CRANFIELD UNIVERSITY

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Oil and Gas Marginal Field Techno-Economics

School of Engineering
Energy Economics

PhD Thesis

Supervisors: Dr. Kenneth Ramsden/Professor Pilidis

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This thesis is submitted for the degree of Doctor of Philosophy

ABSTRACT

The global oil reserve reduction and the unavailability of easy to reach oil have necessitated the need for oil and gas producers and countries to look into marginal oil and gas fields. These are fields defined as abandoned, not commercially and economically viable, and not categorised as a major find. New and emerging smaller companies, especially NOCs and Indigenous oil companies, have seen these fields as opportunities to become truly oil & gas exploration and production companies. However, investment decisions were made by most of these companies without the right financial and economic tools thereby creating gaps in their decision quality and day to day knowledge of their investment profitability indices while in operation. This necessitated the need for the development of an Integrated Techno-Economic/Financial Model that can be used for investment decision and operating of Marginal oil and gas fields.

In the development of this tool/model, a structured process of research and project execution known as the gate system and the PMI-5 Project Management Process was used to carry out this PhD research to develop model/tool with the required flexibility to support robust decisions on investments and operating of Marginal Field Facilities Several Techno-Economic Assessment (TEA) Methods were reviewed and the Discounted Cash Flow TEA type selected to be the best fit method for the analysis because of its ability to look at the entire field life of the opportunity. The integration of these methods with an Integrated Risk Management System led to the development of the UZO-MARG Economic and Financial Model which is one of the key deliverable for this research. The Model tool was validated with an actual operating Marginal Field development data with acceptable error Margin even while not been privy to the entire project execution data for this field.

On using the UZO-MARG tool to evaluate the Shekinah field, it was observed that the PSC agreement returns better VIR, NPV and ROACE, compared to the JV agreement for the operator e.g. NPV $1219.1mln; IRR 18% for PSC terms versus NPV $35.3mln; IRR 2% for JV terms. In addition, the Model tool is also applicable for the determination of economic and financial parameters for various technology applications i.e. using Hybrid Power Generation technology (for reduced CO_2 emissions) instead of a standalone renewable energy or conventional energy technology systems.

Keywords: UZO-MARG, Marginal Fields, CO_2, TEA, DCF, Simulation Model.

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The story of this PhD program will not be complete without special recognition and gratitude to my wife Uzoaku and children, Shekinah, Shammah and Shalom. My wife’s support and understanding was outstanding. She pushed, encouraged, prayed and managed our children while I spent time overseas working on this research and at the same time working on my regular job. To my Pastors and Special Friends, many thanks and God bless all of you in Jesus Name. Amen. Special thanks go to our father in the Lord, Pastor E.A. Adeboye for his pronouncement and prayer when I discussed this project with him some years back. He said to me, “Son, you will finish well”. Praise the Lord.

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B/D	Barrels per Day
BBL	Barrels
BCF	Billion Cubic Feet
BOPD	Barrels of Oil Per Day
CAPEX	Capital Expenditure
CCF	Capital Cash Flows
CEM	Cost Estimation Methods
CO	Carbon monoxide
CO_2	Carbon dioxide
CPF	Central Processing Facility
CSP	Concentrated Solar Power
CT	Corporation Tax
DCF	Discounted Cash Flow
DPR	Department of Petroleum Resources (Nigeria)
ECF	Excess Cash Flow
EIA	Energy Information Administration
EPF	Early Production Facility
FCF	Free Cash Flow
GHG	Green House Gas
GOR	Gas and Oil Reserves
IEA	International Energy Agency
IOC	International Oil Companies
IOGC	International Oil and Gas Companies
IRR	Internal Rate of Return
JV	Joint Venture
KWH	Kilowatt-Hour
MBPD	Million Barrels Per Day
MFDP	Marginal Fields Development Project
MMBBL	Million Barrels
MMBO	Million Barrels of Oil
MMBtu	Million British Thermal Unit
MSCF/D	Million Standard Cubic Feet per Day
MW	Mega Watt

NCF	Net Cash Flow
NOCs	National Oil Companies
NOX	Mono-nitrogen oxides
NPV	Net Present Value
O&M	Operation & Maintenance
OEM	Original Equipment Manufacturer
OML	Oil Mining License / Oil Mining Lease
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating Expenditure
OPL	Oil Prospecting License
PPT	Petroleum Profit Tax
ROACE	Return on Average Capital Employed
ROCE	Return on Capital Employed
SCR	Selective Catalytic Reduction
SMEs	Subject Matter Experts
TEA	Techno-Economic Analysis
TECOP	Technical, Economical, Commercial, Organizational and Political
UZO-MARG	Name of the model that was developed for this study
VAT	Value Added Tax
VIR	Value Investment Ratio
WACC	Weighted Average Cost of Capital
WEO	World Economic Outlook

1 Introduction

1.1 Research Objectives

The development of Marginal Oil and Gas Fields over the years have proven to be a challenge due to some factors such as economic and commercial viability, location of the field, the reserve capacity, all this define the Marginality of the field.

Often, these fields are left undeveloped as it does not offer the kind of return on investment most major oil and gas investors' desire for their respective investments.

Improvement in technology, the need for more oil, increased oil price, the rise of middle level companies interested in the exploration and production of Marginal Oil and Gas fields (entry point to oil and gas development), better commercial terms and fiscal regimes offered by Governments, Tax Holidays for new entrants, cheaper construction costs, especially in the low oil price world are energising and driving continued interest in the development of Marginal Oil and Gas opportunities.

With the above opportunities come several needs/challenges for buyers and operators of Marginal Fields, especially new entrants into this business. This includes amongst others, tools for proper valuation and evaluation of the assets/opportunities i.e. economic and financial analysis/valuation/evaluation of the fields before field purchase and economic/financial optimisation during the operation of the asset using the same tool. It is important to add that most studies that have been done till date in oil and gas has focused mainly on the big opportunities with little attention on Marginal Oil and Gas Filed development.

In the course of this research, one thing that came out clearly is the need to develop an integrated techno-economic and financial model that can be used for valuation/evaluation before purchase and during operation of the marginal field. The outcome of the valuation/valuation will help steer decision makers to robust investment decisions and evaluating asset profitability during the operational phase of fields/assets.

Another important objective of this research is one I refer as an opportunity, which is the use of the developed techno-economic model for evaluation of renewable energy utilisation in marginal oil and gas assets.

Below is a summary of the research aims and objectives: -

1. Develop an Integrated Economic and Financial Model (tool) that can be used by Marginal Field Operators or investors to value assets before they are bought.
2. Develop a Model that can be used by Marginal Field Operators to run Techno-Economic Analysis of Projects to check profitability and commercial viability of assets.
3. Build a Model that will be used for consistent commercial healthiness check of the field or operating asset during the operations phase of the field.
4. Demonstrate the benefits of having an integrated Power system of both Conventional and Renewable Energy in a plant and still remain commercially and economically viable.
5. A Model that gives the Marginal Field operators clear insights on how to sweat the asset i.e getting more profit/value from the asset without compromising technical integrity.
6. Own a credible and robust Economic and Financial Model that is integrated i.e can carry out not just economic analysis but also financial analysis using direct inputs from the economic indices of the model.
7. To illustrate the benefit of the proposed model through the various listed case studies.

The Model is made up of Sub-Surface Production Profiles, Cost Estimates, Risk Analysis, Fiscal Regimes, Environmental Penalty Factors, Share Equity Selection, economic and financial input & output parameters and other variables.

The developed tool, referred to as UZO-MARG Model, has been used to carry out all the case studies with different concepts in this research. The model has also been Verified and Validated using data from marginal field operator.

1.1.1 Research Novelty

In addition to the thesis aims outlined above, further contributions to knowledge would be: -

- Integrating existing methods to develop and build a new tool that can be used for carrying out Economic and Financial analysis of Marginal Oil and Gas Fields/opportunities.
- Holistic evaluation of the use of Renewable Energy for development of Marginal Oil and Gas Fields, including Hybrid approach.
- Appreciation of the impact of government policies on the sale and development of Marginal Fields.
- The impact of policies concerning energy, natural resources and the environment in Marginal oil and gas development, particularly in emerging economies.
- Establishing the use of Net Present Value (NPV) and Value Investment Ratio (VIR) as a robust factor for Investment decision for Marginal oil and gas field Technology Decision compared to Technical Robustness.

1.1.2 Thesis Structure

This thesis consists of nine chapters. This section gives highlights what is contained in the each of the respective chapters.

Chapter 1

This chapter laid the foundation for the entire research/project work for this PhD. Defined the structure upon which the research work has been executed. It is made up of the Introduction, Research Objectives, Aims, Novelty, Structure, Statement, Facts, Assumptions and Boundaries. The applied research methodology is a project management approach which is well known globally by project practitioners known as the project gate process and PMI 5 process approach; it is a well deployed system approach by major oil and gas companies.

The stage gate approach looks at assessing the research (Feasibility), selection the option (Concept Selection), defining the project (Project Specification) and Execute (getting the research intent done with the deliverable). And the PMI-5 Project Management looks at research/project Initiation (why do you want to do this, have a research charter in place), Planning (how do you want to do the research, define scope etc.), Execution (entails performing the planned and outline tasks, evaluating the overall performance of the research outcome while ensuring that quality standards are been met), Control (Monitor research outcomes, validate research results) and Closing (conclusions, future work to be done, close out report-in this case Thesis).

The data management and quality framework for the research is framed on data management life cycle, actual data management plan, how data was stored, types of data, naming, data security and filing i.e. in such a way that someone else can pick the data and use it without challenges is also defined in in this introductory chapter.

