Royal Dutch Shell: Evaluation of Oil Reserves

Master Thesis

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Abstract

In the beginning of 2004, Royal Dutch/Shell group announced that it reduces the quantity of its proved oil and gas reserves. This announcement was the beginning of the largest accounting scandals in history of oil and gas industry.

This event had some very negative consequences for Royal Dutch /Shell and for oil industry in general, but in the same time it represents a brilliant and in some sense unique opportunity to assess the fair value that market grants to oil and gas reserves of an actively traded company. This is also a good opportunity to try to replicate the calculations that the market participants would make in order to arrive to the conclusion about the fair value of reserves. Later, it would be possible to compare these calculations with the fair value observed on the market.

This paper will consist of four chapters. In the first chapter, some background will be given on what meaning reserves restatement could have for the group and for the oil industry as a whole. In addition, the overview will be given regarding the consequences of the scandal for corporate structure of Royal Dutch/Shell.

The second chapter will deal with the issues of legal framework for reporting of oil reserves. It will provide an overview on what stands behind the figures of proved oil reserves (that were restated during the above mentioned scandal) and how this figures different from the ones that market participants would take into account. Furthermore, there will be a discussion regarding other figures on company's annual report related to oil and gas reserves and that can be further utilized for fair value calculation.

In the third chapter, event study will be represented. The aim of this event study would be calculation of fair value observed on the free market using the conclusions of previous chapter

Finally, the fourth chapter will be dedicated to own calculations aiming at replication of the fair value of oil and gas reserves observed on the market. The calculations will be made using discounted cash flow methodology and real options methodology.

As the conclusion of this paper the assessment will be made on how well do different calculations methods can predict the fair value for oil and gas reserves (if at all) and what are the possible factors that influence the quality of this estimation

For the sake of convenience Royal Dutch/Shell Group and parental companies will be defined simply as RDS or Shell as well as word "oil" will de used both for oil and gas. All the figures related to oil and gas reserves (unless mentioned otherwise) represent measure of so called barrels oil equivalent (boe), where 5800 cubic feet of gas equal 1 barrel of oil

1 Royal Dutch Shell Group: Background Information

On May 28, 2002 sir Philip Watts, then chairman of the Comity of Managing Directors (CMD) at Royal Dutch Shell Group wrote e-mail to the CEO of Exploration and Production Unit (EP) in the Group Mr. van de Vijver, which said:

"You will be bringing the issue to CMD shortly. I do hope that this review will include consideration of all ways and means of achieving more than 100% (reserves replacement ratio) in 2002. To mix metaphors considering the whole spectrum of possibilities and leaving no stone unturned"

This e-mail gives a good illustration of the aggressive policy that was undertaken in RDS in order to meet its external promises regarding reserves replacement ratio (RRR) or in other words, the ratio of discovered reserves to production. In fact, the problems did not start in 2002. Ever since Mr. van de Vijver succeeded the position of EP CEO from sir Philip in 2001, he has noticed that the actual situation with oil discoveries is not as rosy and optimistic as it seems to be from company's reports (Davis Polk & Wardwell, 2005).

This aggressive policy to push as much oil reserves into balance sheet as possible was one of the reasons behind the oil reserves scandal that struck one of the oldest and well-established oil companies in the world in the beginning of 2004.

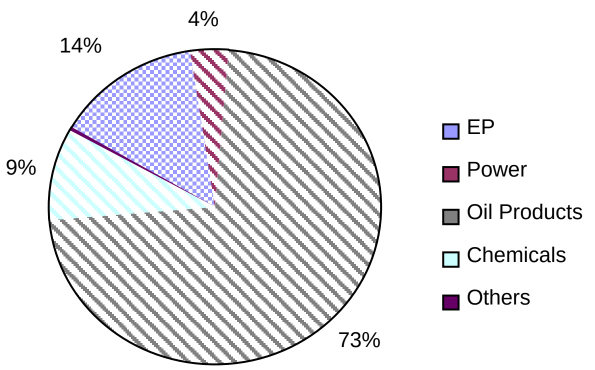
This chapter will give some background on Shell's place in world oil industry. This information will be useful in understanding the scale of recent scandal for oil industry and Shell itself. Afterwards some information will be given on the recent unification announcement, which is also may be regarded as one of the scandal outcomes.

1.1 Oil Industry and RDS Group

Royal Dutch Shell Group of Companies is one of the biggest vertically integrated oil groups in the world that has about 119 thousand employees in 145 countries. Shell unifies practically all the stages that involve energy and chemicals production in its five units: EP, Gas and Power, Oil Products, Chemicals and Renewable Energy.

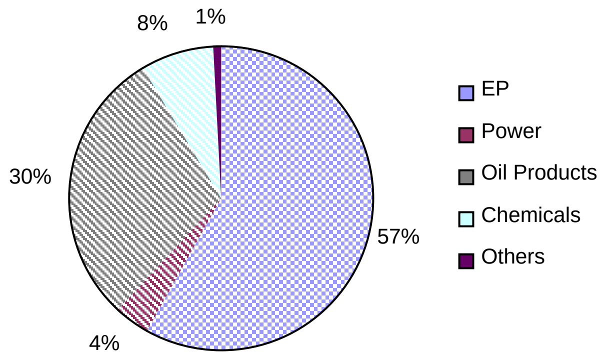
Group's activities involve marketing, transporting and trading oil and gas; providing oil products for industrial uses including fuel and lubricant for ships and planes; generating electricity, including wind power, and producing solar panels; producing petrochemicals that are used for plastics, coatings and detergents; developing technology for hydrogen vehicles (RDS: The Shell Report, 2003).

The split of company revenues between different units in 2003 is shown in Figure 1.1:



(Source: RDS Form F-20)

As in this paper the main attention will be drawn to the oil reserves, the figures in interest will be those of EP unit. The figure shows that the unit provides some 14% of revenues and it is second most important unit after Oil Products. So, the performance of this unit is of importance for the overall company performance. The picture becomes even clearer as one looks at company's assets distribution in Figure 1.2:



(Source: RDS Form F-20)

The figure shows that most of RDS' assets (57%) are concentrated in EP unit. As most of these assets are attributed to oil and gas reserves, it is easy to imagine that any change in reserves will have immediate and substantial consequences on company's balance sheet. Especially when the restatement involves restatement of about a third of the existing oil and gas reserves as it was in case of the latest scandal.

The consequences of the scandal were also reasonably large for the oil industry as a whole. Although, Shell only produced some 3% of world oil and 3.5% of oil gas, it held some 9% of proved oil reserves in 2003 (BP, 2004). Given the degree of dispersion in the industry this is still one of the biggest oil producers in the world.

There is another reason why restatement of oil reserves by Shell had consequences for the oil industry. To see this one should look at the data in Table 1.1:

Company	Production (mbbl) (oil only)	Company	Proved Reserves (mbbl) (oil only)
Saudi Arabian Oil	3055	Saudi Arabian Oil	259300
National Iranian Oil	1385	Iraq National Oil	112600
Petroleos Mexicanos	1299	National Iranian Oil	99060
Petroleos Venezuela	1193	Kuwait Petroleum	96500
RDS	**810**	Abu Dhabi Oil	92200
Nigerian Petroleum	766	Petroleos Venezuela	77783
PetroChina	763	Oil Corp Libya	29500
Kuwait Petroleum	745	Petroleos Mexicanos	25425
Iraq National Oil	715	Nigerian Petroleum	24000
BP	677	Qatar Petroleum	15207
Lukoil	570	Lukoil	14243
Abu Dhabi Oil	568	PetroChina	10959
TotalFinaElf	530	Yukos	9630
Oil Corp Libya	496	**RDS**	**9469**
Petroleo Brasileiro	485	Sonatrach	9200
Pertamina	438	Petroleo Brasileiro	7749
Yukos	362	BP	7217
Petroleum Dev. Oman	329	ToalFinaElf	6961
ENI	312	Petroleum Dev. Oman	5524
Sonatrach	285	Sonangol	5412

(Source: OGJ, 2003)

The table shows top 20 oil producing companies and reserves leaders in 2003. One can see that the number of Western companies in the list is rather limited and that in both cases RDS is ranked one of the biggest among Western or Russian oil companies, which are precisely the companies listed on the stock exchanges and included in the major indexes. Thought RDS is not the market capitalization leader, restatement of its reserves would most probably have an influence on any market index constructed out of oil companies' stocks. This fact will have its implication, as the event study will be conducted in Chapter 3.

It can be added that before the restatement Shell's reserves life ratio (i.e. quantity of reserves divided by yearly production) was about 15 years, which is just slightly smaller than 17, the average number for Europe and Eurasia, where most of Group's reserves and production are concentrated. After the restatement, the ratio fell to only 10, which puts Shell into disadvantaged position in comparison to other companies in the industry (BP, 2004). Just for comparison, one can take a look on Table 1.2, where the reserve life in different world regions is summarized:

Region	N.America	Eurasia	M.East	Africa	S.America	Asia Pacif.
Reserves Life	12	17	88	33	41.5	16

(Source: BP, 2004)

The huge numbers of Middle East and South America can rather be ignored as most of the reserves there are owned by the local state run companies, but it still does not make the overall position of Shell in comparison to industry average much better.

Now as the degree to which the restatement of oil reserves could influence the standing of RDS and the oil industry as the whole becomes clearer, let us take the first look at one of the issues directly affected by this restatement, namely at Shell's ownership structure. To do this one should first turn to the group's history.

The partnership of Royal Dutch and Shell dates back to 1907, when sir Marcus Samuel, than Chairman of deeply indebted Shell Transport and Trading Company, stuck the deal with Royal Dutch Oil Company in desperate effort to save the company from bankruptcy. According to this deal, two companies would share risks and benefits of the oil projects at Caspian Sea coast that were owned by Shell and some smaller Far Eastern oil projects that were owned by Royal Dutch. The cut of this deal was 60:40 in favor of Royal Dutch, the cut that remained throughout the 100 years history of the Group.

Back then, many regarded this deal as a merger, however it was not thru. Both companies remained independent and continued that way until recently. So, definition that is more appropriate would be partnership or alliance.

In the early 20th century, Group started aggressive expansion through acquisitions in Europe, Africa and the Americas, which continued also in interwar period, when Shell entered into chemicals production.

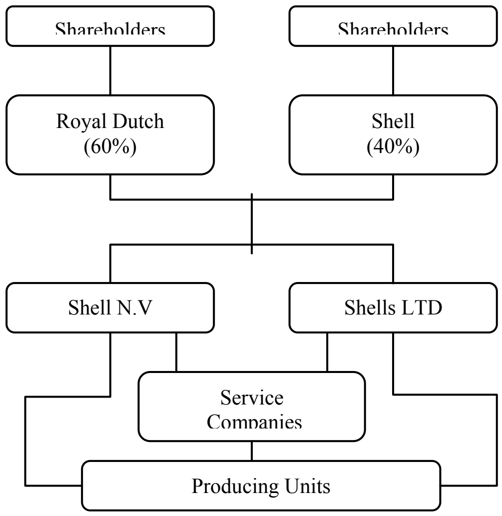
All in all, after the second World War RDS became a global integrated oil and chemicals company, thought its assets have been confiscated twice during the wars. Following the war Shell expanded into transport and refinery businesses.

In the sixties, as world oil output began to rise dramatically Shell was one of the leading oil companies supplying about one seventh of the world demand for oil

In the 70s, just before the recession started, Shell made major oil and gas discoveries in the North Sea, just off the coast of Scotland. This discovery could not come any more on time, since at that time oil prices surged and more and more people turned to natural gas, which accounted to 15% of Europe's energy demand at that time.

With the lower oil prices in 90s, Shell concentrated on its core businesses - mainly oil, gas and chemicals. The group also started to look at sustainable energy solution and renewable energy sources (Howarth, 1997).

Although, Shell for long have been regarded as the single company, in fact throughout its history it remained to be a partnership and consisted until recently of two separate companies, had two board of directors, two CEOs as well as two separate listings on Amsterdam, London, New York and other stock exchanges. The corporate structure of RDS can be illustrated by Figure 1.3:



(Source: RDS: F-20 Form, 2003)

As was mentioned above, the complex structure of ownership that is represented in the figure existed in 2003 due to historical reasons. This structure, by no doubts did not add any clarity for the investors and in fact contributed to the ambiguous internal reporting system that existed in Shell until recently and that allowed group's management to boost the numbers of proved reserves without proper control.

In order to build a more reliable corporate structure, RDS group took several steps, the latest of which was the unification of parental companies into single Royal Dutch Shell PLC.

1.2 Unification of Royal Dutch and Shell

As it was mentioned the ambiguous corporate structure was one of the causes for the mis-presentation of oil reserves resulted in the later scandal. Therefore, already in the

beginning of 2004 the boards of two parental companies announced that they are planning to revive the long planed unification of Royal Dutch Shell into one company. This was made in order to boost its corporate image and to regain investor's confidence in RDS.
On 28 October 2004, the Royal Dutch Boards and the Shell Transport Board announced that they had unanimously agreed, in principle, to propose to their shareholders the unification of Royal Dutch and Shell Transport under a single parent company, Royal Dutch Shell. And than on 19 May 2005 the companies announced the final proposal for the unification.
Among the reasons for unification as announced by companies' management were increased clarity and simplicity of governance, management efficiency, increased accountability and flexibility in issuing equity and debt.
Management proposed clearer and simpler governance structure. This will include one-tier directors board and a simplified senior management structure with a single non-executive Chairman, a single Chief Executive and clear lines of authority.
Increased efficiency of decision-making and management processes generally, including through the elimination of duplication and the centralization of functions.
Clear lines of authority and accountability, with the Executive Committee reporting through the Chief Executive to a single board with a single non-executive Chairman was expected to improve the accountability of the board and management to all shareholders.
A single publicly traded entity is expected to facilitate equity and debt issuances, including on an SEC-registered basis (RDS, 2005).
After the unification, the former parental companies are to become subsidiaries. New company will be incorporated in UK and will have a head office in the Netherlands for tax purposes.
As it concerns the shareholders, the shares of Royal Dutch and Shell will be exchanged in proportions as shown in Table 1.3:

Royal Dutch Share traded in Amsterdam	2 “A” Shares of RDS
Royal Dutch Share traded in New York	1 “A” ADR of RDS
Shell Ordinary Share	0.287333066 “B” Shares of RDS
Shell ADR	0.861999198 “B” ADRs of RDS

(Source: RDS, 2005)

Although, there still will be two types of shares, the trading will become much clearer, since instead of 2 billion shares of Royal Dutch with a nominal value of 0.56 EUR and 9.6 billion shares of Shell with nominal value of 0.25GBP, both “A” and “B” will have nominal value of 0.07 EUR. Both kinds of shares will be traded on Euronext in

Amsterdam and in London. American depository receipts (ADRs) will include two shares and will be traded in New York. As previously, the share of "A" stocks in the new company will be 60% and share of "B" stocks 40%.

Also, the dividend policy of RDS will become clearer, as all the dividends will be announced in Euros. In Chapter 3, it will be shown that previous dividend policy lead to inequality between Royal Dutch and Shell shareholders.

Finally, the event day of unification was July 20, 2005. On that day, RDS was floated on all three bourses and this ended almost hundred-year history of Royal Dutch/Shell partnership.

As the result of unification, new company becomes the biggest oil and gas enterprise on FTSE index ahead of BP and one of the biggest companies in FTSE 100 index.

The overall reaction of markets on the unification was positive. The shares of RD and Shell went up after the announcement and short before the event day. Still it is difficult to filter out markets reaction, since one day before the unification, RDS announced that the costs of oil exploration for one of its projects in Russia would be substantially higher than expected, which pushed the stocks down.

1.3 Summary of Chapter One

In this chapter, several consequences of the recent oil reserves scandal at RDS were discussed. It was shown that oil and gas exploration and production is meaningfully large line of RDS' business both in terms of revenues and assets. It is clear that any asset and income restatement in Exploration and Production unit will have immediate large-scale consequences on the stock price of parental companies in RDS Group.

It was also shown that Royal Dutch Shell was one of the leading oil companies in the world, though its share in oil and gas production constituted only about 3% in 2003. Therefore, the restatement of oil reserves by RDS had also consequences for the oil industry as the whole.

The standing of RDS in comparison to industry average deteriorated on the restatement. It was shown that "reserves life" measure of RDS went down to 10 years, which is significantly lower than world and regional average.

Additionally, one of the possible sources of problems that lead to reserves restatement was discussed, namely, the corporate structure of RDS. Then the consequences of the restatement for the corporate structure were presented. Partially due to the scale of the scandal that was generated by the oil reserves restatement, management of parental companies decided to push forward with the changes in group's corporate structure and unified two parental companies.

In the following chapters, the further consequences of the scandal will be represented and evaluated.

2. Legal Framework for Oil Reserves Reporting

Before one can continue with the analysis of oil reserves restatement assessment of reserves' value, it would be important to understand what stands behind the figures and values restated in 2004. It is vital to remember that during the scandal company announced the restatement of *proved* oil reserves. This chapter is dealing with the question of whether proved reserves is the same as overall reserves and what are the figures that are used by market participants and that should be used in for the analysis in this paper.

In the first and second section of this chapter, the legal framework will be provided for two key figures that will be used in the following chapters:

- Quantity of oil reserves reported by company
- Value of oil reserves on company's balance sheet

In the third section of this chapter, the assessment will be made on what role might have the existing legal framework in the reserves mis-presentation in case of RDS.

This chapter is aimed at explaining how the present reserves disclosure system works, what are the number reported by energy and oil companies and what is degree of freedom given to the company in reporting of the reserves. Later the particular misuse of the existing rules by Shell will be discussed as well as the consequences of the oil reserves scandal in Royal Dutch Shell.

2.1. Legal Regulations and Definitions of Oil Reserves

The way in which management calculates its oil reserves' value and quantity may be not totally transparent and understandable for investors, which in turn adds to the risk and uncertainty in the evaluation of oil producing companies in general and Shell in particular.

Unlike most of the other figures on the company's balance sheet the value of oil reserves is not based on the historical value or on the value observed on the free active market. The oil reserves as well as gas reserves are represented based on the volume of hydrocarbons companies believe they can produce with *reasonable certainty* based on the scientific and engineering analysis (SEC, Regulations §210.4-10 1978). That includes both evaluation of the quantity and the dollar value of the reserves.

In fact, while aiming at the reasonable certainty and greater comparability of oil reserves publicly reported by the oil companies, current system of reporting contradicts the reporting standards that are accepted by industry and is rather confusing for the investors. The main problem with the reporting system as it exists today might be the fact that it omits large part of the oil reserves in the company, namely the reserves that have not yet received reasonably certain geological approval and therefore booked as probable or possible. These reserves are in average 50% larger than the ones reported by the oil companies and therefore constitute the most of the company's potential oil production in the future (Bentley, 2002).

The problems in the current system of accounting for oil and other mineral resources might be tracked down to the time it has been developed in 1978 and approved by US Congress. So called "System 1978" that has been later implemented through rules and guide lines built up by Security and Exchange Commission as well as through the accounting standards of FASB was originally created without having the investors and other market participants as the primer "client" in mind. The Congress created the requirements for reserves disclosure primary targeting the national security and energy security purposes (CERA, 2005).

As one is trying to review the evaluation methods and representation patterns for oil reserves that are generally accepted in the industry and recommended by the regulatory authority like SEC, one should perhaps start with the most basic definition, that is definition for reserves probability.

On one hand, oil reserves are nothing more that another type of company's inventories, but unlike the inventories that can be precisely calculated, oil reserves are uncertain.

Oil and gas reserves represent the cumulative production of a field until it is completely depleted. Production depends mainly on the volume in place (net pay and area), the geology of the reservoir (porosity, permeability), the physics (engineering) of the fluids (pressure, temperature, saturation, density and viscosity), the development scheme (wells producers and injectors), and the economics (cost and price). The geological uncertainty adds to the economic uncertainties.

These uncertainties can only be represented by the range of probabilities. The problem is that investors do not like the uncertainty. Therefore, the guidelines of "reasonable certainty" were issued by SEC in 1978 according to which only proved reserves should be represented. The problem is that everyone can interpret "reasonable certainty" in its own way and it can vary from 51% (more probable than not) to 99% (Laherrere, 2004, p1).

Right now, there are as many reserves definitions and evaluation techniques as there are the parties involved in the process. Namely each oil company, each security commission or government department tends to use its own definition for the reserves. This can certainly cause an enormous chaos and lack of comparability between different evaluations issued by different bodies and above all makes the definition of reserves not that certain as it was intended to be initially.

Still there are two major groups of definition that can be detected and that are used today by most of the players on the oil market for the financial analysis and for technical analysis of the reserves. These are deterministic and probabilistic definitions as they are represented in Table 2.1:

Deterministic Approach		*Probabilistic Approach*	
Proved (P1)	*Reasonable certainty*	*Proved (1P)*	*At least 90% Probability*
Probable (P2)	*More likely than not*	*Proved + Probable (2P)*	*At least 50% Probability*
Possible (P3)	*Less likely than probable*	*Proved + Probable + Possible (3P)*	*At least 10% Probability*

(Source: Harrell Ryder Scott 24 Oct. 2002 in Laherrere 2004)

Method is called deterministic if a single "best estimate" of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Many oil companies base their investments on a most likely case (deterministic), but only after gaining a thorough understanding of the range of reserves and associated probabilities (i.e., probabilistic background). Indeed, the sizing of equipment and facilities to produce oil and gas generally has to be specified and does not allow for a wide range of possible outcomes. Nevertheless, the decisions made by oil companies are often based on a thorough understanding of probabilistic reserves in the first instance (CERA, 2005. p 13).

The latest and the most widely accepted version of probabilistic approach definition was issued by the Society of Petroleum Engineers and World Petroleum Council in 1997. These definitions represent a loose compromise between the probabilistic approach used in the industry and more conservative deterministic approach accepted by US Security and Exchange Commission.

In order to understand what is standing behind the definitions proposed by the industry and by SEC and to have a clearer picture of the expectations of the capital markets and the investors about the reserves booked under each category let us discuss the explanations provided by SEC for reserves booking.

The existing SEC guidelines were first issued in 1978 under the regulations of financial accounting and reporting for oil and gas producing activities pursuant to the federal securities laws and the Energy Policy and Conservation Act of 1975 or so called "Rule 4-

10” and later supplemented by various explanatory guidelines, the latest of which were issued in 2001.

The reserves to be reported under the Rule 4-10 are the reserves that follow the definition of **proved reserves**: “*Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. …Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test…*

…Estimates of proved reserves do not include: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in un-drilled prospects…” (SEC Regulations §210.4-10, 1978)

“Reasonable certainty” is explained by SEC as the concept, which implies that, as more technical data will be available for the particular reserves, the possibility of rescaling reserves upwards is significantly higher than the possibility of the downward rescaling (SEC Financial Reporting and Interpretation Guidelines §II F- 3, 2001). In other words SEC will require reporting a single most probable value of reserves under the existing geological data and the current oil prices, i.e. the quantity that is to be recoverable given existing market conditions and the information provided by the by the company’s oil engineers (Laherrere, 2004, p4 sqq). The quality of data provided by the company and the standards under which it is provided will be discussed later as the special case of Shell will be assessed.

Furthermore, SEC rules are defining two subdivisions of the proved reserves, namely developed and undeveloped proved reserves. **Proved developed** reserves are defined as follows: “*Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods…*”. Whereas **proved undeveloped** reserves according to SEC definition are: ”*Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on un-drilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on un-drilled acreage shall be limited to those* *drilling units offsetting productive units that are reasonably certain of production when drilled…*" (SEC Regulations §210.4-10, 1978)

As it was mentioned earlier the existence of proved oil reserves will anyway require an economical viability of the reserves, therefore, from the SEC point of view this sub-definition should not add an uncertainty to the undeveloped proved reserves, but rather should indicate that an additional capital expenditure is needed in order to put it in to production (SEC Financial Reporting and Interpretation Guidelines §II F- 3, 2001).

To conclude, one can say that instead of providing the whole range of probability SEC rules are aiming on presenting a single best number. This approach does not provide the investors with the comprehensive picture of the oil reserves probabilities. This in turn, makes it much harder for the investors to assess the one single number of their interest, namely the median or expected oil reserves.

To tackle the problem of the information insufficiently so-called probabilistic definitions were accepted by the industry. Although, these definitions are not accepted for the public reporting (at least not in US and EU), they are widely accepted among professionals and are normally used for reporting both by the oil engineers in the companies and by the independent oil consultants (SPE Oil Reserves Definition, 1997; CERA, 2005, p 14 sq)

In the probabilistic approach, oil reserves are broke down in to three categories: Proved, Probable and Possible.

