several		429		
Rogner et al (2012)	Several		2235	3315	
ARI (2013)			438		Russia: "New dedicated chapter." Ukraine: "Added major basin in Ukraine."
This study	McGlade et al (2013), Rogner et al (2012), ARI (2013)	**429**	**1034**	**2235**	

We calculate the Best estimate as a mean of McGlade et al (2013), Rogner et al (2012) and ARI (2013). We take the estimate from Rogner et al (2012) as High estimate and that from McGlade et al (2013) as Low estimate.

India

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several		67		
Rogner et al (2012)	Several		75	112	
ARI (2013)			101		
This study	McGlade et al (2013), Rogner et al (2012), ARI (2013)	**67**	**81**	**101**	

We calculate the Best estimate as a mean of McGlade et al (2013), Rogner et al (2012) and ARI (2013). We take the estimate from McGlade et al (2013) as High estimate and that from ARI (2013) as Low estimate.

Middle East and North Africa

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several	104		1062	
Rogner et al (2012)	Several		298	447	Contained the North African region (NAF) and the Middle East region (MEE)
ARI (2013)			1033		Algeria: "1 basin vs. 7 basins." Lybia: "Higher TOC criterion; moved area to oil. " Egypt: "New dedicated chapter"
This study	McGlade et al (2013), Rogner et al (2012), ARI (2013)	**104**	**665**	**1062**	

We define as Best estimate the mean of Rogner et al (2012), McGlade et al (2013) (midpoint of the low and high estimates) and ARI (2013). For the Low and High estimates we keep those of McGlade et al (2013) as Low estimate.

Other developing Asia

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several	48		818	
Rogner et al (2012)	Several		374	560	Contains the region Other East Asia (OEA), Other South Asia (OSA) and Pacific (PAS)
ARI (2013)			169		
This study	McGlade et al (2013), Rogner et al (2012), ARI (2013)	**48**	**271**	**818**	

We calculate the Best estimate as the mean of Rogner et al (2012) and ARI (2013). For the Low and High estimates we keep those in McGlade et al (2013).

USA

Study	Sources	Low	Best	High	Comment
McGlade et al (2013)	Several	511	714	1766	
Rogner et al (2012)	Several		1863	2683	
EIA (2014)			645		
This study	McGlade et al (2013), Rogner et al (2012), EIA (2014)	**511**	**582**	**1863**	

We take as Best estimate the best-estimate calculated in our study. For the Low estimate we take the one from McGlade et al (2013) whereas for the High estimate we take that reported by Rogner et al (2012).

Western Europe

Study	Sources	Low	Best	High	Comment
Pearson et al (2012)	Several		429		
Rogner et al (2012)	Several		224	336	
ARI (2013)			295		
This study	**see Table 1**	**224**	**316**	**429**	

We take as Best estimate the mean of Rogner et al (2012), Pearson et al (2012) and ARI (2013). For the Low estimates we take the one in Rogner et al (2012) while for the High estimate we take the one in Pearson et al (2012).

Area (A), Percentage of Potential Area (%Pot), Percentage of Untested Area (%Unt)

In this study these estimates are taken from the most recent estimates reported in EIA (2013).

Well drainage, well spacing and well density (WD)

Over a given play the number of potential wells (NPW) is usually computed by multiplying the area of the play with well density and factor accounting for potential interest in the play.

Data has been collected from EIA studies (EIA 2011, EIA, 2012, EIA, 2013) and the resulting NPW is shown in Table 3 for the major US shale plays.

