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Methods of estimating shale gas resources – Comparison, evaluation and implications

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ABSTRACT

Estimates of technically recoverable shale gas resources remain highly uncertain, even in regions with a relatively long history of shale gas production. This paper examines the reasons for these uncertainties, focussing in particular on the methods used to derive resource estimates. Such estimates can be based upon the extrapolation of previous production experience in developed areas, or from the geological appraisal of undeveloped areas. The paper assesses the strengths and weaknesses of these methods, the level of uncertainty in the results and the implications of this for current policy debates. We conclude that there are substantial difficulties in assessing the recoverable volumes of shale gas and that current resource estimates should be treated with considerable caution. Most existing studies lack transparency or a rigorous approach to assessing uncertainty and provide estimates that are highly sensitive to key variables that are poorly defined - such as the assumed ratio of gas-in-place to recovered gas (the 'recovery factor') and the assumed ultimate recovery from individual wells. To illustrate the uncertainties both within and between different methodological approaches, we provide case studies of resource estimates for the Marcellus shale in the US and three basins in India.
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1. Introduction

It is increasingly claimed that the world is entering a 'golden age of gas', with the exploitation of unconventional resources, and in particular shale gas, expected to transform gas markets around the world [1]. This expectation is based upon recent experience in the United States, where the unprecedented growth in production over the last five years has led to oversupply and a collapse in prices. But the future development of shale gas is subject to multiple physical, technical, economic and political uncertainties, including the size and recoverability of the physical resource. Whilst estimates of shale gas resources in the United States remain uncertain, this is eclipsed by the greater uncertainty surrounding these resources in the rest of the world.

The number of studies producing resource estimates for shale gas has proliferated in recent years, paralleling the rapid growth in North American shale gas production (Fig. 1). While the majority of these estimates refer to the United States, an increasing number of estimates are being produced for other countries and regions. As demonstrated by McGlade et al. [2], the wide variation in these estimates has contributed to the vigorous debate on the future potential for shale gas. While there has been a general upward trend in US resource estimates, this is not necessarily the case for individual shale plays[1] or for other regions of the world.

Much of the variation in published estimates may be a function of the rapid advances in shale gas extraction over the past few years, and the limited production history that is available for analysis. Another challenge is the proprietary nature of much of the data required for third party assessment of resource estimates. However, this paper focuses on the methodological issues which may contribute significantly to the variation observed in such estimates.

A notable example of this uncertainty is the recent controversy surrounding resource estimates for the Marcellus shale in the United States [5]. While the confusion over these estimates derives in part from the use of inconsistent terminology and definitions, a more important contributor is the significant differences between resource estimation methods and the widely varying assumptions that have been employed [2]. In this context, a more careful examination of these methods and assumptions can be useful.

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[1] A geological play is defined as '*A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type*' [3].

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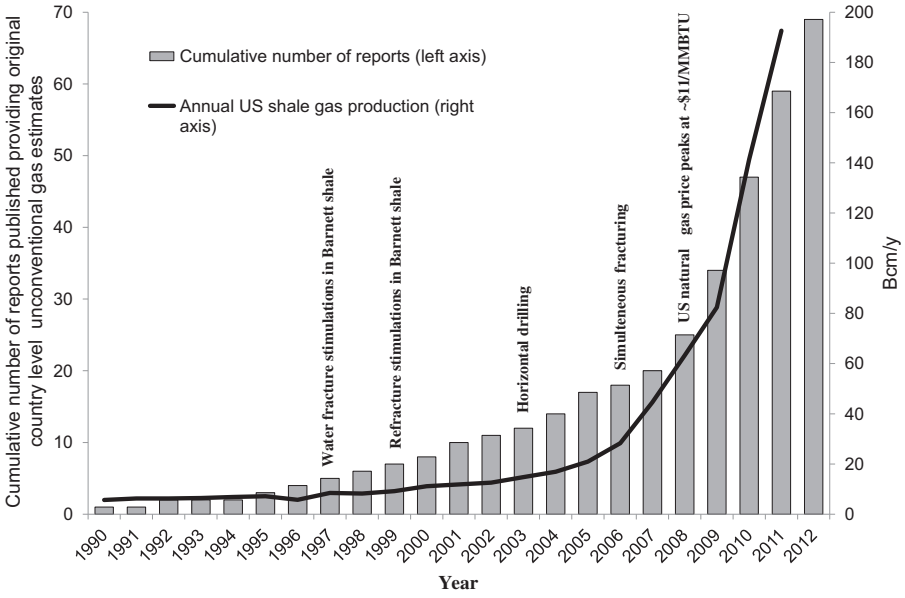

Fig. 1. Cumulative number of reports published providing original country-level estimates of any of the unconventional gases, and annual US shale gas production. Source: [4,5].

Studies of the Marcellus and other regions typically produce estimates of the TRR (Technically Recoverable Resources) of shale gas, but they rarely provide complete and clear definitions of what this means. The TRR is usually regarded as the volume of gas recoverable with current technology, with both future technological advances and economic factors being disregarded [6–8]. Estimates of TRR therefore differ (in principle) from estimates of the URR (Ultimately Recoverable Resources) of shale gas, since the latter refers to the amount of gas that will be produced over the full production cycle and therefore implicitly reflects both economic considerations and future technological change. However, at the current stage of development of the shale gas resource these distinctions have little meaning – with the range of uncertainty over individual estimates of TRR or URR tending to eclipse any differences between them.

