# Financial market pressures, tacit collusion and oil price formation[1]

*by*

Finn Roar Aune,[†] Klaus Mohn,[‡*] Petter Osmundsen[‡] and Knut Einar Rosendahl[†]

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*Abstract*

We explore a hypothesis that a change in investment behaviour among international oil companies (IOC) towards the end of the 1990s had long-lived effects on OPEC strategies, and on oil price formation. Coordinated investment constraints were imposed on the IOCs through financial market pressures for improved short-term profitability in the wake of the Asian economic crisis. We apply a partial equilibrium model for the global oil market to compare the effects of these tacitly collusive capital constraints on oil supply with an alternative characterised by industrial stability. Our results suggest that even temporary economic and financial shocks may have a long-term impact on oil price formation.

*JEL classification*: G31, L13, Q41

*Key words*: Oil market, investment behaviour, market power, collusion, equilibrium model

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[†] Statistics Norway (Research Department), box 8131 Dep., 0033 Oslo, Norway.
[‡] University of Stavanger (Department for Industrial Economics), 4036 Stavanger, Norway.

[*] Corresponding author: klaus.mohn@uis.no

## 1. Introduction

Ever since the oil price shocks of the early 1970s, the Organization of the Petroleum Exporting Countries (OPEC) has been followed with massive interest from the public, reflecting the vital significance of the oil price to industry, households and financial markets. The special structure of the oil market has also attracted scholarly interest, with numerous studies of OPEC's role and strategy in various models of producer behaviour under imperfect competition (e.g., Smith, 2005; Fattouh, 2007). Less attention has been given to the role of producer behaviour in non-OPEC countries. Nevertheless, investment behaviour in the international oil and gas industry is an important part of supply-side dynamics in the oil market, and therefore also an important factor behind the formation of oil prices.

Our key hypothesis is that a strategic redirection of the international oil industry towards the end of the 1990s has had long-lived effects on OPEC strategies – and on oil price formation. Starting in 1998, increased focus on shareholder returns, capital discipline and return on capital employed (RoACE)[2] caused a slowdown in investment rates and production growth among international oil companies (Antill and Arnott 2002; Osmundsen et al. 2006). Strong growth in oil demand and consolidation in the competitive fringe allowed OPEC to raise their price ambitions significantly at the turn of the century (Haskel and Scaramozzino, 2002; Kohl, 2002). The objective of this study is to quantify the oil price impact of these developments. Using a detailed simulation model for the global oil market, we examine the effects of the change in investment pattern on oil supply and oil prices, as compared with a situation characterised by industrial stability and unchanged price ambitions within OPEC.

Oil demand is quite inelastic to oil price changes, and tightly linked to GDP growth.[3] As noted by Lynch (2002), the dissection of crude oil supply is less straightforward, with geology, geopolitics, and imperfect competition as important complicating factors. At the same time, the degree of concentration among the most important oil producers is

[2] RoACE is defined as net income adjusted for minority interests and net financial items (after tax) as a percentage ratio of average capital employed, where capital employed is the sum of shareholders' funds and net interest-bearing debt.

[3] The macroeconomic role of the oil price has intrigued macroeconomic researchers for decades (Barsky and Killian 2004). Empirical studies suggest that oil price changes above some threshold level will have contractionary effects on global economic activity (e.g., Jiménez-Rodriguez and Sánchez 2004; Jones, Leiby and Paik 2004; IMF 2005). Distributional effects are also involved, as the rewards of an increase in the oil price are reaped by oil-exporting nations, whereas the costs tend to be carried by less wealthy oil-dependent countries (e.g, Gately and Huntington, 2002; World Bank, 2005).

significant, leaving a potential scope for pricing power (Fattouh, 2007). Total oil supply is comprised by production from two groups of players. One is the group of OPEC countries, with national oil companies situated in the most resource-rich regions of the world (Noguera and Pecchenino, 2007). The other is often referred to as non-OPEC, strongly influenced by the group of international oil companies (IOCs). Most of these companies have their origin in the western hemisphere, they have private shareholders, and their shares are traded on stock exchanges in London and New York.

Osmundsen et al. (2007) argue that changes in the interaction between listed oil companies and their shareholders have suppressed investment behaviour and production growth among these companies from 1998 and onwards. We present a more comprehensive assessment of the oil market impact of changes in IOC investment behaviour. Our modelling approach allows an empirical assessment of supply side dynamics following the redirection of investment policies in the oil industry after the Asian economic crisis. The model simulations clearly suggest that enhanced capital discipline caused a temporary slowdown in investment and production growth among international oil companies. Consequently, global exploration activities, investment expenditures and oil production growth were suppressed, allowing OPEC to raise their price ambitions. Specifically, we find that the curb on IOC investments around the turn of the century caused an increase in the oil price of 10 per cent in the long run. Both OPEC and non-OPEC producers gain from this development, whereas the cost is carried by oil-importers and consumers.

The paper is organised as follows. Section 2 provides a review of previous research of OPEC behaviour and oil industry dynamics, as well as a discussion of the rationale for our hypotheses about supply side behaviour. In Section 3, we introduce the FRISBEE model, and discuss two different scenarios for the oil market – to isolate the effects on exploration activities, investments, oil production growth and price formation. Concluding remarks and directions for future research are presented in Section 4.

## 2. Financial market pressures and OPEC behaviour

The last serious oil demand shock was experienced in 1998-1999, when the Asian economic crisis reduced anticipated demand growth rates by some 2 percentage points (EIA 2006).

One result was a change in investment behaviour among the IOCs. At the same time, the Asian economic crisis had the effect of pulling the OPEC countries together. OPEC regained market power and oil price ambitions were raised. We explore the behavioural changes of OPEC and the IOCs in greater detail below.

*2.1 Tacit collusion in IOC investment*

In the late 1990s, both the oil market and the financial market turned against the oil and gas industry. First, the "New Economy" euphoria made investors shift their investments from oil and gas to IT stocks. Oil and gas companies were generally perceived as old-fashioned and inefficient, with limited exposure to the exuberance of the IT sector. Second, the Asian economic crisis caused a sharp slowdown in global oil demand. In 1998 the oil price touched record lows of 10 USD/bbl., increasing the uncertainty and anxiety also with respect to oil price expectations. The result was not only a severe pressure on current oil company cash flows, but also an increasing scepticism with respect to future earnings. In consequence, oil and gas companies failed to deliver competitive returns to their shareholders.

One response to these developments was a wave of mergers to build scale, reap synergies, and improve efficiency. This process erased a range of former prominent independent names,[4] and attracted interest both from researchers (e.g., Weston et al. 1999; Fauli-Oller 2000) and regulators (Scheffman and Coleman, 2002; Froeb et al., 2005). Another response from the international oil industry was a strategic redirection from development of reserves and production in the longer term to operational efficiency and capital discipline in the short to medium term. Companies were benchmarked and rated according to a specific set of financial and operational performance indicators (Antill and Arnott, 2002; Osmundsen et al. 2007). The most important of these indicators was RoACE.