Table 3 Number of Potential Wells in the main US shale gas plays

NPW	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Woodford
EIA, 2011	31211	4451	15844	21151	252531	7621
EIA, 2012		21285	10181	24627	90216	5428
EIA, 2013	37126	31860	10927	18895	91400	5568

Estimated ultimate recovery (EUR)

We rely extensively on a comprehensive and publically available EUR dataset reported by USGS (2012) as well as data from EIA (2011). Both reports provide EUR distributions across plays. For most shale gas play across the US, truncated log-normal EUR distributions are provided. Other publications mention only averaged EUR (Nome and Johnston 2008, Jacoby et al 2012, EIA 2012, EIA, 2013). We extend this dataset by using updated data from EIA (2013). A compilation of EUR means are displayed in Table 4 for the main shale plays.

It is interesting to note the decrease in average EUR per well between the EIA studies in 2011, 2012, 2013 and 2014.

Table 4 Estimated Ultimate Recovery in the main US shale gas plays

EUR (Bcf/well)	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Woodford
Nome and Johnston, 2008	4.3 (2.4)	-	2.3	7.0	3.3	4.5
Baihly et al, 2011	3.0	3.8	1.4	5.9	-	1.7
EIA, 2011	1.6 (1.2)	5.5	West: 1.15 Central: 2.25	6.5 (1.5)	3.5 (1.15)	4.0
EIA, 2012	-	2.36	1.3	2.67	1.56	2.89
Sandrea, 2012	1.3	-	1.1	3.0	1.2	3.0
USGS, 2012	0.334 - 1	1.104	West: 0.47 Central. 1.104	2.617	0.129 - 1.158	0.785 – 1.233
EIA, 2013	1.59	1.95	West: 0.93 Central: 2.16	4.16	0.13 – 2.07	2.87
EIA, 2014	Core: 1.615 Rest: 0.192 - 0.627	0.212 – 1.786	West: 0.843 Central: 1.444	3.138 – 3.709	0.257 – 1.589	1.422

Initial decline rate (D_0)

The Society of Petroleum Engineers identifies initial decline rates of shale wells to range between 30%/yr and 80%/yr or more (SPE 2011). They do not specify however well technology. Jacoby et al (2012) states that "shale wells do show high early decline rates, in some cases by 60–80% in the first year". This statement is further confirmed by values reported in Nome and Johnston (2008) and EIA (2011) (see Table 5).

Swindell (2012) looked at more than 1000 horizontal wells in the Eagle Ford play and he calculated an averaged normalized decline rate of 60%/yr for shale gas wells with values ranging between 51%/yr and 85%/yr.

In this study we assume initial decline rates to range between 50%/yr and 85%/yr with a best estimate of 70%/yr.

Table 5 Initial decline rate in the main US shale gas plays

D_0 (%/yr)	Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Nome and Johnston, 2008	68 (65)	62	80	65	66
EIA, 2011	70	-	82	75	-

Hyperbolic exponent (b)

The hyperbolic exponent has been subject to much criticism since its value affects EUR and so TRR. Using large *b* values may indeed lead to an overestimation of TRR.

The Society of Petroleum Engineers defines in its guidelines that an appropriate value for b could range between 0 and 1.5 (SPE 2011). A study of 1957 wells in the major US shale plays (Barnett, Fayetteville, Haynesville, Eagle Ford and Woodford) indicates that values above 1 may be appropriate in some cases (Baihly et al 2010).

In the case of the Barnett play, a study focusing on about 8700 wells showed that b values range between 1.3 and 1.6 with a mean values of 1.5 (Fan et al 2011).

In this study, we take a best estimate of 1.1 and lower and upper estimates of 0.5 and 1.5 respectively for all plays except the Barnett where we use the values reported by Fan et al (2011). Estimates in the major US shale gas plays are reported in Table 6.

Table 6 Hyperbolic factor in the main US shale gas plays

b	Barnett	Eagle Ford	Fayetteville	Haynesville	Woodford
Baihly et al., 2011	1.6	1.7	0.6	1.2	0.8

Investment costs (IC)

Investment costs were compiled from presentations to investors and annual reports (see Table 7). We found information for 13 plays out of the 19 plays listed in the EIA report. When data were missing we used a value of $MM 5. Moreover we assume that well costs range between $MM 3 and $MM 10.

