State Participation and the Corporate Value of Natural Resource Economic Rents

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Abstract

The asset participation relationship between the state and the corporate entity is an essential determinant of corporate value in the natural resource sector. Natural resources deplete, with the result that oil reserve replacement is an accepted imperative for companies that derive earnings and balance sheet values from global resource assets. Corporate asset values in the sector are underpinned by entitlement to future reserves. Specifically, I show that the global nature of government participation varies and that it matters in which country reserves are held since entitlement structures directly determine how the state and corporate producers share economic rents from resource assets. My global Oil and Gas (O&G) sector study provides market evidence of economic and state variable limits on the value of globalization.

Findings revise the low oil price paradigm covered in prior studies and provide evidence that, for O&G producers concerned with reserve replacement, global asset values are directly affected by state entitlement terms. In developed OECD countries, state and corporate agent participation terms are price insensitive, and take the form of concession contracts with royalty or profit taxation terms. By contrast, in emerging NON-OECD countries state agents participate on production sharing terms that are linked to the market price of oil. Relative to comparable OECD oil assets, the value of corporate agent participation in Non-OECD O&G assets is limited by explicit and progressive state agent participation terms that favour sovereign state agent returns.I show that unless price sensitive entitlement clauses are is included in the value of cash flow expectations, state participation terms potentially invert risk return convention under conditions of increasing oil prices. The Fama and French (1993) framework is used to provide market evidence of economic state variable limits on the returns for O&G companies with relatively high asset holdings in Non-OECD countries.

Acknowledgements

My wife, Valentina, who convinced me as to the essential vitality and enjoyment of academic research. As a partner Valentina approaches life with an optimistic dignity, and without her support and editorial input this work would simply not have been possible. Professors Hatherly and Oliver deserve special mention for their recognition that a world class research school depends on corporate engagement through research specialization and collaboration. Professor Hatherly's effortless collegiality and contribution in positioning the school, will I am sure, be remembered long after we have finished our daily walks up Arthur's Seat. Insightful comments by my supervisors, Dr Peter Moles and Dr Paul André, have stimulated healthy debate and added research rigour.

The summer of 2006 proved an inspiring one, not least for the weather in Scotland, but also for the friendship, discussions and debates with Axel Kirchner. Regular research report-backs to the Board of the Bank Of Scotland – Corporate Division, coupled with a structural shift in global commodity prices helped crystalize the significance of my oil and gas findings. The processing assistance of undergraduates H. Reusch and L. Sharifszyanova on the Bank of Scotland Global O&G Risk and Return Project made the sheer volume and scope of my study possible.

I acknowledge the exceptional data provision and research sponsorship from leading global energy research company - Wood Mackenzie - who have enjoyed some small reciprocal benefit from incorporating my research findings into their global asset pricing models. Simulation assistance was made possible by Joseph Stanislaw research funding. This work has been screened to ensure that no confidential data are revealed. Any errors and omissions are the responsibility of the author.

Contents

Part I.

Doctor of Philosophy – Thesis

1. Introduction

This study examines the effect of state economic variables on the corporate value of asset globalization in the natural resource sector. Country state participation terms have important fiscal and legal differences that are relevant when valuing assets across global natural resource markets. The importance of fiscal and legal differences as between emerging and developed markets have recently been noted by Bekaert and Harvey (2002) and Bruner et al. (2002), both of whom suggest that global differences are likely to mitigate against valuation model convergence.

In his review of the history of the oil and gas sector Yergin (2003) suggests that oil's natural resource legacy raises fundamental questions as to how state and corporate entities jointly participate in asset sharing. Natural resources introduce a physical characteristic that enables enables host countries to generate economic rents from land in their jurisdiction. Economic rents in the context of this oil and gas study, are defined as the difference between the market price (of oil), on one hand, and, on the other, the costs of production plus an allowance for additional costs – transportation, processing, and distribution – and some return on capital. In reviewing the global state of economic rent sharing, Yergin (2003) specifically asks, how should – the host country, the producing company, or the consuming country that taxed it – share economic rents? There remains no global agreement on this elemental issue, and as a result the asset pricing effect of state participation on natural resource asset values remains a largely unexplored area of finance.

All parties, Yergin (2003) suggests, have legitimate claims. The host country has sovereignty over the physical oil reserves. Yet, reserves would be without value unless the foreign company risked capital and employed its expertise to discover, produce, and get it to market. The host country is, in essence, the landlord, the company a tenant who would pay an agreed rent. The oilfield exploitation scenario clarifies ".... the great divide of the petroleum industry: a rich discovery means a dissatisfied landlord. He knows that the tenant's profit is far greater than necessary to keep him producing, and he wants some of the rent. If he gets some, he wants more" Adelman (1972).

Economic rent sharing principles vary widely between OECD and Non OECD countries. The oil and gas sector is used to provide evidence that progressive state oilfield participation effectively limits the corporate value of emerging Non-OECD oil and gas (O&G) investment relative to developed OECD country investment. I use an extensive global sample of oilfields to demonstrate that the nature of Non-OECD state participation limits the corporate benefits of globalization in the natural resource sector. Global variations in the form of state and corporate agency oilfield asset participation are also shown be Bruner et al. (2002) to have the potential to mitigate against valuation model convergence.

Country differences between global O&G markets fits well with the state participation concept mooted by Stulz (2005), who identifies redistributative taxation as a tool to facilitate expropriation (from corporate agents) by the state. State participation in the form of Non-OECD production sharing O&G contracts are contrasted with concession state participation structures in OECD countries and included in the market study as a separate factor in addition to the Fama-French Three-Factor Model.[1] It is suggested that emerging countries use state powers to maximize their own welfare by reducing the relative O&G payoffs to investors and corporate insiders. The distinction between predatory and contracting theory of the state, North (1981), is used by Stulz (2005) to suggest that in their best form contracts should be mutually advantageous. I concur, but suggest that the global shortage of replacement O&G reserves, the inability to transfer capital committed to physical fields, coupled with the potential for state asset expropriation means that corporate agents have little choice but to co-invest with Non-OECD countries in the form of production sharing contracts.

[1] In general, OECD countries use royalty systems. Production sharing contracts generally occur in the Non–OECD regions of Africa, Indonesia and much of the former Soviet Union. Reported reserves are based on the economic interest held subject to the specific terms and time frame of the agreement. For a full discussion of entitlement contracts see Guidelines for the Evaluation of Petroleum Reserves and Resources, SPE Working Paper 2005, and Bindemann (1999).

Finance theory suggests that corporate asset values are based on the value of the expected future benefits from reserve entitlement Ross (2004). Natural resource assets deplete, and as result, asset replacement is shown by Strong (1991) to be an accepted imperative for a sector that derives earnings and balance sheet values from resource assets . State oilfield participation terms vary significantly in the sector, with the result that, post state agent participation, expected corporate benefits vary widely. Specifically, it is shown to matter to O&G producers where reserves are held, where replacement reserves originate, and what oil price expectations are. Each of these factors have direct implications for corporate earnings, asset values and, as might be expected, corporate share prices.

The interaction of state effects on asset pricing is supported by all 5 separate empirical chapters. Real asset data for 292 oilfields are used for the first and fourth of the empirical chapters where the simulation intensity is limited. For chapters two and three where simulation runtime intensifies, a subset of 211 oilfields is selected using stratified sampling in line with Cochran (1946). The extensive and global nature of my study asset based approach has precedent in two important natural resource studies. Brennan and Schwartz (1985) study a single copper mine to evaluate natural resource investment and Paddock et al. (1988) model a single offshore oilfield in order to isolate specific and important option characteristics. The structure of my thesis and key contributions are as follows.

My primary research objective is to establish whether when state agent taxation is included, and all other factors held equal, oil and gas assets behave the same across OECD and Non-OECD countries. To provide insights into this objective, a distinction is made in the first chapter between OECD and Non-OECD oil and gas assets. In the first chapter of this study, I introduce the global oil and gas field data and establish valuation methodology using the Securities Exchange Commission (SEC) industry standard NPV valuation. The prescribed SEC discount rate is applied throughout this study. In applying an asset valuation model to oilfields, market uncertainty for oil price is introduced through stochastic simulation. This refinement recognizes the modern asset pricing techniques mooted by Laughton et al. (2000), introducing market uncertainty at the source, in my study oil price market risk. The contribution of this chapter is both tactical and strategic. Tactical in that taxation is shown to not be a constant function in monte carlo simulation. I use a simulation technique proposed by Kretzschmar and Moles (2006), calculating taxation in each iteration. The second and strategic contribution of this first chapter is the demonstration that Non-OECD state agent participation is at the expense of corporate agents, a natural resource finding in line with the recent financial asset study by Stulz (2005).

The second empirical chapter, extends the first chapter by highlighting the effects of the state participation under variable oil price levels and stochastic uncertainty. This allows me to combine key findings of the market price of commodities Bessembinder et al. (1995) and Geman (2005) with underlying oil and gas physical asset values. 211 fields provide insights into natural resource asset pricing. The extensive sample highlights the differences between pre and post tax asset values, and then, in turn, illustrates post tax differences between OECD and Non–OECD assets.

The third empirical chapter uses oilfield data to provide expanded insights into natural resource asset response to oil price volatility. This work uses stochastic simulations at three price levels to provide insights into the effects of state participation on asset volatility and hedge ratios. Findings reinforce post-tax differences in asset value from the previous chapter and illustrate that temporal variance in physical assets is a hidden dimensional outcome of price risk, Geman et al. (2002).

The fourth empirical chapter provides accounting insights into price volatility disclosure work by Rajgopal (1999) and Boone (2001). I support prior findings that price volatility is not disclosed in accounting information. Additionally, I show that OECD and Non-OECD data are not differentiated in SEC disclosures and that SEC accounting disclosures are influenced by regulatory institutions Bushman and Piotroski (2006). This finding of disclosure deficiency suggests an ex ante lack of transparency about asset holdings may inhibit market recognition.

The final chapter provides market evidence of the importance of underlying asset values (as measured in the first four empirical chapters) in sector book to market measures as proposed by Fama and French (1992). Specifically, previous chapters enable me to provide insights to two unanswered questions raised by Fama and French (1995) p 153:

"... (i) What are the underlying state variables that produce variation in earnings and returns related to size and BE/ME?

(ii) Do these unnamed state variables produce variation in consumption and wealth that is not captured by an overall market factor and so can explain the risk premiums in returns associated with size and BE/ME?"

The market evidence in the final chapter of this study strongly suggests that country/state agent effects do explain the risk premiums associated with size and BE/ME. The effects are, in many instances, sufficiently strong as to dominate the explanatory power of size and BE/ME. The expectation is that as oil prices increase, corporates with high Non-OECD asset holdings are likely to begin to experience share price under-performance relative to companies with low Non-OECD asset holdings. State participation, and oil price value response is extraneous to the asset, and is capable of *potentially* inverting the risk return convention proposed by Mehra and Prescott (1985), demonstrating limits to the benefits of globalization for oil and gas companies. I find that despite accounting non-disclosure of homogenous oilfield data, a market discount exists for companies that are overweight Non-OECD assets. This finding is in contrast to industry findings by Cavaglia et al. (2000) and suggests that, relative to comparable OECD oil assets, corporate participation in Non-OECD O&G assets is limited by contracts that favour state participation. A significant contribution of this thesis is the provision of evidence that state participation differences mitigate against valuation model convergence and that these effects have the potential to invert risk return convention.

Findings provide natural resource evidence that state agent participation in oilfield cash flows has the ability to limit the corporate value of globalization on company asset participation. The constrained corporate upside for assets in Non-OECD countries is in contrast to equity market studies by Mehra and Prescott (1985) and Bekaert et al. (2005) who suggest that emerging markets provide consistent and compensatory value premia. This thesis concludes by using the constructs of the Fama and French (1993) Three-Factor-Model to provide market evidence of limits to share returns for companies overweight emerging country oilfield asset holdings. I find market Country/state agent effects explain the risk premiums associated with size and BE/ME, an insight into a state variable factor unresolved by Fama and French (1995).

2. Literature and Institutional Framework

Chapter Research Focus: State Participation Effects on OECD and Non-OECD Assets

Non-OECD market O&G sectors are characterized by production sharing contracts. They typically provide oilfield operators with pre state participation guarantees to cover a return on their capital costs. In exchange, host countries impose a reserve entitlement structure that contractually escalates oilfield participation sharing by the local government based on the price of oil (Angola), and in some cases the volume of oil pumped (Indonesia). The explicit link between operator asset entitlement and commodity prices differentiates Non-OECD market O&G sectors from OECD sectors, Bindemann (1999).

Overview

Concessions (OECD) and PSCs (Non-OECD) have legal and regulatory complexities that have the potential to cause asset cash flow participation inversion between OECD and Non-OECD markets. Studies by Haushalter et al. (2002) and Jin and Jorion (2006) relate to a period when oil prices range between US$18/bbl and US$35/bbl and cover the years 1992 to 1994, and 1998 to 2001 respectively, periods comparable to the US$33.75/bbl to US$45/bbl price range in this study. The coexistence of progressive taxation and oil prices above US$45/bbl has been a reality since 2004, allowing insights into the combined effects on global oilfield asset valuation. Bindemann (1999)

Research Acknowledgements

Appreciation is expressed to my supervisors who suggested the need for the inclusion of an Institutional Structure in this chapter.

2.1. Institutional Oilfield Contracting Structures

The past 24 years have seen a significant shift in global proven reserve distributions. Figure 2.1 illustrates that Non-OECD areas have experienced the greatest growth in oil reserves over the period with direct implications for the returns oil producers when invested in oilfield assets in these emerging markets. Chapter 7 suggests that in the last eight years 75% of reserve replacement has occurred from Non-OECD countries. This oil and gas phenomenon makes the understanding of differential state participation terms a necessity for any meaningful analysis of sector returns.

The equity market convention established by Mehra and Prescott (1985) is that risk and return are positively correlated in global markets, and when compared to OECD markets, higher Non-OECD risks are compensated by higher return premia. I suggest that if no account is taken of differing oilfield responses to stochastic oil prices (as opposed to valuing cash flows based on certain oil prices) globally divergent forms of state participation in oilfield cash flows have the potential to invert this fundamental convention. In this study, the term 'state participation' is used to refer to government participation, or government take as used in the oil and gas sector. This recognizes the ex ante asset claims of all forms of taxation and production sharing against producer reserves in favor of the asset's local government. The claim interpretation recognizes the contractual nature of state claims against oilfield assets, with corporate agents sharing in residual cash flows Kretzschmar et al. (2007). The two main forms of oilfield ownership in the oil and gas sector are production sharing contracts (PSCs) and concession holdings.

The equity market premium puzzle identified by Mehra and Prescott (1985) has been expanded by many studies that have begun to grapple with the distinction between emerging market and developed market characteristics. Conover et al. (2002) provide ex ante tests for difference in equity risk premia, comparing developed and emerging market monetary cyclicality. However, unlike equity markets, oilfield data limitations mean that there is no best practice convention for global real asset value comparison (Bruner et al. 2002). In fact, Yergin (2003) suggests that there is absolutely no agreement on the method of global state participation in natural resource assets. Bekaert and Harvey (2002) encapsulate the multi disciplinary and multi faceted problems facing comparative asset valuation in emerging markets, summarizing the global asset valuation challenge as one that needs to link international economics, asset characteristics, development economics and law with political science and country specific fiscal terms.

Concerns about valuation model convergence recently attracted increasing interest at colloquia with Bruner et al. (2002) and Bekaert and Harvey (2002) identifying the need for further empirical study in this area. Bruner et al. (2002) advance reasons for the importance of emerging market valuation review, noting that investment flows into emerging markets continue to be material. Nowhere is this trend more evident than in the oil and gas sector where there is a strong economic and geopolitical relation between state and corporate agents. The location of global reserve holdings is illustrated in Figure 2.1. The figure highlights several important factors. The balance of asset distribution in the Americas has recently shifted in favor of South America (Non-OECD). The North American region is now the only global region with an overall reduction in proven reserves. Greatest reserve growth occurs in the Non-OECD regions of Central Asia, Africa and the Middle East.

Figure 2.3 provides insights into the highly variable rates of government take where government take is measured as a percentage of pre-tax PV in the regime. It is notable that government take varies widely on a global basis. The detailed terms of which are provided in Appendix C. Due to the difficulty of disclosing detailed tax terms in concession or PSC countries on a field by field basis, I provide an overview of the range of concession and PSC terms applicable to all fields in the sample (Table 2.1).

Oilfield assets are uniquely positioned to provide comparative insights into global real asset valuation and emerging market specificities. The oil and gas (O&G) sector has been extensively used in studies that attempt to isolate asset valuation and risk attributes, Haushalter et al. (2002) emphasize the cost of extraction while Jin and Jorion (2006) note that global commodity oil markets are homogenous, well traded with oilfield assets subject to equivalent global oil price volatility. There exists a representative and comparative spread of oilfield assets between OECD and Non-OECD countries, providing the means to isolate component cost structures and study valuation convergence as between OECD and Non-OECD market real assets. Figure 2.2 quantifies the extent

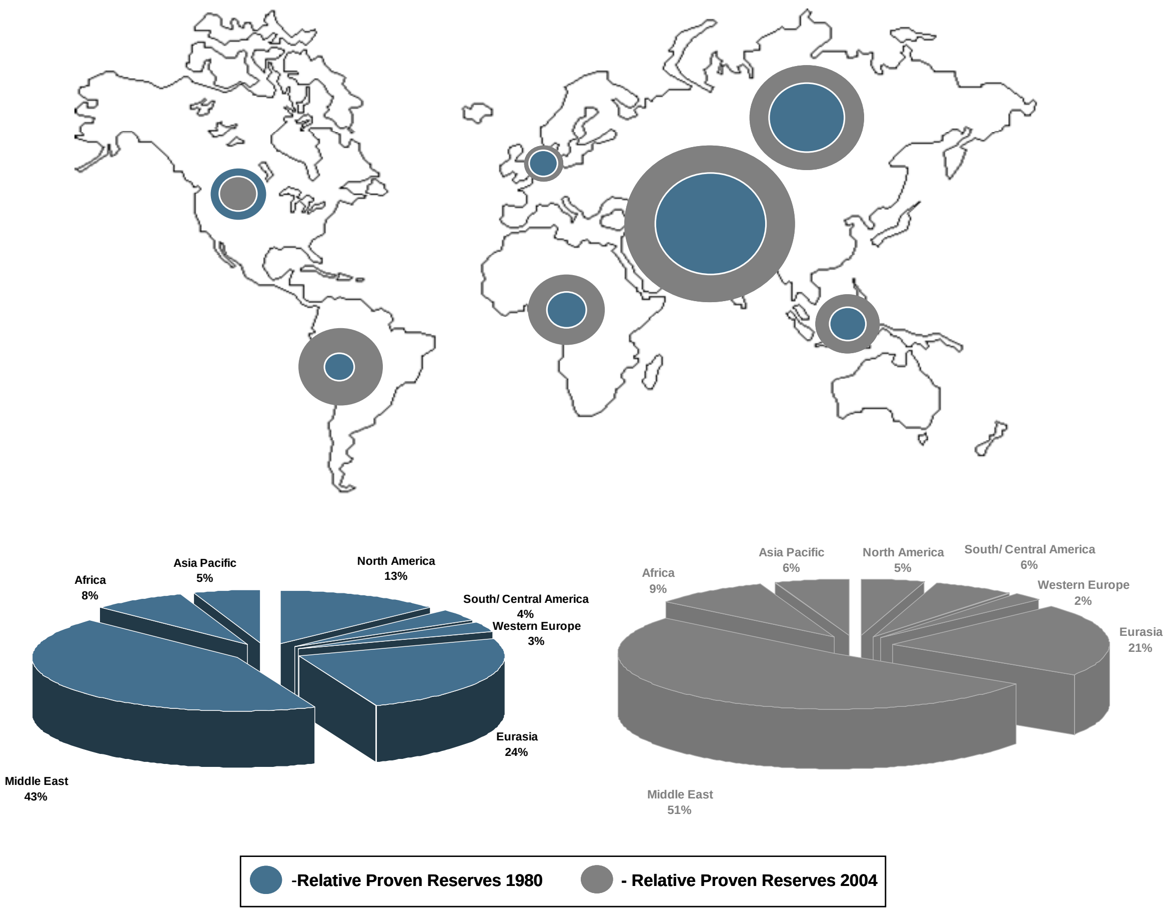

Figure 2.1. Global Proven Reserve Distribution as Between OECD and Non-OECD Regions

The two colour shades illustrate movement in absolute reserves over a twenty four year period, 1980–2004. This figure illustrates in which regions proven reserves are held and provides insights into the likely entitlement structures under which state and corporate agents operate assets (OECD countries operate under concession regimes whereas Non-OECD countries operate under production sharing contracts). By the same measure it matters where replacement reserves originate. The figure does not include Oil Sands and Unconventional Reserves. Source: Reserve movements derived from proven reserve figures in the BP Historical Statistical Review – Tristone

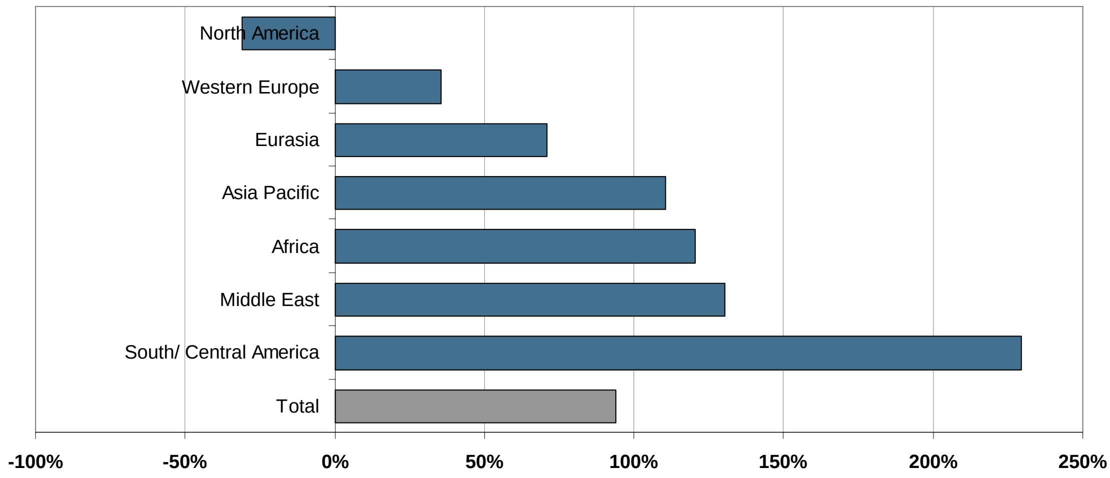

Figure 2.2. Changes in Global Proven Reserve Distribution as Between OECD and Non-OECD Regions

This figure isolates the movement in proven reserve holdings by regions. The axial bar graphs illustrate movement in absolute reserves over a twenty four year period, 1980–2004. Oil Sands and Unconventional Reserves are not included. Source: BP Statistical Review 2004 – Tristone Capital

to which OECD countries (North America and Western Europe) experience the lowest increase (decrease for North America). The use of a representative oilfield assets across both Non-OECD and OECD markets mean that this work embodies a "…unique interdisciplinary interest that bridges both investment and corporate finance", Bekaert and Harvey (2002).

Ross (2005) defines the value of an asset in the context of probability theory under the no-arbitrage assumption with the risk-free probabilities π^*.

$$V(z) = E[\phi z] = \sum \pi_i^* \phi_i z_i \tag{2.1}$$

Where the asset value V in Ross (2005) general form pricing kernel is reflected by the expected value of the product of its future payoffs z with the pricing kernel ϕ. In this study, the asset value payoff to the corporate agent and, in the natural resource sector, the equilibrium of the asset pricing kernel is directly affected by state

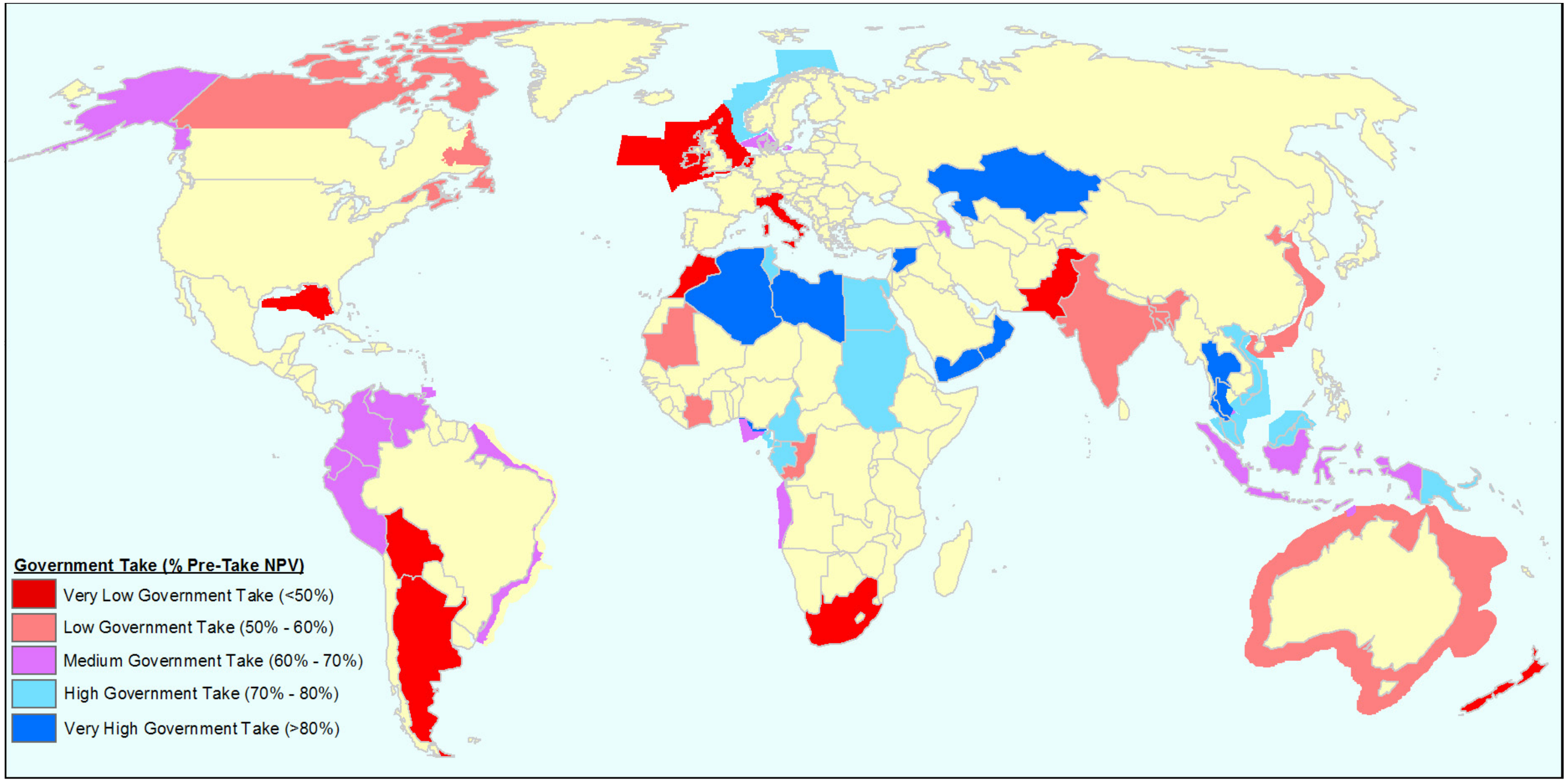

Figure 2.3. Fiscal Regime Rates and Reserve Distribution as Between OECD and Non-OECD Regions

This figure illustrates the rates of government taxation that is paid in each country at January 2006 and provides a global overview of the relatively high tax rates prevailing in Non-OECD regions. Detailed country fiscal terms are enclosed in the penultimate appendix to this thesis.

agent participation in asset returns. This is reflected in the wide global variations of participation rates – where variant forms of taxation are levied on corporate agents.

In order to overcome the effect of stochastic variations in taxation, this analysis considers three simplifying assumptions. First, natural resource assets deplete, and as a result state agents find it optimal to extract value out of existing assets since depletion precludes future expropriation. Second, state agents in both OECD and Non-OECD countries do not have the skills or expertise to deliver technical O&G development projects. Finally, the rate of state taxation participation is deterministic, and is based on terms and rates in existence at January 2006. In line with Stulz (2005) this assumption is a necessary simplification in that ad-hoc changes in either the deterministic tax regime or in political agents in countries are possibilities.

2.2. Literature and Principles of PSC and Concession Fiscal Terms

Indonesia, in the 1960s, introduced the first production sharing agreements in the oil and gas industry. These first PSCs were simple cost recovery agreements that enabled the accelerated recovery of producer development cost and have now been extensively adopted throughout the developing oilfield regions of the world. The terms of these agreements vary from country to country but the principal remains the same; corporate producers have a right to share in the oil resource but to no own it. The state is a participative production sharing partner in the development. An overview of the structural nature of production sharing contracts and concession terms are provided in Section 2.3.

Due to the confidential and closely held nature of information in the oil and gas sector, an effect commented on by Haushalter (2000) few academic studies have been able to penetrate the confidential terms negotiated in Non-OECD countries. Notable exceptions are the Indonesian study performed by Gramlich and Wheeler (2003) and the study of a US company exploration contract Hampson et al. (1991). Both studies are characterized by their limited data, a factor that I overcome using the generous sponsorship of oilfield data across six global regimes. Hampson et al. (1991) cover

Table 2.1. Overview of Concession and PSC fiscal terms in sample countries

Differentiation is made by referring to the concession or PSC Tax Base Terms[a] contained in columns (a) to (e) or (f) to (i) respectively. Full terms and the nature of their application are contained in the fiscal term appendix.
(a) Tax terms for non-PRT oilfields on the UK Continental Shelf (UKCS).
(b) Tax terms for PRT oilfields on the UK Continental Shelf (UKCS).
(c) Tax terms for oilfields on the Norwegian Continental Shelf (NCS)
(d) Tax terms for oilfields in shallow water Gulf of Mexico (GoM Shallow water)
(e) Tax terms for oilfields in deepwater Gulf of Mexico (GoM Deepwater)
(f) Tax terms for the oilfields in Angola which are subject to Rate of Return (IRR) based production sharing contracts.
(g) Tax terms for the oilfields in Angola which are subject to cumulative production (PROD) based production sharing contracts.
(h) Tax terms for the oilfields in Egypt which are subject to PSC contracts
(i) Tax terms for the oilfields in Indonesia which are subject to PSC contracts
[1] Sliding scale IRR (terms are negotiable and field specific),
[2] Sliding scale production terms (terms are negotiable and field specific)
[3] Sliding scale production terms (terms are negotiable and field specific)
[4] Location and contract specific profit splits
[5] The price cap is calculated as the difference between the market price of oil and the negotiated cap.
[6] DM
[7] DM

	Concession Regimes					PSC Regimes			
	(a) UKCS	(b) UKCS PRT	(c) NCS	(d) GoM Shallow Water	(e) GoM Deep Water	(f) Angola IRR	(g) Angola Prod	(h) Egypt	(i) Indonesia
Royalty	—	—	—	16.7%	12.5%	—	—	—	—
FTP	—	—	—	—	—	—	—	—	10-20%
PRT	—	50%	—	—	—	—	—	—	—
SCT	—	—	50%	—	—	—	—	—	—
SCT	10%	10%	—	—	—	—	—	—	—
CT	40%	40%	28%	—	—	—	—	—	—
FIT	—	—	—	35%	35%	—	—	—	—
CIT	—	—	—	—	—	50%	50%	—	—
C&W	—	—	—	—	—	—	—	—	44-56%
B	—	—	—	—	—	S/P	S/P	S/P	S/P/C
PO	—	—	—	—	—	25 – 90%[1]	40 – 90%[2]	70 – 85%[3]	65 – 85%[4]
PG	—	—	—	—	—	25 – 90%[1]	40 – 90%[2]	70 – 85%[3]	55 – 70%[4]
PC	—	—	—	—	—	—	price cap[5]	DM[6]	DM[7]

the contracting essentials of a partnership contract in a case study format, covering a single field. In essence their suggestions are that key features of PSCs need to be tailored between the state and the contractor in order to derive an optimal sharing rule. Important inputs in the derivation of optimal sharing, are the concepts of cost recovery (termed 'cost oil') and profit sharing (termed 'profit oil').

Oil companies under concessionary fiscal terms are allowed to sell all of their production to market prices, while under PSC fiscal terms, they are only entitled to the production which covers the sum of 'cost oil' and 'profit oil'. This principle is covered in Section 2.4 which shows the important difference between these two PSC agreement processes. Cost recovery for instance, allows the contractor to recoup costs during development of new fields (currently the case in Angola, While profit share generally occurs in more mature production provinces, Indonesia in my study. Additionally, in some areas, such as the Angolan deep-water oil fields and new prospecting is encouraged, contractors are therefore also allowed capital costs uplifts, which allows the partner group to uplift all capital costs by at least 40%. In situations where large, high-cost, development projects are required (i.e. the majority of Angola's deep-water discoveries) the capital uplift means that for a project with capital expenditure of US$3 billion the recoverable costs are US$4.2 billion. Production remaining after cost recovery is termed profit oil/gas and is divided between the contractor and the government. The basis on which this division is made varies between contracts with more recent contracts based on the contractor's rate of return (ROR) whereas in earlier contracts the split was based on cumulative production. Figure 2.4 illustrates an example of contractor and state participation in an oilfield governed by a production sharing contract at an oil price of US$45/bbl.

By contrast, concession agreements apply the same fiscal principles as corporate taxation. There is no a priori fiscal claim to profits, nor in the UKCS, GoM and Angola is there government take prior to cost recovery. The state shares pari passu with the corporate in post cost profits, however these may be defined by the state. This concession effectively removes the fist leg of profit sharing shown in Figure 2.4

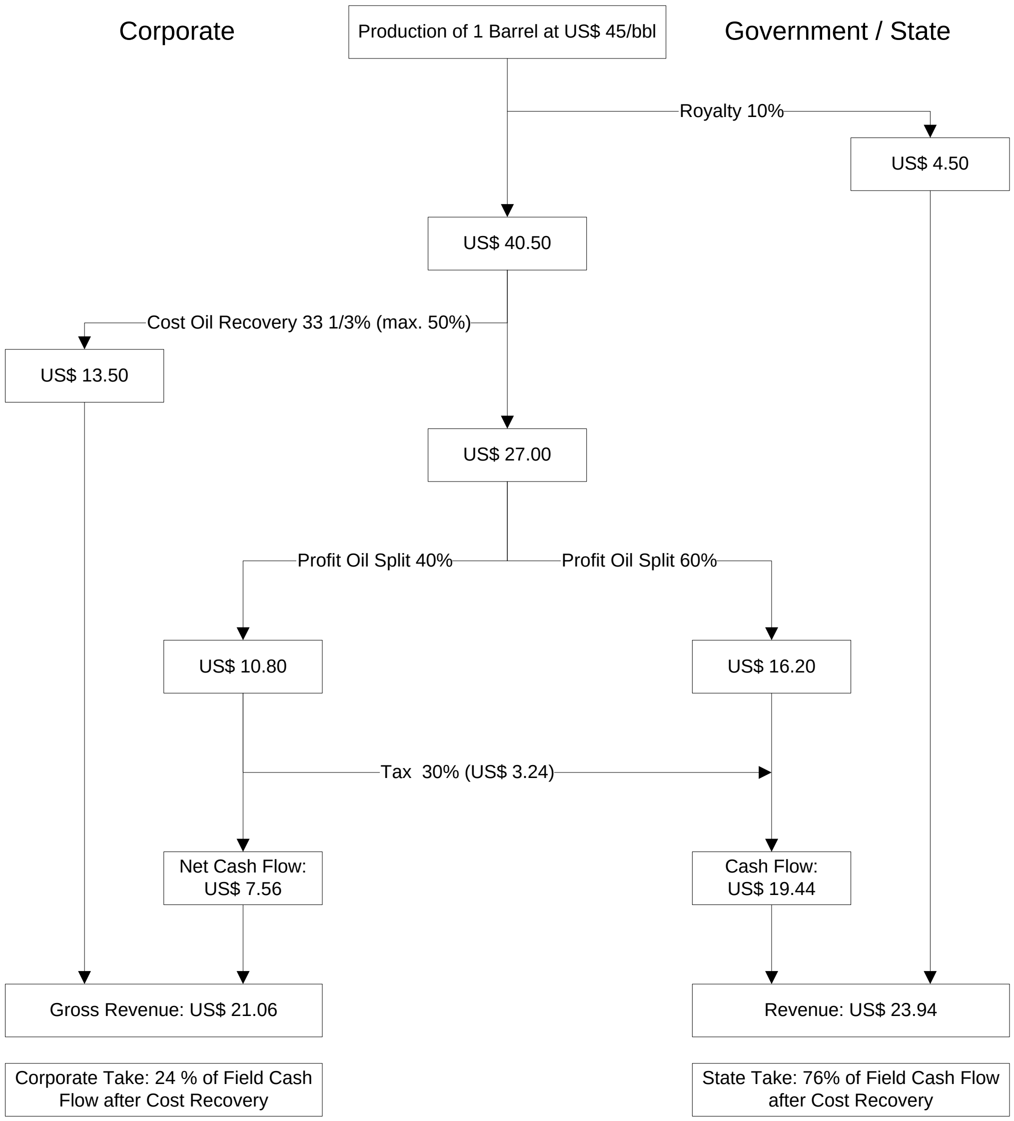

Figure 2.4. Flowchart illustrating an Example of Contractor and Government Participation in a Production Sharing Contract

The figure shows the Institutional Relationship between PSC Producing contractors and the State at an oil price of US$45/bbl. It is instructive to note that cost recovery or Internal Rate of Return (IRR) allocation occurs before the profit split. This illustrates that corporate cost recovery is ensured in PSC regimes. The profit split between producer and state is weighted in favour of the state, while the rate of profit share is connected to oil price. At higher prices state oilfield participation increases, see Table 2.3. By contrast, for concession institutional frameworks, there is no cost recovery guarantee. The profit split is, however, constant and state participation rates are not progressive with oil price. Detailed country participation terms are found in the Fiscal Term appendix. Source Bindemann (1999), amended.

2.3. PSC and Concession Fiscal Terms

Concession terms are set out for each country in columns (a) to (e). In the case of US Gulf of Mexico, oil companies are subject to a royalty tax which is deducted from the well-head value of the oil, and a federal income tax which is taxed on net operating profit. In deepwater GoM, the royalty rate is 12.5%, while it is 16.7% in shallow water fields. Although, royalty tax is no longer applicable for UKCS and NCS oilfields, oil companies operating in these regimes are required to pay either a supplementary corporation tax (UKCS) or a supplementary petroleum tax (in UKCS and NCS).

By contrast, PSC tax terms are more complex. Some PSC contracts are based on the contractor's rate of return (based on the contractor's accumulated compounded post-tax cash flow, e.g. Angola IRR, column (f)), whereas in other contracts the split is based on cumulative production (e.g. Angola PROD, column (g)).

2.3.1. PSC Oilfield Contracting Terms

To facilitate comparative insights into concession and production sharing regimes I perform a comparative taxation computation for the same field. Insights into the detailed calculations are performed by calculating at US 45 for the same field, an Angolan field, under Angolan and GoM terms. To illustrate insights into PSC state participation terms I demonstrate below a detailed Angolan oilfield tax calculation. For ease of comparison of institutional frameworks as between OECD and Non OECD countries, a GoM concession calculation follows.

Table 2.2 shows field data for a large Angolan oilfield.[1] Column (a) shows the production profile (in thousands of barrels of oil per day) for each year in the whole life of the oilfield, while column (b) depicts the corresponding price forecast.[2] In this specific

[1] Oil production, field life, operating expenditures and capital expenditures have all been changed in order to ensure that no confidential information is revealed.

[2] The standardized SEC measure requires the use of the current year-end price of oil over the whole field life, I apply a slightly more conservative approach to incorporate findings from Bessembinder et al. (1995) – for both concessions and PSC calculations. A P_{45} oil price scenario at time 0 consists of US$45/bbl for 2006, US$40/bbl for 2007, US$37/bbl for 2008, US$35.87/bbl for 2009 and US$36.77/bbl for 2010. From 2010 onwards, the oil price is increased by 2.5% a year. In addition, I develop 4 price scenarios where the prices in the P_{45} scenario is scaled down up or down with a constant factor. For instance, I calculate a $P_{33.75}$ scenario where all the P_{45} prices are multiplied

example the oil produced is of Hungo quality (in contrast to West Texas Intermediate (WTI) and Brent blend), a quality of oil typically sold at a discount to WTI or Brent.

Annual expected gross revenue (column c is calculated as the product of production (column a) and price (column b). Columns (d) and (e) describe the expected expenses incurred from operating the field (operating expenses, opex) and investments to prepare the field for production (capital expenditure, capex), respectively. Company cash flow (column l) is calculated as gross revenues less opex, capex and government take.

Columns (f) to (k) relate to the calculation of government take and profit splits between the government and the contractor, and will be described in more detail in Tables 2.3 and 2.4. Table 2.5 articulates how the SEC variables reserves, production and NPV are calculated.

All offshore contracts awarded since 1991 fall under the ROR based model. During the application process bidders must specify the rate of return steps and the profit oil splits applicable to each tier. The contract allows for up to five different tiers of profit splits with rates varying from contract to contract. Typical rate of return based profit splits are given in Table 2.3:

The split is determined by the rate of return achieved in the previous period. The ROR calculation is based on the contractor's accumulated compounded post-tax cash flow. The contractor's cash flow is defined as in Table 2.2 (column (l)). Exploration expenditure is not included in the computation of contractor's net cash flow. Only expenditure after the date of commercial discovery is included.

The contractor's cash flow is compounded at each of the ROR rates specified in the contract and the profit oil split is taken relating to the highest ROR which yields a positive result (Table 2.4).

by 75%, resulting in an oil price of US$33.75/bbl at time 0. Similarly I calculate a $P_{22.5}$ scenario (50% of US$45/bbl, equivalent to US$22.5/bbl), a $P_{67.5}$ scenario (150% of US$45/bbl, equivalent to US$67.5/bbl) and a P_{90} scenario (200% of US$45/bbl, equivalent to US$90/bbl). I tested this mean reversion against SEC tests and found that this is an accurate and more conservative approximation of the price effect on SEC PSC disclosures. Using static SEC year end prices actually increases the PSC price effect on reserves by enabling PSC claims to occur sooner, simply strengthening conclusions made.

Table 2.2. Detailed calculation of cash flows for a typical Angolan oilfield under Angolan PSC tax terms

(a) Production profile
(b) Oil price assumption
(c) Gross revenues are calculated by multiplying oil production (annualised) by the oil price assumption, i.e.(a) × (b) × 0.365]
(c) Opex profile
(e) Capex profile
(f) smallest of (e) × 50% and (c) [uplifted (40 percent) and depreciated (4 years)] + (d)
(g) (c) − (f)
(h) Profit oil splits (see Table 1B)
(i) (g) × (h)
(j) (g) × [1 − (h)]
(k) (j) × 50%
(l) (c) − (d) − (e) − (i) − (k)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Year	Production Liquids	Liquid price Hungo	Gross Revenue	Op Costs	Capital Costs	Cost Recovery	Total Profit Share	State Share	Government Profit Share	Contractor Profit Share	Income Tax	Company Cash Flow
	000 b/d	US$/bbl	US$M	US$M	US$M	US$M	US$M	(%)	US$M	US$M	US$M	US$M
2003	0		0	0	105	0	0		0	0	0	-105
2004	0		0	0	323	0	0		0	0	0	-323
2005	0		0	0	552	0	0		0	0	0	-552
2006	10	41.9	153	29	679	76	76	25%	19	57	29	-603
2007	100	37.2	1358	126	232	679	679	25%	170	509	255	576
2008	200	34.4	2512	198	238	1256	1256	25%	314	942	471	1291
2009	200	33.4	2435	203	122	900	1535	25%	384	1151	576	1151
2010	180	34.2	2246	194	62	289	1957	35%	685	1272	636	669
2011	165	35.0	2111	187	64	273	1838	55%	1011	827	414	435
2012	154	35.9	2023	184	66	258	1765	55%	971	794	397	406
2013	144	36.8	1938	181	67	252	1686	75%	1264	421	211	215
2014	135	37.7	1858	178	0	191	1667	75%	1250	417	208	222
2015	126	38.7	1781	175	0	184	1597	75%	1197	399	200	209
2016	118	39.7	1706	172	0	177	1530	75%	1147	382	191	196
2017	110	40.6	1635	170	0	170	1465	75%	1099	366	183	183
2018	103	41.7	1568	168	0	168	1400	75%	1050	350	175	175
2019	96	42.7	1503	166	0	166	1337	75%	1003	334	167	167
2020	90	43.8	1439	164	0	164	1275	75%	957	319	159	159
2021	84	44.9	1380	163	0	163	1218	75%	913	304	152	152
2022	79	46.0	1323	161	0	161	1161	75%	871	290	145	145
2023	74	47.1	1268	160	0	160	1108	75%	831	277	138	138
2024	24	48.3	423	78	0	78	346	75%	259	86	43	43

Table 2.3. Profit splits for a typical Angolan oilfield under PSC tax terms

(a) IRR	(b) State Share of Profit Oil	(c) Contractor Share of Profit Oil
<15%	25%	75%
15% - 25%	35%	65%
25% - 30%	55%	45%
30% - 40%	75%	25%
>40%	85%	15%

The compounded cash flow will by construct turn positive when the rate of return is achieved. For example, the 2003 company cash flow was minus US$105 million. The relevant Tier 1 cash flow for 2004 is calculated as

$$-105 \times 1.15 - 323 = -\text{US\$444 million},$$

while the Tier 2 cash flow in the same year is calculated as

$$-105 \times 1.25 - 323 = -\text{US\$454 million}.$$

This compounding is done for all the years in the field's life. In 2009, the Tier 1 compounded cash flow turns positive (US$622 million) signifying that the company has achieved at least 15% return on its investment. This results in a change in the profit split in favor of the government. Total profit oil for the following period is split 35%: 65% (government percent: contractor percent). In 2012 the company is expected to have achieved a 30% return on its investment, and will only be allowed 25% of the profit oil.