Chapter 2

This chapter is focused on review of literatures, articles, journals, books and information that is available on Marginal fields. It also contains issues on global challenge of oil and gas reduction and no cheap & easy to reach oil, the opportunities and the threats. In addition, it looked at potential economic and financial analysis, the fiscal regimes that run oil and gas and how they differ from Marginal Oil and gas fields in different countries, how Marginal Fields are currently been valued today and the challenges of profitability of these fields. How have these fields been profitable and the challenges they are currently having? Are their aspirations being met and what can be done to support them? Do they have adequate tools for their investment decisions like the big oil and gas players? And what is the impact of Government policies on Marginal fields?

This chapter also talks about the concerns of the impact of CO_2 on climate change and how renewable energy can be seen as an opportunity to reduce

CO_2 emission by deploying them in Marginal oil and gas fields as an opportunity.

Chapter 3

Chapter three underpinned the fact that a Techno-Economic Analysis (TEA) will be required. Various TEA methods were reviewed before landing on the selected method of Best Fit TEA that was used to develop and building the Techno-economic model. The criteria for selection of method of best fit ranges from ease of use of method, robustness, flexibility, adaptability with other programs for software development. The methods evaluated are Static Cost Benefit Assessment Method, Annuity Assessment Method, Net Cash Flow Assessment Method, Internal Rate of Return(IRR) Assessment Method and Net Present Value (NPV) discounted cash flow Assessment Method.

The Net Present Value (NPV) Discounted Cash Flow Assessment Method was selected because of its ability to look into the future which is a similar trend for oil and gas business because of the need to assess the entire field life and manage the potential risks that come with it i.e. low oil price, fiscal regimes changes etc.

Chapter 4

This chapter presents the deeper focus on model development methodologies and types of models. The different types of Models reviewed in this research ranges from Visual, Mathematical, Empirical and Simulation Models. It came out clearly that Simulation Model is best fit for this research objective because of its ease of use on a computer and its flexibility to be built upon and integrated to software. Two model design platforms were studied with the intention to select one, the One-off (Unique design) for just one off model development and the Template model design that will keep the model and even have it in a network for multiple use. The Template or pattern Model was selected because of the multiple and complicated algorithm that it can handle. The modelling cycle process was detailed out to help define the process the model development has to go through. Different types of computer package programs were reviewed, and spreadsheet was decided to be the one to be used backed by MS Office because of its wide use and not difficult to learn. This chapter also evaluated how the designed and built model will be verified and validated. The validation methods considered are subjective and quantitative methods.

Chapter 5

This chapter describes the importance of oil and gas valuation, especially before investment decisions are made. The various types of valuation methodology including the type covering just only fields with exploration data and fields that are already developed and operation phase. The methods for oil and gas valuation was also described in detail, the methods reviewed are the Cost Approach method (also known as the appraised value method), Comparable Transactions (Market Approach) and the Income Approach Method. The Income approach method came out clearly to suit the simulation model approach and the template model design because it works on the basis of discounted Cash Flow (DCF) which most companies in the oil and gas business use as the business is normally a long term business. A case study property valuation was also carried out in this chapter for both exploration field and developed field.

Chapter 6

To be able to do any Techno-Economic Analysis (TEA) for any system, there is need to establish the financial and economic status of a field to support an investment decision, value the asset, build a model and validate the model. Doing all of the aforementioned only points to the fact that we need to develop costs estimates as one of the very important input variables. Hence, this chapter discusses Cost Estimation for the entire research. It looked at different types of Cost Estimation methods ranging from Bottom up Cost Estimation Method-where you use specifications from engineering drawings and analysis, Analogy Cost Estimation Method, where you use information that are proven from similar projects and Expert Judgement Cost Estimation Method- known to be subjective in nature since it is built around the knowledge and experience of the estimator. Most of this methods do work but depends on what phase a project is i.e. feasibility up to operation phase. The Analogy Cost Estimation method is best for the case studies since cost of similar projects or the same projects exists. It looked at factors that affect costs estimates e.g. contingency.

Chapter 7

This chapter presents the developed UZO-MARG Model. It is the combination and inclusion of all the studies and researches that have been done till date (reference the Thesis structure in Figure 1.3). It describes the model in detail and what the model can deliver in terms of what the model can do- Techno-Economic Analysis, Economic and Financial Analysis and Asset Valuation. This chapter also enumerates the various case studies carried out in UZO-MARG and very important to mention is the validation result of the model.

For the Shekinah Field, the outcome of the concept engineering studies is also captured in this chapter showing the results of the pipeline studies, facilities studies, with the production profiles and process descriptions. Different sensitivities were carried out to demonstrate not just the robustness of the model but the gains and impact of different decisions in Marginal field's development and operatorship.

The commercial viability of two different fields – Shekinah (with all the technical work that was done) and Otakikpo Marginal field was carried out. The already known results of Otakikpo were used to validate UZO-MARG.

Chapter 8

This chapter looked at how marginal fields can be sustained and made to be profitable consistently, using technologies that could offer lower operating and capital costs where possible. The opportunity looked at power generation and renewable energies.

The case studies in this instance evaluated the application of conventional energy system and renewable energies to run the Marginal field in Otakikpo and Shekinah. Also, the use of a combined renewable energy system, conventional and renewable energy technology was also studied as part of this research, this combination is known as a Hybrid solution. The focus was to establish the economic and financial differences under these case studies scenarios and demonstrate that either of these technologies can be used and still have the Marginal field remain profitable.

Chapter 9

This chapter presents the discussions, conclusions, recommendations and future work to be done. The conclusion shows that this is a good tool that can be used and still has potential to be improved upon as part of future work. Also, it is a tool that stands to provide immediate benefit to Marginal field operators.

1.1.3 Research Methodology

This research is carried out with a systemic approach to ensure that all facets of research is entertained and no potential solution is left un-captured, thereby having a robust outcome that not only contributes to knowledge but also provides a solution that can be utilised in the oil and gas industry.

Fundamental to the systematic nature of this research till date is carrying out the research in a structured manner using the project management phase approach.

A combination of two different Project Management processes was applied to deliver the research aims and intents.

1. The Stage Gate Process (Barton, 2015) as shown in Figure 1-1 below:

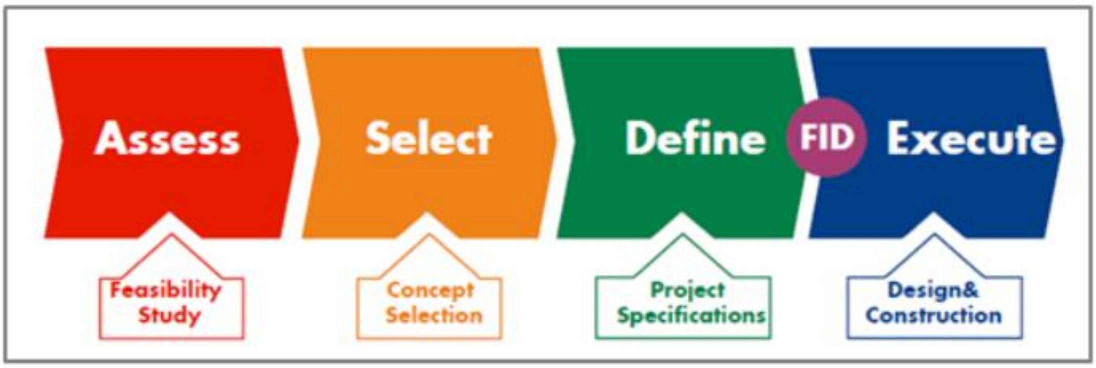


Figure 1-1: Project Execution Stage Gate Process (Barton, 2015)

According to Christopher Barton (2015), the typical activities in each stage are shown in the above Figure 1-1 above ranging from Assess (Feasibility), Select (Concept Selection), Define (Project Specification), Final Investment Decision (FID) and Execute stages (Design and Construction).

This entire process was used in the delivery of this research. It is important to note that two other important stages were applied but not shown in the stage gate process according to Barton but are captured in the PMI process which was also used. This process is Identify/Initiate. The Identify and Initiate process are close but not exactly the same.

The stage gate process ensured the feasibility study, Concept Selection and Project Specification was done in a structured manner.

2. Project Management Institute (PMI) - 5 Project Management Process Groups was another process that was used to ensure that attention was paid to detail and a robust outcome was delivered. The 5 processes in Figure 1-1 consist of the steps listed below, with the corresponding details also described below.

Table 1-1: 5 Project Management Process Groups

Define goals/specifications	INITIATION
Plan the project	PLANNING
Schedule the project	EXECUTION
Manage the project	CONTROL
Finish the project	CLOSING

Almost all the details of work activities as described below was followed and carried out to deliver the model and the research objective. However, some of the process activities were left out since it was not a construction research/project.

