Assessing “New” Upstream Business Models

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Chapter 7

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Abstract

Observers of current upstream oil and gas developments often equate a change in a company’s strategy with a fundamental shift in its underlying business model. But they hardly ever reason the need for new business models based on an explanation of existing ones, their contexts and required modification. This chapter attempts to do just that. Following a brief discussion of the notion of a business model in general and in the context of upstream oil and gas activities, the chapter describes types of upstream players – global majors, independents, contractors and technical service suppliers, NOCs and host country governments – and the characteristic challenges each of them faces. It then proceeds, for each group, to discuss the case of a particular strategy that may be considered to be novel and mould-breaking. An admittedly cursory assessment of the strategies pursued by BP, Spinnaker, Anadarko, Baker Energy, Petrofac, Halliburton and Schlumberger, as well as the UK government in managing the UKCS fiscal regime, does not identify any new or need for new business models. In fact, players seem to develop their given models in line with fairly conventional and even predictable patterns of industry evolution.
Assessing “New” Upstream Business Models

1. Introduction

By mid 2005, strong commodity prices, outpacing increases in production costs and taxes, continued to lift producers’ net income and dividends and translated into a wholesale repurchasing of shares and retirement of debt. While not a single oil company had made the 2000 line-up of the Fortune 100 Fastest Growing Companies, the 2005 roster featured 19 of them, including exploration and production (E&P) companies such as Apache (no. 99), oil tanker operator Overseas Ship-holding (no. 45) and independent refiner Valero (no.19). But there were reasons for concern:

Global production growth had exceeded reserves growth for four years in a row and development costs were rising sharply. Major oil companies were announcing their need for more and bigger projects to meet future demand, but exploration spending industry-wide was still at 1998 levels. In 2004, the average ROE and ROCE of the top 25 independents rose to 20.3% from 13.7% and to 15% from 11% respectively, but while acquisition outlays had gone up, exploration spend had remained flat and CAPEX been cut by $4.6bn. International exploration appeared increasingly to be borne by smaller independents. Also, between 1995 and 2005, new technologies applied to the reassessment of known fields had added 75% of oil and gas reserves; others had the potential to raise the field recovery level from the current level of 35% to an average of 45%. Yet, super majors seemed reluctant to foster innovation or to risk a failed field trial, let alone pay the price for a major technology push. Meanwhile technology owners in the contracting and service sectors, seeing their margins squeezed, explored new ways to market. Finally, three additional factors had begun to change the broader competitive landscape: the arrival of national oil companies (NOCs) as powerful competitors for international E&P acreage; changes in access, taxes and operating conditions in a number of major host countries, and the need to rejuvenate maturing regions. In any of these, potential changes in oil prices figured prominently. In September 2005, futures prices had gone past the $60/bbl mark while some majors continued to assume that $25 to $30/bbl was the mid-cycle range.

Speculating about how the industry would cope with these and related issues, most observers are quick to call for new business models to be found but often fail to explain existing ones, their contexts and the needs for modification. This chapter attempts to do just that. By way of introduction, section 2 briefly discusses the notion of a business model and offers some considerations for its application to the assessment of upstream oil and gas activities. Section 3 characterizes types of upstream players – global majors, independents, contractors and technical service suppliers – and the major challenges they currently face. Section 4 discusses some public policy considerations for managing and adjusting a country’s hydrocarbon economy and the potential role of national oil companies. Section 5 presents a summary and conclusions.

2. Thinking in Terms of Business Models in the Context of Upstream Oil and Gas

Shaping one’s competitive environment requires a clear understanding of the interaction of various factors driving it as well as of one’s own ability to contribute and capture value. Business models distill the essence of this for effective communication, execution and review. Despite being the
subject of vast amounts of business and economic research, business models tend to be presented in a rather fragmented fashion, focusing either on the level of activities, business units, corporate portfolios or industrial clusters, and from either a business or public policy angle. In assessing upstream oil and gas markets, a more integrative perspective is clearly required. Research at IMD has resulted in an economics-based framework that links various levels of analysis and challenges the consistency of business models in pursuing private or public objectives. It tests the definition and attractiveness of a given market, operational and investment decisions for reaching it, and issues of coordination, organization and sustainability. Applied to upstream oil and gas, three aspects need to be considered:

**Figure 1: Elements of an Upstream Business Model**

*First,* characterizing a given play requires an assessment of its fiscal regime, political context, operating conditions, geology and materiality. Fiscal regimes, involving royalty tax systems, production sharing agreements (PSAs) or service contracts, differ in terms of title transfer, government take and participation, ring-fencing and lifting entitlement. Hence, they offer different risks and rewards as well as varying levels of expected stability. Political conditions can be gauged by appraising the process of interest articulation and representation and macroeconomic fundamentals. Operating environments differ most importantly according to location (on- vs. offshore, deep vs. shallow water etc.), seasonal restrictions, availability and cost of data, infrastructure conditions, drilling costs and outsourcing opportunities. Geology drives the probability of success, the minimum required reserve as well as the required number and locations of wells and supporting infrastructures. Materiality equates to the total estimated resource potential of a given quality. However any given play will only be considered by those able to coordinate operational requirements involved in entry, exploration,

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appraisal, development, production and ultimately sales and transport. Hence, the attractiveness of any play is a function of the above characteristics, and the number of suitors willing to offer the adequate resource mix, i.e. the substitution potential for demand and supply.

Second, entry implies that operational roles need to be assumed. Figure 1 identifies 45 separable tasks, not including finance, throughout the upstream business system that need to be brought together by either internal organization or external coordination. Subject to licensing conditions, outsourcing may be an option if adequate operators, contractors and service partners are available, markets are liquid, switching costs are limited and tasks can be controlled. In any other case, tasks will need to be performed internally and their underlying assets, capabilities and systems embedded in a supporting organization. All of these decisions, including entry, require review to reflect changes in the economics of operation, the maturity of the field, regulatory and technological contexts, commodity prices, conditions in supplier and capital markets, the portfolio of investments and opportunity costs.

Third, there is a priori no reason why private or governmental ownership should result in different views on the attractiveness of a play and options for operations. In fact, new public management (NPM) tends to mimic highly contestable market incentives; conversely, a proper fiscal and regulatory regime may substantially reduce or even obviate the need for any direct governmental involvement. Still, national oil companies may be used to pursue non-commercial objectives.

Business models capture the economic logic for aligning internal decisions in view of external conditions. They are explanatory not predictive tools of management. They are unlikely to reflect the specifics of any given circumstance, but rather serve as blueprints for testing the consistency,

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sustainability and required evolution of a given case. Sections 3 and 4 do this for different types of players and plays.