An example of common benchmarking and valuation practices is illustrated in the left-hand panel of Figure 1, where a financial market valuation multiple[5] is plotted against RoACE for major oil and gas companies. A regression is often added to illude "normal valuation", and deviations from this relationship offer signals to buy or sell the stock. This practice of

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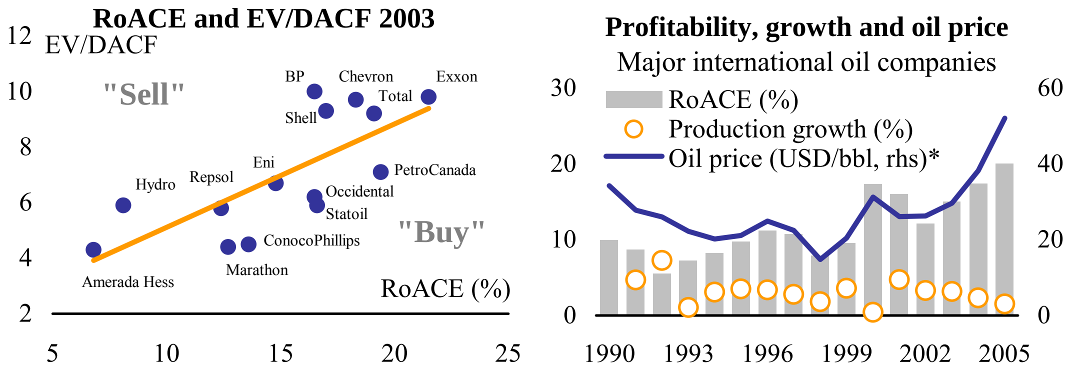
[4] Examples include Elf, Fina, Mobil, Amoco, Arco, YPF, Texaco, Phillips, Lasmo, Unocal – and recently also Hydro.

[5] EV, or Enterprise Value, is the sum of the company's debt and equity, at market values. DACF, or Debt-Adjusted Cash Flow, reflects cash flow from operations plus after-tax debt-service payments.

benchmarking and valuation made reported RoACE increase more than the oil price increase would suggest (see also Dobbs et al. 2006).

**Figure 1. IOC valuation and financial indicators**




* in real terms (at 2004-prices).
Source: Deutsche Bank (2004; oil industry data).

Deutsche Bank (2004) reports that total investment expenditures among the major international oil and gas companies were cut by 16 per cent in real terms from 1998 to 2000, with a 38 per cent reduction in exploration expenditures over the same period. Mohn and Misund (2007) present econometric evidence of a structural break in IOC investment behaviour in 1998, implying that the investment response to the late rise in the oil price is significantly less than the estimated response for the period before 1998. An important reason is the implicit increase in the required rate of return on new investments among international oil companies, to secure improved capital discipline and RoACE performance.[6] Due to conservative valuation procedures,[7] RoACE will improve when investment rates decline, providing an additional argument for IOCs to bridle their capital expenditures.[8]

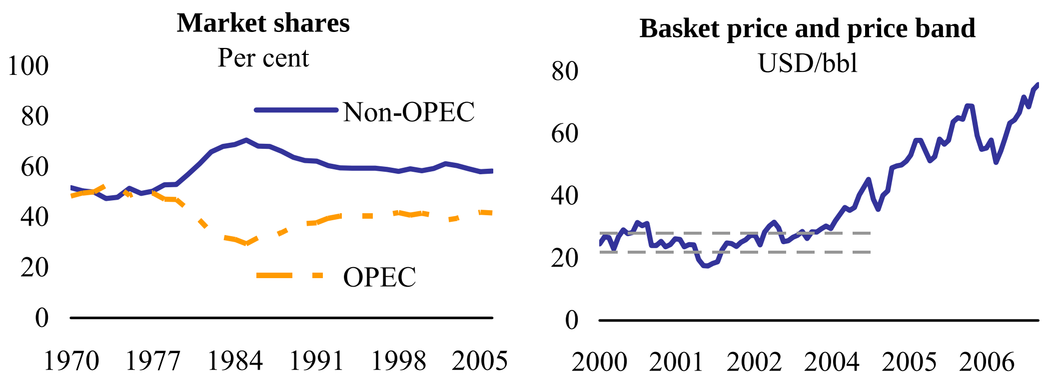
Thus, the emphasis on RoACE in valuation of oil companies curbed investments, implicitly representing a tacit collusion to support an increase in the oil price. In retrospect, maintaining the original investment rate (cheating) would have been beneficial for any one

[6] In spite of differences in terms of definition, there is a close economic relationship between the *ex ante* required rate of return (RRoR) measure and the *ex post* return on average capital employed (RoACE) indicator. See Antill and Arnott (2002) for a more comprehensive discussion of accounting standards, financial market behaviour and corporate investment strategies.
[7] This improvement in RoACE generated simply by reducing activity levels is mainly due to the system of depreciation (production unit method) and the most common way of treating exploration expenses (full cost method).
[8] For an IOC perspective on investment in the first years of the new century, see Smith (2003).

oil company, as earnings would have surged on both higher oil price and higher production. However, the general perception among oil company managers was that a lower ranking in the financial community would reduce the stock price, increase the takeover threat, and reduce the potential for profitable acquisitions.

Over the last couple of years, the tide has turned. Both investors and companies seem to have realised that reserve growth is required to sustain long-term production and activity growth. Accordingly, the pressure for short-term financial returns is relaxed. Spurred by advancing depletion of legacy fields of the past and limited access to new exploration acreage, management focus has shifted back to exploration and business development to access new oil and gas reserves. Our model scenarios are designed to capture both the rise and the fall of the RoACE era in the international oil and gas industry.

**Figure 2. OPEC decision variables**




Source: EIA, http://www.ecowin.com.

*2.2 OPEC behaviour*

Empirical studies of OPEC's role in the oil market have generally failed to establish firm evidence of stable cartel behaviour (e.g., Griffin, 1985; Dahl and Yücel, 1991; Griffin and Nielson, 1994; Alhajji and Huettner 2000a,b). However, recent studies acknowledge that some sort of collusion is taking place. The current discussion is more about which model of imperfect competition the oil price formation adheres to, and to stability issues of OPEC's market power. Böckem (2004) combines theories of new empirical industrial organisation (NEIO) literature with modern econometric techniques, and argues that a price-leader model provides the best description of OPEC behaviour. Hansen and Lindholt (2004) obtain similar results in an econometric study of monthly oil price data over the period 1973-2001. Smith

(2005) provides a critical overview of empirical studies of OPEC behaviour, and concludes his own assessment with weak support for a "bureaucratic syndicate" model.