Three broad approaches are commonly used to generate estimates of shale gas TRR, namely: a) literature review/adaptation of existing literature; b) bottom up analysis of geological parameters; and c) extrapolation of production experience through the use of DCA (Decline Curve Analysis) (Fig. 2). Crossover between these approaches is common, with several reports employing and combining more than one approach. In what follows, we investigate the strengths and weaknesses of each approach and illustrate these issues by means of two case studies. Section 2 briefly describes each of the methods while Section 3 assesses their robustness, looking both at the factors that affect all methods and the specific uncertainties affecting each. Section 4 uses a case study of the Marcellus shale to examine the uncertainties associated with the extrapolation methods, and a case study of three Indian shale plays to investigate the differences between the geological and extrapolation methods. Section 5 concludes by highlighting some of the implications. The discussion is based upon a comprehensive review of over 50 studies, summarised in detail in McGlade et al. [2].

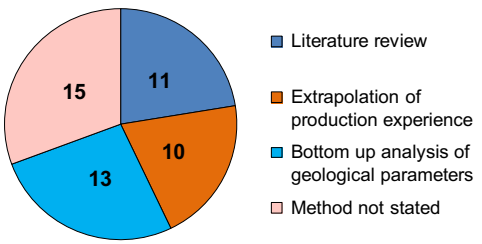

Fig. 2. Approaches used by reports providing original country level shale gas resource estimates. Note: Annual Energy Outlooks from the US Energy information Administration are only included once.

2. Description of methods

2.1. Literature review/adaption of existing literature

A number of studies rely upon resource estimates made by others and collate or adapt these to determine their own estimates. Some studies, for example MIT [7] and Mohr and Evans [9,10], analyse a number of estimates and use the variation between these to identify a range of uncertainty for regional or country values. Others conduct literature reviews but augment this data with additional primary research. Navigant Consulting [11], for example, conducted a survey of natural gas producers and used this to provide a higher bound on its resource estimates (termed the 'maximum reported' estimate) for each shale play in the US. The World Energy Council [12] appears to have used a literature review, but provides no description of its methodology other than noting that the 'most credible studies' were used. It also does not provide details of the literature referred to other than the names of the organisations that produced the estimates. This lack of transparency is an unfortunate feature of much of the relevant literature.

An alternative approach is followed by Medlock et al. [13] who indicate that they use 'peer-reviewed, scientific assessments of the properties of shales to develop technically recoverable resources', but do not cite the relevant sources.[2] For regions outside the US,

[2] Medlock et al. [12] state that '…the resource data derives from sources such as the Oil and Gas Journal (OGJ), U.S Geological Survey (USGS), National Petroleum Council (NPC), Australian Bureau of Agriculture and Resource Economics (ABARE), and Baker Institute research on unconventional resources in North America and globally'.

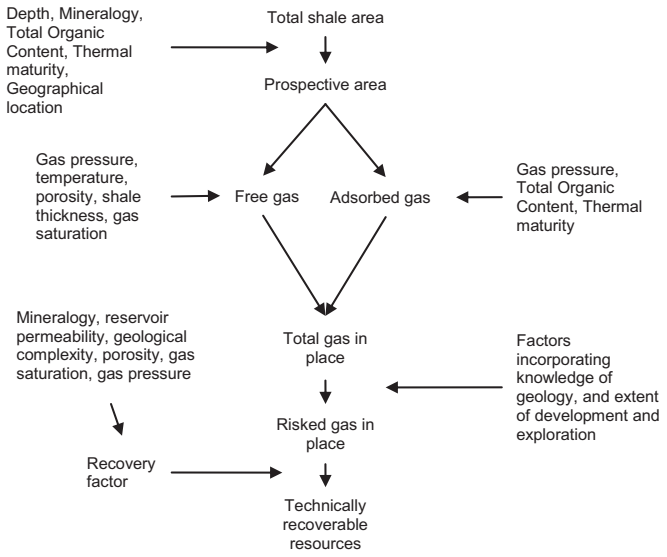

Fig. 3. Schematic representation of the steps used in the geological based approach. Source: Adapted from Ref. [14].

most literature reviews rely heavily upon the estimates generated by ARI (Advanced Resources International) [14] (see below), but several studies modify the resource estimates for individual countries [15,16].

2.2. Bottom up analysis of geological parameters

This approach is most appropriate for providing resource estimates for undeveloped regions. For example, ARI [14] employ this approach to estimate the volumes of gas that exist in shale plays around the world for which there is little or no drilling or production data. The method relies upon geological appraisals of the extent and characteristics of the shale rock to estimate the volume of shale gas that is present (the OGIP (Original Gas in Place)). A percentage 'recovery factor' is then applied to this figure to produce an estimate of the TRR (Fig. 3).

A large number of parameters must be estimated or calculated when using such methods to determine recoverable volumes of gas. These include the area or volume of shale rock, the total organic content (measured as a percentage of the total weight), the minerals (clay/quartz etc.) contained within the shale and the gas pressure (Fig. 3). A number of these parameters are used at more than one stage of the process. There are also some parameters whose estimation, although informed by technical and geological knowledge, is necessarily subjective. For example, ARI [14] introduces two parameters called success factors that convert the original estimate of OGIP into a lower, 'risked' estimate of OGIP.[3] Another key parameter is the recovery factor, reflecting the estimated proportion of (risked) OGIP that is considered to be technically recoverable. The recovery factor is commonly established on the basis of the shale mineralogy, properties of the reservoir[4] and the geological complexity [14]. The values chosen typically lie in the range 20–30%, although factors as high as 35% or as low as 15% may sometimes be employed. For comparison, recovery factors for conventional gas can be as high as 80%.