3. Players: Majors, Independents and Contractor/Technical Service Firms

Players in upstream oil and gas are typically grouped as integrated, independent, national oil companies or contract/service firms. Of the first, five global “majors” (Exxon-Mobile, BP, Shell, Chevron-Texaco and Total) accounted for 17% of the world market in 2004 and cover the full cycle from upstream exploration through transport and storage to marketing and sales of refined products – from plastics to gasoline. The typical independent operates exclusively in the upstream exploration and production segment, with no refining or marketing operations, and ranges in size from one-or-two person companies with small turnovers to large publicly traded “super-independents” with billion dollar sales. A subgroup of independents, the so-called exploration boutiques, focuses entirely on exploration based on a small number of licenses, raises venture capital to begin small-scale operations and tends to be either acquired, if successful, or liquidated, if not. National oil companies accounted for 30% of the world market in 2004 and have persistently grown their technical and commercial capabilities; with strong home government support many are expanding beyond their borders in order to compete. Technology firms and engineering contractors respond to oil companies’ varied outsourcing needs. Subject to client demands and market conditions, their offers cover virtually all areas of exploration and production (E&P) and a variety of performance and financial contracts. Focusing on global majors, independents, technical service firms and contractors, the following outlines their apparent business models and then illustrates each with an actual example.

Table 1: Key Statistics by Type of Industry Player

<table>
<thead>
<tr>
<th></th>
<th>Global Majors</th>
<th>Independents</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>BP</td>
<td>Exxon</td>
</tr>
<tr>
<td></td>
<td>Mobil</td>
<td>RoyalDutch</td>
</tr>
<tr>
<td></td>
<td>Shell</td>
<td>Spinnaker</td>
</tr>
<tr>
<td></td>
<td>Texaco</td>
<td>Anadarko</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>Toreador</td>
</tr>
<tr>
<td>Upstream Revenues</td>
<td>$19.8bn</td>
<td>$16.7bn</td>
</tr>
<tr>
<td></td>
<td>$39.6bn</td>
<td>$9.5bn</td>
</tr>
<tr>
<td></td>
<td>$36.2bn</td>
<td>$272.9m</td>
</tr>
<tr>
<td></td>
<td>$6,067.0m</td>
<td>$22.4m</td>
</tr>
<tr>
<td>Oil: b/d:</td>
<td>2.7m</td>
<td>2.9m</td>
</tr>
<tr>
<td></td>
<td>2.5m</td>
<td>2.4m</td>
</tr>
<tr>
<td></td>
<td>1.7m</td>
<td>1.743</td>
</tr>
<tr>
<td></td>
<td>310,000</td>
<td>1,735</td>
</tr>
<tr>
<td>Gas: boe/d:</td>
<td>1.6m</td>
<td>2.0m</td>
</tr>
<tr>
<td></td>
<td>1.7m</td>
<td>0.8m</td>
</tr>
<tr>
<td></td>
<td>0.9m</td>
<td>5,955</td>
</tr>
<tr>
<td></td>
<td>370,000</td>
<td>n.a.</td>
</tr>
<tr>
<td>Market cap.</td>
<td>$227.8bn</td>
<td>$349.1bn</td>
</tr>
<tr>
<td></td>
<td>$210.1bn</td>
<td>$117.3bn</td>
</tr>
<tr>
<td></td>
<td>$150.6bn</td>
<td>$2.2bn</td>
</tr>
<tr>
<td></td>
<td>$20.4bn</td>
<td>$2.04bn</td>
</tr>
<tr>
<td>No. of employees</td>
<td>102,900</td>
<td>85,900</td>
</tr>
<tr>
<td></td>
<td>112,000</td>
<td>56,000</td>
</tr>
<tr>
<td></td>
<td>111,401</td>
<td>78</td>
</tr>
<tr>
<td></td>
<td>330,000</td>
<td>45</td>
</tr>
<tr>
<td>Upstream revenue/employee</td>
<td>$192,420</td>
<td>$194,412</td>
</tr>
<tr>
<td></td>
<td>$353,571</td>
<td>$169,643</td>
</tr>
<tr>
<td></td>
<td>$324,979</td>
<td>$3,498,564</td>
</tr>
<tr>
<td></td>
<td>$1,838,485</td>
<td>$496,667</td>
</tr>
<tr>
<td>Replacement cost: $ per boe</td>
<td>4.44</td>
<td>5.56</td>
</tr>
<tr>
<td></td>
<td>11.97</td>
<td>6.43</td>
</tr>
<tr>
<td></td>
<td>5.24</td>
<td>n.a.</td>
</tr>
<tr>
<td></td>
<td>8.93</td>
<td>4.54</td>
</tr>
</tbody>
</table>

Note: For Exxon, upstream revenues include exploration, development, production and gas & power marketing. Total's reported E&P revenues include inter-group sales.

3.1. Global Majors:

a. Characteristics and Challenges: Since the very beginning of the modern petroleum industry in the late 1860s in the United States, large-scale, high-risk investments, non-existing markets for logistics and technological services and unsteady supplier relations had driven operators to seek control over all upstream and downstream activities. Vertical integration soon triggered horizontal consolidation until in 1911 the US Supreme Court dissolved Standard Oil Trusts into 34 separate entities. In the late 1940s, two of the descendent firms, Exxon, formerly Standard Oil of New Jersey, and Amoco, formerly Standard Oil of Indiana, joined Mobil Oil, Royal Dutch Shell, BP (British Anglo
Persian Oil Company), Texaco (Texas Fuel Company), and Chevron (including Gulf Oil) in a group known as the Seven Sisters. Operating as interlocking ventures to build negotiation power and share risk and finance, these companies grew fast with the rise of international oil production until, after the wave of nationalizations in the Middle East and South America, every single one of them had to be rebuilt. A series of mergers and acquisitions helped the major companies regain their global scale and scope in operations from exploration to retailing: Exxon teamed up with Mobil, Chevron with Texaco, and BP with Amoco and Arco. In France, Total joined arch-rival Elf Aquitaine. But only by 2004 had BP’s production of 4MMbpd reached its 1975 level.

For more than 140 years, vertical integration in the petroleum industry had offered the means to balance capacity utilization, ensure market access and, together with geographic and product diversification and public share ownership, spread risk. Born out of necessity, systems growth fed increased operational scale, drove up the need to replace reserves at ever-larger rates and the funding needed to fuel exploration. Are current operating and market conditions sufficiently distinct to seriously challenge the majors’ approach and require a new business model? The primary concerns relate to market access, risk aversion, coordination, and bureaucratization.

### Table 2: Key Statistics Top 3 Majors

<table>
<thead>
<tr>
<th>Global majors (as of 2005)</th>
<th>Share of liquid production '000 b/d</th>
<th>Share of gas production '000 boe/d</th>
<th>Share of commercial reserves (total oil eq.) mmbc</th>
<th>Production per employee boe/employee</th>
<th>Market Cap. US$ mio</th>
<th>Sales US$ mio</th>
<th>No. of employees</th>
<th>Credit Rating S&amp;P</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total World</td>
<td>73,967</td>
<td>46,198</td>
<td>1,277,702</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>BP plc</td>
<td>2,735</td>
<td>1,580</td>
<td>33,084</td>
<td>27</td>
<td>227,753</td>
<td>297,507</td>
<td>102,900</td>
<td>AA+</td>
</tr>
<tr>
<td>ExxonMobil</td>
<td>2,906</td>
<td>1,960</td>
<td>40,259</td>
<td>34</td>
<td>349,115</td>
<td>263,989</td>
<td>85,900</td>
<td>AAA</td>
</tr>
<tr>
<td>Shell</td>
<td>2,541</td>
<td>1,686</td>
<td>29,485</td>
<td>23</td>
<td>210,080</td>
<td>276,770</td>
<td>112,000</td>
<td>AA</td>
</tr>
</tbody>
</table>

