

Unconventional-Natural-Gas Business: TSR Benchmark and Recommendations for Prudent Management of Shareholder Value

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Summary

Stock-listed independents have played a leading role in the development of unconventional natural-gas resources in the United States and Canada. Shareholders have provided up to 57% of the total capital tied up in a representative panel comprising the 20 leading US and Canadian operators. The accumulated equity-financed capital also provided the collateral for the complementary 43% debt financing. Prudent management of shareholder value in unconventional-gas businesses is therefore essential for ensuring security of gas supply, not only in North America, but also in other countries with emergent unconventional gas plays. This study analyzes and benchmarks the working capital cycles in unconventional-gas companies. The working capital and cashflow cycles are compared with those of diversified oil and gas majors. The ability to accumulate retained earnings is generally much lower for unconventional-gas producers than for integrated majors. Unconventional-gas producers tend to grow their share capital by new issues and not from economic value added by profit from business operations. Although little or no asset value is built from economic profit, shareholder returns may still grow for unconventional-gas companies as long as investor expectations remain positive about future earnings. In contrast, shareholder returns in conventional-gas companies come from genuine economic value added in profitable business operations. The root cause of the weakness or absence of operational profits in unconventional-gas operations is a combination of low gas prices and well flow rates that are too modest to pay for the total cost of the unconventional-gas production. The operating margins for unconventional-gas companies are either close to zero or negative, but not for the integrated oil and gas majors, which have impressive cash margins even at globally suppressed gas prices. The benchmarks provided here help one to understand which parameters impact the financial performance of unconventional-natural-gas companies most significantly. Recommendations are formulated to avoid the destruction of shareholder value, and to instead maximize total shareholder returns (TSRs).

Introduction

The global consumption of natural gas continues to grow, and competition for access to gas resources will intensify (International Energy Agency 2010a). The world's natural-gas consumption amounted to 111 Tcf (3,149 billion m³) in 2009, with three mature consumer markets (North America, Europe, and Russia) and several emerging markets (Fig. 1). To counter the decline of indigenous gas production from conventional resources, North America pioneered the innovative production of natural gas from so-called unconventional resources. The development of such unconventional gas resources requires horizontal drilling and high-pressure fracturing of the rock, as well as a pioneering spirit to turn these risky geological plays into economically proved reserves. These provide the asset base for a potentially profitable natural-gas business. Over the past decade, the USA and

Canada have succeeded in reversing the imminent decline of their domestically produced natural gas. The production of US domestic gas from unconventional reserves in 2009 surpassed the domestic output of conventional gas. The rest of the world has now become eager to follow the North American example (Jaffe 2010; Knight 2010), mostly spurred by concerns about security of supply. Exploration for unconventional gas resources has attracted some global hype but is still at an early stage of the game because production of unconventional gas outside North America remains insignificant.

From a country perspective, a major motivation for developing newly inventoried unconventional indigenous gas resources is to improve the national security of gas supply. To achieve such security of supply, a sustainable business performance is needed in the emergent unconventional-gas sector. A country may harness substantial gas resources, but if there are no "takers" to upgrade the resource potential into "sustainable" proved reserves (and produce), the gas will not come to the market. Such "takers" may come from a range of E&P companies: international oil companies, national oil companies, public/private partnership oil companies, or independents; ultimately, the development of unconventional natural-gas resources into producing proved reserves is a task that must be executed by oil and gas companies. For example, the reserves maturation process for unconventional gas resources in North America has been fully financed by stock-listed entities, stimulated by some tax incentives (such as Section 29 of the US Tax Code), and accompanied by regulation that boosted both the consumption and production at an earlier stage of the decline in the natural gas business cycle [see Weijermars (2010a) for a recent review of the US gas value chain].

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 by unconventional-gas companies is crucial. Unconventional-gas companies (mostly independents) have attained significant market capitalization in North America with USD 250 billion at stake in 2009 in the 20 leading companies alone. However, the business fundamentals of unconventional-gas companies became the subject of intensifying debate at the end of the past decade. An increasing number of analysts raised concerns about the liquidity of US unconventional-natural-gas companies (Schaefer 2009; Cohen 2009; Berman 2010a, b; Nasta 2010; Dell and Lockshin 2010). Low natural-gas prices have put severe pressure on the operational earnings of natural-gas producers since mid-2008. The competitive advantage of unconventional-gas companies has been weakened by gas prices that remained low in 2009 and 2010, up to the completion date of this study. To remain attractive for investors and to retain their investments, the business performance must improve.

This study provides a rigorous assessment of the business model for unconventional-gas companies, with particular focus on their economic-value-adding capacity and the security of equity invested in them.

Shareholders Stake in Unconventional-Gas Business

It is fair to say that investors have played a key role in the early success of the emerging unconventional-gas business in North America.

*Deceased.

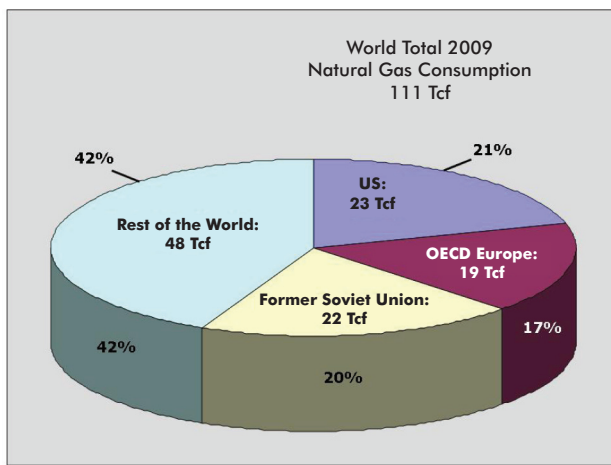


Fig. 1—Gas flows in the world to consumers. (Data source: International Energy Agency 2010b).

The generous supply of equity and debt capital, mostly over the past 2 decades, has built more than 45 unconventional-gas companies in North America (Dell and Lockshin 2010). The 20 leading unconventional gas players are listed in **Table 1**. They all classify as so-called “independents” and represent an average market capitalization of USD 12.1 billion each (Table 1). The total market capitalization of these 20 unconventional E&P leaders amounted to USD 242 billion at the end of the first quarter (Q1) of 2010 (Table 1). For the sustained success of these US and Canadian unconventional-natural-gas businesses and for the development of similar success elsewhere in the world (Jaffe 2010; Knight 2010), security of gas supply must go hand-in-hand with the secure creation of shareholder value.

North American natural-gas companies’ levels of leverage follow primarily from the issuance of shares in return for equity-capital, and secondarily by attracting debt-capital, supported by the equity as collateral. Holders of debt-paper are paid first in case of any insolvency

that would lead to bankruptcy. Unconventional-natural-gas companies in the USA and Canada have become more highly geared, with assets financed by an average of 74% of debt over equity financing for a representative industry panel as per Q1 2010 (Table 1). Equity-financed net assets provide the collateral for the debt-financing. In fact, 57% of the total market capitalization is equity-financed and 43% is debt-financed. These numbers can be derived from an average ratio of debt ÷ equity = 0.74 ÷ 1 (Table 1), so that debt plus equity equals 1.74 normalized capital, equity capital = 1/1.74 = 57% (USD 138 of USD 242 billion total market capitalization is equity capital), and debt capital = 0.74/1.74 = 43% (USD 104 of USD 242 billion total market capitalization is debt).

Clearly, unconventional-gas operations must continue to create shareholder value in order to ensure sustainable security of indigenous gas supply. Although companies with excellent growth potential can sometimes boost shareholder returns by leveraging debt over equity-financing, debt gearing ratios larger than 0.4 to 0.5 can be considered too high and too risky. Small and early-stage companies often rely on private equity and debt financing, but the average gearing ratio of 0.74 for the North American unconventional-gas business in 2010 could be seen as exceptionally high. For a comparison, the world’s five leading oil and gas majors (Exxon, Chevron, Shell, BP, and Total) had an average debt-to-equity ratio of 0.22 at the end of Q1 2010. Equity financing provided 82% (USD 770 billion) of their market capitalization, and debt capital provided the remaining 18% (USD 170 billion).

Equity investors in unconventional-gas companies will continue their support only when future shareholder value is built rather than destroyed. Profit optimization and sustainable business growth remain the principal objectives for shareholders in natural-gas companies, while debt holders are usually more concerned with protecting their investment from default. This study aims to provide detailed insight into past performance and future challenges and opportunities for secure returns on investment in the unconventional-natural-gas business. This study juxtaposes the financial performance of unconventional-gas operators (**Table 2**) with 68 to 97% (mostly unconventional) gas production and diversified oil and gas majors with 32 to 41% (mostly conventional) gas

TABLE 1—THE 20 LEADING US AND CANADIAN GAS OPERATORS (listed *)

Company	NYSE Symbol	Market Cap 31 March 2010 (Bill. USD)	Ratio Gas/Total Production Q1 2010	Debt to Equity 31 March 2010
Southwestern Energy	SWN	13.0	1.00	0.44
Forest Oil Corporation	FST	3.0	0.98	1.51
<i>Petrohawk Energy</i>	<i>HK</i>	5.8	0.97	0.69
EnCana	ECA	22.8	0.96	0.45
Ultra Petroleum Corp.	UPL	7.0	0.96	1.28
EXCO Resources	XCO	3.7	0.96	0.31
Cabot Oil & Gas	COG	3.6	0.95	0.55
<i>Chesapeake</i>	<i>CHK</i>	14.5	0.90	0.89
<i>XTO Energy</i>	<i>XTO</i>	25.0	0.83	0.56
Range Resource Corp.	RRC	7.2	0.81	0.74
Quicksilver Resources	KWK	2.1	0.77	3.31
<i>EOG Resources</i>	<i>EOG</i>	26.5	0.75	0.37
Newfield Exploration	NFX	6.9	0.71	0.69
<i>Devon Energy</i>	<i>DVN</i>	28.5	0.68	0.33
Cimarex Energy	XEC	6.2	0.67	0.15
SM Energy Company	SM	2.7	0.64	0.23
Noble Energy	NBL	10.4	0.59	0.40
Anadarko	APC	25.9	0.58	0.55
Pioneer Natural Res.	PXD	7.4	0.55	0.64
Cenovus Energy	CVE	20.2	0.52	0.63
Average	—	12.1	0.79	0.74

* The 20 E&P operators active in US and Canadian gas production are selected using two criteria: capitalization above 2 billion USD and gas production accounting for more than half of total production output. Companies in red (italicized NYSE symbols) are used in further value analysis.