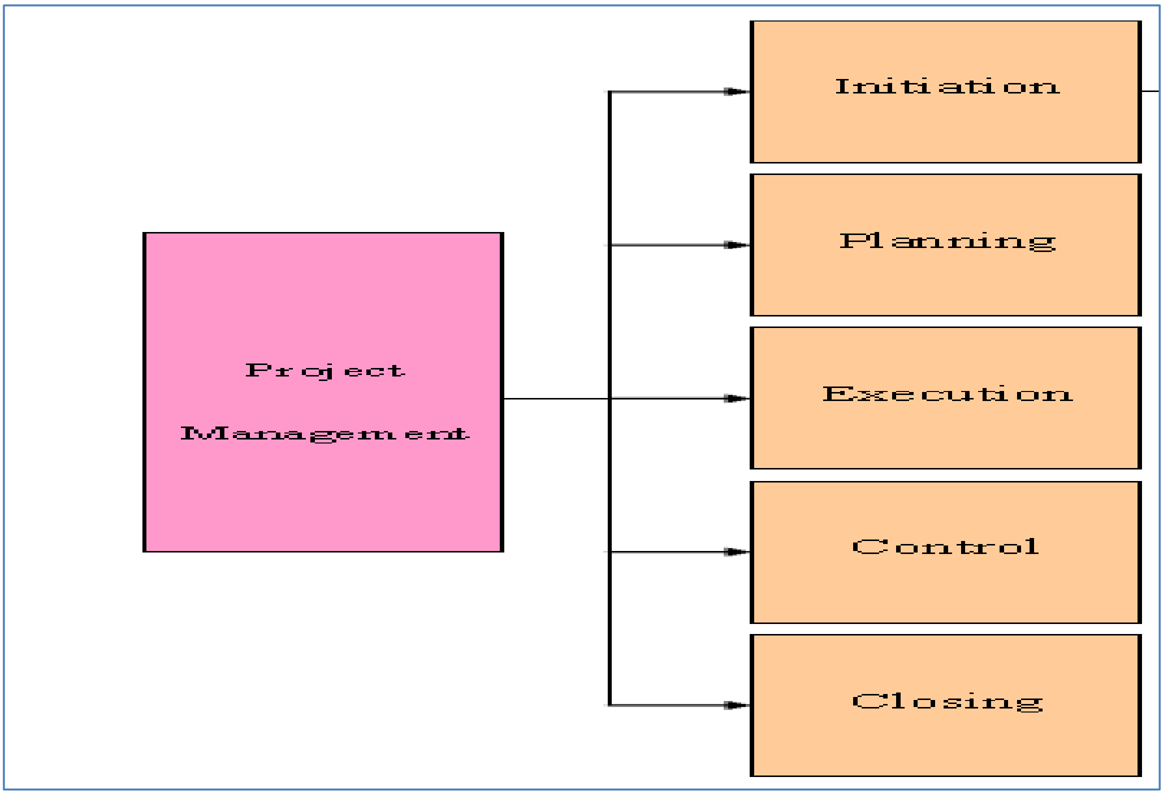


Figure 1-2: PMI-5 Project Management Processes

Defining Goals/Specifications- INITIATION

- Review project charter, Set initial project objectives and scope
- Define project scope, Define project objectives
- Define project benefits, Identify sources of business knowledge
- Prepare preliminary project timeline, Determine preliminary project costs
- Establish business user participation, identify source of project funding - and people
- Decide whether to continue the project, Scope planning, Scope definition

Plan the Project- PLANNING

- Begin to prepare the project plan, Review goals and objectives
- What strategies need to be considered, Identify the specific activities
- Definition of each activity, Sequencing of activities
- Estimate activity duration, Develop schedule
- Develop risk management plan, Determine resource needs
- Determine resource costs, allocate overall cost budget to individual resources, Finalize the project plan

Schedule the Project - EXECUTION

- Perform the tasks and activities from the plan
- Evaluate overall performance to ensure quality standards are being met
- Develop individual and team skills to enhance project performance
- Distribute project information to stakeholders in a timely manner
- Obtain quotes, bids, and offers, or proposals as needed
- Select potential partners and outsource vendors (seller)
- Manage the relationship with the seller

Manage the Project- CONTROL

- Coordinate change control across the entire project, Verify the scope
- Control changes to the project scope, Control changes to the project schedule, Control changes to the project budget
- Monitor specific project results to determine if they comply with relevant quality standards, Disseminate performance information
- Monitor and control project risks

Finish the Project- CLOSING

- Closeout all contracts
- Administrative closure – generate, gather, and disseminate all information to formalize project completion
- Document all lessons learned
- Document best practices
- Create file system for all project documentation

As mentioned above, one stage that was also but not captured in the above process is the Identify stage. This is similar to the INITIATE Stage of PMI process. The questions this stage will ask are stated below:

- Do I understand exactly what I want to do?
- How do I go about what I want to do?
- What are the various options that will lead to obtaining a robust outcome?
- Where am I with this work? What is the progress status of the research?
- Where do I want to be? This is more to do with definition of success ahead of the game. What will a successful research look like? What outcomes will determine this success?
- How do I get to this success? - This is to identify the work and activities that needs to be done to achieve success. Will leads to development of a work plan and schedule of activities.

All the above questions are asked as part of the Identify stage gate which is not shown in Figure 1-1 but used in the stage gate model by other oil companies.

What this means is that for each stage gate there are a number of questions that are asked which helps point to doing the right work that will deliver the correct outcome.

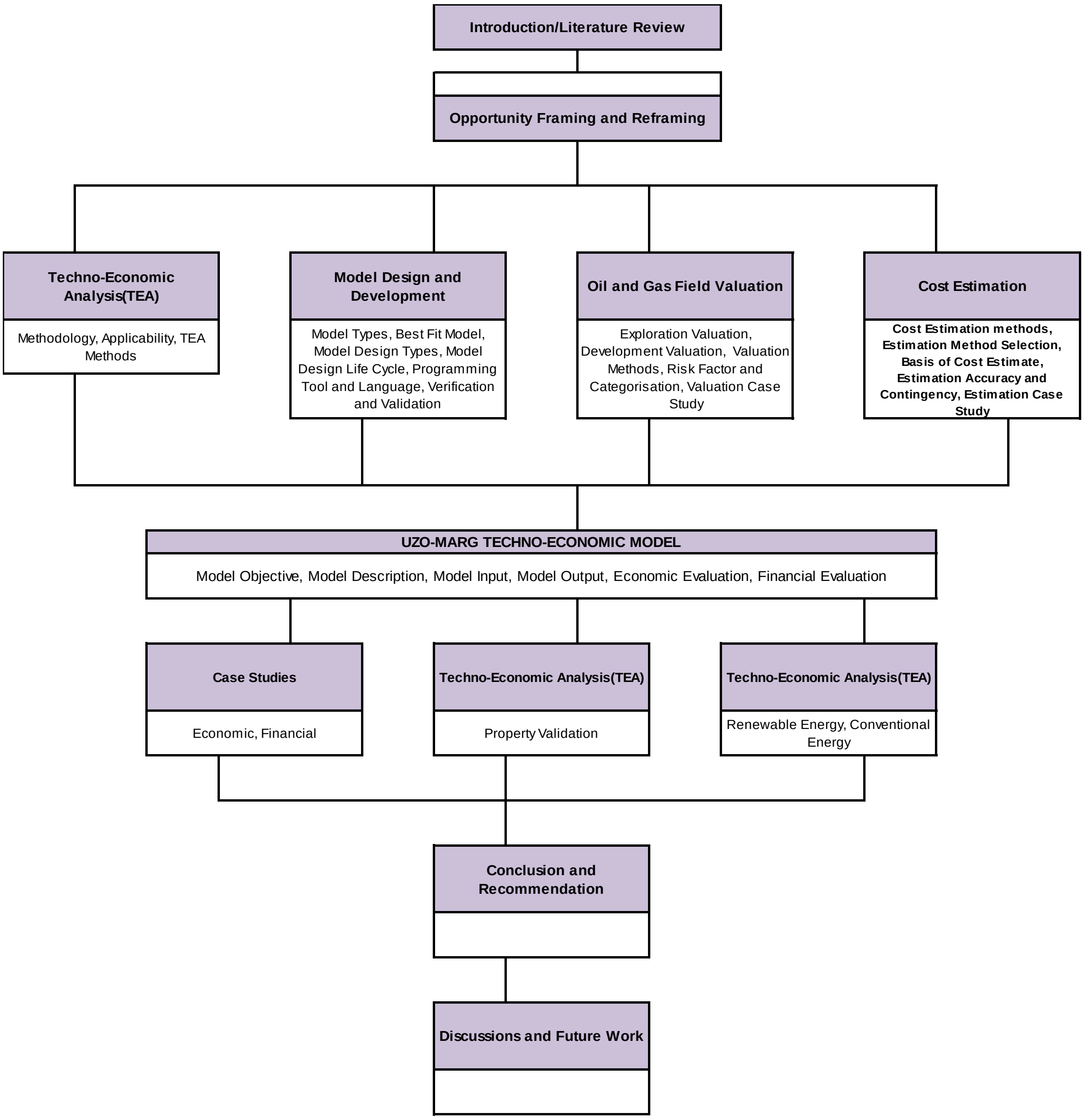


Figure 1-3: The Thesis Structure Chart

This research work has been broken into three phases which ensures that a review holds at the end of each phase confirming readiness to move to another phase of the research study. The review is normally carried out by my supervisor and a selected panel. The final review will be a defence in the structure of a VIVA. This can be likened to final investment decision in the oil and gas industry.

1.1.4 Research Statement

On the initiation of the research/project, the first question was to obtain clarity of this research, what exactly is these research all about, what is it I am to work on, what this PhD research work will deliver. A project/research statement needed to be developed and properly defined and communicated in such a manner that the focus on the key deliverable/reason for this project/research will remain throughout the research.

The project research statement is as follows:

As part of fulfilling the requirement towards the award of PhD in Energy Economics, this project research is carried out to establish the various components in the development of any Marginal Oil and Gas Fields offshore or onshore using various concepts.

To achieve this: -

- Review Global Marginal oil and gas field’s development and production situation and their hindrances/challenges towards its development, production and conversion to useable energy.
- Evaluate and Review various Renewable Energy, maturity and applicability in oil and gas development with special focus on Marginal oil and gas fields.
- Evaluate the Concept of Energy Utilisation in Marginal Oil field development with the use of Renewable energy to make marginal oil and gas fields economic to produce.
- Carry out Concept Identification and Selection of the Marginal Field case study.
- Develop Cost Estimate for all the Concept Options not limited to Wells, Facilities, Engineering, Project Management and others.
- Develop an Economic and Financial Model/Tool that is dynamic and can be used for simulating both the economic and financial behaviours of the different concepts incorporating different fiscal regimes, Taxes, Royalties in the evaluation of Marginal Fields.