In addition, Pearson et al (2012) reports that "drilling cost reduction in the order of 30-60% are judged feasible". No estimate could be found regarding potential increases in drilling costs. We assume here a maximum cost increase of 50%.

Table 7 Investment costs in the main US shale gas plays

IC (million US$)	Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Nome and Johnston, 2008	3.10	3.20	7.00	3.75	6.70
Baihly et al., 2011	3.00	2.80	8.00	-	6.70
EIA, 2011	2.00 – 3.00	1.75 – 3.05	6.00 – 7.00	3.00 – 4.00	4.60 – 8.00
Sandrea, 2012	3.5	2.8	9.5	6.0	7.00
This study	*3.28*	*2.67*	*8.00*	*5.20*	*7.15*

Operation and Maintenance costs (OMC)

Data on operation and maintenance costs are relatively scarce. Nome and Johnston (2008) and Baihly et al (2011) report them for the major US shale plays (Barnett, Eagle Ford, Fayetteville, Haynesville, Marcellus and Woodford). These vary between 0.70 $/mcf and 2.50 $/mcf (see Table 9). We assume here a best estimate of 1.35 $/mcf based on the averaged costs across these 6 plays.

Table 5 Operation and maintenance costs in the main US shale gas plays

OMC ($/mcf)	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus	Woodford
Nome and Johnston, 2008	1.85	-	1.30	1.50	0.90	1.25
Baihly et al., 2011	0.70	1.50	1.10	2.50	-	1.15
This study	*1.28*	*1.50*	*1.20*	*2.00*	*0.90*	*1.20*

Discount rate (r)

USGS usually employs a 12% annual discount rate for the oil and gas extracting industry (Attanasi and Freeman 2010, 2011). Other authors rely often on the concept of internal rate of return or return on investment which range between 10% and 20% or more (Almadani 2010, Jacoby et al 2012, Medlock et al 2012, Duman 2012)

Here we assume 12% to be the best estimate and 10% and 15% to be the lower and upper estimates respectively.

Well's lifetime (T)

This parameter is highly uncertain since the history of shale gas production is too recent and different for each shale play. In addition it is not often reported in studies. In the JRC report, a calculation was done assuming a 30-year lifetime in the Barnett shale play (Pearson et al 2012). Baihly et al (2011) reported EUR with a 30-year lifetime. Duman (2012) used a 10-year and 20-year time frames in the Marcellus shale play.

In addition, a couple of 10-year type curves displayed in ARI (2011) indicate that up to 80% of the gas is extracted after 10 years.

More recently, Browning et al (2013) showed that well lifetime varies significantly across the Barnett shale play with tier-averaged values ranging between 2 and 25 years.

Here we assume a value of 2 years for the lower estimate and 30 years for the upper estimate. Our best estimate is 10 years. We use these assumptions for all plays except the Barnett where we use the range of values from Browning et al (2013).

Sensitivity analysis

The Barnett shale play is the cradle of birth of the US shale gas boom. This shale play has the longest data record. We perform a sensitivity analysis in two steps, first on the techno-economic parameters related to the modified Arps equation and next on the rest of the parameters (LCOG equation).

Sensitivity to modified Arps parameters

A sensitivity study on the parameters reveals that taking smaller values for *b* or *T* (or increasing D_0) would move the function the black curve on Figure 2 downwards and would likely improve the matching between these two distributions. Interestingly, the hyperbolic exponent *b* does not seem to have a large influence. An explanation for this is simply that the implied well lifetime of 7.5 years is quite small and so is the range of *b* values (1.3 and 1.6). An additional point of interest is that the curve becomes increasingly non-linear with increasing and decreasing parameter values. This feature would likely modify the standard deviation of the computed distribution. Overall, these results suggest that either the EUR distribution provided by EIA (2011) could be based on a different set of data or those data limitations that oblige us to keep *b*, D_0 and *T* constant for a given *EUR* leads to biased results. Another explanation could also be that it is still too early to calculate robust *b* values and that *b* values smaller than the current minimum of 1.3 should be used instead. The lack of data leads to significant uncertainties that prevent us from being conclusive on this point.