2.3. Extrapolation of production experience

This approach is more suitable for producing resource estimates for developed regions where production is relatively advanced. It relies upon analysing the production experience in the region and then extrapolating these results to either undeveloped areas of the same shale or to new shales. There are two general methods employed. The first, commonly applied at the play level, is to estimate either the OGIP or the TRR, by multiplying the estimated shale play area (or mass) by an estimated yield per square area (or mass). The yield per unit area is often called the productivity and measured in million cubic metres per square kilometre (mcm/km^2). For undeveloped shale play areas, the values for such calculations are typically based upon historical production experience or estimates from geologically similar regions (analogues) where more information is available. Rogner [17] for example, produced estimates for multiple regions around the world using a single analogue of the gas in place per tonne of shale in the United States. Despite this relatively crude methodology, these estimates formed the basis of nearly all estimates of shale gas resources outside North America until 2009.

The second method is more complex and is likely to be more accurate. The investigated area is split into more and less productive sectors, and more precise estimates of gas yields per unit area for each sector are determined using a greater number of parameters. The most important of these are the EUR (Estimated Ultimate Recovery)[5] per well and the average well spacing (no. of wells per unit area). Production from unconventional gas wells typically declines very rapidly after start-up and estimates of the EUR/well can be derived by statistically fitting a declining curve to the historical production from a well or group of wells and extrapolating this forward into the future (DCA) [18]. This approach is only applicable in regions where production is relatively well established and requires a significant amount of data on historic production from multiple wells.

3. Methodological robustness of each method

We begin by looking at some issues that affect all shale gas resource estimates and then examine the specific uncertainties affecting each estimation method.

3.1. Uncertainties affecting all approaches

There is growing evidence that shale plays are highly heterogeneous, with some areas being more productive than others [19,20]. A frequent distinction is made between the most productive areas (commonly termed 'sweet spots') and the less productive areas ('non-sweet spots') with the former providing considerably higher production flow rates and ultimate recovery from individual wells. There is also significant variation in the productivity of wells within sweet spot areas, although this distinction partly depends on how sweet spots are defined [19,21].

The frequency, extent, and degree of variation between (and within) sweet-spots and other areas remains uncertain, even in

[3] These factors are the 'play success probability factor', which represents the probability that the play will be developed (based on whether suitably high flow rates will be achieved), and … the 'prospective area success factor', which represents the level of geological knowledge of the play, and the probability that there will not be any geological complications or problems in the prospective area that would reduce the volumes of gas present.

[4] Reservoir properties are factors such as the porosity of the reservoir rocks, the relative permeability, and the extent to which these pores filled with gas rather than water (the gas saturation) [13].

[5] The industry standard term for discussing the ultimate recovery from an individual well is the EUR usually denoted EUR/well and also sometimes referred to as the 'productivity'. EUR is essentially identical to the URR, although the term URR is usually preferred when referring to areas or regions.

Table 1
Breakdown and comparison of figures used in estimates of technically recoverable resources from the Marcellus shale.

Source	Engelder			INTEK	USGS			EIA
	P90	P50	P10		P95	Mean	P5	
Total area (km^2)	189,932	189,932	189,932	245,772	260,982	269,521	280,367	269,521
Area divisions	6	6	6	2	6	6	6	6
% Sweet spot	45.1%	45.1%	45.1%	11.2%	11.0%	18.0%	33.1%	18.0%
Sweet spot								
Area (km^2)	85,749	85,749	85,749	27,511	28,757	48,514	92,745	48,514
% Area contributing	70%	70%	70%	100%	100%	100%	100%	100%
Well spacing (wells/km^2)	3.09	3.09	3.09	3.09	1.50	1.87	3.62	1.87
EUR/well (mcm/well)	26.0	58.4	101.5	99.2	4.8	26.3	79.2	44.2
Success factor	Not used			60%	Not used			Not used
Yield (mcm/km^2)	80.2	180.4	313.7	183.8		49.2		82.8
TRR (Tcm)	4.82	10.83	18.83	5.06	1.22	2.39	4.08	4.01
Non-sweet spot								
Area (km^2)	104,182	104,182	104,182	218,261	232,225	194,055	187,622	194,055
% Area contributing	70%	70%	70%	100%	100%			100%
Well spacing (wells/km^2)	3.09	3.09	3.09	3.09	Not assessed			
EUR/well (mcm/well)	6.4	13.5	25.5	32.6				
Success factor	Not used			30%				
Yield (mcm/km^2)	19.7	41.8	78.9	30.2				
TRR (Tcm)	1.436	3.044	5.744	6.589				

It was possible only to calculate approximately the constituent factors of Engleder's estimate as all of the necessary information for this was not supplied; however the averages provided above match the breakdown of estimates and graphical data provided.
Sources: [5,23,45–47].

comparatively well developed shales. As a consequence, resource estimates are sensitive to whether and how the region is disaggregated into more and less productive areas. Some studies e.g. [17, 22] do not make such a distinction and ignore sweet spots altogether. Others (e.g. ARI) reduce the total area of a shale play to a 'prospective area' but do not differentiate this further into sweet and non-sweet spot areas [14].

To date, shale gas production in North America has predominantly focused upon these most productive areas within each play. Assuming that comparable production rates will be experienced across the remainder of the play could potentially lead to significant overestimates of the TRR. The large areal extent of many shale plays means that inadequate delineation could have a major effect on the estimated resource size. To mitigate this risk, the USGS (United States Geological Survey) first splits shale plays into a number of smaller assessment units and employs a probabilistic approach to provide a range of estimates for the ratio of sweet spot area to non-sweet spot area across each assessment unit [7,32,44]. This source of uncertainty should reduce as production experience accumulates and the nature and degree of variation between different regions becomes clearer. It demonstrates, however, the critical importance of delineating shale gas plays when conducting resource assessments.