TABLE 2—UNCONVENTIONAL-GAS PRODUCERS AND DIVERSIFIED OIL AND GAS MAJORS ANALYZED IN THIS STUDY*				
Peer Group of Unconventional Producers	NYSE	Gas Output 2009 (bcf)	Gas/Total Output Ratio	Market Cap 31 March 2010 (Billion USD)
Devon Energy	DVN	966	0.68	28.5
EOG Resources	EOG	600	0.75	26.5
XTO Energy	XTO	855	0.83	25.0
Chesapeake	CHK	834	0.90	14.5
Petrohawk	HK	174	0.97	5.8
Totals	—	3,429	—	100.3
Peer Group of Oil & Gas Majors	NYSE	Gas Output 2009 (bcf)	Gas/Total Output Ratio**	Market Cap 31 Sep 2010 (Billion USD)
Exxon †	XOM	3,385	0.39	330
Shell	RDS	3,096	0.41	190
Chevron	CVX	1,820	0.32	168
British Petr.	BP	3,097	0.36	127
Total SA	TOT	1,797	0.39	123
Totals	—	13,195	—	938

* Production data from annual reports SEC K-10 and F-20 for 2009; Market capitalization from quarterly reports SEC Q-10.
** Ratio based on conversion of natural gas taking 5.8 Mcf gas for 1 bbl oil equivalence as is standard in SEC reports
† Production from XTO acquisition not included.

production. Such a comparison is useful because investors have a choice, and nonconventional gas companies ultimately must be able to compete with the strongest performers in their industry.

Methodology for Analyzing TSRs

TSRs have been calculated for unconventional-gas business and diversified oil and gas majors using representative peer groups, each comprising five companies as shown in Table 2. The Boston Consulting Group (e.g., Olsen et al. 2010) has advocated a model for quantifying the relative contribution of various value-creation components to TSRs. In this study, a similar TSR decomposition is adopted, distinguishing three value-creation components: (1) capital gains from economic growth driven by operational profits, (2) increase in price/earnings ratio (P/E) multiples, and (3) dividend payouts and share repurchases (Fig. 2).

Some principal differences between unconventional-gas companies and diversified majors can be inferred by comparing their cash-flow accounts and balance sheets; unconventional-gas

producers (Fig. 3a) and diversified majors (Fig. 3b) obtain their working capital from different sources. Fig. 3a shows that unconventional-gas producers must typically raise additional cash from financing activities (equity and debt financing) to supplement lagging cash flow from operations, in order to pay for new capital-expenditure (CAPEX) projects. The required CAPEX investments to secure future cash flows cannot be covered from the operational net cash flow of some unconventional-gas producers, as has been elaborated in an earlier cash-flow analysis of 24 oil and gas companies (Weijermars 2010b and 2011a).

The average profitability [return on average capital employed (ROACE)] for the peer group of unconventional-gas companies over the study period (2002–07) was 0.5%, which implies that the weighted average cost of capital (WACC) of approximately 7% was higher than the profits they earned. TSRs for the shareholders in the underperformers of this peer group are not generated by economic value added, but by investor expectations driving an improved share price. If equity finance is subsequently raised, this could provide collateral for new debt-financing, provided that gearing permits this. Debt can boost shareholder value by reducing the total cost of capital, depending on interest rates, and thus may add to capital gains of shareholder value. For some unconventional-gas companies studied here, a track record emerges with negative cash flow from operations (nonprofitable), which leads to a deteriorating cash position (low liquidity) and a weaker solvency for assets.

The diversified oil and gas majors in the peer-group panel studied here can typically cover all CAPEX needs from their net cash flow from operations. In fact, a detailed cash-flow analysis (Weijermars 2010b and 2011a) has shown that only half of their net cash flow suffices to cover new CAPEX outlays and the other half is used to reward shareholders with dividends and share repurchases (Fig. 3b). The average ROACE for the peer group of major oil and gas companies over the study period (2002–07) was 22%, which implies the WACC could be amply covered by them. Real economic value is added by all these diversified oil and gas companies, and new shares need not be issued by them. For these companies, the track record shows a high profitability on the income statement (profit/loss account), which translates to an excellent liquidity on the cash-flow account, which in turn creates room for the building and acquisition of new assets that continue to add value to the corporate balance sheet.

A powerful key performance indicator for monitoring the relative performance of oil and gas producers is the amount of profits

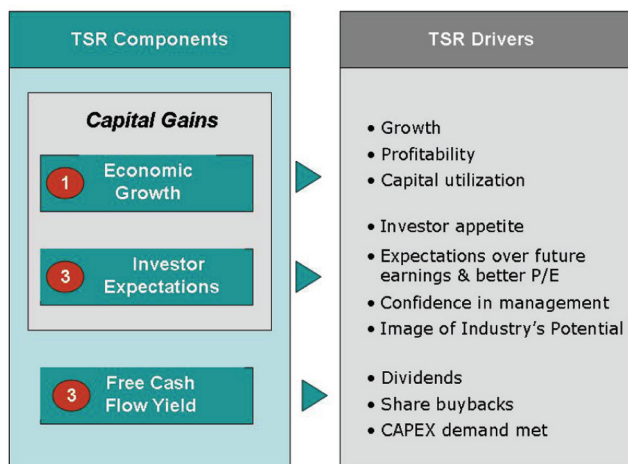


Fig. 2—TSR comprises three components: (1) economic value added from profit growth, (2) additional capital gains created by investor expectations, and (3) dividends and share repurchases, which can create additional value for shareholders.

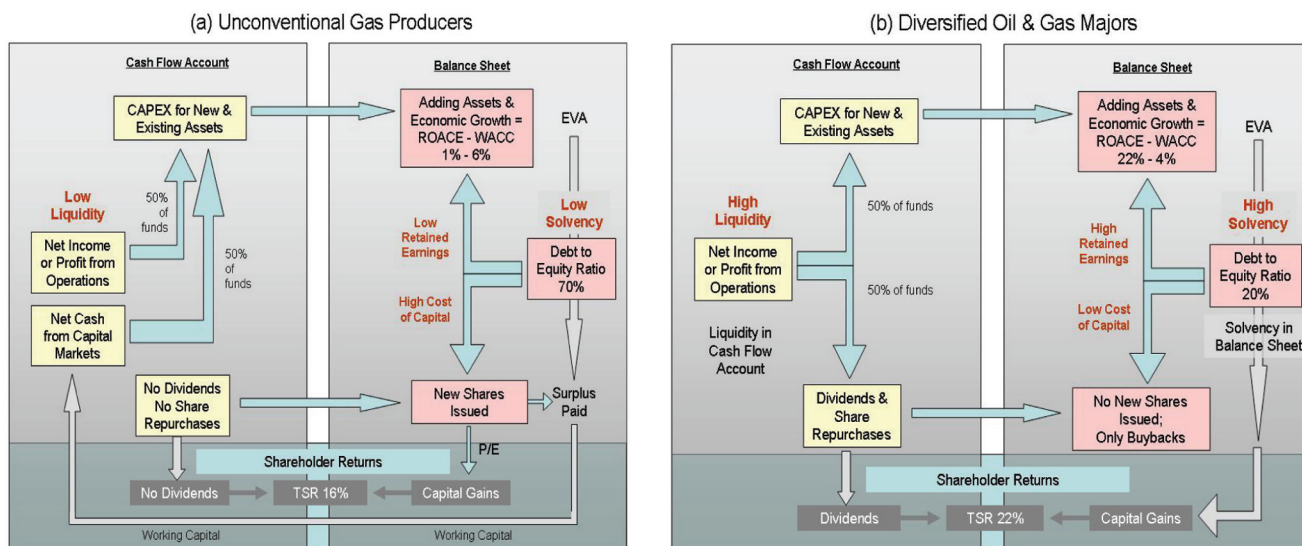


Fig. 3—Working-capital cycle for (a) unconventional-gas producers and (b) diversified oil and gas majors. Cash-flow sources (for liquidity in cash-flow accounts, left) and rate of economic value-added (EVA) by working-capital use (for solvency in balance sheets, right) have been analyzed for the two peer groups. The effects of liquidity and solvency on shareholder returns are schematically indicated.

(net cash flows) used by the company to reinvest in the business. This item is strictly accounted for in the annual US Security and Exchange Commission (SEC) filings of these companies (form 10-K for US companies and forms 20-F and 40-F for foreign entities) and appears as so-called retained earnings on the corporate balance sheet. Synonyms used for retained earnings are retained profits, earnings reinvested, reinvested capital, undistributed income, reserves, and, when negative, accumulated deficit.

Retained earnings start to accumulate from the incorporation of a company and are recorded over the full trading life of the company. The cumulative profits retained by the company (after any dividend payouts and share repurchases) are commonly used by the company to help finance assets growth. Fig. 4 plots the retained earnings for our peer group of diversified oil and gas majors, which grow year-after-year and accelerated over the past decade. Table 3 shows the corresponding data. Rapid growth in retained earnings continued over the past decade in spite of remitting 50% of the net cash flow from operations to shareholders [actual average for the peer group; for details, see the separate cash flow analysis by

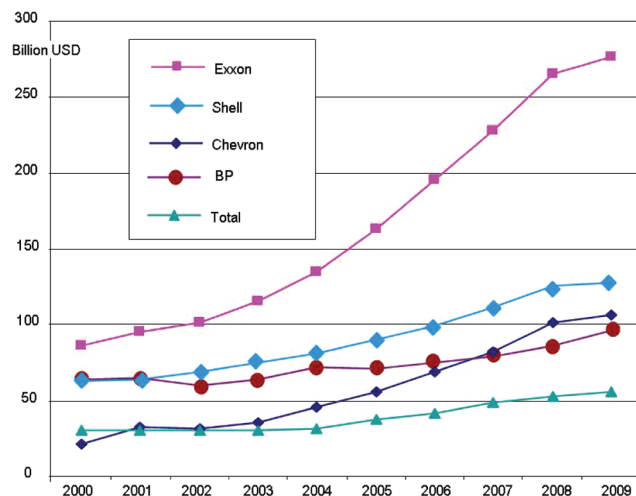


Fig. 4—Accumulation of retained earnings (billion USD) for peer group of diversified oil and gas majors in profitable operations over the past decade, after payment of dividends and share buybacks. Exxon is the outperformer, and Total S.A. is lagging in the peer group. Table 3 has the source data.