It is interesting to look at differences between q_0 distributions. The distribution of initial production rates in the Barnett over the period 2005 to 2009 was reported in Jacoby et al (2012) and is displayed in orange in the background of Figure 2. We then compute a q_0 distribution by taking the inverse of equation (3). As expected, the resulting distribution is overall in good agreement with the observations thanks to the calibration process. It is however skewed to the left and misses out the very high initial production rates contained in the fat tail, as well as the very low initial production rates.

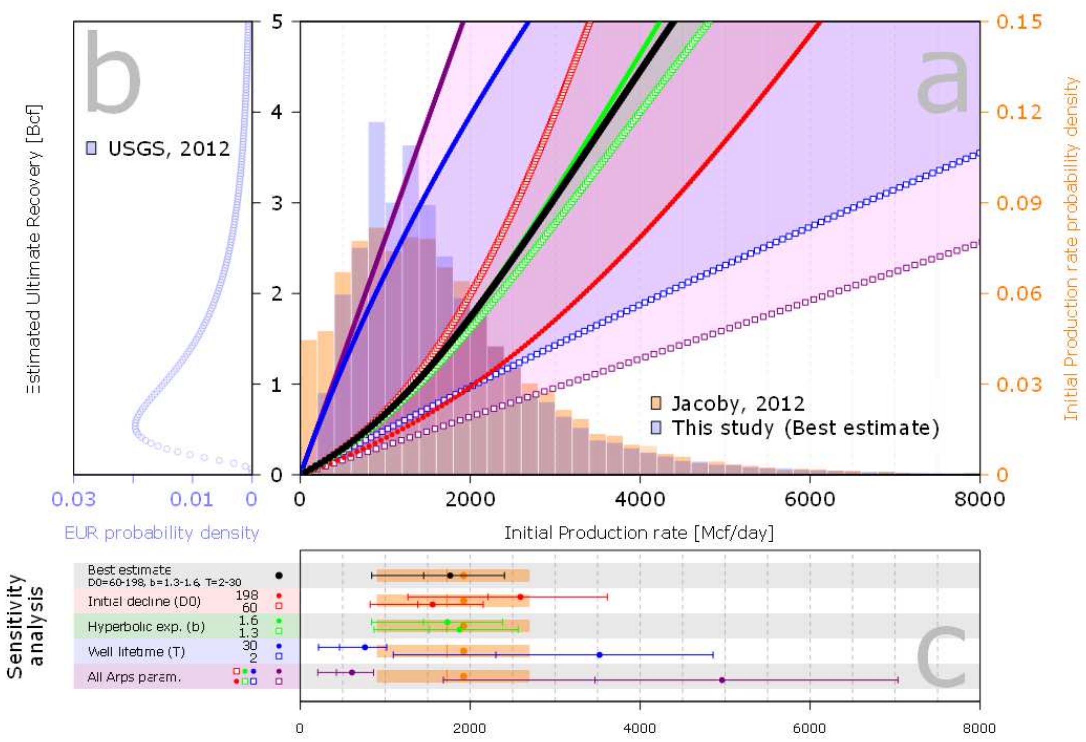


Figure 1 Sensitivity analysis of decline curve analysis in the Barnett play. The two light blue histograms represent the probability density of q0 and EUR as computed by the tool in the best case. The orange histogram displays the observed

IP rates as reported by Jacoby et al (2012). The black line represents the best case whereas the dashed lines represent the lower and upper bound of the range of values reported in the literature for D0 (red), b (green) and T (blue). The purple curves and areas correspond to extreme cases in which all parameters were switched to their lower or upper estimates. The black triangles on panels (a) and (b) indicate the data points provided in EIA (2011).