Liquids = oil, LPG & condensate.
Commercial reserves = reserves in production, under development or likely to be approved for development within 2-3 years. Roughly equivalent to company Proved + Probable reserves.
Source: Petroleum Economist, Thomson Financial

*First*, although global majors operate on every continent, mature regions of North America and northwestern Europe account for about 60% of their current oil and natural-gas production. In those areas, declining output raises production costs and makes justifying additional investments difficult. Opportunities for growth come at a price. Participation in new product markets – from gas-to-liquids (GTL) and liquefied natural gas (LNG) to oil-sands and heavy oils – calls for large scale investments in processing and transport. In addition, many of the world’s remaining conventional sources of oil and natural gas are located in technically challenging regions, such as the Arctic and Asia-Pacific, or in countries with relatively high political and legal instability, such as Nigeria, Russia or Sudan. Since the late 1990s, when several large finds in deep-water locations raised global reserves, the average size of new discoveries around the world has declined threefold, to about 22 million barrels

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of oil. Also majors, concerned about, are often unwilling or unable to operate in highly sensitive regions. How does a typical major respond to these growth challenges?

Second, mergers helped majors to replace their reserves at below drill-bit costs and to expand exploration portfolios with lower-risk prospects. Yet, increasing the scale of operations makes it ever more difficult to find fields large enough to make a real difference. No wonder therefore that in a sustained high oil price environment, players who would normally seek to rationalize the tail-end of their portfolios at the top of the market continue to operate non-core, marginal areas either directly or under some form of outsourcing arrangement. Does this behavior signify risk aversion? Is it necessary for majors to get around avoiding risks? If so, how can management attention be re-focused on capturing true growth opportunities?

Third, future growth requires a combination of acquisitions, exploration activities, and further technology and downstream market developments. Global majors, seen by their investors to hold excellent medium-term growth potential, currently may have little problem financing these. Yet spending these funds in the most efficient way requires companies to prioritize the establishment and control of future, large-scale essential infrastructures – from pipelines to re-gasification and liquefaction plants to hydro-crackers – while leveraging available outside parties for operational tasks wherever possible. In the process, controlling cooperation remains vital. Hence, with high oil prices putting a premium on acquisitions and increasing the value of an exploration upside, majors need to think about “recreating” their dedicated venture teams to find and secure new exploration opportunities and complement their work by taking a stake in, or even partner with, small but tightly focused exploration companies. Similarly, in the area of technology, majors need to step up their in-house investments while, at the same time, cooperating with technology hopefuls and vendors. But would opening up to more extensive market-based coordination and networking fundamentally change the coordination logic underlying the majors’ business model?

Fourth, operating on a global scale and under significant technological, political and economic risk, as well as public scrutiny, calls for comprehensive systems of external and internal supervision. All global majors need to operate sophisticated matrix organizations of significant size and make use of public relations departments to ensure that the corporate image is not tarnished by accidental oil spills or political controversy. Yet, there is growing concern that too much focus on governance concerns may drive up bureaucracy at the expense of market responsiveness. Is it possible to maintain major operations, address stakeholder demands and avoid red tape? How does a global major like BP respond to any of the above concerns?

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4 For example, in 2000 BP was put under a lot of pressure from Christian Aid and others in connection with their investments in PetroChina, whose holding company operates in Sudan.

5 3i Oil and Gas (2005), The Prospects for North Sea Oil and Gas: Challenges and Opportunity in a Maturing Province, Aberdeen.

6 For example, Shell’s Smart Fields program, a series of R&D partnerships with Schlumberger Information Solutions, Invensys, IBM, Intelligent Agent Corporation, Science Applications International Corporation and Microsoft. Signed in October 2004, the goal was to accelerate the development and deployment of next-generation digital oils and gas-field technology. See Shell Smartens up with Technology Partnerships. Aberdeen Press & Journal, 4 October 2004.
b. BP – Scale, Scope and the Markets: In 2005 BP looked back on healthy 2004 results, helped by a surge in production growth (nearly 11% upon the previous year), mostly resulting from TNK-BP operations in Russia. Its 2005 pro forma results equaled US$25.7bn, of which 77% were derived from upstream and 22% from downstream, with some contribution from other segments. Upstream capital expenditure accounted for 65% of capital expenditure in 2004, rising to an expected 68% of US$14.1bn7 by yearend. Downstream represented around 20% of spending, chemicals around 6% and gas, power and renewables around 4%. The company’s current performance was the outcome of a set of deliberate decisions.

When in 2001 BP set out its growth strategy, CEO Lord Brown8 formulated six objectives: (1) grow in size to undertake large scale projects that offer a truly distinctive return to finance more development projects, hold costs down and potentially win more reserve auctions; (2) diversify risk; (3) leverage vertical integration but enforce market discipline across the organization; (4) understand change in all parts of the markets and have the skill to manage that change; (5) have a first-mover advantage in picking your partners; (6) offer a single window to host governments. The resulting actions quite clearly tackle some of the above concerns.

Table 3: Key Statistics BP

<table>
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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>BP plc</td>
<td>-</td>
<td>78.00</td>
<td>1,038.00</td>
<td>8,706.00</td>
<td>9,822.00</td>
<td>-1,451.50</td>
<td>18,471.00</td>
<td>5.28</td>
<td>4.44</td>
<td>117.00</td>
</tr>
<tr>
<td>BP plc ranking</td>
<td>27</td>
<td>23</td>
<td>17</td>
<td>117</td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>

Source: Adapted from J S Herold

In addressing growth challenges and maturing plays, TNK-BP is expected to drive the company’s future performance. In addition, upcoming projects in Vietnam, Australia, Indonesia, Azerbaijan, Algeria, Angola, deepwater Gulf of Mexico, Trinidad and Tobago and Alaska are to help counter-balance losses from mature fields in the North Sea, Egypt and Gulf of Mexico. For the 2004-06 period, the company aims to (1) manage maturing assets and divest itself of non-performing ones; (2) invest in the “largest lowest-cost new hydrocarbon deposits” to keep production growth at 5% from 2004-10; (3) increase LNG and gas production as a share of total hydrocarbon production to around 20% by 2008.9 BP does not intend to pursue unconventional oil and gas.

In October 2005, the company signed a joint venture with India’s Hindustan Petroleum with an initial plan to build a $3bn refinery, and attempted to buy a substantial equity stake in Sinopec, China’s largest refiner and marketer. The deals would give the company a foothold in the markets of the fastest-growing users of energy among large economies, which so far had rejected several such attempts by BP, Exxon and Shell. Still many drawbacks exist, at least in the short term. In both China and India the state exercises strong control over the ownership and pricing of oil and gas products. Yet, for BP this is an acceptable cost for attaining resource and market access and just one more aspect to be considered in the pursuing the company’s strategy of partnering and leveraging integration.

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With regard to the former, BP continues to stress the philosophy of partnering to “seek mutual advantage.” Two years after the TNK-BP merger, President Putin publicly announced that he was pleased to hear the company being called “a corporate citizen of Russia” and that it took part in social welfare programs. On the same occasion, Lord Brown ensured that the venture was carrying out all four “missions” that Mr. Putin had assigned it before the merger in 2003: increasing oil extraction volumes, introducing new technologies, developing corporate management, and maintaining decency in the company.

