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The Impact of Project Flexibility on Project Choice and Capital Structure

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FULL COLOUR THINKING

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ABSTRACT

This research highlights the value of Real Options Analysis (ROA) as a process in the evaluation of an oil extraction project in Sub-Saharan Africa. It shows the benefits it can bring to not only the final project evaluation but also to the project design selection process. The research then extends the application of ROA by developing and applying a framework which incorporates the fact that project flexibility has a positive impact on the projects value in the face of downside risk. ROA, by virtue of its explicit cash flow volatility modelling provides a framework for a consideration of the optimal level of project debt. In this case it suggests that the project can carry more debt than would have been acceptable if the more traditional NPV method was used in its evaluation.

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GLOSSARY OF TERMS

BOPD	Barrels of Oil per Day
MBOPD	Thousand Barrels of Oil per Day
CPF	Central Processing Facility
DCF	Discounted Cash Flow
FPSO	Floating Production Storage Off-take
GBM	Geometric Brownian Motion
JV	Joint Venture
MMBBL	Million Barrels
NPV	Net Present Value
POD	Plan of Development
PSC	Production Sharing Contract
PV	Present Value
ROA	Real Options Analysis
TLP	Tension Leg Platform
VAR	Value at Risk
WACC	Weighted Average Cost of Capital

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1 INTRODUCTION

The upstream petroleum industry and indeed many other sectors of the economy have always focused on improving asset selection and the investment decision-making process. There are a variety of tools that attempt to determine which decision in any commercial situation will maximise the value of the firm. An important part of many of these approaches is the discounted cash flow (DCF) and net present value (NPV) methods which, in short state that the value of any investment is the present value of its future cash flows.

Unfortunately these traditional approaches have some severe limitations. They can't properly value investments whose cash flows are determined by future outcomes or on the development of more accurate and higher quality data through the life of the project and the ability of management to react to that data and make active decisions as the investment or project evolves. In addition, a single risk adjusted discount rate is often employed, typically the company's weighted average cost of capital (WACC), and this overlooks changes in the projects risk profile over time (Triantis, 2003).

Investment decisions and more specifically infrastructure or development projects require large sums of capital which often have a high sunk cost component therefore it is vital that the right decision is made. However, if a company is too risk adverse then opportunities can be lost which impacts their competitiveness alternatively if a company takes on too much risk they can unnecessarily expose themselves by taking on bad projects. The balance of debt and equity used to fund these projects or investments is also important. Too much equity and the company will see diluted returns from a successful project; however if the company is servicing a large amount of debt and it experiences the downside of a project then they could suffer cash flow problems or worse, be at risk of defaulting which may put the entire company's future at risk.

Maintaining these balances is key to success and this study will show how Real Options Analysis (ROA) can be used not only as a tool that adds value to the evaluation process but it can also provide a framework for determining the project's capital structure.

ROA is a way of recognising the value of flexibility inherent in capital investment projects. All projects have flexibility; even the ability to shut it down is worth something in that further losses are avoided and there may even be a salvage value in the project. Simply defined, real options analysis is the application of financial options, decision sciences, corporate finance and statistics to evaluate the flexibility inherent in real or physical assets as opposed to financial assets (Mun, 2006).

The research will focus on a project in the upstream oil and gas industry within the sub-Saharan region and use the project economics already derived using traditional methods of evaluation as a base to develop a real options model in order to show the benefits of using ROA in the evaluation of large infrastructure or development projects.

The review of this project will show that ROA is a tool that should be incorporated in the decision making process from the very beginning and when used in the concept selection phase ROA provides the ability to quantify or value the flexibility and options present in each of the concepts that are on the table. This enables management to make informed decisions on which concepts provide the greater flexibility and if the cost of purchasing that flexibility is worth it.

The project selected for this research is an offshore project involving the drilling of 43 production and injection wells and the installation of two deepwater floating platforms and four fixed platforms in shallower water, three of which are unmanned satellite platforms and one a platform housing a central processing facility which then exports the product via subsea pipeline to a Floating Production Storage (FPSO) vessel in a nearby field.

During the initial evaluation the concept selection phase was narrowed down to two main design concepts. In terms of capital investment and NPV analysis there was little difference between the two concepts however one of the concepts provided a higher level of flexibility in that it allowed for the drilling of future wells at a significantly reduced expense should there be a requirement to expand the project and increase production at a later date. Unlike NPV, the ROA was able to value this flexibility and show how having the ability to take advantage of any potential upside can enhance the overall value of a project and that this enhanced project value should be incorporated into the decision making process.

Under Government regulation the project had to make allowance for abandonment at the end of the field's economic life. This essentially means that wells are abandoned so that they are no longer a threat to the environment and all facilities and equipment are removed returning the seabed to its original state. Having the ability to abandon at any point in the projects life means the project is able to avoid further losses once the project becomes uneconomical due to the amount of reserves left in place, the price of oil or a combination of the two.

With the ability to mitigate against these downside losses the objective is be to then show how the ROA analysis can provide the basis for a framework to assess an optimised capital structure by using it to estimate the projects value at risk (VAR) and from that project a minimum level of equity that will be required to support the project.

1.1 Research Area

1.1.1 Project Description

Due to the commercially sensitive information provided in this report the project and company to which it belongs will remain anonymous. The company is a leading independent oil & gas, exploration and production group with a focus on four core regional areas, one of which is Africa. In this particular project the company is part of a group of companies or Joint Venture (JV) that own a license to a block offshore West Africa. The company is not a majority share holder and is also not the operator of the JV. The terms of the license are captured under a Production Sharing Contract (PSC) between the government and the JV.

The project is an offshore oil field development. A field Plan of Development (POD) was submitted to the relevant government in June 2004. This document, along with extracts of the PSC, forms the basis for the economic evaluation.

The POD describes the following key aspects of the project:

- The current understanding of the reservoirs within the field
- The planned producing infrastructure
- The schedule for implementation of the POD
- The costs for the development of the field
- An estimate of the production profile

The field came on-stream in 2007 with initial production exceeding all expectations. Production facilities that were designed to process 60 000 barrels of oil per day (bopd) had to be upgraded to accommodate up to 85 000 bopd. Oil prices have also increased significantly since the project was evaluated adding to the success of the project which has resulted in the JV executing plans to drill more wells in 2013 in order to exploit untapped reserves and maintain production levels as production begins to come off the plateau and slip down the production profile. This decision to expand is also based on production data that has increased the understanding of the reservoir as well as additional seismic data gathered during seismic acquisition campaigns executed after first oil. The JV is also able to take advantage of and an improvement in the technology of seismic data acquisition since 2004.

As shall be demonstrated the NPV and sensitivity analysis falls short at capturing the potential upside that was inherent in the project and is unable to adequately account for the ability to acquire new data and information over time which reduces the uncertainties and subsequently the risk profile of the project as it evolves. The ROA process provides an insight into the upside of a project without which managers may be led to under-invest in capital projects impacting on growth and shareholder value. The production data and oil price data from 2007 to date therefore provides an opportunity to take a retrospective look at this project and assess how a real options model could have identified and valued the flexibility that was inherent in this project.

Field Layout

The field is comprised of four main reservoirs each made up of numerous compartments, which for the purpose of this report shall simply be termed A, B, C & D. This section should be read in conjunction with the field layout diagrams presented in Appendix 5&6.

Reservoir A is located in the north-eastern part of the license block in 30-65m water depth. Reservoir B is located approximately 5km north-west of Reservoir A in water depths of 80-400m. Reservoir C is approximately 10km west, north-west of Reservoir A in water depths of 420-740m. Finally, Reservoir D is immediately adjacent to the north-east corner of Reservoir C.

The facilities currently in place today are in line with what was submitted with the POD. Centrally located, in the shallower waters of Reservoir A there is a Central Processing

Facility (CPF) with a bridged satellite (unmanned) platform There are also two additional satellite platforms to the to the North and South of the CPF. Reservoirs C and D were drilled from a tender assisted Tension Leg Platform (TLP) strategically located above Reservoir C. Likewise Reservoir B was also drilled from a tender assisted TLP. Both TLPs now act as production platforms.

Reservoir Summary

The four reservoirs were estimated to contain a total of 201 million barrels (MMbbl) of recoverable reserves. The development plan was expected to deliver a plateau of 60 000 bopd for approximately six years with a strategy that required 43 wells. Table 1.1 provides a summary of the reserves in place and number of wells required.

Table 1.1: Field Summary by Reservoir

Reservoir	Reserves (MMbbl)	Producing Wells	Water Injector Wells	Gas Injector Wells	Total Well Count
A	101	14	5	1	20
B	46	6	4	0	10
C	34	5	4	0	9
D	20	2	2	0	4
Total	**201**	**27**	**15**	**1**	**43**

Water and produced gas injection was designed to be implemented shortly after first oil to maintain operating pressures in all four reservoirs.

Drilling & Facilities Summary

Reservoir A was developed using a jack-up rig positioned over the platform structures. The three other reservoirs were developed using two TLPs in conjunction with tender-assisted platform drilling rigs.

Production facilities for the field consist of a CPF on a fixed platform at Reservoir A where fluid processing occurs. The three smaller satellite platforms support wells for both production and injection. The two TLPs support dry tree wells and limited process equipment. Access to wellbores through the use of dry production tress allow for lower cost Workover (well intervention) options compared to subsea trees and lead to reduced Workover expenses over the life of the field. Dry trees also allow for greater analysis of well performance leading to increased recovery and improved production rates.

It is beyond the scope of this report to discuss the sub-surface characteristics of the reservoirs which led to the strategy of location and number of producing and injector wells.

Concept Selection

The POD also makes reference to a concept development phase where a number of other design concepts were investigated. As work progressed through this phase and more information was gathered on the size of the reserves the focus was on two main options:

1. An all subsea development scheme with a Floating Production Storage Off-take Vessel (FPSO) as the main processing and storage facility.
2. A subsea development scheme with a conventional jacket structure located in Reservoir A housing processing equipment with the product routed to an FPSO in a nearby field.

The capital cost advantage made Option 2 the preferred alternative and the focus of further study work. Late in 2003 another variation of Option 2 was investigated which looked into the advantage to using dry tree units in Reservoirs B, C & D due to production experience gained in a nearby field. The initiative was primarily driven by:

- Reducing drilling and completion costs
- Improving flow assurance from the deepwater fields
- Providing increased flexibility in production operations
- Reducing well costs in the event that more were required to improve reservoir drainage

The last bullet point is part of the focus of this study and is due to the fact that by making use of a tender assisted drilling rig, drilling through a TLP platform the costs are far lower than a semi-submersible rig that would otherwise be required to drill when using subsea trees in the water depths at Reservoirs B, C & D. Dry trees were also expected to have a reduced operating cost but all these benefits would be offset by the capital costs of the platforms to support the dry tree units.

In terms of aggregated development and operating costs there was ultimately little difference between the subsea development option and the TLP option with dry trees feeding back to a CPF in shallower water and the product routed to an FPSO in a nearby field. The TLP option was selected on the basis that it eliminated any concerns about flow assurance, improved ease of operation, gave greater flexibility in terms of the future drilling of additional wells and permitted increased reservoir and production monitoring. Table 1.2 provides a summary of the basic functional requirements for each of the platforms and TLPs:

Table 1.2: Summary Platform Requirements

Reservoir	Platform	Drilling Method	Number of well slots	Approximate Water Depth
A	CPF		0	60m
A	Satellite 1 (North of Field)	Jack-up	6	71m
A	Satellite 2 (Bridged to CPF)	Jack-up	12	62m
A	Satellite 3 (South of Field)	Jack-up	9	45m
B	TLP	Tender-assisted Platform drilling rig	12	280m
C	TLP	Tender-assisted Platform drilling rig	16	515m

The subsea option that was considered simply replaced the TLP platforms shown above with subsea equipment.

Although there was very little information available on the initial concept selection phase and in the end there was little difference in the costs of the final two concepts this is certainly an area where ROA can be a valuable evaluation tool. As it shall be presented in this report, ROA provides the ability to quantify or value the flexibility and options present in each of the concepts enabling management to make informed decisions on which concepts provide the greater flexibility and if the cost of purchasing that flexibility makes financial sense.

1.2 Research Questions and Scope

The objective of the research was to select a project that had been valued based on traditional DCF/NPV methods and then build a Real Options Model for the project highlighting the value and benefits that ROA can bring when valuing a project or investment decision that has a high likelihood of receiving new information and has room for management flexibility.

The intention in this part of the study is to use a model that is simple, practical and easy for management to understand. The methodology described in Section 3 should enable the research results to be easily presentable to management in order for the benefits of ROA to be identified with little difficulty. Therefore management should be more willing and able to comfortably adopt the ROA approach as a supplement to the traditional valuation techniques when it comes to capital budgeting decision making.

Africa is a very dynamic environment to work in where variables are constantly changing. Many projects may not see the execution phase because of this and as a result a critical objective of this research is to use a real life project with real world risks and uncertainties, not a simplified hypothetical one, to show that ROA is an approach that can effectively value projects and investment decisions in Africa and elsewhere.

The research will discuss how to increase flexibility in projects, especially in Africa and again show how this flexibility can be valued without using calculus and sophisticated models. The methodology will also identify when options (defer, expansion, abandon) should be optimally exercised.

Once the Real Options Analysis is complete the objective will be to then link the analysis and model output to the company balance sheet. A large inflexible project requires flexible financing (less debt more equity) therefore if flexibility is built in for managements response as the project evolves and that flexibility is valued then it should be possible to obtain less flexible financing (more debt less equity). Using ROA the study will show that it is possible to fund a project with less equity than perhaps would have been initially thought if NPV was the only method of evaluating the project.

Optionality is a natural hedge against the downside risk of a project because in the face of present uncertainty it offers the option to scale down the project or abandon the project, which holds value when compared to the NPV version of the project which assumes it will continue regardless.

As ROA is based on the volatility of the projects rate of return and not the distribution of its total value the research will use ROA to look at how the project cash flows can potentially impact the projects capital structure and in turn the company's financial structure.

The real options process provides the ability to determine the project's VAR and develop a framework which has the ability to show how the flexibility can limit the projects exposure to downside risk and therefore demonstrate that the project can carry a higher amount of debt than originally anticipated.

Therefore the intended outcome of the research will be to show that optionality not only enhances the estimated value of the project but also offers increased financial risk management, which would feedback into the company financial structure.

2 LITERATURE REVIEW

2.1 Short Comings of Traditional Valuation Techniques

By revisiting the NPV formula and critiquing the way in which it is implemented we can quickly review the shortcomings:

$$NPV = \sum_{n=0}^{t} \frac{Net\ Cash\ Flows}{(1+r)^n}$$

Equation 2.1: Net Present Value

The discount rate (r) used in the above formula normally has two key roles:

- Take the time value of money into account (the risk free rate)
- Reflect associated risk of these cash flows (the risk premium)

Projects or investments with higher risk are allocated a higher risk premium. In the formula above this will reduce the NPV of the project, which goes against the notion of higher risk, equals higher reward.

The accuracy of the cash flows (and thus the valuation) relies on the ability of the analyst to predict the future value of key variables that will impact the project over time for example; exchange rates, inflation, selling prices, production volumes etc. this is clearly an impossible task. DCF thus implicitly assumes that all investment decisions are made now and cash flow streams are fixed for the future.

In essence the more traditional approaches of valuing an investment decision fail to account for flexibility and do not adequately deal with uncertainty. As a result the traditional tools for evaluating investment decisions are often questioned and criticised especially when it is felt the proposed investment or project should be executed for strategic reasons or because it offers the company flexibility or it may even form the stepping stone towards future growth opportunities.

A lot of the literature on ROA begins by delving into a critique on the traditional methods of evaluation. As this is well documented the literature review will not go any further into the shortcomings of DCF and NPV.

2.2 Real Options

The breakthrough in the valuation of financial options was made in the early 1970s by Fischer Black, and Myron Scholes (Black & Scholes, 1973) who won a Nobel Prize for their work. Since then hundreds of papers have followed on the topic.

Since the mid to late 1980s people began recognising the value in identifying options in investment decisions that involve real assets. (Brennan & Schwartz, 1985) were some of the early users of options pricing techniques for evaluating natural resource investments. They concluded that "In addition to providing a rich set of empirical research, this framework should be useful for the analysis of capital-budgeting decisions in a wide variety of situations in which the distribution of future cash flows is not given exogenously but must be determined by future management decisions."

A real option is simply defined as the right, but not the obligation, to take an action (e.g. deferring, expanding, contracting or abandoning) within an investment project involving real assets, at a predetermined cost called the exercise price, for a predetermined period of time – the life of the option. (Copeland & Antikarov, 2003)

(Copeland & Antikarov, 2003) provide the learning practitioner of real options with a sound framework from which to understand the fundamental theory of ROA. The authors explain that like their financial cousins real options depend on five basic variables:

1. Value of the underlying risky asset – this is a project, investment or acquisition. One of the important differences between financial and real options is that the owner of a financial option cannot affect the value of the underlying. But, the management that operates a real asset can raise its value and thereby raise the value of all real options that depend on it.
2. The exercise price – this is the investment cost and depends on the option e.g. additional investment to expand.
3. The time to expiration of the option - a longer time frame allows more to be learnt about the uncertainty and therefore increases the value.
4. The standard deviation of the underlying risky asset. The probability of exceeding the exercise price increases with volatility about the present value and therefore the value of the option increases with the riskiness of the underlying.

5. Risk-free rate of interest over the life of the option. As the risk free rate goes up, the value of the option also increases.

There is also an important sixth variable which is the dividends that may be paid out by the underlying asset however the research in this report does not explore the impact of dividend payouts.

The flexibility value comes in the ability to respond to information that may be received in the future. The greater the likelihood that this information will elicit a managerial response and alter the course of the project the more valuable the option will be. Real options essentially capture the contingencies that management can build into a project or opportunity.

2.3 Real Options in Oil Field Exploration and Development

ROA is currently utilised in a number of industries and the oil industry can almost certainly be considered a leader in the development of the concept. Applications of real options in the oil industry soon followed the options frame work established in the 1980s. A paper by (Paddock, Siegel, & Smith, 1988) uses option valuation theory to develop an approach to valuing offshore petroleum leases. They make a number of contributions to the literature of valuing options and the detail of the valuation problem allows the authors "to consider informational and computational economies of the option valuation methodology relative to conventionally applied discounted cash flow techniques."

(Copeland & Antikarov, 2003; Copeland, Koller, & Murrin, 2000) have also used a number of Oil industry examples in their books and there are numerous papers within the Society of Petroleum Engineers (SPE) library on the topic of ROA; (Galli, Jung, Armstrong, & Lhote, 2001) study the impact of additional wells on project value using real options, (Claeys & Walkup, 1999) discuss a series of practical framing techniques that uncover the managerial flexibility and learning that are hallmarks of real options, (De Abreu & Filho, 2009) discuss aspects of uncertainty in the economic evaluation of an exploratory project and apply the real options theory to a few simulated cases and (Lima & Suslick, 2002) compare results of portfolio selection of non-developed reserves using both traditional approaches and options timing. The list of interesting and informative applications of real options in the oil and gas sector continues on from this brief account.

The SPE papers on the subject of ROA show not only the benefit but also the versatility of options valuation in the exploration and development of oil fields. For example a paper by (Chorn & Croft, 1998) introduces the application of ROA in valuing data gathering during reservoir development. Exploration companies make phased investments in data gathering in order to gain more knowledge on the reservoir characteristics which results in reducing the level of uncertainty. The paper by (Chorn & Croft, 1998) shows that real options "provides a management tool to guide the execution of the project, optimising the outcome relative to the residual uncertainty at each decision point". They also state that real options can also provide an insight into when a project lacks upside potential when the uncertainties are small and flexibility is limited. This is an important aspect of the real options process as it not only provides a value for flexibility but the process itself uncovers aspects or particulars of the project that an NPV model wouldn't necessarily provide visibility on.

(Cortazar & Schwartz, 1997) developed a no arbitrage model for evaluating an undeveloped oil field and presented the numerical solution and implementation. The real options model developed in this paper provided several advantages such as not requiring estimates of risk premiums but rather using the risk free interest rates which are subject to far less estimating error. Cortazar & Schwartz also present a user-friendly computer program with graphical interface to help petroleum companies implement what they term a 'sophisticated valuation approach'.

(Lander & Pinches, 1998) concluded in their paper that the various techniques used for real option models are not well known or understood by corporate managers and practitioners and many individuals do not have the required mathematical skills to use the models comfortably and knowledgably.