Traditionally, OPEC has collected data for a "basket" of different crude oil qualities, and the global oil market has been monitored through a reference price based on this basket (cf. Figure 2). In March 2000, OPEC established a price band mechanism to respond more automatically to changes in market conditions (Kohl, 2002). According to this mechanism, production would be adjusted at price levels below 22 USD/bbl and above 28 USD/bbl. The mechanism was later adjusted to allow production adjustments at OPEC's discretion.[9] The price band mechanism was suspended in January 2005. Combining these observations with the oil price development, there are clear indications that OPEC's pricing power was significant at the turn of the century (Fattouh, 2001).

As argued by Haskel and Scaramozzino (2002), physical and financial capacity is likely to affect conjectural variations in an oligopoly. With a cartel strategy contingent on the ability of fringe producers to react, a variety of developments shed light on OPEC's self reliance. First, the outlook for non-OPEC supply was curbed by financial market pressures and strict capital discipline. Second, the oil price outlook was uncertain, and did not provide sufficient incentive for massive private oil and gas investment. Third, the domestic provinces of the IOCs were maturing rapidly,[10] with deteriorating exploration results and decaying reserves. Fourth, the Asian economic crisis demonstrated the importance of internal discipline when demand is insufficient to meet every cartel member's production ambitions. Finally, the global economy was recovering swiftly, with especially high growth in GDP and energy demand in non-OECD countries. Hyndman (2007) and Fattouh (2007) provide convincing evidence that agreements in a cartel like OPEC are easier to achieve when times are good then when times are bad. All in all, OPEC regained strength during 1999, and entered the new century with increased market power – and a willingness to exploit it (Kohl, 2002).

We now turn to a detailed and model-based analysis of these developments, to reveal more precise implications in terms of investments, production growth and oil price formation.

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[9] By 2004 the price band mechanism had been activated only once; In October 2000, total OPEC production was increased by 500,000 barrels per day.
[10] USA, Canada, United Kingdom, and Norway.

## 3. Model scenarios

### *3.1 Overview of FRISBEE*

The FRISBEE model is a recursive, dynamic partial equilibrium model of the global oil market.[11] Particular attention is paid to the oil industry's supply of oil, and the model accounts explicitly for discoveries, reserves, field development and production in four field categories across 13 global regions (including two OPEC regions). The model is calibrated based on market data for the base year 2000, as well as other relevant data and estimated parameters from the literature (e.g. demand elasticities, production costs, oil resources etc.). The global oil market is assumed to clear in each period (year). Regional supply, demand and trade flows are among the outputs of the model. The model does not intend to exactly replicate the historical development of the oil market, or forecast the future, as the oil market obviously is influenced by much more than economics. However, in our view the model can provide valuable insight into the effects of certain changes in the market, such as changes in the international oil industry.

In each region oil is demanded for transport and stationary purposes in three sectors of the economy: Manufacturing industries, Power generation, and Others (including household demand). Oil demand depends on user prices of oil products, and to some degree on other energy prices. In the end-user sectors the direct price elasticities are on average around -0.3 in the long run, and around -0.1 in the short run (cf., Liu 2004). Income growth is particularly important in the longer term, with (per capita) income elasticities on average around 0.6. Population growth and exogenous energy efficiency are also affecting energy demand. In the power sector oil competes with other fuels on a cost basis.

The development of non-OPEC production is influenced by initial production capacity and investments – in exploration, field development and efforts to increase oil recovery (IOR). Non-OPEC producers are assumed to behave competitively, as no single oil company has a market share above 3 per cent.[12] Thus, production volumes from developed fields are

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[11] A more detailed, informal description of the model is given in Appendix A. For a more extensive presentation of the FRISBEE model system, see Aune et al. (2005). More recently, the model has been extended to include international gas and coal markets (see Rosendahl and Sagen 2007).

[12] It could be argued that a *country* like Russia, having a total market share of 12 per cent in 2006, can coordinate oil production from its domestic oil companies so as to influence the market. However, so far there have been few signs of such behaviour in Russia or other non-OPEC countries except in extraordinary situations.

determined by the equalisation of marginal producer costs to producer prices in each region. Investments are driven by expected returns, and net present values are calculated for the four field categories in the 11 non-OPEC regions (i.e., 44 field groups), based on adaptive price expectations and a pre-specified required rate of return.

We assume that oil companies outside OPEC have adaptive expectations, so that they, based on historical prices, make expectations about the future price path. Furthermore, we assume that recent price history dominates price expectations for the short term, whereas a longer historical memory is applied for the longer-term expectations. For tractability reasons, we construct expected mean-prices for each investment activity, measuring the average price expected over the relevant time horizon for the investment activity in question. As the investment horizon is quite different for the three types of investment, the expected mean-price will typically differ across investment activities. We apply the following expectations formation:[13]

$$EP_{it} = \alpha_i P_{t-1} + (1-\alpha_i) EP_{it-1} \ , \qquad [1]$$

where $EP_{it}$ is the expected (real) mean-price of oil applied for evaluation of investment activity $i$, $P_{t-1}$ is the corresponding observed (real) price last year, and $\alpha_i$ are parameters that determine the speed of expectations adjustment for each of the three investment categories. The values of $\alpha_i$ in equation [1] are assumed to be respectively 0.60, 0.35 and 0.10 for IOR activities (*I*), field development (*D*) and exploration activity (*E*).[14] This reflects that IOR investments typically produce returns with a time lag of 0-2 years; field developments have a perspective of 2-5 years before start-up, whereas exploration projects are for the long term. The oil industry will therefore adjust their IOR activities more rapidly than their exploration activities when the oil price changes, as the short-term price expectations change more rapidly than the long-term expectations.[15] It takes time before the oil industry believe that a

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[13] In the model, the oil price differs somewhat across regions (due to transport costs), but this is disregarded in the equations here.
[14] This means that 90 per cent of the weights in the price expectation formation are based on the 3 last years' prices for IOR activities, 6 last years for field development, and about 20 last years for exploration activity. Other values of $\alpha_i$ would alter the investment activities somewhat, but the relative effects of changes in non-OPEC's investment strategy would only marginally change.
[15] When the oil price started rising around the turn of the century, volatility was high, and the longer term outlook was very uncertain. The company response was a redirection of investment toward activities with a short-term horizon, like IOR and (satellite) field developments, at the expense of longer term

price adjustment is permanent, as illustrated by the slow pace of long-term investment response to the current price increase.