Since oil companies under PSC terms are only entitled to the production which covers cost oil and profit oil, their entitled production (Table 2.5 column (d)) will be different from total field production (Table 2.5 column (b)). In 2006 the field is expected to produce 10 million barrels of oil per year.

Under concession terms, the oil companies would be entitled to the entire 10 million barrels/yr. However, under the PSC terms the production entitlement is less than this amount. In 2006 the contractors cost oil is US$76 million and its share of profit

Table 2.4. Profit split tiers for a typical Angolan oilfield under PSC tax terms

(a) Using Table 2.2 column (l)
(b) Previous year's (b)$\times$(100%+15%)+(a) where 15% is the assumed first tier rate of return threshold
(c) As (b) but using 25%
(d) As (b) but using 30%
(e) As (b) but using 40%
(f) Share determined by reference to Table 2.3 above. The split applicable in any one year is that determined by the rate of return achieved in the previous year (goes to column (h) in Table 2.2 (for following year)).

Year	(a) Applicable Cash flow US$M	(b) 1st Tier US$M	(c) 2nd Tier US$M	(d) 3rd Tier US$M	(e) 4th Tier US$M	(f) State Share %
2003	-105	-105	-105	-105	-105	25%
2004	-323	-444	-454	-460	-470	25%
2005	-552	-1062	-1120	-1150	-1210	25%
2006	-603	-1825	-2003	-2097	-2297	25%
2007	576	-1523	-1928	-2151	-2640	25%
2008	1291	-460	-1119	-1505	-2406	25%
2009	1151	622	-248	-806	-2217	35%
2010	669	1384	360	-378	-2434	55%
2011	435	2027	885	-56	-2973	55%
2012	406	2737	1512	333	-3756	75%
2013	215	3363	2105	648	-5043	75%
2014	222	4089	2854	1064	-6839	75%
2015	209	4912	3776	1592	-9365	75%
2016	196	5844	4916	2266	-12915	75%
2017	183	6904	6328	3129	-17898	75%
2018	175	8115	8085	4243	-24883	75%
2019	167	9499	10273	5683	-34669	75%
2020	159	11084	13000	7547	-48377	75%
2021	152	12898	16403	9963	-67575	75%
2022	145	14978	20649	13098	-94460	75%
2023	138	17363	25949	17165	-132106	75%
2024	43	20011	32480	22358	-184905	75%

Table 2.5. Calculation of reserves entitlement, production entitlement and Remaining NPV under Angola PSC tax terms

(a) Total field remaining reserves in million barrels of oil equivalent.
(b) Total field annual production in thousands of barrels of oil equivalent per day.
(c) Companies' remaining reserves in million barrels of oil equivalent.
(d) Companies' entitled annual production (net of royalty) in thousands of barrels of oil equivalent per day. Calculated as (b) less royalty (deepwater: 12.5%).
(e) Companies' net present value of expected entitled cash flows.

	(a) Remaining reserves mmboe	(b) Production 000boe/d	(c) Entitled reserves mmboe	(d) Entitled production 000boe/d	(e) Remaining NPV US$M
2003	800	0	412	0	1614
2004	800	0	412	0	1880
2005	800	0	412	0	2391
2006	800	10	408	9	3182
2007	797	100	377	88	4103
2008	760	200	313	175	3938
2009	687	200	251	168	3041
2010	614	180	206	125	2194
2011	549	165	174	86	1744
2012	488	154	145	80	1483
2013	432	144	127	50	1226
2014	379	135	110	44	1133
2015	330	126	95	41	1024
2016	284	118	81	39	917
2017	241	110	68	36	813
2018	201	103	56	34	711
2019	163	96	44	32	608
2020	128	90	33	30	501
2021	95	84	22	29	392
2022	64	79	13	27	279
2023	36	74	3	25	162
2024	9	24	3	9	39

oil is US$57 million, a total of US$134 million. This is equivalent to a production of 3200 barrels per day, or 8.75 million barrels of oil a year (sum of cost oil and profit oil divided by market price of oil, i.e. 134/41.9). Oil reserves are calculated as the sum of production over the whole field life (columns (a) and (c)). As Table 2.5 shows, the difference between total production and entitled production increases with government share of profit oil. The expected net present value of the company cash flow is calculated using a discount rate of 10%, equivalent to SEC requirements (Table 2.5 column (e)).

2.3.2. Concession Contracting Terms

Subjecting the Angolan field to GoM tax terms indicates two important principles. Firstly, the tax rate in the GoM concessions is lower than that levied against Angolan fields at an oil price of US$45/bbl. This insight is expanded in Chapter 3 and is used to provide extensive and detailed analyses of the effects of differential and price sensitive state participation contract terms on corporate asset values. For ease of reference and completeness inf Table 2.6 and 2.7 I describe the calculation of reserves, production and remaining NPV for the same field as in Tables 2.2-2.5, save that it is subject to US GoM deepwater taxation and not Angolan PSC tax terms. Oil companies' entitlement to production and reserves in the specific oilfield is shown in Table 2.7.

2.4. Literature and Structure for Interpreting OECD and Non OECD Contracting Terms

State participation differences between markets are shown to mitigate against global asset valuation convergence. In this study of global oilfield assets I extend the findings by Haushalter et al. (2002) and provide empirical insights into the effect of state participation costs on corporate asset pricing. Four supporting empirical studies are undertaken in this thesis, each of which builds on a defined body of literature. To enable a structured approach to this analysis, the literature relevant to each chapter is introduced below and then covered in depth when reviewing the results and conclusions in each empirical chapter.

Non-OECD market O&G sectors are characterized by production sharing contracts. They typically provide oilfield operators with guarantees to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure that contractually escalates oilfield participation sharing by the local government based on the price of oil (Angola) and in some cases the volume of oil pumped (Indonesia). The explicit link between operator asset entitlement and commodity prices differentiates Non-OECD market O&G sectors from OECD sectors, Bindemann (1999). Legal and regulatory complexities are demonstrated to have the potential to cause asset cash flow

Table 2.6. Detailed calculation of cash flows for the typical Angolan oilfield under GoM concession tax terms

(a) Oil production profile of a typical field. Yearly figures are shown as thousands of barrels of oil per day. Totals are in millions of barrels, calculated as the sum over (a) $\times$ 0.365 (conversion from thousands of barrels per day to millions of barrels per year).
(b) Gas production profile of a typical field. Yearly figures are shown as mmcf gas per day. Totals are in mmcf, calculated as sum over (b) $\times$ 0.365.
(c) Cumulative production. Calculated as $[(a) + (b) \times cr] \times 0.365$, where cr is the conversion rate from gas (cf) into oil equivalent (bbl).
(d) Oil price assumption
(e) Gas price assumption
(f) Gross revenues are calculated by multiplying oil and gas (in oil equivalents) by their respective price assumptions, i.e. $[(a) \times (d) \times 0.365] + [(b) \times (e) \times 0.176] \times 0.365$.
(g) Operating costs
(h) Capital expenditure excluding abandonment obligations
(i) Depreciation of capex; calculated under MACRS (7 years - double declining balance switching to straight line after 5 years)
(j) (f) x Royalty rate, where Royalty rate = 0 percent for (c) $<$ 87.5 mmboe, or Royalty = 12.50% for (c) $>$ 87.5 mmboe (for deep water oil fields)
(k) $[(f) - (g) - (i) - (j)] \times 35\%$
(l) $(c) - (d) - (e) - (f) - (g) - (h) - (i) - (k)$

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Year	Production		Gross	Op	Capital	Royalty	State	Federal	Bonus	State	State Equity	Company
	Liquids	Gas	Revenue	Costs	Costs		Taxes	Tax		Carry	Cash Flow	Cash Flow
	000 b/d	mmcfd	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
2003	0	0.0	0	0	105	0	0	0	0	0	0	-105
2004	0	0.0	0	0	323	0	0	0	0	0	0	-323
2005	0	0.0	0	0	552	0	0	0	0	0	0	-552
2006	10	0.0	153	29	679	19	0	0	0	0	0	-574
2007	100	0.0	1358	126	232	170	0	0	0	0	0	830
2008	200	0.0	2512	198	238	314	0	426	0	0	0	1336
2009	200	0.0	2435	203	122	304	0	620	0	0	0	1185
2010	180	0.0	2246	194	62	281	0	585	0	0	0	1125
2011	165	0.0	2111	187	64	264	0	547	0	0	0	1048
2012	154	0.0	2023	184	66	253	0	524	0	0	0	996
2013	144	0.0	1938	181	67	242	0	503	0	0	0	946
2014	135	0.0	1858	178	0	232	0	501	0	0	0	947
2015	126	0.0	1781	175	0	223	0	480	0	0	0	903
2016	118	0.0	1706	172	0	213	0	460	0	0	0	861
2017	110	0.0	1635	170	0	204	0	440	0	0	0	821
2018	103	0.0	1568	168	0	196	0	420	0	0	0	784
2019	96	0.0	1503	166	0	188	0	401	0	0	0	747
2020	90	0.0	1439	164	0	180	0	383	0	0	0	712
2021	84	0.0	1380	163	0	173	0	366	0	0	0	679
2022	79	0.0	1323	161	0	165	0	349	0	0	0	647
2023	74	0.0	1268	160	0	158	0	332	0	0	0	617
2024	24	0.0	423	78	0	53	0	102	0	0	0	190

Table 2.7. Calculation of reserves entitlement, production entitlement and Remaining NPV under GoM concession tax terms

(a) Total remaining reserves in million barrels of oil equivalent. Calculated as the sum of column (b), multiplied by 0.365 (transforming thousands of barrels per day into millions of barrels per year).
(b) Total annual production in thousands of barrels of oil equivalent per day.
(c) Entitled remaining reserves in million barrels of oil equivalent. Calculated as the sum of column (d), multiplied by 0.365 (transforming thousands of barrels per day into millions of barrels per year).
(d) Entitled annual production, net of royalty (12.5% in US GoM Deepwater, See Appendix 2.1 in thousands of barrels of oil equivalent per day.
(e) Companies' (and total) net present value of expected entitled cash flows.

Year	Remaining reserves mmboe	Production 000boe/d	Entitled reserves mmboe	Entitled production 000boe/d	Remaining NPV US$M
2003	800	0	700	0	4140
2004	800	0	700	0	4659
2005	800	0	700	0	5448
2006	800	10	700	9	6545
2007	797	100	697	88	7774
2008	760	200	665	175	7721
2009	687	200	601	175	7157
2010	614	180	538	158	6688
2011	549	165	480	144	6232
2012	488	154	427	135	5807
2013	432	144	378	126	5391
2014	379	135	332	118	4985
2015	330	126	289	110	4536
2016	284	118	249	103	4087
2017	241	110	211	96	3635
2018	201	103	176	90	3177
2019	163	96	143	84	2711
2020	128	90	112	79	2235
2021	95	84	83	74	1746
2022	64	79	56	69	1241
2023	36	74	31	64	718
2024	9	24	8	21	173

participation inversion between OECD and Non-OECD markets. Studies by Haushalter et al. (2002) and Jin and Jorion (2006) relate to a period when oil prices range between US$18/bbl and US$35/bbl and cover the years 1992 to 1994, and 1998 to 2001 respectively, periods comparable to the US$33.75/bbl to US$45/bbl price range in this study. The coexistence of progressive taxation and oil prices above US$45/bbl has been a reality since 2004, allowing insights into the combined effects on global oilfield asset valuation.

The equity market premium puzzle identified by Mehra and Prescott (1985) has been expanded by many studies that have begun to grapple with the distinction between emerging market and developed market characteristics. Conover et al. (2002) provide ex ante tests for difference in equity risk premia, comparing developed and emerging market monetary cyclicality. However, unlike exchange traded equity market assets data limitations mean that there is no best practice convention for global real asset model comparison. Bekaert and Harvey (2002) encapsulate the multi disciplinary and multi faceted problems facing comparative asset valuation in emerging markets, summarizing the global asset valuation challenge as one that needs to link international economics, asset characteristics, development economics and law with political science and country specific fiscal terms.

Concerns about valuation model convergence recently attracted increasing interest at colloquia with Bruner et al. (2002) and Bekaert and Harvey (2002) identifying the need for further empirical study in this area. Bruner et al. (2002) advance reasons for the importance of emerging market valuation review, noting that investment flows into emerging markets continue to be material. Nowhere is this trend more evident than in the oil and gas sector where there is a strong economic and geopolitical relation between state and corporate agents. Oilfield assets are therefore uniquely positioned to provide comparative insights into global real asset valuation and emerging market specificities. Johnston (2002) provide specific insights into the oil and gas production sharing state and corporate partnership principles needed for this thesis. Their case study approach is expanded in this multi asset study while chapter 6 expands Gramlich and Wheeler (2003) work on the disclosure of oil and gas contracts.

The oil and gas (O&G) sector has been extensively used in studies that attempt to isolate asset valuation and risk attributes, Haushalter et al. (2002) emphasize the cost of extraction on firm equity value while Jin and Jorion (2006) note that global commodity oil markets are homogeneous, well traded and have comparable oilfield assets subject to equivalent global oil price volatility. There also exists a representative and comparative spread of oilfield assets between OECD and Non-OECD countries, providing the means to isolate component cost structures and study valuation convergence as between OECD and Non-OECD market real assets. The use of representative oilfield assets across both Non-OECD and OECD markets mean that this chapter embodies a unique interdisciplinary interest meeting the Bekaert and Harvey (2002) need of bridging investment and corporate finance.

State participation differences between markets are shown to mitigate against global asset valuation convergence. I extend the findings by Haushalter et al. (2002) and provide empirical insights into the effect of state participation costs on corporate asset pricing. My findings demonstrate that despite starting with a comparable set of global oilfield assets, state participation causes asset risk and return performance to differ significantly across global markets. Specifically, evidence is provided that Non-OECD assets have an initial operational cost and risk advantage that is reversed with the inclusion of state participation. I show that under conditions of oil price variability Non-OECD state participation limits corporate agent returns. Oil entitlement terms in Non-OECD countries are complex, with important implications for asset pricing in the entire O&G sector. Non-OECD market O&G sectors are characterized by production sharing contracts. They typically provide oilfield operators with guarantees to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure that contractually escalates oilfield participation sharing by the local government based on the price of oil (Angola) and in some cases the volume of oil pumped (Indonesia). The explicit link between operator asset entitlement and commodity prices differentiates Non-OECD market O&G sectors from OECD sectors as discussed by Bindemann (1999).

An important question is whether studies by Haushalter et al. (2002) and Jin and Jorion (2006) which relate to a period when oil prices range between US$18/bbl and

US$35/bbl and cover the years 1992 to 1994, and 1998 to 2001 respectively still hold. I answer this question by analyzing asset values at three price levels. The first is US$33.75/bbl comparable to oil prices used in their studies. The coexistence of progressive taxation and oil prices above US$45/bbl has been a reality since 2004, allowing insights into the combined effects on global oilfield asset valuation. I facilitate these insights by valuing the same assets at US$45/bbl.

The variables of oil price expectations, geographic holdings, replacement reserve origin, and total-cost ratio are used as independent determinants of the intensity of state intervention as between OECD and non-OECD countries. The simplifying assumption of deterministic state taxation enables the treatment of state participation as a specific prior claim against the corporate value of the oilfield asset.

Findings provide an important cautionary insight into limits to the corporate value of globalization in the oil and gas sector. Evidence is provided that emerging market sovereign states pursue their own interest more aggressively than developed market agents. This behavior limits corporate upside of asset values, and thereby, the benefits of globalization. The limitation on participation in the corporate asset values in the context of progressive state participation in Non-OECD countries is shown to be capable of causing an inversion of risk return convention. Additionally, as noted by Bekaert and Harvey (2002), global differences in the form of state participation are shown to be capable of mitigating against asset valuation model convergence.

2.5. Stochastic Literature

Informational efficiency and exactly what is meant in the finance of asset pricing by this attractive phrase is not entirely clear suggests (Ross 2005). The lack of clarity stems from the value to be placed on the cash flow expectation and the value to be attached to the uncertainty of state participation in asset cash flows. In the stochastic chapter of this work, I use the detailed field data to price each field at three different price decks to overcome the difficulties in obtaining asset valuation and risk data that have been noted in many studies. Haushalter et al. (2002) sum up the competitive advantage of information, suggesting that companies are unlikely to provide market disclosures about asset holdings that would affect their competitive positioning. Recent work has focussed on the natural resource sector in an attempt to limit endogeneity and separate the value of enterprise assets from the value of risk management. It is demonstrated that, for homogenous assets, country specific oilfield contractual terms cause divergent and heterogenous asset valuation and risk responses to oil price movement, a refinement that combines the industry centric approach of Cavaglia et al. (2000) and the importance of country factors (Stulz 2005). A combination of industry specific entitlement terms and the country location of resource holdings are shown to be important inputs for the accurate pricing of global natural resource assets.

In a general study Allayannis and Weston (2001) find evidence of value premia for 720 corporate entities that undertake risk management, findings supported by Adam and Fernando (2006) who examine 92 North American gold mining firms. Jin and Jorion (2006) question findings by Allayannis and Weston (2001)and identify possible endogeneity between hedging activities and firm value inputs. I concur with the need to limit endogeneity of input variables in risk studies, but note that within their sample of O&G sector US firms, Jin and Jorion (2006) make no distinction between country variant corporate entitlement and "government take" structures that govern oilfield assets (Kretzschmar et al. 2007). This work follows prior studies by Haushalter (2000) and Haushalter et al. (2002) who favor the O&G sector in an attempt isolate the value of risk management by limiting model variables. Jin and Jorion (2006) suggest that the sector is exposed to homogenous risks, the evaluation of which are aided by O&G disclosures, their focus is built on the assumption of equivalent entitlement to proven reserves at all price levels; a condition Kretzschmar et al. (2007) show does not hold. As Haushalter et al. (2002) note, market imperfection arguments for corporate risk management should focus on the cause of cash flow uncertainty, and flows in O&G are directly affected by asset entitlement structures. I highlight difficulties associated with determining risk measures at the firm level. A global sample of O&G assets is used to demonstrate that, for firms with global asset holdings, oil price movements cause asset cash flow measures of value and risk to vary widely and heterogeneously based on the different forms of government participation in oilfield contracts.

Government take, in O&G, is analogous to the concept of "expropriation by the state" mooted by Stulz (2005).[3] The differing global forms of O&G government participation enables a critical comparison of differing forms of ruler discretion. I use the analysis to provide insights into the statement by Jin and Jorion (2006, p.915) that O&G asset "delta equivalents can be measured precisely". Corporate oilfield participation is shown to be country specific and capable of being accurately determined only with reference to underlying asset holdings. This chapter suggests that country differences are a relevant and necessary consideration in studies of international O&G asset holdings, an asset based application of the state participation principle.

The consensus in finance is that asset values are a function of future cash flow benefits (Ross 2005), and that asset and risk pricing accuracy depends, in turn, on information about cash flow risk behavior. Several recent studies have focussed on the effects of commodity prices on firm value, and document a relation between stock returns and factors other than overall market returns. This is particularly true for commodity-producing firms, whose stock prices are ultimately associated with changes in asset values in response to movements in the the price of the underlying commodity. Strong (1991) demonstrates a positive relation between stock prices of oil companies and changes in oil prices and Tufano (1996) and Blose and Shieh (1995) establish correlation between the value of gold mining firms and gold prices. I extend these works and show that cash flow effects of oil price movements on value measures vary widely and heterogeneously based on reserve entitlement contracts.

2.6. Longitudinal Literature

The longitudinal study of oilfields covers the whole life field response to oil oil price shocks and draws on a different body of literature. Chavez-Demoulin et al. (2006) and Szegö (2002) identify the need to model correlation and co-dependence between risk factors. Like Szegö (2002) I find that the relation between asset risk behavior and

[3]The term 'government take' is used as understood in the oil and gas industry and refers to all forms of government taxation, whether royalty, profit based or production sharing. The terms are contractual, determined by the entitlement structure, and are usually specific to the regime that the oilfield is located in. Corporate entitlement is the residual oilfield entitlement available to oilfield producers after government take.

price variability is not linear; an insight that I accommodate by separating the O&G fields into concession and production sharing fields. This allows an analysis of the price response of longitudinal cash flow risks as between production sharing assets (PSCs) and concession fields. PSCs typically provide oil companies with guarantees to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure that contractually escalates oilfield participation sharing by the local government based on the price of oil and in some cases the volume of oil pumped. Linking asset entitlement explicitly and contractually to a range of returns based primarily on commodity prices differentiates production sharing from concessions, Bindemann (1999). Kretzschmar et al. (2007) provide a comprehensive insight into the taxation and accounting effects of these agreements. When subject to identical oil and gas price variability, these regulatory and taxation differences between O&G assets are shown to directly affect longitudinal cash flow risks.

Nawalkha et al. (2003) propose an unrestricted duration vector approach to isolate and hedge interest rate risk exposure for fixed income assets.[4] They investigate the weighted average of the distance between cash flow maturity and the planned hedging horizon by computing generalizing M-vector models and conclude that finite length vector models may improve short-term hedging performance. I differentiate risk periods in this study by dealing with cash flow and risk metrics over the whole–life of the asset. Natural resource asset characteristics limit model choices available, Brealey and Kaplanis (1995) for instance assume that a foreign firm will produce cash flow of £1 in perpetuity, a condition that does not hold for depleting assets. Sercu and Wu (2000) conduct a comparison of historic regression hedges and forward looking future delta hedges. They provide evidence that forward looking hedges outperform hedges based on regression of historic data. I approximate the findings by Sercu and Wu (2000) and base the hedge ratio analysis on estimates of future field cash flows and future oil prices.

Like Brooks et al. (2002) I define the conditional optimal minimum variance hedge ratio under the objective of total return maximization. Two different time horizons of hedges are used in the time period definition. The first period corresponds to rolling

[4] Nawalkha et al. (2003) refer to unrestricted in the context of allowing for shifts in term structure which are not limited by a depleting asset or a "particular function form".

36 months traded futures contracts, (James 2003), and the second discrete measure, draws on the average 60 months duration in oil field financing. This discrete method of hedging field generated cash flows is in contrast to continuous fixed income hedges as analyzed by Nawalkha et al. (2003). In summary, I approximate the discrete hedging approach used by Brealey and Kaplanis (1995) but I incorporate minimum variance hedging that allows for time variant and asymmetric shifts in the covariances as highlighted by Brooks et al. (2002). Findings coupled with detailed asset data demonstrate that at the oilfield level, risks are bounded in time and differ from oilfield asset to asset. Unbounded risk measures, for the purposes of this study, are analogous to whole field life minimum variance hedge ratios.

2.7. Accounting Literature

Prior studies have shown oilfield disclosures to be value relevant in interpreting assets and earnings of companies in the oil and gas (O&G) industry (Boone 2002). Reserve disclosures for companies in the energy sector provide important information needed to interpret the current and prospective performance of oil and gas exploration and production (Quirin et al. 2000). Boone (2002) undertakes a survey of an extensive earlier debate as to SEC present value disclosures and confirms their value relevance. The importance of oil price effects on reserve replacement and reporting is particularly relevant in the energy sector where reliance upon accounting return measures that ignore the economic value of capital invested in oil and gas (O&G) reserves have been shown to be potentially misleading (Antill and Arnott 2004; Osmundsen et al. 2006).

Rajgopal (1999) tested market risk effects in the O&G sector, acknowledging that "while the SEC concludes that 'quantitative disclosures should help investors better understand specific market risk disclosures of different registrants' market risk disclosures are unlikely to be reliable and plagued with measurement problems" (SEC 1997, No.6048, p.252). Pincus and Rajgopal (2002) also touch on the concept of reserve write downs, but in the context of sharp oil price declines that necessitate reserve revision. Despite findings by Clinch and Magliolo (1992) that reserves up to three years in the future are associated with ruling oil price sensitivities, it is not possible from current

SEC O&G financial reporting to assess the potential effect of oil price variability on future SEC proven reserves and production entitlement. In other words the quantity of underlying PSC oil and gas assets for corporates are themselves a function of oil price levels and current disclosures provide no way of measuring this effect.

This chapter examines these price effects on disclosures, and the extent to which oil sector reserve ownership is affected by previously the unstudied effects of high oil prices driving down corporate reserve entitlement. The production sharing contracts (PSC) that cause this effect are shown in this study to have price varying effects similar to derivative contracts. The existence and price sensitivity of these contracts as they relate to underlying oilfields, are an alternative to concession ownership structures, and represent between 30% to 40% of emerging global reserve replacement opportunities. The nature of these contracts is not well understood and nor are details available from current SEC disclosures. As a result little academic work has been done on the effects of oil price on these alternative ownership structures.

PSC agreements vary widely but typically provide oil companies with a guarantee to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure. The contract generally escalates participation sharing by the local government based on the price of oil and in some cases the volume of oil pumped.[5] Specifically and contractually linking asset entitlement to a range of oilfield returns generated primarily by commodity prices differentiates oilfields from other market sensitive corporate assets. This chapter focuses on this trait by interpreting government take as analogous to option claims against company reserves possessed by the field's local government - an interpretation that recognizes the contractual nature of possible fiscal claims against oilfields. This interpretation provides a framework to consider the disclosure requirements of underlying assets and financial instrument disclosures as identified by Rajgopal (1999) and to compare oil price effects on oilfield asset disclosures. The financial effects of production sharing contracts, driven by high oil prices, are becoming widespread in the O&G sector. Exxon's PSC production is expected to

[5]The contractual take by the local government can be interpreted as a form of taxation. In the Oil and Gas sector the term fiscal take is used for the (present) value of all forms of government taxation including any contractual take under the terms of a PSC.

move from 18% to 38% by 2010, and BP from 8 to 20 percent over the same period and, with the exception of Shell, other oil majors are showing similar trends.[6]

Rajgopal (1999) notes that there are problems with price risk data, the disclosure of which provides inconsistent tabular information in his study. Rajgopal (1999) derives a O&G equity value beta as a constant at 0.247% per 1% change in the oil price (gas beta 0.072) and notes that beta "is subject to measurement error because they are averages over the 1993-1996 period, whereas the theory suggests that oil and gas price sensitivities depend on firm-specific and time period-specific stock of underlying reserves and the derivative strategy sensitivities"(Rajgopal 1999, p.268). This observation by Rajgopal (1999) allows the contribution of this empirical study; I use a study of extensive oilfield data to highlight the asymmetrical price sensitivities of O&G reserve entitlement (and thereby SEC disclosures) to price sensitivity.

I use oilfields to measure oilfield disclosures under varying price conditions and contribute to prior work on price risk disclosures. I find that O&G disclosures are significantly more variable than the oil price beta for equity value noted by Rajgopal (1999). Disclosure rules currently do not capture these price variant effects in financial statements, an insight that perhaps goes some way toward explaining the conflicting results in prior value relevance studies. Rules for supplementary information on underlying reserves, SEC (SEC 1981) and FASB (FASB 1982)), are rooted in an era dominated by concessionary oilfield ownership structures. In contrast to concession ownership where reserves entitlement rests with the operator, PSC agreements provide government regimes an entitlement to share oilfield production with producers. The emergence of PSCs in the 1990s, means, however, that the nature and behavior of price sensitive government claims are not reflected in SEC disclosures; nor have their effects on disclosures been covered in previous research. I suggest that present SEC disclosures do not reflect the potential ownership effects of price volatility on 'bookable' reserves. This work bridges this gap and builds upon previous work that examines the importance of supplementary SEC disclosures in the context of concessionary arrangements (Berry et al. 2004; Boone 2002; Alciatore 1993). I specifically examine reserve

[6]Shell is expected to reduce PSC production from nearly 50% to 30% - Anticipated PSC production is sourced from Treynor and Cook (2004)

entitlement structures, their response to price volatility, and the nature of variations in SEC disclosures, comparing concession agreements to PSC contracts.

The results suggest that there should be separate PSC and concession reserve disclosures – based on the evidence that the two kinds of agreement behave significantly differently in response to oil and gas price changes. In line with Rajgopal (1999), I recommend that supplementary information should disclose the effects of oil and gas price changes on underlying reserve disclosures. Finally, given the variety of PSC terms in use between countries, and even from field to field within the same country (Bindemann 1999), I propose that whenever PSC terms are unique, disclosures of claim terms should be separately displayed whenever they are specifically part of the oilfield contract.

2.8. Market Literature

Many papers have sought to critique and refine the underlying approach of Fama French. Lakonishok et al. (1994) for instance focus on growth rates of earnings and the pricing of earnings growth,suggesting that the superior observed return from high-book-to-market stocks are corrections of irrational pricing. Fama and French (1995) refute this explanation and suggest that if size and BE/ME factors are the result of rational pricing processes they are likely to be driven by factors common to expected earnings. Fama French, are explicit and generous in their articulation of the open research questions and suggest guidance for future research. In Fama and French (1995), they identify and articulate the unanswered questions in inter-temporal asset pricing, for which size and BE/ME are likely proxies for sensitivity to risk factors in returns.

Recent work by Petkova (2006) has begun to take up the challenge, examining predictive economic state variables that affect the yield curve and conditional distribution of asset returns. This is certainly a valid approach but, one that overlooks the sector and country specific nature of state variables. The general expectation offered by Petkova (2006) is that HML and SMB loadings should lose explanatory power when predictive economic state variables are identified. I concur but suggest that future work that add predictive state variables to Fama French will need to recognise the two attributes of country and sector specificities. This chapter suggests that the Fama

French Three-Factor Model for returns is likely to progress through the isolation of sector and country specific macroeconomic state variables rather than global measures of GDP or consumption growth. This approach combines industry importance findings by Cavaglia et al. (2000) with country factors Bekaert and Harvey (2002). The approach suggests is that it is precisely sector specificities in state variables that provide insights into underlying causes of risk and return premia in the Fama and French (1993) Three-Factor Model.

Findings are aided by oil and gas sector attributes, state participation attaches to the asset cash flows, as opposed to the corporate entity. The state participation is calculated at or near the oilfield well-head. Country specific state oilfield participation, in the context of Fama and French (1995), therefore, enables a direct link between field taxation terms and corporate returns. I propose a country location factor to provide sector insights into the first of two open questions by Fama and French (1995).

This work has two objectives. First, I build on work in chapter 4 wherein i identify global variations in state participation in the oil and gas sector. The state participation factor suggests that variation in global fiscal participation terms are able to forecast future investment performance in the oil and gas sector. Second, I add a reserve location factor (R-factor) to the Fama-French Three Factor Model as a proxy to show that the inclusion of a sector specific state variable provides insights into causes of variation behind size and BE/ME effects for companies with global oil and gas asset holdings. My variable meets the Cochrane (2001) requirement of including only factors that directly forecast future investment returns. The R-factor isolates a natural resource sector variable that is able to explain the causes of unidentified risk and return premia associated with the size and BE/ME factors defined by Fama and French (1995).

Candidate state variables of gross national product and consumption are noted to have measurement problems that are overcome by isolating state asset participation in the homogenous oil and gas sector. In this chapter, the state return from oilfield assets is directly affected by the nature of fiscal state asset participation and draws on prior findings in chapter 4 in which I demonstrate that the state variable of asset participation varies widely depending on where oilfield assets are held and where reserve replacement occurs. Specifically, emerging market assets in Non-OECD countries have state participation terms that differ from those applied to oilfield assets in OECD countries. This enables the introduction of a proxy measure of state asset participation captured by the R-factor. The use of a single sector to overcome endogeneity in the measurement of risk and return variables has precedent in Jin and Jorion (2006) and is used to isolate the effects of state participation in oilfield assets on the returns of corporate oilfield operators.

Chapter 4 addresses the open Fama and French (1995) question and provide empirical evidence in support of the effects of economic and state variables on the limits of globalization. In the context of this market study, the R-factor considers all forms of state participation in oilfield assets and simplifies insights into state variable effects. I provide evidence that progressive state oilfield participation effectively limits the corporate value of emerging market O&G investment relative to developed markets. Findings support financial market results by Stulz (2005)proposes that all investors risk expropriation by the state, and that outside investors additionally risk expropriation by those who control firms and enables an analysis of conflicts implicit in regulatory, fiscal and legal differences between global O&G markets..

In developed markets, the state generally participates in O&G assets in the form of profit taxation, while in Non-OECD countries. State participation in the form of Non-OECD production sharing O&G contracts are contrasted with concession state participation structures in OECD countries. The R-factor is used to distinguish between global O&G markets and fits well with the state participation concept mooted by Stulz (2005), who identifies redistributive taxation as a tool to facilitate expropriation by the state.

Market findings contrast with prior equity market studies by Mehra and Prescott (1985) and Bekaert et al. (2005) who suggest that emerging markets provide consistent and compensatory value premia. Findings in this study mitigate against neoclassical theory that anticipates large capital flows toward developing countries (Stulz 2005). Emerging market O&G reserve entitlement limits the upside for company earnings, with the potential for knock on effects into capital flows as the government participation effect becomes apparent at higher oil prices. As oil prices increase, the relative operating costs of producing oil decreases and the reserve entitlement structure in O&G will become the most important factor in future corporate cash flow entitlement.

Findings refine Fama and French (2002) and support work by Stulz (2005) providing an important cautionary insight into limits to the corporate value of globalization in the oil and gas sector. Evidence is provided that emerging market sovereign states pursue their own interest more aggressively than developed market agents, effectively limiting the corporate upside of asset values, and thereby, the benefits of globalization. The limitation on corporate asset values in the context of progressive state participation in Non-OECD countries is capable of causing an inversion in corporate cash flow participation. Additionally, global differences in the form of state participation are shown to be capable of mitigating against asset valuation model convergence (Bekaert and Harvey 2002).

This section has market oriented objectives that builds on empirical work that identifies global variations in state participation in the oil and gas sector. The state participation factor suggests that variation in global fiscal participation terms are able to forecast future investment performance in the oil and gas sector. Second, I add a reserve location factor (R-factor) to the Fama-French Three Factor Model as a proxy to show that the inclusion of a sector specific state variable provides insights into causes of variation behind size and BE/ME effects for companies with global oil and gas asset holdings. My variable meets the Cochrane (2001) requirement of including only factors that directly forecast future investment returns. The R-factor isolates a natural resource sector variable that is able to explain the causes of unidentified risk and return premia associated with the size and BE/ME factors defined by Fama and French (1995).

3. OECD vs Non–OECD Asset Pricing

Chapter Research Focus: The Potential of State Participation to Invert Risk Return Convention

This chapter advances the low oil price paradigm advanced in prior oil and gas asset valuation studies. Convention suggests that Non-OECD market investment, characterized by Non-OECD oil and gas (O&G) sector assets, should provide either, commensurately lower risk or higher returns, than assets in OECD countries. I provide specific evidence that global state agency participation terms have the potential to invert this convention. In line with Ross (2004), I suggest that it is important to value the future cash flows at valuation date and have regard to the price risk response of the field under consideration.

Overview

Findings show that it matters where reserves are held, and where reserve replacement originates. Evidence from 292 oilfields is used to demonstrate that if no regard is had to the differential price response of oilfields, the characteristic of progressive state participation in Non-OECD market contracts has the potential to negate ex ante operational oil sector advantage in Non-OECD countries. Oil price linked Non-OECD government participation in assets is shown to occur at the expense of corporate returns. Specifically, relative to OECD market O&G contracts, Non-OECD state participation regulations are shown to have have progressive elements that limit corporate asset cash flow participation under conditions of increasing oil prices. My O&G asset study provides evidence that global markets contain state agent participation terms that challenge asset valuation model convergence, and under high oil prices, potentially invert risk return convention.

Research Acknowledgements

This chapter is based on sole authored paper submitted to the – Journal of Energy Economics – and is under review. Kretzschmar (2006).

3.1. Background

The established equity market convention is that risk and return are positively correlated in global markets. Mehra and Prescott (1985) note that when compared to OECD markets, higher Non-OECD risks are compensated by higher return premia. The state variable of participation in oilfield asset revenue is used to provide evidence that, under rising oil prices, globally divergent forms of state participation have the potential to invert this fundamental convention. In this chapter, the variable 'state participation' recognizes all forms of taxation and royalties as well as revenue and production sharing claims against oilfields in favor of the local government. The claim interpretation recognizes the contractual nature of state claims against oilfield assets, with corporate producers sharing the value of residual cash flows. The isolation of economic state variables for an extensive global sample of oilfield assets directly allows insights into the outstanding Fama and French (1995) question relating to the effect of underlying economic state variables on asset values.

3.2. Research Approach

Detailed oil and gas sector data are used to analyze expected cash flows to oilfield operators in the sector. Differential asset entitlement regulations between Non-OECD and OECD O&G markets and standard measures of operating and fiscal efficiency are used to compare state participation effects on OECD and Non-OECD O&G asset values.

3.2.1. Data and Sample Selection

Detailed global information pertaining to oilfield asset risk and return exposures allows me to compare the effects of state participation on asset values. I use the O&G industry for which equivalent oil price exposure exists across both OECD (developed) and Non-OECD (emerging) markets. Detailed data for oilfield reserve, production, extraction, cost and taxation are used to overcome measurement limitations by facilitating a global comparison of risk and return at the asset level. Through aggregation, a comparison of sector risk and cash flow participation is undertaken at the country level.

Oilfield data are industry standard whole life field data compiled by leading energy research house Wood Mackenzie. All data are derived from publicly available information and operator interviews by Wood Mackenzie oil and gas research teams. Specialist teams compile highly-detailed, full life field models, covering technical field development, production and extraction patterns for each commercial oil and gas field. These data contain industry standard oilfield production, oil price, detailed tax terms and field cost data as estimated for the remaining life of the asset. The industry standard data are typically subscribed to by all major banks and oil companies and are commercially available in Wood Mackenzie's Global Economic Model (GEM). This bottom-up data creates a robust foundation for evaluating O&G fields and enables a comparative global analysis.

In this chapter, I augment the random stratified sample of 211, increasing it to 292 oilfields from Gulf of Mexico (GoM), the UK Continental Shelf (UKCS) and the Norwegian Continental Shelf (NCS), and three PSC regimes, Angola (ANG), Egypt

Table 3.1. Data and Sample Summary

Table includes the number of fields analyzed per country and regime and the percentage of the total population. It also reports the division between small (<100mmboe) and large (>100mmboe) fields. All field data are provided by Wood Mackenzie GEM, containing remaining reserve estimates in a full life field model. Values in parentheses show the actual number of fields in the selected sample. For the following regression analysis 16 fields are excluded from the initial sample selection due to idiosyncratic behavior attributable to large gas reserves (gas reserves are not exposed to comparable market risk). To compensate for these adjustments, six additional fields are selected randomly.

Regulatory Regime	Population	Number of Sample Fields			
	Total	Producing	% of Total	<100mmboe	>100mmboe
OECD Countries	615	154 (167)	25 %	94	60
Gulf of Mexico	130	41 (50)	32 %	28	13
Norwegian Cont. Shelf	105	45 (50)	43 %	19	26
UK Cont. Shelf	380	68 (67)	18 %	47	21
Non-OECD Countries	172	128 (125)	74 %	63	65
Angola	48	28 (28)	58%	11	17
Egypt	53	40 (42)	75 %	27	13
Indonesia	71	60 (55)	85 %	25	35
Total Sample Size	787	282 (292)	36 %	157	125

(EGY) and Indonesia (IDO).[1] The sampling approach is informed by work by Jin and Jorion (2006) who highlight the importance of sample selection in risk return analysis. Selecting oilfield assets on an aggregated country and regime level within the oil and gas sector limits the endogeneity exposures identified by Jin and Jorion (2006) in their oil and gas sector study. Descriptive measures of the selection are presented in Table 3.1. In the study, oilfields are modeled at the “tax ring fence” level, an important factor that allows the isolation of post-tax cash flows. Fields within a “ring fence” are all subject to the same tax terms, a legal specificity of the O&G sector.

3.2.2. State Effects on Field Value and Stochastic Risk Measures

I model corporate and state agent participation in cash flow and risk and compare assets between OECD and Non-OECD countries. My asset approach builds on models by Kretzschmar and Kirchner (2007)who identify that asset values in response to price

[1]GoM, UKCS and NCS represent regions within the territorial waters of the USA, UK and Norway. For improved readability and comparability to countries with PSC regimes, these concession regime regions are also referred to by their country names.

changes in Non-OECD countries differ from OECD countries. Non-OECD fields are subject to progressive production sharing contract terms while OECD countries are subject to concession terms. Whole field life annual estimates of oil and gas production, oil price, operating costs, capital expenditure and fiscal terms are extracted at the individual field level as at January 2006 (see Appendix A, Table A.1 for a sample extract of actual field data). Calculations are based on proven and probable (2P) reserves. The asset model values O&G fields based on conventional industry standard discounted cash flows and incorporates present value calculation of operational and market risks. I extend the whole field life model in chapter 4 to incorporate the present value ($PV^{l,b,h}$) of time variant revenues and costs for three different price decks. Risk is modeled by the the probability of loss calculated on stochastic field present values, defined later in this section. Oilfield reserve, production, extraction, cost and taxation data are used to determine present values (PV) for all fields, enabling a comparative analysis of OECD and Non-OECD countries' risk at the oilfield level.

All 292 fields are valued at three oil price decks of US\$33.75/bbl (l), US\$45/bbl and US\$90/bbl (h) with movements in value used as a measure of return, quantified by corporate cash flow participation measured against the base deck valuation (b).[2]

$$\begin{aligned} l \quad & (LowDeck) && = \text{US\$33.75/bbl} \\ b \quad & (BaseDeck) && = \text{US\$45.00/bbl} \\ h \quad & (HighDeck) && = \text{US\$90.00/bbl} \end{aligned} \tag{3.1}$$

For PV calculations the SEC prescribed discount rate of 10 percent is assumed as a constant throughout, resulting in a discount factor vector defined by.[3]

$$DF = \begin{pmatrix} \frac{1}{(1+r)^0} \\ \vdots \\ \frac{1}{(1+r)^n} \end{pmatrix} \quad \text{with} \quad r = const.\ 10\% \quad \text{and} \quad n = FieldLife \tag{3.2}$$

[2]Price deck is defined as a series of future oil prices at, above or below current estimated oil prices.

[3]It is noteworthy that any discount premium for Non-OECD markets would significantly improve the strength of the arguments for risk and return inversion in this work. For example, discounting Non-OECD fields at higher rates would further reduce their net present value relative to OECD market fields.

The extended vector model is used to meet the first research objective and provides insights on field cost structures. All cost variables are defined as time vectors. Present values ($PV^{l,b,h}$) of cost components are derived by multiplication of the transposed cost vectors with DF as shown in (3.3)

$$\begin{aligned}
PV_{opex} &= (opex)' &\times DF \\
PV_{capex} &= (capex)' &\times DF \\
PV_{opcap} &= (opcap)' &\times DF \\
PV_{fiscal} &= (fiscal)' &\times DF \\
PV_{totcost} &= (totcost)' &\times DF
\end{aligned} \tag{3.3}$$

where

$opex$ = All operational and transport costs for the production and extraction of oil and gas

$capex$ = All capital costs related to investments for future benefits and abandonment costs

$opcap$ = $opex + capex$

$fiscal$ = All Government claims that reflects state participation in income content of fiscal charges against field cash flows

$totcost$ = $opcap + fiscal$

The present value of field revenue $PV_{revenue}$ is defined accordingly by

$$PV_{revenue} = (price \bullet production)' \times DF \tag{3.4}$$

where the time variant vectors *price* and *production* are multiplied using the point-product (Hadamard Product). I define *price* as a series (price deck) of forward oil prices as illustrated in Figure 3.1.[4] The vector of *production* is defined according to (3.5).

$$production = \begin{cases} totalproduction & \text{for} \quad \text{OECD countries} \\ entitledproduction & \text{for} \quad \text{Non-OECD countries} \end{cases} \tag{3.5}$$

For OECD countries *totalproduction* refers to the variable annual production concessions use of the total of oilfield remaining reserves. In Non-OECD countries *entitledproduction* applies to PSCs. Non-OECD terms vary with a contractual limit either on their entitlement to an internal rate of return (IRR) or annual variable production. As a consequence operators in Non-OECD areas are only entitled to a portion of total remaining oilfield reserves, detailed insights are provided by Bindemann (2000). These insights are combined in field valuation models with deterministic field value pre-tax (PV_{pretax}) and post-tax ($PV_{posttax}$) at the US$45/bbl price deck defined by

$$PV^b_{pretax} = PV^b_{revenue} - PV^b_{opcap} \tag{3.6}$$

$$PV^b_{posttax} = PV^b_{revenue} - PV^b_{opcap} - PV^b_{fiscal} = PV^b_{revenue} - PV^b_{totcost} \tag{3.7}$$

To accommodate market risk in valuation models, I introduce oil price uncertainty. Mean reversion is set to co-exist with spot price volatility in a refinement of Bessembinder et al. (1995).

Stochastic simulations (292 fields pre and post-tax) are used to measure the O&G field response to exogenous price volatility and stochastic field risk.[5] This analysis is conducted using Monte Carlo[6] simulations at the field level for the base price-deck b of US$45/bbl. Figure 3.2 illustrates historic 30-day oil futures volatility and the current (2006) implied 30-day oil futures volatility of 25%. Averaging over the period January

[4] Appendix A, Table A.1, columns 6, 7, 8 provides example insights. The price deck at US$45/bbl starts at US$45/bbl in 2006, mean reverts to US$36.70/bbl in 2009 before increasing by inflation set at 2.5 percent p.a. for the remainder of the field life

[5] 'Stochastic' is used for oil fields whose behavior is non-deterministic in that the next state of field value is partially but not fully determined by the previous state of valuation inputs, in this study, the prior oil price. Annual changes in oil prices vary the state of the environment.