1.1.5 Research Facts, Assumptions & Boundaries

To help a research/project remain focused and deliver the necessary value, the facts, assumptions been made and the boundaries of the research has to be clearly defined upfront i.e. before the commencement of the work. This helps you understand the limits of your premise in terms of assumptions, what is true about the project and when you the researcher is making wrong assertions. For this research work, the below have been identified

1.1.5.1 Research Established Facts

In the commencement of this research, there are known facts or what can be categorised as ‘’knowns’’. This ‘’knowns’’ have helped to frame properly the project/research and point the research work to the right sources of information that are required.

1.1.5.2 Boundary Conditions

The conditions that define the frame work for the research are as follows.

- Research is focused purely on Marginal oil and gas development and production
- Validation of developed model is premised on a true work from a marginal investor known as Lekoil Energy.
- Concept for improved Economics is based on application of Renewable Energy
- This research is for the study of PhD
- All required data for analysis within the Oil and Gas Industry and Power Generation Industry

1.1.5.3 Assumptions

Below are the research assumptions: -

- No established Integrated Economic and Financial tool for Marginal oil and Gas fields evaluation
- Oil price remains at an Economic Threshold for economic Evaluation

- Existing power generation technology for Marginal oil and gas development currently is fossil fuel.
- Fiscal regime is premised on Nigeria Fiscal Regime for Production Sharing Contract (PSC), Joint Venture (JV), Marginal Field Offshore and Marginal Field Onshore.

1.2 Research Data Management and Quality

1.2.1 Introduction

This section highlights the basics of data management for this research. It provides guidance on how the research/project data and information has been organized, managed and preserved.

The Data Management Process in line with Data Life Cycle has been used for this research (i.e. components of the data life cycle, Figure 1-4). This approach is meant to improve the chances data being used effectively by others (reused).

1.2.2 Specific Objectives of Data Management

The main objectives of data management for this research are to acquire data and prepare them for analysis. The data management system included the overview of the flow of data from research subjects to data analysts. Before the data were analyzed, data were collected, reviewed, coded, computerized, verified, checked, and converted to forms suited for the analyses to be conducted.

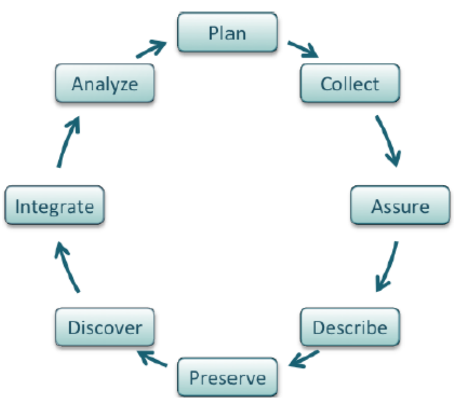


Figure 1-4: Data life cycle (Strasser et al., 2012)

1.2.3 Research Data Life Cycle

Some projects might use only part of the life cycle, see figure1-4 ; for instance, a project involving meta-analysis might focus on the Discover, Integrate, and Analyse steps, while a project focused on primary data collection and analysis might bypass the Discover and Integrate steps. This research has used the entire data management life cycle which entails data Planning, Collection, Assurance, Description, Preservation, Discovery, Integration and Analysis.

1.2.4 Data Management Plan

The data management plan has helped to have a structured approach on how data is collected, documented, organised, managed, and preserved for this research. With a plan in place, data is easier to collect, use and analyse, especially where you may have support colleagues on the research.

With the way data has been documented in this research, those who may be interested in further work of this research and want to use this research as study verification can do so easily without going through the pain of understanding the data and used information.

1.2.5 Types of Data Produced

In this research, summarised data profile such as shown below was developed, utilised and produced throughout the entirety of the work.

- Oil Field Production Profile (Oil and Gas)
- Oil and Gas Fiscal Regime Data
- Economics and Financial information such as NPV, VIR, ROCE, ROACE, IRR
- Cost Estimates for Facilities
- Costs Estimates for Power Generation Technologies
- Cost Estimates for Renewable Energy Technologies
- Economic Performance Validation Information
- Projected Oil and Gas Price Information
- Modelling Results from Scenarios and Sensitivity Analysis

- Model Validation Data

1.2.6 Data Storage

In the management of research data, storage and security of the data is very important and should be a major focus in the data management plan. Data for this research is stored on both computers and external hard drives. Sometimes data is stored in USB sticks for ease of transfer.

For major data, they are split stored in two different locations, personal laptop and external hard-drives. This is to ensure the data is secured and protected in case of unforeseen circumstances or situations. One thing that was not taken for granted during this research is that data can be lost for various reasons.

The value of this research has been greatly impacted by quality control, but achieving and maintaining quality requires activities that are often mundane and difficult to motivate. The quality control the data for this research passed through are not limited to the below:

- Preventing and detecting errors in data through written procedures, training, verification procedures, and avoidance of undue complexity
- Avoiding or eliminating inconsistencies, errors, and missing data through review of data collection forms (ideally while access to the data source is still possible to enable uncertainties to be resolved) and datasets
- Assessing the quality of the data through notes kept by discussions, coders, and data editors, through debriefing of subjects, and through reviews or repetition of data collection for subsamples
- Avoiding major misinterpretations and oversights by “getting a feel” for the data.

1.2.7 File Naming

PhD research of this size and nature attract and generate huge multiple of data files. Because of these huge files, special attention was paid to filing organisation for ease of use and storage.

A filling convention that supports good data management plan was recommended by Eugene Barsky (in Research Data Management Data Guide) and this research data and information filling has been has been managed in the described process below.

- Keeping the file names under 32 characters
- Classifying broad types of files
- Avoidance of spaces and special characters
- Using underscores instead of periods or spaces (check files to ensure conformance)
- Making sure that file names are descriptive outside of their folders (in case they are misplaced or change locations); i.e., the file name with all necessary explanatory information
- Include dates and format them consistently (international standard for date notation is YYYY_MM_DD or YYYYMMDD)
- Including version numbers to track multiple versions of a document

1.2.8 Data Security

Data security for any researcher is an important aspect of the data management plan. Based on the confidential nature of the data been secured or protected, the access control to the data and information is defined. This research will not make open confidential information especially model verification information from international Oil Companies where such information has been used.

The computer laptop used is quite secured with the necessary password, antivirus and firewalls to prevent unauthorised access to the computer.

2 Literature Review

2.1.1 Decline in Global Hydrocarbon Exploration and Production

For decades, the energy community have been engaged in discussions and debates on when easy conventional oil & gas exploration and production will no longer be available, and the push into Marginal oil and gas exploitation and production will become inevitable for global energy production (Myers et al, 2011, p.7). In 1998, it was predicted (Campbell and Jean 1978, p.78) that the world will begin to experience decline in global oil production. His prediction was globally accepted and termed ‘’peak oil’’ (“Peak oil” is the term used to describe the situation where the rate of oil production reaches its absolute maximum and begins to decline), this was validated and expounded by many renowned geologists such as Deffeyes (2001).

From the aforementioned perspective, it became clear to the world that a time is coming so fast that abandoned fields will need to be looked into and also the need to make them profitable was imminent for continuous supply of hydrocarbon to the world.

Already mentioned above is the prediction theory of (Campbell, 1978, p.78). However, at the centre of most of the forecasts is the one made by Marion King Hubbert in 1956. In the mid-1950s, Hubbert used a curve-fitting technique to correctly predict that U.S. oil production would peak by 1970. The so-called Hubbert curve is now widely used in the analysis of peaking production of conventional petroleum. According to the Hubbert curve, “the production of a finite resource, when viewed over time, will resemble an inverted U, or a bell curve’’.

2.1.2 Global Oil and Gas Production Current Realities

The years 2000s saw the sharp increase in the cost of oil and gas and improved technology for exploration and production of oil and gas. The increase cost of oil and gas brought more funds to the market for investors and also an attraction for new frontiers like marginal and unconventional oil and gas fields which were not considered in normal forecasts for the 2000s and 2010s (Myers et al., 2011, p.9).

Onshore United States is the best case in point where shale oil production is now on the rise, with output from the Bakken play in North Dakota growing from less than 100,000 b/d in 2005 to an estimated 375,000 b/d for 2011 (Myers et al., 2011). This is a typical demonstration of a marginal oil and gas field which was not exploitable, and then low oil price impinged with expensive technology is now becoming economic with improved technology aided with good economic cut off oil price as an enabler for its development.

Advances in technology as seen in the Bakken shale—such as longer lateral lengths and the use of multistage fractures—have allowed production rates to increase dramatically in recent years. In fact, this technological advancement in oil and gas development have led some analysts to predict that despite the projected declines in offshore output due to the extended moratorium, total U.S.A oil production will remain relatively flat largely because of oil supply increases from the Bakken shale, which is projected to increase up to 800,000 b/d by 2013. The technological and economic approach that has seen to the increased production from the Shale Oil marginal fields into the US overall production can also be applied in other continents and nations.

‘’The cost of production for Bakken liquids is in line with the costs of conventional U.S. onshore production. Moreover, current high prices are stimulating interest in Wyoming oil shale as well. Based on small-scale field tests, Shell has argued that shale oil will be competitive at crude oil prices in the mid-$20s per barrel. If true, this would certainly be a game-changer in the oil world, in much the same way recent developments in shale gas have been for natural gas markets’’. (Myers et al., 2011, p.9). This increased profitability is amongst what is driving high investments in the development of marginal oil and gas fields.