A related problem is the validity of assumptions for EUR/well, well spacing, and/or geological parameters in areas outside those from which production is currently taking place (see Table 1). Even though assumptions for these areas are necessary to estimate the resource potential of a whole shale play, the level of confidence in these assumptions is significantly lower than that for developed areas. But despite concerns regarding the validity of the assumptions used, sensitivity analysis appears to be the exception rather than the rule.

A key weakness of existing resource estimates is the absence of a rigorous approach to handling uncertainty. While some studies mention uncertainty in passing [5,13,14,23], or give a range in final resource estimates [24–26], few studies provide a thorough analysis of the sources and consequences of uncertainty or present their results in the form of a probability distribution. Studies using the geological approach are particularly poor in this regard, but there is no reason why the uncertainties in individual geological parameters (particularly those used more than once or which are especially uncertain such as the areal extent of the shale), cannot be estimated, stated and accounted for. Use of statistical distributions can be simple, but nevertheless effective: the USGS, for example, assigns a range to all of the relevant variables studied, assumes a triangular (or similar) probability distribution across each range, and combines these using a simple random sampling technique [7].[6]

A final issue is the potential for future technical change to increase resource estimates. Most contemporary studies estimate the TRR, which explicitly excludes the adoption of future technologies, but arguably a more useful measure is the URR which takes this into account. Sources providing estimates of the URR should in principle allow for future technical change. In doing so, it is important to remember that previous forecasts of the potential impact of technological improvements failed to anticipate the increase in EUR/well that has occurred since the 1980s: Technological progress, even if only leading to a small increase in EUR/well or recovery factor, can have a significant impact on the estimated URR. On the other hand, while it is impossible to rule out future major technological breakthroughs, the technologies currently being used for shale gas extraction are now better understood, having been more widely studied and utilised than previously.

Technology can also play a crucial role in increasing the economic viability of shale gas production, but at present there are

[6] The USGS approach to uncertainty is not exclusive to unconventional resources but is also commonly applied to other petroleum resources such as conventional oil and gas [3,62].

far fewer estimates of the economically recoverable resources (i.e. estimates of the resource available with current technology and in current economic conditions) than the TRR [27]. One exception is Medlock [15], who uses an econometric approach to estimate the production costs of shale gas in a number of basins worldwide. He finds that, of the 170 Tcm estimated to be technically recoverable globally; around two thirds should be economically viable at costs of less than $\$0.35/m^3$ ($10/million BTU). This suggests that technological improvements could play an important role in increasing the volumes that can be considered economically recoverable.

Since shale geology is now better understood than previously, the potential impact of future technological improvements, both on the technically recoverable resource and the subset of these that are economically viable at different assumed gas prices, may be easier to characterise.

3.2. Literature review/adaptation of existing literature

Studies relying upon literature reviews draw upon information from a variety of sources and hence from a variety of methods of resource estimation, and so remove some of the uncertainty over the choice of method. They also appear more likely to quantitatively estimate the uncertainty in their final resource figures.

On the other hand, most literature reviews appear to use subjective judgements regarding which studies to include and the relative weight to be given to each study. Most studies provide insufficient clarity over the extent to which and reasons why certain sources have been favoured over others, or on how the quoted literature has been used. MIT [28] for example, cites ICF, USGS and the NPC (National Petroleum Council) as the sources used for its unconventional gas estimates. But while the mean value chosen by MIT for US shale gas corresponds to the values used by ICF, it is unclear how MIT's estimates for its P10 and P90 volumes of shale gas rely upon the USGS and NPC figures.

3.3. Bottom up analysis of geological parameters

The geological approach employs well-known and well-understood equations to estimate the volumes of free and adsorbed[7] gas in place. A number of problems exist however.

The first and perhaps the most important is the inherent subjectivity in choosing the recovery factor to apply to the estimated gas in place and the limited evidence on which this choice is based. It was for this reason that the USGS chose not to use this approach stating: 'the estimation of an overall recovery factor must sometimes be quite qualitative'. ARI [14] attempted to remove some of the subjectivity in its estimates of recovery factors, which lay between 20 and 30% in most circumstances, by linking this to the mineralogy of the sources rocks. However, recovery factors of 15–40% have been used by other authors [10,29,30], while Strickland et al. [21] report that in some instances recoveries can be as low as 1–2%. In addition the more subjective factors that convert the 'total' OGIP to a 'risked' OGIP can have a major affect on the estimated volumes of recoverable gas. The play success probability factor estimated by ARI [14] ranged from 30% to 100% while the prospective area success factor ranged from 20% to 75%. When OGIP volumes are large, the product of these three uncertain factors corresponds to a significant range of uncertainty in the technically recoverable resource (assuming the gas in place can be established with any confidence). While it is generally accepted that estimating recovery factors is challenging, little progress appears to have been made in establishing such factors for shale, even when the geology is well understood.

An additional problem relates to the estimation of the geological variables required for this method. It is important to remember that data may only be available for a subset of these, and for unexplored shale plays such estimates must necessarily have large confidence bounds. Hubbert [31] remarked that for conventional petroleum resource estimates: 'it is easy to show that no geological information exists other than that provided by drilling … that has a range of uncertainty of less than several orders of magnitude'. Even when exploratory drilling has taken place, the range of uncertainty may still be wide. For example, it is often difficult to estimate the gas saturation[8] from well-log data, a key parameter in the estimation of the gas in place [32,33]. This is particularly problematic given that most sources do not explicitly assess and state the uncertainties in values assumed or in the final resource figures produced.

In principle, extensive drilling is the only reliable means of assessing the extent and volumes of shale gas that exists as can be seen by the large number of wells that have been drilled outside the sweet spot areas within the United States. This shows that the productivity of these areas can vary enormously and, although displaying some correlation with parameters such as the shale thickness, is not really known until drilling is well underway [19,34].