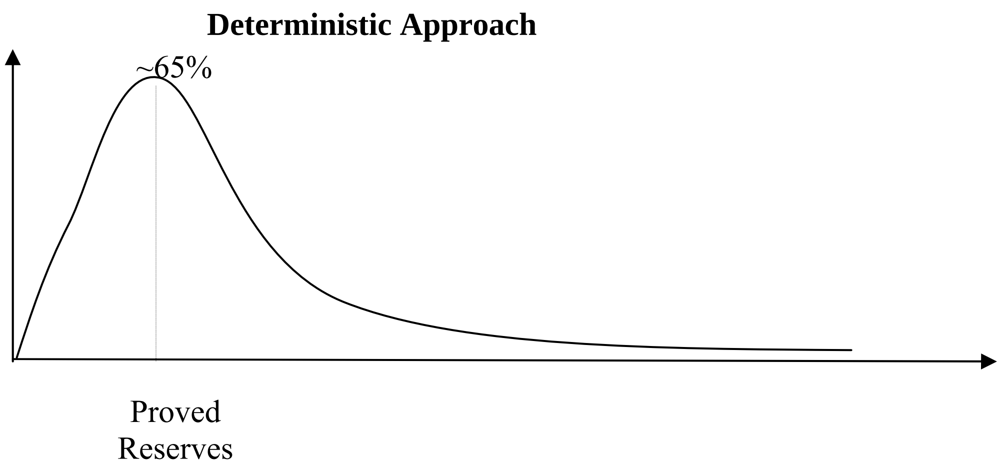
Proved reserves are defined just as they are under the SEC definition – the reserves with reasonable certainty and commercially recoverable or the amount of oil that can be extracted with the certainty of 90%. Although, the definitions are confusingly close, they are not identical, as the deterministic definition of proved reserves is widely interpreted as a single best prediction, it does not always correspond to 90% (OGJ, 2003, p31) The unproved reserves imply that technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

For probable reserves it is required that, there is at least 50% probability that the reserves eventually recovered will be equal or exceed the total quantity of proved and probable reserves. Generally speaking the reserves that are normally included into this category are the reserves, which are expected to be proved in the coming years, by normal drilling procedure, reserves in formation and incremental reserves that require further evaluation and all in all the reserves that require further treatment

Possible reserves are ones, for which the technical analysis suggests that they are more likely not to be recovered or in terms of the probabilistic approach the reserves, for which there is at least 10% probability that the amount of oil eventually recovered will be equal or exceed the total quantity of proved, probable and possible reserves. The reserves under this category are generally those based on geological interpretations and can possibly exist beyond the areas classified as probable. These reserves require further geological data gathering (SPE Oil Reserves Definition, 1997).

The difference between two approaches would be better understood, if illustrated graphically. When the technical and geological analysis of an oil field is made, the probability distribution of oil reserves is usually assumed to be lognormal. This assumption is rather common for the industry, yet it is not the only one possible (O'Connor, 2000 p3 sq; Campbell et al, 2003 p1 sqq; Laherrere, 2004, p 4 sqq). In other words, this assumption implies that at the certain stage of an oil extraction project management already knows that particular oil field or oil producing region posses the reserves that are enough for commercial production. Still the precise quantity of the reserves remains uncertain and company's engineers use the Monte-Carlo approach in order to model the distribution of reserves (Thanh, SPE, 2002, p 2).

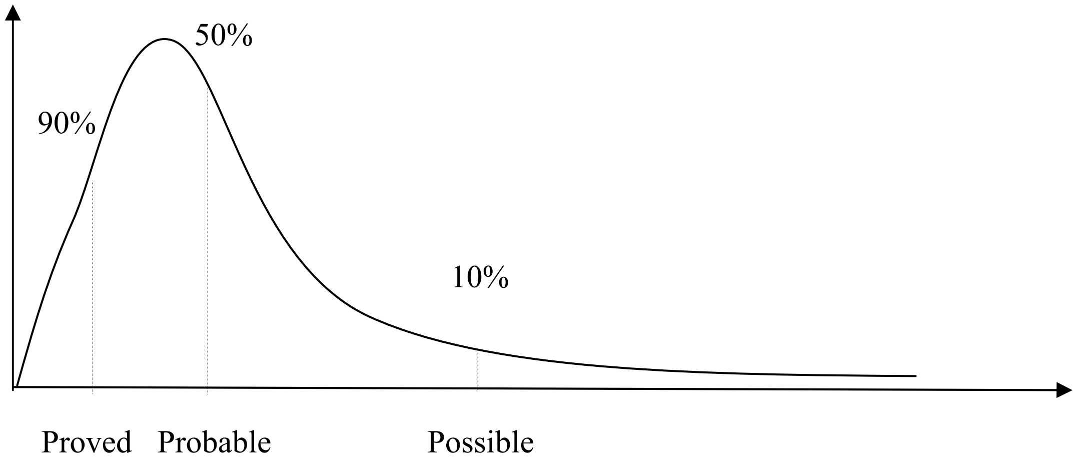
As the companies reporting under the deterministic SEC approach often interpret the proved reserves definition to be the most likely (mode) value of the reserves (SEC Financial Reporting and Interpretation Guidelines §II F- 3, 2001), under the lognormal distribution, companies would report the reserves at 60-65% probability as the proved ones (Laherrere, 2004, p 4). Reserves reported under this approach are shown in Figure 2.1:



In the Figure2.2, probabilistic approach is illustrated under the same assumption of the lognormal reserves distribution.

Figure 2.2:

Probabilistic Approach



As one can see, although the names are the same, the values granted to the proved reserves under different approaches are not identical. In the deterministic approach prescribed by SEC and used by Shell the probable reserves do not represent reserves recovered under 90% probability and in the same time they do not represent the mean reserves (P50 = Proved + Probable under the probabilistic approach), which could signal the expected volumes of the oil reserves lifted.

The general problem with the oil reserves definition today is that the SEC principles, which were created in the 70's mainly for the North American oil reserves, are used nowadays for almost 40% of world oil production and 10% of the reserves (a majority of which is not held by US companies), due to the fact that in the last 20 years SEC has virtually became the world regulator. Although, SEC's underlying principle of "reasonable certainty" for defining proved reserves remains robust, it has become increasingly difficult for companies to reconcile the SEC's interpretation of this principle with how the companies themselves are actually working. This has created an environment in which data disclosed in compliance with the regulations may not be serving the needs of investors and is not providing the appropriate information to make informed investment decisions (CERA, 2005, p 4 sqq).

To conclude this, one can say that when dealing with company's oil reserves, one is in fact dealing with random log normally distributed value. In order to provide the complete information regarding this variable, company should have provided the complete density function or at least some key points of the distribution as it does in internal reports. Instead, current reporting system tries to represent this random distribution as a single figure, which in turn makes company to conduct two separate reporting systems and leads to confusion and sometimes to misrepresentations.

2.2 Standardized Cash Flow Calculation under the SEC and FASB Rules.

Now let us focus on another estimation that the companies reporting under SEC regulations are obliged to represent on their annual report, namely the cash flow that the existing oil reserves are expected to produce in the future.

The requirement of standardized measure of cash flow is stated in the SEC Rule 4-10 and the guidelines are represented in Financial Accounting Standards Board Standard 69. In its guidelines, FASB sticks with the conservative approach in the general spirit of the SEC reporting strategy for oil reserves.

The principal rules on how the standardized measure of discounted net cash flow from producing proved oil and gas (SMOG) is calculated as well as the reasoning behind these rules are represented by FASB back in 1982 and remained practically unchanged since than.

A standardized measure of discounted future net cash flows relating primary to an enterprise's interests in proved oil and gas reserves shall be disclosed as of the end of the year in accordance with the principles and guidelines stated in FAS 69. This mash flow measure should provide the following information to the investors:

a. *Future cash inflows.* These shall be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. *Future development and production costs.* These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation or in other words assuming the continuation of the present conditions principle.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, less the tax basis of the properties involved.

d. *Future net cash flows.* These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. *Discount.* This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. *Standardized measure of discounted future net cash flows.* This amount is the future net cash flows less the computed discount (FASB Standard 69, 1981).

In other words, FASB requires from the companies to reproduce some features of the NPV calculation and omits other features. In that way, oil reserves lifted in the future are to be the same as the oil market prices in the end of the year. The same assumption is used for the operational and development expenditures in the future and in the same time discount factor is to be applied.

One of the obvious factors that make SMOG-approach difficult to use both for the investors and for the companies is the requirement to make the calculation in accordance with end-year prices. As we know, oil commodity prices are subject to fluctuations and speculations nowadays and in many cases, the price on December 31st may not reflect fully the actual average market price for oil. The problem is that the FASB standard was issued in 1981, year before the trading of oil begun on NYMEX. Before that, prices were partly regulated by national governments and were normally posted by buyers, so that not much of the volatility was experienced (CERA, 2005, p 20). Although, deregulation of oil markets made it another tradable commodity with highly volatile prices, yet the rules remained unchanged.

The inconsistencies in the SMOG approach are well recognized and explained by the FASB itself. It is admitted that this measure cannot provide the investors with the present value of the oil reserves, but rather is aimed on providing the standardized measurement. This measure should be a compromise between the need to give a complete information to the investors and the industry constrains that would have to put too much time and effort into the SMOG calculation if any estimations were involved in the measurement (FASB Standard 69, 1981). Indeed, the fact that SMOG does not give companies' management too many degrees of freedom in the calculation process enables the investors to make their own calculation and compare among different companies in the industry. In this study, SMOG would be functional for the calculations in Chapter 4, where the estimation of future operational and exploration expenditures as well as the estimation of future income taxes will be required.

At December 31st 2003, the standardized measure of net cash flow of Royal Dutch Shell Group of Companies was $53.8 billion and the future inflow from oil and gas sales were $281.9 billion that is based on the year-end oil price of $26.66/bbl and natural gas prices of 17.30/boe. Full statement of Standardized Discounted Future Net Cash Flow can be found in Exhibit 2.1.

The above-mentioned figures clearly cannot be seen as a meaningful estimate of the value of company's oil reserves for several reasons. First, it is impossible to determine the production schedule of the company. Second, as it is required by FASB the oil prices are set to the value in the end of 2003. Third, the discounting is made with 10% rate, which should represent the weighted average cost of capital at Royal Dutch Shell. It will be shown in Chapter 4 that this measure is inappropriate and that Rwacc for RDS should be set at about 7.2%. Although the figures themselves are hardly reliable, one can take it as a starting point for the further calculations. Also, in the Chapter 4 SMOG report will be used in order to determine the tax rate and operational margins for oil and gas production in different regions.

Now, after the picture of how the reporting is conducted is more or less clear, let us move further and see what role did the complication of the reporting played in the recent oil resources scandal by RDS.

2.3 Mis-presentation and Restatement of Oil Reserves by Shell Management

As it was shown in the previous sections, the way in which company reports quantity and value of its oil reserves is rather complex and hardly provides the investors with the information that is to any extend close to the reality. Eventually, this should have resulted in a major misuse of the accounting standards and that is exactly what happened to RDS Group's oil reserves.

Between January 9 and April 19, 2004, Shell announced the reclassification of 4.47 billion barrels of oil equivalent, or approximately 23% of previously reported "proved reserves," because they did not correspond to the definition of applicable law as it is required by SEC Rule 4-10 therefore the large quantity of reserves had to be stated as "un-proved" and in accordance to the SEC and FASB rules have to be virtually excluded from the company's balance sheet.

Shell also announced a reduction in its Reserves Replacement Ratio. The Reserve Replacement Ratio (RRR) is probably one most significant figure in the oil industry, which is serving as a basis of long run analysis for the oil and gas companies. This is a ratio of oil production in any particular period to the quantity of new oil reserves discovered and booked as proved. In other words the ratio is aimed to measure whether the company is discovering less resources than it produces and eventually will have to reduce or even shut down the production (this is in case RRR is less than 100%) or will be able to sustain or increase the level of production in the long run (this is in case RRR is equal or greater than 100%)

Although, restatement of oil reserves is a normal practice in the oil companies, in case of Shell this restatement was not conducted on time and this fact draws the attention of the stakeholders. Shell's overstatement of proved reserves, and its delay in correcting the overstatement, resulted from its desire to create and maintain the appearance of a strong RRR.

Another reason was the failure of its internal reserves estimation and reporting guidelines to conform to applicable regulations. And finally, the delay in restatement was result of the lack of effective internal controls over the reserves estimation and reporting processes (as it was discussed in Chapter 1, Shell's corporate structure was not particularly reliable).

In the interest of protecting the public against misleading financial disclosures by public companies, the SEC Security and Exchange Commission filed the complain against Royal Dutch Shell Group (SEC v. Royal Dutch Petroleum Co., et al., 2004).

As a result of the scandal, reserves were downward restated for 2003 and also reserves of 2002 and 2001 were backwardly amended.

The investigation by SEC and by the private adviser company Davis Polk & Wardwell that was later initiated by Shell itself found that although since the 1970's, Shell has utilized a series of comprehensive internal guidelines for the estimation and reporting of oil and gas resources, including its proved reserves, these guidelines failed to conform to the requirements of Rule 4-10, in a number of significant ways. Namely, the guidelines of Shell were originally designed and maintained to serve the probabilistic approach for reserves booking, which is used in Shell for internal reporting. These guidelines failed to reproduce correct and reliable basis for reporting under deterministic approach. As a result, in some cases the P50 reserves (mean or proved + possible reserves) were included into the proved reserves under SEC definition.

Shell also did not implement its own guidelines properly due to the lack of internal controls. Shell failed in several respects to implement and maintain internal controls sufficient to provide reasonable assurance that it was estimating and reporting proved reserves accurately and in compliance with applicable requirements. These failures arose in the first instance from inadequate training and supervision of the operating unit personnel responsible for estimating and reporting proved reserves. The reporting units in Shell were highly decentralized, which in turn made the normal flow of technical and contractual data more difficult. The deficiencies in the internal reserves audit function played additional negative role in the case. The proper internal audit of oil reserves in Shell was either poorly financed or virtually inexistent (SEC v. Royal Dutch Petroleum Co., et al., 2004; Davis Polk & Wardwell, 2005).

All this resulted in the public scandal after which Shell had to make a wide scale restatement of its oil and gas reserves. The restatement concerned some of the major oil and gas reserves of Shell, namely the reserves in Australia, Oman and Nigeria in the first place. Also, other oil fields of Shell suffered from restatement, so that overall restatement was divided fairly among the production facilities of RDS around the globe.

The summarized information about the backward restatement of proved reserves is represented in Table 2.2:

Year	Reduction in "Proved" Reserves	% Reduction	Reduction in Standardized Measure	% Reduction
1997	3.13 boe	16%	N/A	N/A
1998	3.78 boe	18%	N/A	N/A
1999	4.58 boe	23%	$7.0 billion	11%
2000	4.84 boe	25%	$7.2 billion	10%
2001	4.53 boe	24%	$6.5 billion	13%
2002	4.47 boe	23%	$6.6 billion	9%

(Source: SEC v. Royal Dutch Petroleum Co., et al., 2004)

As it can be seen from the Table 2.2, the "final" cumulative restatement (that was also included in the annual report for 2003) was 4.47 billion barrels of proved reserves and the company's management estimated the reduction in $6.6 billion in SMOG report. That gives us an average discounted value for one barrel of oil equivalent of approximately $1.5. For comparison, let us look at the average discounted net profit that is estimated by management from one barrel of oil. For that purpose, one can use the overall estimations of company's proved oil and gas reserves that are found in company's Financial and Operational Information Report for 1999-2003 and that are represented in Exhibit 2.2. According to this measure developed and undeveloped oil and gas reserves of RDS in the end of 2003 after restatement, including company's interest could be estimated in oil equivalent as approximately 14.3 billion barrels. According to SMOG, the future discounted cash flow that company's management expects to receive from lifting and selling these reserves is estimated at $53.8 billion. This gives average net discounted revenue of $3.76 per barrel. The reasoning behind this could be the quality as well as other features of the reserves restated. As one can see from the Exhibit 2.2 the proved reserves of RDS are classified as developed and undeveloped. The quantity of developed reserves is 8.6 billion barrels or 60% of the proved reserves, whereas the quantity of undeveloped reserves is only 5.8 billion barrels or some 40% of total proved reserves. On the other hand, restated reserves containing 88% of undeveloped reserves and only 12% of developed reserves.

The developed reserves are the ones that are already set to produce oil and for which no major capital expenditures will be required, whereas the undeveloped reserves require additional capital expenditure in order to be produced. That may include additional expenditures for exploration, costs of lifting facilities set and so on. For these reasons it is obvious that undeveloped reserves would in average bring lower cash flow to the company and therefore the reduction of the reserves value in this case was significantly lower than it would be in case if the majority of restated reserves were developed. This conclusion is rather strait forward and will be used in Chapter 3 and the later chapters in order to make the assumption regarding market reaction for the restatement announcement.

2.4 Summary of Chapter Two

First of all, this chapter discusses the methods of reserves representation by the company management in the public reports, such as annual report and F-20 form, as well as for the internal reporting with respect to reserves quantity and value.

As it was shown in this chapter, the quantity of company's oil reserves are highly uncertain and often can be modeled assuming lognormal distribution of the reserves.

In addition, there is a material degree of contradiction on how the oil reserves quantity should be reported. The contradictions between two major reporting methodologies are summarized in Table 2.3:

Method	Representation	Use
Probabilistic	Reserves are random distributed variables. Key points of distribution are represented	Internal company reporting; Industry reporting
Deterministic	Represents single best estimate for oil reserves	Public reporting

These contradictions are often confusing and led to certain extend to the restatement of oil reserves by Royal Dutch Shell, which took place in the beginning of 2004.

Estimation of oil reserves value that is made by management for public reporting is rather loose and concentrated in so called SMOG report that is made according to FASB regulations and consists of NPV estimation of the cash flow from oil production assuming year-end oil prices and continuation of the present economic conditions as far as production costs are considered.

According to SMOG report, RDS management estimated its proved oil reserves at the level of $53 billion (after restatement). The value of restated reserves is estimated to be $6.6 billion in the same report. One can notice that the restated reserves have substantially lower value per barrel than average oil barrel on SMOG report.

3 Reserves Restatement – Event Study

As it has been mentioned in Chapter 2 starting from January 9, 2004 until April 19, 2004 Royal Dutch Shell announced series of reserves restatements that came as the surprise for capital markets and pushed the shares prices of both parental companies down by some 12% on the day of the announcement (Louth, 2004).

However this event represented a significant shock to the stock for the oil and gas industry in general and RDS in particular, it embodies a very convenient possibility to assess the evaluation of capital markets regarding the oil reserves of Royal Dutch Shell.

Although, the oil reserves are representing a large portion of RDS' assets as well as oil production is representing significant part of company's revenue, without this restatement it would be hard to "single out" company's assets in oil exploration and production unit from other company's assets. In this sense, this restatement represents a unique possibility to check how do the market players evaluate the oil reserves as well as to try to replicate market calculations with own evaluation models.

Two most important questions that one should answer before the market evaluation becomes clear are:

1) How much of the reserves were restated?
2) What is discount in market capitalization of parental companies attributed to the restatement?

Although, these questions seem trivial, answering them is a rather complicated issue. First of all, the restatements were not made in one day, but were rather starched along three and a half month period and then followed by another series of restatements in the end of 2004 and beginning of 2005. Therefore, the amount of reserves restatement anticipated by the market players after each announcement is rather uncertain. The complicated reporting methods proposed by SEC only add to uncertainty on this matter, since the volume of reserves restatement in company's proved reserves may not be equal to the restatement in the overall reserves, as discussed in the previous chapter.

Second, because the event did not happened in one day, but was starched along several month it becomes more difficult to filter out the reaction of the market on the company's announcement about oil reserves restatement from other events that happened during this period of time.

Given all the complications mentioned and given the issues discussed in Chapter 2, this chapter will be aimed at assessing the value of oil reserves observed at the free market.

3.1 Estimation of Reserves Restated Amount

In order to estimate market reaction on the announcement of reserves restatement by RDS, one should come to the conclusion about what restatement does market anticipates?

As it has been mentioned above, the restatement did not come as a single announcement. In fact, there were two series of announcements. First three announcements were on January 9, March 18 and April 19, 2005. This series of announcements is called First Half Review. The First Half Review constitutes to reduction of total 4.47 billion barrels of oil equivalent that were booked as proved reserves in company's annual report for 2002. As the result of this review, RDS postponed its 2003 annual report until late in 2004 and therefore all the figures regarding oil reserves reported for 2003 already include the First Half Review restatements.

Second series of announcements took place later in 2004 and 2005, namely on October 28, November 26, 2004 and February 3, 2005. During Second Half Review, Royal Dutch Shell further reduced its proved reserves reported for 2003 by another 1.37 billion barrels of oil equivalent (RDS Group: F-20 Form, 2004, p 3)

This study concentrates on the First Half Review only. Whereas first announcement came as the surprise for markets, further series of announcements may well have been anticipated, as market participants started to watch Shell and Royal Dutch stocks more closely. This became especially true after Shell group audit committee engaged independent consultant firm to investigate the re-categorization of reserves on February 3 and SEC filed the claim against Royal Dutch Petroleum in May 2004 (SEC v. Royal Dutch Petroleum Co., et al., 2004; Davis Polk & Wardwell, 2005). All these may lead to the fact that the market anticipated further restatements before they were actually announced and therefore some of it were already priced into the stocks.

The best way in this case would be to include all six announcements into single event. However, such event study would hardly produce any statistically or economically reliable results, since during the period of more than a year a lot of other events influencing the stock prices would occur, which would be virtually impossible to filter out. The best example for such event is the oil price, which nearly doubled itself during the period from January to October 2004. The influence of the oil price increase would push the stock price higher against the rest of the market and the effect of restatement would be lost. In order to avoid such economically unreliable results this study concentrates exclusively on First Half Review (from here on simply "restatement").

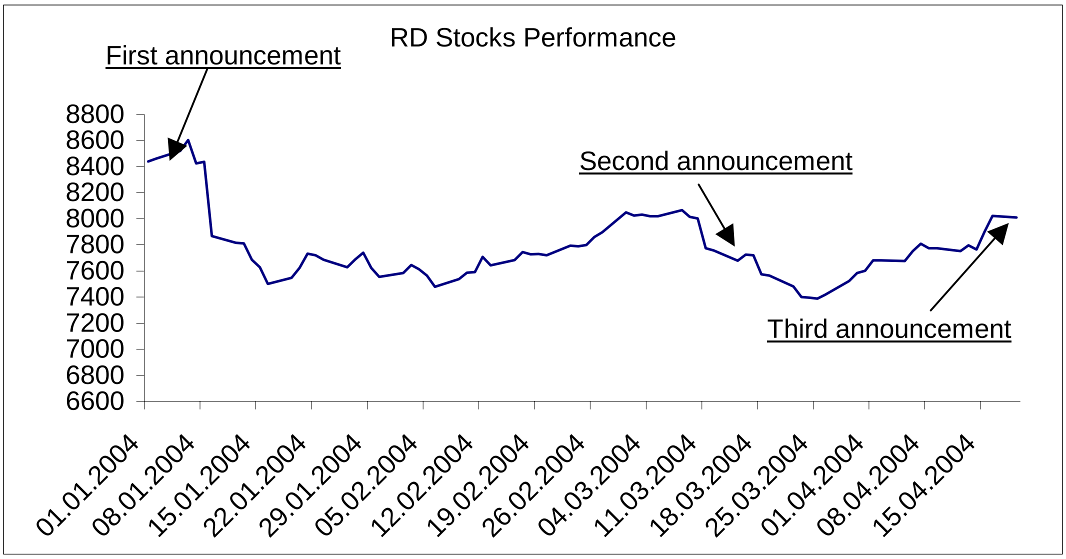
The restatement itself also consisted of 3 consecutive announcements. Timing and size of announcements are shown in table 3.1:

Date of announcement	Size (mboe)
January 9, 2004	3900
March 18, 2004	250
April 19, 2004	320

(Source: www.shell.com Media Center)

It is not entirely clear whether the market anticipated further restatements after each of the announcement. In fact, it could be the case that market players expected larger restatement than the ones announced.