Weijermars (2011a)]. This means diversified oil and gas companies have done well in generating economic value as well as TSRs by using retained earnings for reinvestment in company assets.

Fig. 5 plots the retained earnings for our peer group of unconventional-gas producers over the past decade; Table 4 shows the corresponding data. A modest growth in retained earnings occurred over the past decade for three operators (Devon, EOG, and XTO). However, the two most active unconventional-gas players (Chesapeake and Petrohawk) show a weak track record when it comes to earning any profits for reinvestment in the company: They have not earned any positive net profit for reinvestment in the company as per 31 Dec 2009. Instead of accumulating positive retained profits, both companies accumulated deficits in the 20-year (Chesapeake) and 13-year (Petrohawk) life cycles of their business existence. Chesapeake was beginning to accumulate some positive retained profits between 2004 and 2008 but lost all of these profits in 2009 (Fig. 5). Devon Energy has done well in the past, but has seen some of its previous retained earnings evaporate after operational losses began to mount because of the low gas prices of mid-2008; nearly USD 5 billion of retained earnings was lost again from its balance sheet in the course of 2008 and 2009 (Fig. 5).

Table 5 summarizes some of the major differences observed in the business performance of unconventional-gas producers and diversified oil and gas majors from a financial-analyst perspective. The past decade's track record of some of the unconventional-gas companies studied here is characterized by a declining business performance—low profitability leads to poor liquidity, which in turn diminishes the firm's solvency. The working-capital model of Fig. 3a applies to such unconventional-gas companies. For diversified oil and gas majors, the track record is much better, with high profits, excellent liquidity, and robust solvency. The shareholder returns in these conventional oil and gas companies come from real capital gains due to realized operational profits, plus dividend payments. The working-capital model of Fig. 3b applies to such diversified oil and gas companies.

Quantitative Analysis of Past TSR Performance

The equity investment in any company must satisfy shareholders with a rate of return on investment (TSR) that rewards investors for the risk taken. The cost of equity can be estimated using the capital asset pricing model (CAPM) (Lewis and Pendrill 1996; Lumby and Jones 2003). Management must align its efforts with the interests of shareholders to realize high returns on investment. Shareholder value is critically dependent on profitability and capital use, as discussed in dedicated accounting journals (Andersson et al. 2006,

TABLE 3—CUMULATIVE RETAINED EARNINGS FOR DIVERSIFIED OIL AND GAS MAJORS OVER 10-YEAR PERIOD (2000–2009)*

	NYSE	Listed	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Exxon	XOM	1882	87	96	101	116	134	163	195	229	266	277
Shell	RDS	1890	62	64	68	75	81	91	100	112	125	128
Chevron	CVX	1926	21	33	31	35	45	56	68	82	101	106
British Petr.	BP	1889	64	65	60	64	71	71	75	79	86	96
Total SA **	TOT	1924	30	31	31	30	32	38	41	49	53	55

* in billion USD. All data abstracted from K-10 and F-20 Sec filings.

** Total SA reports in Euro.

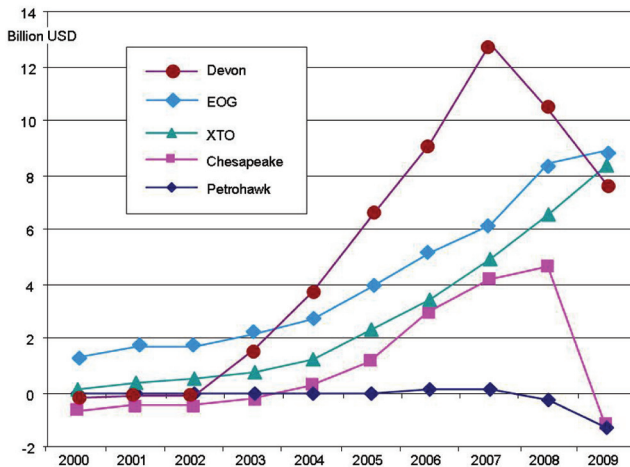


Fig. 5—Accumulation of retained earnings (million USD) for peer group of unconventional-gas producers varies from steady (XTO and EOG), to volatile but still good (Devon), to negative (Chesapeake and Petrohawk). Table 4 has the source data.

2008). Stock performance is a reflection of a firm’s efficiency in attracting earnings and accruals to realize positive cash flows (Dechow 1994) on the basis of future expectations.

TSRs calculated in this study are based on the following definition:

$$TSR (\%) = 100 \times [(P_{T_{final}} - P_{T_{start}} + D_{cum}) / P_{T_{start}}], \dots \dots (1)$$

where P denotes share prices at beginning (subscript T_{start}) and end (subscript T_{final}) of the study period and D_{cum} are the dividends accrued. The capital-gains portion of a company’s TSR performance is given by $(P_{T_{final}} - P_{T_{start}})$.

The three performance components that can affect TSR are profit growth (or decline), an increase (or decrease) in investor expectations, and free cash-flow yield (dividends and share repurchase, Fig. 2). These are detailed below.

Profit Growth (or Decline). One way of representing the components mathematically is as follows:

$$Profit\ growth (\%) = 100 \times (\Delta E / E_{T_{start}}), \dots \dots (2)$$

where ΔE represents the absolute improvement or decline in earnings and $E_{T_{start}}$ is the starting figure. The end result is a percentage improvement or decline in profitability.

Increase (or Decrease) in Investors’ Expectations. The P/E ratio (price per share/company earnings per share) can be understood as the company’s market capitalization divided by its total corporate annual earnings. If the P/E ratio is 10, then the purchaser of the stock is paying USD 10 for every dollar of earnings (net income) for the company. P/E ratios are the most common measure of investor expectations. Higher P/E ratios commonly reflect a greater expectation for further share price appreciation and profit improvement in the future.

$$Increase\ (or\ decrease)\ in\ investor\ expectation = [100 \times (P_{T_{final}} - P_{T_{start}}) / P_{T_{start}}] - profit\ growth (\%). \dots \dots (3)$$

To allow for negative earnings figures, which complicate the mathematics of P/E ratios, this form of equation essentially divides the percentage increase in share price (the capital gain) of the study period into that part that can be explained, with some caution, by profit improvement or decline and that part that might be explained by increased or reduced investor expectations. New capital issues do not necessarily raise share price, but do add working capital on the company’s balance sheet (Fig. 3a).

Free Cash-Flow Yield. The dividend contribution to TSR can be expressed as follows:

$$Dividend\ yield (\%) = 100 \times [D_{cum} / (P_{T_{final}} - P_{T_{start}} + D_{cum})]. \dots \dots (4)$$

Other definitions of free cash flow exist. This one focuses on dividends. In the case of share buy backs, the free cash-flow yield follows from the total amount of cash paid to share buy backs divided by the market capitalization.

Benchmarking TSRs of Conventional and Unconventional Producers

Fig. 6 shows an analysis of past shareholder value creation (TSR) by the five established major oil companies, which hold mainly conventional oil and gas assets. Their average TSR amounted to 23%, which is the compounded annual growth rate (CAGR) over the 6-year study period (2002–07). This TSR came primarily from economic value added through profit growth (27% on average) and in smaller part from free cash-flow yield (7%), while some TSR value was lost because of a decline of P/E multiples (–11%).

TABLE 4—CUMULATIVE RETAINED EARNINGS FOR UNCONVENTIONAL-GAS PRODUCERS OVER 10-YEAR PERIOD (2000–2009)*

	NYSE	Listed	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Devon	DVN	1988	–215	–147	–84	1,614	3,693	6,477	9,114	12,813	10,376	7,613
EOG Res.	EOG	1985	1,301	1,669	1,724	2,121	2,707	3,920	5,151	6,156	8,466	8,866
XTO Energy	XTO	1990	84	329	510	763	1,240	2,311	3,442	4,938	6,588	8,317
Chesapeake	CHK	1989	–659	–442	–426	–168	263	1,101	2,913	4,150	4,596	–1,261
Petrohawk	HK	1997	–6	–15	–23	–22	–15	–32	84	137	–251	–1,276

* in million USD. All data abstracted from K-10 and F-20 Sec filings.