3.4. Extrapolation of production experience

This approach avoids some of the above problems but unfortunately introduces some more, one of which is currently controversial. Given the wide variation in the productivity of shale plays, a key problem with the simple analogue-based approach is the appropriate choice of analogue. For example, the productivity of the analogues used by the UK DECC (Department of Energy and Climate Change) varies by a factor of ten [22]. The USGS [34] suggested using a probabilistic approach with more than one analogue to reduce this problem, which appears to be a sensible approach given the uncertainties that exist. For this reason, studies relying upon simple analogue extrapolation are best viewed as providing preliminary estimates of resource potential.

Studies using more detailed extrapolation approaches should provide more reliable resource estimates. However, a key issue here is the appropriate methodology for estimating the EUR from individual wells. Production from shale gas wells declines continuously and rapidly within a month or two of initial production, with the rate of production frequently declining by as much as 50% within one year. Higher rates of production decline lead to a shorter production life and a lower ultimate recovery. But with only 2–3 years of production experience, it is difficult to know whether production will continue to decline at the same rate, or whether the rate of decline will slow in the future. Different choices are available for the 'shape' and rate of future production decline and these different choices can lead to significantly different estimates of the EUR/well. Commentators such as Berman [35,36] have suggested that future decline rates have been underestimated in the US and that, as a result, both well longevity and EUR/well have been overestimated. However, other commentators contest this interpretation and point to the impressive recent history of shale gas production as evidence that future estimates are realistic [37]. This has lead to a public and politicised debate [36–39].

Production decline is commonly modelled by either a negative exponential 'decline curve', which has a constant rate of decline, or a

[7] Adsorbed gas refers to gas molecules which have formed some adhesion to the solid surface of the medium in which it is contained.

[8] The gas saturation is the fraction of the porosity of the shales filled with gas rather than water.

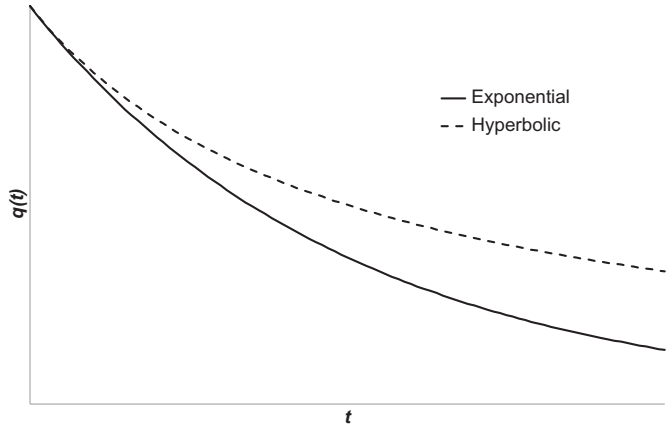

Fig. 4. Exponential and hyperbolic decline curves with equal initial production and decline rate.

hyperbolic decline curve which has a rate of decline that reduces over time (Fig. 4). The parameters for these curves are usually derived by statistically fitting such curves to historical production data, with the key parameter being termed the 'b constant' [18,40]. Larger values of b imply slower rates of production decline and larger ultimate recovery (Fig. 5). Data on shale gas decline rates is sparse given their commercial sensitivity, but b constants between 1.4 and 1.6 have been used by shale gas companies currently active in the US [41].

There is some support in the current literature for b constants in this range: for example, data from 8700 horizontal wells in the US Barnett Shale were best fit to hyperbolic decline curves with b values ranging from 1.3 to 1.6, and a mean of 1.5 [42]. Additionally, analysis of 1957 horizontal wells in the Barnett, Fayetteville, Woodford, Haynesville and Eagle Ford shale plays [43] suggests that while the data does not always support b constants as high as 1.4, values exceeding unity are realistic in shale gas plays.

A different view is provided by Berman [36] who discusses an analysis by Chesapeake Energy of a group of 44 wells with over 12 months production experience in the Haynesville shale [41]. Chesapeake fit a hyperbolic curve to this data with a b constant of 1.1. However, Berman argues that this estimate is optimistic and shows that curves with a range of different b constants fit the data comparably well. Berman suggests that a b constant of 0.5 would more accurately reflect the uncertainty to investors. This difference significantly affects the EUR/well: a b constant of 1.1 results in an estimate of 185 mcm/well, while a value of 0.5 results in only 85 mcm/well.

The limited historical experience does not constrain the choice of b parameters especially well at present and the empirical evidence appears equivocal. Several more years of production experience is likely to be required before any firm judgement can be made. In the interim we anticipate continued controversy over this important issue.

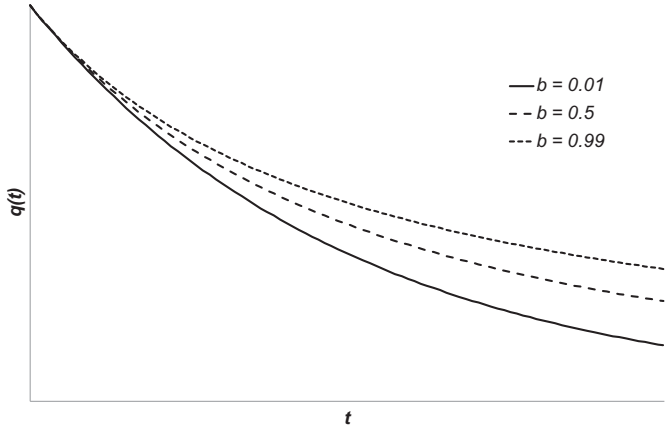

Fig. 5. Variation of hyperbolic decline with the value of b.