As for integration, BP officially downplays the value of vertical integration but its top management nevertheless appreciates “some” vertical control: According to Lord Brown having “(t)he right refineries in the right geographic areas may provide a benefit. Also, shareholders invest in the agency of the management to more easily participate in portions of the industry than they can do themselves. It is easier to invest in BP than obtain a private equity stake in China.”

And in the words of Chief Financial Officer John Buchanan “(s)ome advantages of vertical integration come from unpredictable regulated markets. You never know where the rent will show up. Markets aren’t yet perfect, and there is not contestability at each point in the value chain.”

At the same time, there needs to be a check on potential inefficiencies due to integration. In BP, the absence of purchasing commitments and transfer pricing rules that mimic market mechanisms are to “expose intra-business subsidies and force the businesses to become more competitive.” Also, the market figures strongly in offsetting another potential drawback of in-house scale – red tape. BP business unit leaders’ careers and compensation are driven by annual “performance contracts” specifying cash flow, net income, and new investment targets; they periodically meet in peer groups to benchmark each other against a list of operational key performance indicators. In addition, the top quartile performers are charged with improving the bottom quartile’s results. Furthermore, performance targets, such as the company’s highly publicized unilateral commitment to cut its emissions of greenhouse gases by 10% from a 1990 baseline, are set to fuel internal competition and have been shown to markedly improve innovation and productivity.

Hence, while relative to the early years of the oil industry, current market and outsourcing opportunities may make continued global integration appear anachronistic, BP is set not only on maintaining its size but on increasing it even further. The company uses its balance sheet to finance otherwise unobtainable large-scale infrastructure, and leverages its political and economic network to preempt markets and resource access. Its diversity smooths income over the economic cycle. It is an extension of “big oil” at a time when smaller, non-integrated independents appear to be pursuing a very different business model.

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9 Global majors and host countries typically take on 50% and 30% of the LNG infrastructure investments respectively, and buyers and trading houses contribute the rest.
3.2. Independents:

a. Characteristics & Challenges: Originating in the North American and North Sea markets, a by now global group of non-integrated exploration and production companies is starkly polarized between a few “super-independents” and myriad small ones. While companies such as Anadarko, Apache, or Talisman Energy seem set to join “the big league” in terms of geographic scope, technological complexity and spend, the typical US independent is still a largely US-focused small business owner who has been established for many years. International projects, if any, are mainly onshore E&P and production enhancement, with the biggest hindrances to international operations being CAPEX and political uncertainty. The fact that Northern European independents are on average bigger and more international than their US counterparts reflects differences in both the size of the underlying population and the history of the sectors in each region. Still, in addition to differences in origin and size, the diverse nature of an independent’s operations – from exploration, to development, to production – at different stages of field and industry development – from prospecting to large scale exploitation within an existing infrastructure to maintaining a low capacity stripper well – makes typecasting independents not only conceptually difficult but empirically hard to substantiate. And yet there are some intuitively appealing, size and investment related characteristics that industry members, financial analysts and researchers typically associate with an independent E&P company. These elements of an independent’s business model – related to heritage, funding, market-choice, decision-making and risk-taking – may come under pressure as the company grows and its environment changes.

First, three forms of operations are often seen as the start of an independent: exploration leg-work, farm-ins or consolidation. With regard to the first, smaller companies typically undertake geological studies, seismic testing and early government negotiations and then put together consortia of larger companies to do the actual exploration. In return, the smaller partner receives a carried interest through the first two or three exploration wells, and in case of discovery, expects to participate in the development or production phase covered by the group’s anticipated project financing. In the second case, an independent player takes over acreage from larger oil companies in fields that are past their prime or in small, marginal fields that are deemed less viable by the big operators. Finally,
consolidation involves financing, acquiring and combining operations to share costs and restructure asset portfolios.

Second, funding any of these ventures calls for salesmanship with banks, partners and investors. Start-ups with no track record typically require private capital funds, vendor participation or a joint venture with industry partners. For others, internally generated capital may be complemented by private-equity funding and leveraged by cheaper forms of non-recourse debt financing (possibly involving negative pledges). In either case, taking over operatorship within a partnership improves cost control and reduces financing costs. Volumetric production payments (VPPs) – i.e. presales of a fixed proportion of future production at an agreed price – offer cash up front. Mezzanine financing, combining elements of a junk loan with a retained equity portion, is more expensive as it compensates the lender for extra risk. In any event, investors and borrowers require collateral. Proved reserves are the only reserve classification that the US Securities and Exchange Commission (SEC) allows a publicly traded company to consider as assets, but their value may fluctuate depending on operating costs and commodity prices. The sale of equity is often the ultimate goal of an oil and gas company, and other forms of capital are used as a means to achieve this goal.

Table 4: Key Statistics Independents

<table>
<thead>
<tr>
<th>Independents</th>
<th>Share of liquid production **000 b/d</th>
<th>Share of gas production **000 boe/d</th>
<th>Share of commercial reserves (total oil eq.) mmboe</th>
<th>Production per employee boe/employee</th>
<th>Sales US$ mio</th>
<th>Net Income US$ mio</th>
<th>Market Cap. US$ mio</th>
<th>No. of employees</th>
<th>Credit Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total World</td>
<td>73,967</td>
<td>46,198</td>
<td>1,277,702</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Anadarko Petroleum Corp.</td>
<td>310</td>
<td>370</td>
<td>3,694</td>
<td>94</td>
<td>6,067</td>
<td>1,606</td>
<td>20,382</td>
<td>3,300</td>
<td>BBB+</td>
</tr>
<tr>
<td>Apache Corp.</td>
<td>310</td>
<td>285</td>
<td>3,792</td>
<td>117</td>
<td>5,333</td>
<td>1,669</td>
<td>19,741</td>
<td>2,642</td>
<td>A-</td>
</tr>
<tr>
<td>Encana Corp.</td>
<td>313</td>
<td>585</td>
<td>6,390</td>
<td>77</td>
<td>12,723</td>
<td>3,785</td>
<td>41,137</td>
<td>4,090</td>
<td>A-</td>
</tr>
<tr>
<td>Pogo Producing Co.*</td>
<td>51</td>
<td>54</td>
<td>116</td>
<td>198</td>
<td>1,312</td>
<td>262</td>
<td>3,010</td>
<td>260</td>
<td>B+</td>
</tr>
<tr>
<td>Progress Energy Trust</td>
<td>3</td>
<td>10</td>
<td>54</td>
<td>n/a</td>
<td>134</td>
<td>44</td>
<td>883</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Spinnaker Exploration Co.</td>
<td>2</td>
<td>6</td>
<td>51</td>
<td>22</td>
<td>273</td>
<td>54</td>
<td>2,204</td>
<td>78</td>
<td>n/a</td>
</tr>
<tr>
<td>Toreador Resources Corp.</td>
<td>2</td>
<td>na</td>
<td>14</td>
<td>39</td>
<td>22</td>
<td>25</td>
<td>385</td>
<td>45</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Note: Pogo Producing senior unsecured debt not rated. Rating given is for a September 2005 senior subordinated debt issue.