Neglecting subscript $t$ for simplicity of exposition, oil company investments in field development and IOR activities outside OPEC are derived from the following maximisation problem (Aune et al., 2005):

$$Max_{R_{ij}} \Pi\left(R_{ij},\ EP_i,\ r,\ CO_j,\ CC_{ij}, GT_j,\ NT_j, \vec{F}_j\right), \qquad [2]$$

where $\Pi$ is expected discounted profits, $R_{ij}$ denotes investment in new reserves (new field developments or IOR) in field group $j$, $r$ is the required rate of return, $CO_j$ and $CC_{ij}$ operating and capital costs, respectively, $GT_j$ and $NT_j$ gross and net tax rates on oil production, respectively, and $\vec{F}_j$ is a vector of field characteristics that differ across field groups (notably production profile and time lags). Capital costs are increasing in investment activity, decreasing in undeveloped reserves (new fields), and increasing in the recovery rate (IOR). A simpler approach is applied for exploration investments, where we assume that the process for discovered reserves ($R_{Ej}$) is captured by the following function:

$$R_{Ej} = R_{Ej}(EP_E,\ r,\ U_j,\ \vec{F}_j)\ , \qquad [3]$$

where $EP_E$ is the expected oil price applied for evaluation of exploration activities, $U_j$ denotes (expected) remaining undiscovered reserves, and subscript $t$ is still subdued.

To sum up, oil companies outside OPEC choose optimal levels of exploration activities, field development, and IOR activities, based on expected prices, required rate of return, etc. A higher expected price and/or a lower required rate of return will increase the investments in new fields and IOR activities, and increase the level of discoveries. Because the time lag between capital outlays and revenues is highest for exploration and lowest for IOR, we should expect the required rate of return to be most important for exploration, and least important for IOR activities.

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exploration investments, whose price expectations were not adjusted upward to the same extent (Osmundsen et al., 2007).

OPEC's behaviour is not easily depicted, and has certainly changed over time (see, e.g., Fattouh, 2007). However, as discussed above, several studies conclude that a price-leader model may provide a reasonable description. Since OPEC suspended its price band in 2005 because of the considerable upward pressure on the oil price, no official price targets have been announced. However, OPEC certainly considers the oil price development when production quotas are determined.

Thus, FRISBEE assumes that OPEC searches for the price path that maximises its net present value of oil production until 2030 at a given discount rate,[16] and chooses a production profile consistent with this price path. However, we restrict the analysis to price paths on the following form:

$$P_{t+1}^{OPEC} = P_t^{OPEC} + \gamma^{t-t_0}\psi\,, \qquad [4]$$

where $P_t^{OPEC}$ is the average producer price for OPEC, and $\psi$ and $\gamma$ are parameters that determine the price path from an exogenous base year level ($t_0$ = 2000). The concave price trajectory illustrated in Figure 4 below is the result of a calibration with $\gamma$ = 0.9, which is also applied in our further simulations.[17] The model now searches for the value of $\psi$ that maximises the net present value of OPEC's profit flow. As a comparison, Berg et al. (2002) and Yang (2007) simulate OPEC's behaviour through a dynamic optimisation model ala Hotelling (1931), but their modelling of the oil market is much simpler in other respects. On the other hand, Gately (2007) searches for an optimal strategy for OPEC that is robust to changes in uncertain future market conditions.

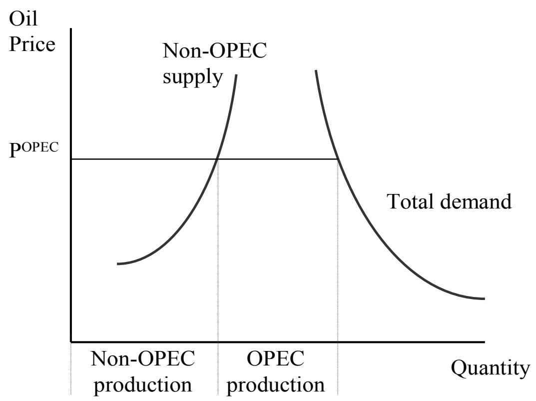
[16] In the simulations presented in this paper, we use a discount rate of 7 per cent. Simulations with much lower (down to zero) or higher discount rates give almost the same conclusion when it comes to the relative price effects of changes in non-OPEC's investment strategy (if anything, the price effect is slightly stronger).

[17] Our choice of $\gamma$ is of course a significant restriction of all the possible price paths OPEC can choose between. We have chosen a $\gamma$ below unity (i.e., concave price path), as this seems to be in accordance with OPEC's mission statement: "OPEC's mission is to … ensure the stabilization of oil markets in order to secure an efficient, economic & regular supply of petroleum to consumers, a steady income to producers & a fair return on capital to those investing in the petroleum industry." (http://www.opec.org/home). In any case, for the purpose of exploring the impacts of a change in non-OPEC's investment strategy this restriction is of minor importance since $\gamma$ only determines the curvature of the price path. Simulations with other values of $\gamma$ (including $\gamma \geq 1$, i.e., linear and strictly convex price paths) indicate that the price differential in the long run (i.e., 2020-2030) is quite similar in relative terms.

Note that we assume different expectation formation for OPEC and non-OPEC. Whereas non-OPEC producers have adaptive expectations about the future oil price, OPEC has (implicitly) rational expectations about future demand and how non-OPEC will react to different oil prices. Reasons for this could be that OPEC's behaviour has changed over time, and is therefore less predictable than non-OPEC's behaviour, which to a larger degree has been based on expected profit maximization (there are of course important exceptions to this generalisation).

Figure 4 provides a stylised overview of oil price formation in the FRISBEE model. Total demand and non-OPEC supply are based on neo-classical behavioural equations for oil and gas producers, other industrial companies and households in 13 regions across the world. The price set by OPEC ($P^{OPEC}$) clears the market, and implicitly determines both total oil production and the market shares for OPEC and non-OPEC. For a given price chosen by OPEC, oil demand and non-OPEC production are determined independently, and OPEC supply is simply closing the gap. A credible defence of the price target will require surplus capacity. In our model, we therefore assume that OPEC will always invest sufficiently in new fields and IOR activities to maintain a capacity surplus of 10 per cent.

**Figure 3. Oil price formation in the FRISBEE model**




In summary, oil companies invest in exploration for new reserves, field developments and in efforts to increase oil recovery from producing fields. Non-OPEC production is profit-driven, whereas OPEC meets the residual "call on OPEC" at a pre-specified oil price path that is determined through an NPV maximisation process, subject to total demand expectations and conjectures for non-OPEC supply behaviour. A higher oil price path (compared to a reference path) will gradually increase production from oil producers outside OPEC. Extraction from existing capacities is fairly fixed, but the profitability of IOR investments is increased, leading to higher production capacity in the short to medium term. In the medium to long term oil companies develop more fields, and in the longer term new fields are discovered and appraised for development. A higher oil price path will also gradually reduce oil demand. The model scenarios below illustrate how the interaction between financial markets and oil and gas companies may affect the supply side of the oil market.

### *3.2. Assumptions and calibration of two scenarios*

Following the discussion in Section 2, we want to explore the market effects of change in non-OPEC's investment strategy observed in the oil market at the end of the last century. According to Deutsche Bank (2004), RoACE increased substantially among the IOCs in the 1990s, from 9 per cent in 1990-1997 to 16 per cent in 1998-2005. This indicates that the required rate of return on new investments was considerably raised in this period.

