

Assessing the economic margins of sweet spots in shale gas plays

Ruud Weijermars^{1, 2*} and Joost van der Linden³ outline a new reality for shale gas plays where even sweet spots may become sub-economic when gas prices collapse. The North American shale-gas bonanza is reviewed and sweet spot sensitivity to gas price volatility is illustrated for the Haynesville shale play. The second part of this article will follow in the January issue.

Today's reality is that nearly all North American shale-gas projects are losing money faster than can be generated from operational income, which means losses must be compensated by asset sales, volumetric production payments, or additional debt-leveraging.

Shale plays previously assumed economic with rising gas prices have instead become sub-economic due to a trend over several years of declining gas-prices (Bloomberg and Credit Suisse, 2011). US wellhead gas prices dwindled, from an annually averaged peak of \$7.74 per million Btu in 2008 to about \$2–3 per million Btu (Mmbtu) in 2012. Profit margins of the developed shale-gas resources have steadily deteriorated and turned negative for a number of shale gas producers. The declining returns on shale-gas assets due to the lower-than-expected US and Canadian gas prices were compounded by a higher-than-anticipated proportion of poorly producing wells for any given acreage spacing.

While the rest of the world is at the beginning of its shale gas development cycle, financial analysts have pointed out that the North American shale gas industry has entered a dangerous phase of marginal liquidity (Dell and Lockshin, 2010). The lessons learned from the North American shale gas bonanza are highlighted in this study and illustrated with cashflow analyses for Haynesville shale gas wells.

New shale gas reality

Shale gas plays around the world are challenged to demonstrate they can beat the odds: well productivity uncertainty, gas price volatility and the emerging misalignment of stakeholders, combined with tightening credit lines in a period of recession, are all depressing the appetite of the global investor community. Landmark studies of shale gas resource potential have been published for global regions (Rogner, 1997; DOE/EIA, 2011a; JRC/EC, 2012) and countries (Canada: PTAC, 2006; China: MLR, 2012; Germany: BGR, 2011; Netherlands: TNO, 2009; Poland: PGI, 2012; US:

PGC, 2009; NPC, 2011). The three key questions commonly asked are: 1. How much gas is in place? 2. Can the gas be safely extracted? 3. What portion of the gas can be extracted with a profit? The state-of-the-art approach for each of these questions is reviewed below, and provides the basis for our subsequent economic analysis.

A renewed effort to quantify the risks and uncertainties of shale project economics is crucial for the success of emergent shale gas plays. Investors' continued willingness to support new and existing shale -gas projects will hinge on their perception of the sector's ability to deliver the expected returns. The current lack of return on investment in North American shale gas projects means the economic valuations of new shale gas projects are now put under much closer scrutiny. Junior, small, and medium-size shale gas companies encounter difficulty in finding access to credit in tight capital markets. Depressed returns on shale investments inevitably lead to a growing gap between estimates of technically recoverable resources (TRR) and the actual economically recoverable resources (ERR).

How much gas is in place?

A brief outline of the intricacies of the shale resource maturation process is warranted. The problem with shale gas resource appraisals is that the distinction between TRR and ERR is frequently confounded – and the estimated ultimate recovery (EUR) part of ERR remains fuzzy – even in major resource assessments, as has been recently highlighted (JRC/EC, 2012). In any emerging shale gas play, the progressive appraisal of the volume of oil and gas resources in place (OGIP) involves various steps to move from OGIP to EUR estimates (Figure 1a). The estimated OGIP volumes are based on geological subsurface studies and then reduced to estimations of technically recoverable resources (TRR) using reliable technology concepts for gas extraction. The volumetric proportion of OGIP that can be classified as TRR follows from the technology factor, TF , in:

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$$TRR = TF \cdot OGIP \quad (1)$$

The technology factor increases over time as new reliable technology will be made available through research and development (Figure 1b). For example, technology advances like hydraulic fracturing and horizontal drilling have increased the TF for shale gas plays. Subsequently, prevailing gas prices and technology cost determine the portion of TRR that can be extracted economically: these are so-called economically recoverable resources. At a certain gas price and extraction cost, only a fraction of the TRR turns out to have a profit potential, which gives the ERR portion.