Liquids = oil, LPG & condensate

Commercial reserves = reserves in production, under development or likely to be approved for development within 2-3 years. Roughly equivalent to company Proved + Probable reserves.


Third, in choosing their markets and growing their operations, British and American independents have been found to follow five types of approaches: (a) country focused operations seek to leverage local knowledge and goodwill; (b) mature asset specialists operate many geographically concentrated licenses and concentrate on invigorating declining plays; (c) regionally focused operators exhibit moderate levels of international license dispersion; (d) internationally diversified independents hold the most geographically dispersed operating licensing; (e) portfolios have more than 90% of their licenses as non-operators. More important, and statistically significant, however, are two findings related to relative size, growth and effectiveness.

14 Proved developed producing (PDP) reserves are the most likely to be recovered while proved undeveloped (PUD) are the least likely to be recovered. In addition to proved reserves, oil and gas companies record probable, possible and potential reserves.

15 Reid and Stewart (2005) op. cit.
Fourth, smaller independents appear to have an advantage over majors in decision-making speed, the authority to commit, the seniority of personnel and the establishment of relationships. They are thus more successful in applying for licenses in non-Western countries and are able to target non-traditional, under-explored overseas areas. In fact, some display an active willingness to engage with prospective countries, where due to relatively high political and/or security risks competition for licenses is reduced. Yet, while speed and the absence of a consumer/investor brand allow small independents to exploit the low risk tolerance of integrated players, super-independents are increasingly facing growth problems similar to those of global majors. Looking at Devon, Apache, Anadarko, Burlington Resources, Kerr-McGee, Amerada Hess and Unocal, Farley (2003) found that the group averaged 15% annualized returns when growing their enterprise value from $5bn to $10bn. But the group’s average annualized returns fell to a negative 5% when the value exceeded $10bn. Do companies face an apparent $10bn enterprise value threshold because it is difficult for them to find, acquire, and exploit opportunities of substantive scale, or because they fail to maintain their entrepreneurial drive and cost control? How will independents of different sizes and origins deal with changes in oil prices that either shrink margins or conversely keep majors holding on to marginal assets? How will they deal with increased costs of capital?

Independent oil companies, as a group, suffered when in 1985 low oil prices exposed their lack of financial strength and management talent. Many simply disappeared. They experienced a renaissance throughout the 1990s when new technologies, such as 3D seismic and horizontal drilling, helped lower finding or development costs, sales of marginal fields allowed farm-ins, and funding and outsourcing opportunities were readily available. Nowadays, funding seems not to be an issue, and the typical independent’s debt capacity has greatly improved. Yet, while some independents deploy large amounts of E&P capital into more drilling, others turn to lower risk methods of growth that offer limited production but far less strain on the balance sheet. Consider the cases of Spinnaker Exploration and Anadarko Petroleum.

b.1 Spinnaker Exploration – Financial Venturing: Founded in 1997, Spinnaker, an independent energy company recognized for its strength in data integration and seismic image enhancement, is engaged in exploration, development and production of natural gas and oil mostly in the Gulf of Mexico (GoM). Beginning as a conventional shelf player the company was soon drawn into deep-water exploration and, by 2004, held approximately 131 blocks covering 745,000 gross acres, or 312,000 net acres, in the deep water of the Gulf of Mexico. At the same time, it had discovered 11 new deepwater fields, two of which are currently producing, four are in development and five more still under evaluation. Spinnaker aimed to offer investors a balanced inventory of conventional and deep shelf activities in various regions of the GoM and, in 2004, increased geographic diversification by venturing internationally to Nigeria’s Tari prospect. It is the financial aspect of Spinnaker’s growth that is of importance here.

At the time of formation, Spinnaker was the largest equity investment into any grassroots energy startup – ever. Petroleum Geo-Services ASA (PGS) had put up $15m capital and granted Spinnaker a perpetual license to use PGS’s existing non-proprietary 3D marine seismic data and any additional non-proprietary seismic data that PGS produced until April 2002. To balance out PGS’s
commitment, Spinnaker received $60min private equity from E.M. Warburg, Pincus & Co. LLC, New York that saw a drillbit-focused strategy potentially big enough to access the public markets. The next stages of financing involved an $85m conventional line of credit based upon the strong balance sheets of Spinnaker’s partners, an initial public offering in September 1999, and a secondary offering of $140m in net proceeds in August 2000. In late 2000, PGS sold all its holdings in the company via a registered offering for $150m in net proceeds. As of September 30, 2001, Warburg owned 26% interest in Spinnaker, management owned 13%, and the public owned 61%. Spinnaker had no debt. A foundation had been laid to fuel the company’s exploration efforts through successive public offerings of preferred and common stocks and debt securities etc. as well as conventional lines of credits with banking consortia.

In September 2005, Norsk Hydro acquired Spinnaker and its fairly modest 62m boe of proven reserves for $2.56bn, i.e. for $41.29 per boe. Following rival Statoil, which in April 2005 had already replaced reserves and a declining home production with GoM deepwater assets, Norsk Hydro radically shifted price assumptions, applying a long-term oil price of around $35 per barrel to value Spinnaker. By comparison, Chevron had acquired Unocal for $8.62/boe of proven reserves and Statoil’s acquisition of EnCana’s US GoM portfolio was valued at $5.99/boe of proven and probable reserves. One may question the willingness of other buyers to follow Norsk Hydro’s price assumptions; in which case, Spinnaker’s timing was right and its exit was very much in line with its existing business model.

b.2. Anadarko Petroleum – Jumping the Growth Hurdle? Set up in 1959 by the Panhandle Eastern Pipe Line Company to find and extract natural gas in the Anadarko Basin of Texas, Oklahoma and Kansas, Anadarko Petroleum expanded in the Gulf of Mexico before being spun off in 1986. Over the next decade the company became one of the largest independent E&P firms in the US. In the late 1990s, low oil and gas prices and rising finding and development costs suppressed financial returns and wanting organic reserve additions obliged Anadarko to make expensive acquisitions in order to grow. A larger reserve base however made aggressive growth expectations harder to achieve and increasingly pushed Anadarko to compete with the majors for opportunities big enough to enable the company to grow. Rising oil prices at the beginning of the new century did not solve Anadarko’s problems – they just made them more visible. The company found itself needing to restructure its assets and recreate an entrepreneurial culture.

By 2003, a new management team was reviewing the company’s properties based on operating costs, remaining growth opportunities, margins, decline rates, rates of return, free cash flow, manpower, skill requirements, and general and administration (G&A) expenses. It was found that around 90% of Anadarko’s value was generated by 25% of its fields. Hence the company identified scattered, ungrowable or declining properties for divestment, and retained sustainable, low maintenance output generators to fuel growth. Management decided to concentrate on its North American onshore asset base to maximize cash and invest it in international and domestic frontier areas. Since in the process, getting rid of ungrowable or scattered yet very profitable wells would dilute earnings per share, stock repurchasing and the retirement of debt were expected to keep share prices up and strengthen the balance sheet. In June 2004, CEO Jim Hackett announced plans to sell 11% of

16 Or $22.65/boe based on Spinnaker’s proven and probable reserves.
Anadarko’s proven reserves and about 25% of production – about 70% of its fields – for anticipated after tax proceeds of over $2.5bn. The $2.8bn after tax actually generated was used first to reduce net debt by $1.5bn and then to return value to shareholders via a share repurchase of $1.3bn.