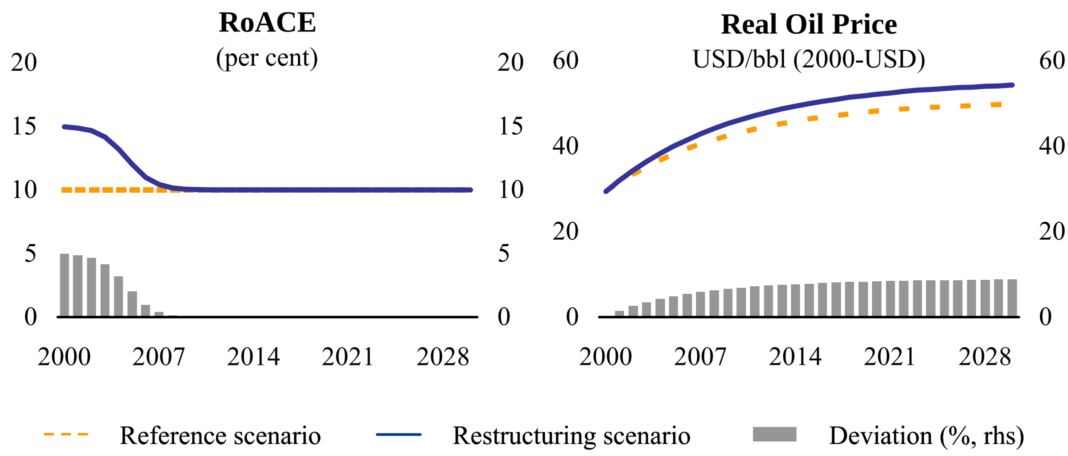
We will consider two different scenarios using the FRISBEE model. The first scenario, called the 'Reference scenario', assumes that the non-OPEC producers follow the attitude of the IOCs from the first half of the 1990s. That is, their required rate of return is assumed to be 10 per cent. The second scenario, called the 'Restructuring scenario', assumes that the non-OPEC producers require a higher rate of return, i.e., 15 per cent, at the beginning of the new century. However, as discussed above, we have seen a gradual change among the IOCs over the last couple of years, with a gradual redirection of attention (and investment) from short-term profitability to long-term reserve and production growth. Accordingly, we allow the required rate of return to fall gradually from 15 to 10 percent towards 2010, as illustrated in Figure 4 (below we also consider the effects of a prolonged period with 15 per cent rate of return). In all other respects, the scenario assumptions are identical.[18]

A higher rate of return in the 'Restructuring scenario' will induce less investment among non-OPEC producers compared to the 'Reference scenario', consistent with the observed behaviour of the IOCs after 2000. On the other hand, when the rate of return is gradually

[18] We assume that OPEC has perfect expectations about the required rate of return in non-OPEC. Alternatively, we could assume that OPEC has adaptive expectations about the rate of return. In this case OPEC would choose a higher initial growth in the oil price in the 'Restructuring scenario', assuming that non-OPEC producers would stick to a high required rate of return also in the future. Simulations indicate that this would lead to a significantly higher oil price level also in the long run.

reduced in the former scenario, investment activities should pick up again. In fact, with more unexploited projects and possibly higher oil price, investment activities may surpass the activity level in the 'Reference scenario' after some years. In the next subsection we will investigate how this may have affected the oil market since 2000, and what impacts it may have on the future market.

**Figure 4. RoACE and oil price scenarios**




Source: Exogenous assumptions (RoACE) and *FRISBEE* Model (oil price).

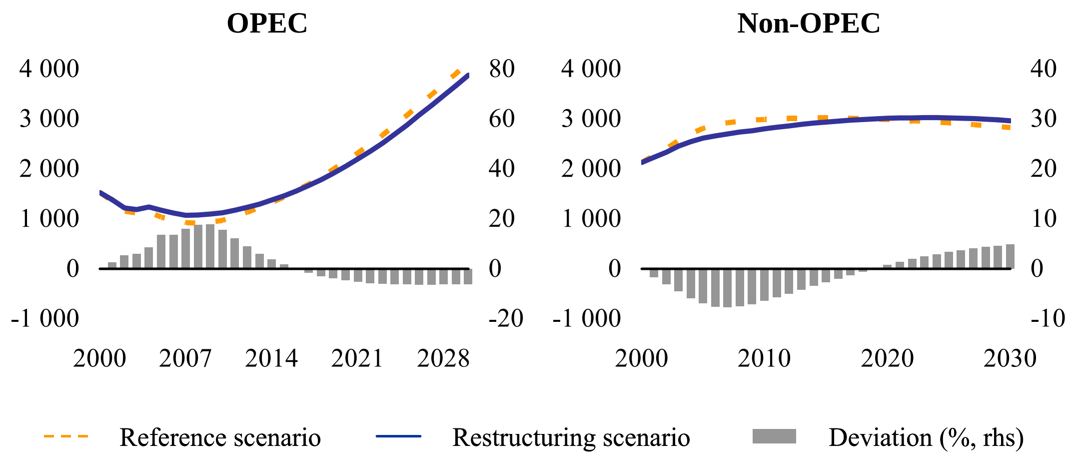
*3.3 Model results*

In the ‘Reference scenario’, the oil price increases from 29 USD/bbl 2000 to 50 USD/bbl in 2030. Hence, it is clearly profitable for OPEC to settle on an increasing oil price path from the level in 2000. In the 'Restructuring scenario', reduced investment activities among non-OPEC producers gradually reduce the supply outside OPEC compared to the ‘Reference scenario’, at least temporarily. This makes it profitable for OPEC to choose a higher oil price than in the latter scenario, cf. Figure 4. The short-term investment effect of the IOC strategy redirection is substantial. As the difference in attitude for non-OPEC producers is fairly short-lived, we shouldn’t expect a big change in the long-term oil price. However, the long-term oil price difference between the scenarios is not negligible (4.4 USD/bbl, or 9 per cent).

Between 2005 and 2010, non-OPEC investment levels in the 'Restructuring scenario' surpass the levels in the 'Reference scenario' for all three investment activities. After 2005 the required rate of return is almost the same, whereas the oil price is higher in the former scenario. Moreover, the recovery rate in existing fields is lower, which means that there are more profitable IOR projects left. In addition, there are more undeveloped fields (despite fewer discoveries), which means that the oil companies have more profitable fields to develop. The (expected) amount of undiscovered oil reserves is also higher.

From Figure 6 we see that non-OPEC supply is somewhat reduced in the 'Restructuring scenario' compared to the 'Reference scenario' in the first 15-20 years. Less investment gradually affects production levels. In the first couple of years this is driven by fewer IOR projects. After 5-10 years the effects of less development projects are perceptible, too. Gradually fewer discoveries also affect supply. However, as investment activity in non-OPEC starts to accelerate when the required rate of return is reduced, production levels outside OPEC gradually catch up with the 'Reference scenario'. From around 2020 non-OPEC supply is highest in the 'Restructuring scenario'.[19]

**Figure 5. OPEC and non-OPEC oil supply (mtoe per year)**




Source: *FRISBEE* Model.