In turn, only part of the ERR can eventually classify as proved reserves: by definition, proved gas reserves are not only to be produced with economic return on investment (Lee and Sidle, 2010; Sidle and Lee, 2010), but also must comply with strict SEC reserve reporting guidelines (for SEC compliant operators; SEC, 2009). This includes the company's final investment decision for proven developed reserves (PDs) and a development plan must be in place justifying the economics for proved-undeveloped reserves (PUDs). The fraction of the estimated initial oil and gas resource in place (OGIP) that can be ultimately booked as a proved reserve (the EUR volume) depends on the realized recovery factor, RF:

$$EUR = RF \cdot OGIP \quad (2)$$

The accuracy of the final EUR estimates is crucial as these constitute a company's proved reserves (after final invest-

ment approval) and provide the principal debt financing collateral.

The technology factor, TF, sets an upper limit for the recovery factor, RF, which is reflected in the ratio of TRR and EUR (given by TF/RF) being for shale-gas resources generally much larger than 1. Over time TF/RF should converge to 1, otherwise technically recoverable resources remain undeveloped. The volume of shale gas that is technically recoverable but left in the ground for economic reasons is given by (Figure 1b):

$$TRR - EUR = (TF - RF) \cdot OGIP \quad (3)$$

The fraction of technical resources unrecovered due to unfavourable economics is coined here as the economic gap, EG:

$$EG = TF - RF \quad (4)$$

Estimates of TF for shale gas plays range between 15 and 40%, but the RF for US shale gas plays are continually adjusted downward (JRC/EC, 2012); even where well spacing is narrowing, the EG is widening. To diminish the growing economic gap between TRR and ERR, finding, development, and completion, costs must come down and gas prices must go up (Dong et al., 2012). Additionally, the cost of capital must be kept as low as possible to increase retained earnings from shale gas operations, which then facilitate the development of new ERR volumes. Meanwhile, the cost of capital is getting more expensive for shale gas operators due to lagging performance and the fact that securing new financing sources has become very difficult (Weijermars, 2011).

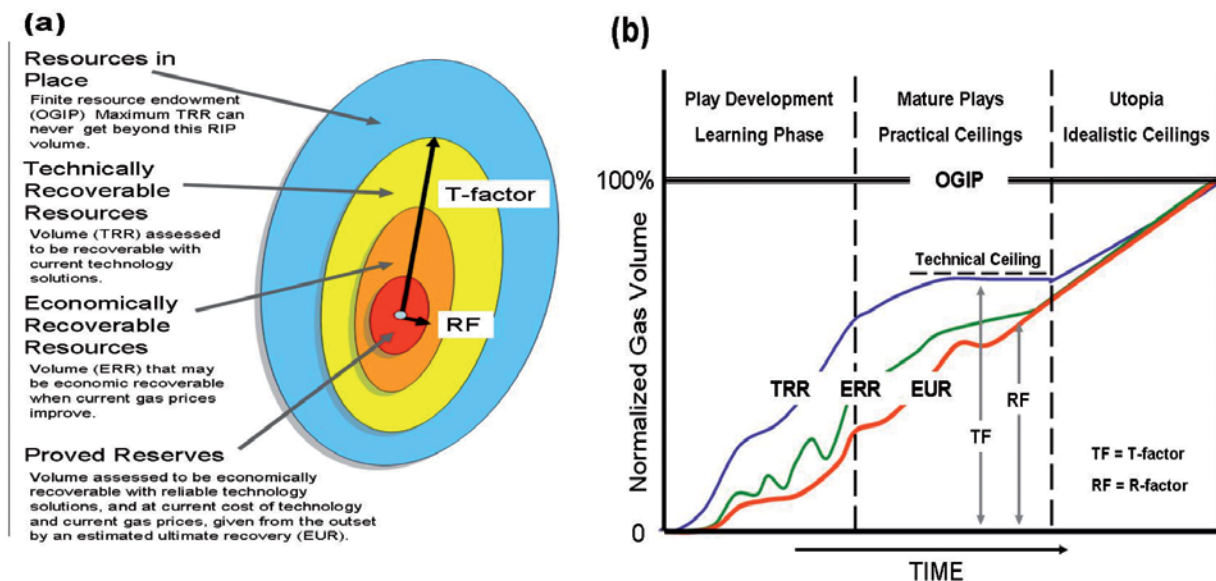


Figure 1 a) Progressive resource maturation process delineates the volume of OGIP, and then narrows down the estimates of TRR, ERR, and proved reserves. b) TRR fractions grow when technology improves; ERR fractions grow when gas prices rise. Negative slopes occur when gas prices slump. EUR volumes are less susceptible to down-grades (that is in conventional gas fields) and tend to grow over time. For shale gas, EUR downgrades may become more common (after Madani and Holditch, 2011).