TABLE 5—MAJOR DIFFERENCES IN FINANCIAL PERFORMANCE OF UNCONVENTIONAL- AND CONVENTIONAL-GAS COMPANIES

Unconventional Gas Company	Diversified Oil & Gas Majors
<p>Income Statement</p> <ul style="list-style-type: none"> • Low profitability • Net income or ROACE is low (0.5%) • Cost of capital is high (6-7%) <p>Cash Flow Account</p> <ul style="list-style-type: none"> • Low liquidity • Net cash from operations insufficient to cover CAPEX programs needed (up to 50% short) • New cash raised from capital markets to supplement net income from operations; income from financing activities is important source of cash <p>Balance Sheet</p> <ul style="list-style-type: none"> • Low solvency • Debt to equity ratio is high (70 to 75%) • No or little earnings retained • Capital gains for shareholders comes from surplus paid for new shares over par value in anticipation of future growth <p>Stock Market</p> <ul style="list-style-type: none"> • Shareholder returns volatile • Initial TSR can be high because of fast rate of capital gains from new equity issuance • Capital gains from economic value added can be negative in the short term • Capital gains mostly coming from new equity surplus paid-in over par value • P/E multiples unpredictable • No share repurchases • No or negligible dividends 	<p>Income Statement</p> <ul style="list-style-type: none"> • High profitability • Net income or ROACE is high (22%) • Cost of capital is low (4-5%) <p>Cash Flow Account</p> <ul style="list-style-type: none"> • High liquidity • Net cash from operations more than sufficient to cover CAPEX programs needed (only 50% needed) • No new net cash raised from capital markets; income from financing activities is negligible <p>Balance Sheet</p> <ul style="list-style-type: none"> • High solvency • Debt to equity ratio is low (20%) • High retained earnings • Capital gains for shareholders comes from the future reliability of a stream of operational profits <p>Stock Market</p> <ul style="list-style-type: none"> • Shareholder returns steady • TSR can be high because of fast rate of capital gains from profits on new projects • Capital gains from economic value added is positive • Capital gains not coming from any new equity issued • P/E multiples are relatively steady • Frequent share repurchases • Attractive dividends

Fig. 7 shows the TSR buildup for the five unconventional-gas companies included in the peer group. These results reveal that capital gains of market capitalization have been largely driven by share price increases fuelled by investors' future expectations and much less by economic value added through profit growth. The analysis of past shareholder value creation in the peer group of unconventional-gas companies further revealed that free cash-flow yields are negligible. The capital gains contribution by investor expectations (P/E multiples) has outperformed the contribution by economic profit for all five companies studied. It can be concluded that investments in unconventional-gas companies deliver TSRs that are based on rapid growth by capitalizing on investors' appetite and issuing new shares. These shares have then funded capital expenditure to amass more asset value, and fuel further investor interest with fast growth of market capitalization. This is what has driven past TSR on investments in the US unconventional-gas business. Such a growth pattern is typical for the early stage of new business development. Nonetheless, the creation of any long-lasting and sustainable shareholder value must be built on profit growth from operations.

Six Principal Value Drivers for Future Shareholder Returns

This study proceeds to analyze the potential for future value growth in the unconventional-natural-gas business segment. Generating economic value added growth by higher profitability (ROACE) and lower cost of capital (WACC) is essential to create sustainable capital gains for shareholders in any natural-gas business (Fig. 3a). A simple framework is adopted here for better understanding the value drivers of a competitive advantage for natural-gas companies

(Fig. 8). This practical model distinguishes six principal value drivers (Watson 2010):

1. Production volume.
2. Commodity pricing.
3. Full-cost accounted production.
4. Fixed asset capacity use.
5. Working capital employed.
6. Rate of capital cost.

These principal value drivers are in any business, including the natural-gas business, interconnected as shown in Fig. 8. The key parameters that affect the value drivers of intrinsic profit growth are production volume, pricing, and full-cost accounted production expenses. Current business profits (on the annual and quarterly profit/loss statements) are created by the product of sales volume and net commodity value (commodity price – unit cost). The balance sheet shows how business value is accumulating in the company, and total net assets (fixed assets plus working capital) must be funded by capital financing (debt and equity). The cost of capital (e.g., WACC), commonly comprising payments for a combination of debt and equity capital, indicates a minimum for how much return investors should expect to make on their investment for the risk they are taking.

Management of unconventional-gas companies must prudently build investor value. Three possible cases of management-competency level and business-opportunity quality can be distinguished:

- Competent management and poor business opportunity. Management of concurrent US gas business commonly operates in this category.
- Competent management and excellent business opportunity. Future higher gas prices may create opportunities that competent management could exploit.

Conventional Oil & Gas Producers

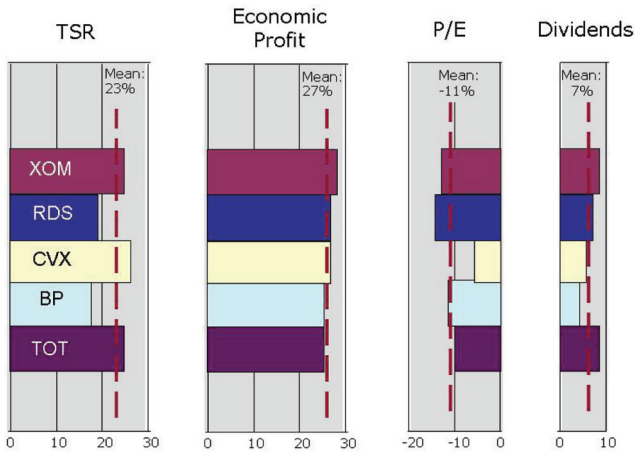


Fig. 6—Example of TSR buildup for the world’s five leading oil and gas majors over a 6-year study period (31 Dec 2002 to 31 Dec 2007). Breakdown of TSR contribution by each of the three components: (1) capital gains through EVA because of profit growth, (2) capital gains through P/E multiples created by investor expectations, and (3) dividends and share repurchases from free cash flow.

Unconventional Gas Producers

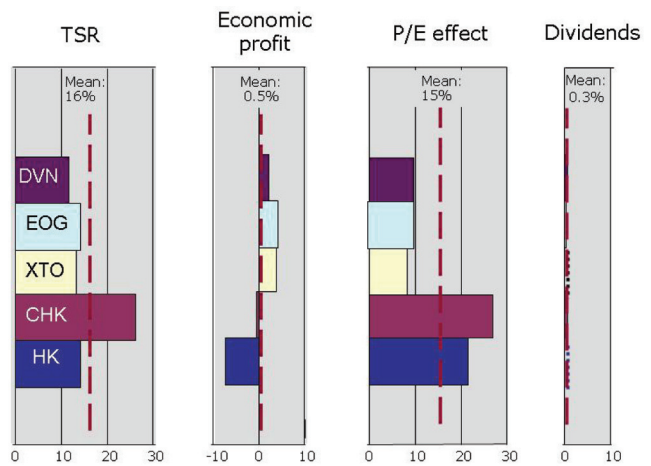


Fig. 7—Example of TSR buildup in the peer group of five unconventional-gas producers over a 6-year study period (31 Dec 2002 to 31 Dec 2007). Breakdown of TSR contribution by each of the three components: (1) capital gains through EVA due from profit growth, (2) capital gains through P/E multiples created by investor expectations, and (3) dividends.

- Incompetent management. No matter what business opportunity arrives, business value will be destroyed by incompetent management in all cases.

The aim of competent management, whether operating in a poor or excellent business climate, must be the optimization of the parameter settings for each value driver. This includes asking questions such as “What is our company’s competitive advantage?” and “How long will it persist?” This is not only an analytical strategy exercise, but also a team challenge, and dedicated training may help to keep the management team aligned (Watson 2010).

The strategic management of unconventional-gas companies can build business value by optimizing operational profits in a difficult business environment. Unconventional-gas business must learn to generate further capital gains from economic value added rather than by issuance of new equity capital. Investors have become increasingly reluctant to bankroll debt rollover, and the equity

market will not easily raise more equity capital for unconventional-gas companies. **Table 6** provides additional questions for optimizing the value drivers for profit growth and business optimization. For example, production volume can be enhanced by acquiring field assets only into acreage that holds sweet spots, so that the volumes for the expected ultimate gas recovery are high. The company must have a strategy to mature its technically recoverable resources into economically recoverable proved reserves with the lowest expenditure and the highest density of sweet spots. Sweet spots are geological conditions that favor commercially viable well flow rates and high ultimately recoverable volumes that surpass the expectations for tail-end gas production. Volume-connected-to-the-well can be enhanced by hydraulic fracturing but is costly and pays back only if sweet spots can be “created” by this method.

Natural-gas prices cannot be influenced by the company, but timing of asset development can. Timing of asset development can positively affect gross margins when seizing the future moment when natural-gas prices are better than today. Gas prices are currently low, but can be higher in the future and that is when production of capped wells of nonproducing proved reserves could become increasingly attractive in Europe and elsewhere. Full-cost-accounted gas production means prudent cost management can make a difference between destruction and creation of shareholder value.

When it comes to the building of long-term business value, the accumulation of profitable net assets in the company’s balance sheet (Table 6) is important, and capital expenditure on additional assets must be funded by free cash flow from operations, often complemented with additional capital financing (Weijermars 2010b). The cost of capital is currently high for startup companies because of relatively low credit ratings (commonly BB Junk bond status, or lower investment BBB grade), which therefore have a distinct competitive disadvantage over established companies with credit ratings of AAA to AA (for details, see Weijermars 2011a). This study further discusses how security of gas supply is influenced by the profit/loss opportunities for unconventional-natural-gas companies under current and future natural-gas prices, and cost of current and future technology recovery capacity.

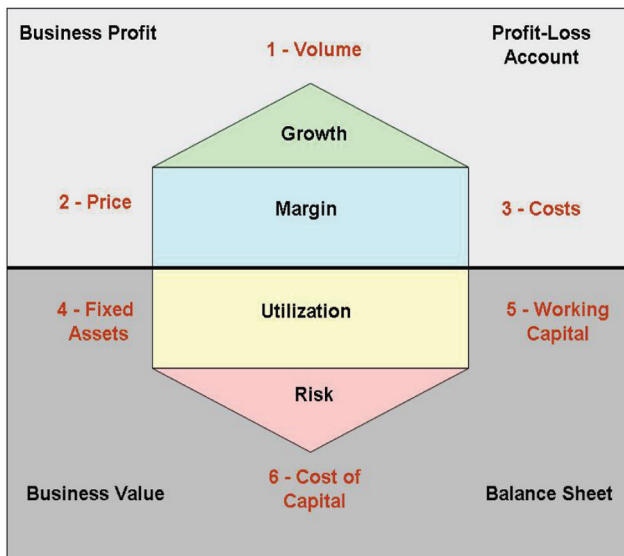


Fig. 8—Six financial drivers of business value must be actively managed in strategic planning and operational execution. [Model after Watson (2010)].