Figure 3.1



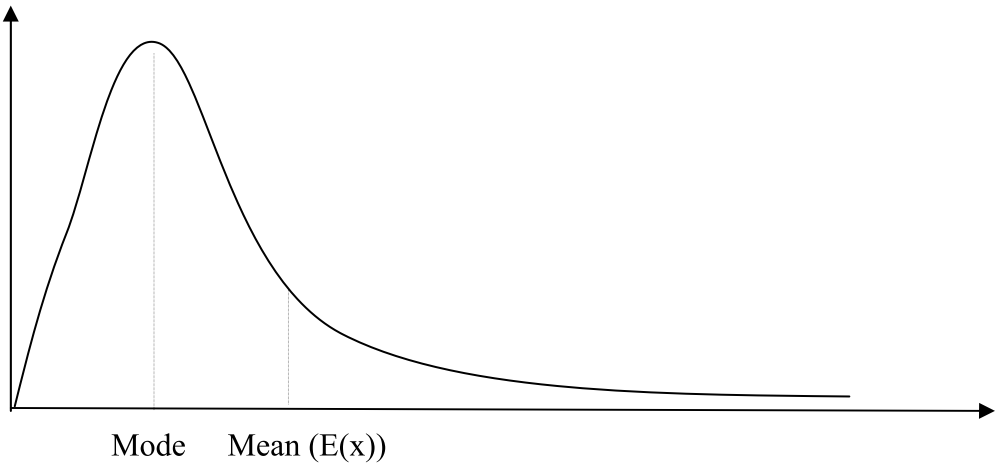
(Source: DataStream)

All the problems that were mentioned above can be shown on an example of figure 3.1. The figure shows the performance of the stocks of one of parental companies, namely Royal Dutch Petroleum. As one can see from the chart, the stocks fell quite sharply after the first announcement, but gradually rebounded afterwards. This rebound continued until the beginning of March when the rumors about the new restatement may have started to spread. The stocks then came down to the level significantly lower than they fell after the first announcement, although the volume of the second announcement itself clearly was not enough to cause this downturn. The stocks then came up towards the third restatement announcement and in fact showed no reaction as the final restatement came in on April 19, 2004.

This lack of obvious connectivity between the events and market reaction makes the analysis of stock movement more difficult. As it will be shown later in this chapter when the results of case study are discussed use of abnormal stock return is not solving this problem, since the move of abnormal returns resembles to a very large extend the move of stocks total returns.

Another problem one is facing when assessing results of reserves restatement is the actual volume of restatement hidden behind the figures announced by management. As it was shown in Chapter 2, company's management is not allowed by SEC regulations to report any reserves estimation apart from proved reserves or the reserves the company is going to produce with reasonable certainty according to so called Rule 4-10. Therefore, the announcements, company made regarding the volume of its reserves, have only been dealing with the proved reserves and not with the overall oil and gas reserves in place.

It has also been shown in Chapter 2 that the figures reported by companies under SEC regulations often represent the mode of oil reserves distribution function. On the other hand, the investors would probably focus not on the mode of distribution, but rather on the expected quantity of reserves or the mean. These two figures may be quite different as it is shown on figure 3.2:



If one accepts perfect market assumption, it is possible to assume that market participants do not relay on the official figures produced by the company, but they rather use the inside information and have the entire distribution function available. Then, assuming that the data regarding available oil reserves is log-normally distributed, market players would take into account the expected value of oil reserves E (x), which is equal to:

$$E(x) = e^{\mu + \frac{\sigma^2}{2}} \quad (1)$$

Where μ represents the mean of ln (x) and σ represents standard deviation of ln (x).

It is also possible to calculate the formula for the mode value of lognormal distribution. Knowing that lognormal distribution density function is represented by

$$f(x) = \frac{e^{-1/2(\frac{\ln(x)-\mu}{\sigma})^2}}{x\sigma\sqrt{2\pi}} \tag{2}$$

one can calculate the first derivative of (2) and than equate it to zero in order to receive the highest point of the distribution density function or in other words the mode.

$$f(x)' = (e^{-1/2(\frac{\ln(x)-\mu}{\sigma})^2} \cdot (-1)(\frac{\ln(x)-\mu}{\sigma}) \cdot \frac{1}{x\sigma} \cdot x\sigma\sqrt{2\pi} - e^{-1/2(\frac{\ln(x)-\mu}{\sigma})^2} \cdot \sigma\sqrt{2\pi}) \cdot (2\pi x^2\sigma^2)^{-1} \tag{3}$$

By equating (3) to zero, one will get the mode value as:

$$M(x) = e^{\mu-\sigma^2} \tag{4}$$

This means that E (x) can be represented as:

$$E(x) = e^{\mu-\sigma^2+1.5\sigma^2} = M(x) \cdot e^{1.5\sigma^2} \tag{5}$$

Than the change in expected value of oil reserves $\widetilde{E}(x)$ is:

$$\widetilde{E}(x) = M_1(x) \cdot e^{1.5\sigma_1^2} - M_2(x) \cdot e^{1.5\sigma_2^2} \tag{6}$$

The value of $M_1(x) - M_2(x)$ is precisely the figures announced by the management of Royal Dutch Shell and represents the restatement of company's proved reserves. If one assumes that standard deviation of natural logarithms of oil reserves σ remained unchanged as the result of restatement, (6) can be rewritten as follows:

$$\widetilde{E}(x) = (M_1(x) - M_2(x)) \cdot e^{1.5\sigma^2} \tag{7}$$

This assumption, allows to make the analysis much more simple and to come to the conclusion regarding the size of actual restatement with out requiring a lot of additional data.

In equation (7), there is still one unknown value on the right hand side, namely the value of σ. Sigma can be estimated from the data provided by company management. According to company's production and exploration presentation, published on www.shell.com web site, management estimates the "total reserves" to be about 60 billion barrels after the restatement (RDS Group: Regaining Upstream Strength, 2004). The expression "total reserves" in this case might be referred to the possible reserves or P10. It is also known that proved (or P65) reserves numbered to 14.3 billion barrels (RDS Group: F-20 Form, p G56 sqq, 2003). The distance between these two values in lognormal distribution can account roughly to 2.1 standard deviations (this results can be obtained by simulating the distribution density function in statistical package such as @Risk). In this case sigma can be estimated as (ln(60)-ln(14.3))/2.1. That gives sigma value of approximately 0.68 and therefore the announced restatement should be multiplied by a factor of 2 in order to calculate the actual restatement in expected value of oil and gas reserves (the calculations are represented in Exhibit 3.2)

3.2 Estimation of Market Capitalization Discount for Parental Companies

Another aspect one should cover in this event analysis is the discount is the market capitalization. As it was mentioned above, stocks of the parental companies reacted quite sharply on the announcements and therefore allowed to assess the investors' reaction on the oil reserves restatement.

In order to do so the event study methodology was used and the cumulative abnormal stock returns (CAR) were calculated. The returns of RD and Shell stocks were compared to the returns of S&P 500 stock index. Although RD and Shell stocks are traded not only on NYSE but also on LSE (denominated in British Pounds) and in Amsterdam (denominated in Euros), the oil is priced in US$ and it makes sense to use a comprehensive index for the dollar denominated stocks in order to filter currency effect. It is important to remember that RDS' assets are strongly dependent on the movement in the oil prices and the upswing in oil prices (or perhaps an expected upswing in oil prices) will most probably lead to stock appreciation. Usually this will not be the case for S&P 500 index, which includes large portion of stocks of oil consuming (industry) companies that are expected to fall on the oil price upturn. In order to control for this effect AMEX Oil & Gas was used. AMEX index consists of major oil and gas producing companies stocks, and therefore would react on the moves in prices of oil it the same manner and to the same extend as the stocks of RD and Shell do.

The problem with AMEX index of course, is that the weight of RD and Shell stocks in it is much larger than in S&P 500, in addition other stocks may have been traded down on restatement announcement, as the markets suspected that similar problems with oil reserves may well have existed in other oil companies. All this would result in smaller negative CAR of AMEX index, than of S&P 500.

To improve the results of event studies the CAR on both indexes were calculated and then compared. The control window for both indexes was 240 days (from the beginning of 2003) and several event windows were calculated. First is the event window of (-5; +20). The window is non-symmetric, since there was virtually no information about the restatement before the announcement and therefore adding more days before the announcement to the event has a very low added value.

First event window ends on February 6, 2004 and covers only first announcement. In order to cover the second announcement another event window (-5; +53) was introduced. This window ends on March 25 and therefore covers first and second announcements and allows 5 additional days after the second announcement, which took place on March 18. This event window is rather long, so the results it would produce are less statistically reliable.

To capture all three announcements another event window of (-5; +70) was introduced. This window stretches up until April 19, 2004, but the results it produces are hardly reliable both from statistical and economical point of view.

The calculations and results of event study summarized in Table 3.2 are shown in Exhibit 3.3 and 3.4 and the full CAR charts are shown in Exhibit 3.5

Table 3.2

Window	**Shell**		**Royal Dutch**	
	S&P	AMEX	S&P	AMEX
(-5; +20)	16.4%	12.7%	14.8%	11.2%
(-5; +53)	15.4%	13.4%	16.3%	14.3%
(-5; +70)**	5.7%	8%	10.5%	12.8%

** - statistically insignificant at 10% level

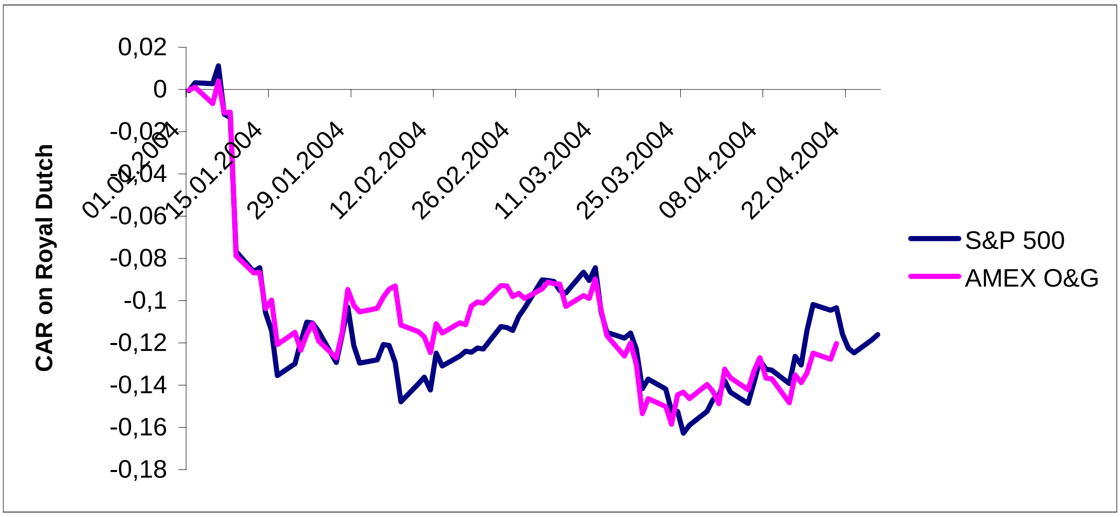
First thing that one would notice by looking at table 3.2 is that the abnormal returns of two parental companies are different quite significantly. In fact, as one calculates the correlation of adjusted dollar denominated returns of two companies stocks the correlation will not be 100%, but rather about 0.92 (see Exhibit 3.6). Theoretically, the only property of both companies is the stake in RDS Group and as the returns are measured in the same currency, they should have the correlation of 1.

The reason behind this difference can be a slightly different dividend policy. For example, in 2003 the dividends paid to Shell shareholders were about $2610 million and dividends to RD shareholders $4292 million (RDS Group: Financial and Operational Information, p 6sq, 2003). The ratio is different from 40:60 holding ratio of the companies.

Another reason might be different holding structure of two companies and therefore different liquidity. Overall, the unification of Royal Dutch and Shell mentioned in Chapter 1 is conducted in order to address precisely this kind of problems, so that in the future no difference in stock returns should exist.

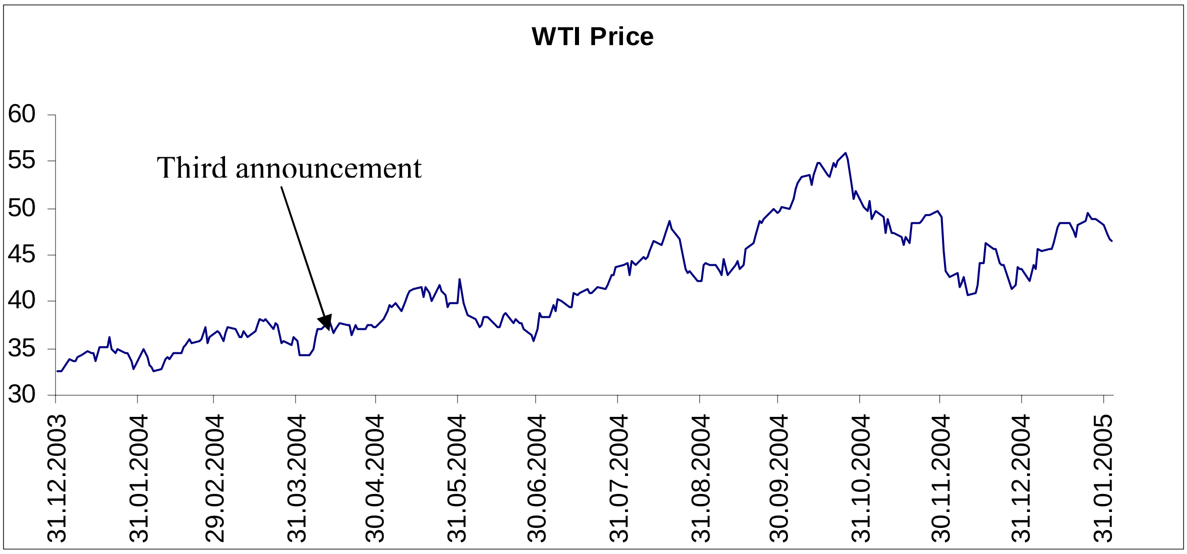
Coming back to the discussion of the event study, one can see from the table 3.2 that CAR of first and second event window is larger for S&P 500 index than for AMEX index. On the other hand, in the third event window CAR of companies' stocks fall dramatically, when S&P index is used, whereas for AMEX index the fall is less sharp.

One can see this effect in Figure 3.3



The figure shows that in the period between two announcements RD shares lost less value in comparison to AMEX than in comparison to S&P. Before the third announcement situation has changed.

To explain this one should remember the pros and cons that both indexes have for the event study analysis. The restatement affected AMEX index and drag it down, so that the negative CAR are smaller for this index, on the other hand as the market started to anticipate the surge in oil prices (or at least started to anticipate that long-term upward tendency of oil prices) RD shares regained ground against S&P 500. The performance of oil prices in 2004 is shown in Figure3.4.



So, the rebound of RD stocks in April 2004 is not entirely driven by market assumptions regarding the oil reserves of RDS Group. For that reason, the results produced by the third event window are neither statistically, nor economically reliable.

Now let us calculate the discount in market capitalization of RD and Shell. In the beginning of event study on January 1, 2004, number of outstanding shares of Royal Dutch was 2083 million and share price was $52.39. Shell had 9667 million shares outstanding at the price of $7.505 (RDS Group: Financial and Operational Information, p 7sqq, 2003). This gives RDS Group market capitalization of $181,679 million. So, the discount in market capitalization will be as follows (see also calculations in Exhibit 3.2):

Table 3.3

Window	Discount ($M)
(-5; +20)	28,049
(-5; +53)	28,910

3.3 Event Study Results

Now as the discount and quantity of reserves restated are known, it is possible to calculate the value capital market participants attribute to the oil reserves.

First of all, as it was mentioned in Chapter 2, 88% of the restatement accounted to proved undeveloped reserves. It was also shown in Chapter 2 that RDS management attributes much smaller value to the restated reserves, than to the average oil reserves in SMOG report. The latter is typical for undeveloped reserves, for which additional capital expenditures are needed. For the purpose of this study it will be assumed that the value of restatement can only represent the value of undeveloped reserves or in other words the value of one barrel calculated using this event study results may only be attributed to the company's proved undeveloped reserves.

As it has been discussed in section 3.1, the announced restatement figures are irrelevant for the investors. The figures should be multiplied by factor of 2 in order to receive the restatement in expected value of oil reserves. The question however remains what figure should be multiplied. It is unclear whether the markets expected the restatement of 4.47 billion barrels already after the first announcement, or the reaction calculated for the (-5; +20) event window includes only the initial restatement of 3.9 bboe. The same question applies to the second event window. Here the discount may represent the restatement of 4.15 bboe or 4.47 bboe as well as any value in between.

The best way in this case is to calculate the barrel value for all possible scenarios. This barrel value should then be multiplied by the quantity of existing proved undeveloped

reserves (5779 mboe as shown in Exhibit 2.2) in order to estimate its fair value for shareholders. Then the total value of reserves is calculated by dividing by (1-leverage).
The calculation for base scenario is shown in Exhibit 3.2 and the results for different scenarios are shown in Exhibit 3.7. These results are also summarized in Table 3.4:

Window/Restatement	3.9 bboe	4.15 bboe	4.47bboe
(-5; +20)	$22,020M	$20,694M	$19,150M
(-5; +53)	-	$21,328M	$19,802M

So, the value of undeveloped proved oil reserves was estimated by markets between $19 and $22 billion. The figures are of cause dependent on the assumption made in section 3.1 regarding the standard deviation of existing oil reserves, still they give a reasonably clear picture of the range in which the fair value of undeveloped oil reserves may rest.
In the next chapter, these figures will be replicated with the own calculation using DCF and real options methodology.

4 Estimation of Oil Reserves Value with Own Calculations

After accessing the evaluation of oil reserves through event study in Chapter 3, it is now possible to try to replicate the results produced by capital market valuation using traditional evaluation techniques. In this chapter two main valuation approaches will be used:

1) DCF modeling
2) Real Option Valuations

These two approaches are the ones that are used most commonly by the company management in order to assess the risks and possible benefits of a project in oil and gas production.

However, the evaluation using DCF is more strait forward and used quite commonly by companies' management it has several negative features that makes real option technique superior as it comes to the valuation of natural resources like oil and gas (Smith; McCardle, 1999, p 1sqq).

In this chapter, it will be possible to confront the results of both valuation techniques and compare it with the results of Chapter 3. This, in turn, will allow to draw the conclusion about how well do this valuations method could predict the free market value and also which one of two may be closer to market valuation (however, the latter result would have, obviously, no statistical backing because of the unique nature of the event discussed in this paper).

Additionally, it should be mentioned that the calculations in this chapter are based exclusively on the information publicly available. In case of oil and gas industry, this may not be sufficient, since such data as reserves distribution density function or production schedule is unavailable. For these reasons, some assumption had to be made in order to simulate the production schedule, development of oil prices etc.

The focus of this chapter will be on one reserve category, namely, proved undeveloped reserves. This is made bearing in mind the assumption made in Chapter 3 regarding the reserves category, according to which all the reserves restated during the First Half Review in 2004 were undeveloped. In fact, however, some of these reserves were developed and therefore had potentially higher value. So, it is important to remember that the actual price that markets allocate to one barrel of undeveloped proved reserves is in fact somewhat lower than the one calculated in previous chapter. Still, it is unclear to which extend should this price be downscaled, if at all. Therefore, for the sake of simplicity the prices per barrel calculated in Chapter 3 will be assumed appropriate for undeveloped proved reserves and will be used as the kernel in order to demonstrate to which extent own calculations are able to predict the fair value assumed by markets.

4.1 Calculation Using DCF Methodology

Before starting with DCF calculation it will be necessary to make some key assumptions regarding the future oil prices, production schedule and production costs, and finally regarding an appropriate discount rate.

First, let us start with the projection regarding the oil prices in the future. As the first step for this projection, it would be important to decide what time frame should be in interest for this particular calculation. Normally, the oil reserves are representing very long lasting project, which can last for 30 or even more years before totally exhausted. According to the management of RDS Group, an average project produces oil for about 20 years (RDS Group: The Shell Report, 2003). In this paper the production of proved developed reserves will be assumed to last 20 years (so that last oil well, which produces oil in 2004, should be exhausted by the end of 2024) and production of reserves that are yet undeveloped and are expected to begin oil lifting in the coming years should be completed by the end of 2034.

This represents a difficult challenge. Although, market expectation in respect of oil prices development in the near as well as in more distance future, should normally exist, they are not explicitly stated in prices of any of financial products, especially when it comes to the oil price in the future as distant as 20-30 years. Still, oil futures that exist on the market can help in the calculations.

One should however bear in mind that price of the futures is not the same as “expected spot oil price” and can not provide perfect prediction regarding how much will cost one barrel of oil at the end of futures contract. The oil futures market is more useful if one wants to hedge, or to speculate on the price of oil, but it does not provide any easy way to predict where the price of oil is headed. When the good in question is easily stored, as is oil, the same supply and demand factors that would drive the futures price up would also drive up today's spot price. Storage costs, interest rates, and convenience yield then account for the difference between spot and futures prices (Miller, 2004).

In fact, prices for oil futures do not develop as one would expect knowing that price for oil is growing most of the time. To the contrary, prices for oil futures remain under the spot price for oil for 70% of the time. This however, should not mean that the markets believe that oil price will fall. This backwardness of futures can be explained by pure non-arbitrage phenomena.

Under uncertainty condition owning the oil reserves is the same as holding a call option, which exercise price is equal to the production expenses (this approach will be exploited later in this chapter). Backwardness arises from the tradeoff between exercising the option and producing oil and keeping the option alive (keeping the oil underground). If present value of future oil price would be higher than the spot price today and production costs will are not expected to rise more than interest rate, all producers would rationally choose to defer production and sell futures (Litzenberger, Rabinowitz, 1995, p 1518). This means that the price of future contracts should decrease whereas the spot price should rise until a proper degree of backwardness is achieved.

In addition to this, when using the future price to estimate oil spot price in time T, one tackle the additional yields that are associated with the contract. As it was mentioned above price for futures contract is constructed using the spot price for oil as well as convenience yield. On one hand, buying the future contract for oil gives an opportunity to reduce oil stock and store the oil underground, which is much cheaper than to store lifted oil as inventory. On the other hand, storing oil underground in sometimes distant location reduces flexibility. For example, if the refinery has faced an anticipated higher demand for oil products it will prefer to have larger inventories of crude oil or otherwise face the lost of revenues due to the time gap associated with production and transportation of crude oil to the refinery plant (Caumon; Bower, 2004 and Considine; Larson, 1996).

These effects can be summarized in convenience yield. So, in this case a non-arbitrage price for futures contracts can be represented as:

$$F(t,T) = S(t) \cdot e^{(r+cy)(T-t)} \tag{8}$$

In (8) *F(t,T)* represents the price of future contract at time t for the period T. *S(t)* represents the spot price, *r* represents a risk-less discount rate and *cy* represents convenience yield.

From here, it is possible to estimate the percentage of total future price, which is allocated to convenience yield as:

$$cy = (\ln(\frac{F(t,T)}{S(t)})) \cdot \frac{1}{T-t} - r \tag{9}$$

(Caumon; Bower, 2004)

Despite obvious complications that are associated with the use of futures to estimate future spot, statistical studies have shown that although explaining a relatively small proportion of fluctuation in commodity prices, futures still represent an unbiased predictor for crude oil price (Chinn et al, 2005)

In this study the prices for future contract net of convenience yields will be used as the estimation of spot prices in the future as far as actively traded contracts are available. Since most of the oil resources of RDS Group are concentrated in the North Sea, the future contracts for Brent Crude Oil were taken as price kernel. The actual prices for futures contracts on 31.12.2003 (the same date as the beginning of event window in Chapter 3) are taken from Wall Street Journal. The prices as well as the calculation of convenience yield are represented in Exhibit 4.1.

The future prices net of convenience yield are some 25% lower than the spot price for Brent. This result is in line with the statistical results represented by Litzenberger and Rabinowitz (1995), according to which backwardness in futures' prices should be between 24 and 29 percent and should be smaller for longer contracts (Litzenberger, Rabinowitz, 1995, p 1518).

Unfortunately, the prices for futures contracts are only available for the period of 12 and 24 months, therefore oil prices for the period of 2006-2034 should be simulated using Monte Carlo technique. In order to simulate future spot prices the assumption has been made that the returns of oil prices are normally distributed. This implies lognormal distribution of future oil prices.

The mean of distribution in time t is assumed to be the ln of oil prices simulated for time t-1 (the mean for 2006 simulation was ln of price for future contract for 2005 net of convenience yield). The standard deviation is calculated from the implied variance of call options for Brent Crude Oil traded on International Petroleum Exchange (IPE) on 31.12.2003 according to the prices published in Wall Street Journal using BS option pricing formula. The prices for options and calculations are represented in Exhibit 4.1.