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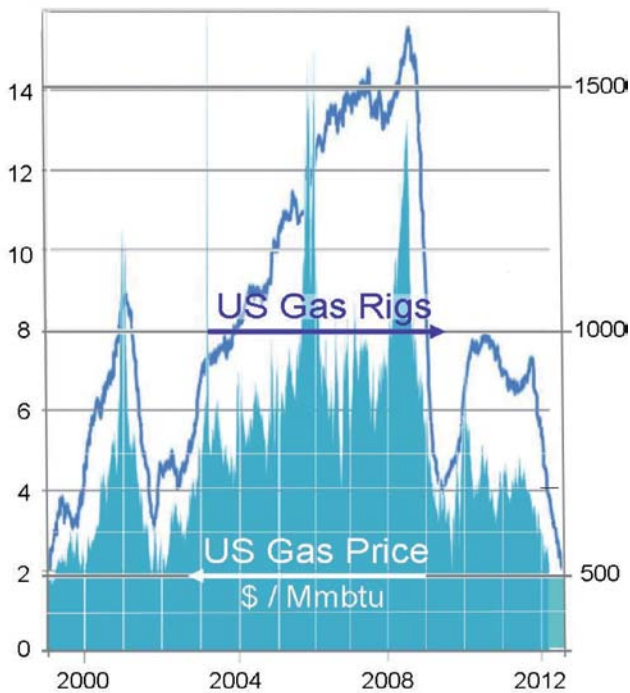


Figure 2 US Henry Hub gas prices (daily averages; left hand scale) and total US gas rig count (right hand scale) over the period covering the US shale-gas bonanza, 1999 to medio 2012. Active drilling rigs are scaled back when gas prices drop. US gas prices for 2012 are similar to January 1999 levels, hovering about \$2/Mmbtu, and the gas-rig count has fallen below 500. (Henry Hub prices from NYMEX and gas-rig counts after Baker Hughes).

Can the gas be safely extracted?

Government backing for shale gas development does not yet exist in many parts of the world where shale resources are mapped to be present. A new suite of stakeholder concerns has emerged with the development plans for major shale gas fields situated on land. Governments and concerned associations around the globe have commissioned studies to assess the engineering principles of hydraulic fracturing (DOE, 2009; NEB, 2009; API, 2011; CAPP, 2012; JRC/EC, 2012). The principal perceived risks are generally three-fold: environmental risk posed by demands on water supplies, use of fracking fluids and the potential seismic risk from the fracking itself. But even air quality and noise associated with on-land drilling and fracking are factors that fuel the opposition to shale gas development. Opposition finds stronger political support in countries where shale gas threatens to displace existing energy sources (like nuclear power in France and coal-fired power stations in Bulgaria; Weijermars and McCredie, 2011). The risk of corporate capital being tied up in shale gas assets that become a liability is rising with moratoria on fracking now in place in the US and beyond, e.g., New Jersey, US; Quebec, Canada; France; UK; Netherlands; Bulgaria; and South Africa.

Meanwhile, the US, EU, France, and UK have all issued recommendations addressing shale gas development con-

cerns (SEAB, 2011; EU Report, 2011; BRGM, 2011; Royal Society Report, 2012). Companies must comply with local land-use regulations, environmental regulations, and infrastructure permits. Environmental impact studies are required and come under different names in different countries (e.g., US: Programmatic Environmental Impact Statement – PEIS; EU: Environmental Impact Assessment – EIA; South Africa: Environmental Management Plan – EMP). The new stakeholder concerns are not only relevant for shale gas development projects, but also for the development of kerogenic shale in the US Green River formation for which a draft PEIS (OSTS PEIS, 2012) was completed in January 2012 as a final step to prepare for commercial licensing. The IEA has issued its Golden Rules for shale gas operations (IEA, 2012), stressing the importance for the global economy to facilitate and increase the pace of shale gas development.

In the end, sustained societal support is needed for realizing shale gas field development projects on an economic scale with a profitable drilling programme. The present study gives quantitative examples that detail field development profitability and its sensitivity to regional well productivity variations and gas price uncertainty.

What portion of the gas can be extracted with a profit?

Even when stakeholder support is favourable, economic returns on investment from shale gas projects are not guaranteed. The massive up-scaling of US and Canadian shale gas output has led to oversupply in a closed North American gas market, causing gas prices to plummet (Figure 2). Even after cutting-back on expensive LNG imports (with terminal capacity already built), and reducing Canadian shale gas imports, US gas prices continued to drop and Canadian prices have tracked the decline.