Fortunately since the beginning of the 2000s technology has developed to bring the application of real options to a position where calculus is no longer a necessary tool. Instead, we can use lattices and algebraic solutions that are easy to implement and easy to understand (Copeland & Antikarov, 2003). A specific goal of this research is to use an options analysis method that is easy to understand and present to the senior management of organisations.

The work of (Copeland & Antikarov, 2003) has been instrumental in providing real options practitioners with the tools to develop practical models that can be used in a wide range of scenarios. Their work is continuously referenced in papers and articles on ROA.

(Dezen & Morooka, 2002) make use of these relatively simpler techniques compared to those developed through the 1990s to value alternatives for deepwater field development. Similar to the four step approach used by (Copeland & Antikarov, 2003), Dezen & Morooka use a three step approach which first builds the cash flow model and calculates the present value for each development plan. Secondly they identify the options present in each development plan and determine the variables needed for the equation developed by (Black & Scholes, 1973). In the third and final step they calculate the expanded NPV of the project or the value of the project including flexibility. Dezen & Morooka conclude that "As a decision making tool, Real Option Valuation can assist the process of selecting the optimal field development plan by providing to the company the insight into the value of managerial flexibility." Although this approach is easy to follow it makes use of a simple hypothetical field development and not an actual project, which is not the intention of this research which will also use a slightly more complex technique.

In a similar paper by (Dezen & Morooka, 2001) they propose that a field development using a FPSO may have a larger NPV than a subsea tieback to an existing facility, however by not valuing the option to defer the project to the last minute, which is possible in the subsea option because the development timeline is a lot shorter, the company may undertake an investment that is not as attractive as another development alternative. This could also be framed another way due to the volatility in the oil price, because by been able to delay the decision to invest gives the ability to avoid a down turn in the oil price and to also take advantage of any information that can still be acquired.

2.4 Real Option Valuation Methods

There is a wide range of literature on the topic of real options and its benefits but unfortunately few of these delve into the mechanics of the different approaches used and fewer still do this in a manner that is easily understood by the average practitioner. (Borison, 2005) provides an easy to follow comparison and critique of each of the more widely used concepts in ROA focussing on the fundamentals rather than granular details. By using a simplified example of a firm evaluating the possible acquisition of an undeveloped natural gas field in the United States, (Borison, 2005) looks at the applicability, assumptions and mechanics surrounding each of the approaches.

As the research presented in this report uses only one of the five concepts presented by Borison it is worth giving a short introduction to the step by step mechanics of each as presented by Borison.

The Classic Approach (No Arbitrage, Uses Market Data)

1. Identify a portfolio of traded investments that replicate the underlying asset in question and calculate its price and volatility
2. Size the investment relative to the replicating portfolio
3. Apply the equation developed by (Black & Scholes, 1973)

The Subjective Approach (No Arbitrage, Subjective Data)

This is the same as the classic approach except the value and volatility of the underlying investment is subjectively estimated

The Market Asset Disclaimer (MAD) Approach (Equilibrium Based, Subjective Data)

This is the approach used for this research and the methodology followed is as per Section 3 of this report.

The Revised Classic Approach (Two Investment Types)

1. Determine if the investment in question is dominated by public (market) or private (corporate) risks.
2. If public risks, apply the classic approach
3. If private risks, use decision tree analysis

The difficulty with this is that generally in reality there is a mix of both public and private risks which leads to the final concept.

The Integrated Approach (Two Risk Types)

In understanding the assumptions of this approach Borison cites earlier work from (J. Smith & McCardle, 1998) which states that ”the basic idea of the integrated valuation procedure is to use option pricing methods to value risks that can be hedged by trading existing securities and decision analysis procedures to value risks that cannot be hedged by trading." The approach is then designed around the fact that most investment decisions have to consider both public and private risks. In the case of an undeveloped oil or gas field the private risk is the amount of reserves and the public risk is the price of oil or gas per unit of measurement.

In summary it is clear that each of these approaches has differing assumptions leading to different mechanics. Perhaps the most important point to draw from this comparative exercise is that a practitioner of real options needs to understand the limitations and benefits of each of these approaches and select the one that best suits the investment in question, the information that is available and just as importantly the time and resources available for evaluation looking to achieve the level of scrutiny and quality that is deemed to be reasonable and practical.

Large engineering project by their nature come loaded with risks and when using the integrated approach it is vitally important that the risks are identified and evaluated at an early stage. (Mattar & Cheah, 2006) present the notion of private risk which, in this case, may either be correlated with the market or be unique. Mattar & Cheah also add that private risks have two additional characteristics in that they represent a substantial portion of the investor's current wealth and they are either not tradable in the securities markets or inhibited from trading by large agency costs. The authors show that it is important to distinguish between unique and private risks and demonstrate that "the methods chosen for pricing private risk can lead to decisively different real options values, exercise strategies and development policies. Effectively, the difference in real option values can be interpreted as a form of private risk premium.

2.5 Limitations of Real Options

When making a comparison between tools for valuing capital investments it is important that both the benefits and limitations of each concept are researched and although a vast majority of the literature explores the value of real options there is some work which questions the justification for using real options and cautions the practise of using a tool which can over value a project.

(Eschenbach, Neal, Henrie, Baker, & Hartman, 2007) conclude that the value of real options is more limited than many suggest. They suggest as an example that using a higher hurdle rate forces projects to wait until profitability is high, similar to a deferral option, although they do concede that it's difficult to translate risk into the hurdle rate and it's subjective. The authors analyse four case studies for different industry sectors and conclude that options are only needed when the NPV is marginal or slightly negative. In the experience of the authors most economic evaluations provide a clear Yes/No answer once the parameters have been analysed and weak models or indicators are often adequate. This is certainly true, if the information at hand clearly points to a profitable project meaning that the company should stop the analyses and execute the project. There is no point in paralysing the decision making process with over analysis. To quote the authors "The payoff comes from doing good projects – not from doing better-than-needed analysis."

While (Eschenbach et al., 2007) provide a valuable critique they also highlight some important benefits of real options in how it forces the analyst to contemplate the value of flexibility and to consider multiple options at time zero that may otherwise have been ignored.

A major failure of real options can lie not in the technique or method used but rather in management. If management fail to exercise their options optimally then this can destroy value. (Copeland & Tufano, 2004) state that "the real reason real options sometime turn out to be less valuable than predicted by models is that managers don't exercise their option rights in a timely rational manner." To demonstrate this point (Copeland & Tufano, 2004) use a simple stock put option example with a one year maturity presented to shows that by not being alert the option holder can destroy up to 64% of the option value depending on its volatility.

(Copeland & Tufano, 2004) also advise that companies will find real options much more user friendly if they move away from the Black Scholes Merton model which is essentially a cookie cutter approach to option valuation and invest time to build binomial spreadsheets and follow the Market Asset Disclaimer approach.

2.6 Linking the benefits of Real Options Analysis to the Corporate Balance Sheet

In the most general form, the Value at Risk (VaR) measures the potential loss in value of a risky asset or portfolio over a defined period for a given confidence interval (Damodaran, 2007). The secondary objective of this research report is to try link the ROA to the calculation of the project VaR and quantify the improvement in the VaR due to flexibility that ROA evaluates. This can then be used as an input into determining the projects leverage ratio assuming the project is analysed as a stand alone company or financed through the structures of Project Finance.

Unfortunately very little relevant literature has been found on this approach. There is, however, a large amount of work in the area of determining the optimal amount of debt and equity in financing corporate expansion projects. (Sarkar, 2011) as part of his work on optimal expansion financing used a real options model in a 'trade-off theory' setting to derive the optimal finance package and optimal investment trigger.

In this field of work the real options approach seems to generally be used in determining the timing of the investment decisions which unfortunately does not assist with the intention of this research which is to rather show how the output of a projects real options analysis can contribute to the financial risk assessment as well as the analyses of the project's sustainability and therefore its influence on the debt/equity ratio.

The work by (Trigeorgis, 1993) provides the best ground work into the secondary objective. His paper has two main sections, first it presents a comprehensive review of all the literature on real options up to 1993 which is summarised in a table presenting the various categories of real options, the sectors of industry where they are important and which authors have analysed them.The second part "takes a first step towards extending the real options literature to recognize interactions with financial flexibility."(Trigeorgis, 1993)

(Trigeorgis, 1993) initially assumes all equity financing and evaluates four different options in an oil extraction and refinery project example. The options are to defer, expand, abandon and to default on future investment outlays. In the next step the paper extends the analysis into a venture capital context and looks at the impact on value for the equity holder. (Trigeorgis, 1993) evaluates the benefits if staged financing and how this creates options such as an option for the lender to abandon or the option to review the financing terms later in the project depending on the optimal execution of abandonment and expansion options and how the risk profile for the project has subsequently changed at the different stages. (Trigeorgis, 1993) concludes that the interactions between a firm's operating decisions and financial decisions can be significant especially in large projects with high uncertainty and long duration with multi-staged investments or growth opportunities. Understanding these interactions and designing a flexible financing deal that recognises the value and reflects the evolution of the project risks over the life of the project can mean a difference between success or failure.

3 RESEARCH METHODOLOGY

3.1 Research Approach and Strategy

The crux of the research approach is to use an existing or past project as a case study to achieve the objectives outlined in Section 1.2. As the author has an engineering background in the upstream oil and gas industry the project was selected from the portfolio currently held by his employer. This made it possible to access the project specific data required for the research.

The first step in selecting the right project was to define some selection criteria. Real options have the greatest value when three key factors come together and these were used as the basis for the project selection criteria.

- Original NPV analysis should have a marginally positive or if possible a marginally negative NPV (if the project has a large NPV then the probability of exercising options that provide flexibility will be low, conversely if the NPV is hugely negative then no amount of flexibility is going to make it look attractive)
- There should be significant uncertainties in key areas (size of asset, price of inputs/outputs, Production volumes etc.)
- Mangers must have flexibility to respond to uncertainty as they receive new information over time i.e. have the ability to expand, contract, abandon the project
- Lastly, the project needs to be a past project in order to have results on which to base the findings.

In reality the main driver for project selection was availability of data and information because oil and gas development projects by their nature are executed over a long time period and in some cases the right level of data was not available. In the end the project selected provided a happy medium between the selection criteria and this limitation.

Once the project was selected and a solid understanding gained on how the project was executed through the Plan of Development Document and the Production Sharing Contract a large portion of time was dedicated to learning and understanding the methodology around Real Options Analysis. This was predominately text book research with specific reference to (Copeland & Antikarov, 2003) and (Mun, 2006). This was supplemented with secondary literature sources on the topic of Real Options which is presented in the Literature Review above.

3.2 Data Collection

Project economic data was gathered through a series of discussion or informal interviews with the company's Economic Manager. There was little electronic information available resulting in the bulk of this data been collected as hard copies that had been filed away in archives. This information consisted of emails, project specific reports and contracts, presentations made within the joint venture, numerous print outs of spreadsheets and outputs from software used to model the reservoirs.

All this information was collated and analysed in order to determine the data to be used to build the base case for the project. This is essentially all the inputs used in defining the original project specifics that were used to model the project and base the execution decision on. This was a time consuming task as the source data contained a large number of model runs that formed part of the sensitivity analysis carried out at the time making it difficult to distinguish between the base case and up or downside sensitivity runs.

Discussions were also held with the company Development Manager to gain an understanding into the concept selection phase of the project and a basic insight into the sub-surface characteristics that drove the concept decision. The Development Manager was also able to give a brief on where the project currently is today and provide the production data collected to date for the field.

3.3 Data Analysis Methods

3.3.1 The Four Step Process

The analysis of the information and data on the selected project followed the four step process as described by (Copeland & Antikarov, 2003) and conceptually shown below.

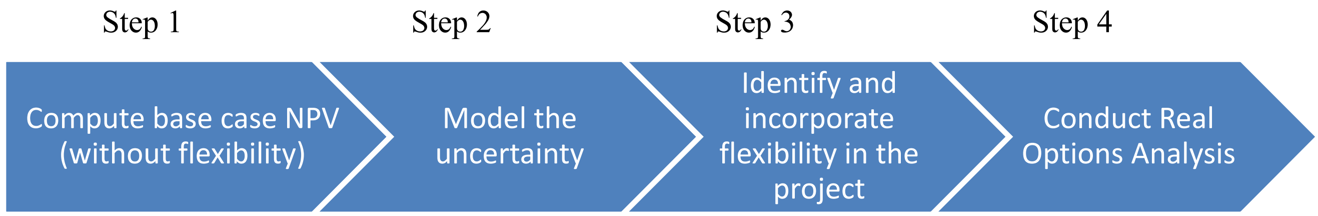

Figure 3.1: Four Step Process (Copeland and Antikarov, 2003)

Step 1: The base case NPV was derived from the source data and compared well with NPV figures shown in JV Partner presentations. This step also included a review of the business strategy at the time taking cognisance of the competitive advantage, goals for growth and technical approaches or advantages with a view to identifying the flexibilities that can be brought into the project in Step 3.

Step 2: This includes identifying the key sources of uncertainty relevant to the project and developing an understanding of how the present value develops over time.

Step 3: The flexibility the managers had at their disposal in order to respond to uncertainty as it evolved was identified and an event tree developed to incorporate these options. An important part of this step is that this is where the flexibility has altered the risk characteristics of the project and therefore the cost of capital has changed. Each of these options are then valued during the ROA in step 4. The event tree gives the ability to identify what the options are at each node.

Step 4: Conduct a real options analysis valuing the project using algebraic methodology and an excel spreadsheet. The ROA results include the base case NPV without flexibility plus the option (flexibility) value.

3.3.2 Binomial Lattice

The real options model that was developed made use of the binomial tree lattice and replicating portfolio approach. As the projects value has the ability to go negative the additive process rather than the multiplicative process was used in developing the binomial tree. In the additive process the up and down movements of the tree are calculated on the basis of the initial project present value (PV) and the estimate of the volatility of the project rate of return.

The present value of the project was taken from the base case NPV model and an estimate of the volatility of returns then used to construct the binomial lattice. The volatility of returns is based on a Monte Carlo analysis of the sources of uncertainty. The Monte Carlo analysis transforms the multiple uncertainties that drive the value of the project into a single uncertainty which is the distribution of returns on the project. This single estimate of volatility is what is needed to build the binomial tree.

The Monte Carlo simulation gives a probability of the projects value however as mentioned above the volatility needed for the binomial tree is the volatility of the rate of return. To convert the values the following formula is used from (Copeland & Antikarov, 2003):

$$\ln \frac{PV_t}{PV_0} = rt$$

Equation 3.1: Volatility of Projects Rate of Return

For t=1, this is a simple transformation that helps to convert between consecutive random draws of present value estimates in a Monte Carlo program and the standard deviation of the rate of return (project volatility).

3.3.3 The Replicating Portfolio Approach

The solution to a binomial lattice can be obtained in two ways. The first is the risk neutral probability approach and the second is the use of market replicating portfolios. The original intention was to use the Risk Neutral Probabilities approach as it is easier to construct within Excel. However during this process it was determined that this approach does not work with additive trees and the switch had to be made to the replicating portfolio approach. It is worth noting that this nuance was not clearly distinguished in the literature. The use of a replicating portfolio is more difficult to understand and apply, but the results obtained from replicating portfolios are identical to those through risk neutral probabilities (Mun, 2006), when using multiplicative trees.

The replicating portfolio approach consists of *m* units of a twin security and *B* units of the risk free bond and uses the assumption called the Market Asset Disclaimer (MAD) (Copeland & Antikarov, 2003). This basically states that the value of the cash flows of the project without flexibility derived from the base case NPV calculation is the best unbiased estimate of the market value of the project were it a traded asset.

The replicating portfolio approach values the option through the equation which is determined in (Copeland & Antikarov, 2003).

$$V = \left[\frac{Cu - Cd}{Vu - Vd}\right] \times V_0 + \left[\frac{Cu - \left[\frac{Cu - Cd}{Vu - Vd}\right] \times Cu}{1 + r_f}\right]$$

Where:

C_u = the up step value of the project with flexibility

C_d = the down step value of the project with flexibility

V_u = The up step value of the project without flexibility (The value of the underlying)

V_d = The down step value of the project without flexibility

V_0 = The underlying project value in the previous time step

r_f = Risk free rate

Equation 3.2: Value of the project with flexibility

This provides the value of the project including flexibility or the options at any point in time in the tree. By determining the maximum between the value of the project and the value of the option it can be decided whether or not to exercise the option. By valuing each time step in a backwards process from the end of the tree the final value of the project, including flexibility can be determined.

3.3.4 Value at Risk

The project value at risk is calculated using Monte Carlo simulation which is one of the three methods described by (Damodaran, 2007).

3.4 Limitations

The information that was gathered for the project was presented in annual time steps. To take full advantage of the real options process the time steps should coincide with the periods at which management can make decisions. This could be monthly or at quarterly or even biannual business reviews or perhaps when ever the Joint Venture partners meet. More time steps means a greater granularity can be achieved leading to an enhanced accuracy of the process. It was not possible to change the annual phasing of the capital and operational expenses as well as the annual production volumes into smaller time steps so the research had to remain with annual time steps.

Real options analysis is a process and therefore as it has been noted there was some difficulty experienced in trying to frame a project that has already been evaluated and executed into a real options model. The lesson taken from this is that ROA is a tool that needs to be incorporated in the decision making process right from the very beginning so that the data used in the analysis can be structured in a format that compliments the real options model.

4 RESEARCH FINDINGS, ANALYSIS AND DISCUSSION

4.1 Base Case NPV Analysis

The source data contained numerous NPV model outputs of spreadsheets making it difficult to determine exactly what the base case was that was originally evaluated. The Plan of Development and Production Sharing Contract along with presentations and other data on reserves provided a clearer picture of what the base case was and it was decided that the most practical solution was to build the base case NPV model from scratch using all the information collected as a platform to work from rather than rely on spreadsheet models from unknown authors.

Once the base case model for the TLP concept was constructed the cost data for the subsea option was then used to build an NPV model for the subsea concept that was also under consideration. The DCF for both options are provided in Appendix 1 & 2

Where possible the same assumptions and methodology that was used in the source data spreadsheets and printouts was used to build the NPV model for this research. The NPV model forms the basis of the ROA and needs to be constructed in the same way as those that evaluated the project did so at the time.

Unless otherwise indicated all results, figures and tables refer to the Base Case of the TLP Option.

4.1.1 Assumptions

Some of the basic assumptions made in the model are:

- The current year of the model is 2004
- The inflation rate throughout the life of the project is 2.5% and all costs incurred after 2004 are subject to inflation
- The first year of production is 2007
- The last year of production is 2026
- The life of the project is 22 years (2004 to 2026)
- Company overheads and loan repayments have not been included
- All shared and corporate costs are also not included in order to show project values only

4.1.2 Reserves

The amount of recoverable reserves in place as presented in the POD is 201 MMbbl. This amount presents the most likely scenario or P50 case. P50 meaning that there is a 50% chance of exceeding this amount. Modelling the reservoir and determining the amount of recoverable reserves has a number of uncertainties in terms of reservoir properties, porosity, trap size and geometry, seal containment, pressures and so forth. It is therefore not an exact science and the amount of recoverable reserves is a major source of uncertainty within the upstream oil & gas industry.

The P50 production profile for the field is shown below along with an upside and downside case, as presented in the source data, which is simply +/-20%. These two cases were part of the many sensitivities cases originally run which is why they are shown here.