Another way to calculate the standard deviation of log oil prices would be to calculate it out of historical data, however this way of calculation would not capture the market expectation regarding the sharp rise of oil prices in the future (if there were such expectation in first hand). The fact that the price for one barrel of Brent went from about $30 in the end of 2003 to about $50 in 2004 and continued to rise throughout 2005 should have made future oil prices more volatile and may represent a structural break. Therefore, the calculation out of historical data has been found inappropriate in this case.

The simulation was then conducted using MS Visual Basic. Oil price for each year is determined based on one thousand iterations where the oil price is calculated out of the simulation output as expected value of lognormal distribution.

Results of the simulation are represented in Exhibit 4.2. One can see that the simulation provides gradually increasing oil prices. This feature is particularly important since it is in line with the basic Hotelling Principle, according to which under conditions of perfect competition and certainty net prices of an exhaustible resources like oil and gas should rise overtime at the rate of interest (Litzenberger, Rabinowitz, 1995, p 1520).

Additionally, it should be mentioned that the simulation was conducted for the Brent prices exclusively. This, however, would not be sufficient. Future oil prices should also be attained for other regions in which RDS operates. According to the Group's annual report it divides its operations into six regions: Europe, Russia and Middle East, Africa, Asia, USA, and other Western Hemisphere. The appropriate oil types for each region are accordingly Brent, Urals, Bonny, Tapis and WTI. For the Western Hemisphere, there is no active market for any particular type of oil, so the prices for this region were assumed to be equal to the prices of Urals.

As it has been mentioned before, the price for Brent was set to be a price kernel, whereas the prices of oil for other regions are calculated according to the prices ratio in the end of 2003. So, the implicit assumption is made here that the ratio of prices for different types of oil will remain unchanged in the long run. This is a very reasonable assumption since the price for oil is determined by its chemical characteristics, which are not expected to change. The calculations are represented in Exhibit 4.3.

After the prices for oil are set, it is possible to construct the estimation of future free cash flow produced by the oil reserves. As the first step, one should simulate the production schedule for existing reserves or in other words, how much the reserves will produce each year. As it was mentioned earlier, information about the speed of production is not included in any of the Group's public reports; therefore, several assumptions should be made in order to simulate it.

First, let us take the assumption that all proved developed reserves should be lifted by the end of 2024 and all the developed + undeveloped proved reserves should be lifted by the end of 2034. This gives the span for production schedule.

Next, assumption is to be taken that an overall oil production will not change and will stay at the level of 2003 close to 1400 million barrels of oil equivalent (see Exhibit 2.2 for details). This assumption may seem to be controversial, yet there are several indications that support it.

First of all the company management estimates production until the year 2006 to be in the range of 3.5-3.8 mboe per day, which gives the yearly production of oil and gas between 1300 and 1400 mboe, so the management is not expecting any growth of production in the coming years (RDS Group: Regaining Upstream Strengths, 2004).

This is also supported by company's statistics that shows that after the production had been increasing until 2002 it actually came down in 2003 from 3.96 mboe/d to 3.86 mboe/d and no recovery in production is expected in the coming years (Royal Dutch Petroleum: Annual

Report 2003, p 18). Poor data on new reserves discovery also makes it harder for RDS to increase production sometimes in the near future. Actually, the company was already producing more than it discovers in the last years and further decrease in RRR might be very negative for company's share price (Davis Polk & Wardwell, 2005)

Same indications could be found in the data for overall world oil production. Although, demand for oil was constantly increasing from year 2001 and reached the level of production in 2003, the supply of oil during these years remained stable about 76.8 mbbl/d (OGJ, 2003, p 33).

Of course, with the world economy growing and therefore growing demand for oil, stable supply would be unsustainable. In fact, it may not be the case, since in the longer term growing demand for oil and gas is expected to be substituted by growing supply of renewable energy and by increasing energy efficiency. For example, in the US amount of energy consumed per dollar of GDP fall some 2% in 2003 (OGJ, 2003, p 22)

All the facts above, make the assumption of constant production quite reasonable, therefore it was accepted for the purpose of DCF estimation.

Now as the issue of overall production is more or less clear, one should assume what part of this production is consists of the oil reserves that existed in the company on 31.12.2003. The problem is that produced reserves are replaced with the new ones, so the percentage of the reserves that were there in the end of 2003 of total production should decline with the time.

The best way to show how this concept should be working is to represent RDS' oil reserves as huge oil tank with the size of 14.4 bboe. In the beginning of 2004, this tank is full. These are company's proved oil reserves. In 2004 1.4 bboe is taken from this tank and sold (this is the amount of oil produced) so that only 13 bboe is left. Afterwards new oil is discovered at put on top of the reserves that are left from the previous year. So, if in 2005 once again 1.4 bboe is taken from the tank only 90% will be from the old reserves and additional 10% out of new reserves, which did not exist in 2004. In this way the percentage of "old" reserves that were there in the beginning of 2004 (and which are to be evaluated by DCF) will constantly go down. That means that the quantity of "old" reserves produced in time t equals to:

$$1.4 \cdot (14.4 - \sum_{s=0}^{t-1} P_s) \div R_t \tag{10}$$

In (10), *Ps* represents production in time *s* and *Rt* represents proved reserves in time *t.*

However, there is still one unknown element in (10), namely *Rt*. RDS' proved reserves may increase as well as decrease in the future from the current 14.4 bboe. Therefore, additional assumptions should be made regarding this figure.

Here one should once again take a look at company's RRR. If the company is be able to reach 100% RRR in the long run then the overall reserves will not change. Three-years RRR stood at 95% in year 2002 and reached 98% in 2003 (SEC v. Royal Dutch Petroleum Co., et al., 2004).

As it was mentioned earlier, company's management is determined to fix long term RRR at 100%. This however, won't be an easy task. Data shows that cumulative oil discoveries in all world regions were growing until early 80's and are slowing down since then towards the asymptote, so that practically no new oil is to be discovered in the future. The curve of remaining oil reserves gives the same indication. From the beginning of 90's remaining oil reserves, have been declining or remained unchanged according to different data sources. The same problems may be attributed to the total available reserves of RDS Group that have reached the current level of 60 bboe already in 1998 and showed no growth pattern since then (Laherrere, 2001, p 11sqq).

The data also shows, that despite management's optimism, the dynamics of cumulative oil discoveries of RDS is not different from overall slowing down world tendency (Bentley, 2002, p 200).

All this should prompt that in the long term, RRR should be smaller than 100%, but this is not the end of the story. The data above corresponds to the overall (proved + probable + possible) reserves, whereas the subject of this study is proved undeveloped reserves only. The fact is that decline in overall reserves may not have immediate consequence on RRR of proved reserves (not even in 20 years time). As the discovery of oil decreases, proved reserves may stay on the old level or even increase because of reserves reclassification (Bentley, 2002, p 195 sqq).

Since more technical data becomes available, the reserves that are now considered unproved will be reclassified as proved. This feature may allow RDS to run proved reserves on the current level for many years to come, given that quantity of unproved reserves is much larger than of proved ones.

To conclude this, 100% RRR was accepted as the base scenario for DCF calculation with allowing upwards and downwards deviations. Now (10) can be rewritten as:

$$1.4 \cdot (14.4 - \sum_{s=0}^{t-1} P_s) \div (14.4 + 1.4 \cdot t \cdot (RRR - 1)) \qquad (11)$$

Interesting feature of (11) is that if RRR is smaller than 1, company will have to lift its reserves faster in order to keep on production and the value of the reserves may actually rise.

Now, having the estimation for oil prices and production schedule one can estimate company's revenue as oil price in year t times oil production in year t. Oil production was allocated to six geographical regions based on the ratio of oil production in each region to overall oil production in 2003.

Operating margins and tax rates can be estimated for each region separately using the data from SMOG report (see Exhibit 2.1) as the ratio of production costs to future cash flow and as ratio of tax expenses to net cash flow accordingly.

Development costs are distributed according to management projections. Group's management plans to spend on development $7 billion during 2004-2006 and another $23 billion during 2007-2009 (RDS Group: Regaining Upstream Strengths, 2004). It was then assumed that no further development will be required for the existing proved reserves and that the development costs are linearly distributed among the years. The development costs are allocated to each region based on the ratio of production in the region to overall oil production in 2003.

As the last step, an appropriate discount rate should be calculated. The yield of US Treasury bond with 30 years maturity was taken as the risk free rate for this study. Beta of both parental companies was calculated in Exhibit 4.4 using S&P 500 index. For both companies beta equals to approximately 0.55. The market risk premium is assumed to be 4.5% according to RWJ (Ross et al, 2002). So, the required rate of return on equity can be calculated from CAPM equation as 7.5%.

The data about return on company's debt can be found in Form F-20. It is stated there that weighted average Rd was equal to 5% in 2003 (RDS Group: F-20 Form, 2003, p G21). Group's market capitalization equals to $181,679M and long term debt equals to $10,974M (RDS Group: F-20 Form, 2003, p G20). That gives leverage of approximately 6% in 2003 (for the data on group's market capitalization see Exhibit 3.2). Now the appropriate weighted average cost of capital can be calculated for each region, given the different tax rates in different regions.

Complete calculation of DCF for proved developed and undeveloped reserves is represented in Exhibit 4.5. Total value for base scenario equals to approximately $99 billion.

Now, in order to estimate the figure that can be compared to the results in Chapter 3, namely value of undeveloped proved reserves solitary, the same calculation was made for developed reserves. In this case, there are no development costs, since the reserves are already producing. For developed reserves (11) should be rewritten as:

$$1.4 \cdot (8.5 - \sum_{s=0}^{t-1} P_s) \div (8.5 + 1.4 \cdot t \cdot (RRR - 1)) \qquad (12)$$

For developed reserves, instead of 14.4 bboe (quantity of developed and undeveloped reserves), 8.5 bboe (quantity of developed reserves) is plugged into the formula.

The result obtained for base scenario is approximately $80.5 billion. This outcome was then subtracted from the previous result in order to obtain value of undeveloped reserves. Calculation of DCF for proved developed reserves can be found in Exhibit 4.6.

This, rather not strait forward way of calculation, was chosen since it simplifies the simulation of production schedule for undeveloped reserves without any loss of precision. The problem is that production of the reserves that were undeveloped in 2004 should not start immediately, but rather should increase gradually and decrease after several years. Such production schedule would be hard to simulate, but using the above mentioned method production schedule with such features is obtained simply as oil produced from developed and undeveloped reserves together minus production of developed reserves.

Finally, the value for undeveloped reserves in base scenario equals to $18.3 billion. So, that for the base scenario one barrel of oil out of undeveloped reserves has a value of $3.2, whereas average value is about $7.

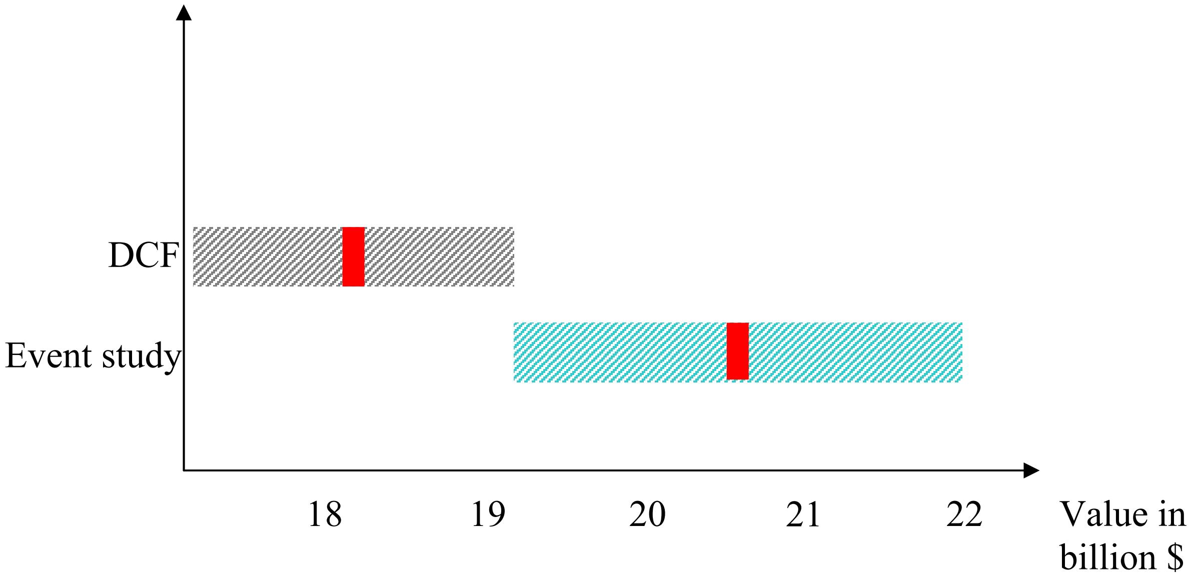
Results for RRR different from 100% are represented in Exhibit 4.8 and in Table 4.1:

RRR	**Value ($M)**
95%	19,096
100%	18,344
105%	17,631

One can see that the values obtained using DCF methodology are, in fact lower than the values obtained from event study and are in fact out of the range of results observed on the free market.

One most obvious explanation for this is that DCF does not capture some features that market attributes to the project, such as greater production flexibility and different scenarios for oil price development.

The comparison of the results obtained from market event study and using DCF methodology is visualized in Figure 4.1:



4.2 Calculation Using Real Options Methodology

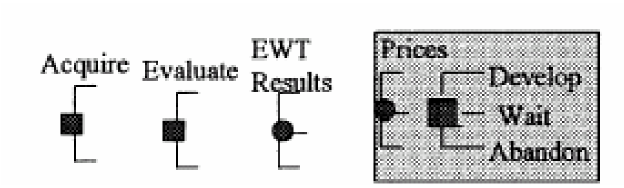
Results of previous section highlight the problem associated with the use of DCF. While DCF approach may seem an easy and strait-forward one, it has several downsides that make the analysis less reliable.

First and most important downside of the method is that the analysis does not capture the project flexibility. Decision models assumed by management when executing DCF analysis do not include uncertainties that may occur during the project. DCF approach requires that all the uncertainties should be resolved after the initial decision is made. After that, the cash flow becomes certain. In reality, company makes a series of investment decisions as uncertainties resolve gradually over time. For example, when company's management considers development of a new oil field. If oil prices or production technology improves, the company may invest aggressively or on the opposite, wait and scale back the investment under the price that is not that beneficial (Smith; McCardle; 1999).

When the value of natural resources is to be calculated, there is always the uncertainty regarding the price of underlying asset, such as uncertainty in oil price. Real options valuation is constructed to tackle exactly this problem. On one hand, this methodology takes in to account possible scenarios of oil prices and on the other hand, it allows calculating the effect of different management decisions such as postponement, extension or abandonment of oil producing projects.

The existing literature on option pricing for natural reserves proposes several different models of decision trees that company's management is facing on each stage of project.

Object of interest of this paper, however, is not the entire project of oil production that starts with acquiring the license, evaluation and exploration. At the point of time when the size of reserves is already determined and management is facing the decision on when and if it should start producing, the tree consists basically of three components: develop, wait and develop, abandon (Smith, McCardle, 1999, p 3). This decision tree is illustrated in Figure 4.2:



(Source: Smith, McCardle, 1999)

Now, let us start the evaluation of RDS' undeveloped oil reserves with the simple option to produce. The literature suggests that project that produces cash flow from exhaustible natural resources resembles call option at the point when irreversible decision is made. In other words, the option is exercised in the point when management makes the decision to invest in development that cannot be canceled without lost of the initial capital outlay (Wang, 2002, p 8 sqq).

So before starting the evaluation one should determine at which point of time should the option to develop oil resources be considered as exercised. The best way in this case would be to attribute planed capital expenditures to each project separately and than determine value of each oil field that yet to be developed according to the benefits it brings to the company and costs associated with it.

Unfortunately, the data for such analysis is unavailable in any of the company's public reports, so the second best solution should be implemented and several assumptions are to be made. As it was mentioned in previous section, management divides expected development costs into two groups. One \$7 billion is to be spent in 2004-2006 and the other \$23 billion is to be spent in 2007-2009. So, the whole project can be divided into two options one with the maturity of one year that is one that should be exercised in the end of 2004 and the other that is to be exercised in the end of 2007. Using the allocation of capital spending from the previous section, it is also possible to divide each group of options into six, one for each geographic region. Two option groups are assumed to be independent of one another. In other words it is possible to invest in the second option and develop the reserves in year 2007 without developing the reserves in 2004 and therefore the value of two options can be calculated separately.

The next step would be to estimate the input data for option pricing. Since, the real option estimated in this case resembles European call option, the required input would be the strike price K, the price of underlying asset S, volatility of returns of underlying assets σ and risk less rate of return r.

As in previous section σ is the implied standard deviation of return of Brent Crude price calculated in Exhibit 4.1 and risk free rate of return is the yield of 30 years US Treasury bonds that is equal to 5%.

The strike price for option can be represented as the present value of capital expenditures as to the year of option exercise discounted with risk free rate. The value of underlying asset in this case is NPV of the project under the present oil price also discounted as for the year of option exercise (Kemna, 1993).

In Exhibit 4.7 the same DCF simulation was constructed for proved undeveloped reserves as the ones that were constructed in the previous section for undeveloped + developed reserves and developed reserves. As it was mentioned above, the production schedule in this case calculated simply as the production of undeveloped + developed reserves minus production of developed reserves.

The cash flow was then divided between the first and the second option. Since there is no clear indication regarding what cash flow is produced by the oil fields developed in different years, the end of 2009 was voluntarily chosen as a splitting point, so that all the cash flow produced before the end is attributed to the first option and all the subsequent cash flow attributed to the second option.

As it was mentioned above, the cash flows and capital expenditures were than discounted to the end of 2004 and 2007 accordingly and the price for options was calculated in Exhibit 4.9 using Black and Scholes call formula. One can see that for the base scenario value of simple option to develop is equal to $19.4 billion, which is slightly higher than the value calculated using DCF approach.

As the next step, the value of option with possibility to wait was calculated. Typically, oil-producing companies have the possibility to wait and start production of reserves later on. Normally, such postponement does not last for long. There are two reasons for this. One is company’s legal obligation. When buying the license for oil field, company should first buy the license for exploration, which is time limited. Second reason is the competition. Concurrent may move faster and acquire the production license for the oil field, so that in the end company will just lose the opportunity to produce oil. Given all this, the postponement should not last longer than two years on average.

The opportunity to postpone production however does not come for free. Company will have to pay additional capital outlay of about 2% of original capital expenditures for each year of postponement. As no new information will normally be provided by this action, the expected NPV will not change, but there is a possibility that price of oil will rise and company will enjoy higher revenues (Kemna, 1993).

For the purpose of calculations in Exhibit 4.10 it was assumed that RDS will be able to postpone the options for two years and that the company will have to pay additional 2% every year as the base scenario. The result for base scenario is $20.4 billion.

One should remember that the value of underlying asset used in calculation of option prices is dependent on the production schedule simulated in previous section and therefore is dependent on company's RRR. Therefore, in order to get complete picture of the valuation attained using real option methodology one should look at the scenarios that include different capital outlay ratio and different RRRs. Some possible outcomes are represented in Exhibit 4.10 and in Table 4.2:

RRR	**Cap. Outlay**	**Value ($M)**
95%	1%	21,260
100%	2%	20,406
105%	3%	19,608

Last step that should be undertaken to conclude the calculation with the real options is to calculate the value of option to abandon the oil field. First of all, this option represents an American put option with NPV as underlying asset and the strike price equals to the cost to abandon (Kemna, 1993).

As for the timing of the option, it probably only makes sense to make calculation for such an option after the decision about development of reserves was already made. Otherwise, company would simply abandon the oil field with no additional costs if the value of option to produce or to wait and then produce will turn to be negative.

So, after the production has started company can still stop production if certain conditions are met. It is also worth mention that at this point of time the development costs should be considered as sunk costs and should not be included into calculation.

It is hard to determine what are the costs of scaling back production, however, company most probably close up production as the price for oil falls to the level that can not cover the costs of oil production. Probability of such a scenario is very low given the oil prices in the end of 2003, still such probability exists at it should provide additional value to oil reserves.

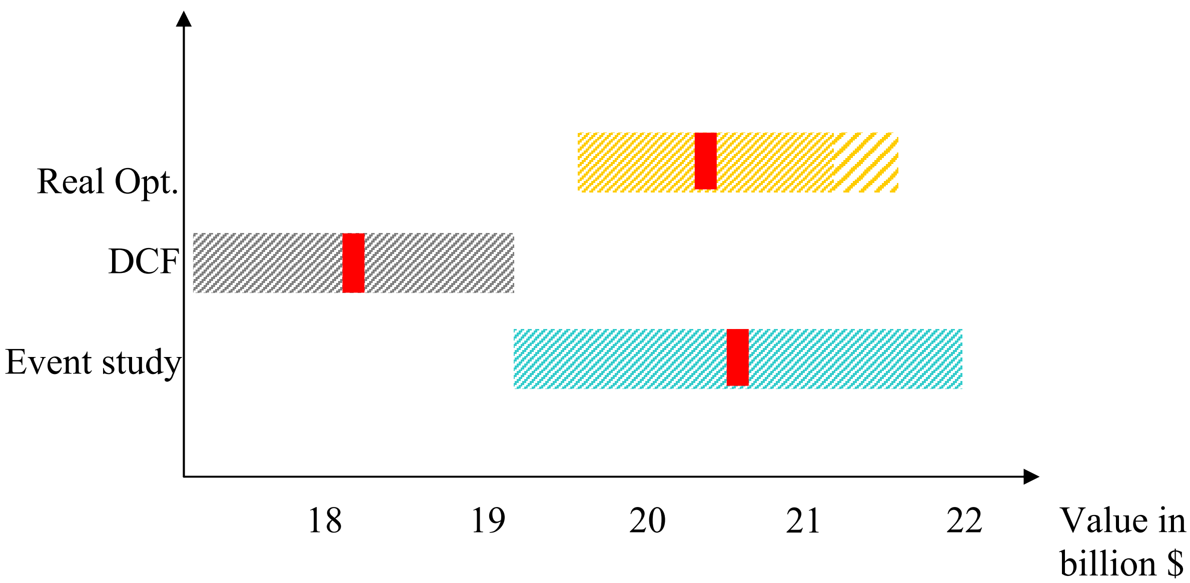
In order to see what effect might have the addition of option to abandon on overall value of oil reserves, small example calculation was conducted.

The value of option to abandon operations in Europe in 2004 was calculated. Estimation of value for American option is rather complicated, but in the short period of time, it can be well estimated with the value of European option (Smith, McCardle, 1999, p 14).

In 2003, cost of producing one barrel of oil was $3.19 per barrel (RDS: F-20 Form, 2003, p 7). So, using this price for oil times production as the strike price, the value for option was calculated using BS formula for European call and then value of put was estimated using put-call parity. The calculations are represented in Exhibit 4.11.

As one can see the option only worth about 2.5% of the option to start production in Europe in 2004. Since addition of the option to abandon has only limited value, no further calculations were made to determine the value of this option. One should also bear in mind that option to abandon is dependent on the exercise of option to produce. As the compounded option, it has less value than it would have as stand alone. This makes its influence on the overall value of reserves is even more limited (Wang, 2002, p 18 sqq). So, the option to abandon can be excluded from the calculation with no particular lost of value.

The calculation made in this section can be concluded in Figure 4.3:



The figure shows that the results provided by real option methodology lay within the range of valuations attained from the event study in Chapter 3. It stays within the range even if extra 2% is added to the value due to option to abandon.

4.3 Calculation Results

In this chapter, calculations were conducted in order to assess the value of proved undeveloped reserves that Royal Dutch Shell Group possessed in the end of 2003.

As one can see from the figures 4.1 and 4.3, the output of both calculations is quite close to the results that were obtained from the event study in Chapter 3.

The median value of results obtained using DCF methodology is approximately $18.6 billion, whereas the median value of results obtained using real options methodology is about $20.4 billion. If one compares these results to the median value of undeveloped oil reserves that was calculated in the event study and equals to approximately $20.6 billion, one can presume that the option pricing methodology gives better estimation of the fair value of oil reserves. One can also come to the conclusion that the value estimation provided by DCF calculations is systematically lower than the one on the fair market.