[6] I use Latin-Hypercube discipline in simulations, testing equal sides of the price distribution for 2,500 trials and 999 bins.

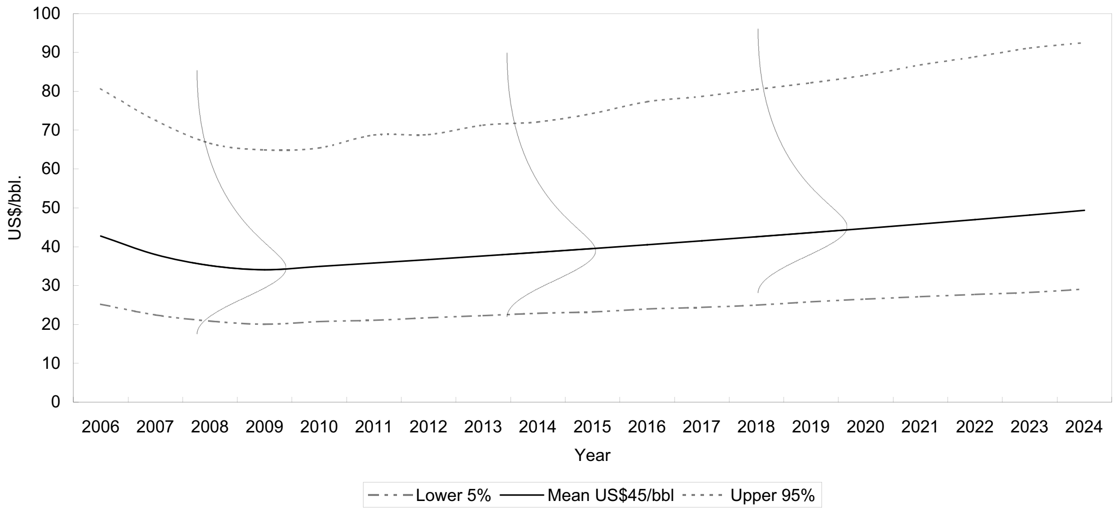

Figure 3.1. Field Model Implied Oil Price Curve

This figure illustrates the movement of the future model-implied oil price derived from the individual field data. Building on findings by Bessembinder et al. (1995), short-horizon mean reverting annual prices are quoted for the three different initial price scenarios (US$33.75/bbl, US$45/bbl, US$90/bbl). I incorporate recent findings by Geman (2005) and apply stochastic lognormally distributed exogenous price volatility to each year's price for US$45/bbl price scenario. The price downside in the lognormal distribution is limited to US$25/bbl. The figure illustrates stochastic price volatility around the US$45/bbl price scenario. Prices for the corresponding scenarios are described in Appendix A, Table A.1, Columns 6 to 8.

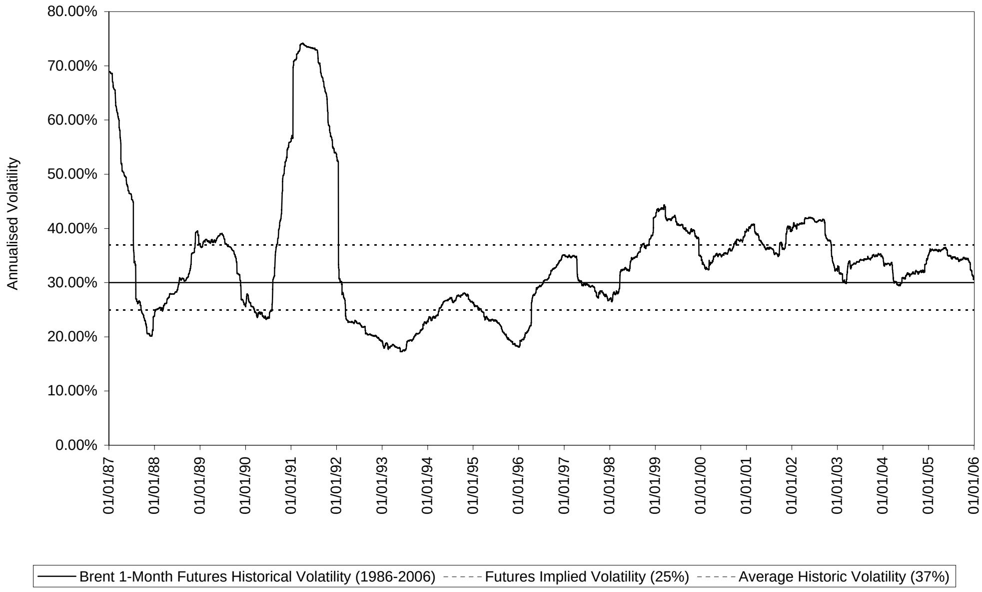

Figure 3.2. Historic Oil Futures Price Volatility Curve

This figure illustrates historic 30-day oil futures volatility and current (2006, ivolatility.com) The implied 30-day oil futures volatility is 25%. By contrast, for the period January 1987 to January 2006, the average annual historic 30-day futures volatility is calculated as 37%. To provide insights into the stochastic effects of market price uncertainty on whole life oilfield cash flows, I use a volatility figure between these two rates, 30%.

1987 to January 2006, the annual historic 30-day futures volatility is calculated as 37%. For the purpose of this study, a mean reverting oil price with $\sigma = 30\%$ price volatility is assumed. The probability distribution function of stochastic pre- and post-tax field value (PV^x_{pretax}, $PV^x_{posttax}$) is estimated by simulation within the field model. Each years spot price with exogenous price volatility is defined as a random variable x following a truncated log-normal distribution.

$$f(x;\mu,\sigma) = \frac{1}{x\sigma\sqrt{2\pi}} e^{-(\ln x - \mu)^2/2\sigma^2} \Big|_{\text{US\$25/bbl}}^{\infty} \quad \text{with} \quad \mu = \text{US\$45}/bbl \quad \sigma = 30\% \tag{3.8}$$

The probability distribution function of stochastic pre- and post-tax field value (PV^x_{pretax}, $PV^x_{posttax}$) is estimated by simulation within the field model.

Loss occurs when the estimated field value is below a predefined break-even point. In this study, break-even is defined by the deterministic present value for $PV^b_{posttax}$ at

US$45/bbl. The benchmark of $PV^b_{posttax}$ is applied to both pre- and post-tax stochastic present value distributions. Probabilities of loss (Λ) for stochastic PV^x_{pretax} and $PV^x_{posttax}$ are calculated using Λ as the risk measure where $PDF[PV^x]$ represents the "best-fit" probability distribution function of stochastic field value based on the Anderson-Darling goodness to fit test for the simulated PV^x_{pretax} and $PV^x_{posttax}$ frequency distributions.

$$\begin{aligned} \Lambda_{pretax} &= \int^{PV^b_{posttax}} PDF[PV^x_{pretax}]dx \\ \Lambda_{posttax} &= \int^{PV^b_{posttax}} PDF[PV^x_{posttax}]dx \end{aligned} \tag{3.9}$$

3.2.3. Isolating State Effects on Return and Risk Measures

To evaluate OECD and Non-OECD O&G sector performance, I subject the fields to price changes and calculate cash flows (*upside*) and losses (*downside*) (3.10) in order to compare regime sensitivity and price variability.

$$\begin{aligned} upside &= PV^h_{posttax} - PV^b_{posttax} \\ downside &= PV^l_{posttax} - PV^b_{posttax} \end{aligned} \tag{3.10}$$

Each field has technical, geological and taxation idiosyncracies that influence field valuation results and their interpretation. State tax terms are attached at the field level and also linked to the oilfield's stage of development. The regression analysis in this study uses dummy variables to encapsulate size and state effects.

Analyses of field cost structures relative to revenue are performed. Regression models isolate the oil price conditions under which sector risk and return conventions hold. The expression of operating and fiscal costs as a percentage of expected revenue provides a useful basis for analyzing the characteristics of the oil and gas fields. Relative cost structures for the three price decks (l, b, h) are defined by $PV^{l,b,h}$ as a percentage of $PV^{l,b,h}_{revenue}$. I determine the drivers of cash flow upside for the US$45/bbl price deck through linear (3.12) regression, using relative $PV^b_{totcost}$ as the independent variable. The regression model is used to provide insights into oilfield valuation for oil prices in the range US$45/bbl to US$90/bbl. Linear regressions on a country basis test for regime specific trends in cash flow upside.

$$upside = \alpha + \beta_1 X_1 \quad \text{with} \quad X_1 = \frac{PV^b_{totcost}}{PV^b_{revenue}} \tag{3.11}$$

Additionally, dummy variables for Non-OECD regimes ($D_{nonoecd}$) and field size below 100mmboe remaining reserves (D_{size}) enable differentiation between state environments in OECD and Non-OECD markets, and large and small fields where large (small) fields are classified as retaining more (less) than 100 mmboe of remaining reserves.

$$upside = \alpha + \beta_1 X_1 + \beta_2 D_{nonoecd} + \beta_3 D_{size} \quad \text{with} \quad X_1 = \frac{PV^b_{totcost}}{PV^b_{revenue}} \tag{3.12}$$

For robustness, I test for normality in the aggregate relative $PV^b_{totcost}$ field sample and test for interaction between the dummy variables and independent variables for the regression analysis. Regression residuals are analyzed for heteroscedasticity. To test for difference between descriptive sample measures t-tests are run for means.

3.3. Empirical Analysis

3.3.1. State Participation Effects on Sector Operational Risk Measures at US$45/bbl

Field present value ($PV^{b,h,l}$) cost structures are analyzed as percentage of $PV^{b,h,l}_{revenue}$ as between OECD and Non-OECD oilfield holdings. Ratios are calculated for the three different price decks. This allows the isolation of the comparative pre-tax operational advantage between OECD and Non-OECD markets at each price level. Findings demonstrate that when state participation is included, the comparative pre-tax operational advantage of Non-OECD Regimes is reversed. I use the US$45/bbl price deck as a benchmark to illustrate that a higher total cost structure for $PV^{b}_{totcost}$ results in a greater probability of loss. The separation of pre- and post-tax cost structures isolates the state participation effects on asset values.

Average country sector asset values at US$45/bbl are described in (3.3). Contrary to findings by Haushalter et al. (2002), at US$45/bbl PV_{opex} and PV_{capex} only comprise 18 percent and 8 percent of OECD $PV_{revenue}$ respectively. Fiscal take by contrast comprises 47 percent of $PV_{revenue}$. This trend is mirrored in Non-OECD areas. Average field cost present values are calculated relative to $PV^{b}_{revenue}$ to derive the corresponding relative field cost structures for PV^{b}. Cost structures provide insight into the operational risks. Table 3.2 shows that for US$45/bbl, the average OECD market PV^{b}_{opcap} is 26 percent, significantly above Non-OECD markets of 21 percent suggesting a comparative Non-OECD market operating advantage.

PV^{b}_{fiscal} in Table 3.2 highlights that in OECD countries state participation is 47 percent of $PV^{b}_{revenue}$ versus 57 percent in Non-OECD. This is opposite to the higher PV^{b}_{pretax} for Non-OECD markets of 79 percent compared to 74 percent for OECD markets. However, when taxation is added to operating and capital costs, the comparative advantage in Non-OECD sector O&G oilfields is reversed where the Non-OECD market $PV^{b}_{totcost}$ increases to 78 percent compared to the OECD market average, comparatively lower at 73 percent (3.2). This state participation effect shows that any shift in comparative advantage pre and post-tax between OECD and Non-OECD assets is directly caused by state participation. Two-sided t-tests with adjustments for heteroscedas-

Table 3.2. OECD and Non-OECD mean revenue and relative cost components for (PV) at US$45/bbl

Table shows the OECD and Non-OECD country segmentation and field present value (PV^b) and cost structure components as percentages of $PV^b_{revenue}$. All absolute numbers are stated in US$M, cost structures relative to $PV^b_{revenue}$ are presented in parentheses. The last two columns present the probability of loss (Λ) for $PV_{posttax}$ based on (3.9). The existence of significant differences between measure of relative cost structures for PV^b_{opcap}, PV^b_{fiscal} and $PV^b_{totcost}$ is verified through two-sided t-tests with adjustments for heteroscedasticity at the field level. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

Average	$PV_{revenue}$	PV_{opex}	PV_{capex}	PV_{opcap}	PV_{fiscal}	$PV_{totcost}$	PV_{pretax}	$PV_{posttax}$	Λ_{pretax}	$\Lambda_{posttax}$
	Costs and Cost Structures as percentage of $PV_{revenue}$ at $45/bbl									
OECD	3,930	695	328	1,023	1,841	2,864	2,908	1,067	<0.001%	20.44 %
	(100 %)	(18 %)	(8 %)	(26 %)	(47 %)	(73 %)	(74 %)	(27 %)		
GoM	3,259	241	283	524	1,175	1,699	2,735	1,560	<0.001%	22.99 %
	(100 %)	(7 %)	(9 %)	(16 %)	(36 %)	(52 %)	(84 %)	(48 %)		
UKCS	1,804	339	131	470	752	1,222	1,334	582	<0.001%	19.76 %
	(100 %)	(19 %)	(7 %)	(26 %)	(42 %)	(68 %)	(74 %)	(32 %)		
NCS	7,755	1,646	666	2,312	4,094	6,406	5,443	1,349	<0.001%	20.65 %
	(100 %)	(21 %)	(9 %)	(30 %)	(53 %)	(83 %)	(70 %)	(17 %)		
Non-OECD	3,173	360	310	670	1,801	2,471	2,504	702	<0.001%	42.95 %
	(100 %)	(11 %)	(10 %)	(21 %)	(57 %)	(78 %)	(79 %)	(22 %)		
Angola	6,210	494	753	1,246	3,499	4,745	4,963	1,465	<0.001%	39.78 %
	(100 %)	(8 %)	(12 %)	(20 %)	(56 %)	(76 %)	(80 %)	(24 %)		
Egypt	1,895	112	68	180	1,245	1,425	1,715	470	<0.001%	38.05 %
	(100 %)	(6 %)	(4 %)	(10 %)	(65 %)	(75 %)	(91 %)	(25 %)		
Indonesia	2,609	463	264	728	1,380	2,108	1,881	501	<0.001%	47.69 %
	(100 %)	(18 %)	(10 %)	(28 %)	(53 %)	(81 %)	(72 %)	(19 %)		
OECD vs Non-OECD t-test for Difference	—	—	—	(0.0001)**	(0.0018)**	(0.0001)**	—	—	—	—

ticity at the individual field level indicate highly significant differences (99% level) in means between OECD and Non-OECD oilfield asset holdings for PV^b_{opcap}, PV^b_{fiscal} and $PV^b_{totcost}$. Cost findings suggest that both PV^b_{opex} and PV^b_{fiscal} are likely to be important independent variables in natural resource valuation.

State participation directly increases the probability of loss ($\Lambda_{posttax}$) for Non-OECD countries. The OECD $\Lambda_{posttax}$ is 20.44% versus 42.95% for Non-OECD (Table 3.2). This cost effect on the post-tax asset value at US$45/bbl is consistent throughout the sample. The loss effect is noteworthy in that fiscal costs comprise the greater proportion of total costs which, in turn, directly affect $\Lambda_{posttax}$.

3.3.2. State Participation and Price Variability from US$45/bbl to US$33.75/bbl and US$45/bbl to US$90/bbl

Price response findings findings provide insights into the effect of oil price increase on cash flow participation in OECD and Non-OECD regimes. To provide insights into the role of state participation in field valuation, I calculate the field values at US$33.75/bbl, US$45/bbl and US$90/bbl. I do this to enable insights into the effect on cost ratios and to isolate the effect of taxation regulation on asset return profiles between OECD and Non-OECD regions. Table 3.3 illustrates a cross-sectional analysis of movements in revenue and total cost structures for oil prices at US$33.75/bbl and US$90/bbl. OECD costs reduce from 76 to 68 percent of total revenue over the price range in panels A and B, compared to an increase from 78 to 80 percent over comparable ranges for Non-OECD market fields.

Tests for difference in responses between OECD and Non-OECD assets are conducted based on individual field data underpinning Table 3.3. Significant differences occur in the changes in cost structures relative to $PV_{revenue}$ for OECD and Non-OECD assets. The strength and consistency of tests for difference as between OECD and Non-OECD O&G countries are supportive of early observations by Bekaert and Harvey (2002), that legal and fiscal environments in Non-OECD markets are likely to mitigate against model convergence.

Figure 3.3 shows the effect of price variability on PV_{pretax} and $PV_{posttax}$ for OECD and Non-OECD markets. OECD markets show a uniform response relation between

Table 3.3. Price variability effect on OECD and Non-OECD revenue and cost components at US$33.75/bbl - US$90/bbl

The table columns contain average country field revenues and costs calculated at US$33.75/bbl and US$90/bbl. Additionally, the last column shows the absolute (relative) change in $PV_{posttax}$ for the two price changes. Panel A summarizes at US$33.75/bbl ($l$) and Panel B the US$90/bbl (h). All absolute numbers stated in US$M. Relative cost structures presented in parentheses.

Average	$PV_{revenue}$	PV_{opex}	PV_{capex}	PV_{fiscal}	$PV_{totcost}$	PV_{pretax}	$PV_{posttax}$	$\Delta PV_{posttax}$
Panel A: Costs and Cost Structures as percentage of $PV_{revenue}$ at $33.75/bbl								
OECD	2963	695	328	1233	2256	1941	707	-359
	(100 %)	(23 %)	(11 %)	(42 %)	(76 %)	(65 %)	(24 %)	(-34 %)
GoM	2446	241	283	825	1349	1923	1097	-463
	(100 %)	(10 %)	(12 %)	(34 %)	(55 %)	(79 %)	(45 %)	(-30 %)
UKCS	1372	339	131	514	984	902	389	-194
	(100 %)	(25 %)	(10 %)	(37 %)	(72 %)	(66 %)	(28 %)	(-33 %)
NCS	5838	1646	666	2693	5005	3526	833	-515
	(100 %)	(28 %)	(11 %)	(46 %)	(86 %)	(60 %)	(14 %)	(-38 %)
Non–OECD	2471	360	310	1258	1928	1801	543	-159
	(100 %)	(15 %)	(13 %)	(51 %)	(78 %)	(73 %)	(22 %)	(-23 %)
Angola	5067	494	753	2558	3805	3820	1262	-202
	(100 %)	(10 %)	(15 %)	(50 %)	(75 %)	(75 %)	(25 %)	(-14 %)
Egypt	1424	112	68	892	1072	1244	352	-118
	(100 %)	(8 %)	(5 %)	(63 %)	(75 %)	(87 %)	(25 %)	(-25 %)
Indonesia	1957	463	264	895	1623	1229	334	-167
	(100 %)	(24 %)	(14 %)	(46 %)	(83 %)	(63 %)	(17 %)	(-33 %)
Panel B: Costs and Cost Structures as percentage of $PV_{revenue}$ at $90/bbl								
OECD	7800	695	328	4303	5326	6777	2474	1407
	(100 %)	(9 %)	(4 %)	(55 %)	(68 %)	(87 %)	(32 %)	(132 %)
GoM	6510	241	283	2575	3099	5986	3411	1851
	(100 %)	(4 %)	(4 %)	(40 %)	(48 %)	(92 %)	(52 %)	(119 %)
UKCS	3532	339	131	1717	2187	3062	1345	762
	(100 %)	(10 %)	(4 %)	(49 %)	(62 %)	(87 %)	(38 %)	(131 %)
NCS	15424	1646	666	9785	12097	13112	3327	1978
	(100 %)	(11 %)	(4 %)	(63 %)	(78 %)	(85 %)	(22 %)	(147 %)
Non–OECD	6347	360	310	4393	5063	5677	1284	582
	(100 %)	(6 %)	(5 %)	(69 %)	(80 %)	(89 %)	(20 %)	(83 %)
Angola	12420	494	753	9083	10330	11174	2090	626
	(100 %)	(4 %)	(6 %)	(73 %)	(83 %)	(90 %)	(17 %)	(43 %)
Egypt	3789	112	68	2687	2867	3609	922	452
	(100 %)	(3 %)	(2 %)	(71 %)	(76 %)	(95 %)	(24 %)	(96 %)
Indonesia	5218	463	264	3341	4068	4490	1150	648
	(100 %)	(9 %)	(5 %)	(64 %)	(78 %)	(86 %)	(22 %)	(129 %)

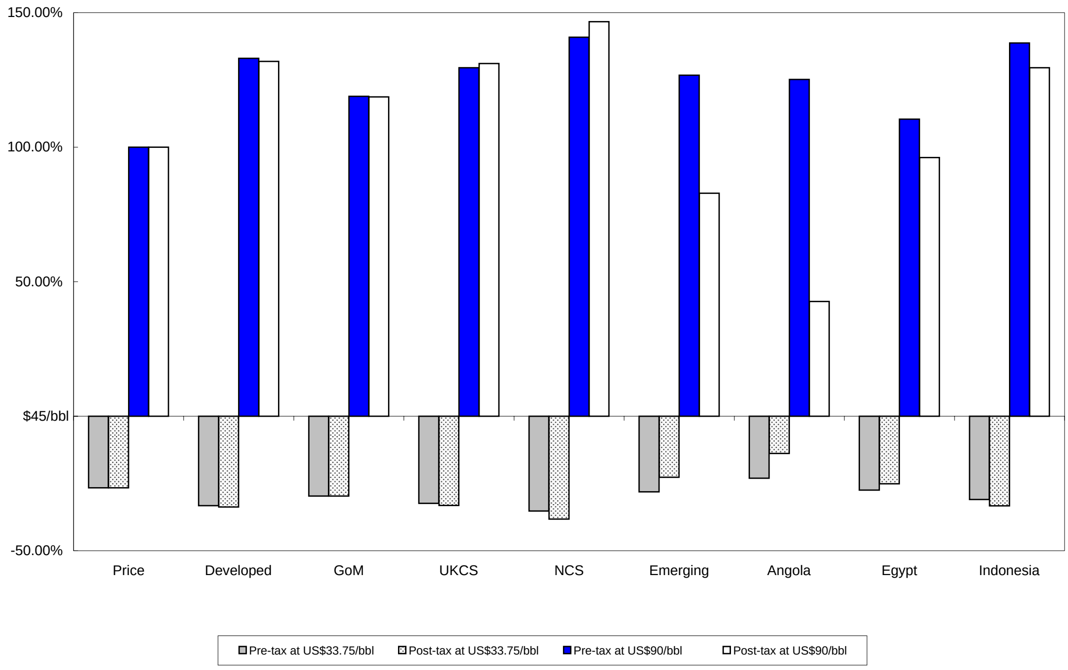

Figure 3.3. Pre- and post-tax PV inversion in corporate cash flow participation in response to oil price changes for OECD and Non-OECD asset holdings

The figure shows the relative change in PV_{pretax} and $PV_{posttax}$ for OECD and Non-OECD countries. The benchmark is US$45/bbl, the intercept. Bars below the benchmark reflect the valuation response to price changes from US$45/bbl to US$33.75/bbl. Movement above the benchmark reflect valuation response from US$45/bbl to US$90/bbl on the y-axis. The scale of the y-axis reflects the price upshock from US$45/bbl ($b$) to US$90/bbl (h), illustrated as a 100% increase in price. The downshock to US$33.75/bbl ($l$) is reflected as a 25% decrease in price (negative on y-axis). For all columns, the x-axis reflects PV (pre and post tax) movements for individual underlying countries. Aggregates for OECD and Non-OECD asset holdings are shown.

PV_{pretax} and $PV_{posttax}$. For a price increase from US$45/bbl to US$90/bbl there is a significant difference between PV_{pretax} and $PV_{posttax}$ in Non-OECD regimes. Non-OECD countries do not reflect the same difference in PV movements pre- and post-tax. Significant potential exist between OECD and Non-OECD country responses and provide evidence of the potential for inversion in corporate cash flow participation. Findings suggest that regulatory and fiscal differences challenge asset valuation convergence.

When the fields are revalued at US$33.75/bbl, Table 3.3 shows that Non-OECD markets have an 8 percent PV_{pretax} advantage (74 percent vs 65 percent). This changes to a $PV_{posttax}$ disadvantage of 2 percent (22 percent vs 24 percent) when state participation is included. This effect is directly caused by higher levels of Non-OECD state participation of 51 percent as compared to 42 percent in OECD countries. Figure 3.4 illustrates the component cost changes for oil price movement from US$45/bbl to US$33.75/bbl. Relative cost structures for PV_{opex} and PV_{capex} increase relative to field revenue for OECD countries. For Non-OECD asset holdings, the decrease in oil price actually decreases the total cost percentage, a direct result of state participation terms that allow cost recovery by producers. The exception is Indonesia with mature production sharing contracts recognizing that producers have completed cost recovery and now entered flat state profit splits.

At US$90/bbl (Table 3.3), the effect of progressive state participation is more noticeable. Non-OECD markets experience a 2 percent PV_{pretax} advantage (89 percent vs 87 percent). $PV_{posttax}$, Non-OECD markets experience a 12 percent adverse swing (20 percent vs 32 percent). Again, the reversal of the pre-tax operational advantage in Non-OECD asset holdings is directly caused by state participation being higher (69 percent) in Non-OECD countries, compared to 55 percent in OECD countries. Findings suggest that during periods of increasing oil prices, the progressive nature of production sharing and their inclusion in the cost structure has a direct effect on total cost of Non-OECD market oilfields. Insights are provided in Figure 3.4 and Figure 3.5 which deconstruct the component cost changes for oil price movement from US$45/bbl to US$33.75/bbl and US$45/bbl to US$90/bbl. The percentage of total cost for OECD asset holdings reduces for an increase in oil price. This is because an exogenous increase in oil price is not usually accompanied by associated increase in operating costs and

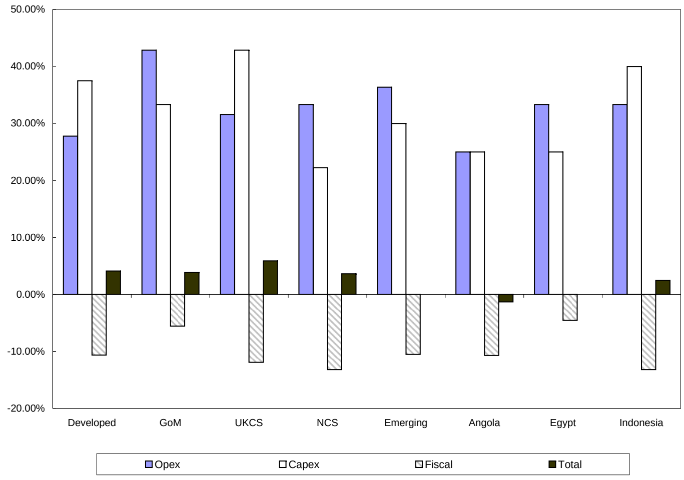

Figure 3.4. Component Cost structure change, US$45/bbl to US$33.75/bbl

The figure shows the relative change in cost structures PV_{opex}, PV_{capex}, PV_{fiscal} and $PV_{totcost}$ for OECD and Non-OECD countries as a percentage of PV_{fiscal} on the y-axis in response to a price downshock from US$45/bbl ($b$) to US$33.75/bbl (l). The x-axis reflects cost structure movements for individual underlying countries and aggregates for OECD and Non-OECD asset holdings.

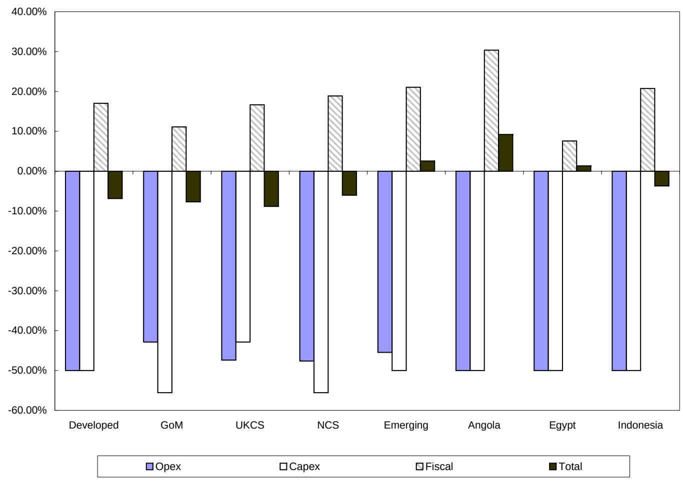

Figure 3.5. Component Cost structure change, US$45/bbl to US$90/bbl

The figure shows the relative change in cost structures PV_{opex}, PV_{capex}, PV_{fiscal} and $PV_{totcost}$ for OECD and Non-OECD countries as a percentage of $PV_{revenue}$ on the y-axis in response to a price upshock from US$45/bbl ($b$) to US$90/bbl (h). The x-axis reflects cost structure movements for individual underlying countries and aggregates for OECD and Non-OECD asset holdings.

OECD fiscal costs are not progressive. An increase in relative total cost in response to oil price increase can therefore only be driven by fiscal participation terms. This effect is observable for Non-OECD asset holdings, the increase in oil price actually increases total cost, a direct result of progressive state participation. An exception is Indonesia, which as result of its maturity as a producing country has completed the stage of cost recovery.

3.3.3. Regression Analysis of State Effects on Cash Flow and Risk

Regression analysis is used to lift out the extent of state and operational cost structure on the directionality of O&G sector return and risk measures. When interpreting results, it is noteworthy that no prior academic global asset study exists that compare OECD and Non-OECD market asset performance to the level of detail in this study. The isolation of economic state variables also allows insights into the outstanding Fama and French (1995) question relating to the effect of underlying economic and state variables on asset values. The regressions analyze the effect of operational and capital expenditure on potential field return represented by the relative cost structure for $PV^b_{totcost}$ and $Upside$ respectively. Inputs are derived from the detailed field models that are used to underpin field value variations. Regression analyses demonstrate the progressive tax nature and limited upside for Non-OECD fields, and the higher gain for OECD markets. This suggests a direct inversion in corporate cash flow participation relative to OECD assets Mehra and Prescott (1985).

The regression model (3.11) analyzes the relation between static cost structures and field performance measured by cash flow upside. The regime specific total cost effect on cash flow upside is used in the regression model as specified in (3.11). The country analysis provides evidence for an aggregate discussion. The regime effect loading in the regression quantifies directionality at the country level (Table 3.4) where the OECD grouping has a positive loading in excess of the Non-OECD grouping, reflecting the stronger upside directionality in response to price changes for OECD countries.

Notwithstanding the high loading for OECD countries, OECD regimes also experience country factor significance at the 99% level. To capture OECD and Non-OECD state effects I introduce a dummy variable for Non-OECD asset holdings $D_{nonoecd}$ incor-

Table 3.4. Regression results, cash flow upside US$45/bbl – US$90/bbl, country level

Regression results for cash flow upside directionality are based on (3.11). Fiscal cost structures are included in relative total cost structure represented by the independent variable X_1. The table presents the key regression statistics for cash flow upside ($Upside$) on a country basis. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

$$Upside = \alpha + \beta_1 X_1 \quad \text{with} \quad X_1 = PV^b_{totcost}/PV^b_{revenue}$$

	Sample Size	Coefficient	Value	t-Stat	p-Value	F	R^2
Panel A: OECD field upside US$45/bbl - US$90/bbl							
OECD	131	α	-0.2927	-2.0692*	(0.0405)	175.2564	0.5760
		β_1	2.7380	13.2384**	(0.0001)		
GoM	41	α	-0.4910	-11.9187**	(0.0001)	1811.2281	0.9789
		β_1	3.2681	42.5585**	(0.0001)		
NCS	42	α	-9.8643	-11.90162**	(0.0001)	203.02047	0.8354
		β_1	13.81165	14.24853**	(0.0001)		
UKCS	48	α	-0.8985	-8.3199**	(0.0001)	478.3644	0.9140
		β_1	3.7653	21.8715**	(0.0001)		
Panel B: Non-OECD field upside US$45/bbl - US$90/bbl							
Non-OECD	112	α	-0.0745	-0.2178	(0.8280)	10.6528	0.0883
		β_1	1.4249	3.2639**	(0.0015)		
Angola	19	α	-0.8810	-1.9664*	(0.0658)	9.6455	0.3620
		β_1	1.7745	3.1057**	(0.0064)		
Egypt	38	α	0.8655	4.5942**	(0.0001)	0.0957	0.0027
		β_1	0.0748	0.3094	(0.7588)		
Indonesia	55	α	-0.3906	-1.1621	(0.2504)	25.5372	0.3252
		β_1	2.1570	5.0534**	(0.0001)		

Table 3.5. Regression Results for Cash Flow Upside US$45/bbl – US$90/bbl

Regression results for cash flow upside directionality are based on (3.12). Fiscal cost structures are included in relative total cost structure represented by the independent variable X_1. I isolate effects of fiscal regulations by using dummy variables for Non-OECD regimes ($D_{nonoecd}$) and field size (D_{size}). Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

$$Upside = \alpha + \beta_1 X_1 + \beta_2 D_{nonoecd} + \beta_3 D_{size} \quad \text{with} \quad X_1 = PV^b_{totcost}/PV^b_{revenue}$$

Coefficient	Value	t-Stat	P-Value	F-Statistic	R^2
α	-0.1947	-1.4077	(0.1605)	95.2384	0.5445
β_1	2.5183	13.1514**	(0.0001)		
β_2	-0.7665	-14.7374**	(0.0001)		
β_3	0.0759	1.5763	(0.1163)		

porating findings by Kretzschmar and Kirchner (2007). A second dummy variable D_{size} isolates size effects for field with remaining reserves less than 100mmboe incorporating findings by Kretzschmar and Moles (2006). The regression model (3.12) shows the cash flow upside response with respect to price over the range US$45/bbl to US$90/bbl. Table 3.5 reports a positive and significant loading on X_1 indicating that fields with initially high relative total cost structures are able to cover their costs. The regression produces a significant negative loading on $D_{nonoecd}$ illustrating Non-OECD markets are limited in the upside as they are subject to production sharing. I find a positive, although not significant, loading on D_{size} suggesting a limited ability of small fields to generate higher returns on cash flow, consistent with Kretzschmar and Moles (2006). This result is best understood by considering a field that is previously at or close to break even in terms of its relative total cost structure. Any increase in price, in the case from US$45/bbl to US$90/bbl, would shift the field in to a profitable position as the incremental revenues cover cost with cash flow benefiting directly from the upside. Table 3.5 isolates the effects of regime on cash flow upside.

Visual inspection of the data distribution at the aggregate level indicates a different cash flow responses for OECD and Non-OECD countries (Figure 3.6). The most important factor to highlight is that OECD assets (left column) have the ability to experience an exponential increase in value as result of flat state participation. The top left graph in Figure 3.6 shows distinct OECD state effects. These effects are disaggregated by regime type. Columns in Figure 3.6 distinguished between OECD and Non-OECD respectively. OECD asset holdings particularly display distinct characteristics suggesting that the *Upside* in response to price movements (as measured by the y-axis) is directionally significant. Values increase as prices increase. This is consistent with findings at the aggregate level, except that county level de-construction leads to increased significance in the quality of directionality. The first column of Figure 3.6 illustrates highly interesting trends. The GoM has the lowest spread of operational cost structures ranging from approximately 45 percent to 70 percent. This results in an average increase in cash flows between 75 percent and 150 percent as oil price increase occurs. A result reflected in the GoM regime regression by a R^2 of 98 percent, the highest for the sample. The R^2 for the NCS in Figure 3.6, Graph E, lifts out two

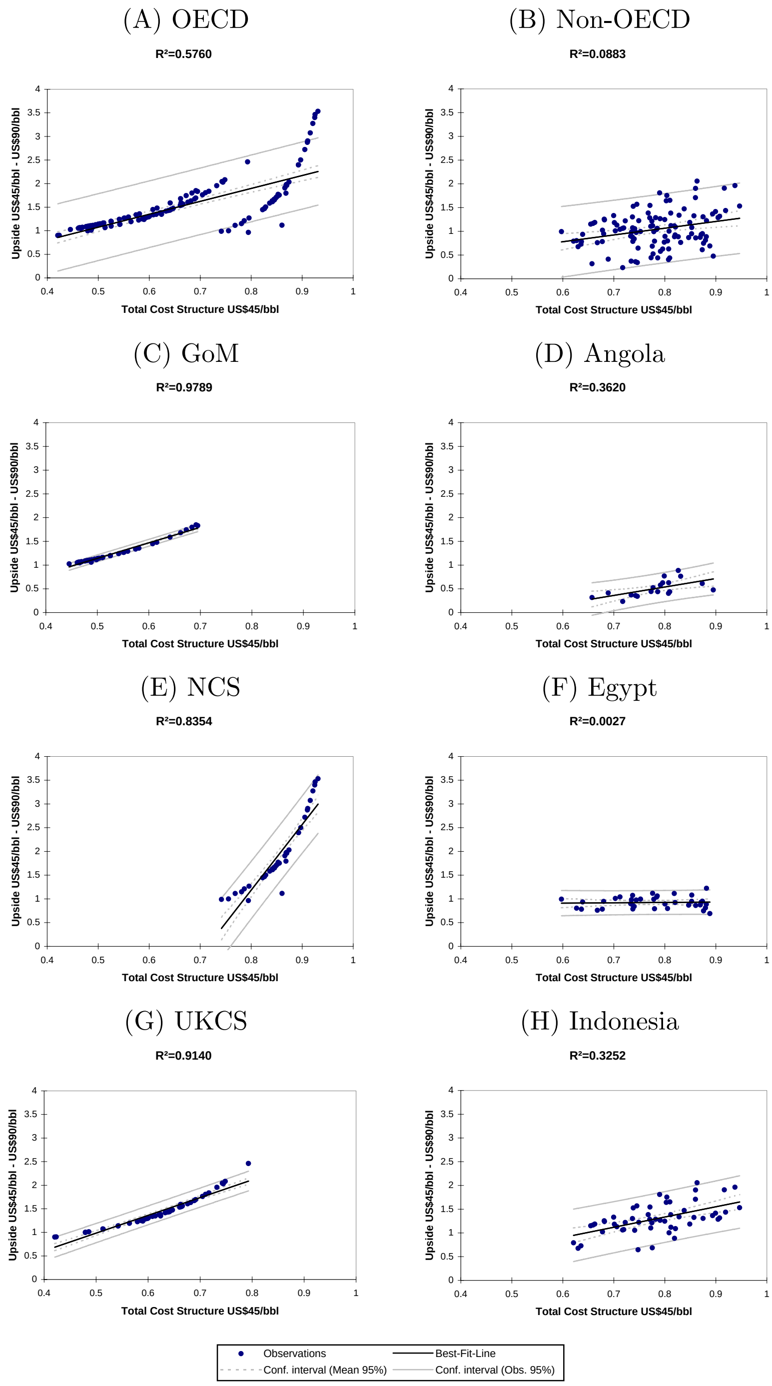

Figure 3.6. Response of Field Upside to an Increase in Oil Price

Figure illustrates the response in cash flow upside directionality relative to total relative cost structure, $PV^{b}_{totcost}$, x-axes, effect on $(Upside)$, y-axes. Column 1 reflects the OECD assets characteristic of upside participation, graph (A) shows the aggregate OECD market sample, graph (C) the GoM, graph (E) the NCS, and graph (G) the UKCS. The OECD concession state taxation terms enables assets to respond to oil price increases. Column 2 reflects the progressive Non-OECD state variable effect of production sharing. The asset upside is limited, and reflected in graphs (B), (D), (F), and (H) which display the aggregate Non-OECD market sample, Angola, Egypt, and Indonesia respectively.

important principles; The first relates to the fact that OECD cash flows are extremely responsive to high oil prices when the cost structure for the field is high. The second important principle is OECD assets do not have progressive taxation and therefore corporate owners participate in asset value upsides in response to positive price shocks.

The Non-OECD column provides an insightful counterpoint to the OECD state participation characteristics. Progressive state participation is apparent in that the price increase attracts progressive taxation against field values. The most notable effect is that for Non-OECD countries the upside in the sample overview is limited. Total field cost structures on average above 60%. At high prices, the corporate the cost of conducting business in Non-OECD O&G sector markets is significantly above OECD sectors, but more significantly taxation is progressive with the result that the corporate benefit of oil price increase is limited. Figure 3.6 illustrates a distinguishing feature in Non-OECD (in the case US$45/bbl to US$90/bbl) cash flow upside is limited by progressive state participation. Angola reflects the same trend with a 36 percent R^2. Egypt displays the least explanatory power in its total cost structures with a R^2 of 0.3 percent (Figure 3.6, Graph F). I assess residuals in order to determine heteroscedasticity for regression results. OECD markets exhibit high variances between small and large fields. In contrast Non-OECD markets show little sign of heteroscedasticity. The analysis of the residuals confirm that OECD assets have a non linear response to oil price variability.

3.4. Concluding Remarks

This chapter examines the country effects on risk return characteristics between OECD and Non-OECD oil sectors. In response to oil price increase, Non-OECD assets have progressive taxes that increase their total cost structures. In comparison, assets in OECD countries experience a reduction in total cost structure as oil prices increase. My sector findings indicate that, despite an initial operational cost advantage in Non-OECD countries, the progressive nature of state participation reverses the comparative advantage at higher oil prices. This result shows the limits to the benefits of emerging market investment, findings consistent with Stulz (2005). Regression results provide empirical evidence of state effects on field valuation in response to price changes. A significant negative effect of Non-OECD regulations on field upside is observable. These divergent findings go some way to providing empirical support for the intuition of Bruner et al. (2002), that regulatory differences are likely to mitigate against global asset valuation model convergence.

This first chapter includes the effects of country specific regulatory and fiscal idiosyncracies anticipated by Bruner et al. (2002) and allows insights into contractual and taxation effects on oil and gas sector asset prices. Evidence of potential risk and return inversion as between OECD and Non-OECD market oilfield assets is provided. State participation specificities are found to mitigate against model convergence. I suggest that it is insufficient to analyze natural resource assets in Non-OECD markets while ignoring state participation (Bekaert and Harvey 2002). There is need for future bottom-up studies of emerging market assets holdings and whether market idiosyncrasies are reflected in lower stock returns. This expanded work is undertaken in the following two chapters where field simulations are undertaken at each price level. In the oil and gas sector my ex ante expectation is that high oil prices will begin to increase value divergence between emerging and developed market asset carrying values.

Given the importance of the role of asset values in the book to market measure proposed by Fama and French (1992) the expectation is that as oil prices increase, corporates with high Non-OECD asset holdings are likely to begin to experience share price under-performance relative to corporates with low Non-OECD asset holdings, this expectation is tested in the final chapter of this thesis. Based on bottom-up evidence, state contractual participation is shown to be extraneous to the asset and potentially capable of inverting the risk return convention proposed by Mehra and Prescott (1985). I suggest that valuation model convergence will, to a large extent, be driven by empirical studies that provide both the insights into differences in underlying Non-OECD assets and method for dealing with global idiosyncracies. For the purposes of this and the following two chapters, the economic state variable framework proposed by Fama and French (1995) enables a robust method for dealing with global differences in state participation in oilfield assets. The following two chapters allow further insights into the limits to the corporate benefits of globalization in the context of sector assets.

4. Stochastic Asset Analysis

Chapter Research Focus

Oil price expectations and volatility levels directly and differentially affect asset pricing in the sector. I use global oil and gas (O&G) sector assets to expand the previous chapter demonstrating that oilfields operated under concession and production sharing contracts respond differently to oil price shocks. This chapter expands the previous valuation and risk chapter, as stochastic analyses are undertaken at three oil prices, revising findings from prior low oil price studies.

Overview

This chapter build on the fact that for financiers of global oil transactions, it matters what expectations are for oil price. Under low oil prices, the gap between OECD and NON-OECD assets is small, but diverges under high oil prices as result of the progressive nature of Non-OECD state agent participation. I subject 211 oilfield assets to price shocks, introduce stochastic price volatility, and measure value and risk response at each price level. This asset based approach allows insights into reserve responses to oil sector price risk. Oilfield valuation risk metrics are used to provide evidence that country specific reserve ownership contracts cause heterogenous value response to price changes. I conclude that the valuation of natural resource assets requires complete information about the price sensitivities of operator entitlement structures, and that under upward oil prices, ceteris paribus, OECD assets have more upside for corporate field participants.

Research Acknowledgements

This chapter is based on a conference paper accepted at the 2007 Journal of Banking and Finance: Gavin L. Kretzschmar and Axel Kirchner, Commodity Price Shocks and Economic State Variables – Empirical Insights into Asset Valuation and Risk in the Oil and Gas Sector, (Kretzschmar and Kirchner 2007). The Real Options implications of these findings are published together with my supervisor Dr Moles in Kretzschmar and Moles (2006).

4.1. Background

Finance theory recognizes that efficient markets require sufficient information to enable the valuation of assets and their associated risks. I extend the previous chapter and provide insights into differing forms of oilfield contracts analyzing their price responses over an extensive range of oil prices, from US$22.5/bbl to US$90/bbl.

Stochastic value distributions are shown to be directly affected by oilfield asset contracts. Additionally, risk, as measured by simulations of expected value, kurtosis, standard deviation, and price response delta are directly affected by regulations that pertain to asset ownership. Price effects, not observable at low prices, affect PSC and concession field asset behaviors differently at higher prices. Evidence is found that constant equity value Beta results in prior oil and gas studies may not hold at high oil prices. This chapter provides insights into difficulties of valuing cash flows noted by Ross (2004), intrinsic asset values are a function of expected future cash flows. They are also a function of the uncertainty associated with them. In Oil and gas, my findings demonstrate that under conditions of price volatility, entitlement to concession and production sharing cash floes, and the risks associated with them, are not homogenous.