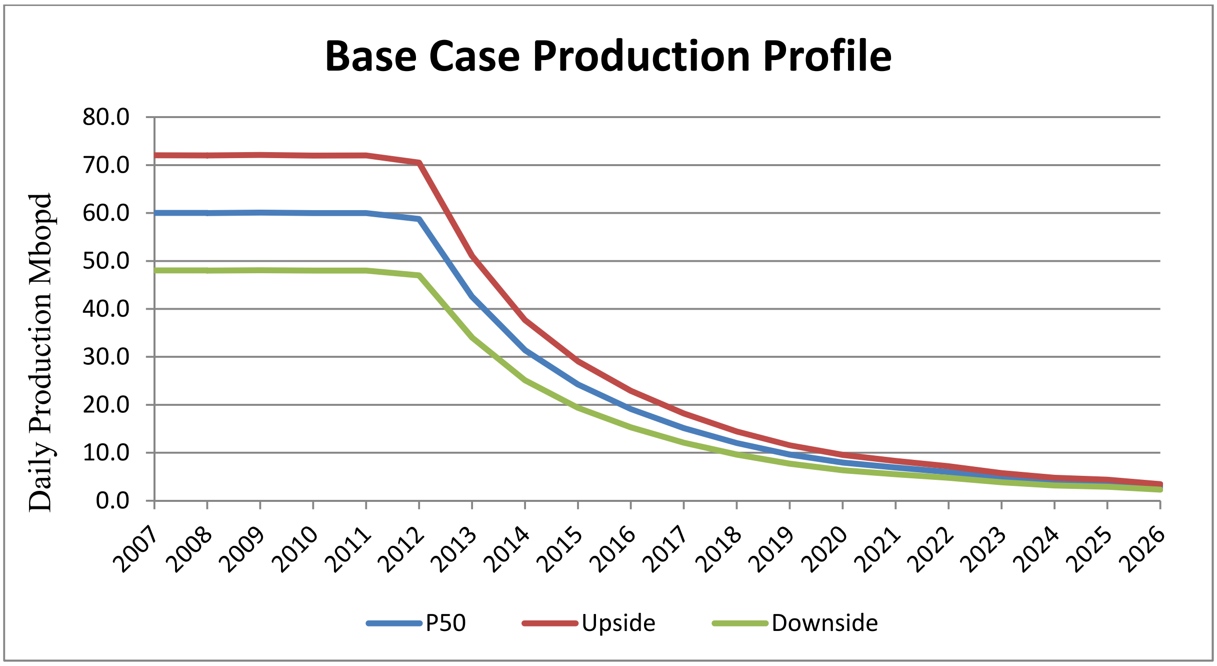

Figure 4.1: Base Case Production Profile

As it can be seen from the above curve the production has a peak plateau for approximately six years and then has a rapid decline down to the end of the life of the field.

4.1.3 Oil Price

The oil price for the NPV calculation is modelled in same way as that found in the original data. From 2004 to 2008 Brent forward curve values are used and for the rest of the project duration a base oil price of $21/bbl adjusted for inflation is used. The oil price is also subject to a -$1 quality premium.

4.1.4 Capital Investment Costs

The capital expenditure and phasing is given for both the TLP and Subsea options in Appendix 3 & 4. A summary of these is provided in the Table Below. The author of this spreadsheet is unknown and therefore cannot be referenced however these costs do correlate with what is presented in the POD.

Table 4.1: Capital Costs – TLP Option

Year	Development Drilling Schedule			Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Shared Infrast ($000's)	Total Capex ($000's)
	Prod	Inj	Tot						
2004	-	-	-	-	-	15 012	26 271	19 584	60 867
2005	-	-	-	-	-	57 473	153 236	107 263	317 971
2006	14		14	62 337	67 209	58 339	95 855	58 778	342 518
2007	1	9	10	57 212	50 694	-	-	-	107 907
2008	9	2	11	54 291	50 882	6 595	-	-	111 768
2009	3	5	8	55 353	41 252	-	-	-	96 605
Total	**27**	**16**	**43**	**229 194**	**210 037**	**137 418**	**275 362**	**185 625**	**1 037 636**

Table 4.2: Capital Costs – Subsea Option

Year	Development Drilling Schedule			Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Shared Infrast ($000's)	Total Capex ($000's)
	Prod	Inj	Tot						
2004	-	-	-	-	-	34 883	14 290	19 839	69 011
2005	-	-	-	-	-	143 044	21 435	109 942	274 422
2006	14		14	64 786	88 056	76 500	-	62 222	291 565
2007	1	9	10	58 342	74 298	-	-	-	132 640
2008	9	2	11	49 453	67 012	6 595	-	-	123 061
2009	3	5	8	54 203	74 395	-	-	-	128 598
Total	**27**	**16**	**43**	**226 785**	**303 761**	**261 021**	**35 725**	**192 004**	**1 019 296**

The difference between the two options is $18 340 000 which is less than 2% on an investment that is over a billion dollars.

4.1.5 Operating Costs

Operating costs have been adjusted for inflation and come to a total expenditure over the life of the project of $799 190 494.

4.1.6 Abandonment Costs

Abandonment refers to not only the plugging and abandoning of all wells in order that they pose no threat to the environment but it also includes the removal of all production facilities and equipment and the re-instatement of the seabed to its original condition as per government or industry regulations. The abandonment costs were estimated to be $65 400 000, making an adjustment for inflation and assuming an abandonment year of 2026 this value is $115 406 539. Under the terms of the PSC the JV has to pay in to an abandonment fund each year in order to ensure the necessary funds are available at the end of the field life. Payment into the fund starts two years after first production. This equates to a value of $6 411 419 each year from 2009 to 2026.

4.1.7 Summary of Production Sharing Contract Terms

Production Sharing Contracts or Agreements are awarded by governments to an oil company which then explores and develops the field in terms of the requirements contained within the PSC. The PSC stipulates the Royalties that need to be paid as well as any other signing or production bonuses. The company is also permitted to use the money from the produced oil to recover capital and operational expenditure, this is termed Cost Oil. The balance of the revenue is then termed Profit Oil and is split between the government and the JV under the terms of the PSC.

The terms of the PSC under which this project falls are summarised as follows:

Royalty

This is paid on a sliding scale and depends on the daily production.

Table 4.3: Royalty Rate

Daily Production (bopd)	Royalty Rate
0 – 30 000	11%
30 000 – 60 000	12%
60 000 – 80 000	14%
80 000 – 100 000	15%
100 000+	16%

Bonus Payments

Bonus payments are not cost recoverable and are made to the government at the following stages:

- Production rate > 30 000 bodp ($3 000 000)
- Production rate > 60 000 bopd ($3 000 000)
- Production rate > 100 000 bopd ($4 000 000)

Cost Recovery (Cost Oil)

The JV is allowed to recover almost all capital investments and operating costs from post-royalty revenues. There is an annual cost recovery ceiling of up to 70% of post royalty revenues; any unrecovered costs are carried forward to the next period. The full amount of the operating expense can be included in the cost recovery pool in the year of outlay. Capital expenditures however are gradually transferred to the cost recovery pool via a four year straight line depreciation.

Profit Oil

Once the JV has recovered the eligible costs in each given year the remainder or Profit Oil is divided between the JV and the government as per the table below:

Table 4.4: Profit Oil

Cumulative Production (MMbbl)	JV Share	Government Share
0 – 200	80%	20%
200 – 350	70%	30%
350 – 450	60%	40%
450 – 550	50%	50%
550+	40%	60%

In addition to this, 5% of the JV share of profit oil is assigned to the State Oil Company. Finally the remaining revenues are subject to a 25% corporate income tax.

The sliding scale of all these parameters is accounted for in the spreadsheet model so that when the Monte Carlo analysis is run as part of the next step in modelling the uncertainty these determinants of the projects present value are properly captured.

4.1.8 Discount Rate

Company has used a standard discount rate of 10% in calculating the NPV. This value will therefore also be used for the purposes of this research.

4.1.9 Results & Sensitivity Analysis

The main output from the NPV model is the project cash flow and other indicators that can be used in the decision making process. The cash flow for the project is depicted below with cumulative net cash flow for the project totalling: $1 391 044 389

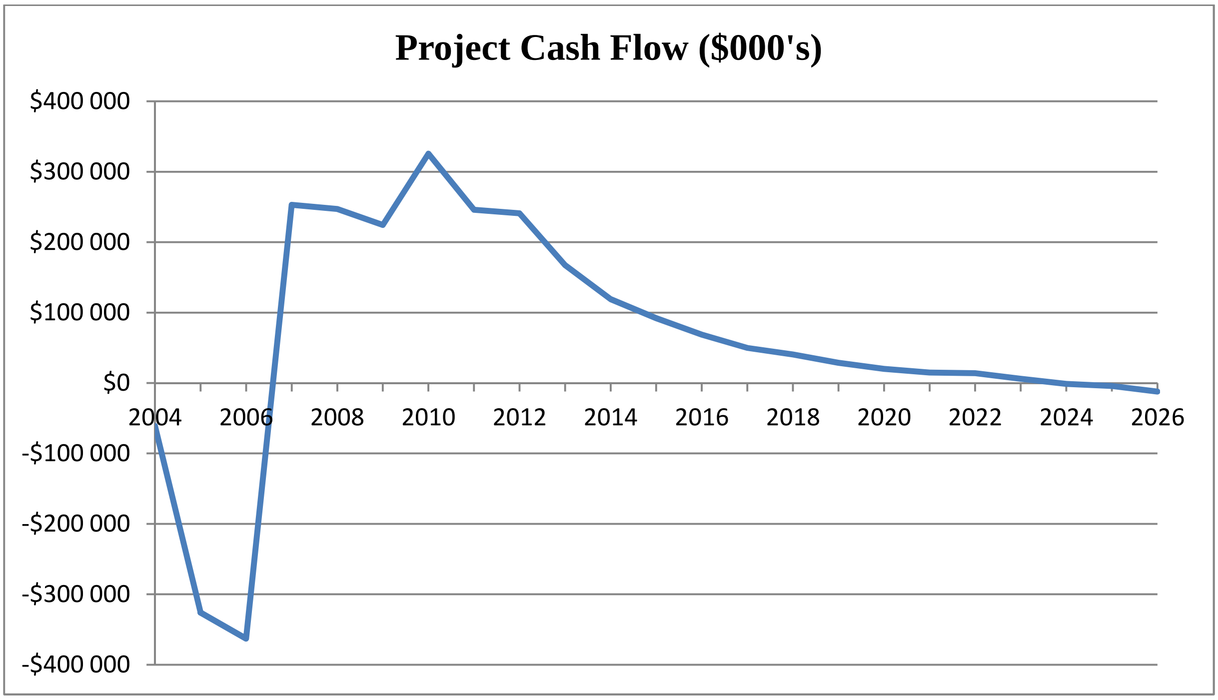

Figure 4.2: Project Cash Flow

A useful indicator to take from this exercise is the Development Costs per barrel of recovered reserves. The values given include for inflation.

- Capex/bbl $5.47
- Opex/bbl $3.99
- Total $9.46

The internal rate of return for the Project is a healthy 24%

A summary of the NPVs for the project is provided in the table below:

Table 4.5: NPV Summary

Discount Rate	TLP ($000's)	Subsea ($000's)
8%	$598 753	$594 682
10%	**$475 324**	**$476 210**
12%	$371 198	$376 248

These values compare very well with those found in a JV partner presentation which was $481MM and $479MM for the TLP and Subsea options respectively using a 10% discount rate.

The summary of the NPV analysis of both options shows very similar and relatively strong NPVs and IRR. It may therefore be argued that given these numbers why is there a need for ROA? As it shall be demonstrated the real options process provides the opportunity to identify the flexibility of both concepts and value that flexibility. Flexibility can come at great cost which can sometimes make it uneconomical and therefore ROA is the tool that can ensure this is properly evaluated.

In this particular case, given the hugely successful outcome of the project more could possibly have been done to prepare for future expansion. The ROA process is able to identify the large potential upside and give management the justification for making those preparations. These preparations may have insignificant costs but if anticipated early on can save time and money in the long run.

In line with the traditional DCF approach to valuing a project a sensitivity analysis has been done on a number of the inputs: see Figure 4.3 below. The results of the sensitivity analysis provide the information required to determine the major uncertainties which the project faces. The sensitivity of the oil price is very pronounced even with a small increase of $4, considering that the model uses a dollar per barrel price of $21 adjusted for inflation and in reality the price rose to over $90/bbl during the production plateau period of the project.

Varying the total number of recoverable reserves between 160MMbbl and 240MMbbl also provided a significant variance in the NPV. Given that the impact of the development costs is relatively small compared with oil price and reserves it shall be ignored as an uncertainty for the purpose of this research and assessing the contribution that ROA can make to the evaluation process. There is also little the project can do to respond to variances in the estimates of capital and operating costs but the project does have the flexibility to respond to changes in the anticipated reserve volumes and oil price.

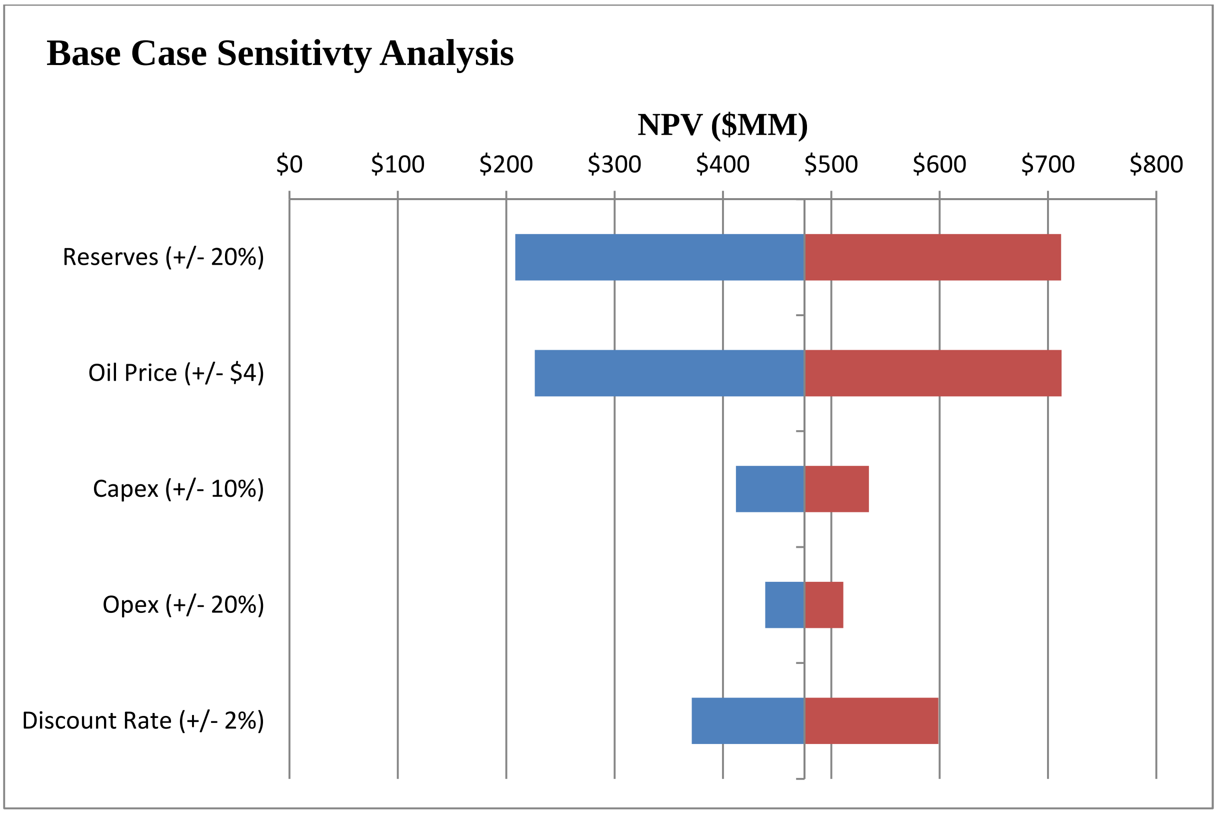

Figure 4.3: Sensitivity Analysis Tornado Diagram

4.2 Modelling the Uncertainty

4.2.1 Oil Price Uncertainty

Mean-reverting versus Geometric Brownian Motion Price models

Initially it was anticipated that because it is a commodity the price of oil would follow a mean reverting process. (J. Smith & McCardle, 1999) assessed both a Geometric Brownian Motion (GBM) Price model and a Mean-reverting Price model. They stated that the Brownian Motion model was the most frequently used in real options literature however the managers they were performing the study for argued against this saying that when prices were high compared to a long run average, oil companies invest in new projects and more production capacity is brought online and older production that was expected to come offline, stays online for as long as possible. Therefore as a result of the increased supply, prices are driven back down towards the long run mean. The managers also stated that conversely, when prices are low less new production comes online creating a higher demand, driving the prices back up towards the long run mean.

This theory seemed to make sense so it was decided to test it. By following the work of (W. Smith, 2010) a spreadsheet was constructed to model the oil price following the popular Ornstein and Uhlenbeck process (Uhlenbeck & Ornstein, 1930).

The work of (W. Smith, 2010) provides a formula to make it simpler to model the mean reverting process of Ornstein and Uhlenbeck:

$$S_t = e^{-\gamma \Delta t} S_{t-1} + (1 - e^{-\gamma \Delta t})\mu + \sigma \sqrt{\frac{(1 - e^{-2\gamma \Delta t})}{2\gamma}} dW_t$$

Where:

St = logarithm of the oil price

γ = the speed of mean reversion

μ = the long run mean

σ = the process volatility

W_t = is a Brownian Motion variable with a mean of 0 and a standard deviation of 1: N(0,1)

Equation 4.1: Ornstein Uhlenbeck Mean Reverting Process

To calculate the volatility in the oil price, Brent Crude Oil Price data was collected from the World Bank. The data was presented as monthly prices in nominal US dollars from 1979 through to 2004. The standard deviation of the monthly percentage price change was calculated at 9.06%. This is converted in to an annual amount by multiplying by the square root of twelve resulting in an annual oil price volatility of 31.38%.

Given that the original NPV calculation used a an oil price of $21 increasing each year due to inflation this was used as the long run mean. The Brownian motion variable is generated at each time step by using Monte Carlo Simulation software called @Risk.

The next step of estimating the speed of mean reversion proved more difficult. (W. Smith, 2010) provides a method for estimating this parameter by regressing a 'y' value of S_t - S_{t-1} against an 'x' value of S_{t-1}. From this it is derived that:

$$\gamma \approx \frac{b}{\Delta t}$$

Where:
b = the regression coefficient

Equation 4.2 Estimating the speed of Mean-reversion

The regression provided a negative coefficient resulting in a negative value for γ which gave a very abnormal oil price distribution that either quickly approached zero and stayed there or quickly increased to infinity.

Further investigation into the presence of the Mean-reverting process in oil prices was required. A paper appropriately titled 'Mean Reversion versus Random Walk in Oil and Natural Gas Prices (Geman, n.d.) provided a simple test to determine if a commodity followed a random walk or not. This consists of estimating the regression coefficient of S_t on S_{t-1}. If the coefficient is significantly below one, it means that process is mean reverting, if it is close to one, the process is a random walk. The result of this exercise yielded a regression coefficient of 0.9682 clearly indicating that the oil price follows a random walk.

Interestingly the work of (Geman, n.d.) goes on further to state that for crude oil a Mean-reversion pattern prevails over the period 1994-2000 and it changes into a random walk as of 2000. Reasons for this could be the ongoing discussion around what has been termed Peak Oil and fears that as a resource the world's oil reserves could be reaching depletion in the near future. This would challenge the logic of the mean reverting price hypothesis – supply is able to respond positively to increases in prices thus driving them down. In addition to this there is also the increase in demand from fossil fuel hungry China.

As a result of these findings a geometric Brownian motion process was used to model the oil price. The geometric Brownian Motion equation is commonly used for modelling in finance:

$$dP = \mu P dt + \sigma P dz$$

Where:

P = Price of oil

μ = is the drift term

σ = the oil price volatility

dz = is a Brownian Motion variable

Equation 4.3 Geometric Brownian Motion Process

The drift term used is the same as the long run mean used in the Mean-reverting process; \$21/bbl adjusted each year for inflation. The volatility is 31.38% as explained above. The Brownian motion variable, which simulates oil price shocks, is generated at each time step by using @Risk. This variable has a normal distribution with a mean of 0 and a standard deviation equal to the oil price volatility. In order to prevent the oil price going negative any generated values of less than zero are rejected.

There is one problem with this approach: as the GBM equation compounds the price shock after every step, the latter years in the project were seeing huge outliers in excess of \$2000/bbl – a very unbelievable result. Applying a filter that excluded the top 1% of simulation results gave the ability to exclude those outliers however this had a negative impact on the mean so it was decided not to use any filters. Applying the filters also had no impact on the value of the standard deviation of the projects rate of return. A comparison of the oil price distribution in 2026 is given below which helps explain the reason for not using filters. The reason for the negative values is that there is a -\$1 oil quality discount premium placed on the price of the product.