This conclusion is rather tempting, but it is important to remember, that in order to attain these results, chapter numerous assumption had to be made and it can be the case that some of these assumptions could result in lost of precision in calculations. Still, even if the assumptions that were made in this chapter are in line with the assumptions of the market (which hopefully is thru) the results obtained here have no statistical significance due to the uniqueness of such large-scale oil reserves restatement (at least in so far).

Nevertheless, the results of this study are in line with the theoretical assumption that the use of DCF methodology cannot capture the full value when it comes to the project in production of natural reserves. It may as well serve as an indication of the kind of estimation market players may conduct, when assessing value of oil and gas reserves.

One can also notice that all tree methods failed to predict the surge in oil prices observed in 2004 and 2005. The price for oil in the middle of 2005 lied within more than tree standard deviations away from the price observed in the beginning of 2003.

Conclusion

This paper was aimed at calculation of the fair value of oil and gas reserves and finding how well can traditional ways of value calculations estimate the value observed on free market. For this purpose, the case of Royal Dutch/Shell reserves restatement was used.

First, the event study methodology was applied to the reaction of stock market on the announcement of proved oil and gas reserves restatement made by Royal Dutch/Shell in the beginning of 2004. Than the fair value of oil and gas reserves was calculated using the appropriate correction necessary to assess the restatement of total company's oil and gas reserves from the announced figures for proved reserves.

In the later chapter value of oil reserves was calculated first using discounted cash flow methodology and than using real options methodology.

From the results of Chapters 3 and 4, one can see that the values obtained using all three methodologies are rather close and lay within 10% range from $20 billion. It is also noticeable that the values obtained using the real options methodology do replicate quite correctly the values observed on free market, whereas the results obtained by applying DCF methodology show systematically smaller results than the ones of event study and of real options method.

These results are consistent with the theoretical assumption that DCF methodology omits some value of natural resources, while real option methodology is a better estimate for fair value, since it is able to incorporate the uncertainties associated with the future prices for produced reserves.

Still the results in this paper lack statistical precision, since only one, rather unique, case was discussed. So, further statistical researches would be necessary in order to determine to which extend the fair value can be predicted by each of the methodologies used here.

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Following web sites have been used:

www.shell.com; www.bp.com; money.msn.co.uk; www.spe.org; www.sec.org;

Following programming packages have been used:

MS Visual Basic Macros

Appendix

Exhibit 2.1
Standard Measure of Cash Flow ($M)
2003

	Europe	Africa	Asia	M.East & Russia	USA	Western Hemisphere	Total
Cash Flow	117.660	47.325	24.115	45.238	31.419	16.224	**281.927**
Production costs	21.853	7.433	4.515	7.745	4.977	4.379	**50.902**
Net Cash Flow	95.807	39.892	19.600	37.493	26.442	11.845	**231.025**
Development costs	6.543	7.337	2.505	9.772	3.085	1.328	**30.570**
Tax expenses	44.361	18.764	4.785	16.391	8.542	2.900	**95.743**
Net CF	44.849	13.791	12.310	11.330	14.815	7.617	**104.712**
Discounting at 10%	22.027	5.826	5.610	9.209	5.231	2.965	**50.868**
Discounted net CF	22.822	7.965	6.700	2.121	9.584	4.652	**53.844**
Share in associated companies							**5.828**
Minority interest		170	38	(976)		547	**(221)**

Source: Company Report

Exhibit 2.2

Developed and undeveloped reserves 31.12.2003(mboe):

	Europe	Africa	Asia	M.East	USA	WH	Totat Grou	Groups Interest
Oil liquids	1.367,00	1.753,00	318,00	1.296,00	550,00	439,00	5.723,00	672,00
Gas (at 5800 eq.)	3641	617,00	1.442,00	626,00	547,00	299,00	7.172,00	287,24
Oil sand							652,00	(143,00)
							13.547,00	816,24
Total							**14.363,24**	

Developed reserves 31.12.2003(mboe):

	Europe	Africa	Asia	M.East	USA	WH	Totat Grou	Groups Interest
Oil liquids	1.056,00	879,00	194,00	898,00	293,00	192,00	3.512,00	672,00
Gas (at 5800 eq.)	2129	189,00	607,00	77,00	303,00	227,00	3.532,00	330,00
Oil sand							652,00	(143,00)
							7.696,00	859,00
Total							**8.555,00**	

Production 2003

	Europe	Africa	Asia	M.East	USA	WH	Totat Group
Oil liquids	245,00	133,00	57,00	181,00	110,00	37,00	763,00
Gas (at 5800 eq.)	225	22,00	93,00	45,00	96,00	34,00	515,00
Oil sand							17,00
							1.295,00
Total							**1.295,00**

Source: Company Report

Exhibit 3.1

Oil Prices

	31.12.2003	31.12.2002	31.12.2001
Brent	29,86	28,93	19,67
WTI	32,55	31,23	19,78
Tapis	31,7	32,7	20,95
Bonny	30,14	30,63	19,88
Urals	28,34	30,5	19,61

	31.12.2003
30 years bond yield	5,08%

Source: DataStream

Exhibit 3.2

	# stocks (mil)	Price $ (01.01.04)	CAR	CAR in $M
RD	2083	52,39	14,80%	16150,999
Shell	9667	7,505	16,40%	11898,337
				28049,336

Reserves Re-categorized (mboe)	8975,880899	Factor	2,008027
$/barrel	3,124967456		
Existing Proved Undeveloped Reserves (mboe)	5779,068966	Restatement	4470
Debt RDS (M$)	10974		
Equity RDS	181679		
Leverage	6%		
Value of Undevelopec	**19150,24884**		

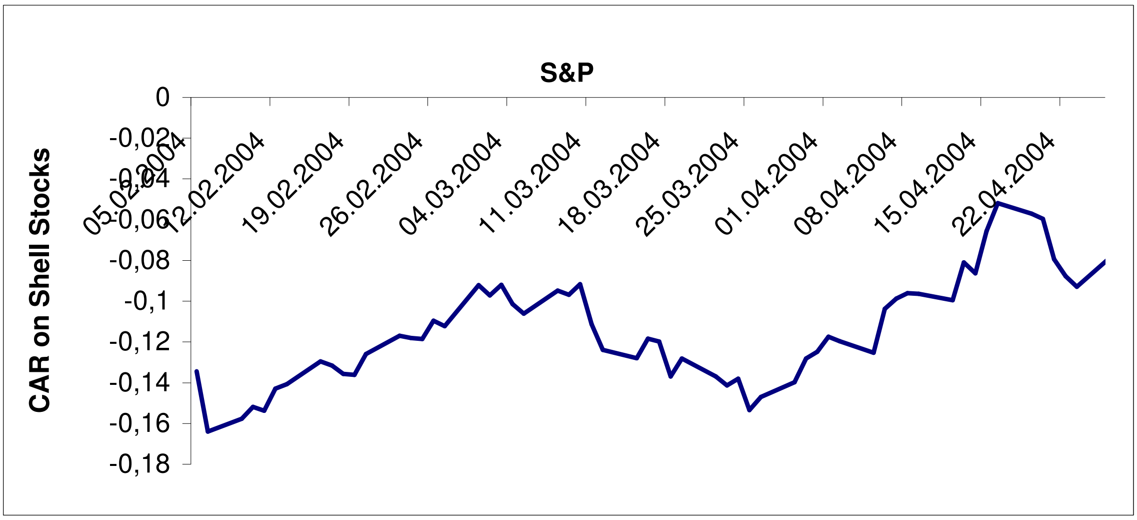
Exhibit 3.3 (full version available in soft copy)

	SHELL		market portfolio data		market model method					
relative date	price index	return	S&P index	S&P return	intercept	slope	residuals	variance	abnormal return	CAR
05.02.2003	49475		1211,04		0,00032292	0,54698901		0,00014011		
05.02.2004	54649	-0,01392084	1649,35	0,00185872			t-stat	alpha	-0,01526047	-0,1343989
06.02.2004	53424,4	-0,02240846	1670,14	0,01260497			-2,66682948	0,00765705	-0,02962616	-0,16402506
09.02.2004	53707,8	0,00530469	1666,16	-0,00238303					0,00628526	-0,1577398
10.02.2004	54186,6	0,00891491	1674,55	0,00503553					0,0058376	-0,1519022
11.02.2004	54430,1	0,00449373	1693,03	0,0110358					-0,00186565	-0,15376785
12.02.2004	54894,4	0,00853021	1684,92	-0,00479023					0,01082749	-0,14294037
13.02.2004	54872,5	-0,00039895	1675,86	-0,00537711					0,00221935	-0,14072102
16.02.2004	55508	0,01158139	1675,86	0					0,01125847	-0,12946255
17.02.2004	55702,8	0,0035094	1692,22	0,00976215					-0,00215331	-0,13161586
18.02.2004	55362,2	-0,00611459	1684,89	-0,00433159					-0,00406819	-0,13568404
19.02.2004	55229,4	-0,00239875	1678,01	-0,00408335					-0,00048812	-0,13617217
20.02.2004	55738,9	0,00922516	1673,71	-0,00256256					0,01030393	-0,12586824
23.02.2004	56167,6	0,00769122	1669,2	-0,00269461					0,00884222	-0,11702602
24.02.2004	56072,9	-0,00168603	1666,42	-0,00166547					-0,00109796	-0,11812398
25.02.2004	56198,6	0,00224172	1673,34	0,00415261					-0,00035263	-0,11847661
26.02.2004	56762,7	0,01003762	1675,63	0,00136852					0,00896613	-0,10951048
27.02.2004	56629,6	-0,00234485	1675,7	4,1775E-05					-0,00269062	-0,11220111
01.03.2004	58080,1	0,02561381	1691,9	0,0096676					0,02000282	-0,09219829
02.03.2004	57626,9	-0,00780302	1681,88	-0,00592234					-0,00488649	-0,09708478
03.03.2004	58002	0,00650911	1685,17	0,00195614					0,0051162	-0,09196858
04.03.2004	57578,1	-0,00730837	1690,83	0,00335871					-0,00946847	-0,10143705
05.03.2004	57381,4	-0,00341623	1693,76	0,00173288					-0,00468702	-0,10612407
08.03.2004	57788,5	0,00709463	1679,74	-0,00827744					0,01129938	-0,09482469
09.03.2004	57507,2	-0,00486775	1670,07	-0,00575684					-0,00204174	-0,09686643
10.03.2004	57369,1	-0,00240144	1645,79	-0,01453831					0,00522794	-0,0916385
11.03.2004	55788,3	-0,0275549	1621,21	-0,01493508					-0,0197085	-0,111347
12.03.2004	55486,1	-0,00541691	1641,42	0,012466					-0,01255859	-0,12390559
15.03.2004	54847,2	-0,0115146	1617,91	-0,01432296					-0,00400302	-0,12790861
16.03.2004	55554,6	0,01289765	1627,03	0,0056369					0,0094914	-0,11841721
17.03.2004	55858,6	0,00547209	1646,29	0,01183752					-0,00132582	-0,11974303
18.03.2004	54878,9	-0,01753893	1644,21	-0,00126345					-0,01717076	-0,13691379
19.03.2004	55045,4	0,00303395	1625,84	-0,01117254					0,00882229	-0,1280915
22.03.2004	54186	-0,01561257	1604,8	-0,012941					-0,0088569	-0,13694841
23.03.2004	53925,2	-0,00481305	1602,67	-0,00132727					-0,00440997	-0,14135838
24.03.2004	54051,9	0,00234955	1598,85	-0,00238352			t-stat	alpha	0,00333039	-0,138028
25.03.2004	53716,9	-0,00619775	1625,01	0,01636176			-1,66037341	0,09683936	-0,01547037	-0,15349837
26.03.2004	54056,7	0,00632576	1623,36	-0,00101538					0,00655823	-0,14694014
29.03.2004	54853,6	0,01474193	1644,75	0,01317637					0,00721167	-0,13972846
30.03.2004	55629,6	0,01414675	1651,43	0,00406141					0,01160228	-0,12812619
31.03.2004	55810,9	0,00325906	1650,42	-0,00061159					0,00327067	-0,12485552
01.04.2004	56404,6	0,01063771	1659,16	0,00529562					0,00741814	-0,11743738
02.04.2004	56566,1	0,00286324	1673,4	0,00858266					-0,0021543	-0,11959168
05.04.2004	56495,4	-0,00124987	1686,24	0,007673					-0,00576984	-0,12536152
06.04.2004	57683,4	0,02102826	1683,23	-0,00178504					0,02168173	-0,10367979
07.04.2004	57784,2	0,00174747	1672,14	-0,00658852					0,0050284	-0,09865139
08.04.2004	57920,5	0,00235878	1670,36	-0,0010645					0,00261812	-0,09603327
09.04.2004	57920,5	0	1670,36	0					-0,00032292	-0,09635619
12.04.2004	57920,5	0	1679,02	0,00518451					-0,00315879	-0,09951498
13.04.2004	58579,6	0,01137939	1655,99	-0,01371633					0,01855915	-0,08095583
14.04.2004	58252,6	-0,00558215	1654,17	-0,00109904					-0,00530391	-0,08625974
15.04.2004	59493,8	0,0213072	1655,15	0,00059244					0,02066022	-0,06559952
16.04.2004	60494,8	0,01682528	1663,62	0,00511736			t-stat	alpha	0,01370322	-0,0518963
19.04.2004	60237,4	-0,00425491	1665,39	0,00106394			-0,57205773	0,56728287	-0,0051598	-0,0570561
20.04.2004	59588,2	-0,01077736	1639,49	-0,01555191					-0,00259356	-0,05964966
21.04.2004	58605,8	-0,01648649	1648,31	0,00537972					-0,01975206	-0,07940172

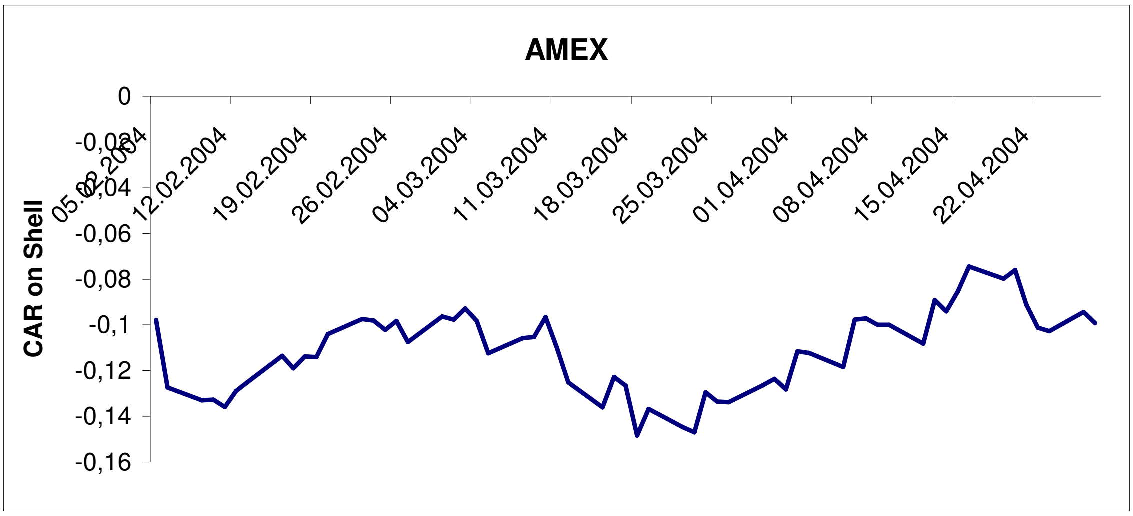
Exhibit 3.4 (full version available in soft version)

	ROYAL DUTCH		market portfolio data		market model method					
relative date	price index	return	S&P	S&P return	intercept	slope	residuals	variance	abnormal return	CAR
05.02.2003	6403,5		1211,04		0,00054256	0,55104076		0,00012199		
04.02.2004	7613,7	-0,00438069	1646,29	-0,00821124					-0,00039852	-0,12117066
05.02.2004	7564	-0,00652771	1649,35	0,00185872			t-stat	alpha	-0,0080945	-0,12926517
06.02.2004	7480,1	-0,01109201	1670,14	0,01260497			-2,57611256	0,00999181	-0,01858043	-0,1478456
09.02.2004	7538,2	0,00776728	1666,16	-0,00238303					0,00853786	-0,13930774
10.02.2004	7586,1	0,0063543	1674,55	0,00503553					0,00303696	-0,13627078
11.02.2004	7591,3	0,00068546	1693,03	0,0110358					-0,00593828	-0,14220906
12.02.2004	7707,1	0,0152543	1684,92	-0,00479023					0,01735135	-0,1248577
13.02.2004	7642,3	-0,00840783	1675,86	-0,00537711					-0,00598739	-0,13084509
16.02.2004	7681,8	0,0051686	1675,86	0					0,00462604	-0,12621906
17.02.2004	7745,3	0,00826629	1692,22	0,00976215					0,00234438	-0,12387467
18.02.2004	7727,5	-0,00229817	1684,89	-0,00433159					-0,00045385	-0,12432852
19.02.2004	7728,6	0,00014235	1678,01	-0,00408335					0,00184988	-0,12247864
20.02.2004	7718,9	-0,00125508	1673,71	-0,00256256					-0,00038557	-0,12286421
23.02.2004	7793,8	0,00970346	1669,2	-0,00269461					0,01064573	-0,11221848
24.02.2004	7787,4	-0,00082117	1666,42	-0,00166547					-0,00044599	-0,11266447
25.02.2004	7798,2	0,00138686	1673,34	0,00415261					-0,00144397	-0,11410843
26.02.2004	7859,9	0,00791208	1675,63	0,00136852					0,00661541	-0,10749303
27.02.2004	7895,7	0,00455477	1675,7	4,1775E-05					0,00398918	-0,10350385
01.03.2004	8047,6	0,01923832	1691,9	0,0096676					0,01336851	-0,09013533
02.03.2004	8023,7	-0,00296983	1681,88	-0,00592234					-0,00024894	-0,09038428
03.03.2004	8032,1	0,0010469	1685,17	0,00195614					-0,00057358	-0,09095786
04.03.2004	8018	-0,00175546	1690,83	0,00335871					-0,00414881	-0,09510666
05.03.2004	8020	0,00024944	1693,76	0,00173288					-0,00124801	-0,09635468
08.03.2004	8066,6	0,00581047	1679,74	-0,00827744					0,00982912	-0,08652556
09.03.2004	8014,2	-0,00649592	1670,07	-0,00575684					-0,00386623	-0,09039179
10.03.2004	8002,2	-0,00149734	1645,79	-0,01453831					0,0059713	-0,08442049
11.03.2004	7774,1	-0,02850466	1621,21	-0,01493508					-0,02081739	-0,10523788
12.03.2004	7756,2	-0,00230252	1641,42	0,012466					-0,00971435	-0,11495223
15.03.2004	7678	-0,01008226	1617,91	-0,01432296					-0,00273228	-0,11768452
16.03.2004	7724,8	0,00609534	1627,03	0,0056369					0,00244661	-0,11523791
17.03.2004	7720	-0,00062138	1646,29	0,01183752					-0,0076869	-0,1229248
18.03.2004	7574	-0,01891192	1644,21	-0,00126345					-0,01875827	-0,14168307
19.03.2004	7565,6	-0,00110906	1625,84	-0,01117254					0,0045049	-0,13717817
22.03.2004	7481,2	-0,01115576	1604,8	-0,012941					-0,0045673	-0,14174547
23.03.2004	7401,5	-0,01065337	1602,67	-0,00132727					-0,01046456	-0,15221003
24.03.2004	7394,6	-0,00093224	1598,85	-0,00238352			t-stat	alpha	-0,00016139	-0,15237142
25.03.2004	7389,2	-0,00073026	1625,01	0,01636176			-1,88562277	0,05934581	-0,01028882	-0,16266024
26.03.2004	7416,7	0,00372165	1623,36	-0,00101538					0,0037386	-0,15892164
29.03.2004	7522,9	0,01431904	1644,75	0,01317637					0,00651575	-0,15240589
30.03.2004	7584,8	0,00822821	1651,43	0,00406141					0,00544764	-0,14695824
31.03.2004	7602,3	0,00230725	1650,42	-0,00061159					0,00210169	-0,14485655
01.04.2004	7681,5	0,0104179	1659,16	0,00529562					0,00695723	-0,13789932
02.04.2004	7679,8	-0,00022131	1673,4	0,00858266					-0,00549327	-0,14339258
05.04.2004	7676,2	-0,00046876	1686,24	0,007673					-0,00523946	-0,14863205
06.04.2004	7750,7	0,00970532	1683,23	-0,00178504					0,01014639	-0,13848566
07.04.2004	7807,2	0,00728966	1672,14	-0,00658852					0,01037765	-0,12810801
08.04.2004	7773,3	-0,00434215	1670,36	-0,0010645					-0,00429812	-0,13240614
09.04.2004	7773,3	0	1670,36	0					-0,00054256	-0,1329487
12.04.2004	7751	-0,00286879	1679,02	0,00518451					-0,00626824	-0,13921694
13.04.2004	7796,4	0,00585731	1655,99	-0,01371633					0,012873	-0,12634393
14.04.2004	7763,4	-0,00423272	1654,17	-0,00109904					-0,00416967	-0,1305136
15.04.2004	7898,2	0,01736353	1655,15	0,00059244					0,0164945	-0,1140191
16.04.2004	8020,9	0,01553519	1663,62	0,00511736			t-stat	alpha	0,01217275	-0,10184635
19.04.2004	8008,3	-0,0015709	1665,39	0,00106394			-1,07870021	0,28072139	-0,00269974	-0,10454609
20.04.2004	7953,5	-0,0068429	1639,49	-0,01555191					0,00118427	-0,10336182
21.04.2004	7881,2	-0,00909034	1648,31	0,00537972					-0,01259735	-0,11595917

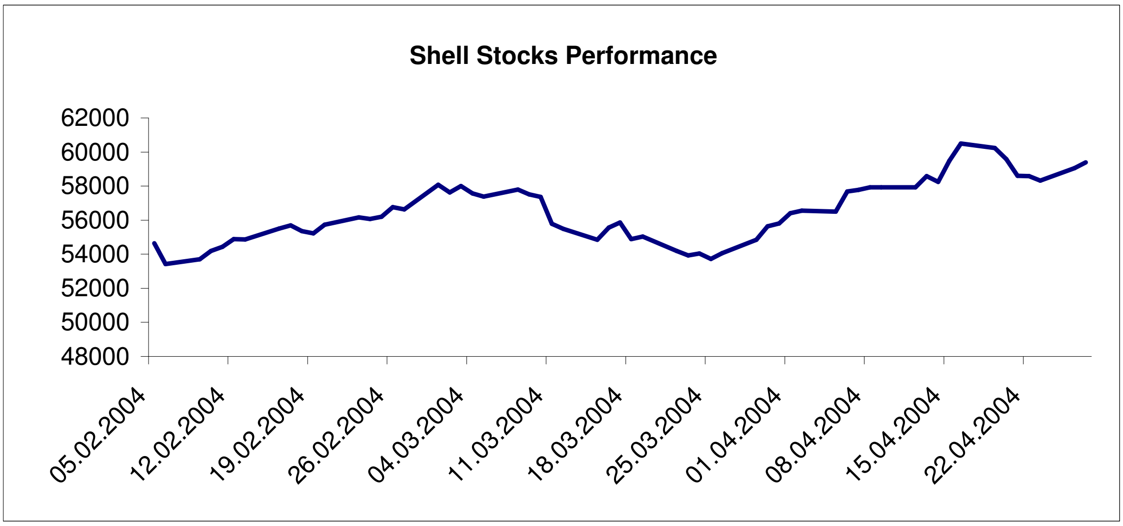
Exhibit 3.5



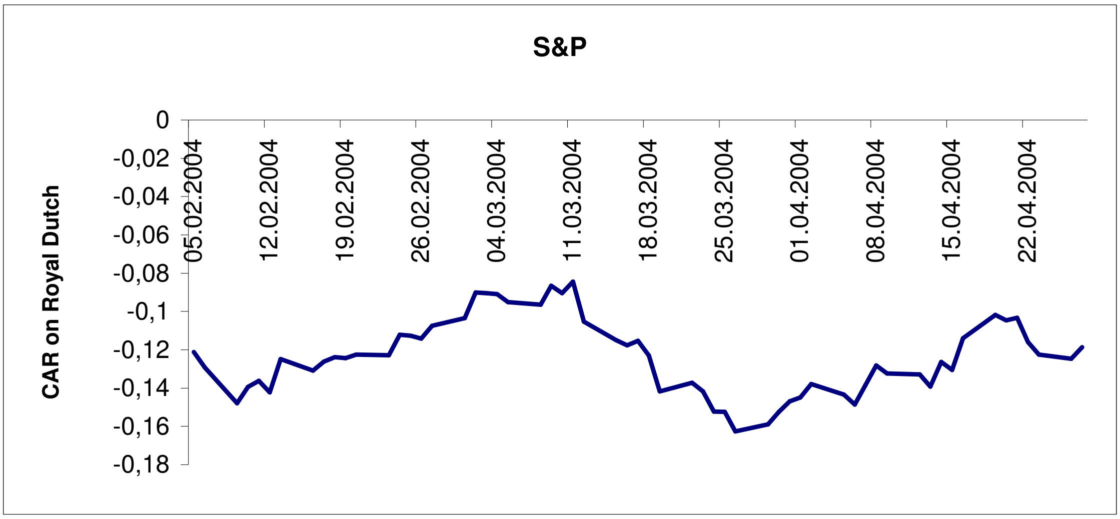
S&P
CAR on Shell Stocks
0
-0,02
-0,04
-0,06
-0,08
-0,1
-0,12
-0,14
-0,16
-0,18
05.02.2004
12.02.2004
19.02.2004
26.02.2004
04.03.2004
11.03.2004
18.03.2004
25.03.2004
01.04.2004
08.04.2004
15.04.2004
22.04.2004