Profit-Optimization Parameters

Sustainable business value in unconventional-gas operations must be built primarily on profits and not on continuous equity issuance. The key parameters that determine the settings of three principal

TABLE 6—KEY QUESTIONS AND OPTIMIZATION AIMS FOR UPPER MANAGEMENT OF UNCONVENTIONAL-GAS COMPANIES

Income Statement (Profit-Loss Account)		
Value Driver	Key Questions for Management	Optimization Aim
1 - Volume	Where did growth come from? Where will it come from? What is our strategy for growth?	Find sweet spots. Minimize development of subcommercial wells.
2 - Pricing	How do we add value in the eyes of our shareholders? What is our strategy for adding value in the future?	Raise the wellhead price of natural gas by stimulating demand or defer production.
3 - Prudent cost management	Do we achieve economics of scale, scope or skill? Will they continue to apply? What strategies do we have for maintaining or gaining economies?	Use smart completion technology and risk analysis for improved decision making profit margins optimization.
Balance Sheet		
Value Driver	Key Questions for Management	Optimization Aim
4 - Fixed assets use	What capacity resources or constraints do we face? Which will we face in the future? What is our strategic response?	Acreage must be used such that reserves mature without undue delay.
5 - Working capital management	How efficient and speedy is our supply chain? Will it be more or less in the future? How critical is it? What strategies do we have?	Clockspeed must be faster to capitalize on the time value of money. Make sure capital comes from operational profits mainly, and not from unsustainable income from financing activities.
6 - Cost of capital	How does the market perceive the level of risk in our business? How will this change? What is our strategy for managing risk?	Risk must be minimized and credit rating improved to bring WACC down and keep volatility in check (beta values should be 1 or lower).

value drivers for value adding through profit growth (production volume, pricing, and costing) are discussed further in this section. **Table 7** shows the typical items that make up the cost structure for oil and gas operators. A direct comparison of total commodity production cost structure for unconventional-gas operators and diversified oil and gas majors is not attempted here. Conventional oil and gas companies in our peer group panel report all production cost (including natural gas) in USD per barrels of oil equivalent (\$/BOE). In contrast, most unconventional operators report all production cost (including oil) in USD per thousand cubic feet gas equivalent (\$/Mcf). Conversion of the cost structure for the two peer groups is included, but remains positively biased for oil-income-dominated conventional oil and gas companies, and negatively biased for natural-gas-income-dominated unconventional operators. Therefore, cost structure is analyzed here separately for each peer group.

The profitability of commodity sales price vs. unit cost of an oil and gas operator can be concisely expressed by the margin. The margin essentially shows the difference between revenue (often before corporate tax) and expenditure, divided by the revenue:

$$\text{Margin (\%)} = 100 \times (\text{pretax profit/revenue}). \dots \dots \dots (5)$$

Pretax profit is gas revenue less expenses; a margin of 15% means that the company makes USD 0.15 profit on every dollar of gas sales revenue (note that the main difference between margin and ROACE used in Eq. 2 is that ROACE is a measure for return on investment while margin is measure for return on sales. Both can be expressed as before or after tax).

Fig. 9 provides a breakdown in the commodity cost per barrels of oil equivalent (BOE) for each of the five leading conventional oil and gas majors. The margins received by the upstream activities of these conventional operators are included in Fig. 9, using the integrated mean of commodity sales price realized over the year. Production volumes of natural gas, oil, and other liquids are indicated in both BOE and Mcfe. The standard conversion used in annual reports by conventional oil and gas companies converts gas-production volumes to oil volume equivalent (and vice versa) using a factor of 5.8 Mcf/bbl. Distinctly different, unconventional-gas companies commonly convert gas and oil in their annual reports on production volumes and reserves using a conversion factor of 6 Mcf/bbl per barrel of oil, on the basis of the approximate relative

energy contents of gas and oil. Convergence and agreement on a universal conversion factor for oil and gas volumes in accounting reports for oil and gas companies clearly is an area that needs attention in future updates of SEC regulation and reporting standards. The conversion scales used in the left and right volumetric price scales of Fig. 9 and **Figs. 10 through 14** are all based on the conversion factors adopted by the respective companies graphed.

The realized pretax margin is highest for Exxon (52%) and lowest for Shell (33%) based on 2009 upstream performance. Cost of interest payments is negligibly small for all operators in the conventional-gas peer group. Fig. 9 reveals principal differences in the cost made for reserves replacement in depletion, depreciation and amortization (DD&A) (Table 7), which are the lowest for Exxon (at 1.04 \$/Mcf) and the highest for Shell (at 1.79 \$/Mcf). This reflects a pattern where Exxon succeeds in replacing depleted production volumes at 58% of the cost made by Shell (using DD&A as the indicator). A future strategy for Shell could focus on an improved margin by finding cheaper finding, development and acquisition (FD&A) (see Table 7) volumes, such as those Exxon succeeds in. What is also striking in Fig. 9 is that BP production cost [lease operating expenses (LOE)] is lowest for the peer group. This cost is a reflection of the fact that much of BP's production is in low-cost economies (e.g., Russian TNK-BP venture), which also explains the relatively low average price per unit volume fetched by BP (Fig. 9) in these regional markets. The concatenated income components from the various business segments of the vertically integrated majors (upstream, downstream, and chemicals) have been analyzed separately in a proprietary study that shows that upstream income growth is lagging compared to the income growth from the downstream and chemical segment over performance period (2002-07).

The commodity unit cost for unconventional-gas companies has also been analyzed for the five peer-group companies. The conventional oil and gas companies all had good to excellent margins in 2009 (Fig. 9), but this cannot be said for unconventional gas companies. In fact, all have negative 2009 income from gas sales, with the exception of XTO, which has managed to mitigate the low natural-gas prices by an exceptional hedging strategy and thus still deliver a positive margin in 2009. In order to track the margin performance of the five unconventional-gas companies in the peer group, their results have been studied over a 3-year period covering 2007 (before the Great Recession), 2008 (onset of the Great Financial Crisis in August 2008), and 2009 (recovery from the Great Recession).

TABLE 7—TYPICAL COMMODITY COST AND EXPENDITURE FOR OIL AND GAS COMPANIES

Term	Description	Alternative Terms and Explanations
LOE	Lease operating expenses or operating expenditure.	Lifting cost, production cost, includes gas processing cost, i.e. removal of water, CO2 and H2S.
Basis	Gathering and transportation cost.	Cost for bringing gas from the wellhead to the entry point of the gas transmission operating system
G&A	General and administration (G&A) costs.	Overhead cost of the company, including insurance policy payments.
Direct Taxes	Direct taxes other than income taxes.	Production, severance and labor taxes; may include royalties.
Interest	Cost of debt capital.	Cost depends on credit rating of the company.
Exploration	Cost of exploration or finding cost. Firms that use the successful effort accounting method capitalize only those exploration costs associated with successfully locating new reserves. Cost for dry holes and unsuccessful plays are immediately expensed.	Firms that use the SEC full-cost accounting method retain all exploration costs and account for cost of dry holes and asset impairments. Includes cost of geophysical data acquisition (logs, seismics) and evaluations of resource potential. This cost then prorates over the FD&A of successfully developed assets.
Acquisition	Acquisition accounts for cost of land leases, any signing bonuses and permits, plus title searches.	Purchases of new acreage by new project, joint venture or M&A activity; Cost of future acreage may be more expensive to acquire when signing bonuses go up (or reverse).
F&D	Finding and development (F&D) cost is complementary to purchases and acquisitions when accounting for finding and development cost, excluding the cost of land lease.	F&D accounts for cost of exploration, drilling and well completion cost, including the cost of any hydraulic fracturing and other well stimulation techniques.
FD&A	All-in finding cost, defined as all costs incurred for acquisition, finding (exploration), and development (drilling and well completion), divided by the sum of reserve extensions, additions, and revisions.	Reserves replacement cost—cost of any EOR or overhaul is also accounted for in FD&A. Incurred cost will lead to higher recovery factor and increases reserves; cost of abandonment of platforms and wells not.
DD&A	Depletion, depreciation and amortization. Depletion means depreciation of cost for replacement of reserves produced; the depreciation matches diminished value of assets acquired through past FD&A cost.	Impairment of gas property asset carrying value can lower current DDA cost; downtime of well will mean production is deferred; no depreciation cost over deferred production.
Other Depreciation, Amortization	Depreciation and amortization of additional property and equipment, often gathering and midstream pipelines.	May also include depreciation cost of company vehicles used for operations and any storage facilities.
Impairment	Impairment of gas property asset carrying value. Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties.	Unproved and proved properties with significant acquisition costs are amortized over the lease term and any impairment in value is immediately expensed based on net present value (NPV) analysis.
Abandonment	Cost of abandonment of installations.	Asset retirement cost.
Research and development (R&D)	Cost of research and development.	Major companies incur significant R&D cost (commonly 1% of earnings), which is expensed on the income statement before income taxation
Discount	Discount value is commonly set at 10% in SEC filings and accounts for risk premium.	Corporate hurdle rate, accounting for return on capital risked.
Comments		
Depreciation	Depreciation refers to prorating a tangible asset's cost over that asset's life. The cost is spread out over the predicted life of the field, with a portion of the cost being expensed each accounting year.	For example, an office building and fixed wellheads can be used for a number of years before these become run down and obsolete.
Amortization	Amortization usually refers to spreading an intangible asset's cost over that asset's useful life. For example, the cost of a licence is spread out over its life cycle, with each portion being recorded as an expense on the company's income statement.	It is important to note that in some countries (e.g., Canada) the terms amortization and depreciation are often used interchangeably to refer to both tangible and intangible assets.