2.1.3 Classifying the Oil and Gas Resources

‘’In many ways, the debate surrounding an impending peak in production is centred on understanding the scale of the recoverable resource’’ (Myers et al., 2011, p.16).

There are quite a lot of oil and gas reserves which are still classified marginal and cannot be produced because of economics. This marginal resources could have been carried through to become proven reserves if the economics was right. It should be noted that the measure of the cost-effectively recoverable resource can vary over time as it depends on the volume of the resource which could be marginal in deposit, existing technologies at the time of evaluation, cost of developing the resource and very importantly, the oil and gas price.

The Figure 2-1 below highlights this important point. ‘’Proven reserves are a subset of resources defined to be economically recoverable.

Beyond this, resources that are economically recoverable are a subset of technically recoverable resources, which are a subset of all resources in-place’’; this is exactly where marginal oil and gas fields resources fall into. Dropping costs of development and rising oil prices will increase the economic resources that are recoverable.

Improvement and advancement in technology will grow the technically recoverable resources. For example the improvement in development technologies such as modular technology concept for packaged equipment, smart drilling technology and increased oil price is now encouraging deeply and immensely economic development of marginal oil and gas fields.

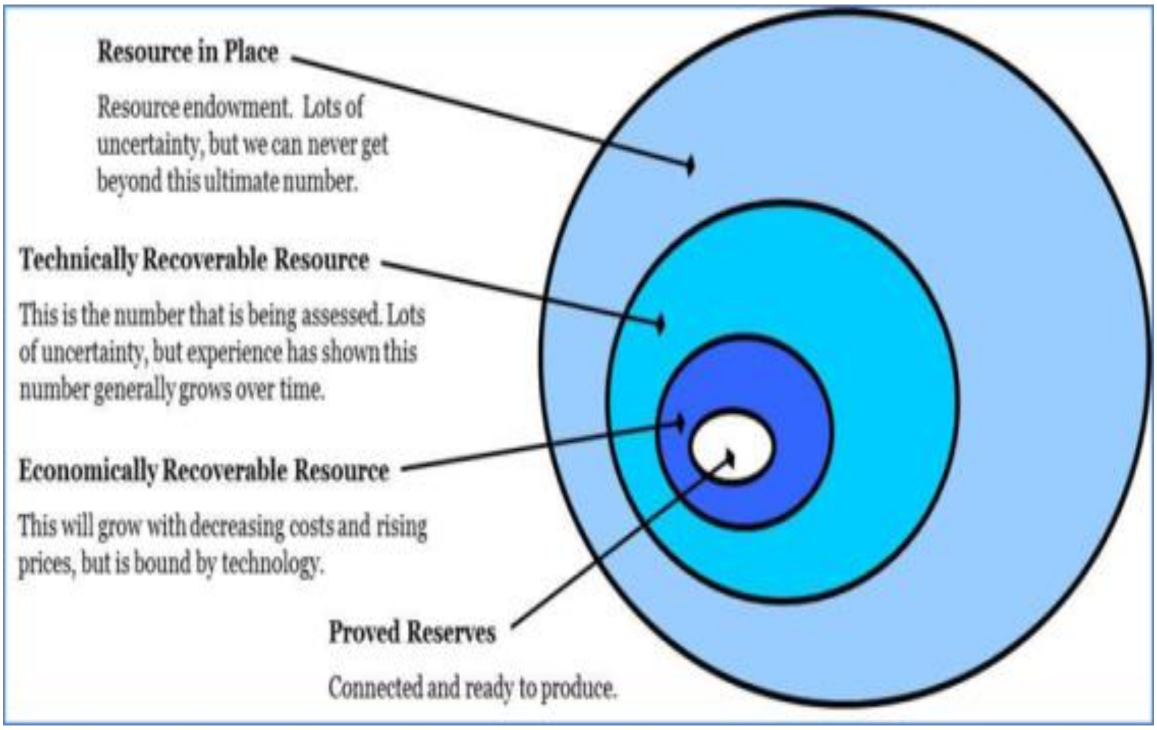


Figure 2-1: Hydrocarbon Resource Envelope (Myers et al., 2011, p.17)

2.1.4 Marginal Oil and Gas Field Definition

The drive behind the push into marginal oil and gas is generally the depletion of "easier-to-produce" oil and that is undoubtedly important to note because of the ultimate objective of any investment which is commercialisation and economics i.e. been profitable, (Heinrich-Böll-Stiftung, 2012).

Marginal Fields have various definitions and classifications around the world depending on the resources, political factors which is a function of the country owning the resources. A review of existing literatures discloses the non-existence of a unified definition of marginal fields (Akhibge, 2007), hence different definitions for different locations and country.

2.1.4.1 The Nigerian Definition

The Nigerian definition of marginal field as described by (Bonnefoy and Poyntz, 2014) to be a field with the following attributes.

- A field that has remained unproduced for 10 years; and is declared to be a marginal field by the President

- An oil field with reserves that has unconventional crude oil characteristics (such as very high viscosity and low API gravity)
- A field with high gas and low oil reserves; and they may have been abandoned by the OML (Oil Mining License) holder for upwards of three years.

2.1.4.2 Marginal fields classification

Since the bidding and licensing rounds for Marginal Fields in Nigeria, Marginal fields have been descried as shown below (DPR, 1996).

- Oil and Gas fields/resources which have not been developed because of calculated and estimated marginal economics under the existing fiscal regimes/terms.
- Fields that has at least one development/exploration wells drilled with discoveries but not completed to a production level for more than 10years.
- Fields with oil and gas characteristics which cannot be developed and produced with conventional / existing technology.
- Fields with high GOR (High gas and low oil reserves).
- Fields that have been abandoned by the owners for about of 3 years for economic reasons.
- Fields which the current licensee may consider farming out due to portfolio management.

2.1.4.3 Other Definitions

On another note, IEA (International Energy Agency) has predicted that 69 million barrels per day (Mbpd) of conventional oil production in 2010, 47Mbpd would not be available in 2035 (WEO, 2011, p.123). So that the increasing demand of oil can be met, another 67Mbpd oil production needs to be brought on stream by 2035 (WEO, 2011, p.122-123).

OPEC is well positioned with its vast resources to meet these demands since they control the vast majority of the remaining oil and gas resources globally especially the easy to produce oil and the non-OPEC production conventional oil will be in unconventional (WEO, 2011, p.85-87)

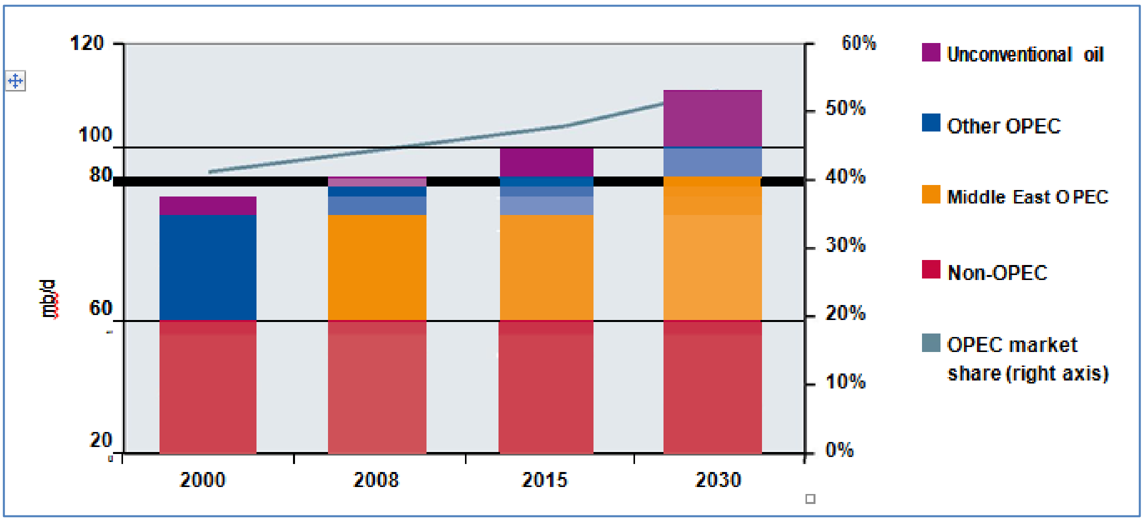


Figure 2-2: Oil Production aligned with source (WEO, 2008)

“In line with these trends, for the last 10 years the oil industry has been moving increasingly toward the production of unconventional oil such as tar sands and pushing into ‘frontier’ zones, such as ultra-deepwater and the offshore Arctic. These oil resources share in common their tendency to intensify the already high social and environmental impacts of current oil production and their high financial costs. For this reason, these resources have been labelled “Marginal Oil” (Heinrich-Böll-Stiftung, 2012).

2.1.4.4 North America Definitions

Using Texas as a premise for marginal field definition in the USA; the productive potential of the well is used as a basis for definition/classification (Aldrich et al., 2000). Going by production numbers, in the USA, a marginal oil field produces no more than 10b/d in terms of oil and 50Mscf/d in terms of gas. The classification as marginal oil fields can also be because they have been found not to be economic and profitable at a particular time driven by the price of oil and gas (Warlick, 2008).

2.1.4.5 UK and Netherlands Definitions

The United Kingdom and the Netherlands classified their marginal fields based on the estimated reserves from that particular field. For example, in the Netherlands, a field is considered marginal if, “it has a volume of less than four thousand million cubic meters” in The Netherlands (Scholten, 1991), while in the United Kingdom a maximal reserve content of 20 million barrels of oil as its benchmark (Hughes, 1991).