Rising gas prices can boost shale investment, but the reverse holds true as well. The vast acreage acquisitions, drilling plans, and final investment decisions of the North American shale gas operators were nearly all committed in the first half of the past decade. Gas prices were rising fast and credit was cheap until the onset of the financial crisis in 2008. The earlier expansion of US shale gas development was abruptly scaled back near the end of the past decade when gas prices declined over a prolonged period. The rise and fall of field development investments is reflected in the rise and fall of US gas rig counts (Figure 2).

The two major US shale gas plays, the Barnett and the Haynesville, have slowed down their gas drilling campaigns (Figures 3a and b). An initial steep rise in Haynesville gas rig counts, which had started in 2007 and gained momentum thereafter, was briefly halted by the 2009 gas price depression, resumed in 2010 when gas prices briefly rebounded, only to fall back fast in 2011 and 2012 (Figure 3b). While oil rig counts are steeply up in other parts of the US, like

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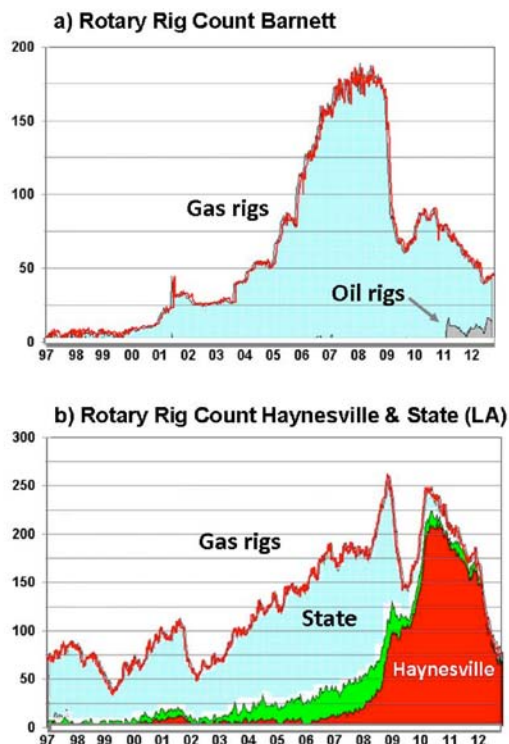


Figure 3 Rig counts for the two major US shale-gas plays. a) The Barnett shale field (TX) development accelerated, as gas prices rose during the first half of past decade. After the onset of the gas price slump, June 2008, rig counts were steeply scaled back. Some oil drilling has started in attempts to take advantage of the firm oil price. b) Gas rig counts for the Haynesville field (TX-LA; red: horizontal wells; green: directional wells). Field development investment decisions were taken shortly before the financial crisis of 2008, but rig counts succumbed and followed the gas price decline. The total gas rig count for the state mirrors the rise and fall of gas prices over the past decade (see Figure 3). (Rig counts courtesy Baker Hughes and WTRG Economics).

the Bakken and Niobrara – with even a modest rise in the Barnett (Figure 3a) – the US total gas rig count continues to fall (Figure 2).

About 150,000 shale gas wells have been drilled in the US over the past decade, and the combined well output has turned around the decline in US domestic gas production. Figure 5 shows the gas output shares of the individual US shale plays, with a six-fold growth of total output since 2008. Note that the gas production from the Barnett is at plateau (Figure 4) as every year since 2008, fewer new wells are drilled (Figure 3a). With fewer rigs drilling for gas in all of the US shale gas plays, the point where productivity decline of older wells starts to outpace the production added by newly drilled wells is getting nearer. Unless the gas rigs return, gas output of the Haynesville play will be flat for 2013 and is likely to shrink thereafter.

Haynesville case study

We use the Haynesville shale gas play as a case study to illustrate how ‘economic producibility’ may vary across a shale

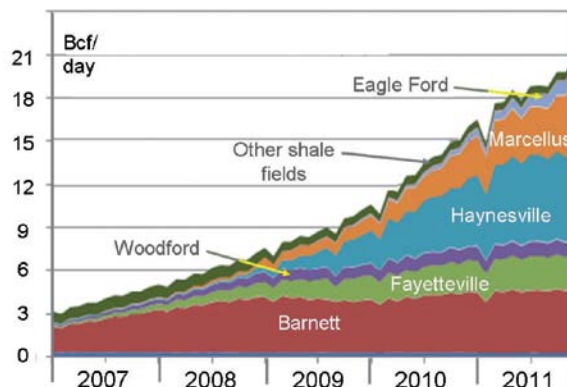


Figure 4 Growth of US shale gas production since 2007 due to the cumulative effect of earlier accelerating gas drilling activity and shifts to horizontal wells. (Data EIA).