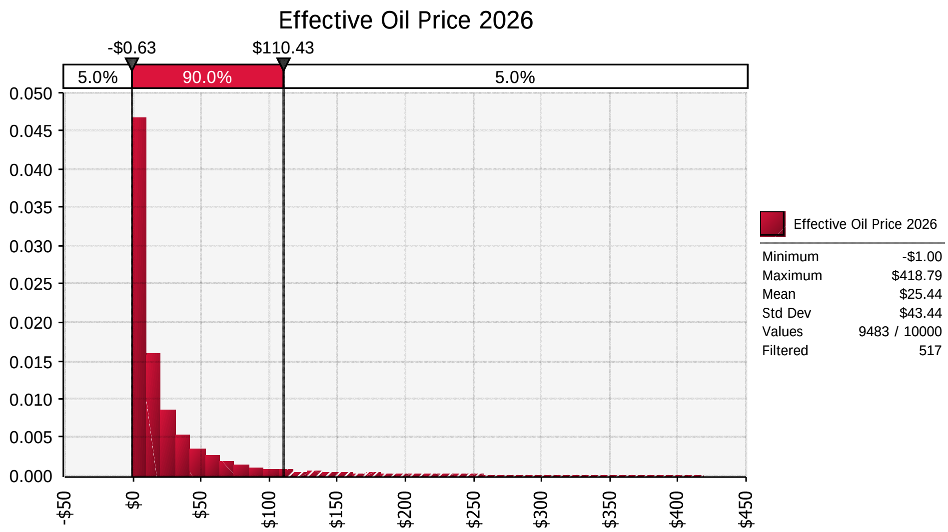

Figure 4.4 Effective Oil Price in 2026 with filters applied

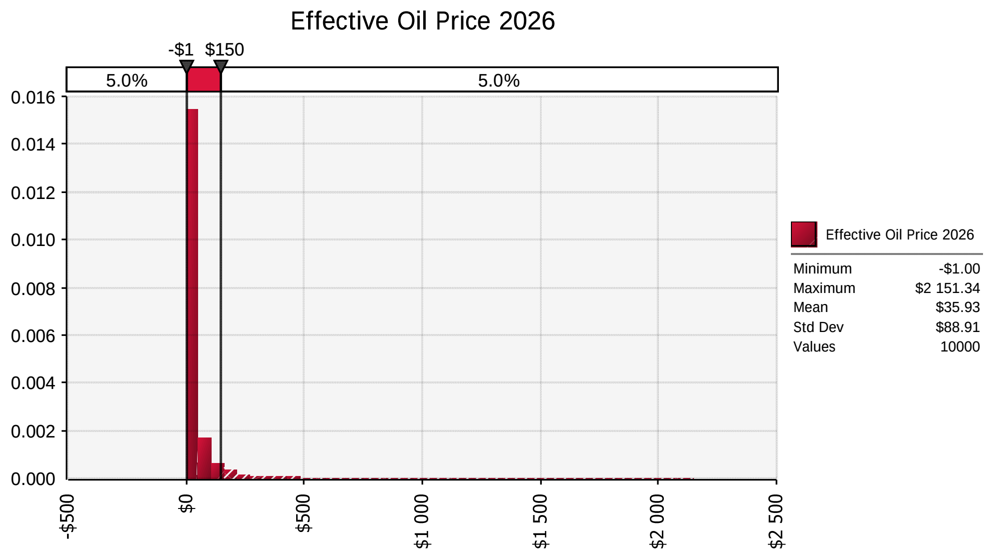

Figure 4.5 Effective Oil Price in 2026 without Filters

As result of this approach the NPV calculation comes down slightly from $475 324M to $431 404M because the larger Brent Forward curve values originally used for the initial time steps has been replaced by $21/bbl adjusted for inflation for the whole life of the project. Therefore for the purposes of modelling the uncertainty the NPV model has this small difference in it compared to the base case NPV model.

4.2.2 Uncertainty in Reserve Volumes

As well as the P50 case the Plan of Development document also makes reference to a P90 (there is a 90% probability of exceeding this value) and P10 (10% probability of exceedance). This gives the probability distribution of total recoverable reserves as:

- P90 – 118MMbbl
- P50 – 201MMbbl
- P10 – 306MMbbl

As there were no production profiles found for the P90 and P10 case it had to be assumed that the curve would follow the same profile as that given for the P50. Using the P50 profile the daily production rates for the other two cases were generated as shown below:

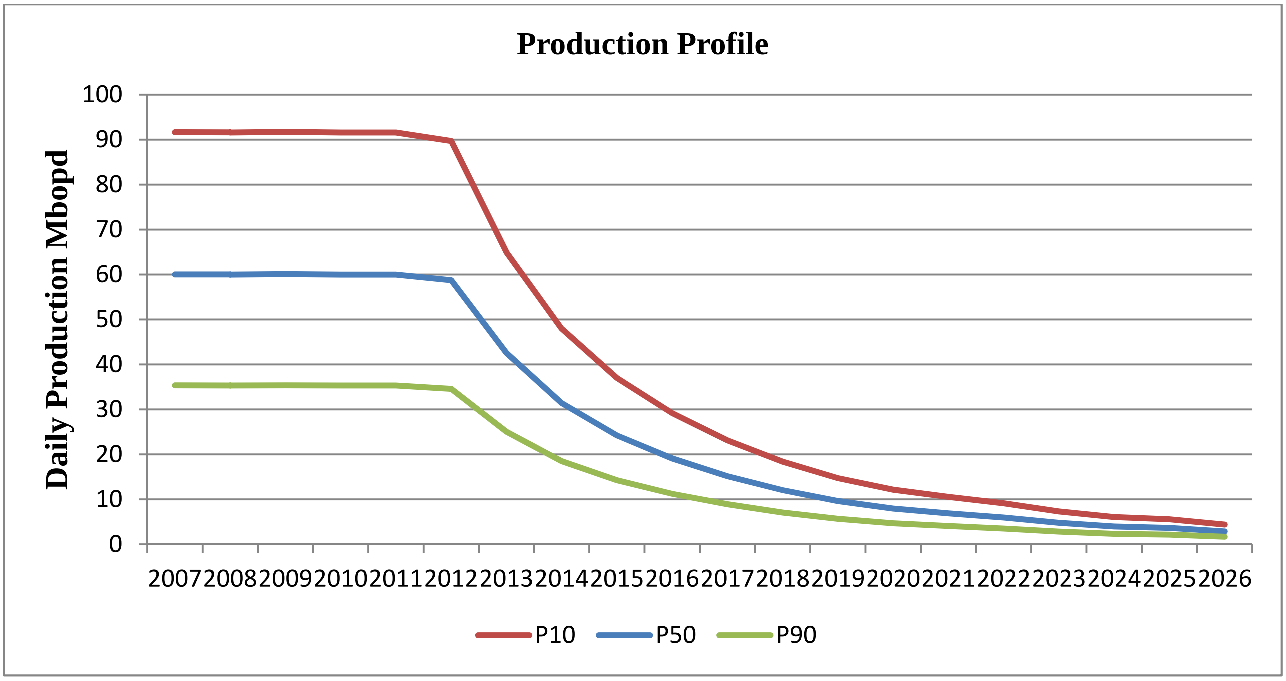

Figure 4.6: Production Profiles P10/P50/P90

Following a discussion with the Development Manager it was ascertained that during the life of the field, production will not vary from a P90 to a P10 case or even to a P50. Once the reservoir is on stream and the plateau is reached, production will more or less follow that profile. This is possibly a slight over simplification but after numerous other attempts at framing this uncertainty problem it was determined that this was the best solution given the level of data available. Having the ability to work closely with a Reservoir Engineer on a project of this nature could potentially yield a more realistic solution.

Therefore, as the main uncertainty was in the start of production. The following values were used in @Risk to create a distribution for the first year of production from which a random number could be drawn on each simulation of the Monte Carlo analysis:

- P10 – 91.626 Mbopd
- P50 – 60.02 Mbopd
- P90 – 35.0 Mbopd

The distribution generated by @Risk is shown in Figure 4.7. The distribution is bound by 0 on the low side and 110 on the upside. Realistically the reserves obviously can't be less than 0 and the facilities can't be designed to process the large upside potential that would be seen, if the distribution was unbounded as this has a capital cost implication. These parameters provided a mean of 60.8Mbopd and a standard deviation of 21.05

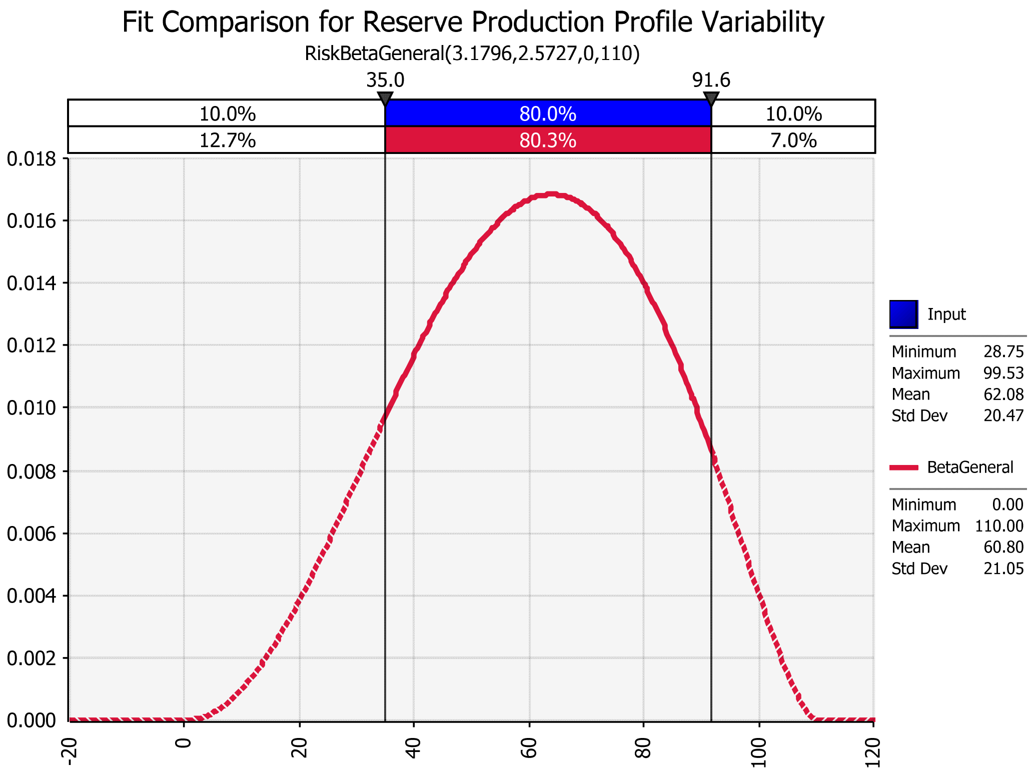

Figure 4.7 Fit Comparison for Reserve Production Profile Variability

Again it was assumed that once the initial production rate was selected the curve would follow the same profile as the P50 case.

Running the Monte Carlo simulation 10 000 times gives a Total Production distribution shown in figure 4.8. This result is a mean of 200.66MMbbl with a standard deviation of 69.47.

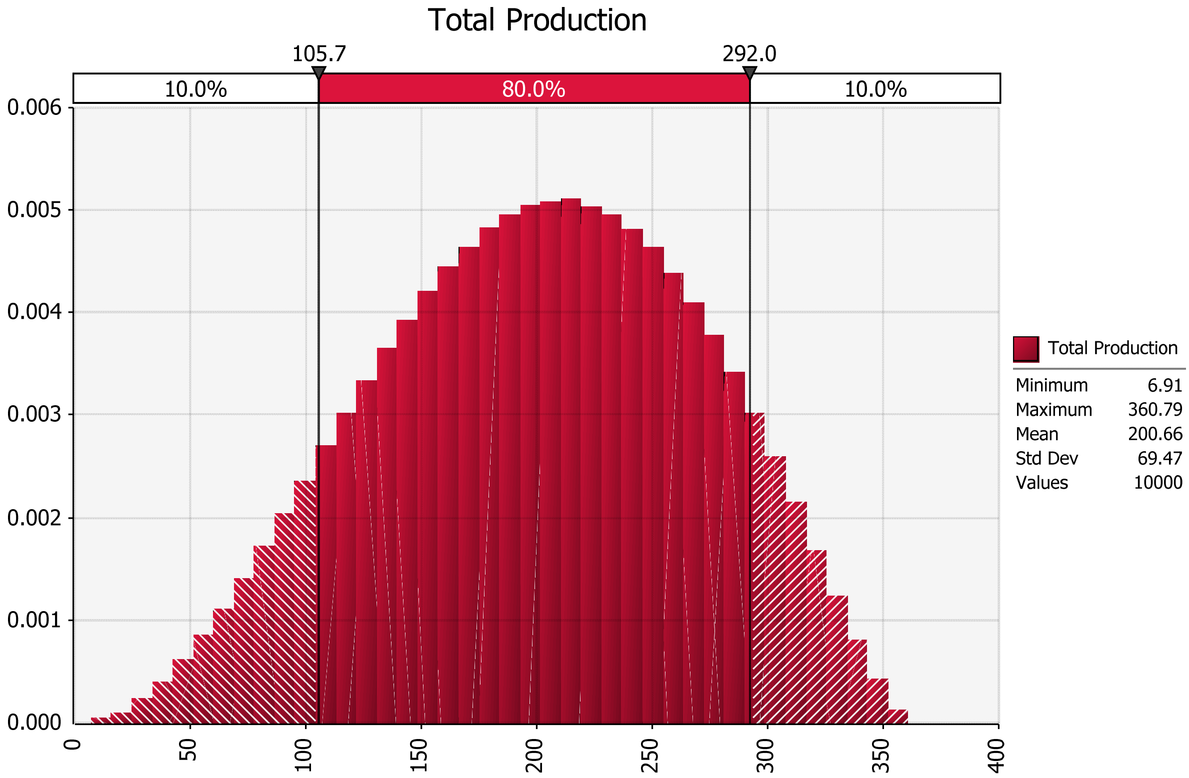

Figure 4.8: Total Annual Production Distribution

The lower P90 and P10 values of 105.7MMbbl and 292MMbbl respectively that were generated compared to the given value of 118MMbbl and 306MMbbl is due to the fact there is not a big enough distribution of potential reserve volumes with which to fit the curve to. With more data it would be easier to generate a distribution that fits in with what the Reservoir Engineers provide.

With the cash flows being discounted at the same value as was used in the original NPV calculation (10%), each simulation of the model with the above set of parameters in @Risk gives a range of present values for the project. As previously mentioned the volatility needed for the binomial tree is the volatility of the projects rate of return. This is captured by holding PV_0 static while varying PV_t in the formula provided in Equation 3.1. The Monte Carlo analysis then gives the standard deviation of this ratio which is used in constructing the binomial tree.

4.3 Additional Benefits from Modelling the Uncertainty

The process of modelling the uncertainty and the output from the Monte Carlo program provides additional benefits in the form of distributions for various model outputs such as Gross Revenue, Project Cash Flow, NPV etc. These distributions provide a far more thorough approach than the tornado diagram shown in Figure 4.2. Each of these distribution graphs can be expressed in various ways in order to best show the project risk in relation to managements risk appetite. The figures below provide just one example of showing the 70% probabilities of the Project Cash Flow and NPV.

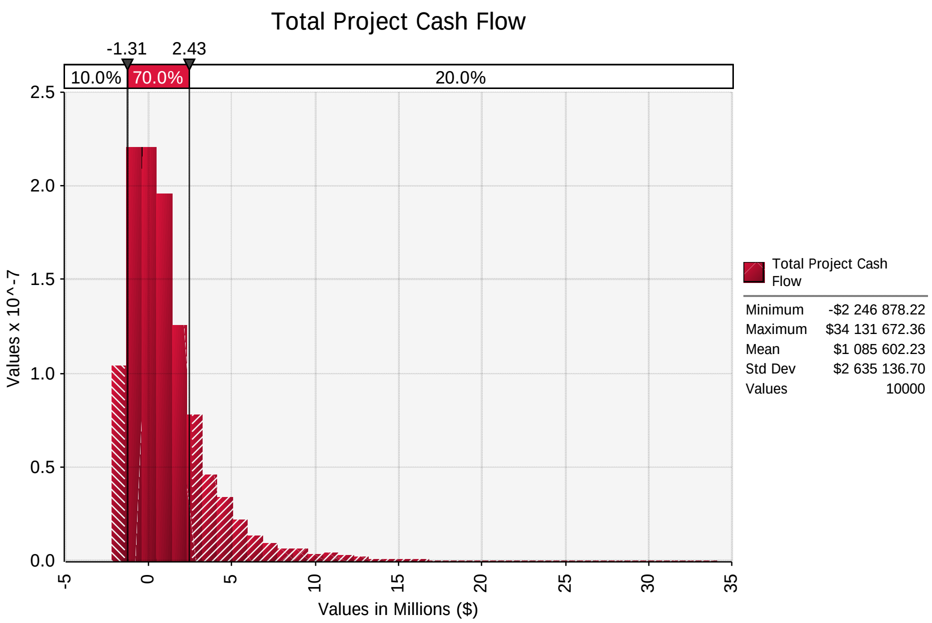

Figure 4.9 Distribution of Total Project Cash Flow ($000's)

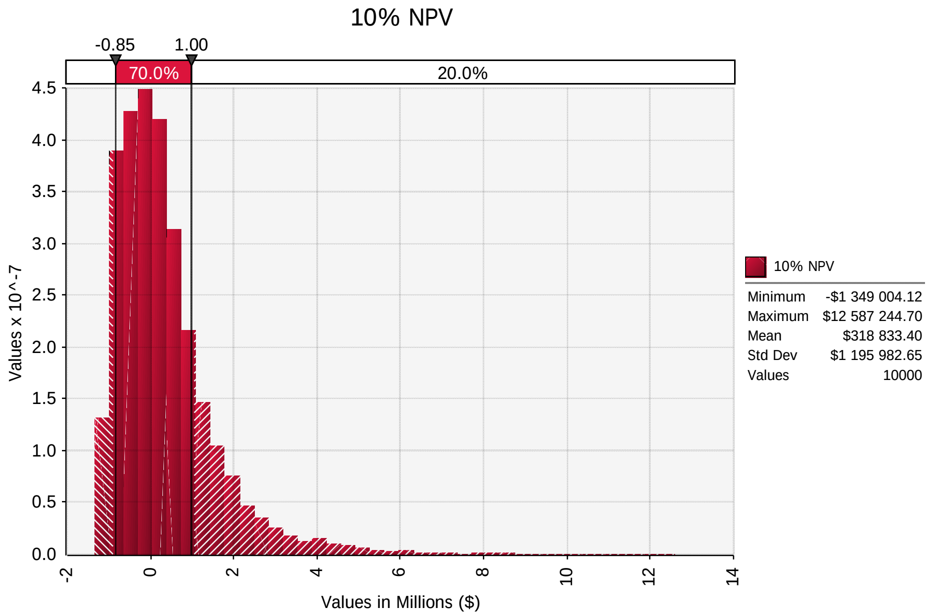

Figure 4.10 Distribution of the 10% NPV ($000's)

As can be seen the NPV has a 70% probability of falling between $1 billion and -$0.85 billion and a large potential upside can be seen in both figures. The process of combining multiple uncertainties provides a much better picture of the project risk which is impossible to capture in a simple NPV tornado diagram which captures only a handful of model simulations.

4.4 Identification and Incorporation of Flexibility

The next part of the four step process is to identify the flexibility within the project.

4.4.1 Flexibility to Expand

The POD makes brief reference to two additional hydrocarbon accumulations that are present in the field but at the time did not fall under the plan for development. Within the cost breakdown in the POD there is an allowance of $68MM to drill seven future wells.

This clearly provides an option to expand the project at a future date however there was no detail as to what the amount of reserves volume these 7 wells could potentially unlock. Following a discussion with the Development Manager it was decided to estimate a value of 3 million barrels per well. This view is made with the benefit of knowledge from production data gathered to date and additional seismic that has been captured in the area but it is the only information available as to what the thinking may have been at the time in terms of what potential the additional wells could unlock.

This additional 21MMbbl was captured by increasing production from 2013 onwards. This assumed a 40% increase in production for 4 years followed by a 20% increase for another 4 years, 10% for 2 years and finally 5% for the remaining life of the field until 2026. This equated to a total increase of 21MMbbl to the total production volume and an increase in the projects Present Value of 13.6%.

Figure 4.6 captures the increase in production and it shows that the additional wells give the ability to increase the 6 year plateau period to 7 years.