4.2. Why Asset Value Responses to Commodity Price Changes are Important

Oilfield contracts are material in determining asset valuation response to oil price movements. Production Sharing Contracts (PSC) account for between 30% and 50% of global reserves. As exploration opportunities decrease, corporate reserve replacement is increasingly set to come from regions with production sharing with production based government take. In an application of the agency problem of state ruler discretion proposed by Stulz (2005), state representatives increase state welfare by participating in oilfield asset upside by reducing corporate asset returns. Total, ENI and Shell already have PSC reserves in excess of 30% of current holdings, with each of these companies expected to increase PSC holdings to 40% and 50% in the next ten years. Exxon's PSC production is for instance expected to move from a low PSC base of 18% to 36% by 2010 and other oil majors show similar trends (Treynor and Cook 2004). Oilfield data is used to show that as production sharing oilfields come onstream, the heterogenous response of asset holdings will be important in pricing asset value and risk. The findings are likely to have wide application in the sector.

Firm level risk studies in the O&G sector have been characterized by two factors. First, research has tended to relate to a period of oil prices between US$18/bbl and US$35/bbl, and market volatility characteristics were low. Haushalter et al. (2002) and Jin and Jorion (2006) for instance focus on the effect of price volatility for periods covering very low prices for oil (1992–1994) and (1998–2001) respectively.

Second, due to a lack of ownership disclosures, prior studies have been unable to isolate the influence of oilfield ownership structures on market risk. Data attributes allow an extension of prior work by examining O&G asset ownership behavior in volatile, high price commodity markets.

The research objectives address the above two characteristics of prior studies. First I examine the O&G assumption of homogenous oil reserve entitlement response to price shocks. All 211 oilfields are valued at three oil price levels; US$22.5/bbl, US$45/bbl, US$90/bbl. Stochastic simulations are introduced to isolate the influence of oilfield ownership structures on market risk at each price level. Secondly, I address the general lack of attention given to price varying asset responses in prior studies. In practice, isolating the oil price response of producer asset holdings is particularly difficult where oilfield cash flows are subject to the simultaneous effects of complex and undisclosed ownership contracts and market uncertainties. This price effect is discussed in depth by Kretzschmar et al. (2007), and directly affects the valuation response of oil production and oil reserves. By conducting analyses over a price range of US$22.5/bbl to US$45/bbl to US$90/bbl I isolate the response ranges that cause progressive PSC contractual clauses to affect valuation response.

4.3. Research Approach

4.3.1. Global Sample of 211 Oilfield Assets

Differences in price responses characteristics between concessions and PSC assets are illustrated using a comparative analyses across a global sample of oilfield assets. Fields with remaining reserves below the threshold of 5 mmboe are omitted due to idiosyncratic responses caused by abandonment costs at the end of each field's life cycle. The total proportional amounts of fields per regime and country represented by the sample are depicted in Table 4.1. The cross-section of field data represents fields with varying remaining reserves ranging from 5 million barrels of oil equivalent (mmboe) up to 7042 mmboe. Fields in the UKCS subject to Petroleum Revenue Tax (PRT) are omitted as they pay special taxation premia. From an available population of 440 producing oil fields, the sample of 211 fields is selected comprising 103 fields from three concession regimes; the Gulf of Mexico (GoM), the UK Continental Shelf (UKCS) and the Norwegian Continental Shelf (NCS), and 108 fields from three PSC regimes, Angola (ANG), Egypt (EGY) and Indonesia (IDO). Country and size strata contain an amount of fields relative to their proportional representation within the population, thus ensuring representativeness of the selection. To preserve statistical significance for country analyses, the strata comprise at least 29 fields per country.[1] The stratification and size of the sample allows detailed and extensive insights into regime and country asset price response behavior.

An example of whole life field data is illustrated for a GoM field in Appendix A, Table A.2. To my knowledge, no other academic study of oilfield asset behavior has analyzed samples of a similar size. The six global oil and gas regimes were selected for their fiscal homogeneity. The field valuations are conducted as at January 2006. According to research by Kretzschmar and Moles (2006), size of remaining reserves is a key determinant and significantly impacts a field's behavior. Hence, in line with their findings, fields with remaining reserves below 60mmboe were categorized as being small as opposed to large fields yielding reserves of at least 60mmboe.

[1] A full list of fields selected is available from the authors on request.

Table 4.1. Description of Randomly Selected Stratified Sample by Regime and Country

This table describes the selection for 211 producing oil fields. The percentage of total field population is calculated on the basis of the sample relative to the total number of fields per country. PRT fields in the UKCS and fields with remaining reserves below 5mmboe have been excluded from the population due to idiosyncratic effects. The table additionally reports the number of fields with reserves below and above 60mmboe.

	Number of Observations	Percentage of Total Field Population	Number of Fields with Reserves	
			below 60mmboe	above 60mmboe
Concession Regimes	103			
Gulf of Mexico	31	32%	24	7
UK Cont. Shelf	43	27%	35	8
Norwegian Cont. Shelf	29	43%	8	21
PSC Regimes	108			
Angola	29	100%	11	18
Indonesia	43	91%	18	25
Egypt	36	88%	23	13
Total Sample Size	211			

4.3.2. Research Objectives

A comprehensive sample allows differentiation between concession and PSC asset price response behavior under commodity price uncertainty for oilfields 'in production'. The existence of low technical and exploration risk for producing fields enables a view of asset responses to oil price changes in isolation of factors of production uncertainty. Also, the sample permits detection of country-specific cost structure and entitlement effects that could otherwise challenge the generalization of obtained results. This asset based approach offers a distinctive advantage over single-field examples or case studies. Tax terms are field- and ownership structure specific. Contractual terms for each field are embedded in models, allowing the simulation of effects that could have implications on risk management and hedging strategies.

Using detailed field models, I set benchmark valuations at US$45/bbl. Exogenous price shocks are approximated for each field by valuing them under oil prices ranging from US$22.5/bbl and US$90/bbl (relative range of 400%). Three initial price scenarios are analyzed to capture the fluctuations in valuation and cost structure for each field. This is done by revaluing field assets at each price scenario, US$22.5/bbl, US$45/bbl and US\$90/bbl. The US\$22.5/bbl valuation covers periods of low oil prices and low exogenous price volatility comparable to that analyzed by Jin and Jorion (2006) and Haushalter et al. (2002). I extend their studies by investigating field value responses to a +100% price up-shock from US\$45/bbl to US\$90/bbl. I also test field value responses to price down-shocks by −50% relative to the US\$45/bbl benchmark. This split of the analysis into two sub intervals allows a test of whether asymmetries in price responses can be identified. A deterministic present value analysis gives important insights into how oil fields respond in general to exogenous price shocks.[2]

The fields' ability to cope with market price uncertainty is analyzed by introducing oil price volatility for each price scenario at the asset level. I simulate each field at each price scenario (211 fields at US\$45/bbl, US\$22.5/bbl, US\$90/bbl) pre- and post-tax. This allows the extraction of pre- and post-tax risk information about the expected mean value of the field, the standard deviation around the mean, skewness and kurtosis. These descriptive measures allow a comparison of the regime effects of exogenous price volatility at each price scenario.

4.3.3. Whole Life Field Model

I develop a whole life oilfield valuation model based on the detailed remaining life field data provided by Wood Mackenzie. The model is driven by remaining asset estimates of components affecting field value; production *(Production)*, price *(Price)*, cost *(Cost)* and taxation terms *(Tax)* under both concession and PSC regimes. Estimates are annualized.

$$CashFlow_t = Production_t \times Price_t - Cost_t - Tax_t \tag{4.1}$$

with

$$Production_t = \begin{cases} TotalProduction_t & \text{for Concession Regimes} \\ EntitledProduction_t & \text{for PSC Regimes} \end{cases} \tag{4.2}$$

[2]I use the term 'deterministic' as representing a present value computation for the oilfield field asset, that given an initial state of valuation of the field, will produce the same final value when given the same valuation inputs

and

$$\begin{aligned} Price_t &= \text{Market price per bbloe } t, \text{subject to exogenous volatility} \\ Cost_t &= OPEX_t + CAPEX_t \\ Tax_t &= ProfitOil_t \times taxrate \end{aligned} \tag{4.3}$$

Oilfield present values *(PV)* as to January 2006 are computed based on discounted annual cash flows *(CashFlow)* at time t with a constant time invariant annual discount rate of 10%.[3] For pre-tax present values (*PreTaxPV*), zero taxes with $Tax_t = 0 \; \forall \; t$ are assumed in (4.1). Post-tax oilfield present value estimates (*PostTaxPV*) are subject to the corresponding taxation rules.

Foreign oil companies (FOC) in concession regimes are entitled to total remaining reserves ($TotalProduction_t$) , as opposed to FOCs in PSC regimes. The annual entitled amount of production ($EntitledProduction_t$) for PSCs is defined by:

$$EntitledProduction_t = \frac{CostOil_t + ProfitOil_t}{Price_t} \tag{4.4}$$

with a cost of recovery share for the FOC following (4.5)

$$CostOil_t = min \begin{cases} CAPEX_t \times SpecifiedMultiplier \\ TotalProduction_t \times Price_t \times Uplift - Depr_t + OPEX_t \end{cases} \tag{4.5}$$

whereas the resulting Profit Oil share of total profit after cost recovery is subject to the foreign oil company's contractual agreements. In the case of an internal rate of return (IRR) contract with a specified $IRR\%$, the achievable annually compounded rate of return (ROR) is measured recursively by

$$ROR_t^{IRR} = ROR_{t-1}^{IRR} \times (100\% + IRR) + CashFlow_t \tag{4.6}$$

Together with

$$TotalProfit_t = TotalProduction_t \times Price_t - CostOil_t, \tag{4.7}$$

[3] A discount rate of 10% p.a. is recommended by FASB supplemental disclosures required by SFAS No. 69 (FASB 1982) and applied to all discounted cash flow calculations in this paper.

the FOC's Profit Oil share is defined by specified profit splits. For a typical Angolan field, (4.8) shows the progressive nature of staged profit splits.

$$ProfitOil_t = \begin{cases} 75\% \;\; TotalProfit_t & \text{if} \;\; ROR_t^{15\%} < 0 \\ 65\% \;\; TotalProfit_t & \text{if} \;\; ROR_t^{15\%} \geq 0 > ROR_t^{25\%} \\ 45\% \;\; TotalProfit_t & \text{if} \;\; ROR_t^{25\%} \geq 0 > ROR_t^{30\%} \\ 25\% \;\; TotalProfit_t & \text{if} \;\; ROR_t^{35\%} \geq 0 > ROR_t^{40\%} \\ 15\% \;\; TotalProfit_t & \text{if} \;\; ROR_t^{40\%} \geq 0. \end{cases} \tag{4.8}$$

The proposed field model enables the computation of the present value price response by varying annual exogenous oil prices in (4.2) on a field basis. The remaining dependent variables *Production*, *Cost* and *Tax* are then populated according to consensus estimates from oil field operators.

4.3.4. Field Valuation and Risk Analysis

I run separate Monte Carlo simulations at the field level. To estimate frequency distributions of field present value responses pre- and post-tax, I perform 1266 Monte Carlo simulations (211 fields at three price scenarios, pre- and post-tax) with 2500 trials to estimate statistical response measures for each field.[4] Although discrete deterministic analyses provides preliminary insights, it fails to capture important dynamics in physical asset responses to price volatility. As stochastic simulation enables risk attribution at its points of origin, discrete price shocks are extended to price shocks with stochastic price volatility as illustrated in Figure 4.1. Following insights into the term structure of oil futures prices for the period January 1982 to December 1991, by Bessembinder et al. (1995) I model oil price as a mean reverting function but accommodate recent findings by Geman (2005), who suggests that arithmetic Brownian motion prevails for the period January 1999 – October 2004. I combine both insights by amalgamating a short-horizon mean reverting oil price trajectory (followed by constant inflation adjust-

[4]Monte Carlo simulations using the Latin-Hypercube sampling method with 999 bins are performed over the log-normal price distribution. For all countries apart from the UKCS, each individual field is run with 2500 trials. UKCS fields, in turn, demand intensive and complex taxation calculations and half year cash flow data. Computational intensity forced a reduction of trials to 1000. The error terms remain less than 1% for all simulations

ment) with annual lognormally distributed stochastic price volatility. These random price fluctuations are applied to each annualised step of cash flow calculation. I perform this process at each level of price jump as schematically displayed in Figure 4.1 for the price scenario of US$45/bbl. For stochastic whole life field simulation, exogenous price volatility follows the continuous probability distribution function of a lognormal price distribution.

$$Price_t = f(x_t; \mu_t, \sigma_t) = \frac{1}{x_t \sigma_t \sqrt{2\pi}} \exp(-(\ln x_t - \mu_t)^2 / 2\sigma_t^2) \tag{4.9}$$

The distribution parameters (4.10) for the mean μ_t are linked to the set of three different initial price scenarios for μ_0 at time $t = 0$. Expected future prices μ_t follow the corresponding mean reverting curve for time t (years) as depicted in Figure 4.1. Future mean reverting oil prices are derived from the individual field data. A constant relative standard deviation σ_t of 30% is applied to retain comparability between simulations.[5]

$$\begin{array}{llll} \text{Down-Shock Price Scenario} & \mu_0 = \text{US\$22.5/bbl} & \sigma_t = & 30\% \\ \text{Base Case Price Scenario} & \mu_0 = \text{US\$45/bbl} & \sigma_t = & 30\% \\ \text{Up-Shock Price Scenario} & \mu_0 = \text{US\$90/bbl} & \sigma_t = & 30\% \end{array} \tag{4.10}$$

Stochastic simulation enables analysis of field responses to changes in price together with variations in moments relative to price movement. I provide information about how the descriptive parameters (mean, variance, skewness and kurtosis) of the estimated present value frequency distribution functions react to changes in oil price and induced exogenous volatility. Insights from cross-sectional analyses are expected to have distinct implications regarding risk management and hedging strategies.

[5] Price volatility is based on the one month FOB futures contract implied volatility – for the period January 1986 to January 2006. Annualised volatility showed two distinct periods, pre 2000 (low volatility) and post 2000 (high – above 35%) (Geman 2005). I select 30% for this study.

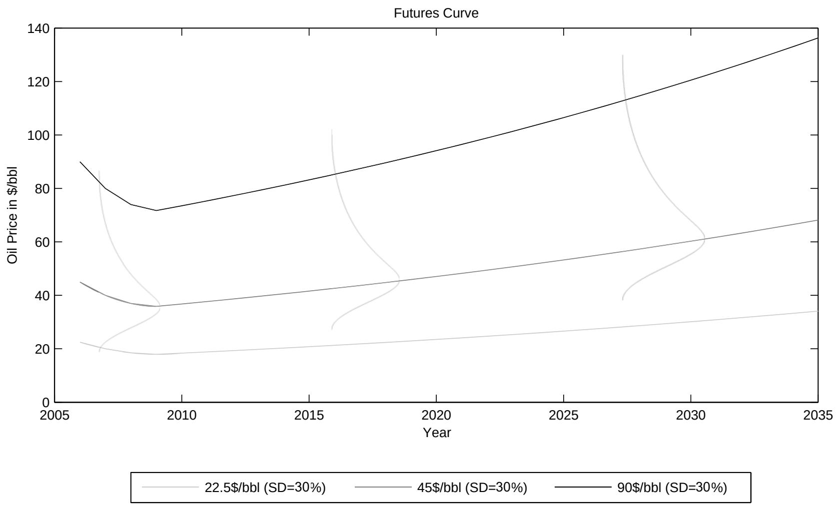

Figure 4.1. Field Model Implied Oil Price Curve

This figure illustrates the movement of the future model-implied oil price derived from the individual field data. Building on findings by Bessembinder et al. (1995), short-horizon mean reverting annual prices are quoted for the three different initial price scenarios (US$22.5/bbl, US$45/bbl, US$90/bbl). I incorporate recent findings by Geman (2005) and apply stochastic lognormally distributed exogenous price volatility to each year's price for all price scenarios under consideration. The figure illustrates stochastic price volatility around the US$45/bbl price scenario as a stylized example, annual stochastic simulations are performed for all three scenarios. Prices for the corresponding scenarios are described in Appendix A, Table A.2, Columns 6, 7 and 8. Only one column is applied at a time.

4.4. Oilfield Price Response Results

4.4.1. Empirical Asset Valuation Insights and Price Response Analysis

In this section I report insights into whether oilfield asset price responses are specific to ownership contract type or whether oilfield values and risk measures respond heterogeneously to price shocks and volatility. As reported in prior firm level studies, there is a sensitivity of equity values to changes in oil price uncertainty (Strong 1991). Differential response rates at the asset level would provide evidence that firm value studies that treat O&G reserve responses as a homogenous calculation (Jin and Jorion 2006) may not hold across all price ranges. I test the response to price variability and use an oil price range of US$22.5/bbl to US$90/bbl to straddle the benchmark of US$45/bbl. The lower part of range covers periods of low oil prices and low oil price volatility comparable to previous studies by Jin and Jorion (2006) and Haushalter et al. (2002).

Fields in different regimes with identical cost structures respond differently to oil price variability, an insight that extends previous findings by Haushalter et al. (2002). Present value responses suggest that oilfields are directly influenced by the tax regime that they are subject to, a factor not covered in previous finance studies. Table 4.2 illustrates that GoM and Angola have, on average, identical pre-tax PV cost structures of 60% at the US$22.5/bbl price scenario. When oil price increases to US$90/bbl (a 4 times increase), the GoM pre-tax PV increases from US$M 395.37 to US$M 2377.77, an oil price response of 6 times. The value increase for Angola over the same oil price range is comparable with change in pre-tax PV of 6 times (US$M 1792 to US$M 10796). Value responses are comparable pre-tax. The comparison changes post-tax, and this is where the differences in entitlement structures are most apparent for oilfield assets. Assets in the GoM have an average post-tax PV response rate of 6.3 times(US$M 216.55 to US$M 1353.68). The progressive Angolan regime shows a price response of 3.1 times (US$M 658.67 to US$M 2017.22).

The second asset response insight occurs when I compare UKCS pre- and post-tax present values for a change in price from US$22.5/bbl to US$90/bbl. Pre-tax PV price response is 7.67 times (US$M 266 to US$M 2041) and 7.7 times (US$M 138 to US$M

Table 4.2. Average Cost Structure of Randomly Selected Stratified Sample by Regime and Country

Panel A describes the absolute and relative cost and tax structure for producing oil fields at an oil price of US$22.5/bbl. Panel B and Panel C reflect the same data at prices of US$45/bbl and US$90/bbl respectively. Each panel reflects concession (GoM, UKCS, NCS) and PSC (ANG, IDO, EGY) regimes separately. Absolute figures are presented in US$M.

Average	Gross Revenue	OPEX	CAPEX	PreTaxPV	Tax	PostTaxPV
			Panel A: Price of US$22.5/bbl			
GoM	661.85	122.90	143.57	395.37	178.82	216.55
	(100%)	(19%)	(21%)	(60%)	(27%)	(33%)
UKCS	598.19	234.64	97.37	266.18	128.08	138.10
	(100%)	(38%)	(16%)	(44%)	(21%)	(23%)
NCS	4277.39	1773.51	612.52	1891.36	1592.82	298.54
	(100%)	(42%)	(14%)	(44%)	(37%)	(7%)
ANG	2996.97	478.36	726.59	1792.03	1133.36	658.67
	(100%)	(16%)	(24%)	(60%)	(38%)	(22%)
IDO	1405.95	380.36	297.11	728.48	524.96	203.52
	(100%)	(27%)	(21%)	(52%)	(37%)	(14%)
EGY	932.71	106.40	67.94	758.36	544.08	213.28
	(100%)	(12%)	(7%)	(81%)	(58%)	(23%)
			Panel B: Price of US$45/bbl			
GoM	1325.20	122.90	143.57	1058.72	462.21	598.16
	(100%)	(9%)	(11%)	(80%)	(35%)	(45%)
UKCS	1176.66	234.64	97.37	844.65	399.74	444.91
	(100%)	(20%)	(8%)	(72%)	(34%)	(38%)
NCS	8439.08	1773.51	612.52	6053.04	4658.83	1394.21
	(100%)	(21%)	(7%)	(72%)	(55%)	(17%)
ANG	6000.78	478.36	726.59	4795.83	3383.66	1412.17
	(100%)	(8%)	(12%)	(80%)	(56%)	(24%)
IDO	2582.68	380.36	297.11	1905.22	1356.33	548.89
	(100%)	(14%)	(12%)	(74%)	(53%)	(21%)
EGY	1864.41	106.40	67.94	1690.06	1238.62	450.44
	(100%)	(5%)	(4%)	(91%)	(66%)	(24%)
			Panel C: Price of US$90/bbl			
GoM	2644.25	122.90	143.57	2377.77	1024.08	1353.68
	(100%)	(5%)	(5%)	(90%)	(39%)	(51%)
UKCS	2373.81	234.64	97.37	2041.80	977.46	1064.34
	(100%)	(10%)	(4%)	(86%)	(41%)	(45%)
NCS	16762.45	1773.51	612.52	14376.42	10875.38	3501.04
	(100%)	(10%)	(4%)	(86%)	(65%)	(21%)
ANG	12001.55	478.36	726.59	10796.60	8779.38	2017.22
	(100%)	(4%)	(6%)	(90%)	(73%)	(17%)
IDO	5125.15	380.36	297.11	4447.69	3201.09	1246.60
	(100%)	(7%)	(6%)	(87%)	(62%)	(24%)
EGY	3727.81	106.40	67.94	3553.47	2669.58	882.88
	(100%)	(3%)	(2%)	(95%)	(72%)	(24%)

Table 4.3a. Relative Present Value Oil Price Responses (Pre-Tax compared to Post-Tax)

Panel A (Table 4.3a) describes relative price response for pre- and post-tax present values for a relative change in oil price over the range of US$22.5/bbl to US$90/bbl. Panel B and Panel C (Table 4.3b) reflect the same data at price changes from US$45/bbl to US$22.5/bbl and US$45/bbl to US$90/bbl respectively. Each panel reflects concession (GoM, UKCS, NCS) and PSC (ANG, IDO, EGY) regimes separately. The existence of significant differences between pre- and post-tax responses is verified through paired 2-tailed t-tests run at the field level of the selected sample. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

	Observations	Reserves	Δ Pre-Tax PV	Δ Post-Tax PV	t-test
Panel A: Price change from US$22.5/bbl to US$90/bbl in Relative Terms					
GoM	31	all fields	1.5369	1.5975	(0.7920)
	24	<60mmboe	1.3354	1.2928	(0.1257)
	7	>60mmboe	1.3851	1.3622	(0.9454)
UKCS	43	all fields	1.9603	1.9696	(0.3489)
	35	<60mmboe	2.7973	5.0117	(0.3268)
	8	>60mmboe	1.6881	1.4836	(0.3653)
NCS	29	all fields	1.9425	2.9970	(0.3116)
	8	<60mmboe	3.0010	5.7150	(0.5258)
	21	>60mmboe	1.9291	2.9696	(0.3328)
ANG	29	all fields	1.5397	0.7827	(0.1476)
	11	<60mmboe	1.4452	0.9873	(0.0699)
	18	>60mmboe	1.5434	0.7798	(0.2673)
IDO	43	all fields	1.5603	1.5653	(0.6793)
	18	<60mmboe	1.9156	1.6202	(0.3293)
	25	>60mmboe	1.5432	1.5621	(0.2272)
EGY	36	all fields	1.1975	1.0579	(0.0384)*
	23	<60mmboe	1.1978	1.0452	(0.1307)
	13	>60mmboe	1.1974	1.0598	(0.1783)

1063.34) respectively. This greater sensitivity and price response is directly in response to higher oil prices allowing a coverage of higher costs in UKCS fields.

Table 4.3a measures the relative change in PVs for a relative change in price from US$22.5/bbl to US$90/bbl. The t-test estimates the significance of the difference between pre-tax PV price response and post-tax PV price response. At the 95% significance level, difference can only be observed for one country, Egypt. When I separate the price response analysis into two ranges (Table 4.3b), it is apparent that the price response is asymmetrical and significant differences are obtained for both ranges.

Table 4.3b. Relative Present Value Oil Price Responses (Pre-Tax compared to Post-Tax)

	Observations	Reserves	Δ Pre-Tax PV	Δ Post-Tax PV	t-test
Panel B: Price change from US$45/bbl to US$22.5/bbl (relative Δ for 1% change in price)					
GoM	31	all fields	0.7469	0.7241	(0.3361)
	24	<60mmboe	0.8304	0.8483	(0.3433)
	7	>60mmboe	0.8018	0.8112	(0.6682)
UKCS	43	all fields	0.6303	0.6208	(0.0105)*
	35	<60mmboe	0.4866	0.2874	(0.0117)*
	8	>60mmboe	0.6972	0.7620	(0.5571)
NCS	29	all fields	0.6249	0.4282	(0.0389)*
	8	<60mmboe	0.4366	0.2141	(0.1928)
	21	>60mmboe	0.6284	0.4326	(0.0218)*
ANG	29	all fields	0.7473	0.9329	(0.8561)
	11	<60mmboe	0.7736	0.7037	(0.8102)
	18	>60mmboe	0.7463	0.9371	(0.6153)
IDO	43	all fields	0.7647	0.7416	(0.0815)
	18	<60mmboe	0.6318	0.6625	(0.2139)
	25	>60mmboe	0.7725	0.7467	(0.1890)
EGY	36	all fields	0.8974	0.9470	(0.6295)
	23	<60mmboe	0.8973	0.9459	(0.4200)
	13	>60mmboe	0.8975	0.9471	(0.8983)
Panel C: Price change from US$45/bbl to US$90/bbl in Relative Terms					
GoM	31	all fields	1.1229	1.1315	(0.3422)
	24	<60mmboe	1.0848	1.0728	(0.3505)
	7	>60mmboe	1.0864	1.0810	(0.5864)
UKCS	42	all fields	1.2087	1.1961	(0.0567)
	35	<60mmboe	1.3316	1.4089	(0.0560)
	8	>60mmboe	1.1514	1.1060	(0.9973)
NCS	29	all fields	1.1875	1.2556	(0.1247)
	8	<60mmboe	1.2817	1.1970	(0.3377)
	21	>60mmboe	1.1858	1.2568	(0.0182)*
ANG	29	all fields	1.1256	0.7142	(0.0000)**
	11	<60mmboe	1.0938	0.6797	(0.0000)**
	18	>60mmboe	1.1268	0.7149	(0.0000)**
IDO	43	all fields	1.1672	1.1356	(0.7144)
	18	<60mmboe	1.1841	1.0500	(0.0168)*
	25	>60mmboe	1.1662	1.1411	(0.3469)
EGY	36	all fields	1.0513	0.9800	(0.0000)**
	23	<60mmboe	1.0514	0.9672	(0.0000)**
	13	>60mmboe	1.0513	0.9820	(0.0492)*

For the range from US$45/bbl to US$22.5/bbl, a range comparable to the prices covered by Haushalter (2000), Rajgopal (1999) and Jin and Jorion (2006), a 1% downward change in oil price leads to a relative drop in post-tax PV for all assets. When prices fall, concession pre-tax PV respond to a 1% decrease in price by a PV decrease of 0.75% in GoM, 0.63% in UKCS and 0.62% in NCS. For PSC regimes, pre-tax PV respond to a 1% decrease in price by a PV decrease of 0.75% in Angola, 0.76% in Indonesia and 0.90% in Egypt. Significant changes from pre- to post-tax response (relative to oil price movement) are experienced in the UKCS and NCS as prices go down. For PSC regimes, pre- to post-tax changes are relatively insensitive to falling oil prices, reflected in the 0.93% post-tax change for Angola showing little variation out of line with oil price changes.

Under upward price conditions, measured by a move from US$45/bbl to US$90/bbl, response rate is 1.3 for the GoM. This field value response is asymmetrical and approximately 1.8 times greater than the relative response under downward price conditions (0.72). For Angola, upward price movements see a relative change in post-tax PV from 0.9 under downward shocks to 0.7 under upward shocks, indicating an asymmetrical PSC present value response. PSC fields share less in the asset value increase caused by the change in price. Asset responses under high oil prices are significantly different between pre- and post-tax for PSC regimes. This is indicative of progressive production sharing contracts that result in government participation in the oil field when agreed returns have been earned by the operator (see Kretzschmar et al. 2007). The exception is Indonesia where a number of mature fields have already completed their cost recovery. Flat profit oil splits in the early Indonesian production sharing contracts cause fiscal behavior similar to concessions.

4.4.2. Response Analysis under Stochastic Price Volatility

Differences for Changes in Price

The above deterministic analysis indicates that pre- and post-tax PVs behave differently in response to price changes for both contractual regimes. When oilfields are simulated I also observe distinct differences between pre- and post-tax simulation behavior. Figure 4.2 links pre-tax PV with post-tax PV in the top left and right chart for GoM and Angola respectively. Pre-tax results for both GoM and Angola respond in a comparably linear fashion for price scenarios under consideration. Pre-tax response rates are characterized by the steeper gradient for Angola, indicative of higher initial CAPEX overcome by lower ongoing OPEX in Angolan fields (Haushalter 2000). The flatter gradient in the Angolan post-tax PV response curve is attributable to progressive profit splits particularly at higher prices. Tax take as a percentage of gross revenue moves for GoM from 27% at US$22.5/bbl to 35% US$45/bbl up to 39% at US$90/bbl. Angola tax take increases from 38% at US$22.5/bbl to 56% US$45/bbl to 73% at US$90/bbl (see Table 4.2 for numerical values).

A comparison of stochastic simulations at US$22.5/bbl shows a distinctive overlap in the lower tail of the pre-tax present value frequency distribution and the upper tail of the corresponding post-tax PV frequency distribution. I illustrate this using the GoM and Angolan field as depicted in the center graphs in Figure 4.2. At low oil prices of US$22.5/bbl, these characteristics are attributable to low tax-loss offset ratios (Lund 2000). When comparing the overlay charts at US$22.5/bbl and US$90/bbl (center and bottom charts in Figure 4.2), it is apparent that pre- and post-tax frequency distributions for the GoM exhibit a similar shape, reflecting the linear tax rate of concession regimes. In the case of Angola the same pre- and post-tax 'concession' symmetry is reflected at US$22.5/bbl. PSC fields at low prices are likely to remain in the stage of cost recovery without triggering progressive profit splits. The distinctive and progressive nature of PSC regimes becomes apparent at high prices. These are depicted in the overlay chart for the Angolan field at US$90/bbl. The distance from the pre-tax mean is influenced by the tax rate and the difference between the distribution means pre- and post-tax.

Table 4.4 highlights the progressive nature of PSC regimes at higher oil prices. A comparison of concession and PSC $\frac{\text{Post-Tax}}{\text{Pre-Tax}}$ in Panels A, B and C indicate a marginally increasing trend in mean for concession post-tax PV. This is in sharp contrast to a degressive trend for PSC fields. When the trend in mean is read together with trends in standard deviation and distribution-width, it is apparent that concession ratios of 38% to 35% remain fairly consistent for all three price scenarios. For PSCs the progressive

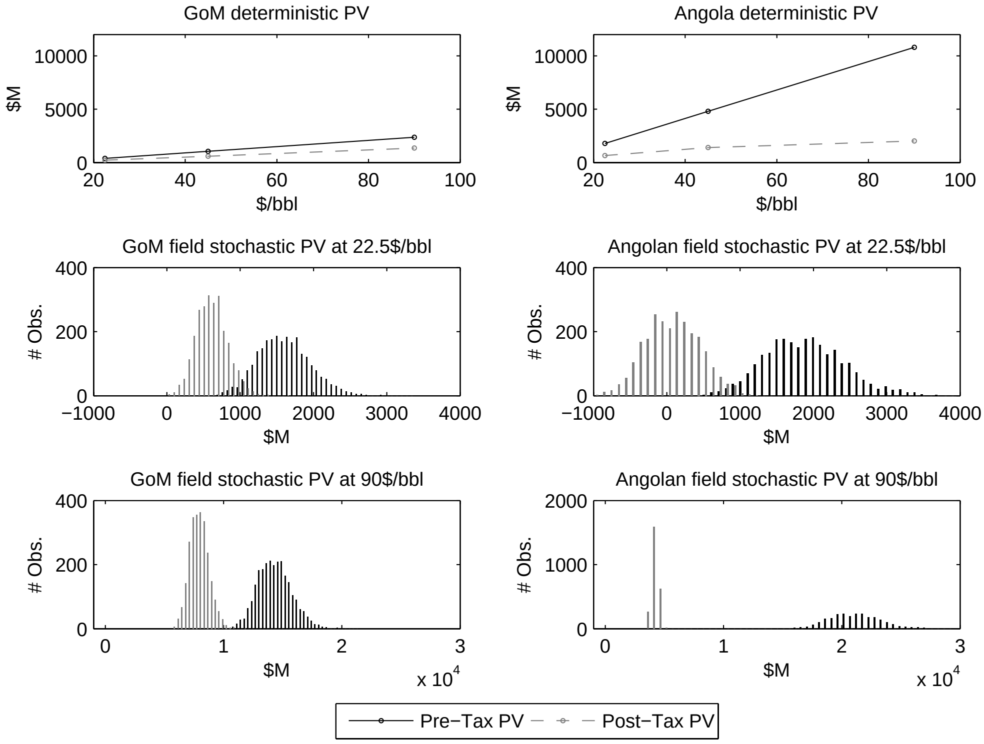

Figure 4.2. Price Response Connection between Deterministic Present Values and Stochastic Simulations

This figure displays in the left column the connection between deterministic and stochastic present values pre- and post-tax for the Gulf of Mexico. The top left chart describes deterministic country average pre- and post-tax compared over the three price scenarios (The plot points marked on the graphs represent the pre- and post-tax PVs at US$22.5/bbl, US$45/bbl and US$90/bbl). Then the center and bottom left overlay charts describe pre- and post-tax simulation results at a year-end price scenarios of US$22.5/bbl and US$90/bbl for a representative GoM field. The movement between the US$22.5/bbl and US$90/bbl stochastic graphs reflect simulated oilfield response to the combined effects of exogenous price shocks, price volatility and taxation terms. The right column depicts results for Angola and a comparable Angolan field respectively.

tax effect on the trend in standard deviation and width results in a relative tightening of distribution bandwidth.

A comparison of the 633 detailed post-tax simulation results for three price scenarios indicate price variant effects of field size and contractual regime. Skewness measures at US$22.5/bbl suggest that NCS, Angola and Indonesia exhibit similar cross-sectional characteristics displaying a skewness measure below 0.1 approximating normality. Simulating post-tax PVs at US$45/bbl results in skewness for NCS (0.34) and Indonesia (0.31) converging to approximating those obtained for UKCS (0.33) and Egypt (0.35) respectively. Angola, however, shows a distinctive shift towards negative skewness -0.18 caused by extremely high progressive taxes for small fields in Angola -0.63. This effect is overridden for the Angolan sample where small field effects are compensated for by large field positive skewness.

To provide granularity I summarize pairwise field movements between key absolute descriptive metrics for each regime. Table 4.5 displays tests for differences in changes of stochastic simulation results for post-tax PV frequency distributions at three price intervals (US$22.5/bbl to US$90/bbl, US$45/bbl to US$22.5/bbl, US$45/bbl to US$90/bbl). Panels A and C display significant differences for all but one descriptive measure over the entire price range. Only kurtosis for concession regimes does not differ significantly if price moves from US$22.5/bbl to US$90/bbl (Panel A) and US$45/bbl to US$90/bbl (Panel C). Panel B displays signage representing directionality of absolute value changes relative to price movements. For changes in price from US$45/bbl to US$22.5/bbl, mean responses differ significantly for both regimes. Standard deviation and skewness differ significantly only for concession regimes. PSC regimes exhibit significant differences in kurtosis, a feature lifted out in Figure 4.2 for an post-tax PV frequency distribution of an Angolan field simulated at US$22.5/bbl and US$90/bbl. All mean responses in Table 4.5 display an increase in absolute value for an increase in price. The opposite trend holds for responses in standard deviation (with the exception of PSC fields in the price range from US$45/bbl US$22.5/bbl).

Table 4.4. Statistical Properties for Simulated Pre- and Post-Tax Present Value Frequency Distributions in Concession and PSC Regimes

Table 4.4 describes results extracted from 1266 simulated pre- and post-tax present value distributions for concession and PSC regimes at three price scenarios (US$22.5/bbl, US$45/bbl, US$90/bbl). Regime averages of descriptive statistic measures for distribution mean, standard deviation and distribution-width (maximum–minimum) are compared pre- and post-tax. Absolute differences and comparative ratios $\frac{\text{Post-Tax}}{\text{Pre-Tax}}$ are computed. Panel A examines descriptive stochastic measures for an oil price of US$22.5/bbl. Panel B and Panel C reflect the same analysis at prices of US$45/bbl and US$90/bbl respectively. Each panel in Table 4.4 reflects the arithmetic sample average for all concession (GoM, UKCS and NCS) and all PSC (ANG, IDO and EGY) regimes. Tables B.1 and B.2 in Appendix A provide detailed additional descriptive statistics for 633 post-tax PV simulations (country averages) of GoM, UKCS, NCS and Angola, Indonesia, Egypt.

Regime		Mean (US$M)	*SD* (US$M)	PV Distribution-Width Max-Min
		Panel A: Price of US$22.5/bbl		
Concession	Pre-Tax	762.47	121.79	864.80
	Post-Tax	204.15	46.85	331.60
	Difference	558.32	74.94	533.20
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	27%	38%	38%
PSC	Pre-Tax	1029.68	135.73	948.61
	Post-Tax	326.63	53.39	350.09
	Difference	703.05	82.34	598.52
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	32%	39%	37%
		Panel B: Price of US$45/bbl		
Concession	Pre-Tax	2375.18	243.66	1730.49
	Post-Tax	758.83	85.30	604.56
	Difference	1616.36	158.36	1125.93
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	32%	35%	35%
PSC	Pre-Tax	2610.40	268.39	1874.62
	Post-Tax	749.19	54.85	398.21
	Difference	1861.21	213.55	1476.41
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	29%	20%	21%
		Panel C: Price of US$90/bbl		
Concession	Pre-Tax	5615.09	489.31	3474.63
	Post-Tax	1839.46	171.54	1215.00
	Difference	3775.62	317.77	2259.63
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	33%	35%	35%
PSC	Pre-Tax	5854.14	536.05	3742.12
	Post-Tax	1343.93	99.42	741.49
	Difference	4510.21	436.63	3000.63
	$\frac{\text{Post-Tax}}{\text{Pre-Tax}}$	23%	19%	20%

Table 4.5. Statistical Properties of Absolute Stochastic Oil Field Price Responses – Overview for Concession and PSC regimes

In Table 4.5, Panel A describes the change of descriptive stochastic measures for a change in oil price in the range from US$22.5/bbl to US$90/bbl. Panel B and Panel C reflect the same comparisons at price changes from US$45/bbl to US$22.5/bbl and US$45/bbl to US$90/bbl respectively. Each panel in Table 4.5 reflects the arithmetic average for all concession (GoM, UKCS and NCS) and all PSC (ANG, IDO and EGY) regimes. Tables B.1 and B.2 in Appendix A provide detailed descriptive statistics for 633 post-tax PV simulations (country averages) of GoM, UKCS, NCS and Angola, Indonesia, Egypt. The existence of significant differences between descriptive measure changes with respect to price changes is verified through paired 2-tailed t-tests run at the field level. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

	ΔMean (US$M)	ΔSD (US$M)	ΔSkewness	ΔKurtosis
	Panel A: Price change from US$22.5/bbl to US$90/bbl			
Concession	1635.3178	124.6944	0.1176	-0.0380
	(0.0000)**	(0.0000)**	(0.0001)**	(0.3115)
PSC	1017.2980	46.0347	0.1449	0.6297
	(0.0000)**	(0.0001)**	(0.0138)*	(0.0008)**
	Panel B: Price change from US$45/bbl to US$22.5/bbl			
Concession	-554.6789	-38.4488	-0.1104	0.0385
	(0.0000)**	(0.0000)**	(0.0002)**	(0.3052)
PSC	-422.5592	-1.4561	-0.0374	-0.2560
	(0.0000)**	(0.7961)	(0.4573)	(0.0010)**
	Panel C: Price change from US$45/bbl to US$90/bbl			
Concession	1080.6389	86.2456	0.0072	0.0005
	(0.0000)**	(0.0000)**	(0.0146)*	(0.7488)
PSC	594.7388	44.5786	0.1076	0.3736
	(0.0000)**	(0.0000)**	(0.0005)**	(0.0059)**

Differences for Changes in Regime

Regime differences in absolute value responses of descriptive measures with respect to price changes are shown in Table 4.5. For ease of interpretation I aggregate prior country based absolute measures according to regime (Table 4.6). I test deterministic absolute present values and descriptive statistics under each price scenario 4.6. In Panels A and C significant differences between concessions and PSCs are observable for the 3rd and 4th moment of the post-tax present value frequency distribution functions. The exception is Panel B where kurtosis behaves similarly regardless of contract. With Table 4.6 I construct six charts to display the price varying relationship of deterministic and stochastic measures between contractual regimes in Figure 4.3.

The top left chart of Figure 4.3 displays the present value post-tax PV for both regimes at three price scenarios. Asset values increase with commodity price increases (Strong 1991). The absolute value of PSC assets is above the value for concession fields at US$22.5/bbl. The US$45/bbl price scenario sees convergence between these two average regime values. The linear post-tax increase of concession fields and the degressive response of PSC fields results in concessions having higher absolute value than PSC fields at US$90/bbl. This trend is emphasized in the ratio $\frac{\text{PostTaxPV}}{\text{PreTaxPV}}$ depicted in the middle graph of the left column. The progressive nature of production sharing in PSC contracts reduces the ratio significantly for an increase in price (for supporting numerical values see Table 4.7 Panel B and Panel C). Post-tax PV responses shown in the bottom left chart support the degressive PV response rate for PSC assets. This phenomenon is expected to become increasingly noticeable in the oil and gas industry under high oil prices. It is demonstrated that concession response rates increase above those of PSC regimes in the range US$45/bbl to US$90/bbl. Replicating the above response rates (analogous to delta hedging ratios) requires detailed oilfield asset price response data and information about the composition of company asset holdings. Specifically, calculating the second, third and fourth moments represented by standard deviation, skewness and kurtosis respectively are important risk attributes. The second moment is significantly different as regards its rate of change between price scenarios measured in Table 4.7. The top figure in the right column indicates the convergence in standard deviation as between concessions and PSCs as does the middle figure for skew-

Table 4.6. Comparison of Price Response Differences as between Concessions and PSCs

This table reflects a comparison of price response differences as between important valuation and risk measures for concession and PSC regimes. Panel A presents a combination deterministic present value results, descriptive statistics for stochastic simulations at a price of US$22.5/bbl. Panel B and Panel C reflect the same information for prices of US$45/bbl and US$90/bbl respectively. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

	Concession	PSC	t-test
	Panel A: Price of US$22.5/bbl		
Pre-Tax PV	762.64	1024.02	(0.3244)
Post-Tax PV	206.88	328.99	(0.1757)
Post-Tax PV (% of Pre-Tax PV)	27.13%	32.13%	
Mean	204.15	326.63	(0.1729)
SD	46.85	53.39	(0.5653)
SD (% of Mean)	23.00%	16.34%	
Skewness	0.28	0.15	(0.0071)**
Kurtosis	3.37	3.19	(0.0093)**
	Panel B: Price of US$45/bbl		
Pre-Tax PV	2375.52	2609.68	(0.7383)
Post-Tax PV	758.31	747.88	(0.9559)
Post-Tax PV (% of Pre-Tax PV)	31.91%	28.63%	
Mean	758.83	749.19	(0.9594)
SD	85.30	54.85	(0.0536)
SD (% of Mean)	11.21%	7.22%	
Skewness	0.39	0.19	(0.0000)**
Kurtosis	3.33	3.45	(0.0778)
	Panel C: Price of US$90/bbl		
Pre-Tax PV	5615.77	5854.42	(0.8810)
Post-Tax PV	1837.48	1332.29	(0.2104)
Post-Tax PV (% of Pre-Tax PV)	32.75%	22.94%	
Mean	1839.46	1343.93	(0.2204)
SD	171.54	99.42	(0.0206)*
SD (% of Mean)	9.29%	7.37%	
Skewness	0.40	0.30	(0.0489)*
Kurtosis	3.33	3.82	(0.0049)**

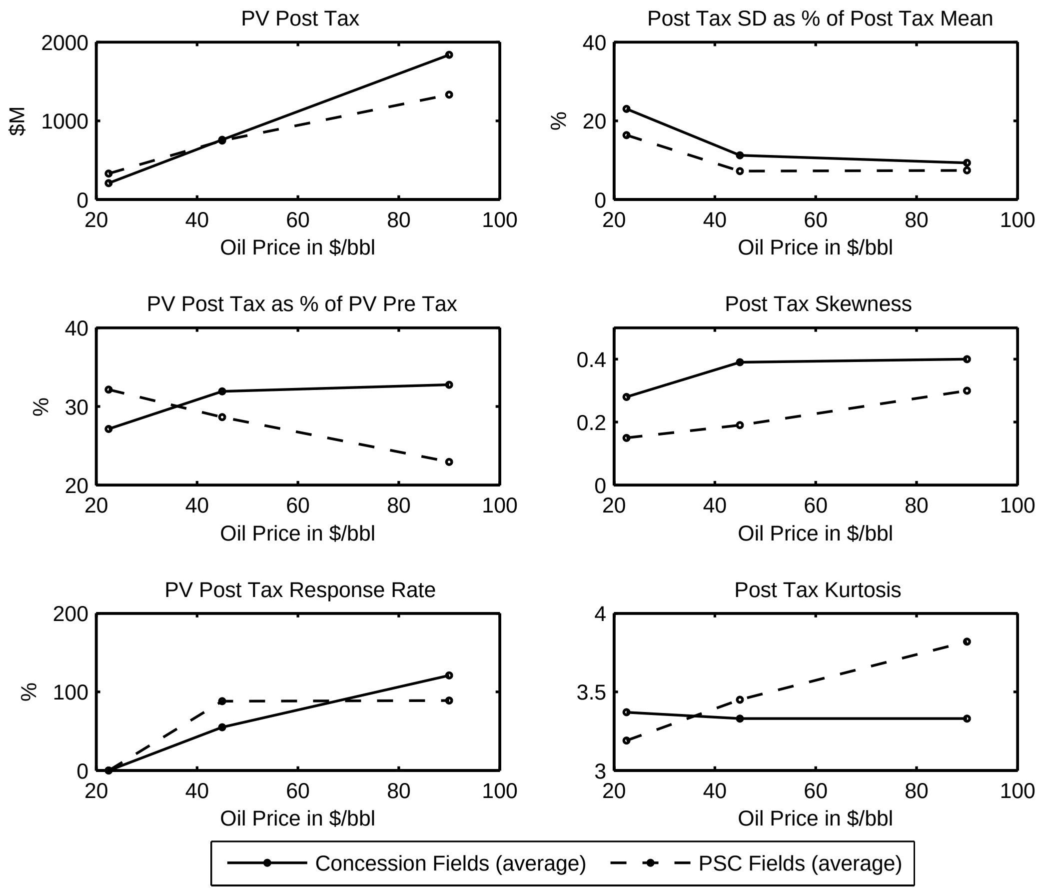

Figure 4.3. Summary of Concluding Findings for Deterministic and Stochastic Analyses

This figure compares concessions to PSCs over a consistent price range in all graphs and illustrates the range dependent specificity of deterministic and stochastic findings. To aid joint interpretation of price scenarios and price change intervals I connect results under each price scenario linearly. In the top graph of the left column the increasing average oilfield post-tax present values (in absolute $M) for the three price scenarios of US$22.5/bbl, US$45/bbl and US$90/bbl on the x-axis are described. The center graph of the left column shows the decreasing average post-tax PV percentage characteristic of reduced production entitlement in progressive tax PSCs (increase for linear tax concession regimes) as a percentage of pre-tax PV. The bottom left graph illustrates the oilfield post-tax price response rate. The right hand column depicts key stochastic data. The tightening range of post-tax standard deviations as a percentage of post-tax means is reflected in the top graph. The chart in the center right shows the increasingly positive skewness for both regimes as prices increase (as cost structures are covered). Finally, in the bottom right corner the crossover in kurtosis response for increasing prices is reflected.

ness (except for the price range US$45/bbl to US$90/bbl where significant differences are observable). The positive skewness measured in the middle figure occurs as fields 'overcome' their underlying cost structures indicating a higher likelihood of achieving mean present value. In the bottom right chart, the most telling kurtosis difference between regimes is observable. The progressive nature of PSC regime taxation occurs at US$90/bbl with production sharing on price upside and reserve recoupment by the operator on price downside. Panels A and C in Table 4.6 illustrate that this relation is significant. Table 4.7 shows with high significance that the same relation holds for price responses.