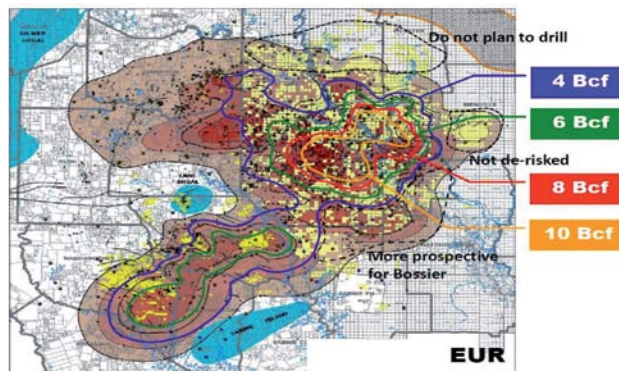


Figure 5 NW Louisiana Haynesville with sweet spot core area defined by EUR contours (Source: Petrohawk, 2010).

play. Unlike conventional gas fields, where a single cash flow model can represent the field’s overall performance, unconventional gas ‘fields’ do not ‘behave’ as single gas fields but remain more of a play throughout field development as each new well drilled involves considerable risk and uncertainty.

The detection of the sweet spot areas has become crucial in unconventional oil and gas development areas. Companies must find the regions where well flow rates deliver EUR volumes that are large enough to make the economic case attractive and sustainable over the life cycle of the well.

Figure 5 shows the Haynesville sweet spot core area and spatial variations in the EUR, based on the initial well flow rate type curves mapped by Petrohawk engineers. Figure 6a shows the synthetic decline curves and corresponding cumulative production profiles for the Haynesville zones of 4, 6, 8, and 10 bcf EUR/well assuming a maximum 25 year well lifecycle. In view of the relatively rapid decline in shale gas well productivity, individual well life can be argued to range between 10 and 25 years. This does not affect our results as tail-end productivity contributes little to the overall EUR (see later).

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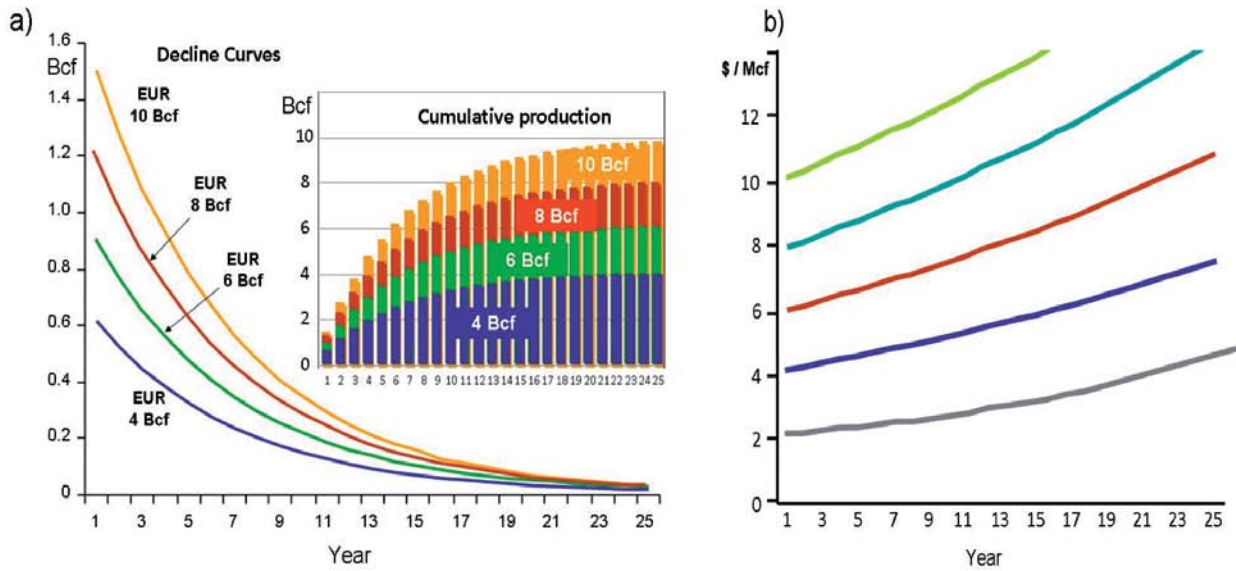