Clearly, one may wonder whether shrinking to grow is the proper strategy to follow in a high oil price environment in which delaying asset sales increases value, repurchasing shares becomes ever more expensive, and an increasing stock value permits more debt to be taken. One may also question Hackett’s decision given Anadarko’s ambition to take on major oil companies by becoming more global, and expanding into more deep water drilling and LNG. Hackett would respond “(w) e want to be able to withstand downturns in oil and gas prices without giving up the ability to take on new opportunities when they become available. The best time to fix a roof is when the sun is shining.” For Hackett this was reason enough to tackle internal structures too.

Over the years, Anadarko’s top management style had not kept up with the company’s growth. The original entrepreneurial approach had succumbed to top-down communication with little consultation and engagement from below, had spread hierarchical thinking, proliferated teams and ultimately dampened any sense of accountability. In the words of an observer “(p)eople have been here for a long time, which created a mentality like working for the government that manifested itself in the administrative side of the business as a culture that existed to service whatever the E&P side wanted. That meant not pushing back when it came to cost.” Hackett adopted four measures to change this:

1. APEX – achieving performance excellence – introducing performance contracts, 360-degree feedbacks for every employee and regular meetings for management communication and buy in;
2. Streamlining of management – increasing the number of reports per manager, collapsing parallel groups into one, reducing the number of technical and executive posts;
3. Announcing the first lay-off in the history of the company;
4. Asking executives to follow his model and have lunch with everyone else in the staff cafeteria.

Despite the difficulties in typecasting independents mentioned above, it is possible to point to some intuitively obvious patterns of funding, market-choice, decision-making and risk-taking that are likely to change as companies grow and their environment changes. Spinnaker and Anadarko follow the same business model of a non-integrated E&P company. But both are at different stages of a company’s evolution and therefore face different challenges and options for responding to those challenges. Spinnaker focused on attracting finance to offer a portfolio of conventional and increasingly deep-shelf activities for acquisition by a bigger player ready to leverage larger internal finance and management scale. To quote Richard Anderson, CEO of First Calgary, another young independent: “Most companies are built to be sold and we’re probably no exception.” Conversely, Anadarko’s decision to shrink for growth and shake up the internal organization reflects prudent housekeeping of a major player in a cyclical business and no downstream diversification opportunities. Super-independents require cost-control and maximum use of outsourcing opportunities; whether they are able to crack the $10bn mark and enter the realm of global majors is unclear – as is the motivation for trying to do so.

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3.3. Technical Services & Contractors:

a. Characteristics & Challenges: By 2005, sustained oil price increases finally lifted the profitability and capacity utilization of contractors and service companies. And yet in 2003/4, around five years after oil prices had rebounded in 1999, contractors and service companies remained under pressure from super majors determined to control costs and maximize their profits. In 2002, when BP increased its return on capital employed (ROCE) by 23%, Elf Exploration UK by 27.7%, Shell by 17.2% and Total E&P by 36.1%, the ROCE of Schlumberger, Halliburton, Smith International and Baker Hughes had slumped by 22%, 16%, 6% and 2% respectively. For the same period in Europe, Stolt’s ROCE figure was down by 14%. Contractors and technical service firms reacted by becoming more client-responsive and in the process combined their offers.

Oil companies, downsizing their technical staff, were increasingly looking for outsourcing opportunities and demanded single contacts and integrated services – from technical services to operations and maintenance to asset sharing programs. Smaller suppliers had to sell out and the industry consolidated. Halliburton merged with Dresser, Schlumberger with Camco, and Baker Hughes with Western Atlas. Consolidation also affected engineering contractors and drilling companies. Where previously the oil majors had undertaken a large share of the industry’s R&D, suppliers now took over.

During the late 1990s, the decision by most of the super majors to react to eroding oil prices by cutting back their technology spend had an immediate impact on US intellectual property filings. In 1997, the big-six (US) service companies (Weatherford, Baker, Schlumberger, Halliburton, BJ Services and Smith International) were granted about 135 upstream patents, compared with some 35 for Shell, BP, ExxonMobil and ChevronTexaco. By 2002, that gap had widened to 400 for the service sector as opposed to only 30 for the super majors. Clearly, there was great potential for contractor and technical service companies to develop technology, expand their offerings and bring them to market. In the process, some changed their business and others their way of contracting. Consider the following cases:

b.1. TetraTechnologies/Maritech – From Contractor to Independent: The US GoM currently houses an estimated 4200 structures with an average age of over 20 years, near or past their intended design life. According to the Mineral Management Services (MMS) operators will spend $10bn over the next decade on well abandonment and decommissioning (WA&D) services. The MMS obliges operators to plug and abandon wells and remove platforms and flowlines within one year of a lease expiring; in addition, the Financial Accounting Standards Board (FASB 143) requires companies to recognize abandonment obligations as a separate liability on the balance sheet. Hence, operators are looking for an opportunity to sell mature fields to an undertaking that specializes and has a track record in abandonment and decommissioning, as well as a strong financial base to limit the bankruptcy risk.

Seeing an opportunity, Tetra Technologies Inc., 18 a provider of traditional WA&D services, set up Maritech Resources Inc. with two goals in mind: 1) To buy properties from operators, who thereafter would be completely freed of regulatory liabilities, somewhat earlier in their lives when there is enough remaining reserve value to pay for some or all of the abandonment costs. 2) To accumulate a large backlog of abandonment work for Tetra, which takes over after remaining field reserves have

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been completed, to improve Tetra capacity utilization and work schedule. Success demands skills in reserve valuation, superior skills in resource exploitation, stability of cost and regulatory requirements, and ability to hedge oil price changes. Maritech started in 2000 with just seven operated fields; by August 2005, it operated 34. In the past five years, the company has plugged over 120 wells and removed 40 structures. A solid track record – poised to grow. Is this a new business model? No, it is an alignment of two businesses through joint ownership. Other players seek alignment through contracts and incentives.

b.2. Baker Energy, Petrofac, Halliburton, Schlumberger – Aligning Incentives: Contractors and technical service continuously expand their offers and ways to incentivise performance. In doing so they reduce barriers to entry for new oil competitors and at times can be seen to be infringing on the business of their current customers. Far from being new, some of these approaches are mere aberrations of the existing business model, carrying substantial financial and strategic risks, and are therefore only sparingly used.

Baker Energy, a provider of operations and maintenance services, acts as the network manager, consolidating production operations between the wellhead and the sales meter for multiple companies. Participating companies share resources such as helicopters, marine vessels, computerized management systems and technical specialists, and monitor Baker Energy’s performance according to previously agreed measures. Baker Energy determines how to deliver the results, making daily operational decisions such as supply vessel routing and capacity utilization or maintenance planning. For assuming this additional responsibility, Baker Energy is eligible to receive a share of the cost savings it achieves, as well as a performance bonus. Total production operated by Baker Energy’s so-called OPCO network is currently in the top 10 of all Gulf of Mexico producers.