Sensitivity to LCOG parameters

We then perform a sensitivity analysis on these economic parameters (Figure 3). As expected, an increase in *IC* and/or *OMC* shifts the curve upwards (green and yellow curves). A counter-intuitive result is the increasing extraction costs resulting from increasing well lifetimes. This unexpected behavior is driven by the fact that in our fitting technique, an increase of the parameter *T* requires a decrease of gas flow rates in order to match the prescribed EUR. Although this feature may appear unrealistic, it simply explains the fact that extraction is continued somewhat longer in case of higher gas prices (which in this framework equal LCOGs). Finally, the purple area represents the overall uncertainty range when all parameters are moved to their extremes. It is worthwhile to note that the variation of the discount rate is negligible because the decline rate of gas flow is much higher than the assumed discount rates.

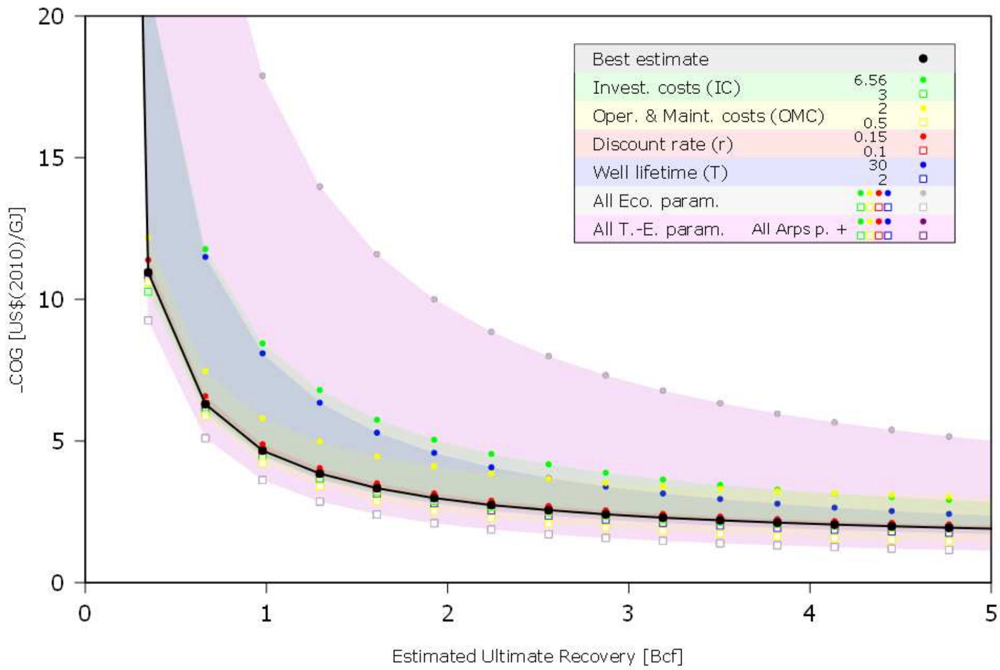


Figure 2 Sensitivity analysis of the LCOG formula. The histogram in light blue color represents the EUR distribution from EIA (2011). The black curve represents the best-estimate LCOG output from the tool. Uncertainty ranges for IC, OMC, r and T parameters are depicted in green, yellow, red and blue respectively. The uncertainty range corresponding to a change in all economic parameters is displayed in grey whereas that combining geophysical and economic parameters is shown in violet. The black triangles indicate the data points provided in EIA (2011).

CECF regressions

As mentioned in the main text we fit 3rd-order polynomials to our CECFs in order to facilitate the utilization of our curves. This regression takes the following form:

$$Q^{norm} = a_0 + a_1 C + a_2 C^2 + a_3 C^3$$

where Q^{norm} is the normalized TRR and C is the LCOG (see Fig. 3 in the main text).