2.1.4.6 Malaysia and Indonesia Definitions

The marginal fields in Malaysia are classified by the number of barrels available in the field in focus. The fields should contain 30million Barrels maximum of oil equivalent or less (Wei, 2011). The general classification is a field with less than 30 million barrels of oil or oil equivalent with a recovery factor of 20 to 30% (Abdullah, 2012).

While in Indonesia, a marginal field is defined as the first field within a contract area and approved by the local oil resource management agency PERTAMINA with a planned production capacity of 10,000bbl/d in the first 2 years of the life of the field. In addition to the aforementioned, a field is also classified as marginal if its economic indicators do not reach acceptable limits for developmental purpose using existing technologies premised on current production sharing contracts for that size of reserves (Reservoir Engineering Forum, Yogyakarta, 1996).

As complex as this definition may sound compared to other countries, it leaves room for negotiation of the fiscal terms that may allow profitability when the resource owner is really interested in developing the reserve.

2.1.5 Marginal Field Development Drivers

One thing is clear, marginal fields are defined not only by the quantity of oil remaining in a reserve (Aldrich et al., 2000), but also the economics which could be marginal for unconventional oil reserves such as oil sands and ultra-deep reserves (Heinrich-Böll-Stiftung, 2012). In the past 20 years, the need for development of marginal fields has increased and this is driven by the following factors.

2.1.5.1 High Oil Price

According to Heinrich-Böll-Stiftung (2012), amongst the factors driving marginal oil field development is high prices and excessive demand for oil; although there are other influencers ranging from advanced technology, careful contracting and project execution strategy (Frost and Sullivan, 2014).

In South East Asia alone, the total revenue estimate from Marginal fields is estimated at trillion of dollars, (Frost and Sullivan, 2014). This is not to mention in Africa where so many fields have been kept in the cooler as marginal fields for potential future development when probably the commerciality is right. The development of this fields are now been driven by crude oil high prices and advancement in technology and its associated cots.

The price of oil will continue to play significant role in the development of Marginal oil fields and a sweet spot for the oil price will always be required for investment decision of marginal oil fields i.e. what oil price makes sense to decide investment.

2.1.5.2 Reduced Easy To Reach Oil

Sometime in 2008, it was announced by then Shell CEO that the era of easy to reach oil was coming to an end (Heinrich-Böll-Stiftung, 2012). In some places in the Middle East such as Iraq, easy to reach oil is still available, however, due to political, security and social challenges, access to this hydrocarbon is limited (IEA, 2010).

At this point in time, it was becoming obvious that the industry has to start moving towards unconventional reserves and initially abandoned reserves due to economic reasons to be able to continue to meet energy supply.

2.1.5.3 National Oil Companies Increased Active Participation

The reduced access to over 85% of the oil resources by major exploration and production company and now controlled by the NOCs is driving major oil companies and independent players into marginal field development which includes unconventional oil (Vivoda, 2009; Stevens, 2008).

2.1.5.4 Technology Breakthroughs and Improvement

New technologies that reduce financial risk and improve significantly return on investment is emanating by the day and this is playing to the development of marginal fields. As a result of this, the development of cheaper production systems and methods is allowing further marginal field development production to be economical (Frost and Sullivan, 2014).

To realise the above, oil companies continue to face pressure from their investors to find new reserves to replace depleting production. Oil companies' response to this is a robust research and development of new technologies that will make marginal fields cheaper to produce (Heinrich-Böll-Stiftung, 2012).

2.1.5.5 Favourable Legislation and Incentives

Because of the importance of marginal fields to most economies, especially emerging economies, governments are paying huge attention to the rules and governance that drive these fields. Where the economic requirements such as fiscal regimes i.e. royalties, taxes, taxes holidays are prolonged, non-economic fields will suddenly become commercially viable fields (Frost and Sullivan, 2014).

Figure 2-3: Marginal fields around the world (Frost and Sullivan, 2014)

While the international oil companies do not find marginal fields favourable and may not want to support such legalisation like tax holiday, small and new entrant companies find it attractive and a major opportunity for entry into the development and production of oil and gas investment.

2.1.6 Marginal Fields Fiscal Regimes

Fiscal regimes in oil and gas deal majorly with the upstream part of the industry which is exploration and production. The beneficiaries of the fiscal regimes can be local governments, state governments and the Federal governments depending on the country. To be able to explore, develop and produce hydrocarbon from a location, the oil company has to go into some legal agreement with the resource owner.

This is normally in the form of a licence, concession, lease, service contract, profit or production-sharing agreement. Also includes royalties, taxes and other conditions that may be local to the property owner (Mornrner, 1999).

Fiscal regimes may be classified into two categories, namely Liberal and Proprietorial. In the Liberal fiscals, the fiscal take is zero while; only excess profit is taxed so as to avoid anything potential to obstruct investment attraction.

The other Fiscal regime is known as Proprietorial Fiscal regime and it is characterised by a marginal rent, ground rent, this could reduce the flow of increased investment to the government, excess profits are also taxed. Except in the UK and few countries most countries run the Proprietorial fiscal regime (Mornrner, 1999).

The table 1-1 below shows the comparison between the Liberal and the Proprietorial fiscal regimes.

Table 2-1: Liberal and Proprietorial Fiscal Regimes (Mornrner, 1999)

Fiscal Regimes	**Liberal**	**Proprietorial**
Objective	*Economic Rents* Free flow of investment **Regulatory Framework**	*Ground-rent* Investment flow and production subject to payment of compensation to natural resource owner **Business relationship**
Supply of new lands	*Ex-ante* reservation profit	*Ex-ante* reservation profit and reservation ground-rent
Bonuses	Signature bonus as decision making device only	Decision making and ground rent collective device
Relinquishment	Discretionary	Recovering appreciated lands
Development and	*Ex-post* reservation profit	*Ex-post* reservation profit and

Production		reservation ground-rent
Principal form of collection	Excess profit levy	Royalties
Duration of Contract	Indefinite or renewable as a matter of course	Shorter offering opportunity to increase ground-rent taking advantage of reversion of producing facilities
National Oil Company	Not Applicable	*Expertise to specify and control variables above* Joint ventures Production Sharing Agreement Production Service Contracts Nationalisation

The Proprietorial Fiscal Regimes is further defined and categorised into the following the concessionary and the Production sharing contract. There is also the Joint Venture Agreement (JV) which is a joint profit sharing approach, readily practised in Nigeria.

2.2 Marginal Field Development Enablers

To make Marginal Field attractive to develop, apart from the fiscal enablers, costs reduction is a major part of it, hence it is important to consider and evaluate new or emerging technologies that can reduce the total unit development and operating costs of Marginal Fields. Amongst these technologies is the use of Renewable Energy for power generation in Marginal Oil and Gas Facilities.

The benefits from renewable energy utilisation in Marginal Fields development can be impressive but can also be a challenge when the natural driving force is impacted, however, where it is possible to deploy it or a combination of the both conventional and renewable energy (hybrid solution), it will go a long way in reducing CO_2 emission into the environment.

Other costs reduction technologies can be: the type of well that is drilled and the technologies that are deployed for well completions, the type of facilities that are deployed i.e. modular technologies, processing facilities etc. For this research, the focus is the use of renewable energy or a combination of both renewable energy and conventional energy for power generation.

2.3 Renewable Energy – An Opportunity

Concerns for the level of CO_2 emission generated from the production of oil and gas both at upstream and downstream side of the industry and its impact on climate change, the need to reduce development cost has necessitated the prerequisite to also review potential renewable energy systems or a combination of both renewable energy and current conventional energy systems that can be used in the oil and gas industry.

Marginal fields present a great opportunity for the introduction of renewable energy as a cost reduction technology that will help oil production become more economic while help reduce CO_2 emission.

Renewable energies are mainly driven by natural processes; amongst this energy types are solar, wind, geothermal, hydro, ocean, wave, tidal and biomass etc. (Torbira, 2009). They use energy sources that are continuously replaced by nature i.e. the Sun, Water, Earth's Heat, Wind, and plants. Renewable Energy systems and technology transform the sources of natural energy into electricity, heat, chemicals and mechanical power (NREL, 2001; Torbira, 2009).

In terms of power generation, electrical energy generation from renewable energy is growing; about 21% of global energy need is met by various renewable energy sources and about 20% of the world's energy requirement is supplied by renewable energy (Iloeje, 2004).

Renewable Energies have their challenges, like intermittent loss of radiation intensity in the case of Solar Power and this varies with time of the day; these challenges also apply to other renewable energy technologies. A good number of the renewable energy technology are remotely located and some distance away from the location where they are required.

2.4 Consideration for Renewable Energy

2.4.1 Fossil Fuel Depletion

Currently, in most of our lives' activities, we use primarily fossil fuel for our energy needs. However, it is important to note that this energy type is not going to be there forever, it is limited in supply.

The depletion rate due to consumption has continued to be on the increase even as global population continues to grow and fossil fuel fast becoming more difficult to find, produce and made available (Torbira, 2009). Renewable energy has been identified to be able to close the gap in short fall that is steering the world on its face (NREL, 2001).

2.4.2 Environmental Impact and Pressure from Investors

According to (NREL, 2001), the use of renewable energy is better for the environment, renewable energy is often called ''clean or green technology because they produce very little or no pollutant compared to fossil fuel technologies. The use of fossil fuel as source of energy sends Green House Gasses (GHG) into the atmosphere and contributing to the planets global warming.

Scientists have agreed that the earth's average temperature have increased in the past century, if this rise continues, sea levels will rise, the environment will be badly polluted and be harmful to mankind. Scientists predict that floods, heat waves, droughts, and other extreme weather conditions could occur more often.