Petrofac offers engineering and construction as well as operational and facility management services in the North Sea. It is currently being used in a range of assignments as a central duty holder, leaving the responsibility of operatorship with the client – typically an independent or major oil company. The company aims to develop as turnkey operator, allowing oil companies to focus on reservoir and investment management. Where Petrofac’s engineering, construction or operational services are likely to drive major value for the client, the company seeks a minority co-investment for alignments.

Halliburton and Schlumberger, world leading providers of wireline, drilling, well and lifting services, are extending their offer into what Schlumberger calls integrated project management (IPM). The IPM business offers a complete suite of consulting, engineering and execution services and is typically priced on a fixed-price “turnkey” basis, with most project execution risk accepted by the provider. The program addresses the needs of national oil companies with only modest geo-technical and engineering manpower and/or producers new to a region. Analysts maintain that “given high factor utilization and rising prices Schlumberger is pursuing less IPM work as its people and equipment are fully occupied.”19 It could also be that IPM-type arrangements simply stretch the limits of what a service provider is willing to handle. Contracts for enhancing brownfield operations are typically based on incremental production improvements with service firms not acting as operators. Costs are repaid

out of cost oil and any potential saving is shared according to a pre-defined sliding scale. On the positive side, oil price fluctuations may offer windfall gains, despite overall profit caps. On the negative side, in dealing with national oil companies, the service supplier is competing for tasks that were traditionally performed by its major or independent oil company client. In sum, Figure 1 identifies 45 separable tasks throughout the upstream business system that need to be brought together by either internal organization or external coordination. Section 2 outlines the logic for determining a player’s scope of engagement and contribution towards a given business model. Global majors and independents differ in terms of their degree of integration and hence diversification opportunities and risk. With the exception of a major’s need to protect its downstream brand, their business challenges are quite similar and focus on balancing exploration and acquisition in replacing and growing reserves, increasing operating efficiency, and accessing low-cost finance and prospective resource plays. All independents pursue a non-integrated business model, but decisions and strategies differ most importantly depending on size, age and play. Recent expansions in outsourcing offers presented by technical service firms and contractors largely follow their tried and proven business model. In some cases, however, their usual clients may consider service providers knowingly or unwittingly assuming operatorship a competitive threat. The latter point frequently surfaces in discussions about the changing roles of national oil companies and the part they may play in shaping a country’s hydrocarbon economy. Section 3 addresses these points.

4. Plays: Fiscal regimes & NOCs

In much the same way as corporate players evaluate the extent of their engagement across the E&P business system, governments face a continuum of options ranging from entirely outsourcing the exploitation of their country’s oil and gas resources to completely “internalizing” operations in the hands of a state-owned, state-run enterprise. If there is a priori no reason why private or governmental asset ownership would result in different views on the attractiveness of a play and options for operations, why would any country set up its own import-competing NOC rather than creating a regulatory and fiscal regime able to attract global specialists? The answer must lie in the perceived inability of a fiscal system to limit a country’s risk of being abused. Countries not only perceive this risk differently but that perception may change over time and trigger reactions that, in turn, put companies’ operations and business at risk. A number of questions arise from this, which the following section will briefly address: What are the main objectives held by host governments and international oil companies in exploiting a resource basin? Is fiscal stability the way to optimize resource utilization? Is there a common thread in the evolution of fiscal regimes around the world? And, finally, what is the role for NOCs in shaping a country’s national hydrocarbon business model?

4.1. Fiscal Regimes & Regulatory Competition: In determining the structure of its fiscal regime, a host country government typically wants to attract investments and guarantee a fair share of profits, an assured periodic income, energy provision, technology transfer, employment creation, and efficient resource use. International oil companies, on the other hand, seek profitable prospectivity, resource and market access, transparency, low transaction costs, maximized shareholder return and a
diversified portfolio. Both parties face one another in a market; but while objectives are clear outcomes are not.

*Ex ante*, plays may have to compete for investments by offering the most favorable terms, or, given superior levels of prospectivity, may not need to do this to induce a feeding frenzy among investors. *Ex post*, committed investors are concerned about the stability of the fiscal regime. Clearly, fiscal stability encourages investments, entry and asset trading, sustains risk-taking in exploration, development and production and so ultimately promotes the competitiveness of a basin. But requiring strictly stable fiscal regimes is tantamount to asking for a long-term contract without an adjustment clause. Over time, changes in global commodity prices, investment activities, or the relative prospectivity of the region are likely to change as much as the country’s economic policy and view on foreign participation. Systems are necessarily in flux, and, as is shown next, it is the process of adjustment that enhances the competitiveness of a basin.

4.2. The Evolution of the UK Fiscal Regime (1963-2005): Between 2003 and 2004, the UKCS – the ninth most important oil and gas province in the world in production terms – recorded the largest oil production decline of all basins in the BP annual review – approximately 230mbpd. A year later, the basin also had the highest level of exploration, appraisal, and development activities (as measured by number of well starts) since 1998. According to a recent Wood Mackenzie benchmarking analysis of oil and gas basins, UKCS ranked 47th out of 58 in both development costs and finding costs and 42nd out of 58 in terms of commercial success with a chance of 10%. Yet, it ranked 5th out of 63 in terms of exploration wells drilled from 1994-2003 and 2nd in terms of expenditure. How did the fiscal regime evolve to maintain such a level of interest – “against all odds”? The answer is by shaping rather than directing the market in line with global conditions, by learning from and reacting to companies’ responses and investment alternatives, and by considering changing use and conditions of the North Sea infrastructure.

(1) Early gas field developments delivering to state-owned British Gas had limited profit potential and were charged 12.5% of the well-head value of gross production as royalty and 52% on companies’ taxable profits as corporate tax. In the wake of the 1973 oil price hike, however, it became apparent that this simple fiscal regime would not capture economic rent and achieve a government “take” comparable to that being obtained by other oil-producing countries. Hence the Oil Taxation Act 1975 introduced (1) a 45% Petroleum Revenue Tax (PRT) charged on profits arising from individual oil fields (rather than on all fields owned by a particular company), (2) various methods for tax relief, particularly in view of smaller and marginal fields, and (3) a ring fence for corporate tax purposes to avoid erosion of North Sea oil profits through intra-company rent-shifting. “The aim of PRT was to allow each project to recover its costs rapidly, then to tax it hard.” In the following years, the PRT rate rose with oil prices to 70% in 1982. In addition, a 20% Supplementary Petroleum Duty was

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imposed in 1981 and 1982. As result, a high marginal tax rate (ca. 90%) discouraged investment, despite record oil prices of over $80.

(2) Reacting to this, the PRT regime was modified in 1983, permitting new exploration and appraisal costs to be set against existing field profits, and doubling oil allowances for new oil fields outside the Southern Basin of the North Sea. In addition, royalty was abolished for new developments, and a new Oil Taxation Act dealt with fiscal considerations arising from the development of infrastructure in the North Sea and the growth in the sharing of assets – for example pipelines – between two or more oil fields. Although briefly muted by the 1986 price collapse, the 1983 tax-relief pushed up exploration and appraisal activity and led to an average of 95 wells pa. between 1984-92. During the same time the rate of corporate tax fell from 52% to 35%. Still, the differential treatment of fields invited gambling. Companies began to shift income into fields that were not liable for PRT and expenses into those that were. In addition, declining average field sizes reduced the number of fields expected to pay PRT.