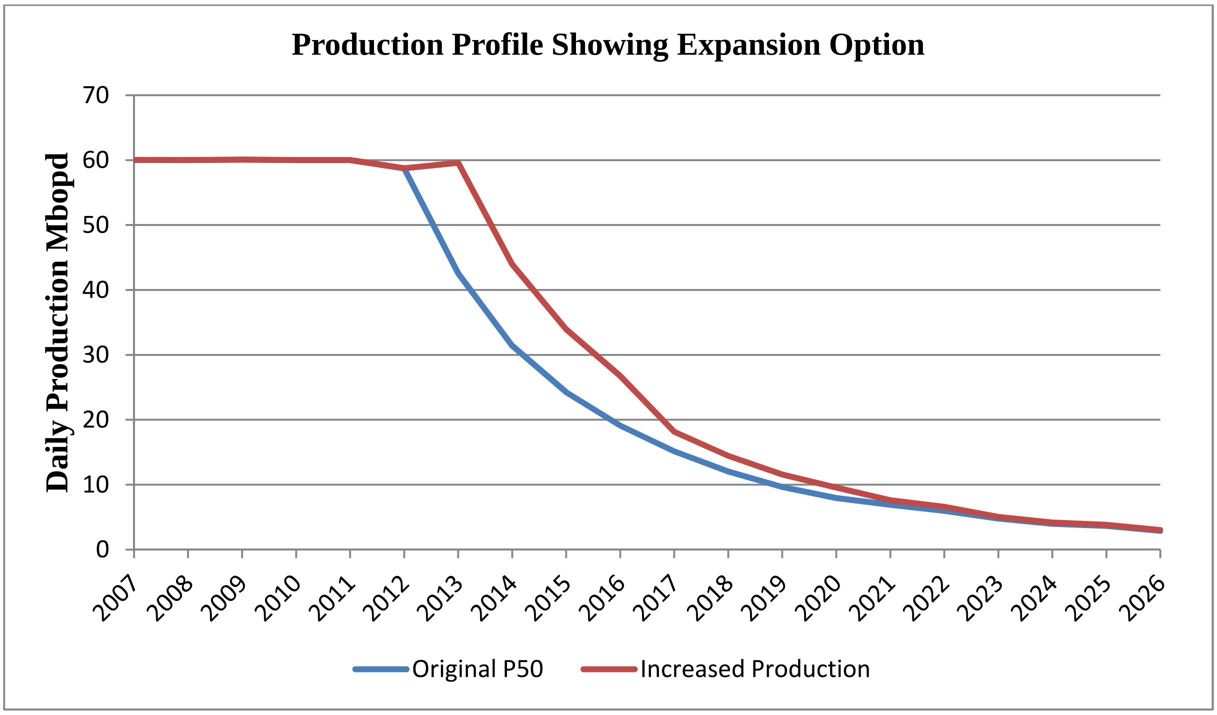

Figure 4.11: Production Profile Showing Expansion Option

4.4.2 Flexibility to Abandon

As described above the cost of abandonment is estimated to be \$65 400M and the JV has allocated \$6 411M per year to an abandonment fund. Having the ability to abandon at any time gives the ability to avoid any potential downside where the operating costs begin to exceed the profitability of the project.

4.5 Real Options Analysis

4.5.1 Input Variables

Before constructing the tree some input data is required, most of which has already been calculated in the NPV model and by modelling the uncertainties.

The current value of the underlying on which the options analysis is based is the Present Value of the projects cash flows discounted at a market adjusted rate which in this case is 10%. The PV of the project, excluding capital costs is $1 325 402M.

The annual standard deviation of the change in the project rate of return (σ) was calculated above as 1.06

As the projects value has the ability to go negative an additive binomial lattice had to be used. The increments for the up (u) and down (d) steps of the lattice for the additive tree were calculated by first using the equations used for multiplicative tree:

$$u = e^{\left(\sigma\sqrt{\frac{T}{n}}\right)}$$

Where:

T = the length of one time step

n = number of steps per year

Equation 4.4: Calculation of the up movement in a multiplicative tree

$$d = \frac{1}{u}$$

Equation 4.5: Calculation of the down movement in a multiplicative tree

For an additive tree the value of the up step for each period simply becomes $u(PV_0)$ and the down step value $d(PV_0)$.

4.5.2 Expansion Option

This was framed as a European Option because the decision to expand will only be made once production begins to fall off the plateau which is in the 7th year after the start of production.

Using the input variables from the section above, the event tree for the underlying was constructed from 2004 moving through the up and down steps to 2013, the option expiry date. The project value at this point is calculated as the maximum between continuing as normal - the value from the event tree, or the project value when expanding which was determined by:

$PV = PV_t$ (% increase in Project PV) – expansion costs

Where:

PV_t = Value from the event tree for that time step

Equation 4.6: Calculation of Expansion Option Present Value

The percentage increase in project PV was previously calculated as 13.6% and the cost of expansion is the $68MM cost estimate adjusted for inflation. This provides the Project Values for the final time step. Moving 'back in time' to the previous time step Equation 3.2 is used to calculate the value of the project including flexibility. This process was repeated all the way to the beginning of the lattice providing the final value of the project including flexibility. Subtracting this from the initial project PV gives the value of the flexibility or the expansion option which is; $71 643M.

The figure below is taken from the ROA spreadsheet model. The binomial tree is rotated clockwise by 45 degrees to make it easier to work in Excel. The cells highlighted in green show when it is optimal to exercise the expansion option.

Project Value when expansion option is exercised at time period 9										
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Period	0	1	2	3	4	5	6	7	8	9
Inflation	1.00	1.03	1.05	1.08	1.10	1.13	1.16	1.19	1.22	1.25
Cost of Expansion	$68 000	$69 700	$71 443	$73 229	$75 059	$76 936	$78 859	$80 831	$82 851	$84 923
Increase in PV										13.60%
0	$1 325 402	$5 151 002	$8 976 603	$12 802 203	$16 627 804	$20 453 404	$24 279 005	$28 104 605	$31 930 206	$40 533 673
1		$866 208	$4 691 809	$8 517 410	$12 343 010	$16 168 611	$19 994 211	$23 819 812	$27 645 412	$35 666 148
2			$407 015	$4 232 616	$8 058 217	$11 883 817	$15 709 418	$19 535 018	$23 360 619	$30 798 622
3				-$52 178	$3 773 423	$7 599 023	$11 424 624	$15 250 225	$19 075 825	$25 931 097
4					-$511 371	$3 314 230	$7 139 830	$10 965 431	$14 791 031	$21 063 571
5						-$970 564	$2 855 037	$6 680 637	$10 506 238	$16 196 046
6							-$1 429 757	$2 395 844	$6 221 444	$11 328 520
7								-$1 888 950	$1 936 651	$6 460 995
8									-$2 348 143	$1 593 469
9										-$2 807 336

Figure 4.12 Expansion Option Binomial Tree

4.5.3 Abandonment Option

The abandonment option is the equivalent of an American put in that the option can be executed at any time up until the expiry date which in this case is the end of the field life.

Within real option theory the flexibility to abandon and expand can be calculated at the same time in the binomial tree as a compound option however because the purpose is to draw a comparison between the TLP option, which had the capacity to expand and the Subsea option which didn’t, the abandonment option shall be calculated separately. The ability to abandon is built into both concepts so for the purpose of fulfilling the objective of linking the analysis to the project capital structure the real option abandonment value will only be calculated for the selected TLP concept which the expansion option valuation has proved as the optimal concept.

In order to purely show the benefits of avoiding down side risk the event tree is then constructed as if there is no option to expand in 2013. The project value at each time step was then calculated as the maximum between either continuing as normal, or abandoning the project. The abandonment value in each time period is equal to the amount of money that is in the abandonment fund at that point in time less the abandonment estimate of $65 400M adjusted for inflation. Therefore this value is 0 in the last year and negative for all the other years, indicating that the JV has to pay in an amount in order to abandon before the estimated end of the fields life which is 2026. This means there is no salvage value only a chance to pay in to avoid further losses in terms of operating costs.

Its not practical to present the whole tree as it contains 22 time steps however the start of the tree and optimal execution of the abandonment option can be seen in the figure below:

Period	0	1	2	3	4	5	6	7	8	9
	1	Continue								
	2		Continue							
	3			Continue						
	4				Continue					
	5					Continue				
	6						Continue			
	7							Continue		
	8								Abandon	
	9									Abandon

Figure 4.13 Abandonment Option Binomial tree

The framing of the abandonment options is a fairly simple view and is based on the information that was available. When evaluating a project from the beginning the phasing of expenditure and contractual terms can be taken into account. The main reason to abandon the project during construction is a drastic drop in the oil price and contracts can potentially be constructed so that they can help facilitate abandonment and project salvage during the construction phase. Alternatively the project could also be placed on hold until the oil price is more favourable.

This sort of risk mitigation and transfer is common place within Project Finance literature and once again the real option process helps in driving management towards thinking about these factors and protecting the investment as much as possible from downside risk. Even though the project has a relatively healthy NPV and using the abandonment value to enhance that NPV would therefore seem irrelevant it can still be worthwhile going through the process in order to think about all possible approaches to try mitigate against downside losses.

The last step in the analysis was to again use Equation 3.2 and work backwards through the lattice to calculate the value of the project, including flexibility at each time step. The start of the lattice provides the value of the project with the flexibility, once again this is subtracted from the initial project PV giving the vale of the flexibility to abandon which is; $227 112M.

Interestingly if the event tree for the abandonment option is expanded though time from the underlying values at the end point of the expansion event tree the abandonment option value is; $148 951M. The decrease in value is due to the fact the project is taking advantage of the potential upside and therefore the downside risk has been reduced.

4.5.4 Summary of the Results

The table below provides a summary for the value of the project with the ability to expand compared to without.

Table 4.6: Summary of Expansion Value

	Value without flexibility ($000's)	Value including flexibility ($000's)	Value of flexibility ($000's)
TLP Option	$475 324	$546 967	$71 643
Subsea Option	$476 210	-	-

The original valuation of the two concepts showed little difference between the two however the TLP option was chosen because it offered the ability to expand and drill more wells at a later date. The ROA analysis has given justification to that decision by providing management with a value, the decision to hold an expansion option is worth just over $70 million or approximately 15% of the initial NPV value.

Similarly the value of the abandonment option is summarised in the table below.

Table 4.7 Summary of Abandonment Value

	Value without flexibility ($000's)	Value including flexibility ($000's)	Value of flexibility ($000's)
TLP Option	$475 324	$702 436	$227 112

The ROA has been able to quantify the value in having the capacity to shut a project down and avoid further downside losses. In this case it is worth just over $227 million, more than three times the expansion option which takes advantage of the upside. Creating the option to abandon was as simple as estimating the costs involved in decommissioning the field and allowing for a savings fund to accumulate the funds needed to abandon the project when it begins to incur losses that exceed the amount required to exercise abandonment.

4.5.5 Current Status of the Project

As this is a development that went ahead and the project is in its 6th year of production there is the ability to analyse the production data and make a comparison with how the project was evaluated and how the project is progressing.

The base case NPV model was used for this exercise except the production data from 2007 to July 2012 as well recorded oil price data is inserted into the model. The production data is recorded on a monthly basis as barrels of oil produced per day. Using a 12 month average of this recorded data the following was inserted into the NPV model:

Table 4.8 Recorded Production Rates

	2007 (Mbopd)	2008 (Mbopd)	2009 (Mbopd)	2010 (Mbopd)	2011 (Mbopd)	2012 (Mbopd)
Recorded Production	36.60	70.47	71.90	82.35	71.76	62.9

For the remaining years the production profile is assumed to follow that of the P50 curve. The figure below makes this comparison graphically:

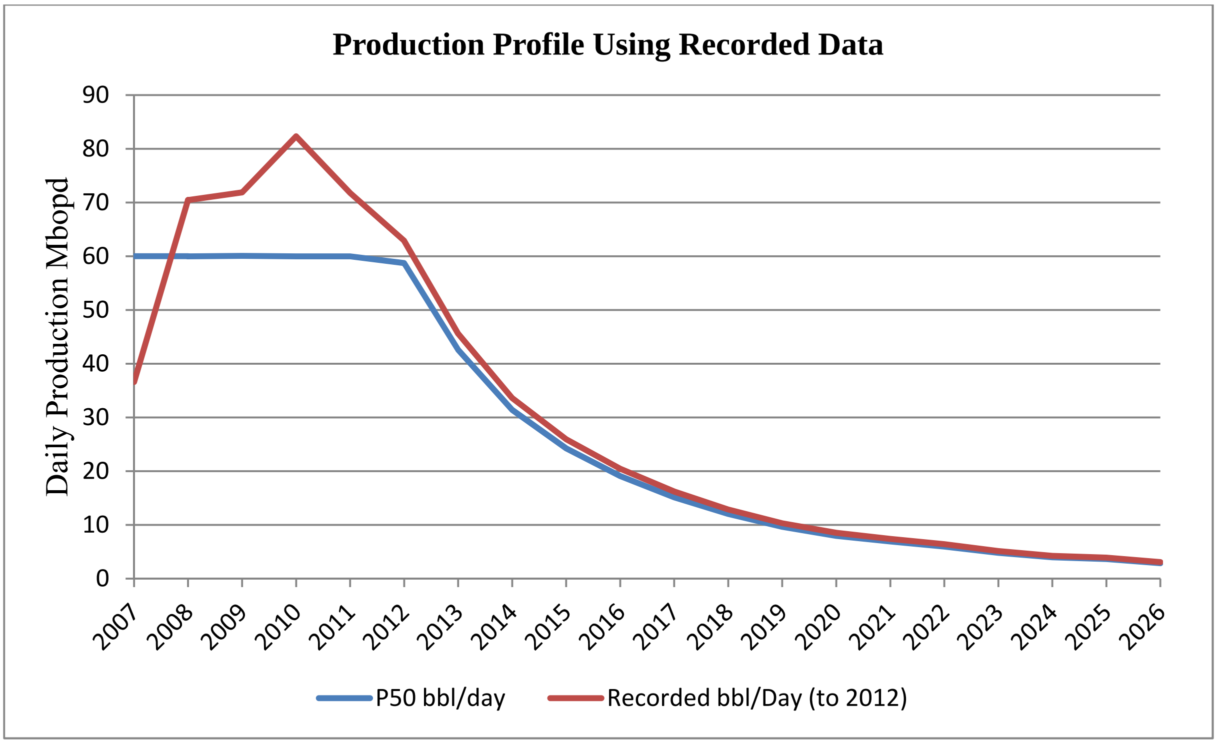

Figure 4.14: Production Profile Using Recorded Data

Production took longer than expected to reach the plateau but exceeded the P50 once there. The production facilities were only designed to be able to produce 60Mbopd and the engineering team had make modifications to the facilities in order to cope with the higher than expected production. The profile that is generated in Figure 4.14 equates to an estimated total production of 219MMbbl compared to the 201MMbbl of the base case. In monetary terms if the additional 18MMbbl is multiplied by the 2012 oil price given in Table 4.9 below this equates to almost $2 billion in additional revenues.

Using the World Bank Oil Price data the 12 month average oil price was calculated for each of the above years of production. The table below makes a comparison between actual oil prices and those used in the NPV calculation:

Table 4.9: Oil Price Comparison

	2007	2008	2009	2010	2011	2012
Recorded Oil Price	$72.70	$97.64	$61.86	$79.64	$110.74	$111.20
NPV Oil Price	$24.55	$24.89	$22.76	$23.35	$23.96	$24.59

The large increase in oil price can be seen in the graph of the World Bank data below.

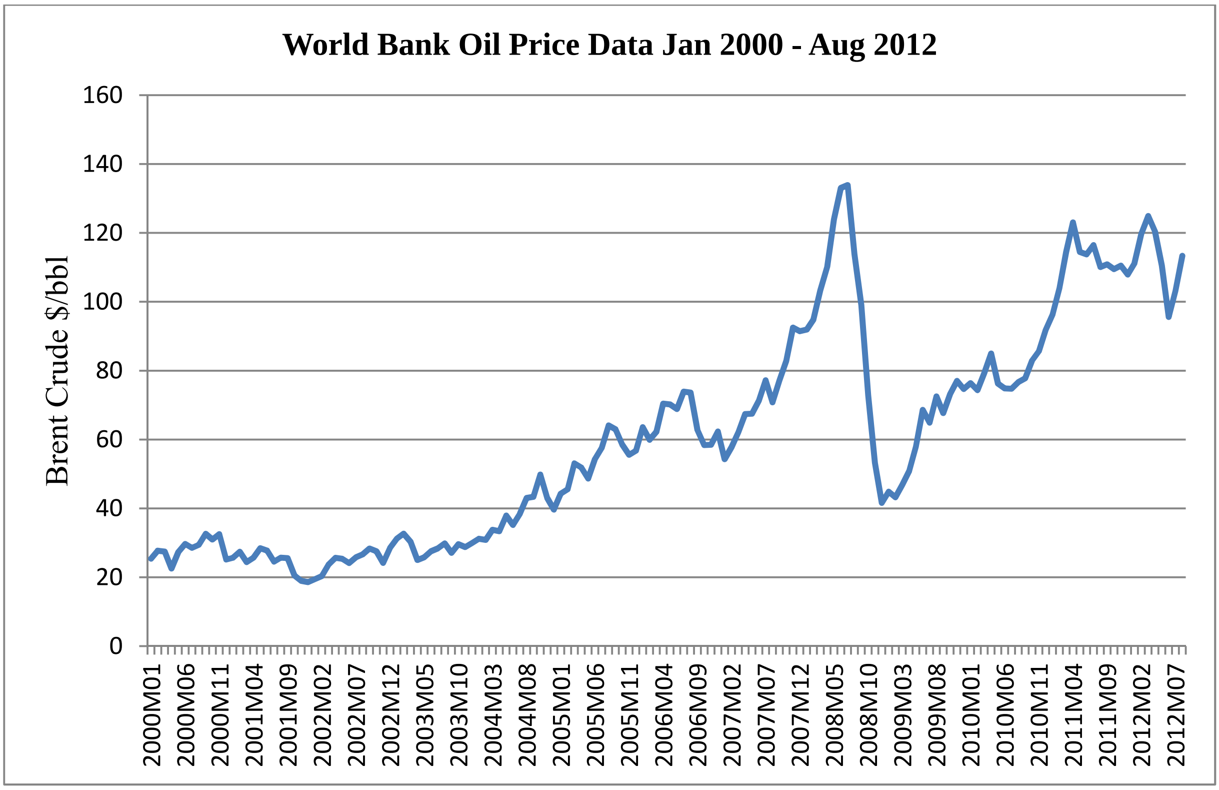

Figure 4.15: World Bank Oil Price Data

The increase in oil prices combined with an increase in production has a dramatic effect on the Project Cash Flow as seen below:

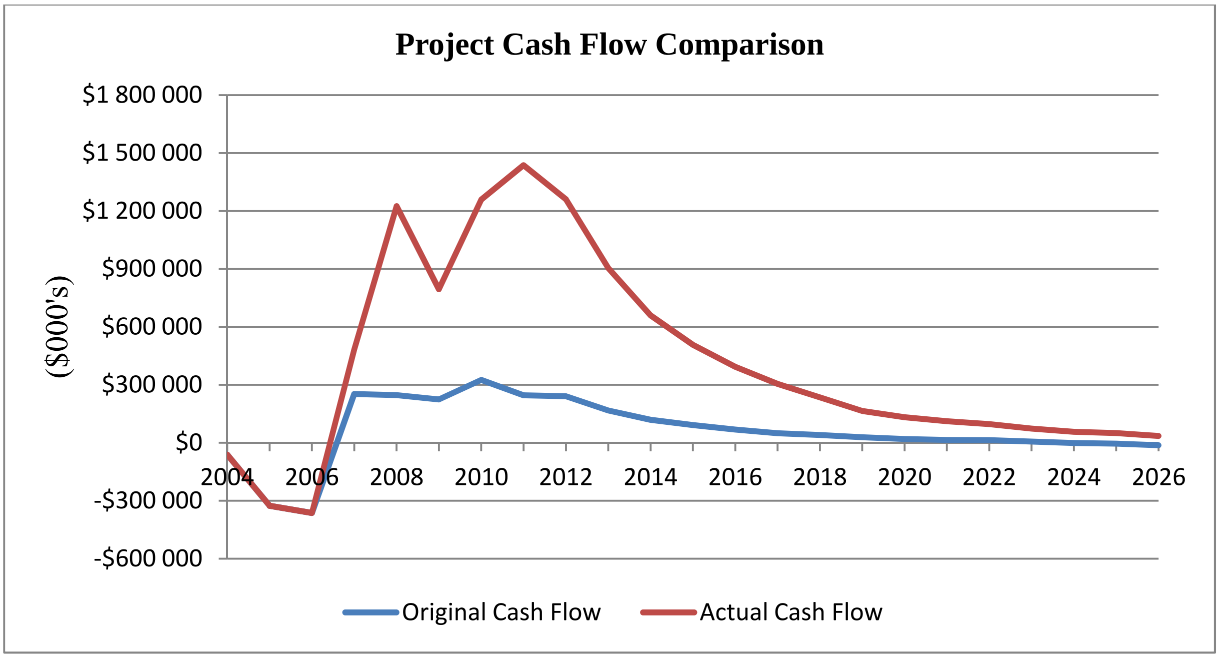

Figure 4.16 Project Cash Flow Comparison

Using the actual data to manipulate the NPV model gives an estimated total Project Cash Flow of $9 437 820M with a NPV of $4 302 955M.