Table 4.7. Comparison of Price Response Differences as between Concessions and PSCs

This table isolates price response differences as between important valuation and risk measures for concession and PSC regimes. Panel A presents a combination deterministic present value price response changes and changes in descriptive statistics for stochastic simulations for a change in price from US$90/bbl to US$22.5/bbl. Panel B and Panel C reflect the same information for price changes from US$45/bbl to US$22.5/bbl and US$45/bbl to US$90/bbl respectively. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

	Concession	PSC	t-test
Panel A: Price change from US$22.5/bbl to US$90/bbl			
Δ Pre-Tax PV	1.88	1.46	(0.3211)
Δ Post-Tax PV	2.27	1.03	(0.2329)
Δ Mean	2.30	1.05	(0.0729)
Δ *SD*	0.94	0.48	(0.0007)**
Δ Skewness	0.36	0.50	(0.6726)
Δ Kurtosis	0.25	0.31	(0.0005)**
Panel B: Price change from US$45/bbl to US$22.5/bbl			
Δ Pre-Tax PV	0.64	0.78	(0.0014)**
Δ Post-Tax PV	0.55	0.88	(0.0499)*
Δ Mean	0.54	0.87	(0.2780)
Δ *SD*	1.10	1.95	(0.0000)**
Δ Skewness	1.43	1.60	(0.2080)
Δ Kurtosis	2.02	1.85	(0.0006)**
Panel C: Price change from US$45/bbl to US$90/bbl			
Δ Pre-Tax PV	1.18	1.12	(0.0746)
Δ Post-Tax PV	1.21	0.89	(0.0037)**
Δ Mean	1.21	0.90	(0.0320)*
Δ *SD*	1.01	0.91	(0.0079)*
Δ Skewness	0.51	0.79	(0.0011)**
Δ Kurtosis	0.50	0.55	(0.0059)**

4.5. Chapter Concluding Remarks

This study uses deterministic and stochastic analyses of oilfields to refine the low oil price paradigm covered in prior valuation and risk studies. I note that research works performed by Haushalter et al. (2002) and Jin and Jorion (2006) relate to a period when oil prices range between US$18/bbl and US$35/bbl. Their studies specifically cover the years 1992 to 1994, and 1998 to 2001 respectively, periods comparable to the US$22.5/bbl to US$45/bbl price range in this study. Findings are therefore likely to remain valid but limited to oil prices in this range.

I add context to the participation study by Stulz (2005). The conclusion is that country specific oilfield contractual terms cause divergent and heterogenous asset valuation and risk responses to oil price movement. Based on this chapter, I suggest that the country and risk and valuation findings for low prices may not hold under higher oil prices. Indeed, high oil price effects go so far as to invert the valuation and risk relationship between PSC and concession countries for key valuation and risk metrics. I show that at low oil prices, US$22.5/bbl, post-tax present values for PSC oilfields are higher than for concession fields. Additionally, oil prices in the range US$45/bbl to US$90/bbl cause the metrics of: present value response, post tax absolute value, the percentage of post-tax relative to pre-tax and kurtosis to invert when compared to identical metrics between US$22.5/bbl and US$45/bbl. My findings combine the industry emphasis of Cavaglia et al. (2000) with the country factors favored Stulz (2005). I suggest that detailed information about industry specific entitlement terms and the geographical location of resource holdings is necessary for an accurate valuation of global natural resource assets.

5. Longitudinal Asset Risk

Chapter Research Focus

This chapter extends the previous – oil price shocks are shown to cause shifts in the timing and quantum of risks in physical Oil and Gas (O&G) assets. I provide evidence that time-unbounded risk measures understate the periodicity of price risk implicit in depleting assets.

Overview

This chapter was informed by a HBOS consultancy. The question asked by the risk team was whether they should hedge by selling forward all production over the traditional 5 year period, or whether it is preferable to construct a rolling three year hedge. Hedging Information recovery is demonstrated to be regime specific and varies heterogeneously in response to the combined effects of oilfield entitlement contracts and price shocks. Timing effects embodied in oilfield entitlement contracts cause asset cash flows, volatility horizons and minimum variance hedge ratios to vary in response to oil price. I conclude that the timing of physical O&G asset risk factors is unable to be directly recovered from market oil prices. Temporal variance for physical assets is shown to be a hidden dimensional outcome of price risk and that rolling hedge construction is optimal.

5.1. Background

Asset valuation in the oil and gas sector is a function of the risks and rewards associated with future reserve entitlement. As noted earlier, this accepted oil industry view fits neatly with the body of theory that holds that 'finance is about the valuation of cash flows that extend over time and are usually uncertain' (Ross 2005). The empirical study of temporal linkages between risk, return, and entitlement for physical assets extends the prior chapter's cross sectional work on the same sample. Difficulties in linking risk, return and time have, in prior studies, been ascribed to differences in global regulatory operating environments (Bekaert and Harvey 2002) and discontinuous information flows (Geman et al. 2001). I show that for physical oil and gas (O&G) assets, both are relevant. Oil and gas physical asset risks are increasingly associated with the relationship between oil prices and operator reserve entitlement contracts. Geman et al. (2001) suggest that continuous market prices accurately, instantaneously and continuously equilibrate to information flows, a behavior that I suggest does not extend to physical assets. The existence of two very different forms of reserve ownership, production sharing and concessions, are shown to result in oil reserve entitlement profiles that respond very differently to oil price variability (Kretzschmar et al. 2007). I demonstrate that physical asset responses to oil market prices depend on hidden contractual field tax terms that are not continuous.

This empirical study supports hidden time work by Geman et al. (2002, p.73) who seek to "discover the law of the time change conditional on the observation of the composite process". Detailed global oilfield data are used to show that variance minimizing hedges depend on ex ante contractual field parameters which are unobservable, analogous to hidden hedging effects identified by Sercu and Wu (2000). Undisclosed oilfield contract terms are shown to cause changes in cash flow timing. In O&G studies, the composite oilfield asset valuation process depends on the relationship between revenue, operating expenses, capital expenditure and "government take". I note that global tax take terms vary, and that the asset response to price shocks is not a constant function with respect to taxation (Kretzschmar and Moles 2006). I show that price shocks interact with producer entitlement contracts to cause shifts in the quantum and timing of oilfield cash flow response. Unlike the general Geman et al. (2002) recovery problem, hidden time changes in physical O&G assets are shown to be contractual and oil price dependent.

For producing oil assets, the past is different from the future for two simple reasons. First, the asset depletes as oil is extracted. Second, recent work suggests that since 2000, there has been a structural shift in global energy markets. The result is that mean reversion models by Bessembinder et al. (1995) will increasingly need to coexist with random walk pricing behavior (Geman 2005). I accommodate this using findings from the cross-sectional study in chapter 4 using stochastic simulation. I isolate the temporal effects of price changes with all other factors equal. Backward looking delta regressions are inappropriate for depleting physical assets. I suggest that price based delta hedging programmes cannot ignore the interaction of oil prices with oilfield asset contracts. I propose that forward looking delta rules require a detailed analysis of the price response attributes for underlying assets. In this study, whole–life field cash flows are subject to market risk at the field level surrogated by subjecting fields to differing levels of oil price. Detailed field data are used to calculate field cash flows at oil prices of US$45/bbl, US$22.5/bbl and US$90/bbl. I isolate periodicity of oil price effects on the oilfield asset cash flows. The oilfield focus of this study isolates discrete annual payoff changes in cash flow quantum, timing, standard deviation and hedge ratios.

This empirical asset risk study is underpinned by detailed data for 211 producing oilfields. I use an asset-up approach to demonstrate that, at the oilfield level, oil price variability is capable of affecting both the quantity and the timing of risk. Oilfield responses are shown to differ depending on the field entitlement structure. Differential oilfield cash flow responses are shown to be a composite function of oil price and entitlement regime. In this study, I lift out an added dimension of oil and gas risk; time. Natural resource assets deplete over time and risk measures lack the defining attribute of an indefinite period going concern assumption. This finite life limitation requires a time-bounded view of risk. Time boundaries allows an isolation of the quantum and timing of risk measures caused by oil price variability acting in concert with field entitlement structures. I use this framework to provide evidence that oil price shocks cause temporal and quantitative shifts in oil and gas sector asset risks.

5.2. Why Temporal Risk Matters in O&G Assets

O&G sector settings facilitate the isolation and study of risk measurement (Jin and Jorion 2006). Following Moshirian and Szegö (2003), the management of global risk variance is set to become more prevalent. Oilfield assets are subject to differential taxation and diverse state participation regimes but homogenous commodity price shocks and therefore are well suited for the study. An ex ante analysis of whole-life field cash flow entitlement describes timing adjustment and shifts in rolling hedge ratios in response to oil price shocks.

Table 5.1. Description of Randomly Selected Stratified Sample by Regime and Country

This table describes the sample selection for 211 producing oilfields. The percentage of total field population is calculated relative to the total number of available producing fields per country. The table additionally reports total reserves and total remaining reserves on an average country level. The ratio $\frac{\text{Remaining}}{\text{Total}}$ represents a proxy for the stage of maturity for the average oilfield on a country and regime level.

	Number of Observations	% of Field Population	Avg. Reserves per Field (mmboe) Total	Remaining	$\frac{\text{Remaining}}{\text{Total}}$
Gulf of Mexico	31	32%	98.29	55.94	57%
UK Continental Shelf	43	27%	160.69	55.98	35%
Norwegian Continental Shelf	29	43%	790.28	345.35	44%
Concessions	103		314.55	135.40	43%
Angola	29	100%	359.77	297.94	83%
Egypt	36	88%	404.08	150.45	37%
Indonesia	43	91%	522.14	254.80	49%
Production Sharing Contracts	108		439.19	231.60	53%

5.3. Longitudinal Oilfield Analysis

5.3.1. Oilfield Cash Flow Analysis

Comparative longitudinal analyses of oilfield cash flows and related risk risk measures are performed. Analyses of timing and quantity of cash flow risk measures are based on the oilfield asset data used in the previous chapter. [1] Annual net field cash flows are extracted for the whole field life as at January 2006.

For this analysis I select a sample of producing oilfields consistent with the stratified random sample used in chapter 4. Table 5.1 describes the sample selection for 211 producing oilfields. The analyzed fields' stage of development and their maturity are approximated in Table 5.1 as a percentage of remaining reserves relative to total reserves.

I extend the previous whole–life oilfield study by computing and extracting underlying forward looking annual field cash flow data. This is in line with the evidence provided by Sercu and Wu (2000) who highlight the superior performance of forward

[1] Appendix A, Tables A.2 and A.3 show a single-field example of the data available for each oilfield under analysis.

looking price-based risk measures, in their case hedge ratios, over regression-based estimates computed from historic data. For the longitudinal analysis I derive annual field cash flows from the field model (5.1) developed in chapter 4:

$$CashFlow_t = Price_t \times Production_t - OPEX_t - CAPEX_t - Tax_t \tag{5.1}$$

Tax calculations are field specific and of time- and value-discrete nature, annual future production and costs are determined based on operators' estimates. For concession fields, production entitlement remains unaffected by changes in oil price. Entitled production for PSC fields, in turn, is affected by oil price as contractually agreed shares of remaining profit (*ProfitOil*) after costs recovery (*CostOil*) vary with price and tax regime (Bindemann 1999).

The longitudinal analysis is focused on temporal and quantitative shifts in the response of oilfield cash flow and corresponding risk measures to oil price changes. For each sample oilfield, series of relevant annual cash flows are obtained by evaluating (5.1). To lift out differential effects of oil price changes on field cash flow, each oilfield is subjected to a price down-shock (−50%) and a price up-shock (+100%) relative to a benchmark price of US\$45/bbl. In absolute price terms, the following three different initial oil price scenarios (5.2) are computed.

$$Price = \{\text{US\$22.5/bbl, US\$45/bbl, US\$90/bbl}\} \tag{5.2}$$

In weak-form efficient oil and gas markets, participants translate all publicly available continuous time information flows into market oil prices reflecting corresponding risk and return characteristics (Ross 2005). The underlying oil price model incorporates findings by Bessembinder et al. (1995) and approximates mean reversion in oil prices over a short time horizon.[2] Geman et al. (2002) provide extended insights into financial pricing models and target composite valuation processes. When empirically analyzing

[2]A single field example in Appendix A, Table A.2, Columns 6 to 8, shows how prices drop from the initial price scenario to a floor over the next few years before they mean revert with a linear increase following an inflation assumption of 2.5% (see Figure 5.1). Capital expenditure (*CAPEX*), operational costs (*OPEX*) and taxes (*TAX*) are also obtained from operators' estimates on an annualised basis as described in Appendix A, Table A.2.

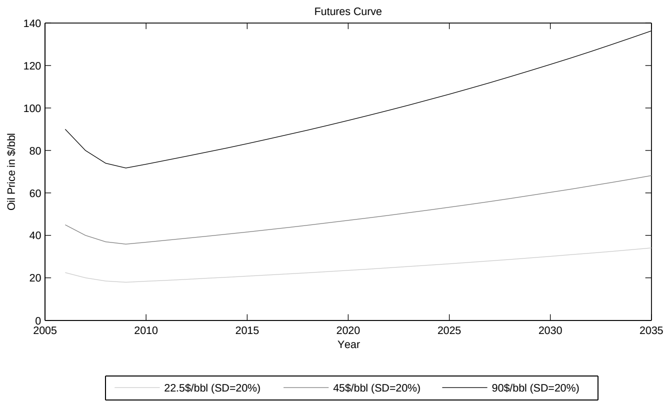

Figure 5.1. Field Model Implied Forward Curve

This figure illustrates the movement of the model implied oil forward price derived from the field data. Deterministic mean reverting annual prices are quoted for the three different price scenarios at initial prices of US$22.5/bbl, US$45/bbl and US$90/bbl incorporating findings by Bessembinder et al. (1995). Exemplary longitudinal prices for the corresponding price scenarios are described in Appendix A, Table A.2, Columns 6, 7 and 8.

oilfields, I evaluate the response of real assets to price shocks. Oilfields as commodities comprise exposure to different factors influencing asset value. Physical characteristics as finite field life (as opposed to the 'going concern' assumption when dealing with entities) and stages of development, extraction costs and differential tax regimes are important factors constituting a composite oilfield valuation process. However, most asset characteristics are not directly recoverable from market oil price information. Following theoretical insights into this "recovery problem" provided by Geman et al. (2002), I provide empirical evidence that unrecovered hidden factors in composite processes introduce random variation which is likely to cause temporal and quantitative shifts in cash flow and risk measures.

5.3.2. Longitudinal Cash Flows Minimum Variance Hedge Ratio

I analyze series of discrete cash flows over selected time intervals at the individual field level which isolates the effects caused by stage of development of the oilfield under observation. Analyses of longitudinal cash flows, cash flow standard deviation and hedge ratios address different interests of operators, risk managers and financiers. I examine annual net cash flows for oil producers with differential asset holdings as between concession and production sharing contracts. Real asset holdings with finite life time have however, implications on model selection. Oilfield life-cycle specific expenditures add field cash flow idiosyncracies, thus causing difficulties in measurement. The longitudinal characteristics of operational costs, capital expenditures and taxation are described in Appendix A, Table A.2, Column 11 to 24. Initial *CAPEX* requirements at the beginning and abandonment costs at the end of the field life adversely affect the magnitude of cash flow. Cash flow behavior is linked to different stages of field life. When comparing fields cross-sectionally at certain points in time incompatibilities arise as high negative cash flow peaks are caused by initial field development and final abandonment. Field specificities violate stationarity constraints on the basis of logarithmic differences for autoregressive time series and volatility models which inform model selection, and preclude models from the GARCH model family (Gourieroux 1997).

Also, time varying changes in amplitude and temporal occurrence of variable responses to price changes are interpreted. I compute time varying minimum variance hedge ratios to support the implementation of a sequence of selective hedges over a specified time horizon in field life. Brealey and Kaplanis (1995) highlight the importance of boundaries for hedge ratios. In the context of this study, I build on insights provided by Brealey and Kaplanis (1995) and define time-unbounded risk measures as minimum variance hedge ratios over the whole field life, approximated by a 30 year discrete time interval. Time-bounded hedge ratios, in turn, are represented by sequential five year forward looking discrete intervals and semi-time-bounded three year forward looking sliding windows. I am guided by James (2003) in selecting a sliding window based on futures contracts that are traded up to 36 months in the case of Brent Crude Futures and 30 consecutive months for WTI Light, Sweet Crude Futures. Field life in the sample extends from 3 to 30 years and I calculate 3 year rolling measures for volatility and hedge ratios in line with the time frames of frequently traded futures contracts. For financier insights, who are exposed to discrete time period risk during the field's stage of life, sequential 5 year discrete financing periods are applied and contrasted to rolling hedges.

The objective is to illustrate the time variant characteristics of hedging at the oilfield asset level. I derive minimum variance hedge ratios for one unit (in US$M) of spot position at price S_t and $\beta^*_{t_0}$ units of futures contracts at price F_t (in \$). The futures price F_t is assumed being equal to the mean reverting futures price assumption implicit in the field model and incorporates insights by Bessembinder et al. (1995). These model implied futures prices (see Figure 5.1) are derived from the field data (see example in Appendix A, Table A.2, Columns 6, 7 and 8) reflecting the three different price scenarios respectively. For ease of interpretation, futures prices are treated as a certain occurrence and are assumed to be equated by the spot oil prices. With the objective of hedging oilfields at the asset level, the derived spot oil price is applied to the oilfield valuation model. The model overlays the individual oilfield's production profile, cost structure and the regime-dependent fiscal structure (*OPEX, CAPEX, TAX*) and sets the spot position S_t equal to the annual post-tax field cash flow with $S_t = CashFlow_t$.[3]

Following Brooks et al. (2002) and Hull (2006) I describe the conditional expected return $E(R_t)$ of the hedged position at time t_0 by

$$E_{t_0}(R_t) = E_{t_0}(S_t - S_{t_0}) - \beta_{t_0} E_{t_0}(F_t - F_{t_0}) \tag{5.3}$$

and the corresponding variance of the hedged position σ^2_{SF} by

$$\sigma^2_{SF,t} = \sigma^2_{S,t} + \beta^2_{t_0}\sigma^2_{F,t} - 2\beta_{t_0}\rho_{SF}\sigma_{S,t}\sigma_{F,t} \tag{5.4}$$

with ρ_{SF} representing the Pearson's product-moment correlation coefficient between the spot and the futures position. Maximizing the expected returns with a given degree of risk aversion ψ is characterized by the maximization of the two-moment utility function in (5.5)

$$\max U(E_{t_0}(R_t), \sigma^2_{SF,t}) = E_{t_0}(R_t) - \psi\sigma^2_{SF,t} \tag{5.5}$$

[3] Cash flows are calculated in US$M (spot position). To match the units of spot with the those of futures contracts quoted in \$, hedge ratios are calculated based on 10^6 units of futures contracts.

With (5.3) and (5.4) I solve for the conditional minimum variance hedge ratio $\beta^*(t_0)$ according to Brooks et al. (2002)

$$\beta^*(t_0) = -\frac{\mathrm{cov}_{SF(t_n)}}{\sigma^2_{F(t_n)}} \tag{5.6}$$

with $\mathrm{cov}_{SF,t}$ representing the conditional covariance between spot and futures price and $\sigma_{F,t}$ the conditional variance of the futures price within the following sequential intervals and rolling ranges

$$\text{30 year discrete hedge} \quad t = (t_0, t_n) = \{(1, 30)\} \tag{5.7}$$

$$\text{5 year discrete hedges} \quad t = (t_0, t_n) = \{(1, 5), (6, 10), \ldots, (26, 30)\} \tag{5.8}$$

$$\text{3 year rolling hedges} \quad t = (t_0, t_n) = \{(1, 3), (2, 4), \ldots, (28, 30)\} \tag{5.9}$$

Minimum variance hedge ratios are derived continuously as proven for example by Hull (2006, p.73). Analyzing real assets however, means that assets are exposed to limited field life – as opposed to 'going concern' for a corporate entity. Also, time- and value-discrete taxation applies to physical oilfield assets. To isolate timing and quantity of risk exposure, I focus the analyses in the following section on sequential 5 year discrete and 3 year rolling measures.

5.4. Regime Effects on O&G Asset Value Responses

This section specifically examines the temporal nature of risk by disaggregating whole–life oilfield present values of producing fields in annual cash flows. Risk measures allocated into 5 year discrete and 3 year rolling time periods are derived from time discrete cash flows series at prices of US$22.5/bbl, US$45/bbl and US$90/bbl. As Ross (2005) notes, the starting point in asset valuation is an estimation of future attributable cash flows and their risks. Insights in these two measures are undertaken in Table 5.2 where observations for concessions and PSCs are analyzed by regime and country.

5.4.1. Asset Cash Flow – Response to Price Shocks (Benchmark US$45/bbl)

First, I analyze price variant average annual cash flows on a country and regime level. As described in Table 5.2 cash flows (over whole field life) are highly responsive to changes in oil price with concessions increasing from US$M 6.59 at US$22.5/bbl to US$M 31.92 at US$45/bbl to US$M 80.23 at US$90/bbl. This change represents a 12.1 times increase in average cash flow for a four times price increase. For PSCs the average cash flow response is distinctively lower with a move from US$M 23.57 to US$M 47.83 ending at US$M 83.19 for comparable prices, a 3.6 times increase. At the sample overview level, concession fields demonstrate a negative cash flow at US$22.5/bbl in the period 2021 to 2025. Insights into temporal movements become apparent when oil price increases cause negative annualized cash flows to shift into future discrete periods. In Table 5.2 this is demonstrated by a five year period shift in negativity for concession fields from years 2021-2025 to years 2026 to 2030. This shift is caused solely by a price movement from US$22.5/bbl to US$45/bbl, no time shift occurs for a change in price to US$90/bbl. For PSCs the effect is also interesting in that negative cash flows occur in the period 2026 to 2030 at US$22.5/bbl but negativity does not recur at higher price levels.

Temporal insights displayed in Table 5.2 suggest that regime specific price response insights should become a feature of risk analysis in oil and gas. Following findings by Geman et al. (2002), I show that regime dependent price responses are an integral

Table 5.2. Country and Regime Cash Flows Annualised

Panel A illustrates in the first column the 1 to 30 year annualized time bounded field cash flows on an average country and regime level for an oil price of US$22.5/bbl. In the following columns, this cash flow is disaggregated to six sequential discrete intervals of 5 years each. Panel B and Panel C reflect the same analysis for prices of US$45/bbl and US$90/bbl respectively. Absolute figures are presented in US$M.

	2006–2035	2006–2010	2011–2015	2016–2020	2021–2025	2026–2030	2031–2035
			Panel A: Price of US$22.5/bbl				
GOM	11.9257	32.4679	28.6074	9.6017	1.3959	-0.0312	-0.4878
UKCS	5.7835	30.4025	10.2213	-0.4102	-3.7027	-1.8097	0.0000
NCS	1.9337	41.0730	52.8058	4.4808	-20.5539	-48.1465	-18.0569
CON	6.5934	33.9594	27.4991	3.9753	-6.7789	-13.9891	-5.1051
ANG	50.1444	24.1895	183.7118	86.6291	19.5364	-9.9239	-3.2764
IDO	14.0604	22.3258	28.6759	18.6398	13.0859	0.9999	0.6352
EGY	13.5475	30.1017	22.4725	15.8474	10.2003	1.9356	0.7274
PSC	23.5787	25.4182	68.2381	35.9654	13.8561	-1.6214	-0.3844
			Panel B: Price of US$45/bbl				
GOM	31.7985	98.2298	64.9669	22.4299	4.3815	1.0421	-0.2591
UKCS	21.5777	84.0172	35.4304	9.3743	1.6044	-0.9601	0.0000
NCS	47.9552	190.3121	116.5787	42.3737	-3.2319	-40.5266	-17.7750
CON	31.9249	117.5157	66.6832	22.4008	1.1208	-11.2130	-4.9582
ANG	87.3322	170.2239	243.7136	91.4362	28.6354	-6.7394	-3.2764
ID	37.9079	65.5144	69.9851	48.0803	32.6901	9.5201	1.6573
EGY	27.8678	66.4857	43.9684	30.9208	20.8849	3.9347	1.0125
PSC	47.8326	93.9546	107.9622	54.0023	27.6663	3.2923	0.1176
			Panel B: Price of US$90/bbl				
GOM	71.2185	227.6314	138.1405	48.0506	10.3524	3.0748	0.0614
UKCS	52.6682	195.1059	84.1409	27.5835	9.5087	-0.3298	0.0000
NCS	132.5252	479.4397	234.5688	109.8839	25.1070	-36.6367	-17.2111
CON	80.2276	283.0435	141.8465	56.3961	14.0470	-9.2617	-4.7060
ANG	113.2619	305.6589	257.8702	90.9740	33.2920	-4.9471	-3.2764
IDO	86.3088	151.9608	150.1170	114.4477	75.9464	22.5826	2.7983
EGY	55.2551	128.4926	86.2019	62.8089	43.4546	8.4733	2.0993
PSC	83.1950	185.4089	157.7457	90.9316	53.6623	10.4873	0.9341

part of the composite oilfield valuation process. Regime characteristics are, however, unrecoverable from oil price information and induce variation in cash flow timing and quantity. In the following paragraph, I use discrete and rolling standard deviation risk measures to lift out the importance of price shocks on the timing of underlying asset cash flows.

5.4.2. Asset Standard Deviation – Response to Price Shocks (Benchmark US$45/bbl)

Secondly, I analyze price variant average annual standard deviations. I measure this as a percentage of mean and in absolute values on a country and regime level. Interesting insights are provided into price induced relative standard deviation movements. For concessions, these movements occur from a standard deviation measure of 3.67 (US$22.5/bbl) to 1.51 (US$45/bbl) to 1.38 (US$90/bbl). For PSCs the move is less, from 1.14 to 0.94 to 0.89, approximately half the reduction in standard deviation experienced by concession fields when calculated on the approximated whole field life of 30 years.

It is instructive to analyze the differences in standard deviations for changes in price. The price effect on the discrete oilfield cash flow standard deviation is significant across all countries for all price changes with the exception of Norway form US$22.5/bbl to US$45/bbl and Angola from US$45/bbl to US$90/bbl (Table 5.3). Approximately the same behavior holds for the three years rolling standard deviation except that the rolling measure smoothes the differences for Norway at US$45/bbl to US$90/bbl.

After t-tests for differences in standard deviation with respect to price changes I now test for difference between concession and PSC regimes (Table 5.4). Sequential 5 year discrete standard deviation and 3 year rolling standard deviation are investigated for the three different price scenarios. For 5 year discrete risk exposure in the oil and gas sector I observe significant differences in cash flow standard deviation between regimes for two price scenarios, US$22.5/bbl and US$90/bbl. This has direct implications for current trading conditions in oil and gas commodity markets where prices are trading in the range US$45/bbl to US$90/bbl, precisely the range for which I expect to see specific differences emerge between concession and PSC oilfield assets. For all three

Table 5.3. Test for Difference in Cash Flow Standard Deviation for Variations in Price (5 Year Discrete and 3 Year Rolling)

This Table highlights the expectation that cash flow SD would differ from one price scenario to another (US$22.5/bbl to US$45/bbl, US$45/bbl to US$90/bbl). The objective is to isolate the standard deviation of cash flows at comparable points in time under different prices. Tests for differences (t-tests for difference in mean with adjustments for heteroscedasticity) are conducted at the individual field level. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

	5 Years Discrete SD		3 Years Rolling SD	
	$22.5/bbl to $45/bbl	$45/bbl to $90/bbl	$22.5/bbl to $45/bbl	$45/bbl to $90/bbl
GOM	(0.0000)**	(0.0000)**	(0.0000)**	(0.0000)**
UKCS	(0.0188)*	(0.0000)**	(0.0374)*	(0.0005)**
NCS	(0.1195)	(0.0033)**	(0.8092)	(0.0509)
CON	(0.2936)	(0.0005)**	(0.7033)	(0.0052)**
ANG	(0.0060)**	(0.0428)	(0.0470)*	(0.2851)
EGY	(0.0000)**	(0.0000)**	(0.0000)**	(0.0000)**
IDO	(0.0000)**	(0.0000)**	(0.0003)**	(0.0000)**
PSC	(0.0022)**	(0.0013)**	(0.0202)*	(0.0092)**

price scenarios, no significant differences between regimes are evident for the 3 year rolling standard deviation. This suggests that the 3 year rolling measure does not trap the periodicity of risk exposure.

5.4.3. Oilfield Asset Value Risk – Response to Price Shocks (Benchmark US$45/bbl)

When cash flow insights (Figure 5.2, top left and right graph) are pulled together with standard deviation calculations (middle two graphs) the combination reflects the price response relation between concession and PSC regimes. It is apparent in the top left graph that price plays a significant effect in post tax cash flows for concession fields, with cash flows increasing across the entire time series if prices increase. The cash flows of concessions and PSCs at US$45/bbl shows a similar concave curvature. For an oil price of US$90/bbl, however, the tax terms applicable to concession regimes allow producers to participate in the upside of the field at higher prices. This results in

Table 5.4. Test for Difference between Concession and PSC Regimes in 5 Year Discrete SD and 3 Year Rolling SD for Three Price Scenarios

This Table highlights the expectation that cash flow SD would differ from one regime to another (Concession and PSC). The objective is to isolate the standard deviation of cash flows at comparable points in time under different prices. Tests for differences (two-sided t-tests with adjustments for heteroscedasticity) are conducted at the individual field level. Significance at a 95% level is indicated by *, at a 99% level by ** respectively; p-values are quoted in parentheses.

Price	5 Years Discrete SD	3 Years Rolling SD
US$22.5/bbl	(0.0034)**	(0.8402)
US$45/bbl	(0.0823)	(0.5986)
US$90/bbl	(0.0075)**	(0.1168)

a change in shape to a convex cash flow profile for concession fields. The progressive nature of PSC taxation, however, results in upward parallel shift across the entire curve.

What is notable for concession fields in the middle left graph of Figure 5.2 is that the cash flow standard deviation maximum shifts. At US$22.5/bbl and US$90/bbl, the maximum is found in the first 5 year period. The maximum, however, shifts to the period 2011-2015 at US$45/bbl. This is indicative of the price varying relation between revenue and field costs in oil and gas assets. The oil price effect on PSC field standard deviation is indicated in the middle right chart of Figure 5.2. It is observable that the PSC cash flow standard deviation maxima shift different compared to concessions. The maximum at prices of US$22.5/bbl and US$45/bbl is evident in the first 5 year period. Shifts to the period 2011-2015 occur at US$90/bbl. This comparative analysis demonstrates the price varying relation between concession and PSC oil and gas asset behavior.

In the bottom left chart in Figure 5.2 I show the rolling 3 year cash flow standard deviation for concession fields. Cash flow standard deviation now moves within a sliding window time frame, as distinct from being constraint within a fixed period of discrete 5 year standard deviation. This characteristic is apparent in the graphical representation of 3 year rolling cash flow standard deviation in Figure 5.2. Concession regimes experience rolling standard deviation at US$22.5/bbl and US$90/bbl and two

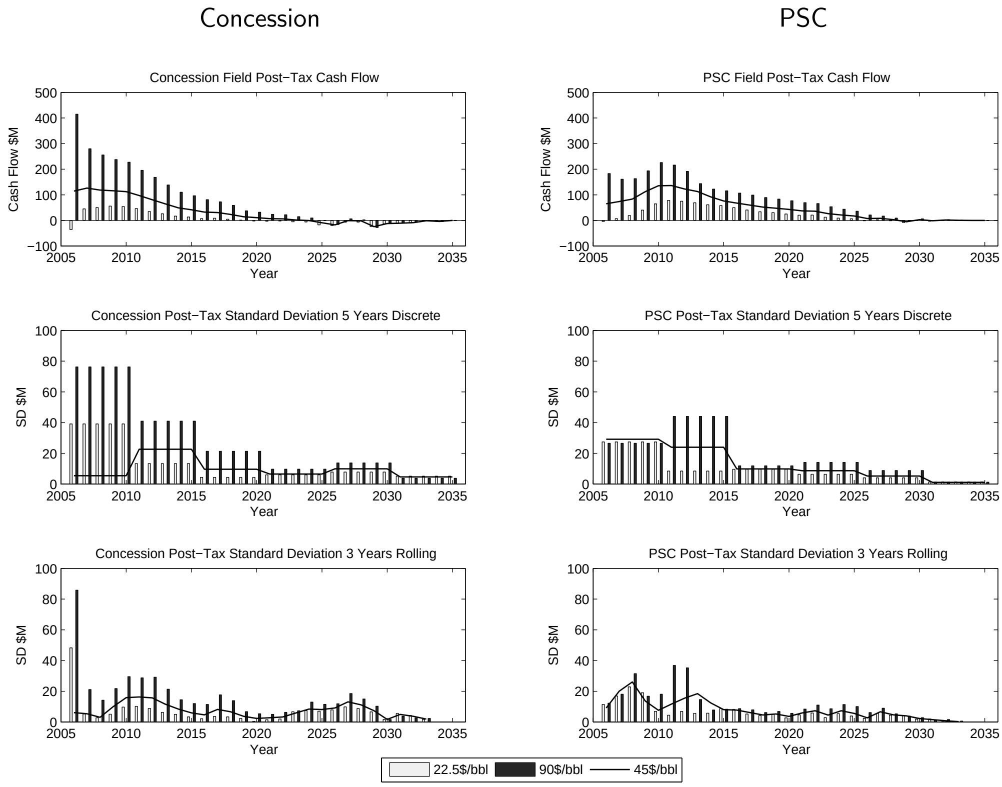

Figure 5.2. Cash Flow and Standard Deviation 5 Years Discrete Sequentially and 3 Years Rolling for Three Different Price Scenarios (US$22.5/bbl, US$45/bbl, US$90/bbl)

The top graph in the left column reflects concession field post-tax cash flows. The center left graph illustrate the concession post-tax standard deviation for six sequential 5 year discrete intervals. The bottom left chart shows 3 year rolling standard deviation calculated on the same underlying cash flow data. All measures are computed for the three different price scenarios (US$22.5/bbl, US$45/bbl, US$90/bbl). The right column reflects the same analyses for PSC regimes. Absolute figures are presented in US$M. Cash flow and standard deviation responses to price shocks (US$22.5/bbl, US$90/bbl, shaded and solid bars) are shown relative to the benchmark of US$45/bbl (solid black line).

later sets of variation at US$45/bbl. PSC regimes, in turn, indicate early SD for the US$45/bbl cash flow and ad-hoc rolling volatility at US$90/bbl and US$22.5/bbl.

The distinction between the trapped discrete standard deviation for the 5 year measure in that for the 3 year rolling is an important characteristic for depleting natural resource assets. For 'going concern' assets it is unlikely that commodity price volatility would affect entity cash flows in the same way, cash flows are expected to continue in perpetuity.

The combination of longitudinal oilfield price response (Panels A, B, C in Table 5.2; Figure 5.2, top two graphs) and time variant standard deviation measures (Figure 5.2, bottom four graphs) has considerable implication for valuation of assets in the oil and gas sector. I provide evidence that finite life physical assets have characteristics that causes heterogenous asset price response behavior. Market oil prices incorporate continuous flows of information available to market participants. Discrete annual oilfield production profiles, field costs and tax terms, however, are not recursively recoverable from oil price. Linking these results to research by Geman et al. (2002) I expect hidden asset response factors to translate into a necessary implementation of divergent risk management strategies. To investigate this expectation, I compute sequential 5 year discrete and sliding 3 year minimum variance hedge ratios.

5.4.4. Time Varying Hedge Ratios – Response to Price Shocks (Benchmark US$45/bbl)

The drivers of return (cash flows) and risk (standard deviation), are combined to compute hedge ratios. The calculations are performed using the minimum variance hedge ratio derived in Section 5.3, based on the initial model of expected risk and return as described in (5.3). Equation (5.6) solves for the minimum variance hedge ratio $\beta^*(t_0)$, representing the optimal number of futures contracts. This amount minimizes the variance of the total hedged position as described by (5.4) under the objective function of total return maximization (5.5). This relation holds, proven by Hull (2006, p.73).

As described in Section 5.3, Figure 5.1, the futures price is treated as a certain occurrence. For ease of interpretation, this futures price is assumed to equate the current spot price. The spot price is applied to the oilfield valuation model which overlays the individual oilfield's cost and regime-dependent fiscal structure (*OPEX, CAPEX, Tax*). Therefore, in absence of production, cost and tax, a lock-step relation between spot and futures price with a constant covariance of 1 is ensured over the whole field life. The incorporation of detailed oilfield asset data causes time varying idiosyncracies in the hedge ratios. The detailed field models allow an isolation of the temporal occurrence of risk.[4]

The first column in Table 5.5 shows the whole–life field hedge ratio calculated based on (5.6) together with (5.7). A distinct decreasing trend for concessions is observable over the 30 year time frame as hedge ratios decrease from 5.55 at US$22.5/bbl (Panel A) to 2.97 at US$45/bbl (Panel B) to 1.57 at US$90/bbl (Panel C). The same reducing trend is reflected in PSC regimes where hedge ratios move from 5.32 to 4.34 to 3.14 over comparable price intervals. The 30 year period is disaggregated into sequential 5 year discrete hedge ratios in adjacent six columns. These are determined by (5.6) under the time intervals described in (5.8). Idiosyncratic trends emerge as between concessions and PSCs with concessions moving from 15.86 (US$22.5/bbl, Panel A) to −0.06 (US$45/bbl, Panel B) to −7.95 (US$90/bbl, Panel C).

This compares to consistently positive hedge ratios over the same price range for PSCs of 9.07 to 4.61 to 0.79. For the first 5 year interval at oil prices US$45/bbl and US$90/bbl, negative hedge ratios suggest that concession regimes carry distinctively lower risks compared to PSC regimes. This is consistent with the overview of cash flow where PSC response rates to oil prices are lower than for concession fields. This is for reasons of unrecoverable factors affecting the composite risk response process. Firstly, concession regimes are not exposed to progressive tax terms. Secondly, fields in concession regimes have, in general, already recovered their initial costs. These developed and mature fields in production enjoy an immediate benefit if price increase. PSC regimes (e.g. Angola) do not experience the same immediate benefit from oil price increases as they are still under early stage development. At these price scenarios, the concession cash flow profiles relative to oil price movements allow producers to sell futures; not selling forward would increase variance. The variance of the total hedged position (5.4) is minimized under the objective of maximized returns (5.3) by shorting

[4]Appendix A (Table A.2 and A.3) shows a single-field example for annual cash flow profiles incorporating field specific *Production, OPEX, CAPEX* and *Tax* profiles

Table 5.5. **5 Year Discrete Hedge Ratios Annualised**

Panel A illustrates in the first column the 1 to 30 year annualized time bounded minimum variance hedge ratio on an average country and regime level for an oil price of US$22.5/bbl. In the following columns, this ratio is disaggregated to six sequential discrete intervals of 5 years each. Panel B and Panel C reflect the same analysis for prices of US$45/bbl and US$90/bbl respectively.

	2006–2035	2006–2010	2011–2015	2016–2020	2021–2025	2026–2030	2031–2035
			Panel A: Price of US$22.5/bbl				
GOM	3.3018	2.3635	12.1690	4.4731	0.7083	0.2260	-0.1290
UKCS	2.6059	6.6342	7.3679	0.0562	2.5822	-1.0052	0.0000
NCS	13.3713	44.9579	24.5585	8.6027	10.4296	2.2418	-10.5626
CON	5.7726	15.8565	13.5460	3.7447	4.1669	0.2603	-2.9388
ANG	15.4289	34.4735	21.6115	26.6226	12.2237	0.8723	-3.2302
EGY	0.8132	-0.9967	2.6317	1.8563	0.6665	0.3042	0.4170
IDO	2.2635	0.3727	5.0834	2.2624	3.6142	1.6873	0.5607
PSC	5.3152	9.0729	8.7043	8.6682	4.9435	1.0074	-0.5051
			Panel B: Price of US$45/bbl				
GOM	2.8750	0.0324	11.3008	4.8592	0.8470	0.1876	0.0231
UKCS	1.6615	0.4527	7.2968	1.2265	1.1998	-0.2069	0.0000
NCS	5.0819	-0.9474	18.5553	8.5200	6.4062	2.8348	-4.8773
CON	2.9693	-0.0594	11.6043	4.3327	2.5218	0.7480	-1.3318
ANG	12.1265	19.7657	35.7288	11.2439	6.3656	1.2699	-1.6151
EGY	0.6918	-1.9102	2.5072	1.5533	0.8011	0.9203	0.2792
IDO	2.1364	-0.1445	4.8115	2.3120	3.7207	1.4273	0.6916
PSC	4.3374	4.6132	12.3452	4.4575	3.4577	1.2161	-0.0653
			Panel B: Price of US$90/bbl				
GOM	2.6993	-1.1936	11.1633	5.0409	0.9163	0.1955	0.0733
UKCS	1.3263	-2.4771	7.6417	1.7707	1.0046	0.0177	0.0000
NCS	0.6934	-23.8315	14.1448	9.2377	4.5071	2.1370	-2.0346
CON	1.5698	-7.9490	10.4972	4.8144	1.9392	0.6535	-0.5362
ANG	8.0993	6.7187	33.6396	4.8138	3.3174	0.9142	-0.8076
EGY	0.6144	-2.3122	2.4252	1.3413	0.8532	1.0905	0.2886
IDO	1.8975	-0.6158	2.9484	2.4429	4.1628	1.8776	0.5689
PSC	3.1351	0.7882	11.0151	2.7124	2.8326	1.3566	0.1059

Futures contracts. This concession trend reverses for the four subsequent 5 year discrete intervals at US$45/bbl and US$90/bbl with hedge ratios reaching their peak in the years 2011 to 2015 under all three price scenarios.

The top graphs in Figure 5.3 show comparable discrete concession and PSC regime hedge profiles over the years 2011 to 2025. A distinguishable difference in magnitude of the hedge ratios for changes in price is observable. For whole–life hedge ratios (2006-2035) an increase in price from US$22.5/bbl to US$45/bbl and US$45/bbl and US$90/bbl, hedge ratios reduce by approximately 50% for concessions, a behavior broadly followed by PSC regimes but at a lesser rate (see Table 5.5).

The sequential 5 year discrete hedge ratios and 3 year rolling minimum variance hedge ratios follow approximately the same profile. These hedge ratios are computed following Equation (5.6); the rolling 3 year intervals are defined in (5.9). For concession and PSC regimes, the lowest 3 year rolling hedge ratios (with the smallest divergence between the highest positive and lowest negative observation) are evident for prices of US$90/bbl (Figure 5.3, middle two graphs). At prices of US$22.5/bbl, distinctively larger minimum variance hedge ratio are computed which also show a higher distance from smallest to largest. The hedge ratio for the base price scenario of US$45/bbl moves most of the time in between the observations for US$22.5/bbl and US$90/bbl. For concessions in 2007, hedge ratios for US$90/bbl are considerably lower (negative) than for 45$ (less negative), a pattern consistent with PSC reserves. Temporal shifts are indicative of the varying nature of risk exposure in oilfield assets. The differences between 3 year sliding periods and 5 year discrete are the result of the discrete periods effectively trapping the periodicity of volatility in the analysis.

The differences between 5 year discrete and 3 year rolling hedge ratios for concession regimes are lifted out in the bottom left graph in Figure 5.3. Notable differences occur in the early years of the analysis where the three year rolling hedge ratios dominate the 5 year discrete. This relation causes negative hedge ratios for the initial period from 2006 to 2010. The trend reverses for PSC fields where 3 year rolling hedges ratios are dominated by the 5 year discrete hedges.