Fig. 10 plots the cash margins for Devon Energy; the company uses the full cost method of accounting. Cost of impairments have evaporated any positive margins in 2008 and 2009 and resulted in pretax margins of -24 and -48%, respectively. For all unconventional-gas companies, the cost of reserves replacement tends to vary over the past 3 years. A rising cost of DD&A trend is highlighted in the graphs for EOG Resources (Fig. 11) and XTO Energy (Fig. 12). Devon energy has impaired significant oil and gas asset carrying value in 2008 and 2009, which tends to offset the cost pressure on

replacement of produced volumes reflected in the reduced DD&A for 2009. The impairment cost can be understood as write-offs or expensing of oil and gas assets for which FD&A was already paid for in the past on the basis of economic proved reserves status at earlier prevailing market projections but now no longer deemed economic for the foreseeable future; DD&A will be unburdened by the impairment charge in most cases. Devon also has taken some asset retirement cost in 2008 and 2009, which differs from impairment, depletion, and depreciation cost; asset retirement costs are related

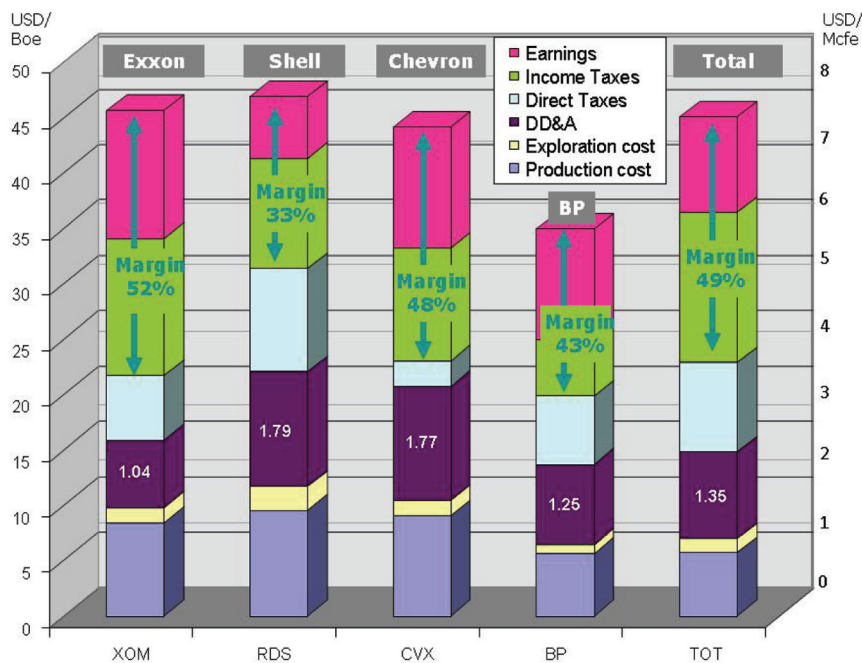


Fig. 9—Breakdown of commodity cost per barrel oil equivalent (BOE) and Mcf gas equivalent (Mcf) for conventional 2009 production by the five leading Oil Majors: Exxon (XOM), Shell (RDS), Chevron (CVX), British Petroleum (BP), and Total S.A. (TOT). Direct taxes include production tax, severance tax, labor tax, royalties, and other cost incurred. Production cost includes G&A and basis cost. Acquisition and development are expensed, and replacement cost of assets is included in DD&A. Meaning of terms is given in Table 7 (All data from 2009 K-10 and F-20 SEC filings).

to facility abandonment, dismantling, and environmental remediation. Devon had some USD 1.5 billion revenue from marketing and midstream activities, contributing USD 0.5 billion to 2009 net income. This income is excluded from the margin for 2009. Devon's minimum full-cycle cost of commodity less impairments is 3.78 \$/Mcf in 2009; this rate does not include FD&A for total asset base (only DD&A for depleted production).

Fig. 11 plots the margins for EOG Resources. The company uses the successful efforts method of accounting. EOG made a

small profit in 2009 by asset sales (hence the income tax), but its margin from oil and gas sales is negative. EOG also received marketing, gathering, and processing revenues of USD 407 million, with a net income contribution of USD 350 million after expenses. The DD&A cost for EOG has steadily increased between 2007 and 2009 because of increasing cost of new land leases to replace depleted production. EOG's minimum full-cycle cost of commodity less impairments is 4.04 \$/Mcf in 2009; again FD&A for the total asset base is not included.

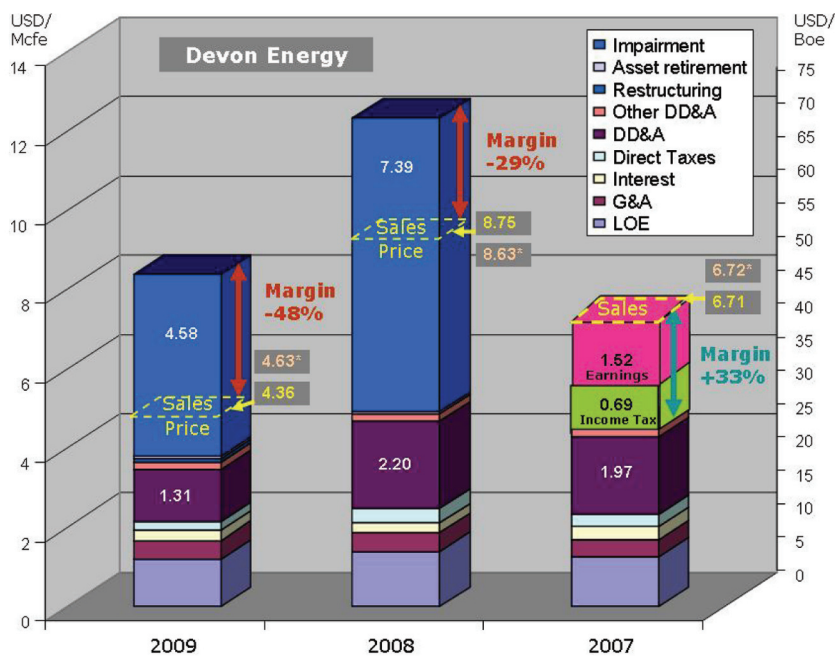


Fig. 10—Margin for Devon Energy based on commodity cost and realized sales price per BOE and Mcfe. Mcfe sale price given with derivative gains included (*) and without derivative gains. Meaning of terms is explained in Table 7 (All Devon data abstracted and converted from SEC K-10 filings).

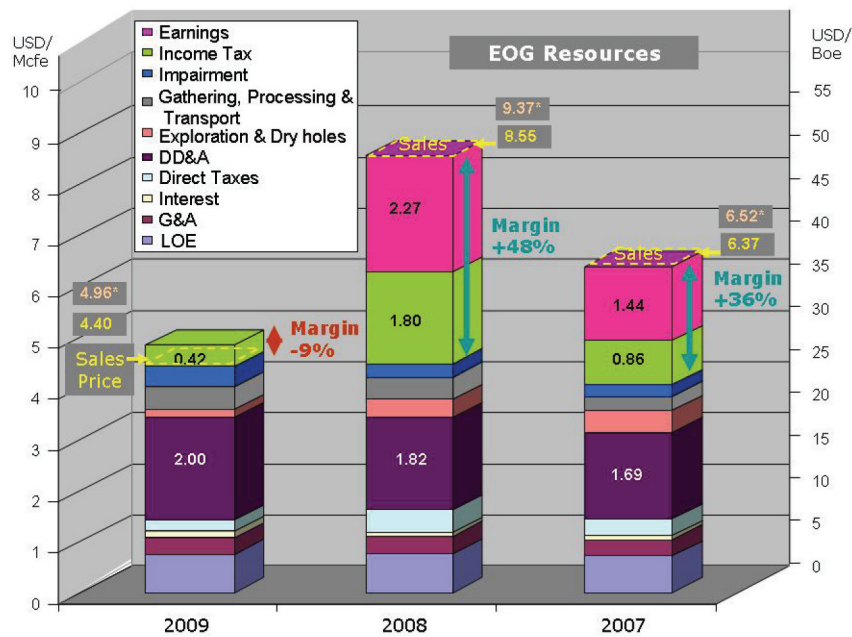


Fig. 11—Margin for EOG Resources based on commodity cost and realized sales price per BOE and Mcfe. Mcfe sale price given with derivative gains included (*) and without derivative gains. Meaning of terms is explained in Table 7 (All EOG data abstracted and converted from SEC K-10 filings).

Fig. 12 plots the cash margins for XTO Energy. The company uses the successful efforts method of accounting. Approximately half of XTO’s realized sales price for 2009 (8.54 USD/Mcfe) is because of effective hedging. Under the provisions of the Derivatives and Hedging Topic of the Accounting Standards Codification, these physical commodity contracts qualify for the normal purchases and normal sales. The financial impact of physical

commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices. The DD&A cost has steadily increased between 2007 and 2009 because of increasing cost of new land leases to replace depleted production. XTO’s minimum full-cycle cost of commodity less impairments is 5.62 \$/Mcfe in 2009; FD&A of the full asset base is only partly accounted for in DD&A.