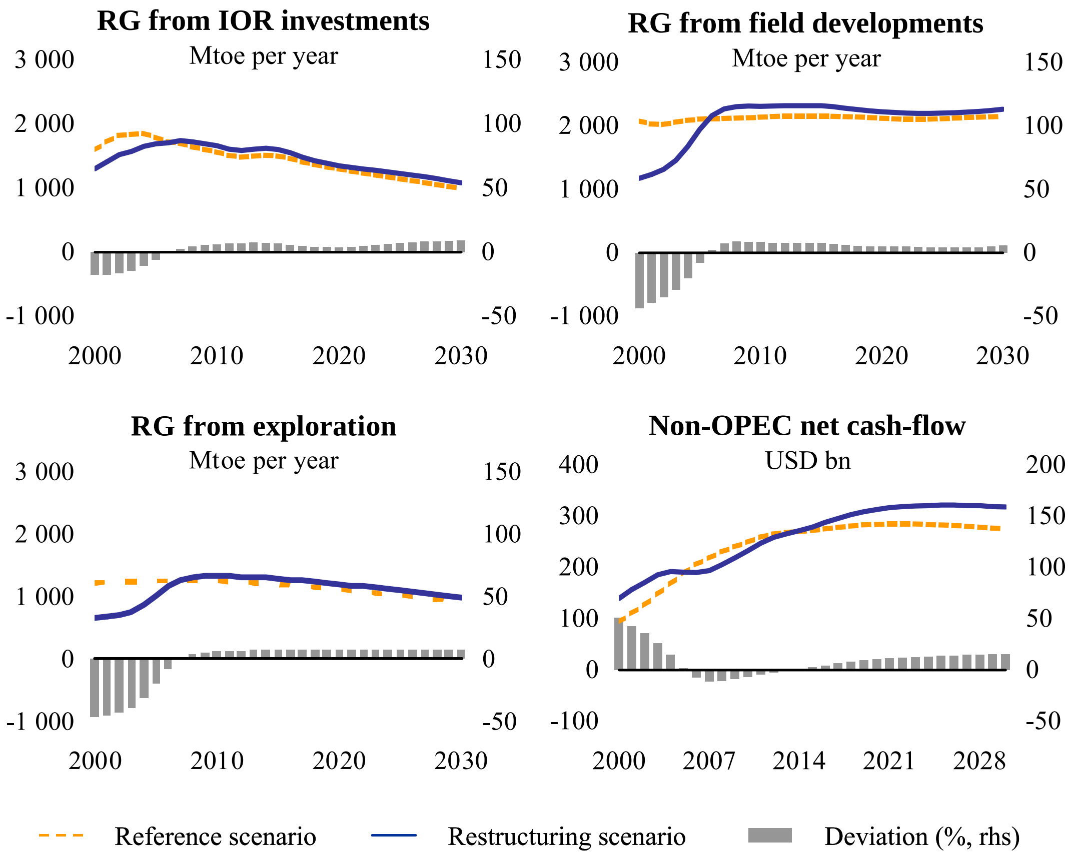
As explained in Subsection 3.1, a higher required rate of return among oil companies outside OPEC will affect new discoveries most and IOR projects least. This is because the time lag between investment expenditures and expected revenues are lowest for IOR activities and highest for exploration activities. Figure 6 shows how the different investment activities develop in the two scenarios. We see that IOR investments are least affected, as expected.

[19] If the oil price path was unchanged in the 'Restructuring scenario', the investment levels would still surpass the levels in the 'Reference scenario' before 2010. However, the investment levels in the two scenarios would be more similar towards 2030, and non-OPEC supply would be highest in the 'Reference scenario' over the entire time horizon.

They are reduced by up to 18 per cent in the 'Restructuring scenario'. New field developments are almost halved in the first couple of years, and so too are new discoveries.

Which scenario is most profitable for oil companies outside OPEC? Figure 7 shows how the net cash flow evolves, i.e., net revenues from oil production minus investment expenditures.

**Figure 7. Non-OPEC net cash flow and reserve-generation (RG) by investment type**[20]




Source: *FRISBEE* Model.

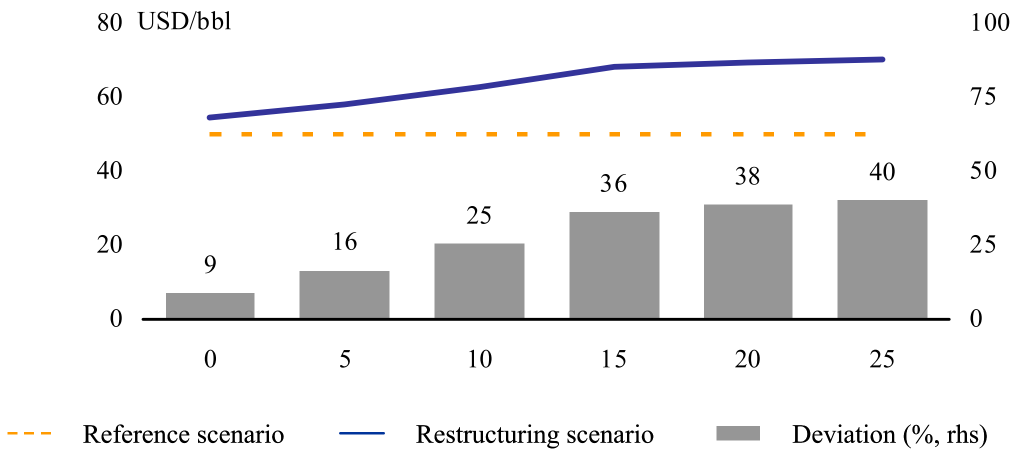
We see that the 'Restructuring scenario' is clearly the most profitable one, whatever discount rate we apply. In the short run, non-OPEC producers gain from reducing their capital

[20] Unconventional oil (i.e., tar sands in Canada) is included in all graphs except for new discoveries. Within our time horizon, conventional oil discoveries are much more important for new field developments than unconventional discoveries, as reserves of tar sand are already huge and not really constraining field development in Canada. If we subtract unconventional oil also in the graph for new field developments, we will see a gradual but distinct decline after 2010 in both scenarios. In 2030 unconventional oil constitutes almost half of new field developments outside OPEC, according to our scenarios.

outlays. In the medium term, they gain from a slightly higher oil price, and lose from a slightly lower supply. Investment expenditures are about the same. In the longer term, both the oil price and non-OPEC production are higher, and these effects dominate the effect of higher capital expenditures. That is, non-OPEC's temporary restraint in investment activities is beneficial for both non-OPEC and OPEC producers, whereas the consumers stand to lose from higher prices.