Table 5.6 illustrates that high oil prices increase cash flows for both concession and PSC fields, but at different rates. Additionally, higher prices accelerate the timing of the

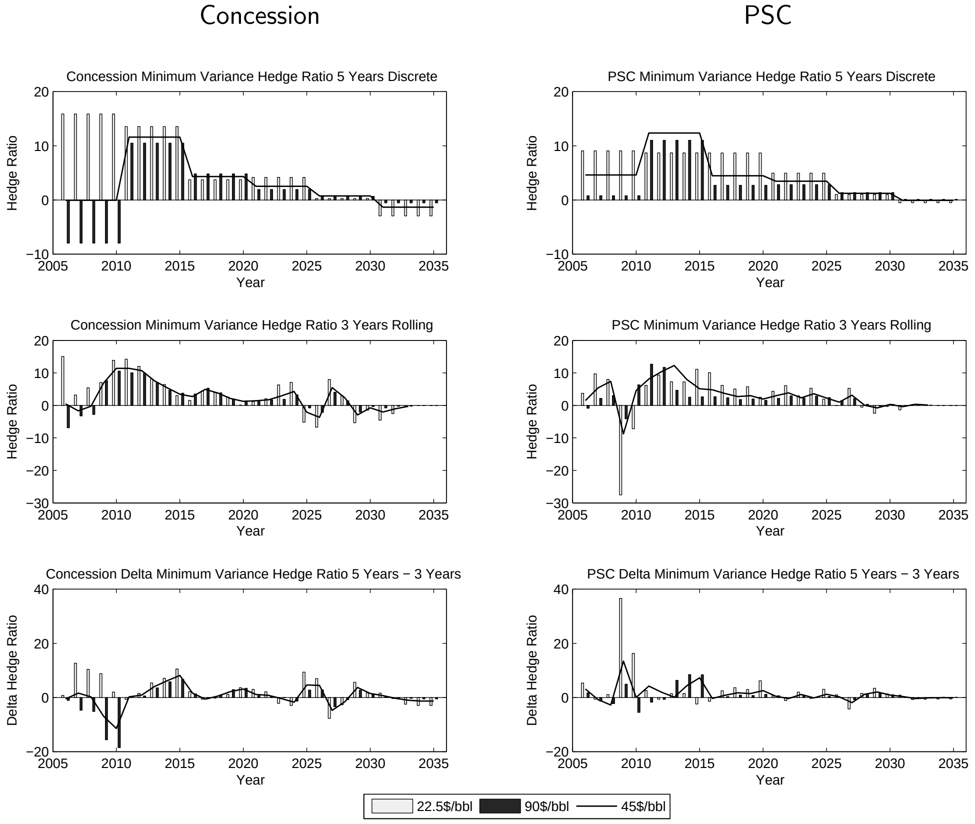

Figure 5.3. Minimum Variance Hedge Ratios for Concession and PSC Regimes at Price Scenarios US$22.5/bbl, US$45/bbl and US$90/bbl (5 Year Discrete, 3 Year Rolling and Differences)

The top graph in the left column reflects concession field minimum variance hedge ratios for 5 year discrete intervals at three different price scenarios. The center left chart illustrates concession minimum variance hedge ratios 3 years rolling. The bottom left depicts the difference between 5 year and 3 year rolling concession delta minimum variance hedge ratio. The right column reflects the same analyses for PSC regimes. Hedge ratio responses to price shocks (US$22.5/bbl, US$90/bbl, shaded and solid bars) are shown relative to the benchmark of US$45/bbl (solid black line).

Table 5.6. Time Variance in Cash Flows, Standard Deviations and Hedge Ratios

The left column of this Table reflects movements in time for key cash flow, standard deviation and hedge ratio movements for concessions. The right column reflects the same analyses for PSC regimes. Absolute figures are presented in US$M.

	Concession			PSC		
	US$22.5/bbl	US$45/bbl	US$90/bbl	US$22.5/bbl	US$45/bbl	US$90/bbl
Cash Flow (max)	55.85	126.40	414.75	77.88	136.15	226.24
Year	2009	2007	2006	2011	2011	2010
Cash Flow (min)	-35.66	-24.13	-27.86	-8.36	-5.06	-1.17
Year	2006	2029	2029	2029	2029	2029
5 Year SD (max)	39.13	22.65	76.25	27.45	29.17	44.07
Years	2006–2010	2011–2015	2006–2010	2006–2010	2006–2010	2011–2015
5 Year SD (min)	4.38	4.69	3.82	1.44	1.10	1.30
Years	2016–2020	2031-2035	2031-2035	2031-2035	2031-2035	2031-2035
3 Year SD (max)	48.24	16.30	85.77	22.86	26.03	36.85
Year	2006	2011	2006	2008	2008	2011
3 Year SD (min)	0.47	1.70	1.63	0.18	0.28	0.58
Year	2020	2030	2030	2033	2033	2033
5 Year HR (max)	15.86	11.60	10.50	9.07	12.35	11.02
Years	2006–2010	2011–2015	2011–2015	2006–2010	2011–2015	2011–2015
5 Year HR (min)	-2.94	-1.33	-7.95	-0.51	-0.07	0.11
Years	2031-2035	2031-2035	2006-2010	2031-2035	2031-2035	2031–2035
3 Year HR (max)	15.07	11.39	10.57	2.07	1.04	0.52
Year	2006	2010	2010	2011	2011	2010
3 Year HR (min)	-6.70	-3.69	-6.87	-27.53	-8.78	-4.14
Year	2026	2026	2006	2009	2009	2009

cash flow maxima in both PSC and concession regimes. At US$22.5/bbl the maximum concession cash flow occurs in 2009 (2007 for US$45/bbl, 2006 at US$90/bbl). The same occurs for PSCs but with less marked movement from 2011 to 2010. Interpreting the cash flow minima meaningfully is more difficult as they are skewed by the abandonment costs, an insight supported by Figure 5.2.

The standard deviation in concession regimes is widely variable for both the 3 year rolling and the 5 year discrete periods. For these measures, the concession standard deviation is highest for the US$90/bbl, but drops for US$45/bbl and increases again for US$22.5/bbl. PSC fields by comparison demonstrate a continuous increase for both discrete and sliding windows of standard deviation from lowest to highest price. The temporal behavior of maximum standard deviation measures is widely variable as between concession and PSC regimes and price scenarios. The minimum measure seems in the main to be constrained to the low cash flow abandonment period at the end of field life.

The hedge ratios for both 5 year discrete and 3 year rolling windows are sensitive to oil price variation. The difference between concession and PSC fields HR (max) is small for all price scenarios in the 5 year discrete measure, for the HR (min), the comparative difference increases. Concession hedge ratio is highest at 22.5 in the years 2006–2010. For PSCs, price shocks cause a temporal shift in hedge ratio with the highest hedge ratio experienced for 45$/bll in the period 2011 to 2015. The pattern is quite different for the 3 year rolling hedge ratio, where the hedge ratio is highest for concessions and PSCs at US$22.5/bbl. For concession the highest 3 year rolling hedge ratio occurs in 2006 at US$22.5/bbl. This maximum hedge ratio shifts at higher prices to 2010. For PSCs it occurs in 2011 at US$22.5/bbl.

5.5. Chapter Concluding Remarks

This chapter provides asset and regime specific insights into price shock effect on the quantum and timing of risk. I show that an analysis of the combined effects of continuous oil price information and regime entitlement terms are important when hedging physical oilfield assets. Evidence is provided that the variance minimizing hedges depend on asset specific tax terms. The findings are that the two very different forms of oil reserve ownership, production sharing and concession directly affect cash flow responses to oil price.

I propose that future studies into forward looking hedging deltas require a detailed analysis of operator entitlement to underlying asset cash flows. Specifically and importantly for risk measurement, asset price responses are shown to have the ability to trap volatility in discrete hedge ratios. Future scope exists to expand the work of this chapter by including price volatility within the term structure of the asset. The chapter contribution concerns empirical insights into the ability of price volatility to act in concert with asset specific taxation terms to affect the timing of risk. Temporal variance is shown to be a hidden dimensional outcome of price risk for depleting natural resource assets.

6. Accounting for Assets

Chapter Research Focus

The findings in the previous three chapters demonstrate heterogenous asset responses to price volatility and state agency participation. This chapter illustrates that SEC disclosures of O&G price risk of these effects are inadequate. 292 oilfields are used to provide evidence that Securities and Exchange Commission (SEC) supplementary disclosures do not capture the price sensitivities of O&G disclosures implicit in the two main forms of oilfield ownership, concession and production sharing contracts (PSCs).

Overview

SEC present value disclosures for both forms of ownership are shown to be significantly more responsive to oil prices than stock return sensitivities noted by Rajgopal (1999). Importantly, I show that unlike concessions, reserve and production disclosures vary in response to oil price movements for PSC regimes. The results highlight the need to differentiate PSC disclosures from concession fields, and to fully reflect price risks implicit in oilfield ownership contracts. I extend findings by Rajgopal (1999) and propose refinements necessary to capture contractual price risk effects on SEC disclosures for assets in the O&G sector.

Research Acknowledgements

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6.1. Background

This chapter provides evidence that current disclosures lack detailed asset data pertaining to ownership structures and their exposures to oil price volatility.

In the next section I provide background in the form of the historical development of the SEC and FASB disclosure rules, the emergence of PSCs and a brief review of the literature that has tested these rules. In particular I emphasize the contingent and contractual nature of PSC terms and the importance of disclosing these separately from concession holdings. I conclude with a discussion of these results and emphasize the need for responses from policy makers in relation to shortfalls in disclosure practice.

6.2. Background And Prior Research

6.2.1. Current SEC Disclosures 'presume' Concession Reserve Structures

SEC disclosures do not differentiate between oilfield ownership structures, notwithstanding the very different nature of their legal entitlement to underlying reserves. During the late 1970s and early 1980s, an era dominated by concession oilfield reserve ownership, the Financial Accounting Standards Board (FASB) and the Securities and Exchange Commission (SEC) issued a series of standards dealing with the accounting and disclosure of underlying oil and gas activities. First, the Statement of Financial Accounting Standards No. 19, (FASB 1977, SFAS19), required oil and gas companies to account for their oil and gas activities at historical cost using successful efforts method (SE) instead of the full cost method (FC). Additionally, SFAS19 required the disclosure of (1) costs incurred in production activities, (2) capitalized costs relating to production activities, and (3) proved reserve quantities. However, the SEC unhappy that neither the SE nor the FC methods were appropriate for communicating oil and gas firms' underlying asset and reserve values, developed a new method of accounting for values of oil and gas reserves.

As a result, the SEC issued Accounting Series Releases No.253 (SEC 1978, No.253) and No.269 (SEC 1979, No.269) through which it proposed Revenue Recognition Accounting (RRA) valuing the reserves directly from estimated cash flows rather than past incurred costs. Additionally, oil and gas firms were permitted to use either of the SE and FC methods, which in turn instigated the FASB to issue Statement of Financial Accounting Standards No. 25 (FASB 1979, No.25), which effectively suspended the historical cost accounting method requirement in SFAS19. Furthermore, the RRA did not gain wide support and a few years later the SEC dropped the concept of pure cash flow estimation (SEC 1981), handing over the issue to the FASB who were developing Statement of Financial Accounting Standards (SFAS) No. 69 (FASB 1982, No.69). This standard, issued in 1982, established the set of reserve disclosures which to this day determine the information content of SEC filings and financial reports. Specifically, neither contractually specified claims, nor the price risk exposures of physical reserves, have historically been subject to disclosure.

To overcome this SEC shortfall, disclosure recommendations build on principles contained highlighted by Rajgopal (1999) and contained in SEC ruling of 1997. Justification for this approach is found in the SEC (SEC 1997, 6044) definition which specifically defines market risk as the risk of loss arising from adverse changes in market rates and prices, such as interest rates, foreign currency rates and similar market rate or price changes.

6.2.2. The Relevance of Market Risk in Supplementary Oil and Gas Disclosures

There is a body of literature that tests accounting measures and supplementary disclosure of reserves in the oil and gas industry. I suggest that the debate in these studies have been in part caused by the lack of data about the type of oilfield assets held by the companies under analysis. Early researchers, for instance, hampered by the lack of access to oilfield data and the applicable contractual terms cast doubt on the reliability of the value relevance of historic cost and even the 'present values' of oil and gas reserves (Magliolo 1986; Harris and Ohlson 1987; Shaw and Weir 1993), (Spear, 1993; 1996). Only recently have several researchers, using revised methodologies, provided evidence supporting the value relevance of present values (Berry et al. 2004; Bryant 2003; Boone 2002). None of these studies, however, covers the distinction between the concession and PSC contracts. Nor do they cover the relative effects of market risk (oil price volatility) on reported reserves.

Likewise, there is little research support for the notion that contractual claims under PSCs might require contingency disclosure under Statement of Financial Accounting Standards No.5 (FASB 1975, SFAS5). Scope for PSC disclosure may also be offered by Statement of Financial Accounting Standards No.133 (FASB 1975, SFAS133) and Financial Reporting Release No.48 (SEC 1997, No.58), which introduced a requirement for commodity price risk disclosures. No studies have until this point applied these statements to contingent claims against underlying oilfield assets, preferring to focus on their application to derivative disclosures which involve using one of three alternative formats: tabular disclosure, response analysis or value at risk.

Rajgopal (1999), for instance, studying the informativeness of commodity price risk financial instrument disclosures required by FR-48 (SEC 1997, FR-48), cast doubt on claims that the new market risk disclosures do not reflect firms' risk exposure in the oil and gas sector. The sensitivity analysis format of the FR-48 requires firms to report explicit estimates of fair value gains and losses on derivative positions due to changes in the underlying commodity. In addition, it encourages firms to voluntarily present fair value gains and losses on the underlying exposure to changes in prices. Rajgopal (1999) did find that proxies for the fair value response of the underlying exposure (oil and gas derivatives) were positively (negatively) associated with oil and gas betas. Moreover, the tabular and response formats each possessed incremental utility in explaining oil and gas betas. Currently in the O&G sector, estimates of the potential fair gains and losses on underlying oilfield contracts are not subject to similar reporting requirements.

Rajgopal (1999) is not alone in his price risk findings, Ahmed et al. (2006), compared the valuation implications of derivative fair value information – in the banking sector. Importantly, their findings suggest that FASB (1975, SFAS133) has increased transparency of the nature of derivative financial instruments. Again, I anticipate that similar disclosure requirements for underlying O&G reserves would result in a transparency of the contingent nature of underlying PSC contracts.

To account for uncertainty surrounding future reserves it has been recommended (Arnott 2004) that there should be a simple adjustment to SEC rules on reserves reporting to require companies to show reserves booked on a field by field basis. Whilst such finely grained tabular information might be regarded as confidential by companies I show that, at a minimum, disclosures should distinguish between PSC and concession reserve entitlement. This chapter adopts a position similar to that proposed for price risk by Rajgopal (1999), establishing the need for price response disclosures of underlying oilfield assets. This proposal recognizes the existence of price sensitive contractual conditions and emphasizes the need for the commodity price responsiveness of present values, reserves and production sharing to be disclosed.

6.2.3. Principal differences between PSC and Concession Market Risk Disclosures

Traditional oilfield concession ownership is found in the Gulf of Mexico, Europe, and Australasia (amongst others). Under these royalty structures, if producers generate a profit from ongoing extraction, they pay corporation tax, sometimes supplemented with revenue, royalty or other taxes. In this instance, producers own the underlying reserves, with reported reserves being the recoverable reserves from the reservoir in total, and future physical reserve entitlement is unaffected by price volatility.

By contrast, early cost recovery production sharing contracts were signed in Indonesia in 1965 and now exist in many of the world's newer oil producing and Non-OECD regions including West Africa, Kazakhstan, Indonesia and Egypt. The proliferation of these agreements in the 1990s has been a direct result of government desire to reclaim control of natural resources once a fair return has been earned by the corporate producers. The PSC allows contractual contingent claims (often in forms of taxation or production sharing) to be made against producer reserves when an agreed threshold of return is met and costs have been covered.

At present the SEC requires a simple disclosure of price risk, measured by the response of profits to changes in oil/gas prices. I use findings above to show that this approach focuses on the immediate 'income effect' without reference to effects on sustainable reserves, future production entitlement or NPV. For instance Exxon Mobil's 2006 SEC disclosures of total price risk state:

> "Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The effect of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, based on the 2005 worldwide production levels, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $400 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take effects, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and nat-

ural gas only provide a broad indicator of changes in earnings experienced in any particular period."

Conspicuously no price response is declared for disclosed SEC reserves in terms of either quantity of reserves or production entitlement or present value. The distinction in market risk on government take has a direct bearing on the two main components of supplementary SEC disclosure requirements of: (1) disclosures of proved oil and gas reserve quantities and annual changes therein, and (2) disclosures of proved oil and gas reserve values (using a standardised measure) and annual changes therein. Proved reserves of oil and gas[1], production[2] (an important element in the changes in proved reserves) and the expected net present value of the proved oil and gas reserves (the standardized measure[3]) have all been shown to be value relevant, I therefore focus on these three SEC measures in the analysis.

The primary research question in the study is whether disclosure requirements for price sensitive contractual claim terms should be differentiated from the SEC disclosures

[1] FASB (1982) defines proved oil and gas reserves as "Net quantities of an enterprise's interests in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids) and (b) natural gas shall be disclosed as of the beginning and the end of the year. 'Net' quantities of reserves include those relating to the enterprise's operating and nonoperating interests in properties as defined in paragraph 11(a) of Statement 19. Quantities of reserves relating to royalty interests owned shall be included in 'net' quantities if the necessary information is available to the enterprise; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact and the enterprise's share of oil and gas produced for those royalty interests shall be disclosed for the year. "Net" quantities shall not include reserves relating to interests of others in properties owned by the enterprise."

[2] FASB (1982) includes production of oil and gas in its definition of the changes in proved reserves: "Changes in the net quantities of an enterprise's proved reserves of oil and of gas during the year shall be disclosed. Changes resulting from each of the following shall be shown separately with appropriate explanation of significant changes; (a) Revisions of previous estimates, (b) Improved recovery, (c) Purchases of minerals in place, (d) Extensions and discoveries, (e) Production and (f) Sales of minerals in place."

[3] FASB (1982) defines the standardized measure as "A standardized measure of discounted future net cash flows relating to an enterprise's interests in (a) proved oil and gas reserves (paragraph 10) and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (paragraph 13) shall be disclosed as of the end of the year. The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes. The following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraph 12; (a) Future cash inflows, (b) Future development and production costs, (c) Future income tax expenses, (d) Future net cash flows, (e) Discount and (f) Standardized measure of discounted future net cash flows."

designed for concession entitlement. I find it instructive to isolate the price variable nature of oilfields by using the sample to examine both the amount and the response of SEC disclosures to oil price variations. Expectations are clear, if SEC concession and PSC supplementary disclosure responses across the empirical sample prove to be differentially responsive to market risks, then as noted by Rajgopal (1999) there would be justification for their separate disclosure.

6.3. Research Design

I conduct an empirical study of how, when subject to commodity price variability, ownership disclosures differ across ownership regimes, and even within regimes. The first test is for the significance of response differences between PSC and concession SEC disclosure requirements. A comparative empirical analysis of PSC and concession oil and gas price responses against GoM concession benchmarks allows me to achieve two insights; firstly, I conduct an analysis of concession oil price responses relative to the GoM – identifying regime differences between concessions and PSCs. Secondly, PSC fields were compared to GoM – identifying the extent of inter sample differences. This approach provides consistent and comparable country insights for all three SEC disclosures, testing whether Corporate SEC PSC and concession disclosures for oil and gas reserves, production and NPV responses differ by country – when compared to GoM concession disclosures.

The second test lifts out the potential differences between PSC regimes by comparing PSCs against each other. This enables the determination of whether it is sufficient to disclose PSC as a homogenous group or whether the wide range of PSC terms illustrated in Appendix 2.1 make it necessary to disclose PSC terms individually.

6.3.1. The Model – Demonstrating Differences in SEC Disclosures for PSC and Concession

Taxation models are computationally intensive and differ (in line with tax terms) from regime to regime and indeed from field to field. The strength of my analysis is that field by field taxation computations are individually performed for the actual taxation terms applicable for each of the 292 oilfields for each of the five prices. Country tax protocols are programmed into GEM and used to underpin an empirical comparison of differential SEC disclosures as between actual PSC and concessionary ownership structures for oilfields in the sample.

To provide the reader with an understanding of the method and details of PSC oilfield calculations, an example of one actual field's calculations at a base case price of US$45/bbl are shown in Appendices 1 and 2. Due to the practical difficulties of disclosing detailed PSC tax calculations on a field by field basis for all fields at all price decks, I do not show these separately, but provide an overview of the range of concession and PSC terms applicable to fields in the sample in Appendix, Table 2.1.

I use an actual Angolan field (with the production profile altered to preserve confidentiality) to provide a simplified insight into the differences that the application of the P_{45} price deck to different concession and PSC terms cause.[4] Firstly, I treat the field as if it is held under a domestic Angolan PSC agreement (Appendix 2.2) and then under GoM concession terms (Appendix, Table 2.6). I use the specimen field to derive and calculate each figure in the P_{45} columns of Table 6.1. This gives the PSC disclosures for reserves (408 mmboe), production (9000 boe/day) and NPV (US$3182 million) figures for an oil price scenario of US$45/bbl in 2006, Appendix 1. Similarly, I calculate the three SEC measures for the same hypothetical field - identical to the specimen PSC field in every respect save that it is subject to concessionary terms. For purposes of the comparison, I have used the terms applicable to a GoM deepwater field. Appendix, Table 2.7 gives the SEC calculation of reserves (700 mmboe), production (9000 boe/day) and NPV (US$6545 million).

The price response analysis of disclosures, as supported by taxation computations for each field, is presented over 5 price ranges. As the benchmark I set US$45/bbl as the base case price deck, with the US$45/bbl price deck analogous to the year end price used in current SEC disclosures. The choice of price range is judgemental based on recent (2006) oil prices and their potential option implied volatility; I calculate SEC disclosures at US$45/bbl, the base case price, two upside price decks US$67.5/bbl and US$90/bbl, as well as two downside decks of US$33.75/bbl and US$22.5/bbl to demonstrate the price variable response of SEC disclosures.

Table 6.1 sets out an analysis of disclosure performances on either side of the P_{45} price deck, and provides a summary of how Angolan field disclosures look as at January 2006 under different price assumptions. The $P_{22.5} - P_{45}$ comparison illustrates the effect that price variability can have upon ownership SEC disclosures, and serves to demonstrate the motivation for this study. The first point to note is that concession reserves remain constant at 700mmboe while reserves vary from 240mmboe to 659mmboe under PSC

[4]The production profile has been changed to preserve confidentiality.

Table 6.1. Angolan Oilfield Calculated under Angolan and GoM Tax Terms

Angolan Field Oil and gas reserves, oil and gas production and net present value of reserves at January 2006 – Under Angolan domestic tax terms and Gulf of Mexico concession tax terms. Absolute figures are presented in US$M.

	Angolan Field under Domestic PSC Tax Terms					Angolan Field under GoM Concession Tax Terms				
	$P_{22.5}$	$P_{33.75}$	P_{45}	$P_{67.5}$	P_{90}	$P_{22.5}$	$P_{33.75}$	P_{45}	$P_{67.5}$	P_{90}
Reserves (mmboe)	659	550	408	293	240	700	700	700	700	700
Production ('000boe/d)	9	9	9	9	9	9	9	9	9	9
Remaining NPV (US$ millions)	1989	3053	3182	3842	4334	2659	4769	6545	11053	15227

terms. Table 6.1 shows that even at a low initial oil price, US$22.5/bbl, production sharing commences.

As the oil price increases, PSC contract terms result in reserves being recouped by government claims, reducing corporate entitlement to 240mmboe at US$90/bbl, less than half the original entitlement. Production appears to remain constant under both regimes. This will be shown to be a short term effect; while concession production does in fact remain constant under differing price scenarios, PSC production terms would vary over time - see Figure 6.1. A PSC phenomenon that would occur if higher prices were to persist and result in operators earning their contracted returns through price increases rather than production volumes.

Finally, while the NPV of the specimen field does vary under both structures – concession fiscal take only increases as a result of price movement, while the PSC reserve claw back is dictated by fiscal terms in Appendix, Table 2.1, where NPV is a composite of price and quantity of oil reserves, discounted at a rate of 10%, in line with SEC regulations.

6.3.2. Empirical Tests of SEC Disclosure Responses

I present tests for differences – as to how actual SEC disclosures respond to price changes across the oilfield sample in three parts; first I reflect the rate of change for the

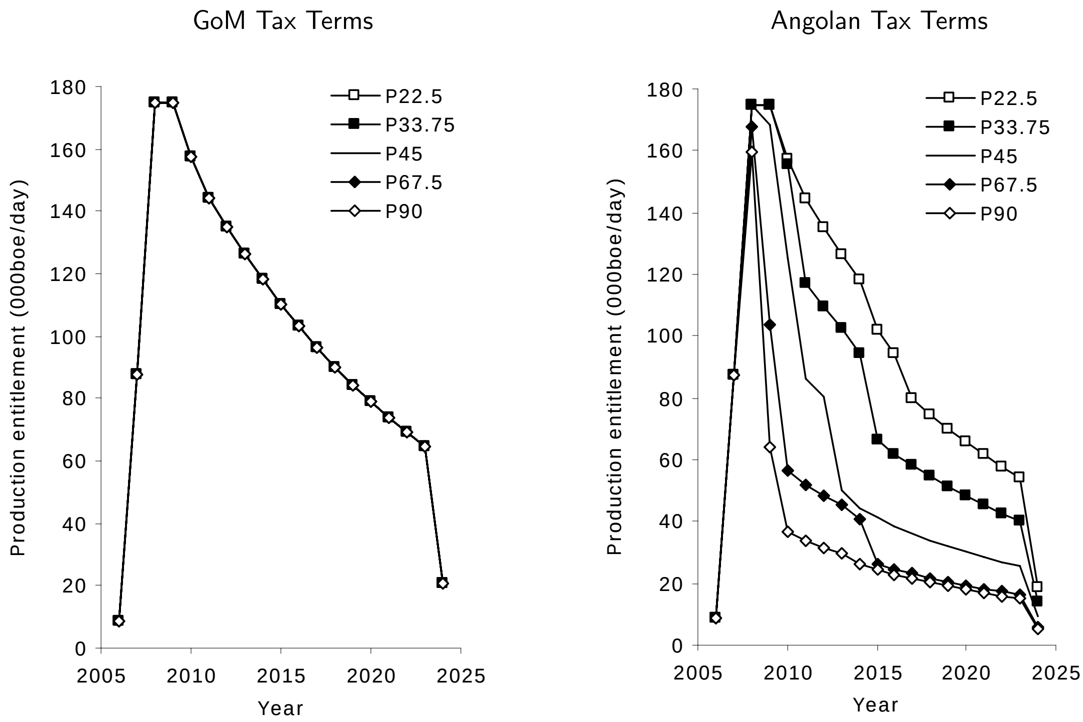

Figure 6.1. Expected Development of Production Entitlement Over Time for a Hypothetical Angolan Oil Field under Conditions of Oil Price Volatility

price intervals, then I reflect statistical tests of difference between PSCs and concessions as represented by GoM. Specifically, disclosure responses are calculated for each field within five specific prices (two on either side of US$45/bbl) to give an indication of the magnitude of change in the SEC disclosures per one percent change in the oil and gas price. For instance, I simulate the response of reserves, production and remaining PV when the oil prices fall from the P_{45} to the $P_{33.75}$ scenario. Reserve entitlement responses between two price scenarios (referred to as P1 and P2) are calculated for each field in all six countries as follows[5]:

$$\text{Reserve Response:} \quad (P_1/P_2) = \frac{(R_{P1} - R_{p2})/R_{P2}}{(P_{P1} - P_{P2})/P_{P2}} \tag{6.1}$$

where R_{P1} and R_{P2} refer to the entitled SEC reserves $R_{22.5}$, $R_{33.75}$, R_{45}, $R_{67.5}$ and R_{90} (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios. For instance, the reserve response between the P_{45} (P2) and $P_{33.7}$ (P1) price decks would be calculated as $\frac{(R_{33.75}-R_{45})/R_{45}}{(P_{33.75}-P_{45})/P_{45}}$ Production entitlement responses are calculated as follows:

$$\text{Production Response:} \quad (P_1/P_2) = \frac{(Q_{P1} - Q_{P2})/Q_{P2}}{(P_{P1} - P_{P2})/P_{P2}} \tag{6.2}$$

where Q_{P1} and Q_{P2} refer to the entitled SEC production $Q_{22.5}$, $Q_{33.75}$, Q_{45}, $Q_{67.5}$ and Q_{90} (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios. PV responses are calculated as follows:

$$\text{PV Response:} \quad (P_1/P_2) = \frac{(NPV_{P1} - NPV_{P2})/NPV_{P2}}{(P_{P1} - P_{P2})/P_{P2}} \tag{6.3}$$

where NPV_{P1} and NPV_{P2} refer to the remaining PVs: $NPV_{22.5}$, $NPV_{33.75}$, NPV_{45}, $NPV_{67.5}$ and NPV_{90} (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios.

The above allow an analysis of whether the commodity price responses of SEC disclosures in the concession regimes NCS and UKCS, and the PSC regimes Angola, Egypt

[5] Formulae are applied such that when P1<P_{45}, the P1 is further from P2, and when P1 is greater than P_{45} then P1 >P2

and Indonesia are statistically different from the equivalent responses in the concession countries US GoM, NCS and UKCS. The use of t-tests for difference are based on underlying field data. This approach introduces the principle that differential responses of SEC measures is based on ownership structures an demonstrate material variations in current disclosure between PSC and concession fields.

6.3.3. Sample Selection and Data

The sample represents oilfields containing between 80% and 90 percent of the total remaining oil and gas reserves in GoM, NCS, Angola, Egypt and Indonesia and approximately 50% of the reserves in UKCS. I am guided in stratification by the findings of Kretzschmar and Moles (2006) who in their study of real option models found that fields displayed size varying characteristics. Fields with less than 6 million barrels of remaining oil and gas equivalent were therefore eliminated as abandonment expenses introduce idiosyncratic behaviour that would focus on the tax relief of abandonment costs rather than reserve disclosures for the predominantly producing fields in the study (see Table 6.2). To my knowledge, no other academic study of oilfield ownership behaviour have analysed samples of a similar size. Each of the six regimes in the sample was selected for their fiscal homogeneity (Appendix, Table 2.1).

Table 6.2. Sample and Population Overview

The table describes the sample with regards to the number of oilfields and the total sample size (measured by total remaining oil and gas reserves), by country and by fiscal regime (concession vs PSC). For comparison, the number of oilfields and total size of reserves in the total population are shown. Fields are presented in absolute numbers, reserve figures are presented in mmboe.

	Sample		Population		Sample % of Population	
	# Fields	Reserves	# Fields	Reserves	# Fields	Reserves
Panel A: Concession						
GOM	50	6063	130	7467	38.5%	81.2%
NCS	50	25851	105	27311	47.6%	94.7%
UKCS	67	5431	380	10127	17.6%	53.6%
CON	167	37345	615	44905	27.2%	83.2%
Panel B: PSC						
Angola	28	8636	48	10755	58.3%	80.3%
Egypt	42	6123	53	6712	79.2%	91.2%
Indonesia	55	10722	71	12426	77.5%	86.3%
PSC	125	25481	172	29893	72.7%	85.2%
Total Sample	292	62826	787	74798	37.1%	84.0%

6.4. Empirical Results

In this section I report the results of tests for differences between field disclosure responses to price movements. GoM fields are used as a concession benchmark for differential responses of fields in the UKCS and NCS. Similarly Angola, Egypt and Indonesia responses are in turn tested against GoM in order to compare PSC SEC disclosure responses with concessions. I also test for differences between individual countries.

6.4.1. SEC Reserve Disclosure Responses to Oil Price Variations – Comparisons to the GoM Benchmark

Concession reserve entitlement does not move in response to oil price changes (upper half of Table 6.3). The UK and Norway concession reserve responses are identical to GoM in showing no response to changing prices in Panel A. By contrast, the lower half of Panel A provides insights into the price response of reserve entitlements for oil companies with reserves in PSC regimes. t-tests reported in Table 6.3 Panel B show that PSCs are (all) significantly different from GoM responses at the 0.1 percent level.

The results layout allows readers to break reserve responses into price ranges and show that the PSC sample measured by Angolan, Egyptian and Indonesian fields are substantially influenced by changes in oil and gas prices. This reflects the intuition of Rajgopal (1999) that beta responses depend on the periodicity and price ruling for the measurement interval. Jin and Jorion (2006) also mentioned the locality of oilfields as having an effect on prices obtained for resources, findings supported by out tabular analysis. For instance, when the oil price (and similarly the gas price per boe) decreases by 33.3% from US\$33.75/bbl to US\$22.5/bbl, the reserve response as per the formula is -0.253 for Egypt, -0.324 for Indonesia, and -0.451 in the case of Angola (Table 6.3, Panel A). This means, for example, that the reserve entitlement for Egypt increases by 25.3% of 33.3%, an increase in actual physical reserves of 8.4 percent. Thus, over the price range, the impact on reserve entitlement is approximately a quarter the size of the price change. Similarly the impact for Indonesia is 32.4% of the price change and for Angola it is 45.1%. The negative signs of the reserve responses in Table 6.3 indicate that reserves move in the opposite direction to price. The movement encapsulates the response of disclosures to moves in oil prices – away from the year end levels of US$45/bbl – that would be shown using SEC guidelines. There is for PSCs therefore an increase in reserve entitlement as price falls and vice versa. It is also noteworthy that, in the case of Egypt and Angola the reserve responses peak in the price range US$45/bbl to US$33.75/bbl whereas for Indonesia the most response is in the lower price range of US$33.75/bbl to US$22.5/bbl. The pattern of reserve responses is a function of the terms of the PSC with the older Indonesian agreements being crafted in an era of lower oil price expectations.

When the oil price increases by 33.3% from US$67.5/bbl to US$90/bbl, Table 6.3 shows a response in reserve entitlement of 0.130 (of 33.3%) for Indonesia, 0.132 for Egypt and 0.388 in the case of Angola. These responses represent decreases in reserve entitlement as price rises. In all three cases the rate of decrease is moderated as prices rise (in the case of Angola from a response of 0.405 over the range from US$45/bbl to US$67.5/bbl to 0.388 over the range US$67.5/bbl to US$90/bbl). Importantly, rate of change is dependent on PSC contract terms as they apply to the field and again varies by price range, depending on the contract terms.

6.4.2. SEC Reserve Disclosure Responses to Oil Price Variations – Comparisons between PSC Regimes

PSCs in turn demonstrate a wide range of responses between different PSC contracts in response to the same price change. Angola has the most aggressive production sharing terms, resulting in a 0.405 (of 50%) reserve decrease for the 50% increase in price from US$45/bbl to US$67.5/bbl. (Egypt and Indonesia are both at 0.154). It is relevant to note that this effect is opposite on the downside, with reserves disclosed increasing for Angola by a rate of 0.684 of 33.3% in response to a 33.3% fall in price from US$45/bbl to US$33.75/bbl.

The significant differences in reserve responses between Angola and both Egypt and Indonesia support the proposal that not only should there be separate reserve disclosures for PSCs in the first instance, but also separate disclosure by contract type.

Table 6.3. Responses of Reserve Entitlement to Oil and Gas Price Change

Panel A denotes reserves disclosure response in reaction to price movements. In Panel B, t-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C, tests for difference are also carried out between individual countries. The existence of significant differences is verified through 2-tailed t-tests run at the field level of the selected sample. Significance at a 90%, 95% level and 99% level are indicated by *, ** and *** respectively; n.s. denotes non-significance; p-values are quoted in parentheses. Absolute figures are presented in US$M.

	$P_{22.5}/P_{33.75}$	$P_{33.75}/P_{45}$	$P_{67.5}/P_{45}$	$P_{90}/P_{67.5}$
	Panel A: Reserve Response			
Concession				
GoM	0.000	0.000	0.000	0.000
NCS	0.000	0.000	0.000	0.000
UKCS	0.000	0.000	0.000	0.000
PSC				
Angola	-0.451	-0.684	-0.405	-0.388
Egypt	-0.253	-0.271	-0.154	-0.132
Indonesia	-0.324	-0.297	-0.154	-0.130
	Panel B: Statistical Analysis (Concession vs PSC)			
GoM vs Angola	***	***	***	***
GoM vs Egypt	***	***	***	***
GoM vs Indonesia	***	***	***	***
	Panel C: Statistical Analysis (Intra-Regime Comparison)			
Concession				
GoM vs NCS	—	—	—	—
GoM vs UKCS	—	—	—	—
NCS vs UKCS	—	—	—	—
PSC				
Angola vs Egypt	*	***	***	***
Angola vs Indonesia	ns	***	***	***
Egypt vs Indonesia	ns	ns	ns	ns

6.4.3. SEC Production Disclosures – Responses to Oil Price Variations – Comparisons to the GoM Benchmark

Production results deconstruct reserve entitlement into annualised production, providing evidence that production in concession regimes is unaffected by changes in oil and gas prices. The production volumes that oil companies are entitled to report remain constant at 100%, Table 6.4, Panel A.

6.4.4. SEC Production Disclosure Responses to Oil Price Variations – Comparisons between PSC Regimes

On the other hand, production entitlement in Angola, Egypt and Indonesia are considerably affected. For example, a 33.3% decrease in oil and gas prices from US$33.75/bbl to US$22.5/bbl increases production entitlement by 0.205 (of 33.3%) for Egypt, by 0.291 for Angola and by 0.466 in the case of Indonesia. Likewise, a 33.3% increase in the commodity price from US$67.5/bbl to US$90/bbl will lead to reserve decreases of 0.064 (of 33.3%) for Indonesia, 0.106 for Egypt and 0.181 in the case of Angola. The negative signs assigned to reserve responses in Table 6.4 indicate that production entitlement moves in the opposite direction to price. The responses for Egypt and Angola are all significantly different from those in GoM at either the 1% or the 0.1% level.

Table 6.4 shows that the three PSC countries of Angola, Egypt and Indonesia are not significantly different from each other in terms of the 2006 production response to 2006 price change. However, Figure 6.1 demonstrates that such a price change does differentially change the pattern of production entitlement for PSC countries in the longer term. It is this longer term differential impact on production that is picked up in the forthcoming paragraphs which examine PV responses to price change.

6.4.5. SEC PV Disclosure Responses to Oil Price Variations – Comparisons to the GoM Benchmark

Table 6.5, Panel A reports responses in oilfield PV to changing oil and gas prices. As before, Panel B also reports the results of t tests to responses between each country and

Table 6.4. Responses of Production Entitlement to Oil and Gas Price Change

Panel A denotes production disclosure response in reaction to price movements. In Panel B, t-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C, tests for difference are also carried out between individual countries. The existence of significant differences is verified through 2-tailed t-tests run at the field level of the selected sample. Significance at a 90%, 95% level and 99% level are indicated by *, ** and *** respectively; n.s. denotes non-significance; p-values are quoted in parentheses. Absolute figures are presented in US$M.

	$P_{22.5}/P_{33.75}$	$P_{33.75}/P_{45}$	$P_{67.5}/P_{45}$	$P_{90}/P_{67.5}$
		Panel A: Production Response		
Concession				
GoM	0.000	0.000	0.000	0.000
NCS	0.000	0.000	0.000	0.000
UKCS	0.000	0.000	0.000	0.000
PSC				
Angola	-0.291	-0.348	-0.162	-0.181
Egypt	-0.205	-0.169	-0.087	-0.106
Indonesia	-0.466	-0.142	-0.173	0.064
		Panel B: Statistical Analysis (Concession vs PSC)		
GoM vs Angola	***	**	***	***
GoM vs Egypt	***	***	**	***
GoM vs Indonesia	*	n.s.	***	n.s.
		Panel C: Statistical Analysis (Intra-Regime Comparison)		
Concession				
GoM vs NCS	—	—	—	—
GoM vs UKCS	—	—	—	—
NCS vs UKCS	—	—	—	—
PSC				
Angola vs Egypt	ns	ns	ns	ns
Angola vs Indonesia	ns	ns	ns	ns
Egypt vs Indonesia	ns	ns	ns	ns

the GoM benchmark and between individual countries. The difficulty in interpreting causality behind changes in the PV measure stems from the fact that it is a composite of price and production, discounted at the SEC rate of 10%. Thus the effect of oil prices upon PV is somewhat more difficult to interpret, possibly contributing to the need for Boone (2002) to revisit previous value relevance studies. It can be seen from Table 6.5 that for all countries the PV response increases as prices fall with the largest responses being to a fall in price from US$33.75/bbl to US$22.5/bbl. For example, in GoM such a 33.3% fall induces an even bigger percentage fall in PV being 1.306 times 33.3%. Nevertheless there are significant differences between the PV responses.

Table 6.5 shows that for price changes from US$33.75/bbl to US$22.5/bbl, Indonesia, a PSC field and NCS, a concession field, have PV response that is significantly different (at the 1% level) from the GOM benchmark. However at higher prices ($P_{67.5}/P_{45}$ and above it is Angola and Egypt that have the significantly higher PV price response compared to the GOM benchmark.

6.4.6. SEC PV Disclosure Responses to Oil Price Variations – Comparisons between PSC Regimes

At high oil prices all oilfields experience an increase in PV if prices rise but those of Egypt, and in particular Angola, rise at a significantly lower rate. This is a reflection of the claw-back of reserves by the Angolan/Egyptian government under their PSC terms. Angola has the most aggressive claw-back. For example, a 50% increase in price from US$45/bbl to US$67.5/bbl results in a PV increase of only 0.33 of 50%. Table 6.5 shows that Angola PV responses are significantly different from Egypt at all price ranges and from Indonesia at the higher price ranges, once again supporting the need for separate SEC disclosures for the individual PSC fields.

6.4.7. Price and SEC Disclosures - Assessing Current Reserves, Production and NPV Reporting

At present the SEC requires a simple disclosure of price risk, measured by the response of profits to changes in oil and gas prices. Conspicuously no price response is declared

Table 6.5. Responses of Remaining Oilfield PV to Oil and Gas Price Change

Panel A denotes PV disclosure response in reaction to price movements. In Panel B, t-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C, tests for difference are also carried out between individual countries. The existence of significant differences is verified through 2-tailed t-tests run at the field level of the selected sample. Significance at a 90%, 95% level and 99% level are indicated by *, ** and *** respectively; n.s. denotes non-significance; p-values are quoted in parentheses. Absolute figures are presented in US$M.

	$P_{22.5}/P_{33.75}$	$P_{33.75}/P_{45}$	$P_{67.5}/P_{45}$	$P_{90}/P_{67.5}$
		Panel A: NPV Response		
Concession				
GoM	1.306	1.197	1.196	1.121
NCS	2.159	1.288	1.243	1.071
UKCS	1.603	1.401	1.352	1.240
PSC				
Angola	1.587	0.713	0.330	0.332
Egypt	1.190	0.974	0.964	0.972
Indonesia	1.976	1.318	1.266	1.125
		Panel B: Statistical Analysis (Concession vs PSC)		
GoM vs Angola	n.s.	***	***	***
GoM vs Egypt	n.s.	***	***	***
GoM vs Indonesia	**	*	n.s.	n.s.
		Panel C: Statistical Analysis (Intra-Regime Comparison)		
Concession				
GoM vs NCS	*	n.s.	n.s.	n.s.
GoM vs UKCS	n.s.	n.s.	n.s.	n.s.
NCS vs UKCS	n.s.	n.s.	n.s.	*
PSC				
Angola vs Egypt	***	***	***	***
Angola vs Indonesia	ns	*	***	***
Egypt vs Indonesia	ns	***	***	***

Table 6.6. Reserves Entitlement (mmboe) and Changes in Reserves (Relative to Base Case, US$45/bbl)

Corporate entitlement to oil and gas reserves is calculated for five specific oil price decks (US$22.5/bbl, US$33.75/bbl, US$45/bbl, US$67.5/bbl and US$90/bbl) for each oilfield in the sample (292 in total). For instance, a P_{45} price deck (and base case) represents the case where the expected oil price (Brent blend) for 2006 is US$45/bbl, and results in a reserve entitlement of R_{45}. The values in the table above show both the total corporate reserve entitlement for all the oilfields by country, for each of the five price decks, and the changes in total country reserve entitlement compared to the US$45/bbl of oil base case. Absolute figures are presented in US$M.

		$P_{22.5}$	$P_{33.75}$	P_{45}	$P_{67.5}$	P_{90}
	Price Change relative to P_{45}	-50%	-25%	0%	50%	100%
	Panel A: Concession					
GoM	Reserves entitlement	6123	6123	6123	6123	6123
	Response to oil price change relative to P_{45}	0%	0%	0%	0%	0%
NCS	Reserves entitlement	25851	25851	25851	25851	25851
	Response to oil price change relative to P_{45}	0%	0%	0%	0%	0%
UKCS	Reserves entitlement	5431	5431	5431	5431	5431
	Response to oil price change relative to P_{45}	0%	0%	0%	0%	0%
	Panel B: PSC					
Angola	Reserves entitlement	6845	5877	4969	3698	3110
	Response to oil price change relative to P_{45}	38%	18%	0%	-26%	-37%
Egypt	Reserves entitlement	3899	3664	3498	3327	3242
	Response to oil price change relative to P_{45}	11%	5%	0%	-5%	-7%
Indonesia	Reserves entitlement	12664	10786	10723	10027	9679
	Response to oil price change relative to P_{45}	18%	1%	0%	-6%	-10%

for the disclosed SEC reserves in terms of either quantity of reserves or production entitlement or present value. This omission could be rectified by an SEC/FASB requirement for straightforward tabular disclosure as illustrated in Tables 6.6 and 6.7, differentiating between Concessions and PSCs for both the quantity and present value of proven reserves over a range of prices.