This is substantially larger than what the base case NPV model was able to anticipate. However the process of combining the multiple uncertainties and then running the Monte Carlo simulation did capture this upside to an extent as it was one of the maximum outliers. The size of the maximum values shown in Figures 4.9 & 4.10 gives an indication of this significant upside against what is a relatively smaller down side risk. The reserve volumes certainly do play a role but the biggest impact is the volatility in the oil price and only the Monte Carlo analysis which gives the ability to add price shocks into the model is able to suitably capture that volatility.

As a combination of the success of the project and the collection of new seismic information the JV is currently planning a campaign to drill additional wells in 2013. In line with the results from the ROA the JV partners have seen the upside of the project and have decided to execute the expansion option.

4.6 Value at Risk

With the Real Options Analysis complete the next objective of the research focussed on linking the real options model to the debt/equity ratio of the project. This proved to be quite difficult because the risk profile is different at each step of the binomial model. In additional to this the determinants of a projects debt/equity ratio will differ from company to company and sector to sector making it very difficult to have a 'one size fits all' approach. What the research was able to develop is a framework which is able to show the potential impact the flexibility of the project can have on the project VaR. This can then be used as an indicator into the impact of flexibility on the projects risk and the level of equity needed to fund the project.

The Monte Carlo analysis of the project's cash flows can be used to determine the initial value at risk before taking flexibility into account. The figure below provides the distribution of the project cash flows with the left tail showing the 95% confidence value of $-1.59 billion.

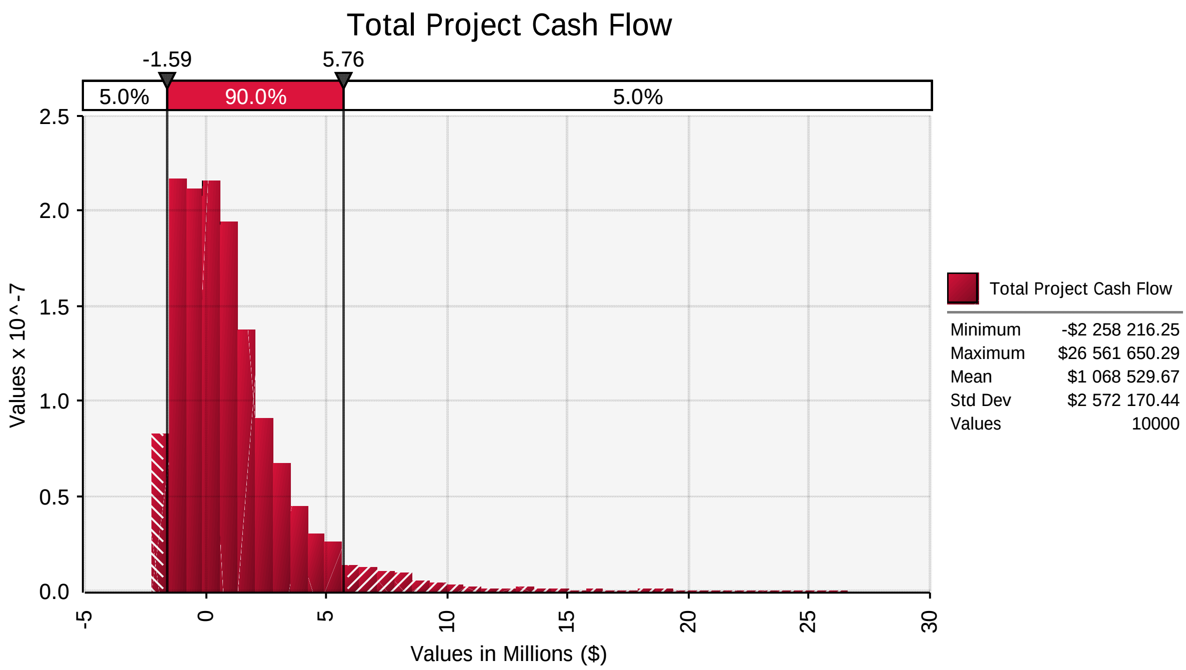

Figure 4.17 Project Cash Flow distribution showing 95% confidence level

Put simply this assumes that over the life of the project there is a 95% confidence that the negative cumulative cash flows will not exceed -$1.59 billion.

The next step is to compare this with the change in the projects risk profile that is created by including flexibility. By following the theory of Pascal's triangle the probabilities for each node of the binomial lattice at any time step can be calculated. Using combinatorial notation the following formula for calculating the probabilities is taken from (Copeland & Antikarov, 2003):

$$B(n, |T, p) = \frac{T!}{(T-n)!\,n!} * p^n (1-p)^{T-n}$$

Where:

T = Number of trials

N = number of 'up steps' at a node

P = the probability of an up step

Equation 4.7 Equation for calculating binomial probabilities

The risk neutral or risk adjusted probability is used as variable 'p' in the above equation. The equation for calculating this is also taken from (Copeland & Antikarov, 2003):

$$p = \frac{\left(1 + r_f\right) - d}{u - d}$$

Where:

r_f = risk free rate

u = as calculated in Equation 4.4

d = as calculated in equation 4.5

Equation 4.8 Risk Neutral Probability

Given that the risk profile changes at each time step it was decided that it would be most beneficial to look at the change in risk profile at a specific and important point in the life of the project which for this project would be the time step where the expansion option is considered. Using equation 4.7 the probabilities for each node at the end of the binomial tree at the 2013 time step can be calculated for 3 different states:

a) with no flexibility
b) including the expansion option
c) including the abandonment option.

Table 4.10 Project Values with no flexibility in 2013

$35 755 806	0.0018%
$31 471 013	0.0380%
$27 186 219	0.3603%
$22 901 426	1.9928%
$18 616 632	7.0864%
$14 331 838	16.7993%
$10 047 045	26.5499%
$5 762 251	26.9742%
$1 477 458	15.9864%
-$2 807 336	4.2109%
	100.00%

Table 4.11 Project Values including expansion option in 2013

$40 534 950	0.0018%
$35 667 272	0.0380%
$30 799 593	0.3603%
$25 931 915	1.9928%
$21 064 236	7.0864%
$16 196 557	16.7993%
$11 328 879	26.5499%
$6 461 200	26.9742%
$1 593 522	15.9864%
-$2 807 336	4.2109%
	100.00%

Table 4.12 Project Values including abandonment option in 2013

$35 755 806	0.0018%
$31 471 013	0.0380%
$27 186 219	0.3603%
$22 901 426	1.9928%
$18 616 632	7.0864%
$14 331 838	16.7993%
$10 047 045	26.5499%
$5 766 923	26.9742%
$1 873 150	15.9864%
-$49 619	4.2109%
	100.00%

Using interpolation the magnitude of the loss in 5% of cases can be calculated:

Table 4.13 Magnitude of Loss

Without Flexibility	-$2 520 195
With Expansion Option	-$2 512 417
With Abandonment Option	$79 234

The expansion option offers a marginal 0.31% improvement in the magnitude of loss while the abandonment avoids all losses with 95% confidence with a 103.14% improvement in the values given above.

This framework can then be used as an indicator when assessing the debt/equity ratio. The way the abandonment option in this particular project has been structured and the results presented in Table 4.13 indicate that this project could be entirely funded with debt. Considering that the total development costs (Capex and Opex) equate to less than $10/bbl in the P50 case this certainly seems achievable. It is worth mentioning here that the development plan allowed for the product to be transported via a subsea pipeline to an FPSO in a neighbouring field, if the project had to absorb the large capital expense of installing its own FPSO the development costs and related risk would have been higher.

The above analysis is only based on the two main uncertainties which are the amount of recoverable reserves in place and the oil price. The company still has to execute the project in a responsible and efficient manner that does not lead to cost or schedule over runs. However this analysis has proved that based on the information currently available and provided the abandonment option is in place, downside losses can be avoided within the 95% confidence band. This would then suggest that the project can be funded with a higher amount of debt than would have been anticipated if only NPV was used to evaluate the project.

5 RESEARCH CONCLUSIONS

The research has demonstrated how Real Options can successfully value flexibility in a project as well as providing a slightly deeper insight into the subject of Real Options by showing the value to be gained in the whole process and not just the final answer.

Ensuring that the analyst works closely with the engineers and project managers of infrastructure and development projects to frame the project in a real options context will bring scrutiny to two vitally important questions.

1. How can the project be designed or structured in order to be able to take advantage of any upside potential?
2. How can the project be designed or structured in order to be able to abandon and prevent further losses in the down side scenario?

Starting the Real Options process this early in the evaluation means that ROA can be used not only as a project evaluation tool but it can also be used in the concept selection phase to assist in determining which concept provides the greatest value in terms of flexibility and if that flexibility is truly adding value. In this instance the TLP concept with the option to expand brought an additional 15% to the value of the project compared to the subsea concept. The POD highlights a number of other benefits to the TLP solution and the use of dry trees however the analysis gave the ability to quantify the benefit of having the option to expand giving substance to any comparison studies that may have been performed during this phase.

The Monte Carlo analysis was able to provide some insight into the potential upside present in the project. It was revealed during the research that engineers had to make modifications to the facilities in order to cope with the initial production which exceeded the 60Mbopd that the facilities were originally designed for. If the real options process was originally used this could have been captured and included as part of the expansion option. Anticipating opportunities like this early in the design process and building the capacity to expand into the facilities while they are still under construction could have brought savings in any downtime or additional costs involved in implementing the modifications once the facilities were in place offshore. Given the remote locations and sometimes hostile environments of offshore platforms, work that can be performed onshore during construction is often significantly cheaper than executing the work offshore.

Even though this project went ahead based on the original NPV calculation a more risk adverse company may not have moved to the execution phase based on the size of the investment required and the uncertainty around the amount of reserves in place and the oil price. One is then led to wonder how many projects are shelved and not executed because the more traditional evaluation methods aren't able to properly capture the volatility or rather have a negative outlook on the volatility in a project as well as not having the ability to properly value the decision making ability of managers.

A lot of the ROA literature suggests that NPV systematically under values projects which would mean a number of projects get left on the table and don't break ground. In reality some of the parameters used in the NPV analysis will change over time and managers will receive new information and assuming they react optimally to these changes there is additional value in a project which ROA can help quantify. Looking ahead in the upstream oil and gas industry the use of ROA seems even more important than ever as the available reserves become more and more difficult to exploit and the industry moves into deeper water and frontier regions like the Arctic.

NPV probably takes some biased and unfair criticism in much of the literature on Real Options. The level of scrutiny and techniques used in NPV analysis has also evolved over the years and it is also vitally important to point out that ROA is not a tool that should replace NPV analysis but rather that ROA is an important addition to NPV especially in cases where the NPV may be marginal or there is an evaluation to be made between different concepts.

Part of the objective was to present the benefits of ROA by using a model that was simple, practical and easy for management to understand. The intention is for the Real Options model not to be seen as a black box that just produces a number but rather to be seen as a process that is understood and accepted as a value adding tool within the evaluation process. Unfortunately there wasn't time to properly measure this objective by presenting the results to the company before submitting the final report however the company's management have expressed an interest in ROA and have showed an interest in the outcome of this research.

Although the research has only investigated the use of simple expansion and abandonment options there are more complex options which can be used for development projects. Unfortunately these can become intricate and require a detailed understanding of real options theory. This presents a significant barrier to the use of real options however there is software available that can simplify this process and cut down the computing time required.

Examples of these more complex options are sequential compound options which give the ability to segregate a project into different phases presenting the company with the option but not the obligation to move to the next phase depending on the success of the previous phase. There are also switching options which are used more commonly in manufacturing but can also be used to evaluate situations where a company may want to look at switching a well from a producer to an injector in order to maintain reservoir pressures towards the end of a field's life. The list of the various types of options goes on; Customised Sequential Compound Options, Simultaneous Compound Options, options using trinomial lattices or quadratic lattices, Rainbow Options, Barrier Options and more. (Mun, 2006) provides a number of examples and small case studies of the various options available.

The research has also shown how real options can be used as a tool to evaluate different concepts at the conceptual design stage of a project. Each concept presents different levels of flexibility which when using real options can be quantified and used as part of comparative studies weighing up the advantages and disadvantages of each concept as well as determining if the cost involved in purchasing that flexibility is actually worth it.

Although it proved difficult to make a direct link between the ROA and the risk profile of the project the research was able to provide a framework which can be used to help determine the optimal level of equity required for a project. The results were able to show how the flexibility or ability to abandon a project when the downside was realised could mitigate against losses or in this case completely avoid a negative project value. The framework can, within a confidence band, show what the potential losses are at a particular time step prior to taking flexibility into account and then demonstrate improvement in the project value once the ability to abandon was incorporated.

The intention is that this framework can be used as part of the projects financial risk management evaluation and have an impact when assessing the ability of the project to carry more debt when there is an abandonment option in place which reduces the downside exposure.

Companies executing Projects in regions such as sub-Saharan Africa which have a higher perceived risk can benefit from this by hopefully been able to not only negotiate a lower leverage ratio but also and perhaps more importantly negotiate better terms on their debt.

6 RECOMMENDATIONS FOR FUTURE RESEARCH

Within the objective of linking real options to the capital structure of a project and subsequently the capital structure of the company there was very little literature and this research report is possibly only just starting to scratch the surface of this topic.

The framework developed here can be used to assess or test various capital structures for the project taking into account the cost of the debt, the payment structures, the timing of expenditures and how contractual terms with contractors and suppliers affect the ability to abandon or delay the project when the downside scenario is seen. The overall project or investment portfolio of the company should also be taken into account as the risk profile of the whole portfolio will obviously impact the capital structure of the company.

This framework is however probably best suited to the Project Finance environment and this is potentially the best area for future research. Project Finance transactions are by their nature highly leveraged and are executed by an independent entity with a finite life making it much easier to apply the framework rather than assessing a project within a company that has a large portfolio and indefinite time horizon. The non-recourse nature of the transaction also means that there are complex contractual arrangements which will almost by default bring a focus on the two questions raised at the start of the Conclusion section as well as other risk mitigating and transfer measures.

There were limitations in this research in trying to frame the objective around a project that had already been executed. Expanding this research by applying it to a Project Finance transaction that is still under evaluation would give the researcher the ability to interface with all the stakeholders in the project at an early stage and structure the data and information in order to get the optimal benefit out of the real options process. With the ability to interact with equity shareholders and those providing the debt financing, various capital structures can be evaluated with the objective of improving the framework to the extent that it can determine the ultimate leverage ratio for the project.

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APPENDICES

Appendix 1 TLP Option NPV Model

Appendix 2 Subsea Option NPV Model

Appendix 3 TLP Option Capital Expenditure

Appendix 4 Subsea Option Capital Expenditure

Appendix 5 TLP Option Schematic

Appendix 6 Subsea Option Schematic

TLP Option		Unit	Total	2004	2005	2006	2007	2008	2009	2010	2011	2012
				1	2	3	4	5	6	7	8	9
Assumptions												
Inflation Rate	2.5%			1.000	1.025	1.051	1.077	1.104	1.131	1.160	1.189	1.218
Current Year	2004											
First Production Year	2007											
Last Production Year	2026											
Life of Project	22											
Reserves												
Production												
Oil Production (Upside +20%)		mbopd					72.019	72.000	72.098	71.994	72.000	70.501
Oil Production (Most Likely)		mbopd					60.02	60.00	60.08	60.00	60.00	58.75
Oil Production (Downside -20%)		mbopd					48.013	48.000	48.066	47.996	48.000	47.001
Annual Oil Production		mmbbl	200.433				21.906	21.900	21.930	21.898	21.900	21.444
Cummulative Oil Production		mmbbl					21.906	43.806	65.736	87.634	109.534	130.978
Revenue												
Oil Price Input												
Brent Oil Price	$21											
Price year	2004											
Oil Price Escalator	2.5%											
Oil Price Quality Discount Premium	-$1	$/bbl										
Oil Price Escalation				1.0000	1.0250	1.0506	1.0769	1.1038	1.1314	1.1597	1.1887	1.2184
Effective Oil Price (Green = Brent Fwd Curve)				$27.99	$25.48	$24.66	$24.55	$24.89	$22.76	$23.35	$23.96	$24.59
Gross Revenue		($000's)	$5 066 045.61			$0.00	$537 788.37	$545 091.00	$499 115.83	$511 400.38	$524 776.58	$527 234.89
Costs												
Capital Investment Costs												
Drilling		$000's	$229 193			$62 337	$57 212	$54 291	$55 353			
Completions		$000's	$210 037			$67 209	$50 694	$50 882	$41 252			
Production Facilities, Flowlines, Contrl Lines & Subsea Equipment		$000's	$137 419	$15 012	$57 473	$58 339		$6 595				
Platforms & Structures (excl CPF)		$000's	$275 362	$26 271	$153 236	$95 855						
Shared Infrastructure (CPF, Oil Export Line, Ceiba Modificationss)		$000's	$185 625	$19 584	$107 263	$58 778						
Total Capex		$000's	$1 037 636	$60 867	$317 972	$342 518	$107 906	$111 768	$96 605			
Capital Investment Cost - Adjusted for inflation												
Drilling		$000's	$249 658			$65 493	$61 611	$59 927	$62 627			
Completions		$000's	$228 040			$70 611	$54 592	$56 164	$46 673			
Production Facilities, Flowlines, Contrl Lines & Subsea Equipment		$000's	$142 494	$15 012	$58 910	$61 292	$0	$7 280				
Platforms & Structures (excl CPF)		$000's	$284 046	$26 271	$157 067	$100 708						
Shared Infrastructure (CPF, Oil Export Line, Ceiba Modificationss)		$000's	$191 282	$19 584	$109 945	$61 754						
Total Capex		$000's	$1 095 520	$60 867	$325 921	$359 858	$116 203	$123 371	$109 300			
Operating Costs												
Fixed Operating Costs		$000's	$602 979				$39 364	$39 364	$39 364	$39 699	$39 699	$38 054
Operating Costs including inflation		$000's	$799 190.494				$42 391	$43 450	$44 537	$46 039	$47 190	$46 365
Abandonment Cost Estimate		$000's	$65 400									
Abandonment Costs		$000's	$115 405.539				$0	$0	$6 411.419	$6 411	$6 411	$6 411
Bonus Payments												
Discovery Bonus		$000's										
Production Bonus		$000's				3000	3000					
Royalty												
Royalty Rate						0.00%	11.50%	11.50%	11.50%	11.50%	11.50%	11.49%
Royalty						$0.00	$61 849.25	$62 685.47	$57 415.35	$58 810.83	$60 349.31	$60 575.97
Depreciation												
Depreciable Capital		$000's	$845 862	$60 867	$325 921	$294 365	$54 592	$63 444	$46 673			
Depreciable Capital from year of production		$000's	$845 862	$0	$0	$0	$735 745	$63 444	$46 673	$0	$0	$0
Years of Straight line depreciation	4											
Salvage Value	0											
Depreciation		$000's	$845 862			$0	$183 936	$199 797	$211 466	$211 466	$27 529	$11 668
Cost Recovery												
Amount available for Cost Recovery		$000's		$0	$0	$0	$333 157	$337 684	$309 190	$316 813	$325 099	$326 661
Recoverable Costs		$000's				$65 493	$287 938	$303 175	$325 041	$263 916	$81 130	$64 445
Cost Recovery		$000's	$1 970 056			$0	$333 157	$323 448	$309 190	$279 766	$81 130	$64 445
Unrecovered Cost Pool		$000's				$65 493	$20 274	$0	$15 850	$0	$0	$0
Production Sharing												
Tranche 1 (0-200mmbo) - Project 80% / State 20%			200.00	0	0	0	21.90584	21.9	21.92993	21.898175	21.9	21.444115
Tranche 1 (200-350mmbo) - Project 70% / State 30%			0.43		0	0	0	0	0	0	0	0
Project Production Share						0.00	0.80	0.80	0.80	0.80	0.80	0.80
Project Share of Profit Oil		$000's	$2 016 989			$0	$114 225	$127 166	$106 008	$138 259	$306 638	$321 771
State Share of Profit Oil		$000's	$504 755			$0	$28 556	$31 791	$26 502	$34 565	$76 659	$80 443
Share of Profit Oil assigned to State Oil Company	5.0%					$0	$5 711	$6 358	$5 300	$6 913	$15 332	$16 089
Net Project Share of Profit Oil						$0	$108 514	$120 807	$100 708	$131 346	$291 306	$305 683
Tax												
Income Tax Rate	25.0%											
Tax Payable on Net Project Share of Profit Oil			$479 035			$0	$27 129	$30 202	$25 177	$32 837	$72 826	$76 421
Cash Flow												
Project Cash Flow			$1 391 044.389	-$60 867	-$325 921	-$362 858	$252 949	$247 233	$224 473	$325 825	$246 008	$240 930
Discount Rate	10.0%	$000's	$475 324	-$60 867	-$296 292	-$299 883	$190 045	$168 863	$139 380	$183 920	$126 241	$112 396
Discount Rate	12.0%	$000's	$371 198	-$60 867	-$291 001	-$289 268	$180 044	$157 121	$127 372	$165 073	$111 282	$97 308
Discount Rate	8.0%	$000's	$598 753	-$60 867	-$301 779	-$311 092	$200 799	$181 723	$152 773	$205 325	$143 544	$130 167
Economic Indicators												
IRR			24.04%									
Capex per bbl			$5.47									
Opex per bbl			$3.99									
Total			$9.45									