**Figure 7. Oil price effects if the shock is permanent**

Long-term oil price with varying degree of shock persistence (duration in years)




Source: *FRISBEE* Model.

Finally, what if the oil companies outside OPEC had required a higher rate of return (i.e., 15 per cent) for a longer period of time? Figure 7 shows the relative increase in the long-run oil price level when the decline in the rate of return is delayed by different number of years (e.g., 0 years is equivalent to the original 'Restructuring scenario', whereas 25 years means that non-OPEC has 15 per cent rate of return over the entire time horizon). As the figure shows, the long-run effect on the oil price would be much stronger if the restructuring of the oil industry was more than a short-lived phenomenon.

## 4. Conclusion

The process of capital formation in the oil and gas industry is an important part of the supply side dynamics in the oil market. Understanding how oil and gas companies think in terms of investment is therefore essential in order to develop and maintain the required insights for meaningful analyses of oil price formation. Over the last 15 years, international oil and gas companies have gone through a period of escalating market turbulence, restructuring and redirection of investment strategy. From the beginning of the 1990s, the focus on short-term accounting returns increased, at the expense of reserve replacement. We explore the impact of this strategy redirection on oil price formation.

The temporary one-dimensional focus on RoACE forced the international oil companies to cut back on investments, thus generating higher oil prices. This change in strategy has clearly proved profitable for the international oil industry. Through the capital market analysts' RoACE-benchmarking of companies, an implicit coordination on lower investment levels was achieved. In retrospect, it can easily be demonstrated that deviation from the common strategy of low investment would have been profitable for any individual oil company. By maintaining its standard investment policy (e. g., a constant reinvestment ratio), it could have reaped the joint benefit of high oil prices and high production. However, tight co-operative capital discipline was maintained, as managers feared that a lower RoACE than the industry average would harm share prices in the short run, thus making it harder to raise capital and increasing the takeover probability.

This study demonstrates how increased focus on shareholder returns, capital discipline and return on capital employed (RoACE) have caused a temporary slowdown in investment and production growth among international oil companies. We find that the strategic redirection of the international oil industry towards the end of the 1990s had long-lasting effects on OPEC behaviour – and on oil price formation. Our scenarios suggest that the industrial restructuring of the late 1990s caused a lift of approximately 10 per cent in the long-term oil price. Both OPEC and non-OPEC producers gain from this development, whereas the cost is carried by oil-importers and consumers.

Industrial leaders and their companies do not operate in a vacuum. Rather, they respond continuously to changing political and market environments. Their models and ways of thinking may be stable for periods. However, their mindset will also be challenged by external forces from time to time. And sometimes these pressures even bring about deeper changes. This study demonstrates that such a change took place in the oil and gas industry in the late 1990s, that had persistent effects on the oil market.

From the perspective of the investors, an adequate question is if strategies now have shifted too far away from accounting returns. The international oil industry has a history of over-investment at high oil prices (e.g., Jensen 1986). However, there are signs that the current situation is different from the traditional high price cycle scenario: The lack of adequate investment projects actually put an effective curb on investments, and reserve replacement levels are low. On the other hand, some of the current investment projects in the oil industry have break-even prices considerable above historic oil prices. Company managers thus face some tough decisions. Traditional counter-cyclical asset trading (selling reserves at top of the oil price cycle) may not seem so tempting when the company is unable to replace its reserves. On the other hand, buying reserves in the current market sentiment may seem risky. Assets are traded at prices that entail a considerable downside risk. Part of this picture is the fact that the IOCs are competing for new reserves against NOCs that are not subject to the same capital market scrutiny.

An interesting direction for future research would be to study the stability of the investment process in the oil and gas industry in greater detail, preferably with micro-econometric studies of company data. Modern econometric techniques may reveal more exact information on how the process of capital formation in the oil and gas industry was altered in the late 1990s.

## Appendix A. Description of the FRISBEE model

In this appendix we give a more detailed, informal description of the FRISBEE model, with emphasis on the oil market.[21] FRISBEE is a recursively dynamic partial equilibrium model of the global oil market. The world is divided into 13 regions (see Appendix B). In each region oil companies produce oil, which they sell on the global market. Three different end-users in each region consume oil products, which they buy at regional prices linked to the global market. We assume that the oil market clears in each period, i.e., total supply from all regions equals total demand in all regions, and all trade between regions goes through a common pool. The time periods in the model are one year, and the base year is 2000. Exchange rates are held constant over time.

*Production of oil*

In each of the 13 regions the model distinguishes between 4 field categories based on field size and geology (see Appendix B). Within each of the resulting 52 operational areas, there are developed and undeveloped reserves. New discoveries add to the stock of undeveloped reserves at the end of each year.

Both production and investment decisions are explicitly modeled. For each region and field category we apply a pre-specified production profile. This profile is taken for granted in the investment decisions, but can to some degree be altered during the lifetime of the field (see below). The profile is divided into four phases: The first phase is the *investment phase*, i.e., the time lag between the investment decision and start of production. The second phase is the *pre-peak phase*, i.e., when production builds up towards the peak level. The two first phases are quite short, varying between 2 and 6 years in total across regions. The third phase is the *peak phase*, when capacity is at a constant and pre-specified level. This phase lasts between 5 and 10 years. The fourth and final phase is the *decline phase*, when capacity declines at a constant rate per year until production is too low to be profitable. Thus, all developed reserves are divided into region, field category and vintage (phase). The initial allocation is based on input from an extensive database of global petroleum reserves in the year 2000.

At the end of each year, oil companies decide how much to invest in developing new fields and in improved oil recovery (IOR) from existing fields (see below). When new fields are

[21] A formal description is found in Aune et al. (2005), whereas Rosendahl and Sagen (2007) describes the gas market modelling in more detail.

developed, the stock of undeveloped reserves is reduced. We assume that new discoveries are made each year in every region and field category. The volumes of new discoveries are assumed to be a concave function of the expected oil price, and a linear function of the expected remaining undiscovered reserves. This discovery function is calibrated for each region so that if the oil price stays at $40 per barrel, total accumulated discoveries over the time horizon (i.e., until 2030) equal USGS's (2000) mean estimate of potential new discoveries over a 30 years period.

The model includes supply of conventional oil (crude oil and NGL), and unconventional oil from Canada (tar sand) and Venezuela (extra heavy oil).

*Production in non-OPEC*

The oil production capacity in a region is by and large fixed at each point of time, and determined by investments in earlier years. However, production is not totally fixed, but can be above or below the pre-specified production profile if profitable. A short-term marginal cost function decides whether a deviation from the pre-specified profile is optimal. For non-OPEC regions we assume that oil supply is determined by equalizing the producer price of oil with the sum of marginal operating cost and gross sales taxes in each field category and vintage. The producer price of oil in a region is mainly determined by the global crude oil price and transport costs, but may also differ due to crude oil quality. We assume that the initial differences in producer prices across regions are unchanged over time.