The tabular disclosure encapsulates the asymmetrical relationship between price and PSC reserves, reflected in Table 6.6. Concession reserve entitlement does not change in response to price movements, with the response remaining firmly at 0 on the Y axis. Angola shows the most variance followed by Egypt and Indonesia. The price response

Table 6.7. NPV (US$M) and Changes in NPV (Relative to Base Case, US$45/bbl)

Corporate entitlement to the net present value of the remaining oil and gas reserves is calculated for five specific oil price decks (US$22.5/bbl, US$33.75/bbl, US$45/bbl, US$67.5/bbl and US$90/bbl) for each oilfield in the sample (292 in total). For instance, a P_{45} price deck (and base case) represents the case where the expected oil price (Brent blend) for 2006 is US$45/bbl, and results in a remaining NPV of NPV_{45}. The values in the table above show both the total corporate remaining NPV for all the oilfields by country, for each of the five price decks, and the changes in total country remaining NPV compared to the US$45/bbl of oil base case. Absolute figures are presented in US$M.

		$P_{22.5}$	$P_{33.75}$	P_{45}	$P_{67.5}$	P_{90}
	Price Change relative to P_{45}	-50%	-25%	0%	50%	100%
	Panel A: Concession					
GoM	Remaining NPV (US$M)	25475	45328	66174	106792	147400
	Response to oil price change relative to P_{45}	-62%	-32%	0%	61%	123%
NCS	Remaining NPV (US$M)	29015	56614	82110	132387	182483
	Response to oil price change relative to P_{45}	-65%	-31%	0%	61%	122%
UKCS	Remaining NPV (US$M)	20518	28594	41184	67050	92848
	Response to oil price change relative to P_{45}	-50%	-31%	0%	63%	125%
	Panel B: PSC					
Angola	Remaining NPV (US$M)	19166	33092	41016	50576	58530
	Response to oil price change relative to P_{45}	-53%	-19%	0%	23%	43%
Egypt	Remaining NPV (US$M)	6720	14101	18851	27958	36966
	Response to oil price change relative to P_{45}	-64%	-25%	0%	48%	96%
Indonesia	Remaining NPV (US$M)	9334	20178	30238	49800	69296
	Response to oil price change relative to P_{45}	-69%	-33%	0%	65%	129%

of PSC reserves is also not linear across the range of prices, reflecting the differing contract terms from Appendix 3.

The same price asymmetry exists with PV except that the asymmetry is less given the compensatory effects of price increases. Figure 6.2, (a), pulls the price response of reserves together with Figure 6.2, (b), which shows the NPV response to price variations. The effect of the plus 50 and plus 100% price movement effects are most apparent in Angola, where aggressive production sharing causes reserves entitlement to fall 40%, while the corresponding growth in PSC NPV is 25% (relative to concession regime reserve loss of zero percent and NPV gain of 125%).

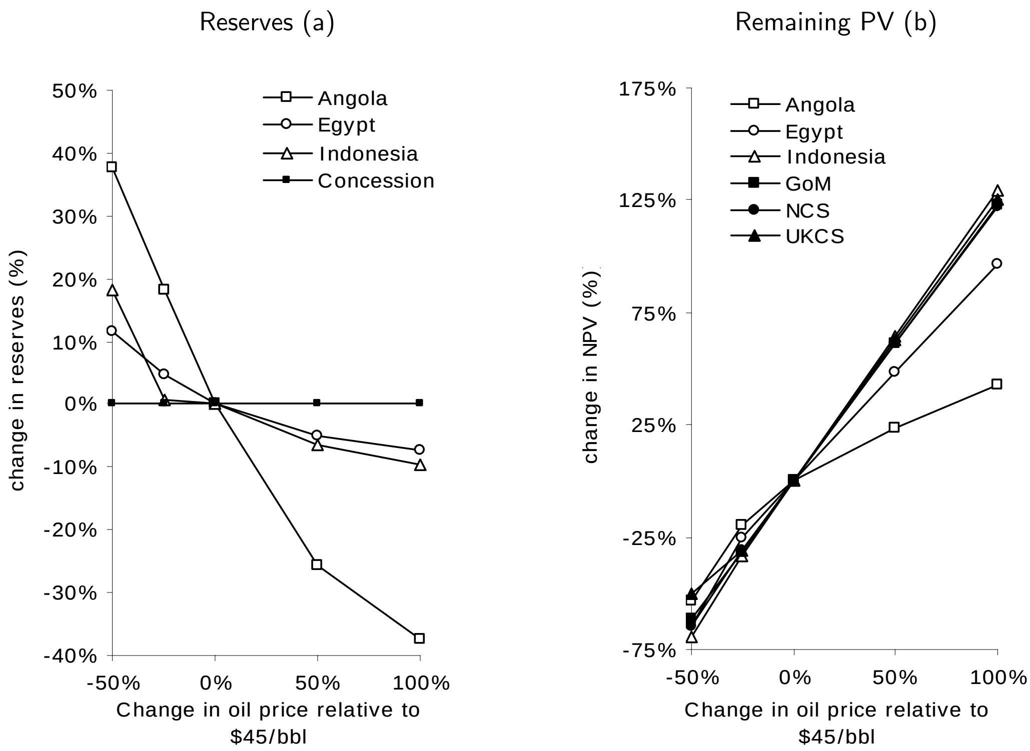

Figure 6.2. The Oil Price Relationship between Reserves and NPV

Distinction is made between countries based on specific tax terms aggregated across the sample. Concession tax terms are represented by the US Gulf of Mexico (GoM), the Norwegian Continental Shelf (NCS) and the UK Continental Shelf (UKCS), and production-sharing contract tax terms are represented by Angola, Egypt and Indonesia. Changes in aggregate reserves are plotted against changes in oil prices relative to US$45/bbl (a) and aggregate remaining NPV (b) when oil price changes from a base case of US$45/bbl.

6.5. Chapter Concluding Remarks

The SEC disclosure presumption that entitlements are consistent across ownership structures has been shown to be incorrect for all three SEC measures. I suggest that the practice of reporting year end reserves as a homogenous asset class conceals value relevant information that would enable analysts to determine companies with oil reserves most affected by price movements. The arguments in support of my recommendations are rehearsed in the following paragraphs.

In essence I question the very tenets of SEC resource disclosures. I base the enquiry on the existence of undisclosed claims in oilfield ownership contracts; noting that an oil and gas firm value can be decomposed into (1) the present value of future discretionary cash flows, (2) the present value of proven reserves (less contingencies) and (3) the present value of growth and development opportunities associated unproven reserves. Given declining reserve opportunities and the emergence of production sharing contracts (PSCs) an important corporate value determinant is the role that government contractual take (and hence residual corporate entitlement) plays in each of these three value elements. Each element is contractually dependent upon an assumed pattern of future oil prices, and as energy prices rise, fields producing through production sharing contracts are shown to have their 'bookable' barrels reduced due to participation by the local government.

PSCs are expected to increasingly affect the value of growth and development opportunities for oil companies as most of the regions of the world where opportunities exist, are adopting PSC arrangements. Since growth and development opportunities do not form part of the current supplementary disclosures, I do not examine this third effect, but I have examined the effect of PSC arrangements upon proven reserve quantities, their present values and upon production. Although SEC disclosures are made net of contingent claims (at year end prices), the size of potential contractual claims is not disclosed and hence the effect of the PSC terms at year end prices, let alone their potential effect at future prices, is not readily understood by users of financial information.

I have provided an overview of contract terms for a sample of countries through which I make a rigorous empirical investigation of the effect of PSCs upon the SEC reserve disclosures. I find that, in comparison to concessionary terms, the present value of reported reserves under PSCs, is significantly more sensitive to oil and gas prices. Moreover, PSC terms directly affect both reserve and production quantities also making these disclosures sensitive to oil and gas prices. Hence company entitlement is difficult to understand in a period of price change and volatility. This in turn makes the analyst's assessment of the annual replacement of reserves more difficult, and the isolation of sustainable discretionary cash flow problematic. Another effect is that on earnings disclosure - as the price of oil rises and a larger share of production comes from PSC regimes, oil companies will experience a larger effective tax take. This means that if the current relationship between concession and PSC tax rates hold, companies with larger PSC holdings are likely to experience greater increases in effective tax rates than those with concession holdings.

Chapter recommendations suggest that as a minimum there should be separate PSC and concession reserve disclosures. Secondly, I recommend that supplementary information should reflect the disclosure response, resulting from contractual obligations, of SEC reserve disclosures to oil and gas price changes. As a general rule I propose that there be separate reserve disclosures whenever differences in contract terms result in significantly different price response behaviours. The recommendations are to a large extent an extension of emergent principles contained in the extension to SEC (1997) dated June 15 1998 which require corporates to disclose market risk exposures resultant from derivative and underlying non derivative items (or contractual positions) that affect a reader's understanding of the balance sheet. I conclude that contingencies associated with proven reserves are important data needed for the valuation of oil and gas companies. It is not clear whether, despite non-disclosure, there is market recognition of the difference in reserve holdings. This work is performed in the following chapter.

7. State, Size and Book to Market Factors in Earnings and Returns

Chapter Research Focus

This final chapter of this (O&G) sector study uses the 'constrained capital characteristic' of physical natural resource assets, and the state agency attribute of directly taxing oilfield assets to directly address an outstanding research question posed by Fama French (1995). I provide market evidence that global variations in state participation terms produce variations in shareholder earnings and returns that are not captured by an overall market factor. The state variable also explains energy sector anomalies in risk premiums in stock returns associated with size and BE/ME (Fama and French 1993). Specifically, I find market evidence that companies with OECD asset holdings outperform those with Non- OECD assets, with earnings and returns differentiated from OECD assets by progressive state participation tax terms.

Overview

This study provides market evidence of the effects of economic state variables on stock returns and risk premia. Corporate values are underpinned by state reserve participation terms that directly affect corporate cash flow entitlement. Non-OECD contracts favor sovereign state asset participation resulting in relative stock return under-performance compared to companies invested in OECD oil assets. I provide evidence of variation in corporate wealth not captured by an overall market factor and demonstrate that state variables limit the value of emerging market investment.

Research Acknowledgements

This chapter was suggested by my supervisor Dr Paul André – and a version is planned for journal submission – early in 2007. Kretzschmar (2007)

7.1. Background

This section provides insights into an important open research question by identifying and isolating state variables that produce variation in corporate returns. A research objective in finance has long been to identify state variables not captured by an overall market factor. Many papers have sought to critique and refine the underlying approach of Fama French (Fama and French 1993; 1995; 2002). Lakonishok et al. (1994) for instance focus on growth rates of earnings and the pricing of earnings growth,suggesting that the superior observed return from high-book-to-market stocks are corrections of irrational pricing. Fama and French (1995) refute this explanation and suggest that if size and BE/ME factors are the result of rational pricing processes they are likely to be driven by factors common to expected earnings. Fama French, are explicit and generous in their articulation of open research questions and suggest guidance for future research. In Fama and French (1995), they identify and articulate the unanswered questions in inter-temporal asset pricing, for which size and BE/ME are likely proxies for sensitivity to risk factors in returns.

Recent works for instance by Petkova (2006) have begun to take up the challenge, examining predictive economic state variables that affect the yield curve and conditional distribution of asset returns. This is certainly a valid approach but one that overlooks the sector and country specific nature of state variables. The approach continues to fall foul of identified difficulties associated with accurate measurement of state variables. The general expectation offered by Petkova (2006) is that HML and SMB loadings should lose explanatory power when predictive economic state variables are identified. I concur but suggest that future work that add predictive state variables to Fama French will need to recognise the attributes of country and sector specificities. Our work suggests that the Fama French Three-Factor Model for returns is likely to progress through the isolation of measurable sector and country specific macroeconomic state variables rather than global measures of GDP or consumption growth. This approach brings together the industry importance findings by Cavaglia et al. (2000), with country factors Bekaert and Harvey (2002), and will provide a basis for understanding the conditions under which equity premia findings by Mehra and Prescott (1985) hold.

I suggest that it is precisely sector specificities in state variables that provide insights into underlying causes of risk and return premia in the Fama and French (1993) Three-Factor Model and propose a country location factor to provide sector insights into the first of two open questions identified by Fama and French (1995). Findings are aided by oil and gas sector attributes, state participation attaches to asset cash flows, as opposed to the corporate entity. State participation is calculated at or near the oilfield well-head. Country specific state oilfield participation, therefore, enables a direct link between field taxation terms and corporate returns in the context of Fama and French (1995).

Candidate state variables of gross national product and consumption are noted to have measurement problems that are overcome by isolating state asset participation in the homogenous oil and gas sector. The state return from oilfield assets is directly affected by the nature of fiscal participation and draws on prior findings that demonstrate that state participation varies widely depending on economic rent sharing principles between the state and the corporate (Adelman 1972). Specifically, in this prior work we show emerging market assets in Non-OECD countries have state participation terms that differ from those applied to oilfield assets in OECD countries. This distinction enables the introduction of a proxy measure of state asset participation captured by the R-factor. The use of a single sector to overcome endogeneity in the measurement of risk and return variables has precedent in Jin and Jorion (2006) and is used to isolate the effects of state participation in oilfield assets on the returns of corporate oilfield operators.

This chapter builds on previous work where I identify that global variations exist in state participation in the oil and gas sector. The previous chapters show that the state participation factor suggests that variation in global fiscal participation terms are able to forecast future investment performance in the oil and gas sector. By adding a reserve location factor (R-factor) to the Fama-French Three Factor Model as a proxy I show that the inclusion of a sector specific state variable provides insights into causes of variation behind size and BE/ME effects for companies with global oil and gas asset holdings. The addition of a state variable meets the Cochrane (2001) requirement of including only factors that directly forecast future investment returns. The R-factor isolates a natural resource sector variable that is able to explain the causes of unidentified risk and return premia associated with the size and BE/ME factors defined by Fama and French (1995).

I provide evidence that progressive state oilfield participation effectively limits the corporate value of emerging market O&G investment relative to developed markets. Findings support financial market results by Stulz (2005) and enable an analysis of the market effect of global differences in economic state variables (implicit in regulatory, fiscal and legal differences). In developed markets, the state generally participates in O&G assets in the form of profit taxation, while in Non-OECD countries. State participation in the form of Non-OECD production sharing O&G contracts are contrasted with concession state participation structures in OECD countries.[1]

Market findings contrast with prior equity market studies by Mehra and Prescott (1985) and Bekaert et al. (2005) who suggest that emerging markets provide consistent and compensatory value premia. Findings in this study mitigate against neoclassical theory that anticipates large capital flows toward developing country oil and gas sectors. Emerging market O&G reserve entitlement limits the upside for company earnings, with the potential for knock on effects into capital flows as the government participation effect becomes apparent at higher oil prices. As oil prices increase, the relative operating costs of producing oil decreases and the reserve entitlement structure in O&G will become the most important factor in future corporate cash flow entitlement.

In summary, this section refines Fama and French (2002). I find that, on average, small companies tend to have higher returns compared to large companies. Value stocks, in turn, tend to outperform growth stocks. The contribution of this work goes to the effect of underlying economic state variables on expected returns. I deconstruct the Fama French Three-Factor model portfolios into separate portfolios with low Non-OECD and portfolios with high Non-OECD reserve holdings. This allows the isolation of state participation effects on share price returns. Results from twelve portfolios

[1] In general, OECD countries in Europe, Russia, Australia and both North and South America use royalty systems. Production sharing contracts generally occur in the Non-OECD regions of Africa, Indonesia and much of the former Soviet Union. Reported reserves are based on the economic interest held subject to the specific terms and time frame of the agreement. For a full discussion of entitlement contracts see Guidelines for the Evaluation of Petroleum Reserves and Resources, SPE Working Paper 2005, and Bindemann (1999).

demonstrate that favorable Fama French portfolios, when weighted with a fourth factor that reflects high Non-OECD reserve holdings, tend to under-perform compared to unfavorable Fama French portfolios with low Non-OECD reserve holdings. I find that small value stocks with low Non-OECD holdings outperform all other portfolios. This fourth factor state variable loading suggests that relative share price performance for the O&G sector directly depends on state variable effects.

7.2. Research Design

7.2.1. Size, BE/ME and R-Factor Effects on Corporate Returns

In prior chapters I use a global sample of oilfield assets to provide insights into the effects of economic state variables on the BE/ME factor, enabling insights into the first of the two unanswered questions raised by Fama and French (1995). Based on this prior study, a distinction is made between differential state participation effects on OECD and Non-OECD assets. The distinguishing feature of this research is therefore the addition of an R-factor that focuses on the share price effect of state variables. The Fama French factors of size (market capitalization) and BE/ME are used as determinants of performance while the addition of a new R-factor proxies for state variable effects from OECD and Non-OECD countries. This variable allows the encapsulation of intensity of participation effects on full field life reserve values, as between developed (OECD) and emerging (Non-OECD) markets. The contribution is in analyzing the market allocation (OECD vs Non-OECD) of these assets and the state participation effect on the corporate returns of emerging market natural resource investment.

Natural resources deplete, with the result that oil reserve replacement is an accepted imperative for companies that derive earnings and balance sheet values from global resource assets and looking for sustainable earnings and shareholder value. For O&G producers concerned with reserve replacement, reserve entitlement generally varies from concession contracts in OECD countries to oil price related production sharing in Non-OECD countries. The corollary is that state participation is increased by reserve entitlement terms that vary with oil price. At high prices, marginal corporate cash flow entitlement is lower for oil and gas reserves in emerging economies than in developed countries – see chapter 4.

The Fama French factor variables of size (market capitalization) and BE/ME are derived from the annual financial statements. In line with the approach described by Fama and French (1995), companies are allocated annually into six groups with respect to size and BE/ME. At the first level, we break the sample into two groups with market capitalization above (B, big) and below the Median size (S, small). At the second level, a split into three sub-groups of high (H, top 30% percentile of BE/ME), medium (M, middle 40%) and low (L, bottom 30%) BE/ME is performed.

To expand the Fama-French Three-Factor-Model (Fama and French 1993; 1995) with a proxy state variable, each of the six Fama French (size, BE/ME) portfolios are disaggregated annually by percentage of reserve holdings in Non-OECD. I introduce the R-factor to reflect Non-OECD holdings below 30% and above 30% of total reserves and derive twelve new portfolios with annually re-balanced geographic asset classification. The inclusion of this annual R-factor serves as proxy for the effect of state variables on asset returns. In the context of the Fama-French framework, the R-Factor is calculated as a weighted long position in portfolios with low Non-OECD holdings and an equally weighted short position in portfolios with high Non-OECD holdings.[2] Following the Fama-French terminology, the R-factor is described as follows .

$$\text{FFR} \quad r_i - r_f = \alpha + \beta_1(r_M - r_f) + \beta_2\text{SMB} + \beta_3\text{HML} + \beta_4\text{OMN} + \varepsilon_i \tag{7.1}$$

with OMN representing 'Low Non-OECD Holdings Minus High Non-OECD holdings'

$$\begin{aligned}\text{OMN} = 1/6(&\text{SLO} + \text{SMO} + \text{SHO} + \text{BLO} + \text{BMO} + \text{BHO}) - \\ &- 1/6(\text{SLN} + \text{SMN} + \text{SHN} + \text{BLN} + \text{BMN} + \text{BHN})\end{aligned}$$

Findings in chapter 4 suggest the out-performance of a long position in low Non-OECD holdings resulting in a positive loading on the R-factor.

I analyze 770 O&G companies ranked by commercially held reserves (liquids in mmboe) and focus on the top 100 entities holding 70% of global reserves.[3] The focus is on O&G producers rather than exploration and service companies. National oil companies such as Saudi Aramco, Iraqi Oil Ministry and National Iranian Oil Company and the lack of disclosure by these entities inhibits market analysis and so they are excluded. The market approach requires the isolation of companies that report detailed reserve data to the market. Therefore, 32 O&G producers are selected from the top

[2]Key: S (size, small), B (size, big); L (low BE/ME), M (medium BE/ME), H (high BE/ME); O (low Non-OECD), N (high Non-OECD)

[3]Wood Mackenzie's Corporate Analysis Tool (CAT) is used to extract global commercial oil and gas reserves by company

100 representing 60% of commercially held global reserves (See Table 7.1 for 2005 reserve data). The sample selection is informed by extracting only companies compliant with SEC reporting requirements. This standardizes reserve extracts to SEC *proven* reserves. Companies which do not comply with SEC reporting standards or recommendations and therefore fail to disclose regional allocation of reserves or quote *proven and probable* (2P) reserves are not considered (e.g. Cairn Energy UK). The sample selection includes the six independent oil majors BP, Exxon-Mobil, Chevron, Shell, Total, Conoco-Phillips and 26 companies that comply with SEC reporting requirements.

For oilfield holdings I extract reserve data for the selected 32 oil producing companies on an annual basis. The differences in state participation terms allow the grouping of oil and gas reserves as between OECD and Non-OECD countries by company and informs the formation of portfolios based on state variables. OECD generally comprise concession holdings and Non-OECD assets comprise production sharing contracts. The exception is Russia where concessions dominate, but taxation terms are progressive with oil price. For the purpose of this study, Russian concession holdings are included in the sample of Non-OECD countries with PSC characteristics. Figure 7.1 illustrates the change in relative reserve holding allocations since 1997. Specifically, it matters where replacement reserves originate. Relative OECD and Non-OECD reserve allocation as a percentage of total reserves is illustrated on the company level in Table 7.1. Panel A displays companies with low relative reserve holdings in Non-OECD countries (less or equal to 30% of their total reserves in 2005), Panel B reflects $NOECD_{H05}$ companies with high Non-OECD holdings (above 30% of total reserves in 2005).

The global allocation of *proven* reserves is the focus of this study. Company disclosures, however, are generally not standardized and nor do SEC regulations require reserve reporting by country of origin.Therfore, all direct reserve holdings are manually classified into either OECD or Non-OECD reserves. 'Other' reserves from the SEC reports were similarly analyzed on the basis of company financial statement footnote disclosures, as were 'Equity' participation interests. This process involves manual analysis of all proven holdings for 32 companies as to the country of origin and is summarized by company in Table 7.1 as for 2005 reserve holdings and allows for the allocation of an annual R-Factor.

Daily share price data for a sample of 32 oil producing companies covering the eight year period from 31.12.1997 to 31.12.2005 are extracted. SEC 'EDGAR' 10-K and 20-F reports are extracted for nine reporting periods from 1997 to 2005. The MSCI ACWI Energy is used as a proxy to assess market performance for oil producing companies, the risk free interest rate is approximated by the 30-day Treasury Bill rate. Daily observations are converted to monthly return data. All computations in the FFR-framework are performed on a monthly basis and over a period of 8 years, where excess return is calculated as:

$$\text{Excess Return in } \% = \frac{\text{Return-1}}{100}. \tag{7.2}$$

Table 7.1. Company Total Reserves (Liquids) and Company Relative Reserve Holdings based on 2005 SEC Reserve Disclosures

This Table shows the absolute amount of total reserves in liquids (SEC disclosures in mmboe) and the relative OECD and Non-OECD country allocation for the sample of 32 O&G companies as at 31 December 2005. These reserves exclude synthetics, gas and oilsand holdings – price response behavior differs from liquid reserve holdings. Companies are sorted ascending by their amount of relative Non-OECD holdings. Panel A displays $NOECD_{L05}$ companies with low relative reserve holdings in Non-OECD countries (less or equal to 30% of their total reserves in 2005), Panel B reflects $NOECD_{H05}$ companies with high Non-OECD holdings (above 30% of total reserves in 2005).

	Total	Reserves in OECD			Reserves in Non-OECD		
	Reserves (mmboe)	Disclosed Reserves	Other Reserves	Equity Interest	Disclosed Reserves	Other Reserves	Equity Interest
Panel A: Relative Non-OECD Reserve Holdings $\leq$ 30% ($NOECD_{L05}$) as % of Total Reserves							
Suncor	7	100%	0%	0%	0%	0%	0%
Husky	565	97%	0%	0%	0%	3%	0%
Norsk Hydro	853	81%	9%	0%	0%	9%	0%
Pioneer	428	90%	0%	0%	10%	0%	0%
Apache	976	90%	0%	0%	9%	1%	0%
CanNatResources	1118	88%	0%	0%	12%	0%	0%
Encana	1121	88%	0%	0%	12%	0%	0%
EOG	106	88%	0%	0%	12%	0%	0%
Talisman	627	86%	0%	0%	14%	0%	0%
Woodside	281	81%	5%	0%	0%	14%	0%
Statoil	1760	65%	18%	0%	0%	18%	0%
Occidental	2127	77%	0%	0%	21%	2%	0%
Devon	895	75%	0%	0%	0%	25%	0%
Panel B: Relative Non-OECD Reserve Holdings > 30% ($NOECD_{H05}$) as % of Total Reserves							
Anadarko	1130	66%	3%	0%	29%	3%	0%
Hess	692	68%	0%	0%	24%	8%	0%
PetroCanada	446	66%	0%	0%	34%	0%	0%
Murphy	182	65%	0%	0%	35%	0%	0%
ExxonMobil	10491	36%	0%	26%	34%	4%	0%
Nexen	379	62%	0%	0%	35%	3%	0%
Shell	4636	27%	0%	25%	44%	3%	0%
BP	9565	46%	0%	0%	14%	6%	34%
ConocoPhillips	6333	45%	0%	0%	0%	16%	39%
Marathon	704	41%	0%	0%	53%	6%	0%
Eni	3773	18%	16%	0%	51%	16%	0%
BG	572	31%	0%	0%	59%	9%	0%
Chevron	8000	23%	4%	0%	40%	4%	30%
Total	6592	18%	0%	0%	38%	28%	15%
RepsolYPF	1167	0%	0%	0%	99%	1%	0%
Petrobras	9716	0%	0%	0%	93%	7%	0%
CNPC	10961	0%	0%	0%	0%	100%	0%
Sinopec	3294	0%	0%	0%	0%	100%	0%
CNOOC	1456	0%	0%	0%	98%	2%	0%

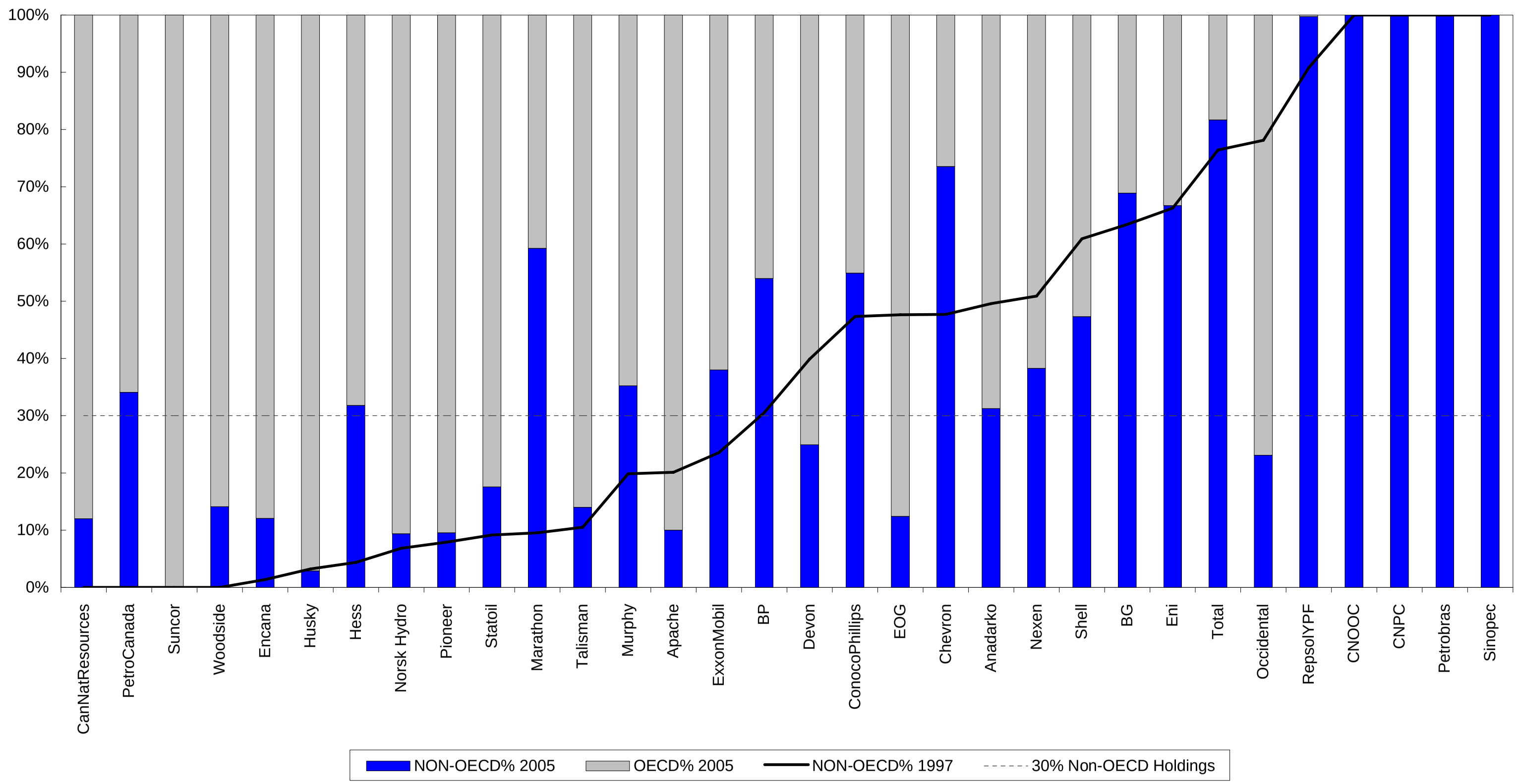

Figure 7.1. Changes in Companies' Relative OECD and Non-OECD Reserve Allocation as from 1997 to 2005
The graph in this Figure depicts, at each individual company level, the relative OECD and Non-OECD country reserve allocation based on 1997 and 2005 SEC data. The sample of 32 companies is sorted ascending based on their amount of relative Non-OECD holdings in 1997, represented by the solid line. The stacked bars illustrate each company's relative reserve allocation in 2005 while retaining the sort. Compared to the solid line for the 1997 allocations, shifts towards more Non-OECD country holdings are indicative for the majority of companies analyzed.

7.3. Empirical Analysis

7.3.1. The Fama French Three-Factor Model in the Oil and Gas Sector

As expected, the Fama French Three-Factor Model performs robustly for returns over the sample, with high indicative R^2 as shown in Table 7.2. Significant factor loadings for β_1 being market outperformance as measured against the MSCI ACWI energy index are observable. Factor loadings for β_2 show significant outperformance for small companies and significant underperformance for large companies with high BE/ME factors (B/H), loadings for β_3 indicate significant underperformance for low BE/ME portfolios and significant outperformance for portfolios comprising high BE/ME stocks.

Fama and French (1995) suggest that common factors in returns mirror common factors in earnings and suggest that market, size and book-to-market factors are the source of corresponding returns. They acknowledge, however, the absence of evidence concerning the causality of earnings book-to-market factors driving returns. It is suggested that in the oil and gas sector pure reliance on Fama French factors while ignoring the causality of differential returns in the sector (in this study state participation in oilfield assets) could be potentially misleading.

I test this postulation by differentiating the results from Table 7.2 on the basis of reserve holdings. This allows the introduction of geographic reserve distribution as a proxy for the economic state variable of state participation in oilfield assets. The ex ante expectation is that the dominance of Non-OECD assets in the company's portfolio would likely lead to an underperformance in returns without necessarily changing the book-to-market measure used in the Fama French Three-Factor model. The addition of a sector specific measure of the effects of economic state variables is necessary to identify causality in return differentiation in the FF model. The contention is that in line with Salomons and Grootveld (2003) and Bekaert and Harvey (2002) an ex ante measure of returns should necessarily be country specific in the first instance and industry specific in the second instance (Cavaglia et al. 2000). The proxy variable as well as being measurable meets both of these requirements.

Table 7.2. Pure FF Regression Results

This Table illustrates the estimated coefficients for Fama French Three-Factor Model regressions. Calculations are performed for 32 companies and over 8 years. Significance at a 90% level is indicated by *, at 95% and above by ** respectively; t-statistics are quoted in parentheses.

FF $r_i - r_f = \alpha + \beta_1(r_M - r_f) + \beta_2\text{SMB} + \beta_3\text{HML} + \varepsilon_i$

	Size (US$M)	BE/ME	Return	α	β_1	β_2	β_3	R^2
S/L	5676	0.2634	16.70%	0.0020	1.0211**	0.7343**	-0.2331*	0.7793
				(0.5322)	(13.7674)	(7.8338)	-(2.3297)	
S/M	5925	0.4486	23.29%	0.0024	1.1205**	0.9062**	0.0751	0.8629
				(0.7273)	(17.0551)	(10.9133)	(0.8469)	
S/H	5211	0.6988	27.60%	0.0024	1.0229**	0.9817**	0.5091**	0.8714
				(0.6950)	(15.3653)	(11.6682)	(5.6682)	
B/L	99387	0.2680	7.94%	0.0020	1.0490**	-0.0981	-0.4845**	0.7048
				(0.5330)	(14.6291)	-(1.0824)	-(5.0078)	
B/M	47855	0.4170	16.84%	0.0033	1.0683**	0.0659	0.0623	0.8691
				(1.3064)	(21.8488)	(1.0663)	(0.9441)	
B/H	50140	0.8486	18.71%	0.0016	1.0472**	-0.3455**	0.7733**	0.8046
				(0.4138)	(13.7881)	-(3.5992)	(7.5459)	

7.3.2. Testing the R-Factor

Kan and Zhang (1999) highlighted the effects of "useless factors" on asset pricing models. I conduct preliminary tests to show the effectiveness of the R-Factor. Limited disclosure of company reserve allocation combined with limitations of available time series data suggests the need for insights into the R-factor. Corporate values in the commodity sector are driven by entitlement to, and valuation of, the underlying asset (Strong 1991). All things equal, the process of Non-OECD reserve replacement rather than OECD replacement is expected to reduce share value. Stock returns embody the expected benefit from assets over their whole life. Since Non-OECD asset entitlement is limited, each increase in Non-OECD asset holdings is expected to results in a decrease in returns in line with Kretzschmar and Kirchner (2007). The ex ante expectation is that companies with low Non-OECD relative reserve holdings should, on average, outperform companies with high holdings in Non-OECD countries.

Table 7.3 illustrates average annual share price returns as between low and high Non-OECD holdings. The company allocation into $NOECD_{Low}$ and $NOECD_{High}$

portfolios is re-balanced on an annual basis. Re-balancing is based on the earnings effect that reserve replacement from Non-OECD countries has on the overall company reserve holdings. In a year where Non-OECD holdings exceed 30% a company is re-classified from $NOECD_{Low}$ to $NOECD_{High}$ and vice versa. Table 7.3 indicates that for the whole period (years 1998 to 2005) $NOECD_{Low}$ outperforms $NOECD_{High}$ by an absolute difference of 11% $(1.21 - 1.10)$. The significance of the out-performance of $NOECD_{Low}$ portfolio is particulary marked in 2000 and 2005.

As a second test, I analyze daily company equity betas with references to daily WTI oil future returns. Two separate portfolios provide annual re-balanced beta insights for Non-OECD holdings above and below 30% of total reserves as between December 1997 and December 2005. Linking the market response of OECD and Non-OECD reserves to movements in oil futures price is based on forward looking asset price response factors derived in previous research in chapter 4. In Table 7.3, I demonstrate on the basis of state participation in reserve holdings that oil price betas are not homogenous. Both Rajgopal (1999) and Haushalter (2000); Haushalter et al. (2002) find betas in the range 0.24 ... 0.25. Their findings cover low oil price periods comparable to 0.20 for $NOECD_{Low}$ (0.13 for $NOECD_{High}$) in Table 7.3 for the period of 1997 to 2001. Structural shifts are reflected in beta movements to 0.24 for $NOECD_{Low}$ (0.14 for $NOECD_{High}$).

7.3.3. Reserve Holdings in OECD and Non-OECD Countries

The importance of the R-Factor in the oil and gas sector is evident. Total reserves for the sector have increased in absolute terms by 13,492mmboe for the observed period 1997 to 2005. Of the absolute increase in total reserves, (disclosed reserves, other reserves and equity interest) 90% are sourced from Non-OECD counties with only 10% (disclosed reserves, other reserves and equity interest) from OECD countries (Table 7.4). The expectation is that state participation in replacement reserves which have significant effect on long-term shareholder returns, a factor not previously measured in Fama French studies. Table 7.4 provides instructive insights into the reserve movement for the period 1997 to 2005. Total reserves and movements in disclosed relative allocation in OECD and Non-OECD countries are reported for 1997 and 2005. Equity

Table 7.3. Annually Re-Balanced Equity Betas Relative to WTI Oil Futures

This Table displays equity betas for companies and illustrates the relation between WTI futures returns and company share price returns. Following insights into structural shifts in oil price provided by Geman (2005), the analysis is split into annual time periods. Portfolios are annually re-balanced to $NOECD_{Low}$ and $NOECD_{High}$ based on the percentage of company reserve holdings ($\leq$ 30% and > 30%) in Non-OECD countries. To provide comparability, eight annually re-balanced betas for $NOECD_{Low}$, $NOECD_{High}$ are computed. The existence of significant differences in returns between the $NOECD_{Low}$ and $NOECD_{High}$ portfolios is verified through paired 1-tailed t-tests run at the daily individual stock return level for the sample. Significance at a 90% level is indicated by *, at a 95% level by ** respectively; p-values are quoted in parentheses.

Year	Stock Returns and Tests for Difference			Equity Betas on WTI Futures Returns		
	$NOECD_{Low}$	$NOECD_{High}$	t-Test	$NOECD_{Low}$	$NOECD_{High}$	WTI
1998	–20%	–15%	(0.3451)	0.14	0.11	–32%
1999	26%	23%	(0.4011)	0.28	0.16	18%
2000	35%	09%	(0.0737)*	0.18	0.09	5%
2001	–4%	–8%	(0.3748)	0.23	0.13	–23%
2002	07%	–6%	(0.1528)	0.25	0.15	53%
2003	45%	35%	(0.2544)	0.09	0.01	4%
2004	40%	23%	(0.1047)	0.27	0.14	33%
2005	66%	31%	(0.0223)**	0.46	0.26	40%
1998–2005	21%	10%	(0.0143)**	0.22	0.10	17%

[1)] WTI Futures daily continuous time series annualized

Table 7.4. Reserves

This Table reflects the total amount of reserves and their absolute and relative allocation (OECD, Non-OECD, Other, Equity) across the entire sample of 32 companies as at 1997 and 2005. To illustrate the origins of reserve replacement, the relative and absolute composition of the difference in total reserves as of 2005 and 1997 is calculated. The origin of the increase is analyzed and indicates a preponderance of Non-OECD replacement. Negative replacement occurs as a result of the utilization of other Non-OECD reserves. Absolute figures are presented in mmboe.

	Total Reserves	Disclosed Reserves		Other Reserves		Equity Interest	
	(mmboe)	OECD	Non-OECD	OECD	Non-OECD	OECD	Non-OECD
1997	77,462	26,971 35%	18,580 24%	897 1%	23,108 30%	3,167 4%	4,739 6%
2005	90,953	27,190 30%	28,716 32%	1,314 1%	20,846 23%	3,848 4%	9,040 10%
1997-2005 increase	13,492	219 2%	10,135 75%	417 3%	-2,262 -17%	681 5%	4,301 32%

participation and cumulated reserves from unspecified 'other' regions are also allocated into OECD and Non-OECD based on the availability of more detailed information in the notes of individual companies' annual financial statements. 'Other' international reserve holdings are only classified where they comprise more than 5% of total reserves.

7.3.4. FFR Model – Proxied by Global Reserve Distribution

The introduction of a state variable necessitates the creation of a extra set of portfolios to lift out the performance effects of the R-Factor. In Table 7.5 I incorporate a measure of low Non-OECD state participation (below 30% of relative reserve holdings in Non-OECD regions) described by the suffix 'O' and high Non-OECD state participation described by 'N' (above 30% of relative reserve holdings in Non-OECD regions). At the sample level, 90% of reserve replacement in the period 1997 to 2005 has been sourced from Non-OECD holdings (Table 7.4, 75% from disclosed reserves, -17% being a reduction in other reserves, 32% from an increase in equity interest). This compares to the 1997 holding of 40% in OECD and 60% in Non-OECD, reflecting an increase in industry dependence on Non-OECD holdings.

Omitting the R-factor in the Fama French Model masks the underperforming effect of high Non-OECD reserve holdings. A comparison of Panels A and B in Table 7.5 demonstrates that with the exception of BHN, portfolios with Non-OECD holdings below 30% of reserves outperform portfolios with high Non-OECD holdings. This effect is not observable in Table 7.2 where excess return of 16% for S/L oversimplifies the SLO excess return of 22% by including SLN of −2%.

Following the inclusion of the R-factor accounting for high Non-OECD reserve holdings, it is possible to observe results from twelve portfolios. Table 7.5 demonstrates that most favorable Fama French portfolios (as defined by underlying Fama French factors), tend to under-perform compared to unfavorable Fama French portfolios with low Non-OECD reserve holdings. Table 7.5 presents two panels of data differentiated by low Non-OECD holdings as distinct from high Non-OECD holdings. In all instances except BHO and SHN, portfolios comprising low Non-OECD holdings outperform portfolios with high Non-OECD holdings. These findings are consistent with chapter 4. The BE/ME measure is the book value of common equity divided by market equity at year end, calculated as the portfolio average of annual BE/ME factors.

If the trend of replacing reserves from Non-OECD countries continues, reserve replacement is expected to be reflected in significant differences in share returns between companies that have high levels of OECD holdings relative to those that have low levels of OECD exposure. Table 7.6 shows two sets of annually re-balanced portfolios based on relative reserve holdings. The first with low relative Non-OECD holdings equal or below 30% ($NOECD_{Low}$), the second with high Non-OECD holdings greater 30% of total reserves ($NOECD_{High}$).

7.3.5. FFR Model Regressions Analysis – R-Factor vs Size and BE/ME

As Fama and French (2002) note, the equity premium – defined as the difference between returns on the market portfolio of stocks and the risk free rate – is important in modeling portfolio allocation decisions. An outstanding question remains as to the effect of state variables on equity premia. This effect is approximated through the introduction of the R-Factor, Table 7.7b distinguishes between low and high Non-OECD

Table 7.5. Fama French Portfolios with R-Factor Factor

This Table illustrates factor characteristics of 12 portfolios. Panel A describes factors for the first group of size and BE/ME portfolios consisting of companies with relative Non-OECD reserve holdings below 30%. The return above risk free $r_i - r_f$ is calculated for each of the 12 FFR portfolios, with annual re-balancing. The excess return calculation is performed using annualized daily data. Panel B shows the same measure factors for portfolios with relative Non-OECD reserve holdings in excess of 30%.

	$r_i - r_f$	ME (US$M)	BE/ME	Non-OECD Reserves
		Panel A: Low Non-OECD Holdings		
SLO	22%	7,250	0.26	22%
SMO	25%	6,444	0.46	15%
SHO	34%	6,347	0.64	11%
BLO	27%	41,128	0.26	5%
BMO	15%	36,261	0.43	23%
BHO	15%	88,453	0.71	8%
		Panel B: High Non-OECD Holdings		
SLN	–2%	4,751	0.26	69%
SMN	–1%	6,501	0.42	65%
SHN	41%	5,205	0.76	62%
BLN	2%	123,408	0.28	61%
BMN	13%	52,791	0.41	61%
BHN	17%	33,796	1.06	84%

Table 7.6. Test for Difference in Low/High Non-OECD Portfolio Returns

The existence of significant differences in excess returns between the six $NOECD_{Low}$ and $NOECD_{High}$ portfolios is verified through paired 1-tailed t-tests run at the daily individual stock return level for the sample. Significance at a 90% level is indicated by *, at a 95% level by ** respectively; p-values are quoted in parentheses.

$r_i - r_f$	SLO SLN	SMO SMN	SHO SHN	BLO BLN	BMO BMN	BHO BHN
t-test	(0.0162)**	(0.0210)**	(0.2716)	(0.0749)*	(0.4139)	(0.4393)

holdings in the portfolio construction. The focus is on positive or negative factor loadings and their contribution to expected excess portfolio returns. For β_1, market premium, an analysis of 60% of global commercially held oil reserves across 32 companies indicates a positive and significant effect on expected returns. This intuitive result is consistent with evidence from Fama and French (2002).

The findings for the β_2 factor, in which small companies are expected to outperform big companies, are also consistent with Fama and French (2002). Small companies with low Non-OECD holdings (Panel A) significantly outperform large companies with comparable holdings. These results are repeated in Panel B for high Non-OECD reserve holdings. Interestingly, when reading Table 7.5 together with Table 7.7b, large companies with low Non-OECD holdings are shown to outperform small companies with high Non-OECD holdings. This provides early insights into the possibility that country variables (R-factor) have an effect on expected returns.

The β_3 factor which links out-performance of companies with high BE/ME ratios (value stocks) to positive factor loadings provides results inconsistent with Fama and French (2002). Specifically, high BE/ME is consistent with Fama and French (2002), medium BE/ME is only consistent with Fama and French (2002) only for low Non-OECD holdings (Panel A). Panel B indicates negative loadings for this factor, an observation inconsistent with findings by Fama and French (2002). The addition of the low BE/ME ratio provides inconsistent results in both panels.

The ex ante expectation is that progressive state participation in Non-OECD asset cash flows are likely to translate into return discounts for companies overweight Non-OECD asset holdings. This fourth factor in the FFR model is included as β_4 with positive loadings expected to reflect the benefits of low Non-OECD holdings. Findings in both Panels A and B are consistent with ex ante expectation and evidence provided in chapter 4. Panel A reflects a significant and positive effect of low Non-OECD holdings across all portfolios. In Panel B, five out of six portfolios have the expected negative loading with only SHN demonstrating a positive but insignificant loading.