TLP Option	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Inflation Rate	1.249	1.280	1.312	1.345	1.379	1.413	1.448	1.485	1.522	1.560	1.599	1.639	1.680	1.722
Oil Production (Upside +20%)	51.077	37.685	29.086	22.932	18.161	14.446	11.566	9.546	8.294	7.180	5.761	4.770	4.384	3.458
Oil Production (Most Likely)	42.56	31.40	24.24	19.11	15.13	12.04	9.64	7.96	6.91	5.98	4.80	3.98	3.65	2.88
Oil Production (Downside -20%)	34.051	25.123	19.390	15.288	12.107	9.630	7.710	6.364	5.530	4.786	3.841	3.180	2.922	2.306
Annual Oil Production	15.536	11.462	8.847	6.975	5.524	4.394	3.518	2.904	2.523	2.184	1.752	1.451	1.333	1.052
Cummulative Oil Production	146.514	157.976	166.823	173.798	179.322	183.716	187.234	190.138	192.661	194.844	196.597	198.048	199.381	200.433
Oil Price Escalation	1.2489	1.2801	1.3121	1.3449	1.3785	1.4130	1.4483	1.4845	1.5216	1.5597	1.5987	1.6386	1.6796	1.7216
Effective Oil Price (Green = Brent Fwd Curve)	$25.23	$25.88	$26.55	$27.24	$27.95	$28.67	$29.41	$30.17	$30.95	$31.75	$32.57	$33.41	$34.27	$35.15
Gross Revenue	$391 909.51	$296 668.82	$234 918.19	$190 021.68	$154 386.28	$125 983.02	$103 475.55	$87 614.27	$78 093.19	$69 341.68	$57 077.43	$48 475.11	$45 695.36	$36 978.49
Fixed Operating Costs	$38 054	$38 054	$31 461	$31 461	$31 461	$24 441	$24 441	$24 441	$24 441	$19 836	$19 836	$19 836	$19 836	$19 836
Operating Costs including inflation	$47 524	$48 712	$41 280	$42 312	$43 369	$34 534	$35 398	$36 283	$37 190	$30 937	$31 711	$32 504	$33 316	$34 149
Abandonment Costs	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411
Royalty Rate	11.30%	11.04%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Royalty	$44 266.88	$32 766.20	$25 841.00	$20 902.38	$16 982.49	$13 858.13	$11 382.31	$9 637.57	$8 590.25	$7 627.58	$6 278.52	$5 332.26	$5 026.49	$4 067.63
Amount available for Cost Recovery	$243 350	$184 732	$146 354	$118 384	$96 183	$78 487	$64 465	$54 584	$48 652	$43 200	$35 559	$30 200	$28 468	$23 038
Recoverable Costs	$53 936	$55 124	$47 691	$48 723	$49 781	$40 946	$41 809	$42 694	$43 601	$37 349	$38 122	$38 915	$39 728	$40 561
Cost Recovery	$53 936	$55 124	$47 691	$48 723	$49 781	$40 946	$41 809	$42 694	$43 601	$37 349	$35 559	$30 200	$28 468	$23 038
Unrecovered Cost Pool	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2 563	$11 278	$22 537	$40 060
Tranche 1 (0-200mmbo) - Project 80% / State 20%	15.53586	11.46246	8.84687	6.97515	5.52391	4.39387	3.51787	2.903575	2.52288	2.183795	1.752365	1.450875	1.333345	0.619115
Tranche 1 (200-350mmbo) - Project 70% / State 30%	0	0	0	0	0	0	0	0	0	0	0	0	0	0.432815
Project Production Share	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.76
Project Share of Profit Oil	$234 966	$167 023	$129 109	$96 317	$70 098	$56 943	$40 227	$28 226	$20 721	$19 492	$12 192	$10 354	$9 761	$7 492
State Share of Profit Oil	$58 741	$41 756	$32 277	$24 079	$17 525	$14 236	$10 057	$7 056	$5 180	$4 873	$3 048	$2 589	$2 440	$2 381
Share of Profit Oil assigned to State Oil Company	$11 748	$8 351	$6 455	$4 816	$3 505	$2 847	$2 011	$1 411	$1 036	$975	$610	$518	$488	$375
Net Project Share of Profit Oil	$223 217	$158 672	$122 654	$91 501	$66 594	$54 096	$38 216	$26 815	$19 685	$18 518	$11 582	$9 837	$9 273	$7 118
Tax Payable on Net Project Share of Profit Oil	$55 804	$39 668	$30 663	$22 875	$16 648	$13 524	$9 554	$6 704	$4 921	$4 629	$2 896	$2 459	$2 318	$1 779
Project Cash Flow	$167 413	$119 004	$91 990	$68 626	$49 945	$40 572	$28 662	$20 111	$14 764	$13 888	$6 124	-$1 338	-$4 305	-$12 185
Discount Rate 10.0%	$70 999	$45 881	$32 242	$21 866	$14 467	$10 684	$6 861	$4 377	$2 921	$2 498	$1 001	-$199	-$582	-$1 497
Discount Rate 12.0%	$60 371	$38 316	$26 445	$17 615	$11 446	$8 302	$5 236	$3 281	$2 150	$1 806	$711	-$139	-$398	-$1 007
Discount Rate 8.0%	$83 748	$55 122	$39 453	$27 252	$18 365	$13 813	$9 035	$5 870	$3 990	$3 476	$1 419	-$287	-$855	-$2 241

Subsea Option		Unit	Total	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
				1	2	3	4	5	6	7	8	9	10	11	12
Assumptions															
Inflation Rate	2.5%			1.000	1.025	1.051	1.077	1.104	1.131	1.160	1.189	1.218	1.249	1.280	1.312
Current Year	2004														
First Production Year	2007														
Last Production Year	2026														
Reserves															
Choosen Production															
Oil Production (Most Likely)		mbopd					60.016	60.000	59.862	59.638	59.567	58.283	42.091	30.944	23.804
Annual Oil Production		mmbbl	198.432				21.906	21.900	21.850	21.768	21.742	21.273	15.363	11.295	8.688
Cummulative Oil Production		mmbbl					21.906	43.806	65.655	87.423	109.165	130.439	145.802	157.096	165.785
Revenue															
Oil Price Input															
Brent Oil Price	$21														
Price year	2004														
Oil Price Escalator	2.5%														
Oil Price Quality Discount Premium	-$1	$/bbl													
Oil Price Escalation				1.0000	1.0250	1.0506	1.0769	1.1038	1.1314	1.1597	1.1887	1.2184	1.2489	1.2801	1.3121
Effective Oil Price				$27.99	$25.48	$24.66	$24.55	$24.89	$22.76	$23.35	$23.96	$24.59	$25.23	$25.88	$26.55
Gross Revenue		($000's)	$5 011 342.31			$0.00	$537 788.37	$545 091.00	$497 288.24	$508 357.30	$520 989.44	$523 035.03	$387 554.34	$292 323.27	$230 711.80
Costs															
Capital Investment Costs															
Drilling		$000's	$226 784			$64 786	$58 342	$49 453	$54 203						
Completions		$000's	$303 761			$88 056	$74 298	$67 012	$74 395						
Production Facilities, Flowlines, Contrl Lines & Subsea Equipment		$000's	$261 022	$34 883	$143 044	$76 500		$6 595							
Platforms & Structures (excl CPF)		$000's	$35 725	$14 290	$21 435										
Shared Infrastructure (CPF, Oil Export Line, Ceiba Modificationss)		$000's	$192 003	$19 839	$109 942	$62 222									
Total Capex		$000's	$1 019 295	$69 012	$274 421	$291 564	$132 640	$123 060	$128 598						
Capital Investment Cost - Adjusted for inflation															
Drilling		$000's	$246 806			$68 066	$62 828	$54 587	$61 326						
Completions		$000's	$330 664			$92 514	$80 011	$73 969	$84 171						
Production Facilities, Flowlines, Contrl Lines & Subsea Equipment		$000's	$269 156	$34 883	$146 620	$80 373	$0	$7 280							
Platforms & Structures (excl CPF)		$000's	$36 261	$14 290	$21 971	$0									
Shared Infrastructure (CPF, Oil Export Line, Ceiba Modificationss)		$000's	$197 902	$19 839	$112 691	$65 372									
Total Capex		$000's	$1 080 789	$69 012	$281 282	$306 324	$142 839	$135 835	$145 497						
Operating Costs															
Fixed Operating Costs		$000's	$631 025				$40 872	$40 872	$40 872	$43 597	$43 597	$42 716	$42 716	$42 716	$32 962
Operating Costs including inflation		$000's	$831 761				$44 015	$45 115	$46 243	$50 559	$51 823	$52 045	$53 346	$54 680	$43 249
Abandonment Cost Estimate		$000's	$65 400												
Abandonment Costs		$000's	$115 406				$0	$0	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411
Bonus Payments															
Discovery Bonus		$000's													
Production Bonus		$000's				3000	3000								
Royalty															
Royalty Rate						0.00%	11.50%	11.50%	11.50%	11.50%	11.50%	11.49%	11.29%	11.03%	11.00%
Royalty						$0.00	$61 849.25	$62 685.47	$57 182.42	$58 445.66	$59 894.85	$60 071.99	$43 744.26	$32 244.74	$25 378.30
Depreciation															
Depreciable Capital		$000's	$833 982	$69 012	$281 282	$238 259	$80 011	$81 248	$84 171						
Depreciable Capital from year of production		$000's	$833 982	$0	$0	$0	$668 563	$81 248	$84 171	$0	$0	$0			
Years of Straight line depreciation	4														
Salvage Value	0														
Depreciation		$000's	$833 982			$0	$167 141	$187 453	$208 496	$208 496	$41 355	$21 043			
Cost Recovery															
Amount available for Cost Recovery		$000's		$0	$0	$0	$333 157	$337 684	$308 074	$314 938	$322 766	$324 074	$240 667	$182 055	$143 733
Recoverable Costs		$000's				$68 066	$273 983	$287 155	$322 476	$265 466	$99 589	$79 499	$59 758	$61 092	$49 660
Cost Recovery		$000's	$1 991 704			$0	$333 157	$296 047	$308 074	$279 868	$99 589	$79 499	$59 758	$61 092	$49 660
Unrecovered Cost Pool		$000's				$68 066	$8 892	$0	$14 402	$0	$0	$0	$0	$0	$0
Production Sharing															
Tranche 1 (0-200mmbo) - Project 80% / State 20%			198.43	0	0	0	21.90584	21.9	21.84963	21.76787	21.741955	21.273295	15.363215	11.29456	8.68846
Tranche 1 (200-350mmbo) - Project 70% / State 30%			0.00		0	0	0	0	0	0	0	0	0	0	0
Project Production Share						0.00	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Project Share of Profit Oil		$000's	$1 961 311			$0	$114 225	$149 087	$105 625	$136 035	$289 204	$306 771	$227 242	$159 190	$124 538
State Share of Profit Oil		$000's	$490 328			$0	$28 556	$37 272	$26 406	$34 009	$72 301	$76 693	$56 810	$39 797	$31 135
Share of Profit Oil assigned to State Oil Company	5.0%					$0	$5 711	$7 454	$5 281	$6 802	$14 460	$15 339	$11 362	$7 959	$6 227
Net Project Share of Profit Oil						$0	$108 514	$141 633	$100 344	$129 233	$274 744	$291 432	$215 880	$151 230	$118 312
Tax															
Income Tax Rate	25.0%														
Tax Payable on Net Project Share of Profit Oil			$465 811			$0	$27 129	$35 408	$25 086	$32 308	$68 686	$72 858	$53 970	$37 808	$29 578
Cash Flow															
Project Cash Flow			$1 355 183	-$69 012	-$281 282	-$309 324	$224 690	$221 321	$185 181	$319 822	$247 413	$239 617	$161 910	$113 423	$88 734
Discount Rate	10.0%	$000's	$476 210	-$69 012	-$255 710	-$255 640	$168 813	$151 165	$114 983	$180 531	$126 962	$111 783	$68 666	$43 729	$31 101
Discount Rate	12.0%	$000's	$376 248	-$69 012	-$251 144	-$246 592	$159 930	$140 653	$105 077	$162 032	$111 917	$96 777	$58 386	$36 519	$25 509
Discount Rate	8.0%	$000's	$594 682	-$69 012	-$260 446	-$265 196	$178 366	$162 677	$126 031	$201 542	$144 363	$129 458	$80 995	$52 537	$38 056
Ratios															
Capex (unescalated)		$/bbl	5.14												
Opex (unescalated)		$/bbl	3.18												
Capex + Opex (unescalated)		$/bbl	8.32												

Subsea Option	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	13	14	15	16	17	18	19	20	21	22	23	24	25
Assumptions													
Inflation Rate	1.345	1.379	1.413	1.448	1.485	1.522	1.560	1.599	1.639	1.680	1.722	1.765	1.809
Reserves													
Choosen Production													
Oil Production (Most Likely)	18.708	14.768	11.708	9.344	7.695	6.685	5.785	4.629	3.826	3.525	2.772		
Annual Oil Production	6.828	5.390	4.273	3.411	2.809	2.440	2.112	1.690	1.396	1.287	1.012		
Cummulative Oil Production	172.613	178.004	182.277	185.688	188.496	190.936	193.048	194.737	196.134	197.420	198.432	198.432	198.432
Revenue													
Oil Price Input													
Oil Price Escalation	1.3449	1.3785	1.4130	1.4483	1.4845	1.5216	1.5597	1.5987	1.6386	1.6796	1.7216	1.7646	1.8087
Effective Oil Price	$27.24	$27.95	$28.67	$29.41	$30.17	$30.95	$31.75	$32.57	$33.41	$34.27	$35.15	$36.06	$36.98
Gross Revenue	$186 024.36	$150 652.61	$122 529.42	$100 319.10	$84 750.70	$75 528.49	$67 046.90	$55 032.58	$46 658.05	$44 094.21	$35 567.10	$0.00	$0.00
Costs													
Operating Costs													
Fixed Operating Costs	$32 962	$32 962	$25 274	$25 274	$25 274	$25 274	$18 617	$18 617	$18 617	$18 617	$18 617		
Operating Costs including inflation	$44 330	$45 438	$35 712	$36 604	$37 519	$38 457	$29 036	$29 762	$30 506	$31 269	$32 050	$0	$0
Abandonment Cost Estimate												**115 405.539**	
Abandonment Costs	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$6 411	$0	$0
Royalty													
Royalty Rate	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	0.00%	0.00%
Royalty	$20 462.68	$16 571.79	$13 478.24	$11 035.10	$9 322.58	$8 308.13	$7 375.16	$6 053.58	$5 132.39	$4 850.36	$3 912.38	$0.00	$0.00
Cost Recovery													
Amount available for Cost Recovery	$115 893	$93 857	$76 336	$62 499	$52 800	$47 054	$41 770	$34 285	$29 068	$27 471	$22 158	$0	$0
Recoverable Costs	$50 742	$51 850	$42 123	$43 016	$43 931	$44 869	$35 448	$36 173	$36 918	$37 680	$38 462	$0	$0
Cost Recovery	$50 742	$51 850	$42 123	$43 016	$43 931	$44 869	$35 448	$34 285	$29 068	$27 471	$22 158	$0	$0
Unrecovered Cost Pool	$0	$0	$0	$0	$0	$0	$0	$1 888	$9 738	$19 947	$36 251	$36 251	$36 251
Production Sharing													
Tranche 1 (0-200mmbo) - Project 80% / State 20%	6.82842	5.39032	4.27342	3.41056	2.808675	2.440025	2.111525	1.689585	1.39649	1.286625	1.01178	0	0
Tranche 1 (200-350mmbo) - Project 70% / State 30%	0	0	0	0	0	0	0	0	0	0	0	0	0
Project Production Share	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.00	0.00
Project Share of Profit Oil	$91 856	$65 785	$53 543	$37 015	$25 198	$17 881	$19 379	$11 755	$9 966	$9 419	$7 597	$0	$0
State Share of Profit Oil	$22 964	$16 446	$13 386	$9 254	$6 299	$4 470	$4 845	$2 939	$2 492	$2 355	$1 899	$0	$0
Share of Profit Oil assigned to State Oil Company	$4 593	$3 289	$2 677	$1 851	$1 260	$894	$969	$588	$498	$471	$380	$0	$0
Net Project Share of Profit Oil	$87 263	$62 496	$50 865	$35 164	$23 938	$16 987	$18 410	$11 167	$9 468	$8 948	$7 217	$0	$0
Tax													
Tax Payable on Net Project Share of Profit Oil	$21 816	$15 624	$12 716	$8 791	$5 984	$4 247	$4 603	$2 792	$2 367	$2 237	$1 804	$0	$0
Cash Flow													
Project Cash Flow	$65 447	$46 872	$38 149	$26 373	$17 953	$12 740	$13 808	$6 487	-$749	-$3 499	-$10 891	$0	$0
Discount Rate (10.0%)	$20 854	$13 577	$10 046	$6 313	$3 907	$2 521	$2 483	$1 061	-$111	-$473	-$1 338		
Discount Rate (12.0%)	$16 799	$10 742	$7 806	$4 818	$2 929	$1 856	$1 796	$753	-$78	-$324	-$900		
Discount Rate (8.0%)	$25 990	$17 235	$12 988	$8 314	$5 240	$3 443	$3 455	$1 503	-$161	-$695	-$2 003		

Data Entry Sheet / Expenditure Schedule

Case ID:		1 000
Case Description:	TLP Option	

Reservoir A

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 2 981	$ 14 290	$ 17 271
2005			-		$ -	$ -	$ 14 654	$ 21 435	$ 36 090
2006	9		9		$ 30 578	$ 39 835	$ 15 177		$ 85 590
2007		4	4	10 956	$ 13 590	$ 17 704			$ 31 295
2008	5	2	7	10 950	$ 23 783	$ 30 982	$ 6 595		$ 61 360
2009			-	10 980	$ -	$ -			$ -
2010			-	10 948	$ -	$ -			$ -
2011			-	10 950	$ -	$ -			$ -
2012			-	10 494	$ -	$ -			$ -
2013			-	7 243	$ -	$ -			$ -
2014			-	5 166	$ -	$ -			$ -
2015			-	4 054					$ -
2016			-	3 317					$ -
2017			-	2 724					$ -
2018			-	2 245					$ -
2019			-	1 864					$ -
2020			-	1 627					$ -
2021			-	1 535					$ -
2022			-	1 417					$ -
2023			-	1 189					$ -
2024			-	1 009					$ -
2025			-	986					$ -
2026			-	778					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	**14**	**6**	**20**	**100 432**	**$ 67 952**	**$ 88 521**	**$ 39 407**	**$ 35 725**	**$ 231 605**

Reservoir B

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 5 522	$ 5 643	$ 11 165
2005			-		$ -	$ -	$ 20 029	$ 62 073	$ 82 103
2006	4		4		$ 22 958	$ 21 837	$ 19 765	$ 45 144	$ 109 704
2007		3	3	7 300	$ 17 218	$ 16 378			$ 33 596
2008			-	7 300	$ -	$ -			$ -
2009	2	1	3	5 951	$ 17 218	$ 16 378			$ 33 596
2010			-	4 852	$ -	$ -			$ -
2011			-	3 956	$ -	$ -			$ -
2012			-	3 225	$ -	$ -			$ -
2013			-	2 629	$ -	$ -			$ -
2014			-	2 143	$ -	$ -			$ -
2015			-	1 747					$ -
2016			-	1 425					$ -
2017			-	1 161					$ -
2018			-	947					$ -
2019			-	772					$ -
2020			-	629					$ -
2021			-	513					$ -
2022			-	418					$ -
2023			-	341					$ -
2024			-	278					$ -
2025			-	227					$ -
2026			-	185					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	**6**	**4**	**10**	**46 000**	**$ 57 394**	**$ 54 592**	**$ 45 316**	**$ 112 861**	**$ 270 164**