4. Case study comparison of methods

In examining the above approaches, it is useful to compare directly some of the results and assumptions of the most influential and widely cited sources. This assists not only in examining the differences that exist between approaches, but also in investigating the extent of and reasons for variability between sources using the same approach.

We first examine four estimates that have been made for the Marcellus shale play in the US by the extrapolation of production experience, and secondly estimates by ARI [14] and the USGS [44] for three shale plays in India.

4.1. Marcellus shale

The Marcellus is potentially the largest shale play in North America, but recent resource estimates have been a source of confusion and the focus of controversy. A number of significantly different estimates have been produced by different organisations using different terminology and definitions. However, once the inclusion or otherwise of reserves is taken into account; the estimates may all be interpreted as the TRR [2]. The difference between these estimates therefore result from differing methodologies and assumptions.

Fig. 6 shows the publically available resource estimates for the Marcellus shale published prior to June 2012. The estimates are categorised by the date of publication and the methodological approach adopted. Also shown is the number of wells that have been drilled to appraise or produce from the Marcellus formation. The first point to note is that considerable uncertainty remains in the size of resources even after a large number of wells have been drilled. Moreover, an upward trend in resource estimates cannot be discerned. Table 1 compares four recent and high profile estimates of the Marcellus by the EIA [5], the USGS [45,46], INTEK [23], and Engleder [47]. These estimate the TRR to be 4 Tcm, 2.4 Tcm, 11.6 Tcm and 13.9 Tcm respectively – in other words, the largest estimate is over five and a half times larger than the smallest. The table breaks down these estimates into sweet spot and non-sweet spot areas, and shows the key assumptions upon which each estimate is based - such as the assumed EUR/well. Two of these sources (USGS and Engleder) provide sufficient information to derive high and low bounds around their mean estimates. While these bounds are not identical (the USGS giving P95 and P5 and Engleder P90 and P10), they do provide useful information.

For the USGS study, as explained above, the TRR estimate can be derived through the product of the total area, the percentage that is sweet spot, the percentage of the area contributing, the average well spacing, and the EUR/well. The USGS provides P95, mean and P5 estimates for each of these variables (Table 1). If these variables were perfectly positively correlated[9], then the P95 TRR estimate

[9] Correlation indicates the level of dependence between two variables and in its most simple form (the Pearson product-moment correlation coefficient) is given as any value between +1 and −1. +1 correlation, known as perfect positive correlation, between two variables indicates that they have an increasing linear relationship. A correlation of −1 means that there is a decreasing linear relationship between the two variables and a value of 0 that they are independent. If two variables with probability distributions are perfectly positively correlated, then one can simply say that the P5 (or P95) value of the product of the two variables is the product of the two individual P5 (P95) values. If they are not perfectly correlated then this does not hold and one must use random sampling techniques from the two distributions to calculate an aggregate distribution.

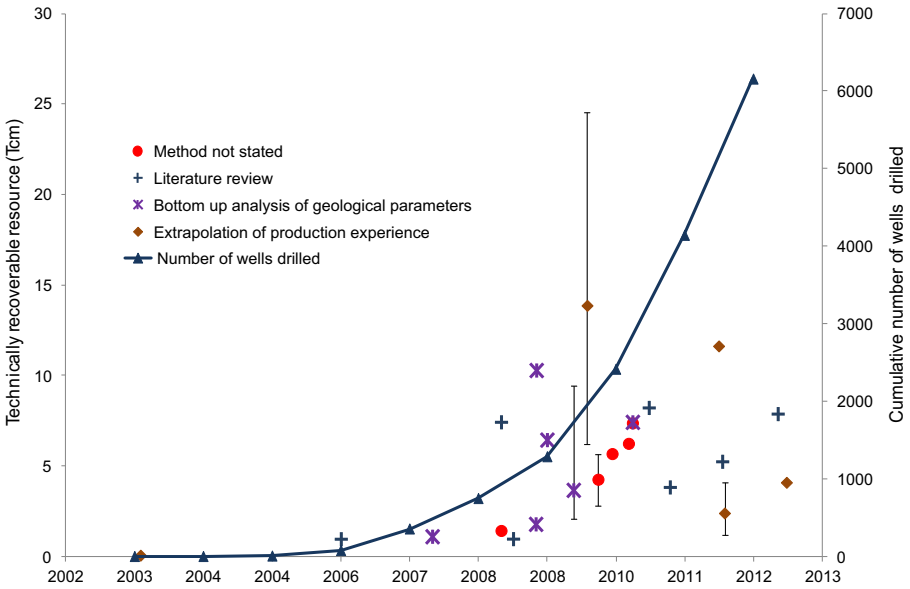

Fig. 6. Resource estimates and number of wells drilled in the Marcellus shale play. Source: Resource data: [5,7,11,13,15,23–25,28–29,45,47–56], Well data: [57–61]

would be equal to the product of the P95 estimates of each variable. But since the USGS does not assume perfect positive correlation, the P95 TRR estimate is greater than the product of the individual P95 estimates. Similar comments apply to the P5 TRR estimate.

We do however assume perfect positive correlation for aggregating or averaging individual variables in the three USGS assessment units to produce the figures shown in Table 1.[10] For example, this means that the P95 area for the total shale play is equal to the sum of each assessment units' P95 areas and the overall P95 well spacing is equal to the average of each assessment units' P95 well spacing.

Table 1 compares the assumptions used in the four studies and illustrates the primary reasons for the variation in the 'headline figures'. Each of the studies divides the Marcellus into component areas, but the number and boundaries of these components varies from one study to another. The USGS and EIA use three assessment units, each divided into sweet spot and non-sweet spot; Engleder identifies six 'tiers' with different assumptions for the EUR/well in each; and INTEK simply distinguishes between one sweet spot and one non-sweet spot area. The USGS and EIA exclude resources in non-sweet spot areas altogether, while Engleder and INTEK include them. Indeed, the INTEK estimate for non-sweet spot resources is greater than its estimate for sweet spot resources and three times larger than the USGS estimates for the Marcellus as a whole.