2.4.3 Green House Gas (GHG) Global Challenge

One of the main thrusts of this research is the techno-economic evaluation of Marginal Oil and Gas Fields using Renewable Energy Technologies as part of energy systems for the Marginal field facility - Hybrid Energy Solution (April et al., 2012), especially for electrical energy that will run the static and rotating machineries in the oil and gas facility.

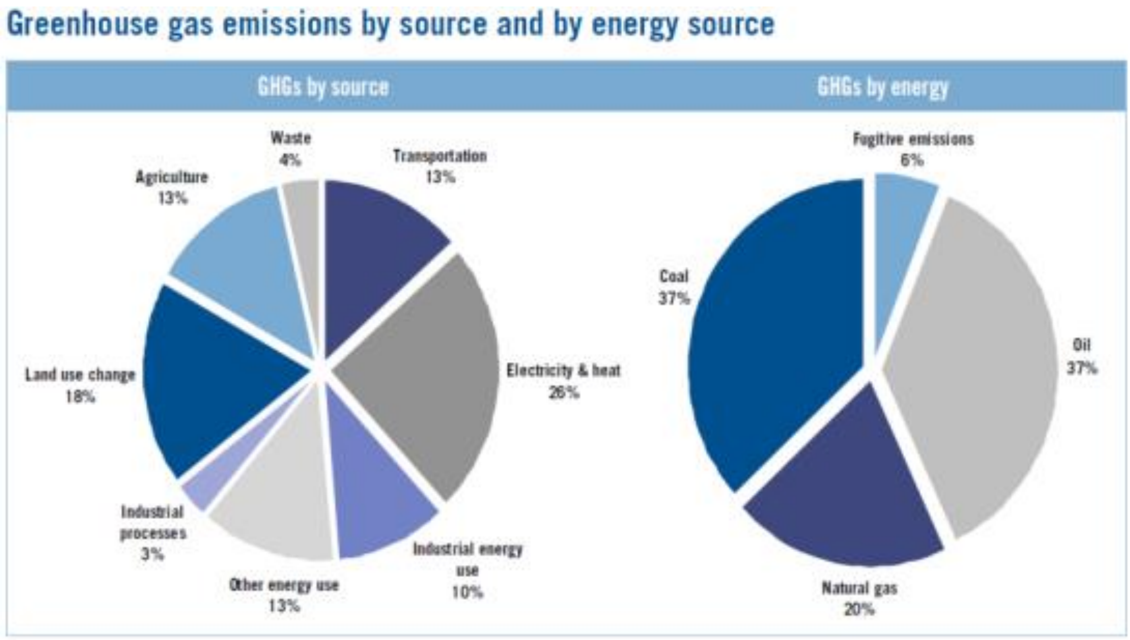


Figure 2-4: **Greenhouse gas emissions (IIGC, 2009)**

Apart from cost reduction for developing Marginal oil and gas fields, the use of Renewable Energy in running the plant will help reduce the Green House Gas Emission and at the same time support the global cry for CO_2 reduction (Baker and Mckenzie, 2015) since energy related activities contribute circa 70% of the world's GHG emissions and oil and gas contributes circa 60%- Figure 2-4 of the Green House Gas (GHG) emission to the atmosphere through their extraction, processing and energy combustion activities (IIGC, 2009).

2.4.4 Pressure from Stakeholders to Reduce Emission

Diverse range of stakeholders have continued to challenge the oil and gas companies to reduce emissions generated from their respective operations (IIGCC, 2009). Going into the future, investments will have to be justified alongside the investments by the oil companies in Renewable Energies and their seriousness to have potential hybrid solution for power generation to attract investors.

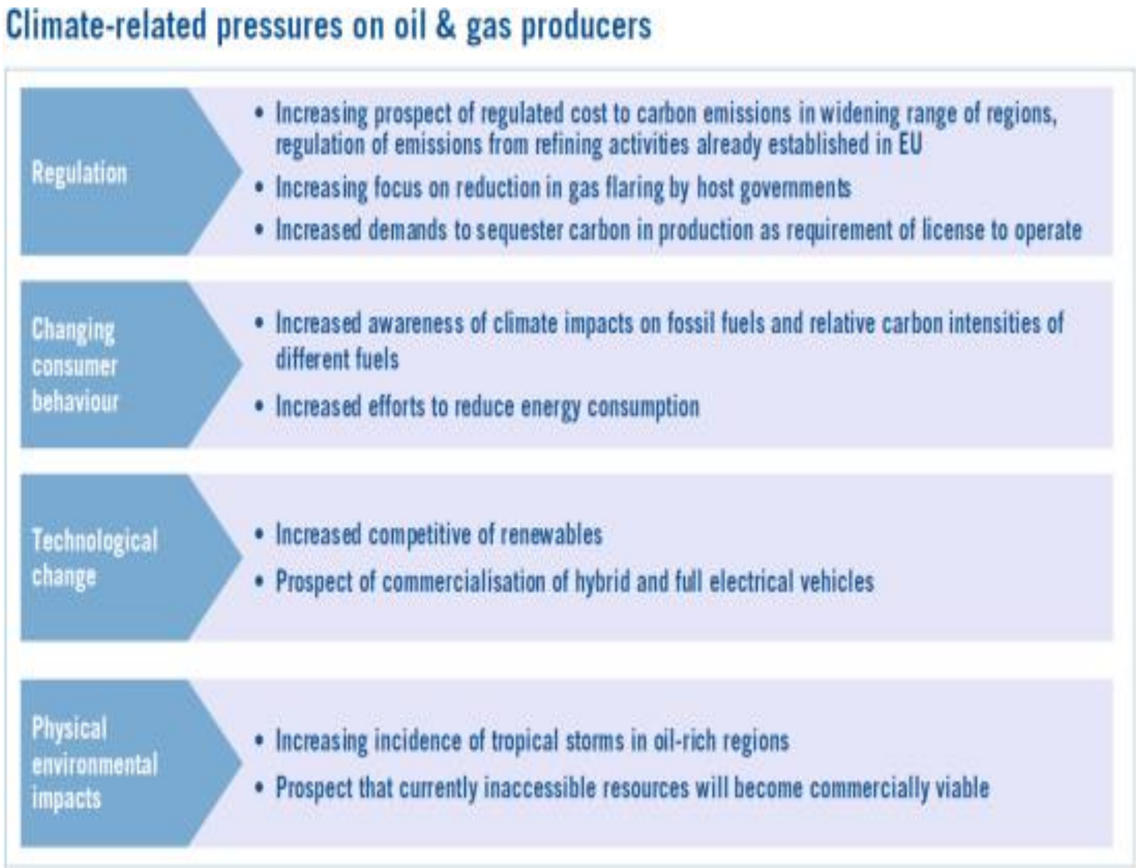


Figure 2-5: Climate-related pressures on Producers (IIGC, 2009)

This has formed a great part of the reason why this research has developed a techno-economic assessment tool that has the ability to evaluate the use of both renewable and conventional energy for new Marginal Fields.

It is worth mentioning that every research in the oil and gas industry is required to evaluate the impact of the environmental aspect of its research to be credible going by the global trend. The figure 2-6 below shows the pressures on oil and gas producers by the global market. Technology change is obviously one of them as shown in the figure 2-6 below.

For the purpose of carrying out the techno-economic analysis, a bottom up cost estimate was developed (Black, 2012). Market demand and supply factors also evaluated as part of the cost estimate (Hernández and Tübke, 2011).

2.4.5 Reduced Operating Cost and Energy Security

With the huge focus by oil companies to reduce operating cost of their plants and facilities with the aim to improve their profitability, renewable energy has a big role to helping the oil and gas industry realise this objective. For example

Figure 2-6: A PV-System (NREL, 2001)

The PV-system at the Pinnacles National Monument in California eliminates a $20,000 annual fuel bill for a diesel generator that produced each year 143 tons of carbon dioxide—a greenhouse gas.

The replacement of fossil fuel fired technologies with renewable technology in elected areas can also ensure and support energy security while reducing costs. Renewable energies have continued to get better and cheaper by the day (NREL, 2001).

2.5 Renewable Energy Application in Oil and Gas

The oil and gas industry is a major producer and also consumer of energy. Energy is used in various areas for different purposes ranging from pumping of crude, water treatment and desalination, compression of gas, electrical energy for utilities and heavy and light loads in the plant.

The need to increase produced capacity from typical oil and gas production, and refining facilities with revenue increase in mind has subsequently raised the demand for more energy by the production and processing oil and gas facilities.

According to Al-Alawi, of Petroleum Development Oman, renewable energy can be used for the following:

1. Pumping and Injection of fluids i.e gas
2. Heating services
3. Steam Generation
4. Gas Compression and Transmission
5. Power Generation

In the oil and gas industry, specific areas of application includes, for example, Solar Power which can be used for light loads, remote monitoring & telecommunication, Cathodic Protection system, Chemical Injection Systems, Instrumentation & Control, Solar Pumping System, Solar Water Treatment and Water Ozonation.

Biomass can also be used in the oil and gas industry. The Industry produce waste in different forms and these wastes can be used to generate electricity or heat using inclinator to produce power and heat for oil and gas processing. Biomass is a mature renewable energy technology and currently been used in different parts of the world.

3 Techno-Economic Analysis (TEA)

3.1 Introduction

Literature reviews from the different papers, articles on Marginal oil & gas development and non-Marginal oil Fields carried out on this research study points to one fact that the core of this research centres on:

- Developing a tool/model that can be available to marginal field operators for economic and financial analysis leading to robust investment decisions,
- How to make marginal fields profitable before and during plant operation
- Getting marginal fields to contribute to CO_2 reduction been a requirement for oil and gas development going forward, particularly with the use of new technologies.