Reservoir C

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 4 902	$ 6 339	$ 11 241
2005			-		$ -	$ -	$ 18 294	$ 69 727	$ 88 021
2006			-		$ -	$ -	$ 17 482	$ 50 710	$ 68 192
2007			-	-	$ -	$ -			$ -
2008	4		4	-	$ 30 508	$ 19 899			$ 50 407
2009	1	4	5	1 349	$ 38 135	$ 24 874			$ 63 009
2010			-	3 487	$ -	$ -			$ -
2011			-	5 127	$ -	$ -			$ -
2012			-	6 390	$ -	$ -			$ -
2013			-	4 780	$ -	$ -			$ -
2014			-	3 576	$ -	$ -			$ -
2015			-	2 675	$ -	$ -			$ -
2016			-	2 001					$ -
2017			-	1 497					$ -
2018			-	1 120					$ -
2019			-	838					$ -
2020			-	627					$ -
2021			-	469					$ -
2022			-	351					$ -
2023			-	262					$ -
2024			-	196					$ -
2025			-	147					$ -
2026			-	110					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	**5**	**4**	**9**	**35 000**	**$ 68 643**	**$ 44 774**	**$ 40 678**	**$ 126 776**	**$ 280 870**

Reservoir D

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 1 607		$ 1 607
2005			-		$ -	$ -	$ 4 495		$ 4 495
2006	1		1		$ 8 801	$ 5 537	$ 5 916		$ 20 254
2007	1	2	3	3 650	$ 26 404	$ 16 612			$ 43 016
2008			-	3 650	$ -	$ -			$ -
2009			-	3 650	$ -	$ -			$ -
2010			-	2 611	$ -	$ -			$ -
2011			-	1 867	$ -	$ -			$ -
2012			-	1 335	$ -	$ -			$ -
2013			-	955	$ -	$ -			$ -
2014			-	683					$ -
2015			-	489					$ -
2016			-	349					$ -
2017			-	250					$ -
2018			-	179					$ -
2019			-	128					$ -
2020			-	91					$ -
2021			-	65					$ -
2022			-	47					$ -
2023			-	-					$ -
2024			-	-					$ -
2025			-	-					$ -
2026			-	-					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	**2**	**2**	**4**	**20 000**	**$ 35 205**	**$ 22 150**	**$ 12 017**	**$ -**	**$ 69 372**

Shared Infrastructure

Central Processing Platform (CPF) ($000's)	Oil Export Line (CPF --> Sendje Ceiba) ($000's)	Sendje Ceiba Modif. ($000's)	Total Shared Infrastr. ($000's)
$ 18 365	$ 504	$ 715	$ 19 584
$ 100 903	$ 5 174	$ 1 185	$ 107 263
$ 52 685	$ 5 753	$ 340	$ 58 778
			$ -
			$ -
			$ -
			$ -
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			$ -
			$ -
			$ -
			$ -
			$ -
$ 171 954	**$ 11 431**	**$ 2 240**	**$ 185 625**

Total

Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling	Completions	Production	Platforms	Shared	Total Capex ($000's)
-	-	-	-	$ -	$ -	$ 15 012	$ 26 271	$ 19 584	$ 60 867
-	-	-	-	$ -	$ -	$ 57 473	$ 153 236	$ 107 263	$ 317 971
14	-	14	-	$ 62 337	$ 67 209	$ 58 339	$ 95 855	$ 58 778	$ 342 518
1	9	10	21 906	$ 57 212	$ 50 694	$ -	$ -	$ -	$ 107 907
9	2	11	21 900	$ 54 291	$ 50 882	$ 6 595	$ -	$ -	$ 111 768
3	5	8	21 930	$ 55 353	$ 41 252	$ -	$ -	$ -	$ 96 605
-	-	-	21 898	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	21 900	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	21 444	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	15 607	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	11 568	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	8 965	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	7 092	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	5 632	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	4 490	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	3 601	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	2 974	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	2 582	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	2 233	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	1 792	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	1 483	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	1 359	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	1 073	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
27	**16**	**43**	**201 431**	**$ 229 194**	**$ 210 037**	**$ 137 418**	**$ 275 362**	**$ 185 625**	**$ 1 037 636**

Data Entry Sheet / Expenditure Schedule

Case ID:		**1 000**
Case Description:		**Subsea Option**

Reservoir A

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 2 981	$ 14 290	$ 17 271
2005			-		$ -	$ -	$ 14 654	$ 21 435	$ 36 090
2006	9		9		$ 29 030	$ 39 835	$ 15 177		$ 84 041
2007		4	4	10 956	$ 12 902	$ 17 704			$ 30 606
2008	5	2	7	10 950	$ 22 579	$ 30 982	$ 6 595		$ 60 156
2009			-	10 980	$ -	$ -			$ -
2010			-	10 948	$ -	$ -			$ -
2011			-	10 950	$ -	$ -			$ -
2012			-	10 494	$ -	$ -			$ -
2013			-	7 243	$ -	$ -			$ -
2014			-	5 166	$ -	$ -			$ -
2015			-	4 054					$ -
2016			-	3 317					$ -
2017			-	2 724					$ -
2018			-	2 245					$ -
2019			-	1 864					$ -
2020			-	1 627					$ -
2021			-	1 535					$ -
2022			-	1 417					$ -
2023			-	1 189					$ -
2024			-	1 009					$ -
2025			-	986					$ -
2026			-	778					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	14	6	20	100 432	$ 64 510	$ 88 521	$ 39 407	$ 35 725	$ 228 163

Reservoir B

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 15 344		$ 15 344
2005			-		$ -	$ -	$ 61 281		$ 61 281
2006	4		4		$ 27 480	$ 39 143	$ 29 650		$ 96 272
2007		3	3	7 300	$ 20 610	$ 29 357			$ 49 967
2008			-	7 300	$ -	$ -			$ -
2009	2	1	3	5 871	$ 20 610	$ 29 357			$ 49 967
2010			-	4 722	$ -	$ -			$ -
2011			-	3 798	$ -	$ -			$ -
2012			-	3 054	$ -	$ -			$ -
2013			-	2 456	$ -	$ -			$ -
2014			-	1 976	$ -	$ -			$ -
2015			-	1 589					$ -
2016			-	1 278					$ -
2017			-	1 028					$ -
2018			-	827					$ -
2019			-	665					$ -
2020			-	535					$ -
2021			-	430					$ -
2022			-	346					$ -
2023			-	278					$ -
2024			-	224					$ -
2025			-	180					$ -
2026			-	145					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	6	4	10	44 000	$ 68 699	$ 97 858	$ 106 275	$ -	$ 272 831

Reservoir C

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 10 230		$ 10 230
2005			-		$ -	$ -	$ 40 854		$ 40 854
2006			-		$ -	$ -	$ 19 766		$ 19 766
2007			-	-	$ -	$ -			$ -
2008	4		4	-	$ 26 875	$ 36 030			$ 62 905
2009	1	4	5	1 349	$ 33 594	$ 45 037			$ 78 631
2010			-	3 487	$ -	$ -			$ -
2011			-	5 127	$ -	$ -			$ -
2012			-	6 390	$ -	$ -			$ -
2013			-	4 709	$ -	$ -			$ -
2014			-	3 470	$ -	$ -			$ -
2015			-	2 557	$ -	$ -			$ -
2016			-	1 884					$ -
2017			-	1 388					$ -
2018			-	1 023					$ -
2019			-	754					$ -
2020			-	556					$ -
2021			-	409					$ -
2022			-	302					$ -
2023			-	222					$ -
2024			-	164					$ -
2025			-	121					$ -
2026			-	89					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	5	4	9	34 001	$ 60 468	$ 81 067	$ 70 850	$ -	$ 212 385

Reservoir D

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling ($000's)	Completions ($000's)	Production Facilities, Flowlines, Contrl lines, & Subsea Equipment ($000's)	Platforms & Structures (excl CPF) ($000's)	Total Capex ($000's)
2004			-		$ -	$ -	$ 6 327		$ 6 327
2005			-		$ -	$ -	$ 26 256		$ 26 256
2006	1		1		$ 8 277	$ 9 079	$ 11 907		$ 29 263
2007	1	2	3	3 650	$ 24 831	$ 27 236			$ 52 067
2008			-	3 650	$ -	$ -			$ -
2009			-	3 650	$ -	$ -			$ -
2010			-	2 611	$ -	$ -			$ -
2011			-	1 867	$ -	$ -			$ -
2012			-	1 335	$ -	$ -			$ -
2013			-	955	$ -	$ -			$ -
2014			-	683	$ -	$ -			$ -
2015			-	489					$ -
2016			-	349					$ -
2017			-	250					$ -
2018			-	179					$ -
2019			-	128					$ -
2020			-	91					$ -
2021			-	65					$ -
2022			-	47					$ -
2023			-	-					$ -
2024			-	-					$ -
2025			-	-					$ -
2026			-	-					$ -
2027			-						$ -
2028			-						$ -
2029			-						$ -
2030			-						$ -
Total	2	2	4	20 000	$ 33 108	$ 36 315	$ 44 490	$ -	$ 113 913

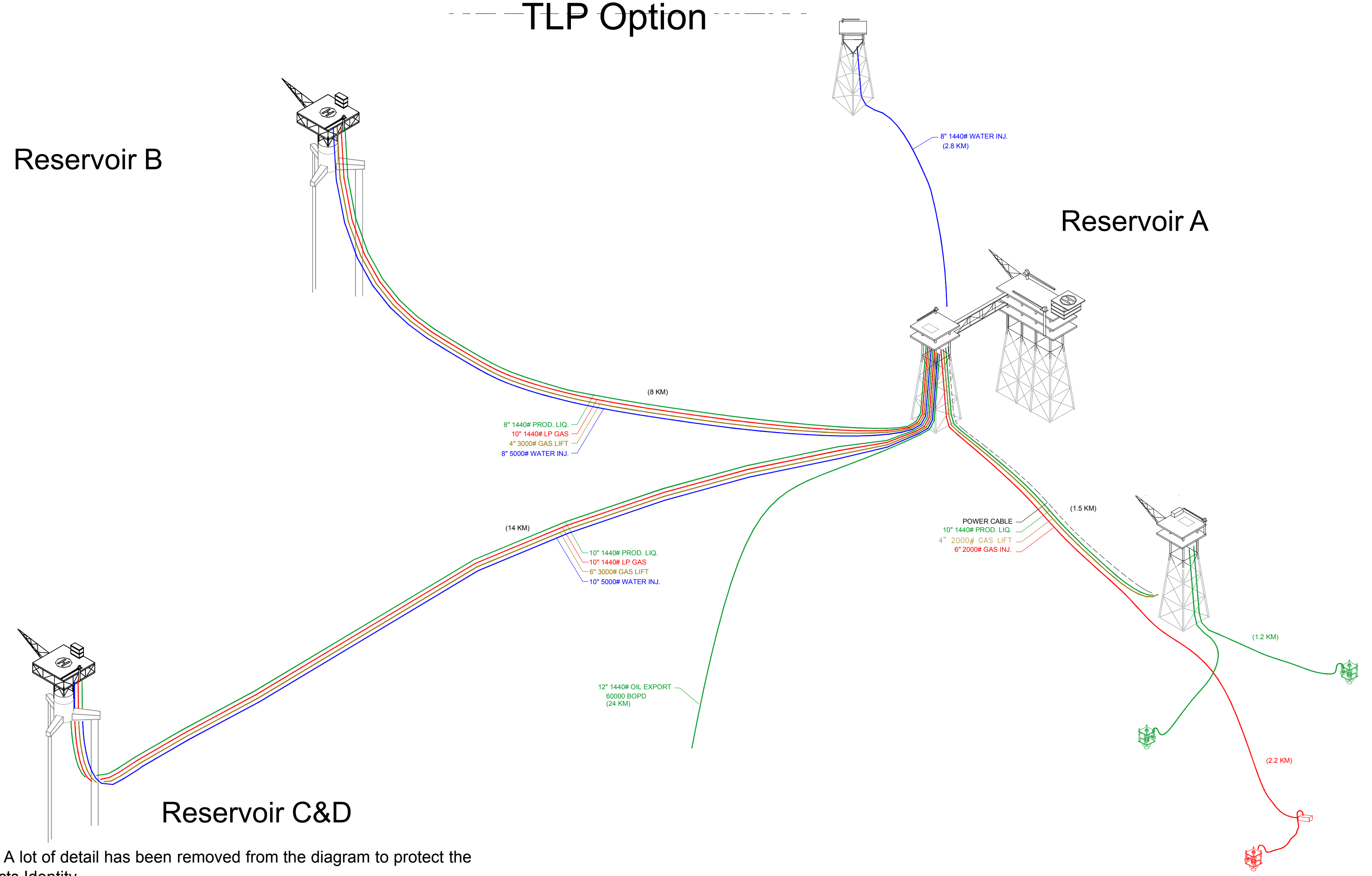
Shared Infrastructure

Year	Central Processing Platform (CPF) ($000's)	Oil Export Line (CPF --> Sendje Ceiba) ($000's)	Sendje Ceiba Modif. ($000's)	Total Shared Infrastr. ($000's)
2004	$ 19 088	$ 504	$ 247	$ 19 839
2005	$ 103 625	$ 5 174	$ 1 143	$ 109 942
2006	$ 55 617	$ 5 753	$ 852	$ 62 222
2007				$ -
2008				$ -
2009				$ -
2010				$ -
2011				$ -
2012				$ -
2013				$ -
2014				$ -
2015				$ -
2016				$ -
2017				$ -
2018				$ -
2019				$ -
2020				$ -
2021				$ -
2022				$ -
2023				$ -
2024				$ -
2025				$ -
2026				$ -
2027				$ -
2028				$ -
2029				$ -
2030				$ -
Total	$ 178 331	$ 11 431	$ 2 242	$ 192 004

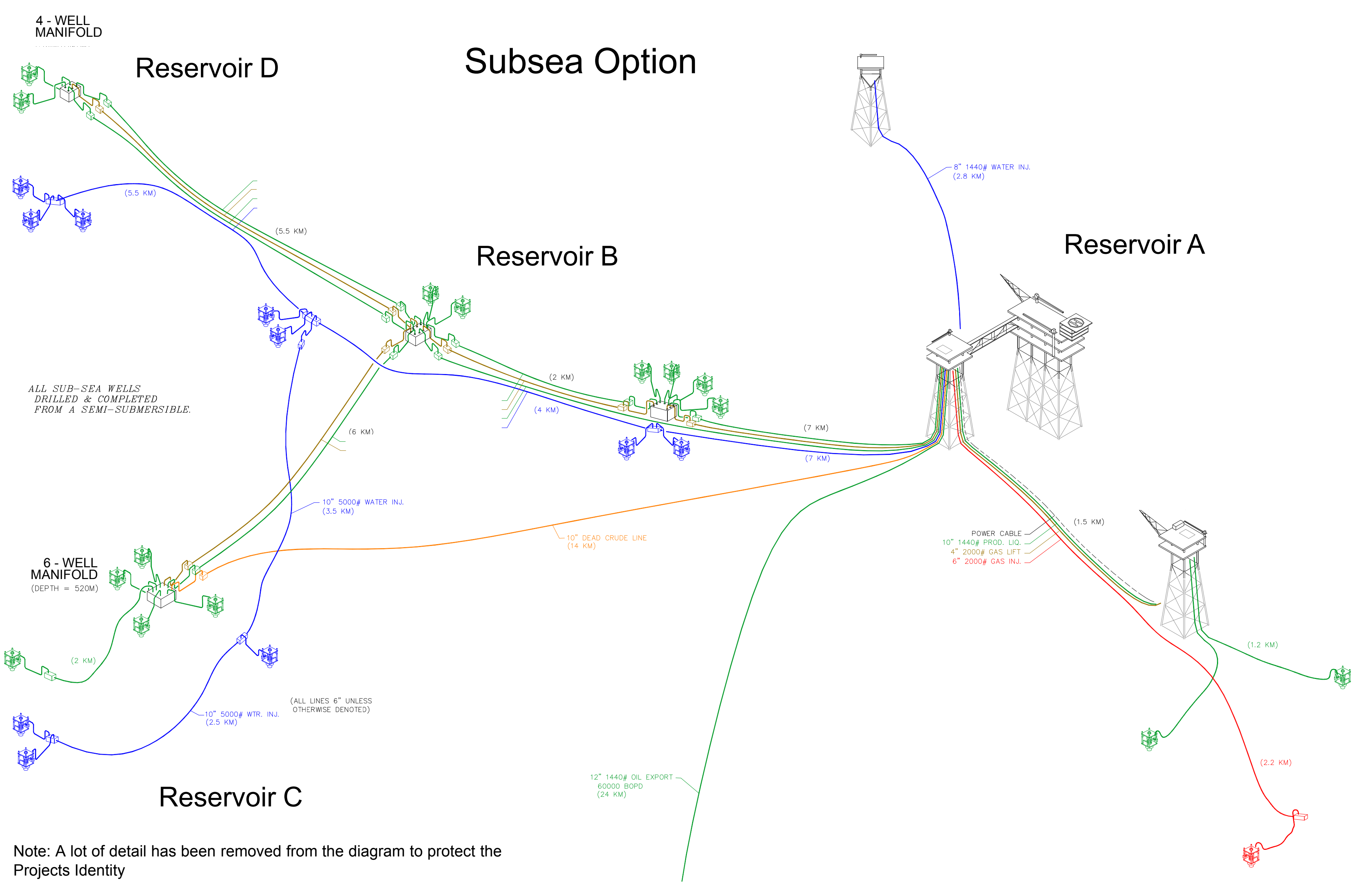
Total

Year	Development Drilling Schedule (No. wells per year) Prod.	Inj.	Tot	Gross Annual Oil Prod. (MBO)	Gross Capital Investment: Drilling	Completions	Production	Platforms	Shared	Total Capex ($000's)
2004	-	-	-	-	$ -	$ -	$ 34 883	$ 14 290	$ 19 839	$ 69 011
2005	-	-	-	-	$ -	$ -	$ 143 044	$ 21 435	$ 109 942	$ 274 422
2006	14	-	14	-	$ 64 786	$ 88 056	$ 76 500	$ -	$ 62 222	$ 291 565
2007	1	9	10	21 906	$ 58 342	$ 74 298	$ -	$ -	$ -	$ 132 640
2008	9	2	11	21 900	$ 49 453	$ 67 012	$ 6 595	$ -	$ -	$ 123 061
2009	3	5	8	21 850	$ 54 203	$ 74 395	$ -	$ -	$ -	$ 128 598
2010	-	-	-	21 768	$ -	$ -	$ -	$ -	$ -	$ -
2011	-	-	-	21 742	$ -	$ -	$ -	$ -	$ -	$ -
2012	-	-	-	21 273	$ -	$ -	$ -	$ -	$ -	$ -
2013	-	-	-	15 363	$ -	$ -	$ -	$ -	$ -	$ -
2014	-	-	-	11 295	$ -	$ -	$ -	$ -	$ -	$ -
2015	-	-	-	8 688	$ -	$ -	$ -	$ -	$ -	$ -
2016	-	-	-	6 829	$ -	$ -	$ -	$ -	$ -	$ -
2017	-	-	-	5 390	$ -	$ -	$ -	$ -	$ -	$ -
2018	-	-	-	4 274	$ -	$ -	$ -	$ -	$ -	$ -
2019	-	-	-	3 411	$ -	$ -	$ -	$ -	$ -	$ -
2020	-	-	-	2 809	$ -	$ -	$ -	$ -	$ -	$ -
2021	-	-	-	2 440	$ -	$ -	$ -	$ -	$ -	$ -
2022	-	-	-	2 111	$ -	$ -	$ -	$ -	$ -	$ -
2023	-	-	-	1 689	$ -	$ -	$ -	$ -	$ -	$ -
2024	-	-	-	1 397	$ -	$ -	$ -	$ -	$ -	$ -
2025	-	-	-	1 287	$ -	$ -	$ -	$ -	$ -	$ -
2026	-	-	-	1 012	$ -	$ -	$ -	$ -	$ -	$ -
2027	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
2028	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
2029	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
2030	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Total	27	16	43	198 433	$ 226 785	$ 303 761	$ 261 021	$ 35 725	$ 192 004	$ 1 019 296

TLP Option



Note: A lot of detail has been removed from the diagram to protect the Projects Identity



Note: A lot of detail has been removed from the diagram to protect the Projects Identity