Figure 6 a) Gas production decline profiles and cumulative production (inset) for single well with initial flow rate of 1.5, 1.22, 0.91, and 0.61 bcf/y correspond to Haynesville EUR of 10, 8, 6, and 4 Bcf over a 25 year well lifecycle. An exponential decline function is assumed with decline factor set at 0.15 per year. b) Haynesville annually averaged wellhead price forecast, based on initial wellhead prices of 4, 6, and 8 \$/Mcf at the year of project approval and forward inflation correction at 2.5% per year.

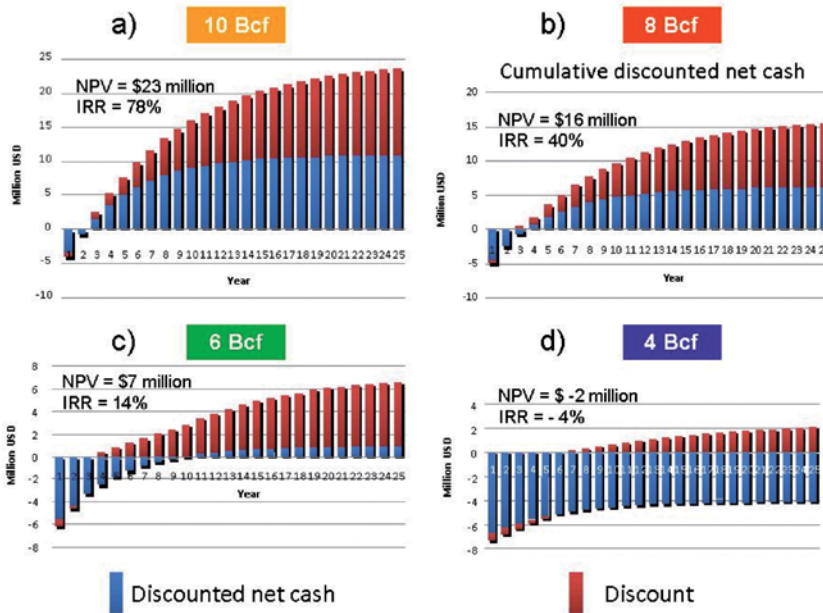


Figure 7 a-d) Cumulative discounted cash flow for 10-4 Bcf wells in Haynesville sweet spot core area for an initial gas price of \$6/Mcf (assuming 1Mmbtu in 1 Mcf gas). Discount rate is set at 10% and other parameters are given in Table 1.

Cash flow model runs were generated to quantify the effect of gas price volatility on the economic returns of the various Haynesville EUR zones. The models are based on generic well-productivity-decline functions and discounted cash flow equations outlined in an online repository (Alboran, 2012). The algorithms are incorporated in a proprietary excel-based interface suitable for evaluating the discounted cash flow of both single and multiple wells in shale gas projects.

For the gas price sensitivity analysis of the Haynesville cash flow, gas prices were varied between \$2-10/Mcf. We assume 1000 cubic ft (1 Mcf) of gas is equivalent to a calorific value of 1 million British thermal units (1 Mmbtu) used in spot market pricing. In all cases the initial gas price is valid for the start of well production and is thereafter adjusted for inflation at 2.5% on yearly basis over the well's productive lifecycle. The corresponding gas price development, based on a standard inflation function,

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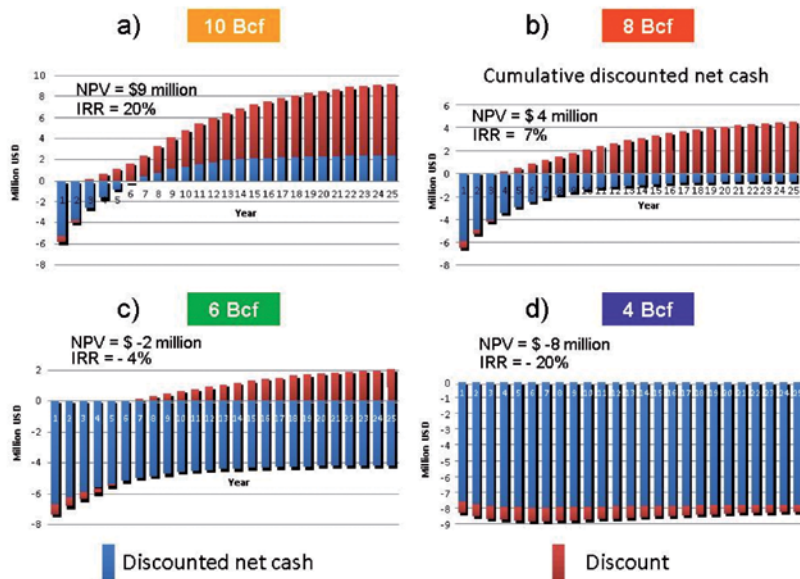