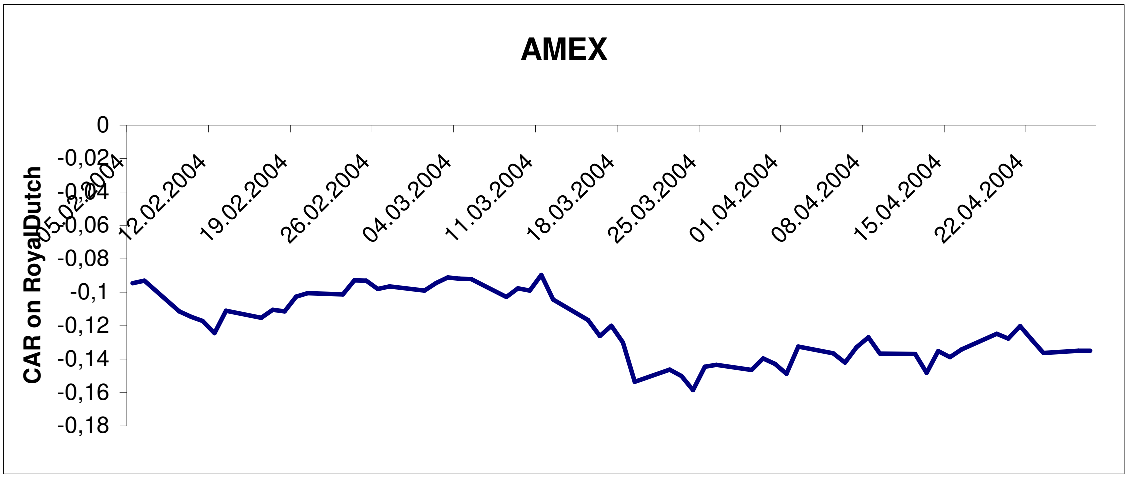


AMEX
CAR on Shell
0
-0,02
-0,04
-0,06
-0,08
-0,1
-0,12
-0,14
-0,16
05.02.2004
12.02.2004
19.02.2004
26.02.2004
04.03.2004
11.03.2004
18.03.2004
25.03.2004
01.04.2004
08.04.2004
15.04.2004
22.04.2004



Shell Stocks Performance
62000
60000
58000
56000
54000
52000
50000
48000
05.02.2004
12.02.2004
19.02.2004
26.02.2004
04.03.2004
11.03.2004
18.03.2004
25.03.2004
01.04.2004
08.04.2004
15.04.2004
22.04.2004


S&P
CAR on Royal Dutch
0
-0,02
-0,04
-0,06
-0,08
-0,1
-0,12
-0,14
-0,16
-0,18
05.02.2004
12.02.2004
19.02.2004
26.02.2004
04.03.2004
11.03.2004
18.03.2004
25.03.2004
01.04.2004
08.04.2004
15.04.2004
22.04.2004


AMEX
CAR on Royal Dutch
0
-0,02
-0,04
-0,06
-0,08
-0,1
-0,12
-0,14
-0,16
-0,18
05.02.2004
12.02.2004
19.02.2004
26.02.2004
04.03.2004
11.03.2004
18.03.2004
25.03.2004
01.04.2004
08.04.2004
15.04.2004
22.04.2004

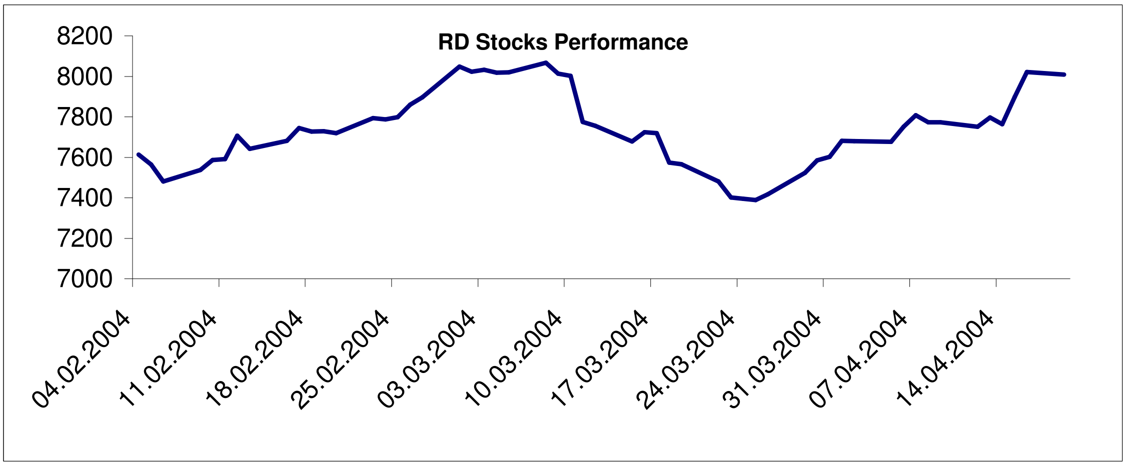

RD Stocks Performance
8200
8000
7800
7600
7400
7200
7000
04.02.2004
11.02.2004
18.02.2004
25.02.2004
03.03.2004
10.03.2004
17.03.2004
24.03.2004
31.03.2004
07.04.2004
14.04.2004

Exhibit 3.6 (full version available in soft copy)

relative date	return Shell	return RD	corr
05.02.2003			0,920303
06.02.2003	-0,05234563	-0,04138362	
07.02.2003	-0,01494288	-0,01676305	
10.02.2003	-0,00037675	0,006279409	
11.02.2003	0,00464616	0,005548695	
12.02.2003	-0,03113081	-0,02659156	
13.02.2003	-0,01254846	-0,00652671	
14.02.2003	0,01195973	0,01628852	
17.02.2003	0,0191428	0,008313618	
18.02.2003	0,01139319	0,011483617	
19.02.2003	-0,0118633	-0,01437533	
20.02.2003	0,00220393	0,000447494	
21.02.2003	0,02100909	0,013335984	
24.02.2003	-0,00898071	0,002092597	
25.02.2003	-0,02136481	-0,02208953	
26.02.2003	-0,01245674	-0,01106069	
27.02.2003	0,0037681	0,004605341	
28.02.2003	0,02268373	0,017749194	
03.03.2003	0,01713639	0,022702899	
04.03.2003	-0,00138029	-0,00120997	
05.03.2003	-0,00427926	-0,00423195	
06.03.2003	-0,0071126	-0,00402284	
07.03.2003	-0,02201441	-0,02164495	
10.03.2003	-0,00907966	-0,00592632	
11.03.2003	0,00933035	0,001758352	
12.03.2003	-0,0557655	-0,05583417	
13.03.2003	0,05276033	0,044918555	
14.03.2003	0,01822043	0,017994815	
17.03.2003	0,02954562	0,034671016	
18.03.2003	0,00240139	-0,01224221	
19.03.2003	0,00550297	0,015504633	
20.03.2003	-0,00196332	-0,01226886	
21.03.2003	0,01982376	0,017568357	
24.03.2003	-0,01859812	-0,02109462	
25.03.2003	0,03222609	0,034671057	
26.03.2003	0,0164691	0,009641591	
27.03.2003	-0,02846301	-0,02284395	
28.03.2003	0,01587216	0,021302078	
31.03.2003	-0,02191294	-0,02598621	
01.04.2003	0,02748848	0,026920299	
02.04.2003	0,01190737	0,003501532	
03.04.2003	-0,00516269	0,001074833	
04.04.2003	0,00762318	0,001229285	
07.04.2003	0,01933431	0,018214597	
08.04.2003	-0,01870104	-0,01330973	
09.04.2003	0,00749555	0,004718149	
10.04.2003	-0,01590049	-0,01207101	
11.04.2003	-0,00276172	0,003148134	
14.04.2003	0,01156026	0,008234033	
15.04.2003	0,00145573	0,010955822	
16.04.2003	-0,0045363	-0,0029722	
17.04.2003	0,00699871	0,011282161	
18.04.2003	0	0	
21.04.2003	-0,00946832	-0,00430832	

Exhibit 3.7

restatement of 4.47B	+20	Mar25	Apr19
RD	14,80%	14,80%	10,49%
Shell	16,40%	16,40%	5,70%
Results	*	**	
Value	19150,24884	19801,5705	10673,40524

restatement of 4.15B	+20	Mar25
RD	14,80%	14,80%
Shell	16,40%	16,40%
Results	*	
Value	20693,54753	21328,4385

restatement of 3.9B	+20
RD	14,80%
Shell	16,40%
Results	
Value	22020,05699

Exhibit 4.1

Futures Options Crude Oil (NYMEX); Apr04

X ($)	C	S	SD	risk free	d1	d2	C (calculated)	T
28,50	1,87	29,62	0,166871	5%	0,578609	0,495174	1,870149226	0,25
29,00	1,61	29,62	0,180922		0,348167	0,257706	1,610488653	
29,50	1,38	29,62	0,191628		0,155506	0,059692	1,38004915	
30,00	1,17	29,62	0,199093		-0,015499	-0,115045	1,169991126	
30,50	0,98	29,62	0,204249		-0,174416	-0,27654	0,980027221	
31,00	0,82	29,62	0,209439		-0,322808	-0,427527	0,820097249	
SD of oil price annual return			**0,192**					

Brent Crude Oil Spot (IPE)

29,62

Futures Brent Crude Oil (IPE)

	price	net price	t	CY
Dec04	27,2	23,52167	1	13,52%
Dec05	25,65	22,5219	2	12,20%

Source: WSJ (31.12.03) and self calculations

Exhibit 4.2 (full version available in soft copy)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Price	29,62	23,52	22,52	23,25	24,29	25,25	26,06	27,15	28,17	29,21	30,54	31,58	32,68	33,64	34,72
SD	5,69														
Steps	1000														
				20,593465	28,66383	23,42659	17,58909	26,65027	31,63991	26,72008	35,44764	32,68022	36,52703	24,94471	24,53009
	1			27,971532	27,51675	24,7745	24,66653	36,04956	28,66783	23,27507	36,28598	25,7832	36,26516	38,22094	26,25926
	2			17,107977	21,71843	23,55557	19,74641	23,43954	28,38762	29,86674	28,76177	22,80284	27,88896	32,77265	29,50661
	3			21,236019	27,29554	26,81382	24,78086	38,36055	20,35349	18,75475	25,18869	19,7197	29,13417	49,1783	25,64834
	4			22,185754	24,03599	25,94614	19,93624	25,50255	23,64939	30,87696	30,03379	29,22777	28,7496	30,14088	38,96531
	5			21,515583	27,69142	23,61326	18,10546	26,70472	26,75496	18,96166	33,62373	32,20199	26,16938	56,54978	34,5101
	6			21,68374	27,70583	28,42199	36,68092	44,10552	21,37822	20,95975	25,94462	26,30894	34,29255	29,24753	33,69604
	7			24,21318	23,13497	19,46357	20,93132	30,93332	27,38707	35,12593	31,29295	38,55432	30,72548	25,68652	34,60433
	8			32,941177	23,12392	18,68297	27,1077	23,11204	28,69619	32,68918	25,30062	30,07917	30,19502	26,50508	35,84269
	9			41,704573	19,21435	18,34189	27,3005	27,63226	29,35639	29,13803	29,31734	35,07893	25,7506	33,45583	30,23294
	10			29,970171	32,12808	25,01527	19,72003	24,57266	22,91491	25,9695	23,8572	39,503	33,75726	29,20369	19,08885
	11			24,682023	35,7412	16,35262	33,73955	21,62286	29,9602	34,27977	30,3705	34,5277	30,61371	26,68107	43,04703
	12			20,808751	20,18186	30,40547	20,12752	24,8367	29,56505	25,06491	26,23079	37,35555	29,70119	39,57345	33,83205
	13			19,600621	36,16265	21,07984	23,9799	29,23483	24,93542	39,4698	23,67988	27,73907	32,67624	27,60442	25,98094
	14			18,712227	24,05918	36,07666	15,94304	35,38009	19,15132	27,32668	40,27645	29,22087	29,86939	38,69474	40,32848
	15			23,938736	26,63659	21,64695	30,4586	21,21453	35,79303	27,25162	28,77683	32,58814	31,2243	27,12913	24,54815
	16			18,090136	29,16152	22,61547	25,532	33,4149	31,53903	21,35382	25,55738	32,35353	27,91347	31,45078	28,95813
	17			18,549474	21,79132	25,73672	32,04994	23,33683	23,02966	32,05614	35,19731	27,90637	32,11614	37,05382	34,53061
	18			28,70677	29,45495	21,40862	24,80306	27,62	37,21599	24,3111	28,75662	22,97833	27,04121	42,25901	41,84896
	19			27,650336	22,83689	27,09587	29,98414	24,43413	30,69264	33,06754	24,46956	45,8855	35,01054	31,00441	32,96426
	20			14,042057	24,28527	25,85303	30,79228	25,61091	29,99619	20,29081	26,11968	27,39954	43,26363	38,12904	30,03724
	21			19,665747	24,16212	27,43941	36,82593	24,77244	19,69244	23,63046	27,16375	22,00147	28,84292	43,66327	25,95358
	22			24,381939	21,50589	18,20374	36,2922	25,30408	23,04644	34,49295	40,99592	32,74023	26,81404	26,0675	33,37488
	23			23,576802	26,40322	21,31515	26,47621	30,98979	22,07629	33,76802	39,56201	26,12432	32,94987	33,24196	30,24695
	24			18,852851	25,65003	27,04076	26,02684	30,31307	28,6684	31,0037	25,807	18,23141	36,09566	26,30468	32,46949
	25			24,404162	24,1566	23,04434	34,62789	35,11703	27,47031	22,00332	24,00528	36,56439	30,7986	36,365	33,36796
	26			26,640153	25,93593	30,15427	22,67596	30,47205	24,319	25,73352	47,98652	35,90063	24,82702	29,81992	40,669
	27			28,721614	27,67146	22,16523	21,84635	23,16044	21,35177	31,46414	35,14457	33,97838	40,05598	25,11362	30,28435

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
36,05	37,54	38,87	40,46	41,70	43,18	44,93	46,46	48,48	49,57	51,60	53,39	55,52	57,18	59,35	61,79	64,18
28,8436	40,49379	31,2198	38,85516	28,69998	60,73429	43,2191	50,4307	36,66763	41,42275	44,98331	51,61971	46,72032	37,41681	53,02669	54,43048	81,70023
33,40859	31,02938	36,43347	35,87978	50,95711	29,0245	34,50553	50,76986	55,36454	53,47213	31,14342	53,65278	45,56125	59,73777	60,07824	57,47059	63,52577
46,1174	40,59025	43,30895	44,50785	33,01845	53,87142	47,13606	45,8721	46,84373	48,94907	62,80245	48,23907	34,24846	43,20309	57,2118	60,8594	89,99933
33,51078	27,94062	30,01259	46,41336	35,68325	51,12214	39,69107	55,3176	47,34398	80,85109	43,27829	48,02275	49,62561	70,47498	52,95261	73,57898	77,5298
32,33363	56,85759	38,36605	35,47104	46,02693	49,97453	36,73358	52,2831	46,57895	62,19229	62,75265	57,06435	54,94811	49,32103	52,97138	45,92875	79,09828
34,74861	28,01593	29,64346	52,63619	46,89174	50,21904	35,10326	48,96026	35,51641	40,14606	42,65276	45,35811	60,30928	64,67687	70,2609	53,94336	58,57708
32,04585	32,62206	44,07635	48,04819	36,39382	45,73301	44,95648	63,29334	49,45292	64,76219	42,7038	53,93504	89,99424	61,21627	70,12417	56,32515	56,68477
25,73035	43,87621	31,48282	42,94512	41,47514	42,43545	44,02233	62,22216	45,70753	47,0383	60,41863	51,85856	34,90609	64,86703	83,25623	74,59417	99,74435
23,91559	43,79894	37,38998	43,78326	48,8998	42,66506	49,03531	41,51387	44,35596	58,34236	48,79374	43,37195	47,75745	55,70564	56,70924	31,94573	66,64087
27,24977	40,54929	40,79003	45,98402	48,60131	46,10342	44,64359	41,17488	45,74304	66,64599	38,34622	47,90376	65,38475	57,09295	45,47003	66,56009	63,68601
50,47426	38,91208	39,90513	36,2554	50,26218	45,0268	35,51901	50,0914	36,20396	54,89234	48,51969	65,02391	49,01103	66,7144	64,21495	31,53066	65,65579
37,46695	45,31974	40,26497	38,58863	57,22258	32,85602	62,34492	42,36991	32,58352	62,63596	43,43417	62,81982	58,97687	50,57057	64,76117	57,98985	79,12744
27,70318	40,86028	34,83912	38,33744	39,72388	32,79865	34,28302	58,69985	33,19898	42,56848	42,60312	60,88908	54,40968	61,49894	46,76269	67,03108	60,01178
31,87728	45,22695	39,99503	33,64245	50,05841	32,53753	43,27156	46,42578	44,34244	56,09583	47,01198	73,28272	54,78311	37,47444	52,31968	44,42139	39,42579
45,43881	34,11822	27,65005	37,83943	43,65169	65,03192	37,05892	45,42124	44,26392	52,3603	38,25299	46,70869	61,27331	50,84249	56,37777	42,53831	70,98596
26,55929	30,21743	32,1596	30,33694	27,19981	31,11087	37,03848	57,50453	41,61201	48,78317	42,62431	50,0393	46,02947	53,2877	52,42186	54,48968	64,09355
36,76708	33,91183	34,44329	29,77982	35,65855	48,91986	42,4193	39,80404	55,18264	47,29866	46,18739	44,32956	54,34844	65,87223	58,0028	80,20977	69,56042
24,39211	46,32816	45,70747	29,94424	37,20536	35,62323	52,9741	31,54174	42,64799	51,58758	50,45465	66,5088	51,40808	66,81208	55,1104	61,90569	93,58716
60,66892	32,6724	31,98306	25,05771	33,79309	36,37951	53,2543	41,20478	48,58026	53,51335	59,15359	35,48085	64,26019	55,10832	66,27688	73,09689	56,49226
36,98381	33,82409	37,92855	30,0836	38,80406	49,81423	33,35043	38,13439	40,36548	34,74537	45,40665	65,51623	43,53013	42,76777	52,40234	51,41415	65,50965
37,95535	31,67928	35,67168	41,99306	46,40324	40,00779	33,18035	45,31698	36,77656	53,24168	46,53819	44,07655	52,39974	57,43475	69,90428	60,62636	51,53151
36,62151	31,11452	45,81481	41,8107	40,08706	40,30204	40,53626	39,07297	35,29568	58,955	51,98034	49,64584	87,34928	63,45292	43,31957	82,22327	57,78025
45,91952	54,66945	39,33501	42,11536	33,96634	54,92645	41,7732	36,43171	38,35065	50,65694	55,29256	57,33633	56,61073	52,73292	48,47566	69,27235	45,80113
41,54721	32,33687	39,37856	50,08112	35,21184	37,68743	44,96609	43,44885	43,10643	44,45915	43,98442	37,61682	48,73915	49,06506	64,5276	52,51754	80,61828
28,92042	33,44381	53,94177	38,8958	32,21868	41,97926	48,34975	48,37715	50,27403	43,61511	47,35776	47,45268	65,57987	53,3009	77,76293	52,61968	69,2251
38,97679	29,61823	40,4608	46,18304	49,7405	35,42971	40,95778	46,67603	49,34003	59,67261	42,40047	43,717	68,90916	53,32706	42,75433	40,73795	54,26881
25,60776	41,95293	41,2838	22,42442	34,01201	50,86159	51,75038	43,03726	57,13988	52,1796	39,28486	47,93856	66,20309	40,27173	46,71521	72,98747	79,60546
33,94577	35,32715	39,57337	48,25927	38,42323	45,80596	39,34574	36,32979	43,35558	67,77433	41,93186	48,90442	80,77378	59,783	51,07999	60,28269	66,04046

Exhibit 4.3

	WTI	Brent	Urals	Tapis	Bonny	Kernel price
30.12.2003	32,78	29,62	28,34	31,7	30,14	29,62
Ratio to kernel price	**1,106685**	**1**	**0,956786**	**1,070223**	**1,017556**	

Source: DataStream & WSJ (31.12.03)

Exhibit 4.4 (full version available in soft copy)

	Shell					Royal Dutch				
	company data		market portfolio data			company data		market portfolio data		
relative date	price index	return	S&P index	S&P return	Beta	price index	return	S&P	S&P return	Beta
05.02.2003	49475		1211,04		0,54698901	6403,5		1211,04		0,55104076
06.02.2003	46885,2	-0,05234563	1203,58	-0,00615999		6138,5	-0,04138362	1203,58	-0,00615999	
07.02.2003	46184,6	-0,01494288	1191,46	-0,01006996		6035,6	-0,01676305	1191,46	-0,01006996	
10.02.2003	46167,2	-0,00037675	1200,51	0,00759572		6073,5	0,00627941	1200,51	0,00759572	
11.02.2003	46381,7	0,00464616	1190,83	-0,00806324		6107,2	0,0055487	1190,83	-0,00806324	
12.02.2003	44937,8	-0,03113081	1176,15	-0,01232754		5944,8	-0,02659156	1176,15	-0,01232754	
13.02.2003	44373,9	-0,01254846	1174,43	-0,0014624		5906	-0,00652671	1174,43	-0,0014624	
14.02.2003	44904,6	0,01195973	1199,61	0,02144019		6002,2	0,01628852	1199,61	0,02144019	
17.02.2003	45764,2	0,0191428	1199,61	0		6052,1	0,00831362	1199,61	0	
18.02.2003	46285,6	0,01139319	1223,11	0,0195897		6121,6	0,01148362	1223,11	0,0195897	
19.02.2003	45736,5	-0,0118633	1214,66	-0,00690862		6033,6	-0,01437533	1214,66	-0,00690862	
20.02.2003	45837,3	0,00220393	1203,18	-0,0094512		6036,3	0,00044749	1203,18	-0,0094512	
21.02.2003	46800,3	0,02100909	1219,1	0,0132316		6116,8	0,01333598	1219,1	0,0132316	
24.02.2003	46380	-0,00898071	1196,71	-0,01836601		6129,6	0,0020926	1196,71	-0,01836601	
25.02.2003	45389,1	-0,02136481	1205,32	0,00719473		5994,2	-0,02208953	1205,32	0,00719473	
26.02.2003	44823,7	-0,01245674	1189,98	-0,01272691		5927,9	-0,01106069	1189,98	-0,01272691	
27.02.2003	44992,6	0,0037681	1204,11	0,01187415		5955,2	0,00460534	1204,11	0,01187415	
28.02.2003	46013,2	0,02268373	1209,71	0,00465074		6060,9	0,01774919	1209,71	0,00465074	
03.03.2003	46801,7	0,01713639	1200,6	-0,00753073		6198,5	0,0227029	1200,6	-0,00753073	
04.03.2003	46737,1	-0,00138029	1182,17	-0,01535066		6191	-0,00120997	1182,17	-0,01535066	
05.03.2003	46537,1	-0,00427926	1193,87	0,00989705		6164,8	-0,00423195	1193,87	0,00989705	
06.03.2003	46206,1	-0,0071126	1182,82	-0,00925561		6140	-0,00402284	1182,82	-0,00925561	
07.03.2003	45188,9	-0,02201441	1192,61	0,00827683		6007,1	-0,02164495	1192,61	0,00827683	
10.03.2003	44778,6	-0,00907966	1161,85	-0,02579217		5971,5	-0,00592632	1161,85	-0,02579217	
11.03.2003	45196,4	0,00933035	1152,15	-0,00834875		5982	0,00175835	1152,15	-0,00834875	
12.03.2003	42676	-0,0557655	1157,61	0,00473897		5648	-0,05583417	1157,61	0,00473897	
13.03.2003	44927,6	0,05276033	1197,56	0,03451076		5901,7	0,04491856	1197,56	0,03451076	
14.03.2003	45746,2	0,01822043	1199,55	0,00166171		6007,9	0,01799482	1199,55	0,00166171	
17.03.2003	47097,8	0,02954562	1242,09	0,0354633		6216,2	0,03467102	1242,09	0,0354633	
18.03.2003	47210,9	0,00240139	1247,39	0,004267		6140,1	-0,01224221	1247,39	0,004267	
19.03.2003	47470,7	0,00550297	1258,37	0,00880238		6235,3	0,01550463	1258,37	0,00880238	
20.03.2003	47377,5	-0,00196332	1260,76	0,00189928		6158,8	-0,01226886	1260,76	0,00189928	