(3) Henceforth, fiscal changes in 1993 cut the PRT rate from 75% to 50% for existing oil and gas fields, abolished the tax for fields given development consent after 15 March 1993 and introduced the opportunity to set 100% of expenditure on new exploration and appraisal against profits of existing fields. The industry responded by bringing some 95 projects to approval by 1997, representing over 4bn boe sanctioned reserves and accounting for 44% of year 2000 production (2m boepd). For the UK government, cutting the PRT rate on old fields and abolishing PRT and its reliefs on new ones effectively raised the tax yield as it eliminated costly cross-field PRT reliefs.

(4) In 2002, the Labor government introduced a major tax reform intended to balance the promotion of investments and profiting from the use of significant national resources. A new element, a 10% supplementary surcharge, with no deduction opportunities, was added to the 30% corporate tax rate for oil and gas producers in the UK and on the UKCS. In addition, royalty, which applied to older fields, was abolished and a 100% immediate allowance for most capital investment in the North Sea against corporate tax and supplementary charge was introduced. Although the de facto increase of corporate tax to 40% dampened exploration and appraisal activity, repeated government commitments to stability and rising oil prices increased exploration activity in 2004 by 40%.

(5) In 2005, the UK Department of Trade and Industry (DTI) estimates that some 30bn boe have been produced, but that the remaining reserves base was in the range of 22-31bn boe, of which around half had yet to be found. Concerned about majors and North American “super-independents” flocking to West Africa or deep water Gulf of Mexico, the UK government had earlier launched a number of initiatives to prop up mid-size independents. Promote, a new discounted licensing program, gives companies two years to assess the value of a field before committing to its production. As a result of this, a record high of 27 new entrants to the North Sea participated during the 2003 licensing round. The Fallow Initiative seeks to rejuvenate activity in dormant fields by allowing third parties to propose technical ideas that would stimulate new exploration and development. Finally, a number of tax changes were introduced to encourage new entrants and increased production, such as a direct tax allowance for 100% of new investment. Yet, sustained high oil prices tightened the North Sea assets market during 2004-05, making it close to impossible for new, small oil companies to secure initial
stages. At current oil prices there is simply no reason for the majors to sell, as they are focusing on development and tidying up portfolios around the edges. The DTI stands by.

In sum, the UKCS’s fiscal regime has not only been successful in encouraging and directing entry and investments into a maturing basin but, in view of the level of commercial risk and overall cost, it has delivered a disproportionately high level of exploration activity. The fiscal regime evolved to grow both profit and tax return. As a result, the government has generated a substantial amount of tax revenue, an estimated £5.2bn in 2004 alone. Future UK primary energy demand is projected to grow from 233Mtoe (gas: 42%; oil: 32%) in 2004 to 255Mtoe (gas 48%; oil 37%) in 2020. Under these conditions, accepting maturity as a fact and as a result decommissioning around 40% of assets until 2020 would lead to production being cut to 0.5m boepd and 90% of demand being covered by imports at an estimated cost of £25bn. Conversely, delaying decommissioning by 10 years, and producing 1.5-2m boepd would meet 50% of total UK oil and gas needs. Extending North Sea production however not only reduces import dependence and costs but also generates substantial tax revenue. The difference between the two scenarios in cumulative tax receipts at 2004 oil prices would amount to £60bn by 2020. This constitutes a clear win-win – are we seeing this replicated elsewhere?

4.3. No Common Trend in Fiscal Regimes: A recent global update of changes in fiscal regimes\(^{23}\) found that Azerbaijan, Georgia, Ukraine, Uzbekistan, Brunei, Pakistan, Cameroon and Senegal had all switched to production sharing regimes that offered somewhat better investment and performance terms than previous laws. In addition, more than 20 countries have cut tax rates and excess profits taxes, and are now offering tax holidays and customs exemptions. An equal number of countries improved E&P investment incentives by reducing or completely eliminating state participation, abolishing or reducing royalty rates, or offering preferential treatment of high-cost projects, such as deep water. However, some countries did exactly the reverse. In 2004\(^{24}\), Venezuela unilaterally increased its royalty on contracts to develop and produce heavy oil from the Orinoco region from 1% to 16.67%. And the Bolivian draft hydrocarbon law provides for mandatory conversion of existing E&P agreements into service contracts that would strip contractors of their share of production. Likewise, in April 2003, the Russian government stalled international E&P investment by not signing off on 30 already negotiated production-sharing agreements (PSAs) and two months later issued a law, which rendered new PSAs virtually inaccessible to investors. By auctioning off most of YUKOS’ assets to a shell company and then transferring these to state-owned Rosneft, the Russian government has effectively moved towards indirect nationalization of its oil and natural gas resources. Clearly, in line with the argument presented above, the Kremlin seems convinced that a fiscal and regulatory system will not suffice to protect the country against the risk of being abused. But is an NOC likely to do this? In what circumstances can an NOC be presumed to be efficient? Given these conditions, can it play a political function? What is the role of an NOC in international markets?

4.4 Implications for NOCs: Internalizing the otherwise outsourceable exploitation of a country’s oil and gas resource – entirely or partly – in the hands of a single state-owned, state-run enterprise raises efficiency concerns. Internal benchmarking exercises and incentive plans are unlikely to substitute for missing market references. Where market principles apply, NOCs will be unable to pursue non-economic political goals such as employment generation – in general or for particular political allies – the subsidization of domestic oil prices, or investment planning in line with governmental budgetary requirements rather than pure business needs. In addition, the reliance on a nationalized oil producer distorts competition in factors markets, negatively affects the country’s non-oil economy, and thereby deepens the dependence on hydrocarbon exports and volatile oil prices. Their international impact is equally questionable. State-financed NOCs need to worry less about environmental and human rights campaigners and may over-bid on assets to assure energy security. Difficult to benchmark domestically, they are – as a business model – a fall-back into earlier mercantile times and a straightforward contradiction of internationally accepted state-aid rules.

5. Summary and Conclusions

Observers of current upstream oil and gas developments often equate a change in a company’s strategy with a fundamental shift in its underlying business model. This chapter described types of upstream business models and offered a cursory assessment of the strategies pursued by BP, Spinnaker, Anadarko, Baker Energy, Petrofac, Halliburton and Schlumberger, as well as the UK government in managing the UKCS fiscal regime. There seems to be no new or need for new business model. In fact, seen from a conventional international product/industry life-cycle perspective, players appear to develop their given models in line with fairly predictable patterns of industry evolution. While limited opportunities for risk spreading and efficient productive specialization triggered the vertical and horizontal integration of early oil and gas producers, ensuing changes in market conditions, play characteristics and political contexts caused the functional specialization of independent players and technology providers and the operational involvement of international resource owners. In each case, market definition and operational involvement reflect the specific economics of the business as well as coordination and organizational requirements. Currently, the evolution of the LNG sub-sector follows the same pattern, albeit in a sped up fashion. While global majors again provide the initial capital, coordination function and bridge to end-consumers, markets are already deepening and their impact is lessened.