The USGS, INTEK and EIA also exclude any volumes classified as reserves from their estimates and so these should be added to compare directly with Engleder's estimate. However, Marcellus reserve volumes are currently small (0.13 Tcm) [62,63], so their inclusion or exclusion is not the primary reason for the difference in resource estimates between the studies.

The EIA [5] adopts exactly the same assumptions as the USGS (mean values) for all relevant variables except for the assumed EUR/well. The EIA assumption for this variable is 68% larger than the USGS mean figure, thereby leading to a resource estimate that is also 68% larger.

The USGS, INTEK and Engleder studies vary widely in their assumptions for individual variables. For example, the USGS mean estimate for the area of the Marcellus is 40% larger than Engleder's estimate. At the same time, Engleder estimates that over 45% of the Marcellus is sweet spot, while the USGS estimates that only 18% is sweet spot. A further complication is that Engleder assumes that only 70% of the sweet spot area contributes to the estimated resource volume. The net result is that USGS's mean sweet spot area is 20% smaller than Engleder's, while the INTEK sweet spot area is 45% smaller.

INTEK assumes identical well spacing to Engleder, but assumes a EUR/well that is 70% larger (taking Engleder's mean estimate). Similarly, INTEK's assumed EUR/well is over three and a half times larger than the mean USGS estimate and 25% larger than the USGS P5 estimate. Engleder's P10 EUR/well is also around 30% larger than the USGS P5 estimate.

INTEK does employ a 'success factor'[11] that is used to reduce the EUR/well[12] and well spacing. A direct comparison is therefore best made between the implied yield per km^2 in each study which is given by the product of the well spacing, EUR/well and success factor (if used). On this basis, Engleder and INTEK assume similar yields of around 180 mcm/km^2, which is considerably higher than the EIA (83 mcm/km^2) and over three times the mean USGS estimate (50 mcm/km^2).

One potential reason for the lower USGS estimate is that it considers a 30 year time horizon while Engleder assumes production will continue for 50 years. Using the production profile and parametric values given by Engleder, we calculate that around 20% of the total production of a 50-year well can be expected between

[10] The sweet spot areas for the USGS estimates are calculated assuming triangular distributions for the total area, area untested, and percentage likely to contribute, as explained in [8] with data from [46].

[11] INTEK refers to applying a 'recovery factor' to the product of the EUR/well and well spacing. This is easily confused with the recovery factor used to estimate the TRR from the OGIP. INTEK's recovery factor more closely resembles the factor that geologists apply to estimate the risked OGIP from the total OGIP and so the term 'success factor' seems more appropriate to avoid confusion.

[12] INTEK's success factor, a percentage that can vary between 0–100%, was assumed to depend upon three factors: whether the estimates for URR/well and the well spacing currently used were considered to be representative of what can be expected across the whole ('active' or 'undeveloped') area; how much experience there was of geological factors that can affect production; and how much gas had already been produced or added to reserves. Choice of appropriate values for the success factor appears to be relatively subjective and varies between 10% in the 'active' area of the Fayettesville shale to 100% in the 'active' areas of the Eagle-Ford and Barnett-Woodford shales. The arithmetic mean success factor across all shale plays is 49%.

Table 2
Breakdown and comparison of figures used in estimates of technically recoverable resources from three Indian shale plays.

Source	ARI				USGS		
Play	Cambay	Cauvery	Krishna-Godavari		Cambay	Cauvery	Krishna-Godavari
Total area (km^2)	51,800	23,569	20,202	Max area (km^2)	1,416	2,630	8,094
				Min area (km^2)	445	809	1,396
Prospective Area (km^2)	2,435	2,603	11,241	Mean area (km^2)	931	1,551	4,108
Average TOC (%)	3	2	6	TOC	~4	2-2.5	<2.4
Average thermal maturity (Ro%)	1.1	1.15	1.6	Thermal maturity (Ro%)	>1.1	1-1.5	<1.6
Total OGIP (Bcm)	6,138	4,060	19,263	Well spacing (well/km2)	1.65	1.65	1.65
Play success factor (%)	60	50	50	Average EUR (mcm/well)	19.8	15.3	19.8
Prospective area success factor (%)	60	60	40	Success ratio (%)	87	87	87
Risked OGIP (Bcm)	2,210	1,218	3,853				
Recovery factor (%)	26	21	20				
TRR (Bcm)	567	255	765	TRR (Bcm)	26	32	116

TOC is the total organic content.
Sources: [14,44]

Table 3
Advantages and disadvantages of geological and extrapolation approaches to estimating shale gas resources.

Bottom up analysis of geological parameters		Extrapolation of production experience	
Advantages	Disadvantages	Advantages	Disadvantages
Robust and well established geological approach	Limited data and wide range of uncertainty in many of the geological parameters	No need to assume a recovery factor	Uncertainty over long-term decline rate and EUR/well
Reduces emphasis on the use of analogues	Difficulties in delineating sweet spot areas		Difficulties in delineating sweet spot areas
	Subjectivity in choice of recovery factor(s)		Subjectivity in choice of key variables such as 'success factor'
	Not directly based on actual drilling data		Estimation of productivity in undeveloped areas
			Risk of using inappropriate analogues

years 30 and 50. Engleder's 50-year horizon could be considered optimistic, since a 30 year life is more commonly assumed [42,43]. Moreover, this difference is insufficient to account for the large difference in the assumed EUR/well between these two studies. This is more likely to result from differences in the assumed b constant and/or initial rate of production.