Exhibit 4.5

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
RRR		100,00%												
percentage			100%	90%	81%	73%	66%	60%	54%	49%	44%	40%	36%	32%
oil lifted		*1440*	1.400,00	1.263,27	1.139,89	1.028,57	928,11	837,47	755,68	681,88	615,28	555,19	500,97	452,04
cumulative oil lifted			1.400,00	2.663,27	3.803,16	4.831,73	5.759,84	6.597,31	7.352,99	8.034,87	8.650,15	9.205,34	9.706,31	10.158,35
Europe	*32,61%*													
Production (mboe):	469,66		456,61	412,01	371,78	335,47	302,70	273,14	246,46	222,39	200,67	181,07	163,39	147,43
Oil price (Brent) $/bbl			23,52	22,52	23,25	24,29	25,25	26,06	27,15	28,17	29,21	30,54	31,58	32,68
Total revenue			10.740,21	9.279,36	8.644,61	8.149,59	7.642,91	7.118,43	6.692,49	6.265,78	5.861,19	5.529,37	5.159,26	4.817,85
Production expenses	18,57%		1.994,78	1.723,46	1.605,56	1.513,62	1.419,52	1.322,11	1.243,00	1.163,74	1.088,60	1.026,97	958,23	894,82
Taxes	46,30%		3.297,26	2.848,78	2.653,91	2.501,94	2.346,39	2.185,37	2.054,61	1.923,61	1.799,40	1.697,53	1.583,90	1.479,09
Development costs			508,90	508,90	508,90	1.672,10	1.672,10	1.672,10						
Net CF			4.939,27	4.198,22	3.876,24	2.461,93	2.204,91	1.938,85	3.394,89	3.178,43	2.973,19	2.804,88	2.617,13	2.443,94
Discounted Net CF@	**7,20%**		4.607,43	3.653,07	3.146,30	1.864,07	1.557,30	1.277,39	2.086,42	1.822,15	1.589,98	1.399,20	1.217,83	1.060,84
USA	*17,17%*													
Production:	247,21		240,34	216,87	195,69	176,58	159,33	143,77	129,73	117,06	105,63	95,31	86,00	77,60
Oil price (WTI)			26,03	24,92	25,73	26,89	27,94	28,84	30,05	31,18	32,32	33,79	34,95	36,16
Total revenue			6.256,31	5.405,34	5.035,60	4.747,24	4.452,09	4.146,58	3.898,46	3.649,90	3.414,22	3.220,93	3.005,34	2.806,46
Production expenses	15,84%		991,05	856,25	797,68	752,00	705,24	656,85	617,54	578,17	540,84	510,22	476,07	444,56
Taxes	32,30%		1.700,93	1.469,57	1.369,05	1.290,65	1.210,41	1.127,35	1.059,89	992,31	928,24	875,69	817,07	763,00
Development costs			239,94	239,94	239,94	788,39	788,39	788,39						
Net CF			3.324,39	2.839,58	2.628,93	1.916,20	1.748,05	1.573,99	2.221,03	2.079,42	1.945,14	1.835,03	1.712,20	1.598,89
Discounted Net CF@	**7,24%**		3.099,90	2.469,02	2.131,49	1.448,71	1.232,34	1.034,70	1.361,44	1.188,56	1.036,73	912,00	793,49	690,94
Africa	*10,77%*													
Production:	155,07		150,76	136,04	122,75	110,76	99,95	90,18	81,38	73,43	66,26	59,79	53,95	48,68
Oil price (Bonny)			23,93	22,92	23,66	24,72	25,69	26,52	27,63	28,67	29,72	31,07	32,13	33,25
Total revenue			3.608,42	3.117,61	2.904,35	2.738,04	2.567,81	2.391,60	2.248,49	2.105,13	1.969,20	1.857,72	1.733,37	1.618,66
Production expenses	15,71%		566,75	489,66	456,17	430,04	403,31	375,63	353,15	330,64	309,29	291,78	272,25	254,23
Taxes	47,04%		1.430,71	1.236,11	1.151,55	1.085,61	1.018,12	948,25	891,51	834,67	780,77	736,57	687,27	641,79
Development costs			570,66	570,66	570,66	1.875,01	1.875,01	1.875,01						
Net CF			1.040,30	821,19	725,98	(652,63)	(728,63)	(807,29)	1.003,83	939,83	879,14	829,37	773,85	722,64
Discounted Net CF@	**7,20%**		970,43	714,58	589,30	(494,18)	(514,67)	(531,94)	617,01	538,87	470,22	413,81	360,18	313,75
Asia	*16,48%*													
Production:	237,31		230,72	208,19	187,85	169,51	152,95	138,01	124,53	112,37	101,40	91,49	82,56	74,50
Oil price (Tapis)			25,17	24,10	24,89	26,00	27,02	27,89	29,06	30,15	31,26	32,68	33,79	34,97
Total revenue			5.807,97	5.017,99	4.674,74	4.407,04	4.133,05	3.849,43	3.619,09	3.388,34	3.169,55	2.990,11	2.789,97	2.605,34
Production expenses	18,72%		1.087,41	939,51	875,24	825,12	773,82	720,72	677,59	634,39	593,43	559,83	522,36	487,79
Taxes	24,41%		1.152,44	995,69	927,58	874,46	820,10	763,82	718,11	672,33	628,92	593,31	553,60	516,96
Development costs			194,83	194,83	194,83	640,17	640,17	640,17						
Net CF			3.373,28	2.887,96	2.677,08	2.067,29	1.898,96	1.724,72	2.223,38	2.081,62	1.947,21	1.836,97	1.714,01	1.600,59
Discounted Net CF@	**7,26%**		3.144,83	2.510,03	2.169,17	1.561,63	1.337,33	1.132,36	1.360,89	1.187,83	1.035,88	911,05	792,50	689,93
M.East&Russia	*15,73%*													
Production:	226,48		220,19	198,69	179,28	161,77	145,97	131,72	118,85	107,25	96,77	87,32	78,79	71,10
Oil price (Urals)			22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27
Total revenue			4.955,46	4.281,43	3.988,56	3.760,16	3.526,39	3.284,39	3.087,87	2.890,99	2.704,31	2.551,21	2.380,45	2.222,92
Production expenses	17,12%		848,40	733,00	682,86	643,76	603,74	562,31	528,66	494,95	462,99	436,78	407,55	380,58
Taxes	43,72%		1.795,50	1.551,28	1.445,17	1.362,41	1.277,71	1.190,03	1.118,82	1.047,49	979,85	924,38	862,50	805,43
Development costs			760,04	760,04	760,04	2.497,29	2.497,29	2.497,29						
Net CF			1.551,51	1.237,10	1.100,49	(743,30)	(852,35)	(965,23)	1.440,38	1.348,55	1.261,47	1.190,06	1.110,40	1.036,92
Discounted Net CF@	**7,21%**		1.447,17	1.076,31	893,07	(562,64)	(601,80)	(635,67)	884,80	772,68	674,18	593,25	516,31	449,72
Western Hemisphere	*7,24%*													
Production:	87,97		101,38	91,48	82,54	74,48	67,21	60,64	54,72	49,38	44,55	40,20	36,28	32,73
Oil price (Urals)			22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27
Total revenue			2.281,56	1.971,23	1.836,39	1.731,23	1.623,60	1.512,18	1.421,70	1.331,05	1.245,10	1.174,61	1.095,99	1.023,46
Production expenses	26,99%		615,81	532,05	495,66	467,27	438,22	408,15	383,73	359,26	336,06	317,04	295,82	276,24
Taxes	24,48%		407,82	352,35	328,25	309,45	290,21	270,30	254,12	237,92	222,56	209,96	195,91	182,94
Development costs			103,29	103,29	103,29	339,38	339,38	339,38						
Net CF			1.154,64	983,54	909,19	615,13	555,78	494,35	783,84	733,87	686,48	647,62	604,27	564,28
Discounted Net CF@	**7,26%**		1.076,44	854,83	736,70	464,67	391,41	324,57	479,78	418,77	365,20	321,19	279,40	243,24

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
RRR													
percentage	29%	26%	24%	21%	19%	17%	16%	14%	13%	12%	10%	10%	10%
oil lifted	407,89	368,06	332,11	299,68	270,41	244,00	220,17	198,67	179,26	161,76	145,96	145,96	145,96
cumulative oil lifted	10.566,24	10.934,30	11.266,41	11.566,08	11.836,49	12.080,49	12.300,66	12.499,32	12.678,58	12.840,34	12.986,30	13.132,26	13.278,21
Europe													
Production (mboe):	133,03	120,04	108,32	97,74	88,19	79,58	71,81	64,79	58,47	52,76	47,60	47,60	47,60
Oil price (Brent) $/bbl	33,64	34,72	36,05	37,54	38,87	40,46	41,70	43,18	44,93	46,46	48,48	49,57	51,60
Total revenue	4.475,61	4.167,98	3.904,71	3.669,03	3.427,65	3.220,19	2.994,66	2.798,06	2.627,04	2.450,84	2.307,95	2.359,72	2.456,54
Production expenses	831,26	774,12	725,22	681,45	636,62	598,09	556,20	519,68	487,92	455,19	428,66	438,27	456,25
Taxes	1.374,02	1.279,58	1.198,75	1.126,40	1.052,30	988,60	919,37	859,01	806,51	752,41	708,54	724,44	754,16
Development costs													
Net CF	2.270,33	2.114,28	1.980,74	1.861,18	1.738,74	1.633,50	1.519,10	1.419,37	1.332,62	1.243,23	1.170,75	1.197,01	1.246,12
Discounted Net CF@	919,27	798,57	697,87	611,69	533,06	467,15	405,25	353,20	309,34	269,20	236,47	225,54	219,02
USA													
Production:	70,02	63,18	57,01	51,45	46,42	41,89	37,80	34,11	30,77	27,77	25,06	25,06	25,06
Oil price (WTI)	37,23	38,43	39,89	41,54	43,01	44,78	46,15	47,79	49,73	51,41	53,65	54,86	57,11
Total revenue	2.607,10	2.427,90	2.274,54	2.137,26	1.996,65	1.875,80	1.744,43	1.629,91	1.530,29	1.427,65	1.344,41	1.374,56	1.430,97
Production expenses	412,98	384,60	360,30	338,56	316,28	297,14	276,33	258,19	242,41	226,15	212,96	217,74	226,68
Taxes	708,80	660,08	618,39	581,06	542,84	509,98	474,26	443,13	416,04	388,14	365,51	373,71	389,04
Development costs													
Net CF	1.485,31	1.383,22	1.295,85	1.217,64	1.137,53	1.068,68	993,83	928,59	871,83	813,36	765,94	783,12	815,25
Discounted Net CF@	598,51	519,74	454,03	397,81	346,54	303,58	263,26	229,36	200,80	174,68	153,39	146,24	141,96
Africa													
Production:	43,92	39,63	35,76	32,27	29,12	26,28	23,71	21,39	19,30	17,42	15,72	15,72	15,72
Oil price (Bonny)	34,23	35,33	36,68	38,20	39,55	41,18	42,44	43,94	45,72	47,27	49,33	50,44	52,51
Total revenue	1.503,68	1.400,33	1.311,88	1.232,69	1.151,60	1.081,90	1.006,13	940,07	882,62	823,42	775,41	792,80	825,33
Production expenses	236,17	219,94	206,05	193,61	180,87	169,93	158,02	147,65	138,63	129,33	121,79	124,52	129,63
Taxes	596,20	555,22	520,15	488,75	456,60	428,96	398,92	372,73	349,95	326,48	307,44	314,34	327,24
Development costs													
Net CF	671,31	625,17	585,68	550,33	514,12	483,01	449,18	419,69	394,04	367,61	346,18	353,94	368,46
Discounted Net CF@	271,89	236,19	206,41	180,93	157,67	138,18	119,87	104,48	91,50	79,63	69,95	66,72	64,79
Asia													
Production:	67,22	60,66	54,73	49,39	44,56	40,21	36,28	32,74	29,54	26,66	24,05	24,05	24,05
Oil price (Tapis)	36,01	37,16	38,58	40,18	41,59	43,31	44,63	46,22	48,09	49,72	51,89	53,05	55,23
Total revenue	2.420,27	2.253,91	2.111,55	1.984,10	1.853,57	1.741,38	1.619,42	1.513,10	1.420,62	1.325,34	1.248,07	1.276,06	1.328,42
Production expenses	453,14	422,00	395,34	371,48	347,04	326,03	303,20	283,30	265,98	248,14	233,67	238,91	248,72
Taxes	480,24	447,23	418,98	393,69	367,79	345,53	321,33	300,24	281,89	262,98	247,65	253,20	263,59
Development costs													
Net CF	1.486,89	1.384,69	1.297,22	1.218,93	1.138,74	1.069,81	994,89	929,57	872,76	814,22	766,75	783,95	816,11
Discounted Net CF@	597,52	518,76	453,08	396,90	345,68	302,76	262,49	228,65	200,13	174,06	152,81	145,66	141,37
M.East&Russia													
Production:	64,15	57,89	52,23	47,13	42,53	38,38	34,63	31,25	28,19	25,44	22,96	22,96	22,96
Oil price (Urals)	32,19	33,22	34,49	35,92	37,19	38,72	39,90	41,32	42,99	44,45	46,39	47,43	49,37
Total revenue	2.065,01	1.923,08	1.801,61	1.692,86	1.581,49	1.485,77	1.381,72	1.291,00	1.212,10	1.130,80	1.064,87	1.088,76	1.133,43
Production expenses	353,54	329,24	308,44	289,83	270,76	254,37	236,56	221,03	207,52	193,60	182,31	186,40	194,05
Taxes	748,21	696,78	652,77	613,37	573,02	538,34	500,63	467,77	439,18	409,72	385,83	394,49	410,67
Development costs													
Net CF	963,26	897,05	840,39	789,66	737,71	693,06	644,52	602,21	565,40	527,48	496,73	507,87	528,71
Discounted Net CF@	389,68	338,49	295,79	259,24	225,90	197,96	171,71	149,65	131,06	114,04	100,17	95,53	92,76
Western Hemisphere													
Production:	29,54	26,65	24,05	21,70	19,58	17,67	15,94	14,39	12,98	11,71	10,57	10,57	10,57
Oil price (Urals)	32,19	33,22	34,49	35,92	37,19	38,72	39,90	41,32	42,99	44,45	46,39	47,43	49,37
Total revenue	950,76	885,41	829,48	779,42	728,14	684,07	636,16	594,40	558,07	520,64	490,28	501,28	521,85
Production expenses	256,62	238,98	223,89	210,37	196,53	184,64	171,71	160,43	150,63	140,52	132,33	135,30	140,85
Taxes	169,95	158,27	148,27	139,32	130,15	122,28	113,71	106,25	99,75	93,06	87,64	89,60	93,28
Development costs													
Net CF	524,20	488,17	457,33	429,73	401,46	377,16	350,74	327,72	307,69	287,05	270,31	276,38	287,72
Discounted Net CF@	210,66	182,89	159,74	139,93	121,87	106,74	92,54	80,61	70,56	61,37	53,88	51,35	49,84

2029	2030	2031	2032	2033	2034	
10%	10%	10%	10%	10%	10%	
145,96	145,96	145,96	145,96	145,96	145,96	
13.424,17	13.570,13	13.716,09	13.862,05	14.008,00	14.153,96	
47,60	47,60	47,60	47,60	47,60	47,60	
53,39	55,52	57,18	59,35	61,79	64,18	
2.541,56	2.643,21	2.722,12	2.825,16	2.941,61	3.055,18	
472,04	490,92	505,58	524,72	546,35	567,44	
780,26	811,47	835,70	867,33	903,08	937,95	
1.289,25	1.340,81	1.380,85	1.433,12	1.492,19	1.549,80	
211,37	205,06	196,99	190,71	185,23	179,46	32.496,52
25,06	25,06	25,06	25,06	25,06	25,06	
59,09	61,45	63,28	65,68	68,39	71,03	
1.480,49	1.539,70	1.585,67	1.645,69	1.713,53	1.779,68	
234,52	243,90	251,18	260,69	271,44	281,91	
402,51	418,60	431,10	447,42	465,86	483,85	
843,46	877,20	903,39	937,58	976,23	1.013,92	
136,96	132,81	127,54	123,43	119,84	116,06	22.085,95
15,72	15,72	15,72	15,72	15,72	15,72	
54,33	56,50	58,19	60,39	62,88	65,31	
853,90	888,05	914,56	949,18	988,30	1.026,46	
134,12	139,48	143,64	149,08	155,23	161,22	
338,56	352,10	362,62	376,34	391,85	406,98	
381,22	396,46	408,30	423,76	441,22	458,26	
62,53	60,66	58,28	56,42	54,80	53,10	5.581,46
24,05	24,05	24,05	24,05	24,05	24,05	
57,14	59,42	61,20	63,51	66,13	68,69	
1.374,40	1.429,36	1.472,04	1.527,76	1.590,73	1.652,15	
257,33	267,62	275,61	286,04	297,83	309,33	
272,71	283,62	292,09	303,14	315,64	327,83	
844,36	878,13	904,34	938,58	977,26	1.014,99	
136,36	132,20	126,93	122,81	119,22	115,43	22.506,32
22,96	22,96	22,96	22,96	22,96	22,96	
51,08	53,13	54,71	56,78	59,12	61,41	
1.172,66	1.219,56	1.255,97	1.303,51	1.357,24	1.409,64	
200,77	208,79	215,03	223,17	232,37	241,34	
424,89	441,88	455,07	472,30	491,77	510,75	
547,01	568,88	585,87	608,04	633,11	657,55	
89,52	86,84	83,42	80,75	78,43	75,98	8.564,41
10,57	10,57	10,57	10,57	10,57	10,57	
51,08	53,13	54,71	56,78	59,12	61,41	
539,91	561,50	578,27	600,15	624,89	649,02	
145,73	151,55	156,08	161,99	168,66	175,18	
96,51	100,37	103,36	107,28	111,70	116,01	
297,68	309,58	318,82	330,89	344,53	357,83	
48,07	46,61	44,75	43,30	42,03	40,70	7.603,72
		Total Developed and Undeveloped				98.838,37
					Developed	80494,076
					Undeveloped	**18344,2929**

WACC

Rf	**5,00%**	20 years US Bonds
Rm	**4,50%**	
Beta equity	**0,55**	**Beta is calculated from the comparison to AMEX Oil and Gas Index both for Shell and Royal Dutch**
Debt RDS (M$)	**10974**	
Equity RDS	**181679**	**Data from company reports**
Leverage RDS Group	**6%**	
Rd	**5%**	

RDS Equity is calculated as RD equity+Shell Equity: #Shell stocks 9667M*$7.505 + #RD stocks 2083*$52.39

Developed reserves 31.12.2003(mboe):

	Group	Interests
Oil liquids	3.512,00	672,00
Gas (at 5800 eq.)	3.532,76	330,00
Oil sand	652,00	(143,00)
	7.696,76	859,00
Total	**8.555,76**	

Developed and undeveloped reserves 31.12.2003(mboe):

	Group	Interests
Oil liquids	5.723,00	643,00
Gas (at 5800 eq.)	7.172,59	287,24
Oil sand	652,00	(143,00)
	13.547,59	787,24
Total	**14.334,83**	

Allocation to the regions based on production level in 2003; Expenses allocation and taxes are based on Standardized CF; Oil prices are calculated based on the relative price to Crude Oil and results of the simulation; Development costs are allocated based on company's projection to spend $7000M in next 3 years and another $23000M from 2007 till 2009