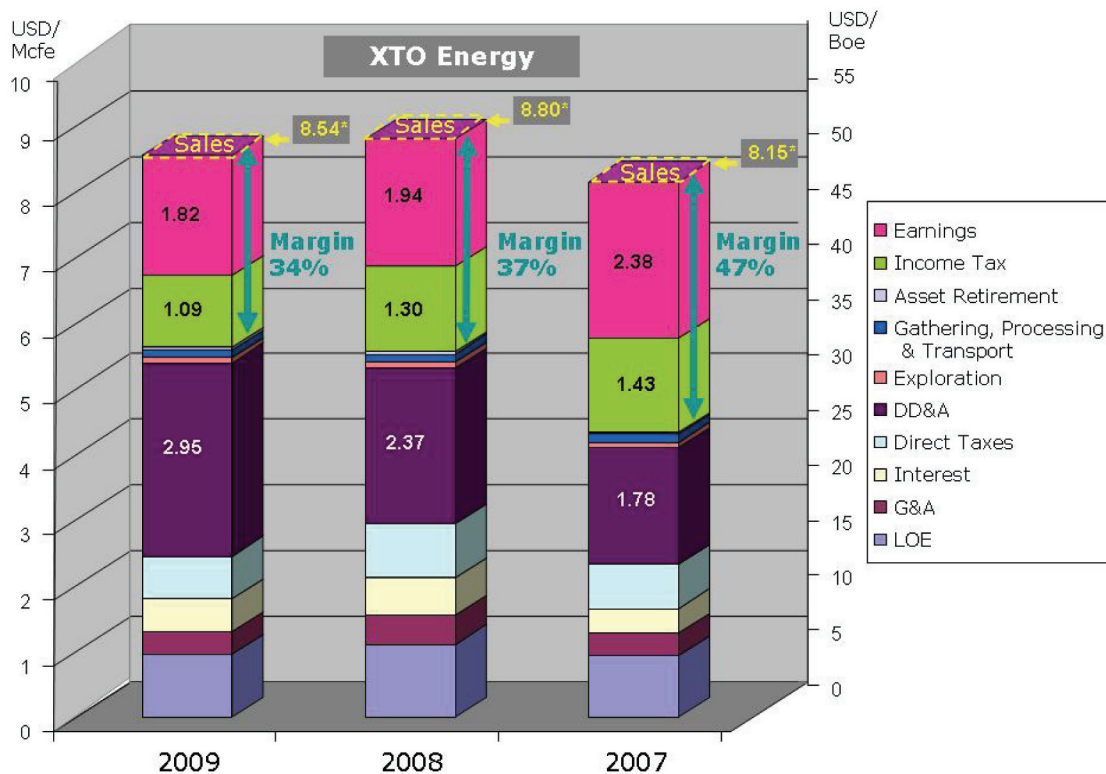


Fig. 12—Margin for XTO Energy based on commodity cost and realized sales price per BOE and Mcfe. Mcf sales price indicated with (*) includes proceeds from hedging activities. Meaning of terms is explained in Table 7 (All XTO data abstracted and converted from SEC K-10 filings).

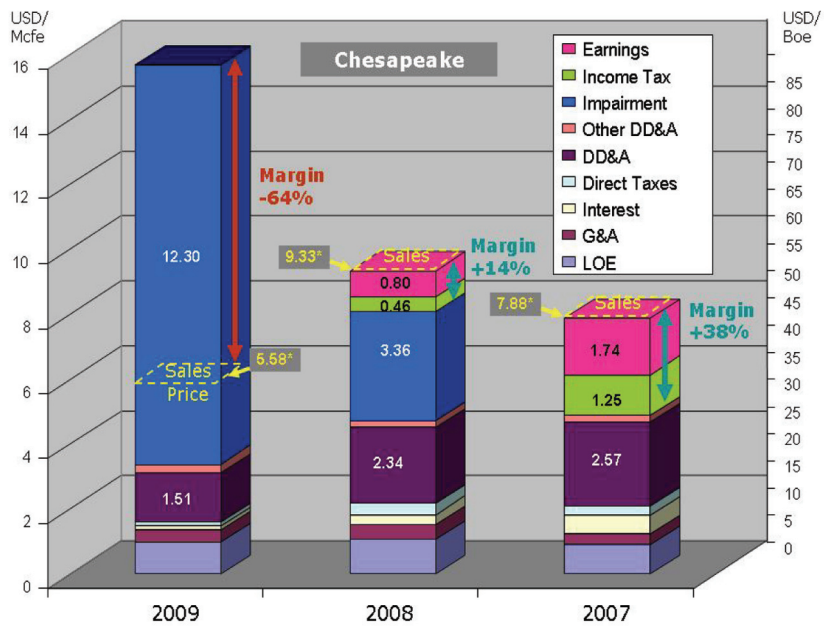


Fig. 13—Margin for Chesapeake based on commodity cost and realized sales price per BOE and Mcfe. Mcf sales price indicated with (*) includes proceeds from hedging activities. Meaning of terms is explained in Table 7 (All Chesapeake data abstracted and converted from SEC K-10 filings).

Fig. 13 plots the cash margins for Chesapeake. The company uses the full cost method of accounting. DD&A cost should increase over the years in principle, but is reduced by the impact of impairments. The hefty impairment charges taken in 2008 and 2009 had to be capitalized by CHK because the evaluated portion of its full-cost portfolio exceeded the present value of expected future cash flows of proved reserves (using the SEC’s mandatory 10% discount rate). The impairment charge brings the company’s asset carrying value of oil and gas properties back into balance with their expected future values. CHK’s minimum full-cycle cost of commodity less impairments is 3.38 \$/Mcf in 2009; FD&A is only partly accounted for in DD&A.

Fig. 14 plots the cash margins for Petrohawk; the company uses the full cost method of accounting. As with Chesapeake, the DD&A cost incurred by Petrohawk should increase over the years in principle, but this increase is reduced in 2009 by the impact of impairments. Fig. 5 already showed that the company has not managed to retain any earnings from operations over its trading. Petrohawk has some additional revenue from marketing activities, but only USD 12 million net income remains as revenues (USD 350 million) are nearly equal to expenses (USD 338 million) for marketing activities in 2009. HK’s minimum full-cycle cost of commodity less impairments is 5.29 \$/Mcf in 2009; FD&A is only partly accounted for in DD&A.

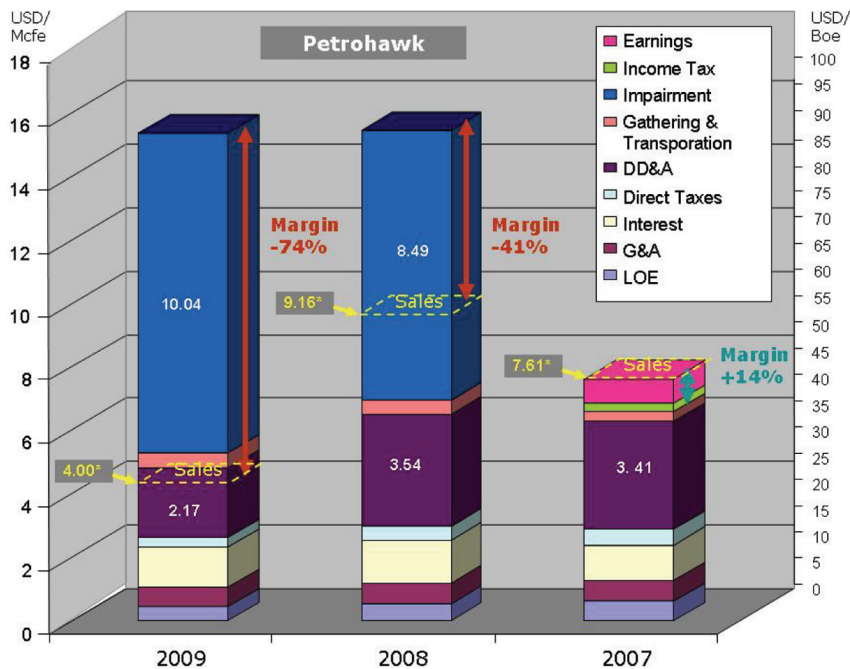


Fig. 14—Margin for Petrohawk based on commodity cost and realized sales price per BOE and Mcfe. Mcf sales price indicated with (*) includes proceeds from hedging activities. Meaning of terms is explained in Table 7 (All Petrohawk data abstracted and converted from SEC K-10 filings).

In conclusion, XTO and EOG both have deployed past FD&A strategies that have not resulted in any disproportional impairment cost over the 3-year performance period highlighted here. They have located sweet spots and acquired acreage that can be produced economically under current expectations of asset carrying value. In contrast, Devon, Chesapeake, and Petrohawk all have taken huge impairment charges. Their portfolio's included poor acreage that now has been expensed by these companies in 2008 and 2009. A note of caution must also be added for the future asset carrying value of XTO (part of Exxon as of June 2010), which has benefited from extraordinary price hedging between 2008 and 2009 that may not be sustainable if natural-gas prices remain suppressed for several more years.

Recommendations for Maximizing Shareholder Value

Previous studies have shown that unconventional-gas companies have maintained liquidity in their cash flow and solvency in their assets, using a range of tactical instruments:

- Debt rollover and new equity issuance (Weijermars 2010b and 2011a)
- Asset sales and leases or outright mergers (e.g., XTO-Exxon; Weijermars 2010c, 2011b)
- Shift of gas CAPEX to Oil CAPEX (Weijermars 2011c)
- Improving proved reserves by infill drilling (Weijermars 2011d)

The present study has analyzed the TSR performance and sources of capital gains in unconventional-gas production companies and compared these to those of conventional oil and gas majors. Unconventional-gas companies need to adopt a new view to improve the current economic case over the medium and longer term. They must evolve beyond autonomous strategies that make tactical use of management accounting principles to maintain corporate liquidity. Their balance sheets must be restored with retained earnings from operational profits after dividend payments. The shareholder returns can be paid as long as adequate liquidity in the cash flow account can be maintained by the entry of new shareholders that buy into newly issued equity paper. For sustainable business success, operational profits must take over the role of providing capital gains.

Profitable unconventional-gas companies distinguish themselves from unprofitable ones by having acquired quality acreage, entirely similar to the global chase for locating and acquiring access to prime asset value by conventional E&P companies. Cost should be kept down, but there are practical limitations to rapid gains in costs associated with the FD&A of unconventional-gas assets. Instead, most gains can be made by optimizing production volumes from acreage. Acreage finding and development must result in wells with high flow rates (for maximum internal rate of return) and high economic ultimate reserves (EURs) (economically recoverable ultimate reserves for maximum NPV). Costly impairments of previously acquired acreage can be avoided by better screening of smaller leaseholds before acquiring bigger plots. Establishment of reliable well-productivity type curves and improved horizontal-well completion methods are essential for the successful assessment of well flow rates and high EURs.

Discussion

This study is based entirely on primary data reported by the companies involved in audited annual reports. We also reviewed numerous investor presentations made by unconventional oil and gas companies and concluded that these are based on a very selective subset of data that sometimes could even be labeled as conjured. Investor presentations typically understate the structural weakness of the business fundamentals in the unconventional-gas industry and overstate the future potential. An explicit example of a turnaround in profit boasting resumes is provided by an April 2011 investor presentation by Chesapeake, the unconventional-gas-industry leader. The presentation confirms negative earnings from past gas production and emphasizes that these have been partly compensated by speculative gains in acreage value. The volatility of unconventional assets and acreage value itself provides reason

for grave concern, as is discussed in a companion study that is in review (Weijermars *In press*).