Case	a_0	a_1	a_2	a_3
Best-estimate	-4.45e-1	2.88e-1	-2.20e-2	5.90e-4
Lower estimate	-1.29e-1	4.32e-1	-7.87e-3	4.65e-4
Upper estimate	-4.60e-1	3.58e-1	-3.12e-2	9.26e-4

Unit conversion

1 cubic feet of natural gas = 1.055 MJ (Rogner et al 2012)

1 cubic feet of natural gas = 35.31 cubic meter of gas (Rogner et al 2012)

Glossary

Model parameters and variables

Acronym	Stands for...	Description
b	Hyperbolic factor	Factor used in the modified Arps equation (2).
D0	Initial decline rate	Factor used in the modified Arps equation (2).
CECF	Cumulative Extraction Cost Function	Mathematical function that relates cumulative extraction to marginal extraction costs in a given region.
ERR	Economic Recoverable Resources	Same as TRR but account for economic factors. (in this study we do not include the effect of tax and royalties)
EUR	Estimated Ultimate Recovery	The expected amount of resources to be produced from a single well. Used in equation (2).
LCOG	Levelized Cost Of Gas	Unit cost of producing one unit of energy including all costs over the well lifetime. Result of equation (3).
TRR	Technically Recoverable Resources	The amount of resources that can be produced over an area (e.g. shale play) with currently existing technologies, discarding any economic factor. Result of equation (4)
IC	investment costs	In this study investment costs are represented by average well costs. Used in equation (3).
OMC	Operation and Maintenance costs	In this study operation and maintenance costs include field operating costs and transportation costs. Used in equation (3).
r	Discount rate	Used in equation (3).
A	Area	Shale play area. Used in equation (1).
WD	Well Density	Used in equation (1).
%Pot	Percentage of Potential area	Used in equation (1).

%Unt	Percentage of Untested area	Used in equation (1).

Institutions

Acronym	Stands for…
EIA	Energy Information Administration
USGS	United States Geological Survey
IEA	International Energy Agency

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EIA 2013b, Technically Recoverable Shale Oil and Shale Gas resources: An Assessment of 137 Shale Formations in 41 Countries outside the United States, a report prepared by ARI for the Energy Information Administration, Washington, USA

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Appendix A: Investment Costs estimates

The list of documents reviewed to estimate investment costs is given below.

1. EIA[2011] - ReviewOfEmergingResources.pdf
2. AnadarkoPetroleumCorp - [11-2012] - 111312APC_BOA Appendix.pdf
3. ConchoResources - [11-2012] - November Investor Presentation VFinal2.pdf (slide 14)
4. ClimarexEnergy - [11-2012] - BAML Global Energy Conf Miami.pdf
5. DevonEnergy - [2011] - DVN_2011AR_Full.pdf (own calculations from p. 14, p. 92)
6. Abraxas - [11-2012] - Presentation Stephens 11-6-12 v2.pdf
7. Baytex - [11-2012] - November Corporate Handout - Nov 15.pdf
8. Continental Resources - [11-2012] - 1pm 3Q12 Investor Presentation as of 11 9 12.pdf

9. GMX Resources - [10-2012] - Johnson+Rice+2012.pdf
10. Halcon - [10-2012] - Halcon Elephant Rollout_vFINAL6.pdf
11. Chesapeake Energy Corp. - [2012] - Annual_Report_2011.pdf
12. http://info.drillinginfo.com/urb/barnett/uncategorized/2012/07/barnett-showing-some-gray-yet-still-providing-opportunity/
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26. Carrizo Oil&Gas Inc. - [11-2012] - Stephens, Inc. 2012 Fall Investment Conference.pdf
27. ZaZA - [12-2012] - ZaZa Investor Presentation to Capital One Southcoast 2012 Energy Conference.pdf
28. Halcon - [08-2012] - EnerCom_Halcon_vFINAL2.pdf
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