Exhibit 4.6

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
RRR	100,00%																						
percentage		100%	84%	70%	59%	49%	41%	34%	29%	24%	20%	17%	14%	12%	10%	8%	7%	6%	5%	4%	3%	3%	
oil lifted	*1440*	1.400,00	1.170,91	979,31	819,07	685,04	572,95	479,19	400,78	335,20	280,35	234,48	196,11	164,02	137,18	114,73	95,96	80,26	67,12	56,14	46,95	39,27	
cumulative oil lifted		1.400,00	2.570,91	3.550,23	4.369,30	5.054,34	5.627,28	6.106,48	6.507,26	6.842,46	7.122,81	7.357,29	7.553,40	7.717,42	7.854,60	7.969,33	8.065,29	8.145,54	8.212,67	8.268,81	8.315,76	8.355,03	
Europe	*32,61%*																						
Production (mboe):	469,66	456,61	381,89	319,40	267,14	223,43	186,87	156,29	130,71	109,33	91,44	76,47	63,96	53,49	44,74	37,42	31,30	26,18	21,89	18,31	15,31	12,81	
Oil price (Brent) $/bbl		23,52	22,52	23,25	24,29	25,25	26,06	27,15	28,17	29,21	30,54	31,58	32,68	33,64	34,72	36,05	37,54	38,87	40,46	41,70	43,18	44,93	
Total revenue		10.740,21	8.600,96	7.426,83	6.489,67	5.641,24	4.870,00	4.243,86	3.682,80	3.193,14	2.792,14	2.414,78	2.090,12	1.799,70	1.553,47	1.348,95	1.174,86	1.017,33	885,88	763,61	661,31	575,50	
Production expenses	18,57%	1.994,78	1.597,46	1.379,39	1.205,33	1.047,75	904,51	788,21	684,01	593,06	518,58	448,50	388,20	334,26	288,53	250,54	218,21	188,95	164,53	141,82	122,83	106,89	
Taxes	46,30%	3.297,26	2.640,51	2.280,05	1.992,34	1.731,87	1.495,10	1.302,87	1.130,63	980,30	857,19	741,34	641,67	552,51	476,92	414,13	360,68	312,32	271,97	234,43	203,02	176,68	
Net CF		5.448,17	4.362,99	3.767,39	3.292,00	2.861,62	2.470,40	2.152,78	1.868,17	1.619,78	1.416,36	1.224,94	1.060,25	912,93	788,02	684,28	595,97	516,06	449,38	387,35	335,46	291,93	
Discounted Net CF@	**7,20%**	5.082,14	3.796,45	3.057,95	2.492,56	2.021,13	1.627,59	1.323,05	1.071,00	866,21	706,55	570,00	460,22	369,65	297,64	241,09	195,87	158,21	128,51	103,33	83,48	67,77	24.720,49
USA	*17,17%*																						
Production:	247,21	240,34	201,01	168,12	140,61	117,60	98,36	82,26	68,80	57,54	48,13	40,25	33,67	28,16	23,55	19,70	16,47	13,78	11,52	9,64	8,06	6,74	
Oil price (WTI)		26,03	24,92	25,73	26,89	27,94	28,84	30,05	31,18	32,32	33,79	34,95	36,16	37,23	38,43	39,89	41,54	43,01	44,78	46,15	47,79	49,73	
Total revenue		6.256,31	5.010,17	4.326,22	3.780,31	3.286,10	2.836,84	2.472,10	2.145,28	1.860,04	1.626,46	1.406,64	1.217,52	1.048,35	904,91	785,78	684,37	592,61	516,04	444,81	385,22	335,24	
Production expenses	15,84%	991,05	793,65	685,31	598,83	520,54	449,38	391,60	339,83	294,64	257,64	222,82	192,86	166,07	143,35	124,47	108,41	93,87	81,74	70,46	61,02	53,10	
Taxes	32,30%	1.700,93	1.362,13	1.176,19	1.027,77	893,40	771,26	672,10	583,24	505,70	442,19	382,43	331,01	285,02	246,02	213,63	186,06	161,11	140,30	120,93	104,73	91,14	
Net CF		3.564,34	2.854,39	2.464,73	2.153,72	1.872,15	1.616,20	1.408,40	1.222,21	1.059,70	926,62	801,39	693,65	597,26	515,55	447,67	389,90	337,62	294,00	253,42	219,47	190,99	
Discounted Net CF@	**7,24%**	3.323,64	2.481,89	1.998,36	1.628,28	1.319,82	1.062,44	863,32	698,59	564,81	460,53	371,39	299,75	240,67	193,71	156,85	127,38	102,85	83,52	67,13	54,21	43,99	16.143,22
Africa	*10,77%*																						
Production:	155,07	150,76	126,09	105,46	88,20	73,77	61,70	51,60	43,16	36,10	30,19	25,25	21,12	17,66	14,77	12,36	10,33	8,64	7,23	6,05	5,06	4,23	
Oil price (Bonny)		23,93	22,92	23,66	24,72	25,69	26,52	27,63	28,67	29,72	31,07	32,13	33,25	34,23	35,33	36,68	38,20	39,55	41,18	42,44	43,94	45,72	
Total revenue		3.608,42	2.889,69	2.495,21	2.180,35	1.895,30	1.636,19	1.425,82	1.237,32	1.072,81	938,08	811,30	702,22	604,65	521,92	453,21	394,72	341,79	297,63	256,55	222,18	193,35	
Production expenses	15,71%	566,75	453,86	391,91	342,45	297,68	256,98	223,94	194,34	168,50	147,34	127,43	110,29	94,97	81,97	71,18	62,00	53,68	46,75	40,29	34,90	30,37	
Taxes	47,04%	1.430,71	1.145,74	989,33	864,49	751,47	648,74	565,33	490,59	425,36	371,94	321,67	278,43	239,74	206,94	179,69	156,50	135,52	118,01	101,72	88,09	76,66	
Net CF		1.610,96	1.290,09	1.113,97	973,41	846,15	730,47	636,55	552,40	478,95	418,80	362,20	313,50	269,94	233,01	202,33	176,22	152,59	132,88	114,54	99,19	86,32	
Discounted Net CF@	**7,20%**	1.502,76	1.122,61	904,25	737,08	597,68	481,32	391,26	316,73	256,17	208,96	168,58	136,11	109,33	88,03	71,31	57,93	46,80	38,01	30,57	24,69	20,05	7.310,31
Asia	*16,48%*																						
Production:	237,31	230,72	192,97	161,39	134,98	112,89	94,42	78,97	66,05	55,24	46,20	38,64	32,32	27,03	22,61	18,91	15,81	13,23	11,06	9,25	7,74	6,47	
Oil price (Tapis)		25,17	24,10	24,89	26,00	27,02	27,89	29,06	30,15	31,26	32,68	33,79	34,97	36,01	37,16	38,58	40,18	41,59	43,31	44,63	46,22	48,09	
Total revenue		5.807,97	4.651,13	4.016,20	3.509,41	3.050,61	2.633,55	2.294,95	1.991,54	1.726,75	1.509,90	1.305,84	1.130,27	973,22	840,07	729,47	635,33	550,14	479,06	412,93	357,62	311,21	
Production expenses	18,72%	1.087,41	870,82	751,94	657,06	571,16	493,07	429,68	372,87	323,30	282,70	244,49	211,62	182,21	157,28	136,58	118,95	103,00	89,69	77,31	66,96	58,27	
Taxes	24,41%	1.152,44	922,90	796,91	696,35	605,31	522,56	455,37	395,17	342,63	299,60	259,11	224,27	193,11	166,69	144,74	126,06	109,16	95,06	81,94	70,96	61,75	
Net CF		3.568,12	2.857,41	2.467,34	2.156,00	1.874,14	1.617,91	1.409,90	1.223,50	1.060,83	927,60	802,24	694,38	597,90	516,09	448,15	390,31	337,98	294,31	253,69	219,70	191,19	
Discounted Net CF@	**7,26%**	3.326,46	2.483,48	1.999,23	1.628,64	1.319,84	1.062,23	862,97	698,16	564,34	460,05	370,93	299,31	240,27	193,35	156,52	127,09	102,60	83,29	66,93	54,04	43,84	16.143,66
M.East&Russia	*15,73%*																						
Production:	226,48	220,19	184,16	154,03	128,82	107,74	90,11	75,37	63,03	52,72	44,09	36,88	30,84	25,80	21,58	18,05	15,09	12,62	10,56	8,83	7,38	6,18	
Oil price (Urals)		22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27	32,19	33,22	34,49	35,92	37,19	38,72	39,90	41,32	42,99	
Total revenue		4.955,46	3.968,42	3.426,69	2.994,29	2.602,83	2.246,98	1.958,09	1.699,22	1.473,29	1.288,27	1.114,16	964,37	830,37	716,76	622,39	542,07	469,39	408,74	352,32	305,13	265,53	
Production expenses	17,12%	848,40	679,42	586,67	512,64	445,62	384,70	335,24	290,92	252,24	220,56	190,75	165,11	142,16	122,71	106,56	92,81	80,36	69,98	60,32	52,24	45,46	
Taxes	43,72%	1.795,50	1.437,87	1.241,58	1.084,91	943,08	814,15	709,47	615,67	533,81	466,78	403,69	349,42	300,87	259,70	225,51	196,41	170,07	148,10	127,66	110,56	96,21	
Net CF		2.311,55	1.851,13	1.598,43	1.396,73	1.214,13	1.048,14	913,38	792,63	687,24	600,94	519,72	449,84	387,34	334,34	290,33	252,86	218,95	190,66	164,35	142,33	123,86	
Discounted Net CF@	**7,21%**	2.156,11	1.610,54	1.297,16	1.057,26	857,23	690,27	561,07	454,15	367,29	299,57	241,66	195,10	156,70	126,16	102,18	83,01	67,05	54,46	43,79	35,37	28,71	10.484,92
Western Hemisphere	*7,24%*																						
Production:	87,97	101,38	84,79	70,92	59,31	49,61	41,49	34,70	29,02	24,27	20,30	16,98	14,20	11,88	9,93	8,31	6,95	5,81	4,86	4,07	3,40	2,84	
Oil price (Urals)		22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27	32,19	33,22	34,49	35,92	37,19	38,72	39,90	41,32	42,99	
Total revenue		2.281,56	1.827,12	1.577,69	1.378,61	1.198,38	1.034,54	901,53	782,34	678,32	593,14	512,98	444,01	382,31	330,01	286,56	249,58	216,11	188,19	162,21	140,48	122,25	
Production expenses	26,99%	615,81	493,15	425,83	372,10	323,45	279,23	243,33	211,16	183,09	160,09	138,46	119,84	103,19	89,07	77,34	67,36	58,33	50,79	43,78	37,92	33,00	
Taxes	24,48%	407,82	326,59	282,01	246,42	214,21	184,92	161,15	139,84	121,25	106,02	91,69	79,37	68,34	58,99	51,22	44,61	38,63	33,64	29,00	25,11	21,85	
Net CF		1.257,92	1.007,37	869,85	760,09	660,72	570,39	497,05	431,34	373,99	327,02	282,83	244,80	210,79	181,95	157,99	137,60	119,15	103,76	89,44	77,46	67,40	
Discounted Net CF@	**7,26%**	1.172,73	875,54	704,82	574,17	465,31	374,49	304,24	246,14	198,96	162,19	130,77	105,52	84,71	68,17	55,18	44,81	36,17	29,36	23,60	19,05	15,46	5.691,48
																						Undeveloped	**80.494,08**

Exhibit 4.7 (full version is available in soft copy)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
RRR	100,00%																
oil lifted	*1440*	0,00	92,36	160,58	209,50	243,07	264,52	276,48	281,09	280,08	274,84	266,49	255,93	243,87	230,88	217,38	203,72
cumulative oil lifted		0,00	92,36	252,93	462,43	705,51	970,03	1.246,51	1.527,61	1.807,69	2.082,53	2.349,02	2.604,95	2.848,82	3.079,70	3.297,08	3.500,79
Europe	*32,61%*																
Production (mboe):	469,66	0,00	30,12	52,37	68,33	79,28	86,27	90,18	91,68	91,35	89,64	86,92	83,47	79,54	75,30	70,90	66,44
Production (Disc)		0,00	26,11	42,26	51,33	55,44	56,17	67,74	64,11	59,47	54,33	49,05	43,85	38,90	34,29	30,05	26,22
Oil price (Brent) $/bbl		23,52	22,52	23,25	24,29	25,25	26,06	27,15	28,17	29,21	30,54	31,58	32,68	33,64	34,72	36,05	37,54
Total revenue		0,00	678,40	1.217,78	1.659,92	2.001,67	2.248,43	2.448,62	2.582,98	2.668,05	2.737,24	2.744,48	2.727,72	2.675,91	2.614,51	2.555,76	2.494,17
Production expenses	18,57%	0,00	126,00	226,18	308,30	371,77	417,60	454,78	479,74	495,54	508,39	509,73	506,62	497,00	485,59	474,68	463,24
Taxes	46,30%	0,00	208,27	373,86	509,60	614,52	690,27	751,73	792,98	819,10	840,34	842,56	837,42	821,51	802,66	784,62	765,71
Net CF		0,00	344,13	617,74	842,02	1.015,38	1.140,56	1.242,11	1.310,26	1.353,42	1.388,51	1.392,19	1.383,69	1.357,40	1.326,26	1.296,46	1.265,21
Discounted Net CF@	**7,41%**	0,00	298,26	498,45	632,52	710,10	742,58	752,88	739,37	711,00	679,09	633,89	586,53	535,67	487,26	443,43	402,87
Development costs		508,90	508,90	508,90	1.672,10	1.672,10	1.672,10										
Discounted@	**5,00%**	484,67	461,59	439,61	1.592,48	1.516,64	1.444,42										
		1.385,86			**4.553,54**												
USA	*17,17%*																
Production:	247,21	0,00	15,85	27,57	35,97	41,73	45,41	47,46	48,26	48,08	47,18	45,75	43,94	41,87	39,63	37,32	34,97
Production (Disc)		0,00	13,73	22,22	26,98	29,13	36,60	35,60	33,68	31,23	28,52	25,74	23,00	20,40	17,97	15,75	13,73
Oil price (WTI)		26,03	24,92	25,73	26,89	27,94	28,84	30,05	31,18	32,32	33,79	34,95	36,16	37,23	38,43	39,89	41,54
Total revenue		0,00	395,18	709,37	966,92	1.166,00	1.309,74	1.426,35	1.504,62	1.554,17	1.594,47	1.598,70	1.588,93	1.558,75	1.522,99	1.488,76	1.452,89
Production expenses	15,84%	0,00	62,60	112,37	153,17	184,70	207,47	225,94	238,34	246,19	252,58	253,25	251,70	246,92	241,25	235,83	230,15
Taxes	32,30%	0,00	107,44	192,86	262,88	317,00	356,08	387,79	409,07	422,54	433,50	434,64	431,99	423,78	414,06	404,76	395,00
Net CF		0,00	225,14	404,14	550,87	664,29	746,18	812,62	857,21	885,44	908,40	910,81	905,25	888,05	867,67	848,18	827,74
Discounted Net CF@	**7,45%**	0,00	225,14	404,14	550,87	664,29	746,18	812,62	857,21	885,44	908,40	910,81	905,25	888,05	867,67	848,18	827,74
Development costs		239,94	239,94	239,94	788,39	788,39	788,39										
Discounted@	**5,00%**	228,52	217,64	207,27	750,85	715,09	681,04										
		653,43			**2.146,98**												
Africa	*10,77%*																
Production:	155,07	0,00	9,95	17,29	22,56	26,18	28,49	29,77	30,27	30,16	29,60	28,70	27,56	26,26	24,86	23,41	21,94
Production (Disc)		0,00	8,62	13,95	16,95	18,31	18,55	22,37	21,17	19,64	17,94	16,20	14,48	12,85	11,32	9,93	8,66
Oil price (Bonny)		23,93	22,92	23,66	24,72	25,69	26,52	27,63	28,67	29,72	31,07	32,13	33,25	34,23	35,33	36,68	38,20
Total revenue		0,00	227,92	409,14	557,69	672,51	755,41	822,67	867,81	896,39	919,64	922,07	916,44	899,03	878,40	858,67	837,97
Production expenses	15,71%	0,00	35,80	64,26	87,59	105,63	118,65	129,21	136,30	140,79	144,44	144,82	143,94	141,20	137,96	134,86	131,61
Taxes	47,04%	0,00	90,37	162,22	221,12	266,64	299,51	326,18	344,08	355,41	364,63	365,59	363,36	356,46	348,28	340,45	332,25
Net CF		0,00	101,76	182,66	248,98	300,24	337,25	367,28	387,43	400,19	410,57	411,65	409,14	401,37	392,16	383,35	374,11
Discounted Net CF@	**7,41%**	0,00	88,20	147,39	187,04	209,99	219,60	222,65	218,66	210,27	200,84	187,47	173,47	158,43	144,12	131,16	119,16
Development costs		570,66	570,66	570,66	1.875,01	1.875,01	1.875,01										
Discounted@	**5,00%**	543,48	517,60	492,95	1.785,72	1.700,69	1.619,71										
		1.554,04			**5.106,12**												
Asia	*16,48%*																
Production:	237,31	0,00	15,22	26,46	34,53	40,06	43,59	45,56	46,32	46,16	45,29	43,92	42,18	40,19	38,05	35,82	33,57
Production (Disc)		0,00	13,18	21,32	25,88	27,93	28,28	34,15	32,30	29,95	27,34	24,67	22,04	19,54	17,21	15,08	13,15
Oil price (Tapis)		25,17	24,10	24,89	26,00	27,02	27,89	29,06	30,15	31,26	32,68	33,79	34,97	36,01	37,16	38,58	40,18
Total revenue		0,00	366,86	658,54	897,63	1.082,44	1.215,88	1.324,14	1.396,80	1.442,80	1.480,21	1.484,13	1.475,07	1.447,05	1.413,85	1.382,08	1.348,77

Production expenses	18,72%	0,00	68,69	123,30	168,06	202,66	227,65	247,92	261,52	270,13	277,14	277,87	276,17	270,93	264,71	258,76	252,53
Taxes	24,41%	0,00	72,79	130,67	178,11	214,78	241,26	262,74	277,16	286,29	293,71	294,49	292,69	287,13	280,54	274,24	267,63
Net CF		0,00	225,38	404,57	551,46	665,00	746,97	813,48	858,12	886,38	909,37	911,77	906,20	888,99	868,59	849,08	828,61
Discounted Net CF@	**7,48%**	0,00	195,11	325,88	413,29	463,71	484,64	491,08	481,99	463,23	442,18	412,51	381,47	348,19	316,53	287,89	261,41
Development costs		194,83	194,83	194,83	640,17	640,17	640,17										
Discounted@	**5,00%**	185,56	176,72	168,30	609,68	580,65	553,00										
		530,58			**1.743,33**												
M.East&Russia	*15,73%*																
Production:	226,48	0,00	14,53	25,26	32,95	38,23	41,60	43,49	44,21	44,05	43,23	41,91	40,25	38,36	36,31	34,19	32,04
Production (Disc)		0,00	12,59	20,37	24,75	26,73	27,08	32,66	30,91	28,67	26,19	23,64	21,13	18,75	16,52	14,48	12,63
Oil price (Urals)		22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27	32,19	33,22	34,49	35,92
Total revenue		0,00	313,01	561,88	765,87	923,56	1.037,41	1.129,78	1.191,77	1.231,02	1.262,94	1.266,29	1.258,55	1.234,65	1.206,32	1.179,21	1.150,79
Production expenses	17,12%	0,00	53,59	96,20	131,12	158,12	177,61	193,42	204,04	210,76	216,22	216,80	215,47	211,38	206,53	201,89	197,02
Taxes	43,72%	0,00	113,41	203,58	277,50	334,63	375,88	409,35	431,81	446,03	457,60	458,81	456,01	447,35	437,08	427,26	416,96
Net CF		0,00	146,01	262,10	357,25	430,81	483,92	527,00	555,92	574,23	589,12	590,68	587,07	575,92	562,71	550,06	536,81
Discounted Net CF@	**7,42%**	0,00	126,53	211,44	268,29	301,18	314,93	319,28	313,53	301,48	287,93	268,74	248,65	227,07	206,54	187,95	170,74
Development costs		760,04	760,04	760,04	2.497,29	2.497,29	2.497,29										
Discounted@	**5,00%**	723,85	689,38	656,55	2.378,37	2.265,11	2.157,25										
		2.069,79			**6.800,74**												
Western Hemisphere	*7,24%*																
Production:	87,97	0,00	6,69	11,63	15,17	17,60	19,16	20,02	20,36	20,28	19,90	19,30	18,53	17,66	16,72	15,74	14,75
Production (Disc)		0,00	5,79	9,37	11,37	12,27	12,43	15,01	14,19	13,16	12,01	10,84	9,69	8,59	7,56	6,63	5,78
Oil price (Urals)		22,51	21,55	22,25	23,24	24,16	24,94	25,98	26,96	27,95	29,22	30,21	31,27	32,19	33,22	34,49	35,92
Total revenue		0,00	144,11	258,70	352,62	425,22	477,64	520,17	548,71	566,78	581,48	583,02	579,45	568,45	555,40	542,93	529,84
Production expenses	26,99%	0,00	38,90	69,82	95,18	114,77	128,92	140,40	148,10	152,98	156,95	157,36	156,40	153,43	149,91	146,54	143,01
Taxes	24,48%	0,00	25,76	46,24	63,03	76,01	85,38	92,98	98,08	101,31	103,94	104,21	103,58	101,61	99,28	97,05	94,71
Net CF		0,00	79,46	142,63	194,41	234,44	263,34	286,79	302,53	312,49	320,59	321,44	319,48	313,41	306,22	299,34	292,12
Discounted Net CF@	**7,48%**	0,00	68,79	114,89	145,71	163,48	170,86	173,13	169,92	163,31	155,89	145,43	134,49	122,76	111,59	101,50	92,16
Development costs		103,29	103,29	103,29	339,38	339,38	339,38										
Discounted@	**5,00%**	98,37	93,69	89,22	323,22	307,83	293,17										
		281,28			**924,21**												

Exhibit 4.8

Scenario Structure	Historical 2	Historical	Company	Optimistic	Optimistic 2
RRR	95,00%	97,00%	100,00%	103,00%	105,00%
Undeveloped Reserves	19096,14865	18790,52223	18344,208	17911,98671	17631,3723

Exhibit 4.9

Additional capex 2%

First Option

t	1	2	3
Europe			
PV(X)	1455,154	1413,578	1441,85
Production (Disc)	231,3059	231,3059	231,3059
Oil price	29,86	29,86	29,86
S	2425,979	2425,979	2425,979
d1	2,887834	2,308694	1,956102
d2	2,695801	2,037118	1,62349
C	1041,948	1148,124	1188,602
US			
PV(X)	653,4282	666,4968	679,8267
Production (Disc)	128,6558	128,6558	128,6558
Oil price	32,55	32,55	32,55
S	2171,539	2171,539	2171,539
d1	6,480095	4,669151	3,883407
d2	6,288061	4,397574	3,550795
C	1549,979	1568,468	1586,408
Africa			
PV(X)	1554,037	1585,117	1616,82
Production (Disc)	76,37812	76,37812	76,37812
Oil price	30,14	30,14	30,14
S	857,6632	857,6632	857,6632
d1	-2,869084	-1,941717	-1,514344
d2	-3,061118	-2,213294	-1,846956
C	0,135482	3,097965	10,66601
Asia			
PV(X)	530,5795	541,1911	552,0149
Production (Disc)	116,5834	116,5834	116,5834
Oil price	31,7	31,7	31,7
S	2101,517	2101,517	2101,517
d1	7,393923	5,315325	4,411006
d2	7,201889	5,043748	4,078394
C	1596,814	1611,827	1626,393
M.East&Russia			
PV(X)	2069,79	2111,185	2153,409
Production (Disc)	111,5101	111,5101	111,5101
Oil price	28,34	28,34	28,34
S	1237,594	1237,594	1237,594
d1	-2,451855	-1,646691	-1,273456
d2	-2,643889	-1,918268	-1,606069
C	0,72618	9,039258	25,20031
Western Hemisphere			
PV(X)	281,2813	286,9069	292,645
Production (Disc)	51,22797	51,22797	51,22797
Oil price	28,34	28,34	28,34
S	704,5039	704,5039	704,5039
d1	5,007333	3,627751	3,033108
d2	4,815299	3,356174	2,700495
C	436,9409	444,9017	452,6413
Total First Option	**4626,544**	4785,458	4889,91

Second Option

t	4	5	6
Europe			
PV(X)	4553,543	4644,614	4737,506
Production (Disc)	646,6928	646,6928	646,6928
Oil price	31,9	31,9	31,9
S	7246,015	7246,015	7246,015
d1	1,661947	1,541534	1,45747
d2	1,277879	1,112134	0,987085
C	3543,405	3663,717	3778,956
US			
PV(X)	2146,978	2189,918	2233,716
Production (Disc)	339,0194	339,0194	339,0194
Oil price	36,18	36,18	36,18
S	6360,34	6360,34	6360,34
d1	3,280085	2,988841	2,778674
d2	2,896017	2,55944	2,308289
C	4602,565	4654,865	4705,566
Africa			
PV(X)	5106,12	5208,243	5312,408
Production (Disc)	213,5679	213,5679	213,5679
Oil price	33,75	33,75	33,75
S	2685,433	2685,433	2685,433
d1	-1,220733	-1,036813	-0,896228
d2	-1,604801	-1,466214	-1,366613
C	71,46136	113,3915	159,024
Asia			
PV(X)	1743,333	1778,199	1813,763
Production (Disc)	324,7076	324,7076	324,7076
Oil price	35,75	35,75	35,75
S	6600,936	6600,936	6600,936
d1	3,919015	3,560318	3,300358
d2	3,534948	3,130917	2,829974
C	5173,614	5216,058	5257,208
M.East&Russia			
PV(X)	6800,737	6936,752	7075,487
Production (Disc)	311,6232	311,6232	311,6232
Oil price	30,15	30,15	30,15
S	3679,436	3679,436	3679,436
d1	-1,146979	-0,970845	-0,836008
d2	-1,531046	-1,400246	-1,306393
C	112,3791	174,0205	240,0074
Western Hemisphere			
PV(X)	924,2099	942,6941	961,5479
Production (Disc)	142,6817	142,6817	142,6817
Oil price	30,15	30,15	30,15
S	2087,527	2087,527	2087,527
d1	2,573896	2,357206	2,202073
d2	2,189828	1,927806	1,731688
C	1331,148	1353,916	1376,003
Total First Option	14834,57	15175,97	15516,76

With option to wait	**20406,67**
Developed	**80494,08**
	100900,8
Without option to wait	**19461,12**
Developed	**80494,08**
	99955,19

PV(X) represents the present value of development costs discounted to the beginning of the project with the Rf = 5%. For the First Option - total amount of $7M discounted to the end of 2004.For the Second Option - $23M discounted to the end of 2007. S represents the net revenue from oil lifting discounted under the same principle under the regional Rwacc. The CF 2004-2009 is attributed to the First Option, CF of 2010-2024 is attributed to the Second Option

Exhibit 4.10

Scenario Structure (Cap Outlay = 2%)			
	Company	Historical	Optimistic
RRR	100,00%	95,00%	105,00%
With option to wait	20406,67	21040,25	19821,51

Scenario Structure (RRR=100%)			
	high	mid	low
Cap.Outlay	3,00%	2,00%	1,00%
With option to wait	20190,7	20406,67	20623,4

Scenario Structure			
	lowest	highest	base
RRR	105,00%	95,00%	100,00%
Cap.Outlay	3,00%	1,00%	2,00%
With option to wait	19608,47	21260,17	20406,67

Exhibit 4.11

Option to abandon

Cost of production/bbl	3,19
PV(X)	2282,96
S	9498,80
d1	7,65
d2	7,46
C	7327,18
P	111,34
	2,37%

Declaration of Authorship

I hereby confirm that I have authored this master thesis independently and without use of other than the indicated resource. All passages, which are literally of in general matter taken out of publications of other resources, are marked as such

Roman Kremer

Berlin, July 26, 2005