Figure 8 a-d) Cumulative discounted cash flow for 10-4 Bcf wells in Haynesville sweet spot core area for an initial gas price of \$4/Mcf (assuming 1Mmbtu in 1 Mcf gas). Discount rate is set at 10% and other parameters are given in Table 1.

is graphed in Figure 6b. Representative input parameters were used in our cash flow models, specifying capital expenditure (CAPEX), operating expenses (OPEX), royalties, taxes, depreciation and discount rate (Table 1). These input parameters assume equal access to state-of-the-art ‘reliable technology’ for operators in all sections of the acreage.

The net present value (NPV) and internal rate of return (IRR) was calculated for each of the EUR zones using the discounted cash flow model. Figures 7a-d show the cumulative discounted cash flows (and undiscounted cash flows when discount is added back in) for an initial gas price of \$6/Mcf. The wells in the 4 Bcf zone are certainly not profitable for \$6/Mcf (Figure 7d), and wells in the 6 Bcf zone are just below the common corporate hurdle rate of 15%. The conclusion is that for a gas price of \$6/Mcf only wells in the zones with EUR > 7 Bcf are profitable.

Figures 8a-d shows the cumulative cash flows for each of the EUR zones using a lowered initial gas price of \$4/Mcf. What stands out is that 10 Bcf wells are profitable even at \$4/Mcf initial gas prices (Figure 8a), but lower productivity zones are below the 15% hurdle rate assumed

here. Production from the 10 Bcf zones should be abandoned approximately after 13 years of operation as the discounted cash flow is not growing thereafter. The well rates have declined so much in year 13 that revenue is not high enough to leave positive earnings after payment of cost and discount rate. The time of abandonment can be delayed several years when gas prices are higher (Figures 7a), but for all cases the profitable part of the well lifecycle is shorter than 25 years. The recommended well abandonment is within two decades of first production, but can be expanded when re-stimulation is used after a decade to boost well flow rates.

Wells of 8 Bcf EUR are no longer profitable at \$4/Mcf average gas prices (Figure 8b) and thus no longer economically producible. If SEC reserve reporting guidelines (SEC, 2009) were strictly applied and enforced, proved undeveloped reserves in such zones would need to be impaired in a reporting year with the 12-month trailing average price below \$4/Mcf. However, a recovery of the wellhead gas price to \$6/Mcf would render these assets profitable again (Figure 7b).

Wells of 6 Bcf and 4 Bcf EUR are not profitable and thus no longer ‘economically producible’ at \$4/Mcf average gas prices for the reporting year (Figure 8c,d). A recovery of the wellhead gas price to \$7/Mcf would be needed to render 6 Bcf EUR wells profitable again (yielding an IRR of 20%). However, 4 Bcf EUR wells remain below the hurdle rate with 7% IRR at \$8/Mcf, these wells are only profitable when gas prices rise above \$9/Mcf.

Figure 9a is a stylized version of the Haynesville sweet spot core region with lower well-productivity zones contoured as one moves away from the core area. Figure 9b shows the hurdle rate for the corresponding wells based on our detailed cash-flow analysis, indicating that all wells have

Well CAPEX (\$/MM)	8
OPEX (\$/Mcf)	1.2
Other OPEX (\$/Mcf)	0.3
Royalty Rate (%)	20
Effective Corporate Tax (%)	20
Depreciation (%)	10
Discount rate (%)	10

Table 1: Input Rates Haynesville Type Play.

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become sub-commercial at 2009–2012 wellhead gas prices (using a commonly accepted corporate hurdle rate of 15%). We have also analyzed the EUR spread for the Haynesville wells within the EUR zones using OLOGSS data (DOE/EIA, 2011b), which gives our P10-P50-P90 bandwidth. The gas price sensitivity analysis of wells in the various EUR zones of the Haynesville shale gas play is summarized in Figure 9b. An overall conclusion is that all Haynesville gas wells with EUR below 10 Bcf are sub-economic at current gas prices. Similar conclusions for Haynesville economics have been reached in independent assessments by Kaiser (2012a,b).