The four factors β_1 to β_4 are all expected to have direct relevance to expected stock returns. Difficulties in measuring state effects contrast with the general equity risk premium findings of Bekaert et al. (2005) and Mehra and Prescott (1985). Findings

Table 7.7a. FFR Regression Results for 12 Portfolios

This Table illustrates the estimated coefficients for the first and second stage regressions. Significance at a 90% level is indicated by *, at 95% and above by ** respectively; t-statistics are quoted in parentheses.

FFR $r_i - r_f = \alpha + \beta_1(r_M - r_f) + \beta_2\text{SMB} + \beta_3\text{HML} + \beta_4\text{OMN} + \varepsilon_i$

	SMB β_2			HML β_3			OMN β_4		
	BE/ME Low	BE/ME Middle	BE/ME High	BE/ME Low	BE/ME Middle	BE/ME High	BE/ME Low	BE/ME Middle	BE/ME High
Panel A: Relative Non-OECD Reserve Holdings as % of Total Reserves $\leq$ 30%									
Size Small	0.5197**	0.7118**	0.7687**	-0.2854**	0.1204	0.2916**	0.2444	0.5677**	0.6280**
Size Big	-0.4346**	0.2546	-0.1823	-0.1949	-0.1513	0.6308**	1.5689**	0.3568	0.5036**
Panel B: Relative Non-OECD Reserve Holdings as % of Total Reserves > 30%									
Size Small	0.5703**	0.7938**	1.2737**	-0.3480*	-0.4495**	1.0822**	-0.4214*	-0.1924	0.0431
Size Big	0.1101	-0.0152	-1.0947**	-0.5472**	0.0539	0.6199**	-0.8731**	-0.0309	-0.6559**

Table 7.7b. FFR Regression Results

This Table illustrates the estimated coefficients for the first and second stage regressions. Significance at a 90% level is indicated by *, at 95% and above by ** respectively; t-statistics are quoted in parentheses.

FFR $r_i - r_f = \alpha + \beta_1(r_M - r_f) + \beta_2\text{SMB} + \beta_3\text{HML} + \beta_4\text{OMN} + \varepsilon_i$

	α	β_1	β_2	β_3	β_4	F-Statistic	R^2
			Panel A: Low Non-OECD Holdings				
SLO	0.0088	1.0128**	0.5197**	-0.2854**	0.2444	38.1906	0.6103
	(1.6876)	(10.4909)	(4.0179)	-(2.4936)	(1.5480)		
SMO	0.0016	1.2381**	0.7118**	0.1204	0.5677**	90.8720	0.7910
	(0.3493)	(14.6237)	(6.2758)	(1.1996)	(4.0997)		
SHO	0.0058	1.1472**	0.7687**	0.2916**	0.6280**	127.9880	0.8424
	(1.5057)	(16.0707)	(8.0378)	(3.4455)	(5.3785)		
BLO	0.0043	0.8750**	-0.4346**	-0.1949	1.5689**	22.5018	0.4752
	(0.5820)	(6.3550)	-(2.3560)	-(1.1940)	(6.9664)		
BMO	0.0012	1.1410**	0.2546	-0.1513	0.3568	32.0700	0.5668
	(0.1917)	(10.1921)	(1.6976)	-(1.1401)	(1.9484)		
BHO	-0.0043	0.8367**	-0.1823	0.6308**	0.5036**	43.7042	0.6426
	-(0.8401)	(8.8713)	-(1.4423)	(5.6419)	(3.2648)		
			Panel B: High Non-OECD Holdings				
SLN	-0.0040	1.1293**	0.5703**	-0.3480*	-0.4214*	26.5100	0.5179
	-(0.5853)	(8.8789)	(3.3466)	-(2.3085)	-(2.0257)		
SMN	-0.0036	0.9558**	0.7938**	-0.4495**	-0.1924	19.0932	0.4324
	-(0.4685)	(6.7623)	(4.1920)	-(2.6831)	-(0.8322)		
SHN	0.0088	0.7677**	1.2737**	1.0822**	0.0431	70.0656	0.7441
	(1.5065)	(7.0936)	(8.7847)	(8.4358)	(0.2433)		
BLN	0.0072	1.0620**	0.1101	-0.5472**	-0.8731**	38.0875	0.6096
	(1.3667)	(10.8146)	(0.8371)	-(4.7011)	-(5.4357)		
BMN	0.0029	1.0086**	-0.0152	0.0539	-0.0309	113.5363	0.8257
	(1.0497)	(19.5212)	-(0.2192)	(0.8801)	-(0.3661)		
BHN	0.0060	1.3275**	-1.0947**	0.6199**	-0.6559**	51.5107	0.6802
	(0.8562)	(10.1901)	-(6.2721)	(4.0144)	-(3.0782)		

suggest recognition of the effects of state participation in O&G production and provide sector evidence in support of Stulz (2005), who notes that when rulers of sovereign states pursue their interests at the expense of corporate agents, investor payoffs are directly affected.

7.4. Chapter Concluding Remarks

The results of this study present early evidence that state variables captured by the FFR model directly and differentially affect stock returns. Evidence is provided of limits to the corporate value of Non-OECD asset participation. Discounted share returns for companies overweight Non-OECD assets provide evidence of market awareness of long-term value divergence based on OECD and Non-OECD asset holdings. Reasons for Non-OECD discounts are explored in this study.

On the basis of this work, a constant and consistent discount, regardless of oil price levels, should exist if the discount is based purely on risky Non-OECD asset holdings. Market returns for shares overweight Non-OECD assets suggest evidence that markets are price sensitive to state asset participation.

Reserve replacement is a 'presumed' imperative for companies operating in the natural resource sector. The source of reserve replacement as between OECD and Non-OECD countries is a significant factor in the determination of share price returns. Shares of companies with OECD dominated asset holdings trade at a consistent premium as compared to shares of companies with high Non-OECD reserve holdings. The premium is particularly observable when oil prices are above US$45/bbl, a finding that corroborates work in chapter 4. Further work on state effects in sectors other than the natural resource sector is required to determine the state variables that affect market pricing.

8. Thesis Conclusion

The findings of this work revise asset valuation findings by Rajgopal (1999), Haushalter et al. (2002) and Jin and Jorion (2006), who derive O&G findings during the low oil price paradigm extant in the 1990's. Specifically, I show that the global nature of government participation directly affects asset prices and as a result, it matters in which country reserves are held and the entitlement structures under which the state and corporates share economic rents from resource assets. Evidence is provided that progressive Non–OECD state entitlement structures affect the corporate value of assets adversely when compared to OECD state asset participation.

This thesis provides empirical insights into the effect of state participation on the value of expected cash flows. State agency differences are shown to potentially prevent asset valuation model convergence, a finding in support of those anticipated in works by by Bekaert and Harvey (2002) and Bruner et al. (2002). Intrinsic asset values are a function of expected future cash flows, but, they are also a function of market uncertainty associated with them. My findings demonstrate that under conditions of stochastic commodity price volatility, entitlement to global concession and production sharing reserve asset cash flows is not homogenous. As result, it matters what expectations are for oil price. The corporate asset value response of OECD and NON-OECD assets diverges under high oil prices as result of the progressive nature of Non-OECD state agent participation in economic asset rent. Despite the lack of adequate accounting disclosures, a value premium exist for companies with OECD assets – in periods of low oil prices. The premium increases in times of high oil prices, providing market evidence corporate agents in OECD countries benefit from non progressive state agency participation. Findings are consistent with work by Hampson et al. (1991) who suggest that state agency does have the ability to affect asset pricing and limit the value of globalization (Stulz 2005).

The final chapter of this study presents early market evidence that state variables (captured by the FFR model) directly and differentially affect stock returns. Evidence is provided of limits to the corporate value of Non-OECD asset participation. Discounted share returns for companies overweight Non-OECD assets provide insights into a market awareness of the potential for long-term value divergence based on OECD and Non-OECD asset holdings. This allows me to provide a natural resource sector refinement to work seeking to adapt the Fama and French (1995) model. Prior works overlook the sector and country specific nature of state variables. The general expectation offered by Petkova (2006) is that HML and SMB loadings should lose explanatory power when predictive economic state variables are identified. This work suggests that future studies that aim to add predictive variables to the Fama French models will need to recognise the attributes of country and sector specificities.

List of Abbreviations

000 b/d	Barrels per Day in Thousands
ANG	Angola
bbloe	Barrel of Oil Equivalent
bbl	Barrel
B	Bonus (S = Signature bonus, P = production bonus and C = Compensation bonus). Signature bonuses are payable for each contract, and the amount varies widely, but typically reflects the perceived prospectivity of the area. A production bonus is payable for each contract and the amount is typically a biddable item
CAPEX	Capital Expenditure
CAPM	Capital Asset Pricing Model
CF	Cash Flow
CIT	Corporate (petroleum) Income Tax (Angola). Calculated on the contractor's share of profit oil (gas), less price cap
CON	Concession Regime
CT	Corporation Tax (UKCS). Calculated on pre-tax profits (revenues – operating costs – capital allowances) less PRT
C&W	Corporation and Withholding tax (Indonesia, effective rate). An effective tax rate integrating both standard income tax and dividend withholding tax, and is levied on the contractor's FTP, and the contractor's share of profit oil less allowable costs
DCF	Discounted Cash Flow

DM	Domestic Supply Obligation. A percent of the contractor's share of oil production must be supplied to the local market at a price considerably lower than prevailing market prices
EGY	Egypt
FASB	Financial Accounting Standards Board
FC	Full Cost Method
FIT	Federal Corporate income Tax (GoM). Calculated on operating profit net of allowable deductions
FOC	Foreign Oil Company
FR	Financial Reporting Release
FSA	Financial Services Authority, UK
FTP	First Tranche Petroleum. A percent of production is divided between the contractor and the government according to their pre-tax profit share entitlements
GARCH	Generalized Autoregressive Conditional Heteroscedasticity
GEM	Wood Mackenzie "Global Economic Model"
GoM	Gulf of Mexico
IDO	Indonesia
mmboe	Million Barrel of Oil Equivalent
NCS	Norwegian Continental Shelf
NOC	National Oil Company
NPV	Net Present Value
OECD	Organisation for Economic Co-operation and Development
OPEX	Operational Costs
O&G	Oil and Gas
PC	Price cap. A capping mechanism where the government receives an excess fee, calculated as the difference between the market price and the price cap, multiplied by the number of barrels in the contractor's share of profit oil
PDF	Probability Distribution Function
PG	Profit gas

PO	Profit Oil. Under PSC tax terms a percent of production is available for the recovery of operation and capital costs. The remaining production after cost recovery is termed profit oil/gas and is divided between the contractor and the government. The basis on which this division is made varies between contracts. Some contracts are based on the contractor's rate of return (based on the contractor's accumulated compounded post-tax cash flow), whereas in other contracts the split is based on cumulative production. Within each contractor the split varies according to a sliding scale or is based on a constant basis. Profit oil/gas shares are negotiable and therefore oilfield specific
PRT	Petroleum Revenue Tax (UKCS). Calculated on pre-tax profits (revenues – operating costs – capital allowances)
PRT	Petroleum Revenue Tax
PSC	Production Sharing Contract
PV	Present Value
RRA	Revenue Recognition Accounting
R	Royalty tax. Calculated on wellhead value of petroleum produced, where the well-head value is calculated as the sales value of production net of 'off-lease' costs relating to production and transport to point of sale
SCT	Supplementary Corporate Tax. Calculated on total taxable profits
SD	Standard Deviation
SEC	U.S. Securities and Exchange Commission
SE	Successful Efforts Method
SPT	Special Petroleum Tax (NCS). Calculated on total taxable profits
U.S.	United States of America
UKCS	United Kingdom Continental Shelf

UK	United Kingdom
WTI	West Texas Intermediate
$M	U.S. Dollars in Million

List of Variables

b	Base Price Deck US$45/bbl
$Capex$	Capital Expenditure (Vector)
$CAPEX_t$	Capital Expenditure at Time t
$CashFlow_t$	Cash Flow at Time t
$CostOil_t$	Amount of Production Available for Cost Recovery at Time t
$Depr_t$	Depreciation at Time t
DF	Discount Factor (Vector)
$Downside$	Dependent Variable for Field Downside
D_{NOECD}	Dummy Variable Non-OECD Reserve Holdings below 25%
D_{OFP}	Dummy Variable Oil Futures Price above US$45/bbl
D_{Regime}	Dummy Variable Non-OECD Country
D_{Size}	Dummy Variable Remaining Reserves above 100mmboe
$EntitledProduction$	Entitled Production for PSC Contracts (Vector)
$EntitledProduction_t$	Entitled Production for PSC Contracts at Time t
$Fiscal$	Fiscal Costs (Vector)
F_t	Futures Price at Time t
h	High Price Deck US$90/bbl
IRR	Internal Rate of Return
l	Low Price Deck US$33.75/bbl
n	Field life in years
NPV_{yy}	NPV Response with $_{yy}$ denoting the price scenario in US$/bbl

OFP	Oil Futures Price
OFR	Oil Futures Returns
$OpCap$	Operational Costs plus Capital Expenditure (Vector)
$Opex$	Operational Costs (Vector)
$OPEX_t$	Operational Costs at Time t
$PostTax$	Post-Tax
$PreTax$	Pre-Tax
$price$	Price (Vector)
$Price_t$	Oil Price at Time t
$production$	Production (Vector)
$Production_t$	Production at Time t
$ProfitOil_t$	Profit Split between Foreign Oil Company and State at Time t
PTP	Post-Tax Profit
PV_{zz}	Present Value of Cost Structures with $_{zz}$ denoting Cost Variable
P_{yy}	Price Deck with $_{yy}$ denoting the Price Scenario in US$/bbl
Q_{yy}	Production Entitlement Response with $_{yy}$ denoting the Price Scenario in US$/bbl
$Revenue$	Revenue (Vector)
ROR_t	Realized Rate of Return at Time t
r	Discount Rate
R^2	Coefficient of Determination
R_{yy}	Reserve Entitlement Response with $_{yy}$ denoting the Price Scenario in US$/bbl
$SpecifiedMultiplier$	Specified Cost Multiplier in PSC Contracts
SPR	Share Price Returns
S_t	Spot Price at Time t
$taxrate_t$	Annual Composite Tax Rate at Time t
Tax_t	Taxes Payable at Time t

$TotalProduction$	Total Production (Vector)
$TotalProduction_t$	Total Production at Time t
$Total$	Total Costs and Expenditures (Vector)
$TotCost$	Total Costs and Expenditures (Vector)
$Uplift$	Cost Recovery Uplift Factor in PSC Contracts
$Upside$	Dependent Variable for Field Upside
U	Utility Function
V	Asset Value
x	Random Variable
X_i	Independent Variable in Regressions
z	Asset Payoffs (Vector)
α	Constant in Regressions
β	Equity Beta
β^*	Hedge Ratio
β_i	Coefficient for Independent Variables in Regressions
ΔTR	Change in Total Reserves
Λ	Probability of Loss
μ	Mean
ϕ	Asset Pricing Kernel (Vector)
π^*	(Risk Neutral) Probabilities (Vector)
ψ	Degree of Risk Aversion
Ψ	Field Cost Structures
σ	Standard Deviation

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Part II.

Appendices

A. Wood Mackenzie GEM Data Extraction

Annual Price, Cost and Cash Flows Estimations over the Whole Field Life

Table A.1. Wood Mackenzie Global Economic Model (GEM) Data Extraction for OECD vs Non-OECD Asset Pricing

Wood Mackenzie's field model contains detailed data relating to the underlying oil and gas reserves. Column 1 contains year of production, where 2006 represents the base year NPV calculation. Columns 2, 3, 4, and 5, represent the underlying oilfield technical data, as agreed between WM specialist oil and gas researchers and signed off by oil field operators. Columns 6, 7, and 8, represent the 3 mean reverting price decks as applied to the NPV analysis, where 6 is the Basedeck (b) 7 is the Lowdeck (l) and 8 the Highdeck (h). Columns 9 and 10 represent the gas price deck and the underlying specific gas prices contracted to the field. Columns 13 through to 20 inclusive, summarize the capital expenditure in respect of the field. These are differentiated as between production facilities, subsea and drilling, and transportation. Columns 21 and 22, represent the field operational costs. 23 and 24 represent direct tariffs with 25 and 26 comprising royalty, production sharing, or the applicable fiscal terms for the regime.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
Year	Production				Price					Capital Costs										Operational Costs				Tax	
										Field Capex					Transport Capex			Other Capex		Field Opex					
	Liquid 1	Liquid 2	Gas 1	Gas 2	BaseDeck	LowDeck	HighDeck	Gas 1	Gas 2	E&A Costs	Product. Facilities	Process. Equip.	Subsea	Dev. Drilling	Pipeline	Offshore Loading	Terminal	Other	Abandon. Costs	Field Fixed	Field Variable	Tariff Oil	Gas	Royalty	Federal Tax
2005	000b/d	000b/d	mmcfd	mmcfd	$/bbl	$/bbl	$/bbl	$/mcf	$/mcf	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
2006	–	–	–	–	45.00	33.75	90.00	7.02	–	–	370.2	166.59	111.06	222.12	–	–	–	12.34	–	–	–	–	–	–	–
2007	–	–	–	–	40.92	30.69	81.84	6.61	–	–	370.2	92.55	111.06	222.12	24.68	–	–	12.34	–	–	–	–	–	–	–
2008	61.70	–	27.77	–	37.85	28.39	75.70	6.31	–	–	61.7	–	–	–	12.34	–	–	12.34	–	18.51	17.28	33.78	2.03	105.65	–
2009	141.91	–	78.98	–	36.70	27.52	73.39	6.22	–	–	–	–	74.04	246.8	12.34	–	–	12.34	–	24.68	39.73	77.70	5.77	241.40	258.45
2010	148.08	–	82.68	–	37.61	28.21	75.22	6.33	–	–	–	–	222.12	296.16	24.68	–	–	12.34	–	24.68	41.46	81.07	6.04	257.82	436.78
2011	148.08	–	76.51	–	38.55	28.91	77.11	6.45	–	–	–	–	–	–	–	–	–	6.17	–	24.68	41.46	81.07	5.59	262.40	542.91
2012	135.74	–	61.70	–	39.52	29.64	79.03	6.57	–	–	–	–	–	–	–	–	–	6.17	–	24.68	38.01	74.32	4.50	244.33	512.22
2013	117.23	–	53.06	–	40.50	30.38	81.01	6.69	–	–	–	–	–	–	–	–	–	6.17	–	24.68	32.82	64.18	3.87	216.21	464.07
2014	98.72	–	44.42	–	41.52	31.14	83.03	6.81	–	–	–	–	–	–	–	–	–	6.17	–	24.68	27.64	54.05	3.24	186.59	416.67
2015	111.06	–	49.98	–	42.55	31.92	85.11	6.94	–	–	–	–	55.53	148.08	–	–	–	12.34	–	24.68	31.10	60.81	3.65	215.40	439.38
2016	93.78	–	39.98	–	43.62	32.71	87.24	7.07	–	–	–	–	–	–	–	–	–	6.17	–	24.68	26.26	51.35	2.92	185.76	418.69
2017	76.51	–	31.65	–	44.71	33.53	89.42	7.19	–	–	–	–	–	–	–	–	–	6.17	–	24.68	21.42	41.89	2.31	155.13	353.49
2018	59.23	–	24.99	–	45.83	34.37	91.65	7.33	–	–	–	–	–	–	–	–	–	6.17	–	24.68	16.58	32.43	1.82	123.32	282.33
2019	46.89	–	19.99	–	46.97	35.23	93.95	7.46	–	–	–	–	–	–	–	–	–	6.17	–	24.68	13.13	25.67	1.46	100.09	226.51
2020	35.79	–	16.10	–	48.15	36.11	96.29	7.60	–	–	–	–	–	–	–	–	–	6.17	–	24.68	10.02	19.59	1.18	78.54	173.33
2021	28.38	–	12.77	–	49.35	37.01	98.70	7.73	–	–	–	–	–	–	–	–	–	6.17	–	24.68	7.95	15.54	0.93	63.82	136.87
2022	22.21	–	10.00	–	50.58	37.94	101.17	7.87	–	–	–	–	–	–	–	–	–	6.17	–	24.68	6.22	12.16	0.73	51.17	107.31
2023	17.28	–	7.77	–	51.85	38.89	103.70	8.02	–	–	–	–	–	–	–	–	–	6.17	–	24.68	4.84	9.46	0.57	40.77	83.26
2024	14.19	–	6.39	–	53.15	39.86	106.29	8.16	–	–	–	–	–	–	–	–	–	6.17	–	24.68	3.97	7.77	0.47	34.32	67.03
2025	11.11	–	5.00	–	54.47	40.86	108.95	8.31	–	–	–	–	–	–	–	–	–	6.17	–	24.68	3.11	6.08	0.36	27.51	49.93
2026	8.64	–	3.89	–	55.84	41.88	111.67	8.51	–	–	–	–	–	–	–	–	–	6.17	–	24.68	2.42	4.73	0.28	21.93	35.83
2027	7.40	–	3.33	–	57.23	42.92	114.46	8.73	–	–	–	–	–	–	–	–	–	6.17	–	24.68	2.07	4.05	0.24	19.27	28.85
2028	6.17	–	2.78	–	58.66	44.00	117.32	8.94	–	–	–	–	–	–	–	–	–	6.17	–	24.68	1.73	3.38	0.20	16.46	21.51
2029	4.94	–	2.22	–	60.13	45.10	120.26	9.17	–	–	–	–	–	–	–	–	–	6.17	–	24.68	1.38	2.70	0.16	13.50	13.78
2030	3.70	–	1.67	–	61.63	46.22	123.26	9.40	–	–	–	–	–	–	–	–	–	2.47	–	24.68	1.04	2.03	0.12	10.38	5.99
2031	2.47	–	1.11	–	63.17	47.38	126.35	9.63	–	–	–	–	–	–	–	–	–	1.23	–	18.51	0.69	1.35	0.08	7.09	2.27
2032	1.85	–	0.84	–	64.75	48.56	129.50	9.87	–	–	–	–	–	–	–	–	–	1.23	6.17	12.34	0.52	1.01	0.06	5.45	–
2033	–	–	–	–	66.37	49.78	132.74	10.12	–	–	–	–	–	–	–	–	–	–	29.62	–	–	–	–	–	–

Table A.2. Wood Mackenzie Global Economic Model (GEM) Data Extraction for Stochastic Field Life Analysis

Wood Mackenzie's field model contains detailed data relating to the underlying oil and gas reserves. Column 1 contains the year of production, where 2006 represents the base year for DCF calculations. Columns 2, 3, 4 and 5 represent the underlying oilfield technical data, as agreed between Wood Mackenzie specialist oil and gas researchers and signed off by oilfield operators. Columns 6, 7 and 8 represent the three mean reverting price scenarios as applied to the DCF analysis, where 6 represents US$22.5/bbl 7 represents US$45/bbl and 8 represents US$90/bbl. Columns 9 and 10 represent the underlying specific gas prices contracted to the field. Columns 11 through to 20 summarize the capital expenditure in respect of the field. These are differentiated as between exploration, production facilities, subsea and drilling, and transportation. Columns 21 and 22 represent the field's operational costs. 23 and 24 represent direct tariffs with 25 and 26 comprising royalty and the applicable fiscal terms for the regime.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
Year	Production				Price Scenarios					Capital Costs										Operational Costs				Tax	
										Field Capex					Transport Capex			Other Capex		Field Opex					
	Liquid 1	Liquid 2	Gas 1	Gas 2	DownShock US$22.5/bbl	BaseCase US$45/bbl	UpShock US$90/bbl	Gas1	Gas2	E&A Costs	Product. Facilities	Process. Equip.	Subsea	Dev. Drilling	Pipeline	Offshore Loading	Terminal	Other	Abandon. Costs	Field Fixed	Field Variable	Tariff Oil	Gas	Royalty	Federal Tax
	000b/d	000b/d	mmcfd	mmcfd	$/bbl	$/bbl	$/bbl	$/mcf	$/mcf	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
2006	–	–	–	–	22.50	45.00	90.00	6.86	–	300.00	135.00	90.00	180.00	–	–	–	10.00	–	–	–	–	–	–	–	–
2007	–	–	–	–	20.00	40.00	80.00	6.46	–	300.00	75.00	90.00	180.00	20.00	–	–	10.00	–	–	–	–	–	–	–	–
2008	50.00	–	22.50	–	18.50	37.00	74.00	6.17	–	50.00	–	–	–	10.00	–	–	10.00	–	15.00	14	27.38	1.64	85.62	–	–
2009	115.00	–	64.00	–	17.94	35.87	71.74	6.08	–	–	–	60.00	200.00	10.00	–	–	10.00	–	20.00	32.2	62.96	4.67	195.63	209.44	–
2010	120.00	–	67.00	–	18.39	36.77	73.54	6.19	–	–	–	180.00	240.00	20.00	–	–	10.00	–	20.00	33.6	65.70	4.89	208.93	353.96	–
2011	120.00	–	62.00	–	18.85	37.69	75.38	6.30	–	–	–	–	–	–	–	–	5.00	–	20.00	33.6	65.70	4.53	212.64	439.96	–
2012	110.00	–	50.00	–	19.32	38.63	77.26	6.42	–	–	–	–	–	–	–	–	5.00	–	20.00	30.8	60.23	3.65	198.00	415.09	–
2013	95.00	–	43.00	–	19.80	39.59	79.18	6.54	–	–	–	–	–	–	–	–	5.00	–	20.00	26.6	52.01	3.14	175.21	376.07	–
2014	80.00	–	36.00	–	20.29	40.58	81.16	6.66	–	–	–	–	–	–	–	–	5.00	–	20.00	22.4	43.80	2.63	151.21	337.66	–
2015	90.00	–	40.50	–	20.80	41.60	83.20	6.78	–	–	–	45.00	120.00	–	–	–	10.00	–	20.00	25.2	49.28	2.96	174.55	356.06	–
2016	76.00	–	32.40	–	21.32	42.64	85.28	6.91	–	–	–	–	–	–	–	–	5.00	–	20.00	21.28	41.61	2.37	150.53	339.29	–
2017	62.00	–	25.65	–	21.85	43.70	87.40	7.03	–	–	–	–	–	–	–	–	5.00	–	20.00	17.36	33.95	1.87	125.71	286.46	–
2018	48.00	–	20.25	–	22.40	44.80	89.60	7.16	–	–	–	–	–	–	–	–	5.00	–	20.00	13.44	26.28	1.48	99.94	228.79	–
2019	38.00	–	16.20	–	22.96	45.92	91.84	7.29	–	–	–	–	–	–	–	–	5.00	–	20.00	10.64	20.81	1.18	81.11	183.56	–
2020	29.00	–	13.05	–	23.53	47.06	94.12	7.42	–	–	–	–	–	–	–	–	5.00	–	20.00	8.12	15.88	0.95	63.65	140.46	–
2021	23.00	–	10.35	–	24.12	48.24	96.48	7.56	–	–	–	–	–	–	–	–	5.00	–	20.00	6.44	12.59	0.76	51.72	110.91	–
2022	18.00	–	8.10	–	24.73	49.45	98.90	7.70	–	–	–	–	–	–	–	–	5.00	–	20.00	5.04	9.86	0.59	41.47	86.96	–
2023	14.00	–	6.30	–	25.34	50.68	101.36	7.83	–	–	–	–	–	–	–	–	5.00	–	20.00	3.92	7.67	0.46	33.04	67.47	–
2024	11.50	–	5.18	–	25.98	51.95	103.90	7.98	–	–	–	–	–	–	–	–	5.00	–	20.00	3.22	6.30	0.38	27.81	54.32	–
2025	9.00	–	4.05	–	26.63	53.25	106.50	8.12	–	–	–	–	–	–	–	–	5.00	–	20.00	2.52	4.93	0.30	22.30	40.46	–
2026	7.00	–	3.15	–	27.29	54.58	109.16	8.32	–	–	–	–	–	–	–	–	5.00	–	20.00	1.96	3.83	0.23	17.77	29.03	–
2027	6.00	–	2.70	–	27.97	55.94	111.88	8.53	–	–	–	–	–	–	–	–	5.00	–	20.00	1.68	3.29	0.20	15.62	23.38	–
2028	5.00	–	2.25	–	28.67	57.34	114.68	8.74	–	–	–	–	–	–	–	–	5.00	–	20.00	1.4	2.74	0.16	13.34	17.43	–
2029	4.00	–	1.80	–	29.39	58.78	117.56	8.96	–	–	–	–	–	–	–	–	5.00	–	20.00	1.12	2.19	0.13	10.94	11.17	–
2030	3.00	–	1.35	–	30.13	60.25	120.50	9.19	–	–	–	–	–	–	–	–	2.00	–	20.00	0.84	1.64	0.10	8.41	4.86	–
2031	2.00	–	0.90	–	30.88	61.75	123.50	9.42	–	–	–	–	–	–	–	–	1.00	–	15.00	0.56	1.10	0.07	5.75	1.84	–
2032	1.50	–	0.68	–	31.65	63.30	126.60	9.65	–	–	–	–	–	–	–	–	1.00	5.00	10.00	0.42	0.82	0.05	4.42	–	–
2033	–	–	–	–	32.44	64.88	129.76	9.89	–	–	–	–	–	–	–	–	–	24.00	–	–	–	–	–	–	–
2034	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2035	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		

Table A.3. Wood Mackenzie Global Economic Model (GEM) data extraction for Longitudinal Asset Risk

Wood Mackenzie's field model contains detailed data relating to the underlying oil and gas reserves. Column 1 contains the year of production, where 2006 represents the base year for DCF calculations. Columns 2, 3 represent the underlying oilfield production data, as agreed between Wood Mackenzie specialist oil and gas researchers and signed off by oilfield operators. Columns 4, 5 and 6 represent the Gross Revenue based on production and price for three mean reverting price scenarios where 4 represents US$22.5/bbl, 5 represents US$45/bbl and 6 represents US$90/bbl. Columns 7 and 8 represent the underlying operational costs and capital expenditures for the field. Columns 9 through to 18 summarize tax and other government takes in respect to the price scenarios for the field. These are differentiated regarding the regime. Columns 19 and 21 represent the field's cash flow attributable to the operating company. Columns 22 and 24 represent the annual total net field cash flows.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
Year	Production Liquids	Gas	Gross Revenue			Op Costs	Capital Costs	Royalty			State Taxes	Federal Tax			Bonus	State Carry	State Equity Cash Flow	Company Cash Flow			Total Field Cash Flow		
At Price			US$22.5/bbl	US$45/bbl	US$90/bbl			US$22.5/bbl	US$45/bbl	US$90/bbl		US$22.5/bbl	US$45/bbl	US$90/bbl				US$22.5/bbl	US$45/bbl	US$90/bbl	US$22.5/bbl	US$45/bbl	US$90/bbl
	000 b/d	mmcfd	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
2006	–	–	–	–	–	–	732.88	–	–	–	–	–	–	–	–	–	–	-732.88	-732.88	-732.88	-732.88	-732.88	-732.88
2007	–	–	–	–	–	–	709.17	–	–	–	–	–	–	–	–	–	–	-709.17	-709.17	-709.17	-709.17	-709.17	-709.17
2008	50.00	22.50	362.94	725.89	1451.78	47.40	75.38	40.25	85.62	176.35	–	–		96.43	–	–	–	199.91	517.48	1056.20	199.91	517.48	1056.20
2009	115.00	64.00	823.78	1647.57	3295.13	96.73	309.07	92.65	195.63	401.57	–	–	209.44	839.88	–	–	–	325.33	836.70	1647.88	325.33	836.70	1647.88
2010	120.00	67.00	880.86	1761.72	3523.45	102.50	509.13	98.82	208.93	429.14	–	–	353.96	893.48	–	–	–	170.41	587.21	1589.19	170.41	587.21	1589.19
2011	120.00	62.00	896.65	1793.29	3586.58	104.63	5.80	100.56	212.64	436.81	–	95.56	439.96	989.16	–	–	–	590.09	1030.25	2050.19	590.09	1030.25	2050.19
2012	110.00	50.00	834.04	1668.09	3336.17	99.70	5.94	93.74	198.00	406.51	–	159.66	415.09	925.94	–	–	–	474.99	949.36	1898.08	474.99	949.36	1898.08
2013	95.00	43.00	737.77	1475.54	2951.08	91.56	6.09	82.99	175.21	359.65	–	150.13	376.07	827.96	–	–	–	406.99	826.60	1665.82	406.99	826.60	1665.82
2014	80.00	36.00	636.27	1272.55	2545.09	82.96	6.24	71.67	151.21	310.28	–	142.80	337.66	727.38	–	–	–	332.60	694.48	1418.24	332.60	694.48	1418.24
2015	90.00	40.50	733.38	1466.76	2933.51	92.46	224.01	82.88	174.55	357.90	–	131.47	356.06	805.26	–	–	–	202.56	619.67	1453.88	202.56	619.67	1453.88
2016	76.00	32.40	632.23	1264.46	2528.92	83.94	6.56	71.50	150.53	308.59	–	145.67	339.29	726.53	–	–	–	324.55	684.13	1403.30	324.55	684.13	1403.30
2017	62.00	25.65	527.43	1054.87	2109.74	75.07	6.72	59.78	125.71	257.57	–	124.93	286.46	609.51	–	–	–	260.93	560.91	1160.87	260.93	560.91	1160.87
2018	48.00	20.25	418.89	837.77	1675.54	65.84	6.89	47.58	99.94	204.66	–	100.51	228.79	485.36	–	–	–	198.07	436.31	912.79	198.07	436.31	912.79
2019	38.00	16.20	339.99	679.98	1359.96	59.33	7.06	38.62	81.11	166.11	–	79.44	183.56	391.80	–	–	–	155.55	348.92	735.66	155.55	348.92	735.66
2020	29.00	13.05	266.77	533.54	1067.09	53.34	7.24	30.30	63.65	130.34	–	58.76	140.46	303.86	–	–	–	117.13	268.86	572.31	117.13	268.86	572.31
2021	23.00	10.35	216.77	433.54	867.08	49.51	7.42	24.62	51.72	105.91	–	44.53	110.91	243.69	–	–	–	90.70	213.98	460.56	90.70	213.98	460.56
2022	18.00	8.10	173.81	347.62	695.24	46.33	7.61	19.74	41.47	84.92	–	33.73	86.96	193.42	–	–	–	66.40	165.26	362.97	66.40	165.26	362.97
2023	14.00	6.30	138.50	277.01	554.02	43.87	7.80	15.73	33.04	67.67	–	25.06	67.47	152.31	–	–	–	46.05	124.83	282.38	46.05	124.83	282.38
2024	11.50	5.18	116.57	233.14	466.28	42.64	7.99	13.24	27.81	56.95	–	18.62	54.32	125.72	–	–	–	34.08	100.38	232.98	34.08	100.38	232.98
2025	9.00	4.05	93.46	186.93	373.85	41.33	8.19	10.61	22.30	45.66	–	11.84	40.46	97.71	–	–	–	21.49	74.64	180.96	21.49	74.64	180.96
2026	7.00	3.15	74.51	149.02	298.04	40.41	8.40	8.46	17.77	36.40	–	6.21	29.03	74.67	–	–	–	11.02	53.40	138.16	11.02	53.40	138.16
2027	6.00	2.70	65.46	130.93	261.85	40.43	8.61	7.43	15.62	31.98	–	3.33	23.38	63.48	–	–	–	5.66	42.89	117.36	5.66	42.89	117.36
2028	5.00	2.25	55.92	111.83	223.66	40.41	8.82	6.35	13.34	27.32	–	0.31	17.43	51.68	–	–	–	0.03	31.83	95.43	0.03	31.83	95.43
2029	4.00	1.80	45.85	91.70	183.41	40.37	9.04	5.21	10.94	22.40	–	–	11.17	39.25	–	–	–	-8.77	20.18	72.34	-8.77	20.18	72.34
2030	3.00	1.35	35.25	70.50	140.99	40.31	3.71	4.00	8.41	17.22	–	–	4.86	26.45	–	–	–	-12.77	13.22	53.31	-12.77	13.22	53.31
2031	2.00	0.90	24.09	48.17	96.35	30.71	1.90	2.74	5.75	11.77	–	–	1.84	16.59	–	–	–	-11.26	7.98	35.38	-11.26	7.98	35.38
2032	1.50	0.68	18.53	37.05	74.10	21.17	11.69	2.10	4.42	9.05	–	–		10.13	–	–	–	-16.44	-0.23	22.06	-16.44	-0.23	22.06
2033	–	–	–	–	–	–	47.92	–	–	–	–	–	–	–	–	–	–	-47.92	-47.92	-47.92	-47.92	-47.92	-47.92
2034	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2035	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

B. Descriptive Statistics for Stochastic Simulations

Table B.1. Descriptive Statistics for Stochastic Present Value Price Response Simulations Post-Tax (US$22.5/bbl)

Panel A (Table B.1) summarizes important descriptive statistics of stochastic post-tax present value simulations at an oil price of US$22.5/bbl. Results were obtained through Monte Carlo simulation with exogenous price volatility at the field level and aggregated to arithmetic country averages. Each simulation is based on log-normally distributed price estimates (see (4.9) and (4.10)) and feeds pre-tax present value forecasts through a field specific tax filter in order to estimate a post-tax present value frequency distribution. Panel B and Panel C (Table B.2) reflect the same data at price of US$45/bbl and US$90/bbl respectively.

	Reserves	Mean ($M)	*SD* ($M)	Skewness	Kurtosis
		Panel A: Price US$22.5/bbl			
GoM	all fields	216.1929	38.5807	0.4996	3.4625
	<60mmboe	136.0108	21.5311	0.5106	3.4687
	>60mmboe	433.2417	64.0079	0.5159	3.5605
UKCS	all fields	137.7850	22.9253	0.2892	3.2465
	<60mmboe	23.2800	11.6008	0.3032	3.2785
	>60mmboe	638.7447	72.4699	0.2282	3.1062
NCS	all fields	289.6678	91.1648	0.0227	3.4530
	<60mmboe	9.9089	14.6915	0.0123	3.6163
	>60mmboe	396.2426	120.2975	0.0266	3.3907
ANG	all fields	654.2789	130.4100	0.0587	3.0267
	<60mmboe	22.6070	9.8699	0.0940	2.8629
	>60mmboe	1040.3006	204.0735	0.0370	3.1269
IDO	all fields	201.1981	28.7864	0.0835	3.2407
	<60mmboe	26.1051	7.2562	0.1112	3.1844
	>60mmboe	327.2651	44.2882	0.0635	3.2813
EGY	all fields	212.5215	20.7317	0.3033	3.2664
	<60mmboe	44.0891	5.7150	0.3524	3.3222
	>60mmboe	510.5174	47.2998	0.2164	3.1679

Table B.2. Descriptive Statistics for Stochastic Present Value Price Response Simulations Post-Tax (US$45/bbl, US$90/bbl)

	Reserves	Mean ($M)	*SD*($M)	Skewness	Kurtosis
		Panel B: Price US$45/bbl			
GoM	all fields	597.8627	76.4922	0.5005	3.4676
	<60mmboe	320.8999	42.6408	0.5122	3.4779
	>60mmboe	1068.8848	128.8400	0.5048	3.5410
UKCS	all fields	444.7852	42.8523	0.3360	3.2492
	<60mmboe	162.5723	20.9145	0.3530	3.2778
	>60mmboe	1679.4667	138.8299	0.2617	3.1242
NCS	all fields	1396.5351	157.6514	0.3444	3.3067
	<60mmboe	103.2768	18.3481	0.3268	3.3474
	>60mmboe	1889.2050	210.7193	0.3512	3.2912
ANG	all fields	1417.8667	96.6283	-0.1838	3.9589
	<60mmboe	65.6689	5.3137	-0.6347	4.2520
	>60mmboe	2244.2097	152.4317	0.0917	3.7799
IDO	all fields	548.5307	44.8433	0.3056	3.2266
	<60mmboe	80.1935	9.8437	0.3662	3.2827
	>60mmboe	885.7335	70.0431	0.2620	3.1862
EGY	all fields	450.2173	33.1340	0.3454	3.3005
	<60mmboe	92.3534	9.7980	0.3921	3.3453
	>60mmboe	1083.3610	74.4207	0.2627	3.2212
		Panel C: Price US$90/bbl			
GoM	all fields	1353.1761	152.8813	0.5030	3.4657
	<60mmboe	688.5946	85.2414	0.5152	3.4754
	>60mmboe	2311.1390	257.6317	0.5052	3.5414
UKCS	all fields	1064.2787	88.1822	0.3481	3.2502
	<60mmboe	458.3071	45.1818	0.3672	3.2781
	>60mmboe	3715.4045	276.3090	0.2649	3.1283
NCS	all fields	3508.7030	315.1012	0.3492	3.3089
	<60mmboe	249.0173	36.5152	0.3384	3.3511
	>60mmboe	4750.4880	421.2292	0.3534	3.2928
ANG	all fields	2060.8427	159.7016	0.1105	5.3283
	<60mmboe	91.3000	6.2096	-0.7751	6.7142
	>60mmboe	3264.4522	253.5023	0.6516	4.4815
IDO	all fields	1246.5440	88.3127	0.3376	3.2275
	<60mmboe	168.8104	19.0978	0.4042	3.2853
	>60mmboe	2022.5121	138.1474	0.2896	3.1858
EGY	all fields	882.7426	64.1390	0.3929	3.3172
	<60mmboe	178.7798	19.1610	0.4466	3.3549
	>60mmboe	2128.2153	143.7155	0.2978	3.2505

C. Fiscal Term References

Detailed Fiscal Terms used in Wood Mackenzie GEM

OECD Countries – Concession Regimes

- UK Continental Shelf
- Gulf of Mexico
- Norwegian Continental Shelf

Non-OECD Countries – Production Sharing Contracts

- Angola
- Egypt
- Indonesia

D. Publications

CONFERENCES:

Real Options Group

Journal of Banking and Finance

PUBLISHED

Journal of Applied Corporate finance

E. Working Papers

SSRN REFERENCES FOR ALL PAPERS

http://papers.ssrn.com/sol3/cf_dev/AbsByAuth.cfm?per_id=419073

Acknowledgement of Co-Research

The University of Edinburgh Postgraduate Assessment Regulations for Research Degrees

For Ease of Reference – Extracts: These regulations apply to all postgraduate research degrees which are assessed solely or primarily on performance in a single thesis/project report. Full text available at: http://www.aaps.ed.ac.uk/regulations/exam.htm

September 2006 This version applies to work submitted for assessment during the Academic Year 2006/2007. This document should be read in conjunction with University's Degree Regulations and Programmes of Study; the Code of Practice for Supervisors and Research Students; the Guidelines for the Examination of Research Degrees; and the External Examining Code of Practice.

2.2 Material to be included in a thesis may be published before the thesis is submitted but only with the approval of the supervisor. The thesis must record the fact of such publication.

2.3 Theses do not include work submitted for any other degree or professional qualification unless a clear statement is made as to the precise extent of the work so included.

2.4 The proposed field of a candidate's study must be approved by the Committee at the time of admission. A thesis title, de novo or amended, must be proposed with the candidate's notice of intention to submit the thesis for examination. The proposal must be supported by the supervisor.

2.5 Every candidate must incorporate in the thesis a signed declaration (a) that the thesis has been composed by the candidate, and (b) either that the work is the candidate's own, or, if the candidate has been a member of a research group, that the candidate has made a substantial contribution to the work, such contribution being clearly indicated, and (c) that the work has not been submitted for any other degree or professional qualification except as specified.

To the Board of The University of Edinburgh Postgraduate Assessment Regulations – Co-Research Declaration

I hereby acknowledge that I have been research assistant in all asset pricing and oil and gas research directed by Gavin Kretzschmar. Gavin has been the lead researcher in all aspects of the work.

One of the beneficial by-products of the research time that we spent together has been the publication of joint working papers. These have been submitted as conference papers to the Journal of Banking and Finance Special Edition and to the European Journal of Finance. Gavin was the major author and contributor to each of these papers. Indeed, all data, method and literature were supplied by Gavin. Results were obtained under his direct guidance.

In recognition of his major contribution to the research time that we spent this summer, Gavin has my full permission to use all research work and working papers in his PhD thesis. Additionally, and where writing style and University rules demand, he has my permission to refer to all research findings in the first person.

Axel Kirchner Edinburgh, January 2007

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Gavin has made a major contribution to all of our published work.

Gavin also made a major contribution to our working papers.

In all instances of joint research, he supplied data, its analysis and made a major contribution to result write-ups.

He has my express permission to publish research findings.

Dr Peter Moles   Edinburgh, January 2007

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Journal of Business, Finance and Accounting

Gavin has made a major contribution to all of our published work.

Gavin also made a major contribution to working papers.

He supplied the all data, its analysis and was involved in writing up.

He has my express permission to publish his research findings. Additionally, and where writing style and University rules demand, he has my permission to refer to all research findings in the first person.

Prof David Hatherly Edinburgh, January 2007

Author Declaration

I hereby declare that:

(a) This thesis is based on research studies conducted by the author – or where work has been part of a research group, for instance where I led research work for the Board of the Bank Of Scotland – Corporate Division, I have made a major contribution to the research.

(b) My substantial contribution to all research work, is clearly indicated. I am first author on all papers used in this thesis.

(c) I have not submitted this work for any other degree or professional qualification.

(d) Joint research is acknowledged by co-authors at the end of this thesis. Chapter 4 acknowledges findings from a joint published paper submitted to the Journal of Banking and Finance conference on commodities held at Birkbeck College. Results from this joint paper are also included and acknowledged in a University of Edinburgh Masters dissertation submitted by Axel Kirchner in 2006 and conducted under my direct supervision. Finding from this paper form part of a global oil and gas investment opportunity study conducted by me, funded by Bank of Scotland - Corporate Division, and presented to their Board in 2006.

Gavin Kretzschmar – Edinburgh, April 2007