In conclusion, the four studies vary widely in the assumptions used for almost all the variables that underpin their resource estimates. The large differences between the four estimates can only be explained by considering each of these assumptions in turn. In practice, the most important differences lie in the assumptions used for the sweet spot area, the average EUR/well, and whether gas contained in non-sweet spots should be included. Greater consensus on resource size in the Marcellus and elsewhere will depend upon greater consensus on these variables.

4.2. India

There have been two detailed investigations of three shale basins in India – the Cambay, Krishna-Godavari and Cauvery. One by ARI used the bottom up geological approach [14], to estimate a total of 1.59 Tcm and the second by the USGS used the extrapolation approach [44] to estimate 0.17 Tcm – an order of magnitude difference.

The USGS employed a similar approach to that used for its Marcellus study, but this differed in three important ways. Firstly, it included a 'success ratio' representing the assumed percentage of wells that will produce at least the minimum EUR/well. Inclusion of this variable reduces the volume of gas that is estimated to be technically recoverable. Secondly, since no production history exists for these shale plays, the USGS employed analogues based on US shale plays for the well spacing, the EUR/well, and success factor. The choice of an appropriate analogue was based on many of the same factors used in geological approach including: shale thickness, total organic content, shale mineralogy, thermal maturity, gas pressure, and geological complexity [8]. Finally, the updated USGS methodology should also include an assessment of the resource potential of non-sweet spot areas [8]. However, it is not clear whether the Indian study includes this as no information is given on the resource breakdown between sweet spot and non-sweet spot areas [44].

A major difference that can be seen from Table 2 is the area assumed for each of the three basins, with the ARI prospective area being around two and a half times larger than the USGS area. The ARI area is 70% larger than the USGS P5 area in the Cambay basin, 40% larger in the Krishna-Godavari and similar in the Cauvery. Nevertheless, even if the USGS assumptions of well spacing, EUR/well and success ratio were applied to the ARI prospective areas, the total USGS TRR estimate would still be only 30% of ARI's.

Another major difference exists in the assumed TOC (Total Organic Content) of the Krishna-Godavari basin. ARI assumes a TOC of 6%, while the USGS indicates that this basin contains a maximum of 2.4%. The geological approach explicitly includes this factor in the calculations performed, while, as mentioned above, the USGS takes the TOC into account in its choice of appropriate analogue [8]. It is however unclear the extent to which a change in TOC from 2.4% to 6% would have modified the USGS choice of analogue. All other TOC and thermal maturity[13] assumptions appear consistent.

The most important variable for the ARI study is the assumed recovery factor, while the most important variable for the USGS study is the assumed EUR/well. But these are not directly

[13] [14] states that the thermal maturity measures '*the degree to which a formation has been exposed to high heat needed to break down organic matter into hydrocarbons. The reflectance of certain types of minerals (Ro%) is used as an indication*'.

comparable. Hence, while the EUR/well for these basins is not significantly below the EUR/well the USGS assumed for the Marcellus shale, we are unable to further narrow down the reasons for the differences in the estimates. Efforts are therefore needed to reduce or characterise the uncertainty around these parameters through probabilistic techniques.

5. Implications and conclusions

Table 3 summarises some of the advantages and disadvantages of the two main resource assessment methodologies. The choice between them will depend upon the extent of development of the region, the level of access to the relevant data, and the human and financial resources available. While a high-level of uncertainty is inevitable at this stage of the development of the resource, this can be addressed, or at least mitigated, through the use of probabilistic methods.

One major drawback of both the geological and extrapolation methods are their sensitivity to a single parameter, namely the recovery factor with the geological approach and the assumed functional form for the production decline curve with the extrapolation approach. Both of these parameters are poorly understood with regard to shale gas production and remain the focus of controversy. In principle, the reliability of the extrapolation method should improve as production experience increases. Hence, we would expect approaches based upon actual production experience to provide more reliable resource estimates in the medium term. At present, however, the level of uncertainty from these methods appears to be comparable to that from geological methods. As recommended by Ref. [32], future studies that seek to derive mean estimates of the TRR for a region, should use as many different approaches as possible. It also appears prudent to favour conservative estimates of key parameters such as recovery factor or the functional form of decline curves until the uncertainties can be reduced or properly characterised.

In the absence of drilling data, analysts also often rely upon analogues to estimate resource potential. Historical production data has however shown that shale productivity can vary widely both amongst and between different shale plays. Therefore, if the extrapolation of production experience method is used rather than performing a bottom up analysis of geological parameters, any such assessments should delineate the shale as much as possible, indicate why certain analogues have been chosen for particular areas, and employ a range of analogues to demonstrate the uncertainty in estimates derived. As noted above, studies relying upon simple analogue extrapolation are likely best viewed as providing preliminary estimates of resource potential.

Given these multiple limitations, it is essential to address and report on the level of uncertainty in the estimates whichever approach is adopted. The failure of the majority of studies to do this is a major limitation of the existing literature. To date, only the USGS has consistently handled uncertainty in a rigorous manner, but there is no reason why other studies could not do so. The sensitivity of these methodologies could also be explicitly acknowledged in published estimates through sensitivity analysis of the model assumptions. Such analyses are common in the energy modelling literature and would provide an assessment of the impact on resource estimates to changes in the model assumptions.

The large and continuing uncertainty in shale gas resource estimates has important implications for the future of the shale gas industry and national energy policy. Even in areas where production is currently taking place, there remains significant uncertainty over the size of the resource and considerable variation in the available estimates. Therefore, given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties described above, current resource estimates should be treated with considerable caution.

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