Conclusions

For the sustained success of unconventional gas operations in North America, and for expansion of this success elsewhere in the world, a sound business performance of shale gas projects is crucial. Persistently low US natural gas prices have put severe pressure on the operational earnings of US natural gas producers since mid 2008. A detailed ‘forensic’ cash flow analysis showed that 2009 income was negative for a representative peer group of US shale gas operators, whereas the income of the integrated oil majors remained robust (Weijermars and Watson, 2011). Clearly, US gas shale plays are not easy cash cows as sometimes asserted, and improved templates for field development are much needed for shale gas to become a sustainable business with operational profits.

Corporate cash flow analyses for the North American shale gas plays have been positively biased and the economic risks and uncertainties of shale gas development have remained under-exposed in all major shale gas reports. Over the past four years, the spot prices for wholesale gas in North America paid for only about half the full cycle cost of producing the gas. Shale gas operators have covered

operational losses by financing activities and have encountered increasing difficulty in finding access to new credit lines in the tightening global capital markets. Wholesale gas consumers (like US gas-fired power stations) continue to receive gas supplies at steep price discounts paid for by shale gas investors. Independent shale gas operators finance a gap in operational earnings with asset sales to meet maturing debt payment schedules, a situation that is unsustainable and leads to shale gas assets either becoming illiquid or a growing concern.

Meanwhile, a significant proportion of North American shale assets has been acquired by major internationals such as ExxonMobil (through XTO acquisition December 2010), BHP Billiton (through acquisition of Petrohawk and Chesapeake assets in 2011), CNOOC, Shell, BP, BG, and Statoil. Some of these companies have taken major charges on their shale gas assets, but possess sufficient credit to take a long-term strategy view.

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Ruud Weijermars has been generously seconded by Alboran Energy Strategy Consultants to spend time on natural gas research.

Disclaimer

This study analyzes shale gas economics based on data abstracted from industry reports and academic studies. The analysis of these empirical data inevitably involves a degree of interpretation and uncertainty connected to the assumptions made. Although the results derived here are reproducible using the outlined research methods, the authors, Alboran Energy Strategy Consultants and the publisher take no responsibility for any liabilities claimed by companies that hold assets in the field areas included in this study.

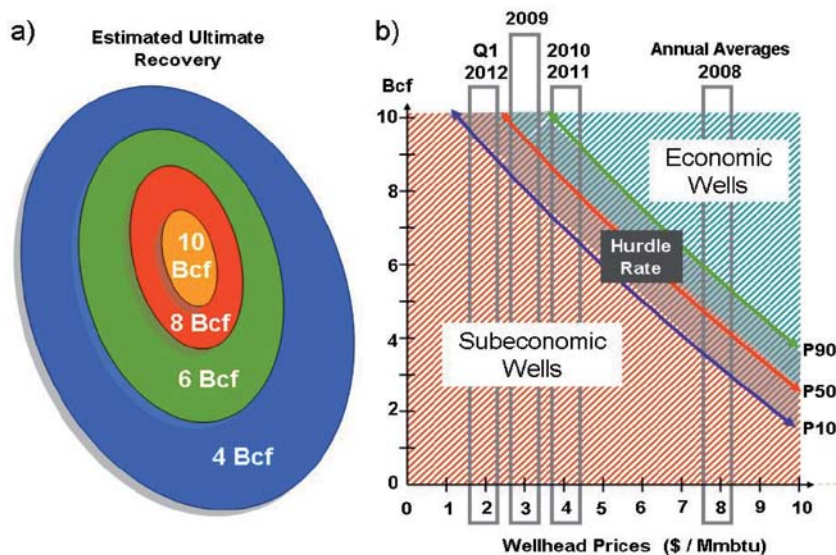


Figure 9 a) Summary of EUR zones of shale gas wells in the core area of the US Haynesville shale gas play. b) Hurdle rate curve of 15% separates economic wells from sub-economic wells, based on NPV and cash flow analysis using representative input parameters. The hurdle rate spread is indicated for best producing wells (P10), average (P50) wells, and below average (P90) wells. The columns outlined show the annually averaged wellhead prices for 2008–2012 (Q1). Virtually all wells are sub-commercial for the gas prices fetched between 2009 and 2012.

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