In the pre-peak and peak phase we assume that marginal operating costs are fairly constant (and low) except when production is very close to capacity. Thus, there is only a slight possibility to adjust production in these two phases. In the decline phase, however, marginal operating costs increase more rapidly as production rises. This reflects that some of the declining fields are approaching the end of their lifetime, and extraction is falling for a given operational input. That is, costs per unit production get higher, and the oil price level will to a larger degree affect the optimal production level. Thus, production is more flexible in the decline phase. Marginal operating costs are based on detailed information about unit costs in different types of fields in the most important oil producing countries.

*Production in OPEC*

In the model OPEC chooses a fixed price path, and we search for the price path that maximizes OPEC's net present value (given some restriction on the form of the price path). The fixed price path assumption implies that demand and non-OPEC supply are determined independently of each other, and that OPEC supply is solely determined by the residual demand (or call on OPEC oil). OPEC must therefore continually possess enough capacity so as to support the chosen price path (see OPEC's investment decisions below).

*Investment decisions in non-OPEC*

The basic incentive for oil companies is to invest in provinces and field types with the highest expected return. To sort out the most profitable among projects, net present value (NPV) is calculated for investments in each of the 44 non-OPEC provinces/field types over the entire project lifetime at a given discount rate. Linear capital allowances are made over 6 years (this seems to be a reasonable approximation over different fiscal regimes). As explained in the main text, non-OPEC producers have adaptive price expectations.

Oil companies continuously target the most profitable reserves. Reserves that are more costly to extract gradually enter as candidates for investment, and the cost of production will rise as the reserves are depleted. On the other hand, new discoveries and technological change reduce the costs of developing new fields.

Besides investing in new fields, oil producers have the option to invest in improved oil recovery (IOR) from fields in the decline phase. IOR investments generate additional reserves and open up for increased output in the short- to medium-term by lifting the tale of the production profile of a given field. The costs of IOR investments increase as the recovery rate becomes higher.

Risk is a factor that affects oil companies' investment strategies. Risk can be political, fiscal or related to exploration and production as such. FRISBEE incorporates an exogenous risk premium to account for variations in risk assessment in different provinces and field types. The risk premium is expressed in terms of additional costs per barrel that is required to make the investment project as attractive as a risk neutral project.

FRISBEE further incorporates other factors in the investment cost function, postulating that

- a large current production modifies the rising trend in field development costs (technical, institutional learning, "materiality")
- a large regional activity level modifies the rising trend in development costs (infrastructure, competitive subcontractors)
- few undeveloped reserves increase the rising trend in development costs

These factors make it more attractive to stay on in an area rather than enter new locations with a lower degree of reserve development, as long as the mature area still has much undeveloped fields left.

*Investment decisions in OPEC*

OPEC is a residual producer filling the supply gap necessary to keep the oil price at the preferred level. In FRISBEE, the operational rule for OPEC is to invest enough in new fields and IOR to maintain a current capacity surplus of about 10 per cent, in order to demonstrate the ability to increase production and control the price level. The distribution of investments between OPEC Core and Rest-OPEC, and between new fields and IOR, is exogenous.

*Demand for oil*

We distinguish between three end-users of oil products, i.e., Manufacturing industry, Power generation and Others (including households). Manufacturing industries and Others consume both transport oil and stationary oil (including processing), whereas Power producers consume fuel oil. All oil products are bought at a regional product price, which is determined by the global crude oil price, transport costs and refinery costs. The end-user prices of the different oil products must also cover distributional costs and taxes, and will generally differ across end users. End-user prices and regional product prices are generally taken from IEA, but other sources and some guesstimates have been used to fill the gaps. Transport-related costs, refinery costs and taxes are held constant in real terms over the time horizon. Stock changes are exogenous and are phased out over time.

Demand for oil in Manufacturing industries and Others are log-linear functions of population, income per capita, prices of other energy products and an autonomous energy efficiency improvement (AEEI), as well as demand in the previous year. This means that we distinguish between short- and long-run effects of price and income changes via an adjustment parameter.

Between 30 and 55 per cent of the long-run effect is obtained after one year (varies between oil products and end-users), whereas the long-run price elasticity varies between -0.1 and -0.6 (weighted average is -0.19 for Manufacturing industries and -0.37 for Others). The price elasticities and adjustment parameters are mainly taken from Liu (2004). Prices of gas and coal are endogenous in the model, based on supply and demand in those markets. Demand for fuel oil in Power generation depends on unit costs for various power technologies.

Growth rates of GDP and population are exogenous in the model. Income elasticities are calibrated based on projections of energy demand, and vary between 0.1 and 1.1 in the long run (weighted average is around 0.6 for both Manufacturing industries and Others). Transport oil is generally about twice as income elastic as stationary oil. AEEI is set equal to 0.25 per cent per year in OECD and 0.5 per cent outside OECD.

## Appendix B. List of regions and field categories in the FRISBEE model

| Regions | Field categories 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Africa | Onshore All | Offshore deep < 400 Mboe | Offshore deep > 400 Mboe | Offhore shallow All |
| Canada | Onshore All | Unconventional All | Offshore < 400 Mboe | Offshore > 400 Mboe |
| Caspian region | Onshore < 400 Mboe | Onshore > 400 Mboe | Offshore < 400 Mboe | Offshore > 400 Mboe |
| China | Onshore < 100 Mboe | Onshore >100; < 1000 Mboe | Onshore > 1000 Mboe | Offshore All |
| Eastern Europe | Onshore < 100 Mboe | Onshore > 100 Mboe | Offshore < 100 Mboe | Offshore > 100 Mboe |
| Latin America | Onshore All | Offshore deep < 1000 Mboe | Offshore deep > 1000 Mboe | Offhore shallow All |
| OECD Pacific | Onshore All | Offshore deep All | Offshore shallow < 100 Mboe | Offshore shallow > 100 Mboe |
| OPEC core* | Onshore < 400 Mboe | Onshore >400; < 1000 Mboe | Onshore > 1000 Mboe | Offshore All |
| Rest-Asia | Onshore < 400 Mboe | Onshore > 400 Mboe | Offshore < 400 Mboe | Offshore > 400 Mboe |
| Rest-OPEC | Onshore < 400 Mboe | Onshore > 400 Mboe | Offshore deep All | Offhore shallow All |
| Russia/Ukraine/Belarus | Onshore < 400 Mboe | Onshore > 400 Mboe | Arctic < 400 Mboe | Arctic > 400 Mboe |
| USA | Onshore All | Alaska All | Offshore deep All | Offhore shallow All |
| Western Europe | Offshore deep < 400 Mboe | Offshore deep > 400 Mboe | Offshore shallow < 100 Mboe + Onshore | Offshore shallow > 100 Mboe |

* OPEC core consists of Saudi Arabia, Iran, Iraq, Kuwait, UAE and Venezuela, whereas Rest-OPEC consists of the remaining OPEC member countries.

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