One question that is frequently surfacing is this: If we accept that unconventional-gas companies are not turning a profit, then why are oil and gas majors and foreign oil and gas companies flocking to get into these areas? The answer is that there has indeed been considerable strategic interest in the unconventional-resource plays. The tactical assumptions made by these companies are as follows:

1. They have seen conventional gas prospects dwindling, which leaves unconventional plays as the only long-term alternative.
2. They want to buy into the skills and competencies and master the technology required to develop unconventional plays.
3. They have seen unprecedented reserves growth reported by unconventional-gas companies (more than 350% for the past decade), while oil and gas majors themselves maintained reserves replacement ratios close to unity, without any significant net growth in reserves.
4. They have acquired nearly all potential acreage in China, India, Australia, South Africa, and Europe, mostly to ensure future access when these plays become economic.

As per completion date of the final revision of this study, it is becoming clear from informal discussions with a substantial number of unconventional-gas professionals at major oil and gas companies that the traditional industry players are becoming increasingly critical about the business fundamentals of unconventional gas for the short-term. Among the assets they have recently acquired, tight gas has the least problems and shale gas the most. It is beyond the scope of this study to disclose further details, but with the entrance of majors in unconventional-gas assets a new set of hurdle rates and a more stringent reserves reporting culture are now applied to unconventional-gas assets. This will inevitably lead to a more-realistic business model for unconventional-gas operations. We also think this next phase in the unconventional-gas business will be accompanied by major litigation and recourse on the basis of unprecedented volatility in asset value allegedly because of gross misrepresentation of business fundamentals for a number of asset sales and joint ventures.

Finally, a comprehensive 2009 supply cost analysis for 20 unconventional-gas companies by Deutsche Bank (Fig. 15) indicates an average break-even cost of USD 6.50/Mcf for new and current acreage, using a 10% discount rate. To rival the typical 2009 margins of between 33 and 52% realized by conventional gas operators (Fig. 9), the natural-gas price for unconventional-gas operators would need to be higher than 10 USD/Mcf. Current US wellhead gas prices are atypically low (hovering near USD 4/Mcf), and the North American unconventional-gas industry may be well placed to consolidate its business performance, provided that the price of natural gas recovers past 2008 highs.

Until the recovery sets in, Table 6 provides further practical suggestions for attention areas to improve corporate value creation by capital gains through true economic growth. Practical hints for improving the business performance by modulating the firm's operational clockspeed in times of recession and recovery have been formulated elsewhere (Weijermars 2011e). Additional discussion may be needed for a broad engagement by personnel at all levels in the company to agree on and implement the right value drivers. An approach for this is outlined by Watson (2010).

Conclusions

Unconventional-gas companies in North America have paved the way for a new unconventional-gas industry. Their pioneering spirit required risk taking and a long-term vision. Now is the time to review the achievements, improve transparency in operating results, and consolidate the business model for sustainable success. This is much needed because the majority of investors are still trusting the industry's fundamentals, while some have already started to bail out. Once investors get burned on gas investments, shale-gas exploration and production companies now emerging around the world will have a difficult time finding venture capital—the reputation of the upstream gas business with the global investor community is at stake.

This study juxtaposes the business fundamentals of unconventional-gas operators and oil and gas majors. Retained earnings accu-

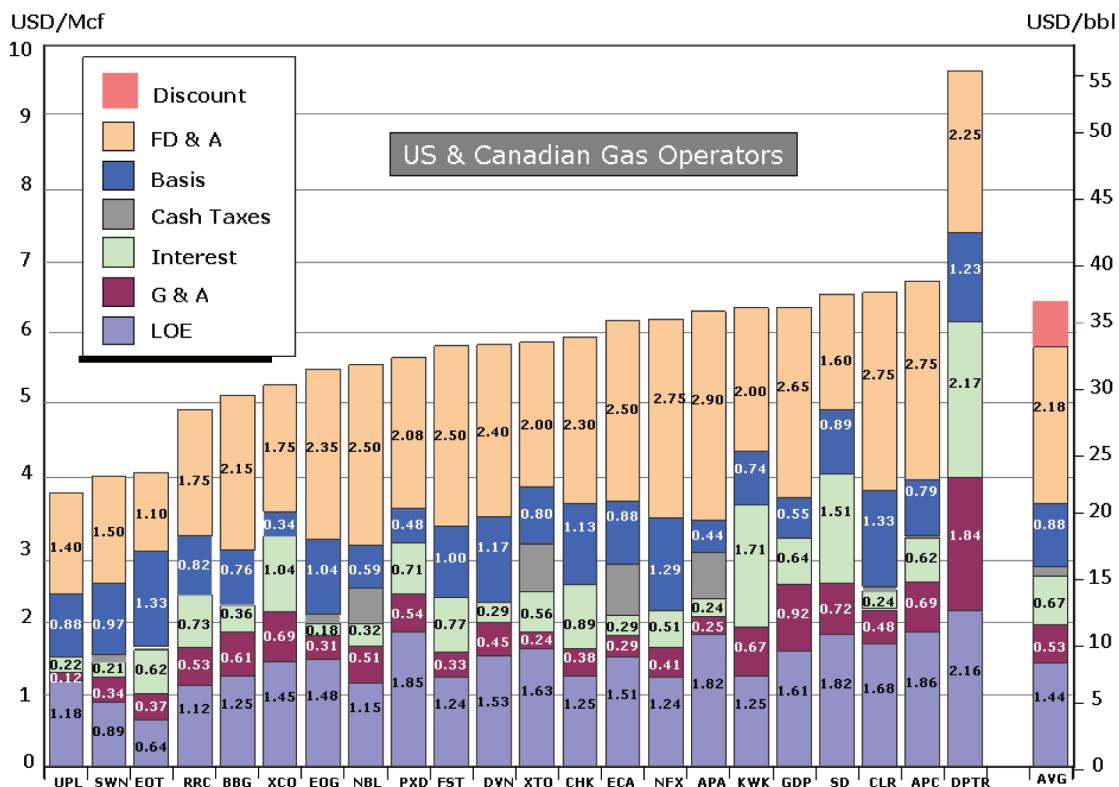


Fig. 15—Average full-cycle supply cost for 20 North American unconventional-gas operators analyzed by Deutsche Bank based on 2009 data. Companies are identified by their New York Stock Exchange symbols (Courtesy Adam Sieminski, Chief Energy Economist, and Patrick Johnston, also at Deutsche Bank Houston Office).

multate positively year upon year for all five oil and gas majors. In contrast, new unconventional-gas operators include a majority with negative earnings. These companies accumulated deficits instead of positive retained earnings over the past 2 decades of their existence. Further analysis shows the peer group of conventional oil and gas companies have excellent margins, ranging between 33 and 52% in 2009. In contrast, the margins for representative unconventional gas operators such as Chesapeake, Petrohawk, and Devon ranged between -49 and -74% in 2009. Among the peer group of independent unconventional-gas operators, only XTO Energy managed to realize a positive margin of 34%. This positive margin was entirely because of derivative trading and price hedging, which in XTO's case held their 2009 gas sales price locked in at approximately 8 USD/Mcf, twice the actual gas spot price in 2009.

A central part of our study explains the difference in the working-capital cycles of conventional- and unconventional-resource companies (Fig. 3). Oil and gas majors have profits high enough to pay for shareholder dividends and new assets for real business growth. Unconventional-gas operators need to raise new cash (equity and debt) from the market to pay for new assets, generally 50% or more of the annual cash flow comes from financing operations. In an attempt to pinpoint the critical TSR components, a Boston Consulting Group method is adopted and adapted.

The overall conclusion of this study is that unconventional-gas companies must now rapidly improve on their past hit-and-run strategies (acquisition and impairment). They should practice less of a "braille" method for FD&A, a term coined in Berman (2010a, b) meaning that poor acreage is drilled indistinctly from high-yield acreage. Smarter FD&A would be aided by massive research spending, something that unconventional companies have not been particularly good at in the past. The data compiled in this analysis have shown that research that leads to better acreage performance is more than likely to deliver returns on investment that easily outweigh the cost of past impairments. Technology improvements will help to improve margins in the longer run, but such improvements take time. Until that happens, locating a sweet spot by super

exploration, optimum well-completion and -stimulation technology, fracture-fairway using, and EUR optimization is what companies should invest in. Delft University of Technology has recently launched an Unconventional Research Initiative (Weijermars et al. 2011) to help accelerate the development of unconventional gas resources for play openers in Europe by providing integrated research and knowledge support. Such research is complementary to ongoing efforts in North America and elsewhere.

Acknowledgments

Watson passed away suddenly on 30 June 2011, leaving behind his wife Liz and son Chris. Past discussions on the topic of TSR with principals, senior partners, and experts from Boston Consulting Group (BCG, Amsterdam Office) are gratefully acknowledged. Deutsche Bank (Washington, D.C., office) provided permission to use the full-cycle cost data of Fig. 15. The views expressed in the present study are the sole responsibility of the authors and do not necessarily reflect Boston Consulting Group or Deutsche Bank policies or opinions.

Disclaimer: This study analyzes company performance based on data abstracted from company reports. 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 publisher take no responsibility for any liabilities claimed by companies included in this study. Readers, especially serious investors, should perform their own due diligence analysis regarding internal corporate technical risk management, considering the wisdom of some risk premium for companies having primary assets in newly evolving plays and potentially unstable business models. Additional risk may arise from safety issues and fines or penalties paid by companies under review. Investors must be cautious in trusting the conclusions of the established rating agencies and energy business analyst agencies without in-depth consultation and inquiries on the agencies relationship with the targeted companies.

The 2004 Shell reserves “problem” should not be simply glossed over as a unique, one-of-a-kind event as internal corporate (and may be national) pressures remain high for all stock-listed E&P companies (particularly unconventional players) to report excellent (and impressive) results from investment funds spent.

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