In addition, it also focuses on the flexibility and robustness of the developed tool towards its use for optimal profitability derivation during the operating life of the facility. It is evident, that whichever tool type or structure that will be developed and adopted, one thing is clear, it must have the capacity and capability to analyse hydrocarbon volume, technology and costs, and be able to show economic and financial indicators as an output. Whatever this tool does, it will be a combination of technology and economic viability of the fields, Techno-Economic Analysis (TEA) has to be carried out, and hence this chapter is the front runner for other chapters in this research study.

Techno-economic analysis will enable the running of different scenarios and sensitivities that will provide more information and insight that will support investment decisions and what should be focused on for optimal and profitable operation of the facilities when they are built or for already operating ones.

In addition to all the above, according to Ling et al., (2015), Techno-economic analyses or assessment are carried out to determine the economic viability of various technologies in different applications, especially during feasibility stage or when a change of technology is been applied into an existing facility.

It can be used for different analysis in various aspects of the processing industry like the oil and gas, particularly for carrying out cost benefit analysis, evaluating the economic feasibility of a specific project, building and analysing cash flows over the life of an opportunity, evaluating different technology applications, comparison of economic viability of different technology for the same service (Max, 2008), i.e. replacing fossil fuel technologies with renewable technologies. In doing this, a spreadsheet can be prepared depending on the complexity of the analysis. The outcome of this analysis can be used to determine which upcoming technologies have the latent for economic success and value addition when deployed. In summary, it is an economic evaluation in which the technical aspects of a project are coupled to the economic aspects (Ryan et al. 2010).

Evaluating the use of cheaper technologies for marginal fields, renewable energy for power generation towards the operation of the facilities or a combination of the conventional power generation and renewable energy power generation has been considered. Using Renewable Energy as a source of energy for marginal oil and gas field's implementation falls into evaluating new technology applications because of the various environmental and economic benefits that is associated to its deployment. It has the potential to reduce the cost of producing oil and gas and at the same time achieve Green House Gas Emission Reduction.

Techno-economic analysis assessment will also be carried out on potential renewable energies that can be used in the operation of oil and gas facilities. This is born out of the concern for the impact of CO_2 on climate change which the oil and gas facilities have been identified as a major contributor, (April et al., 2012). To carry out Techno-Economics, a methodology can be followed, as shown below Ryan et al., (2010):

3.2 Techno-Economic Analysis Applicability

Techno-economic Analysis (TEA) in summary is a cost-benefit assessment using different methods of evaluation. This is mainly applied when comparisons such as the ones captured below are required to be carried out (Max, 2008).

- Economic Feasibility Evaluation of a Project
- Economic and Financial Cash Flow Analysis/Investigation over project life
- Technology Performance Scales and Applications
- Evaluation of Economic Worth of different technology application for the same service and duty.

"There is no specific format proposed for doing the assessment, because practical calculation uses different methods and in general is very simple using a spreadsheet program'' (Max, 2008).

This research has used the excel spreadsheet methodology to develop a Techno-Economic Model for the analysis.

The case studies in this research is an oil and gas marginal field, as a result the developmental and production CAPEX and OPEX costs, production profiles are all part of the designed Excel Model.

The influence of taxation is not discussed in the guideline. As a simple rule taxes should be included in cost and benefit assessment, if they are not refundable (e.g. transport fuel taxes). Value added tax (VAT) usually is refunded (except for private use) and so should not be included in TEA (Max, 2008). All this factors have already been considered and built into the economic and financial.

3.3 Techno- Economic Analysis Methods

According to Max (2008), there are several methods of carrying out Techno-Economic Analysis. Some of the methods are:-

- Static cost benefit assessment
- Annuity method
- Net cash flow table
- Net present value (NPV) (Discounted Cash Flow)
- Internal rate of return (IRR)

3.3.1 Static Cost Benefit Assessment Method

Static cost benefit assessment is a comparison of benefit and cost of an investment without taking into account interest rate and inflation rate etc., (PSRC, 2010), With respect to application and use, this method is easier when compared methods used for Techno-Economic Analysis. It is also very fast in delivering results without the development of complicated computer models (Max, 2008).

The main objective of this cost benefit analysis is to compare the gains associated with an investment decision and with the costs of implementing the investment (Stephanie et al., 2010). From the analysis of a typical case, where the investment outcome and benefits exceeds the costs of executing the investment, then the investment can be further progressed or studied (PSRC, 2010).

This method does not take cognisance of interest, inflation rates and other economic factors, which makes the result not to be fully reliable and cannot be used to make investment decisions such as in the oil and gas industry. It can only be used for a preliminary check e.g. of an idea, just to investigate whether further investigation should be done or not for techno-economic analysis, extremely difficult to trust the result (Riegg et al., 2010). For this reason, this method cannot be used for this Marginal Field Techno-Economic Analysis.

3.3.2 Annuity Assessment Method

According to Max (2008), annuity method is similar and also the same as the static cost benefit analysis method type, but for calculating investment payback, the interest rate is normally included as part of the evaluation of the annuity.

The rise of cost and of income over the lifetime which is known as inflation is usually not considered. This method puts into consideration the net benefit (income less cost) for each year of project operation just as the static method does, but spreads the initial investment cost over the project lifetime using an assumed interest rate.’’ It does not take into account any changes or reduction in the value of the incomes received or costs expended each year’’.

The annuity method is very useful for simple TEA, obviously confirming that it will not be suitable for the oil and gas TEA in a model which sometimes has complicated calculations, rather realistic in results as long as inflation rate is not too high and not too different to the interest rate. The results of TEA on different projects are easy to compare with each other and the calculation is transparent and easy to understand.

Sensitivity Assessment: A disadvantage of the annuity method is that it is not possible to distinguish variations in costs and benefits from one year to the next, the same net benefit is applied to every year. This is an opposite for the oil industry as production and costs varying from year to year.

3.3.3 Net Cash Flow Table Assessment Method

Companies profit after tax (or net income) is pretty an illogical figure, obtained using certain accounting premises regarding cash out flow and cash inflow. On the other hand, the cash flow is an objective measure, a single figure that is not subject to any personal criterion, (Pablo, 2006).

It has been proven that Cash Flow gives a sound basis for company accounting, especially when carrying out TEA. It gives a sound overview on the timeline of incomes and payments over project period (Max, 2008) and helps you establish how many years it will take before a positive cash flow can be expected with a clear picture of the financial requirements of that Business.

Table 3-1: Cash Flow Table (Max, 2008)

Example for a cash flow table

	year from start of project development								
	1	2	3	4	5	6	7	8	Sum 1-8
benefits [btot]			6.000	12.000	12.760	13.483	14.293	15.150	
operation cost [cop[			5.000	5.250	5.513	5.788	6.078	6.381	
investment related [ia+ii]			1.000	1.030	1.061	1.093	1.126	1.159	
Investment [I]	15.000	15.000							
sum of payments	15.000	15.000	6.000	6.280	6.573	6.881	7.203	7.541	
net cash flow (NCF)	-15.000	-15.000	0	5.720	6.187	6.602	7.090	7.609	3.208

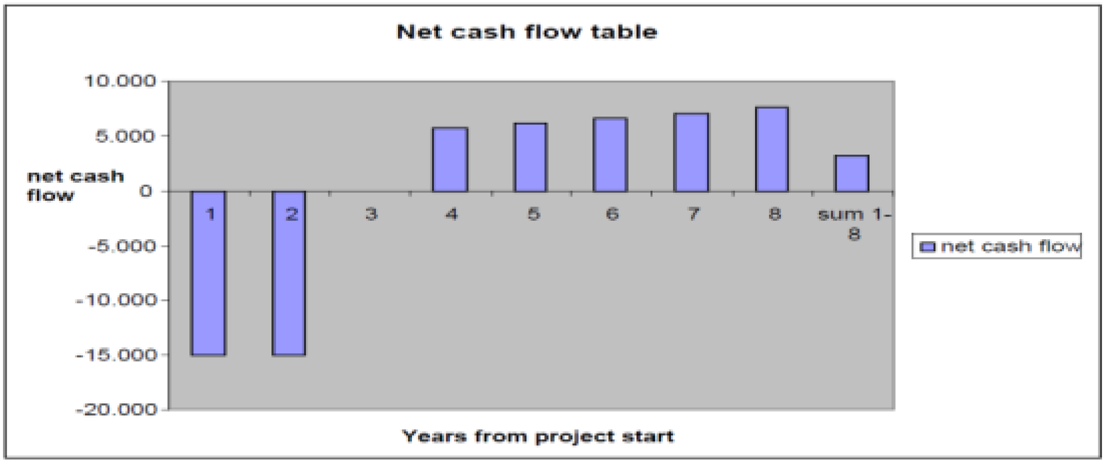


Figure 3-1: Cash Flow Chart (Max, 2008)

In general, to study a company's situation, it is more useful to operate with the cash flow (ECF, FCF or CCF) as it is a single figure, while the net income is one of several that can be obtained, depending on the criteria applied (Pablo, 2006). In Cash Flow Assessment methods, all costs that will be carried by the company and the investment in focus are calculated. Cost for a capital loan (capital payback and interest rate etc.) has to be included.

The above Figure 3-1 and Table 3-1 shows the typical cash flow table and figure (bar chart). It helps describes clearly where and when the income and expense resides. The above shows that the first two years is negative cash flow and the project is not making money, that money is paid out and no income. However, from year 3, sales have commenced and from year 4-8, some level of profitability has kicked in and the plant is stable without obstruction.

Sensitivity Assessment: Because this is built in a model, it becomes easier to simulate performance in terms of cash inflow and outflow of any kind and see how it impacts the business/opportunity in a Cash Flow Table or Model. Assumptions on various changes of prices and cost can be integrated easily. While this can be used for the oil and gas industry, it has not shown some key output from the model.

3.3.4 NPV (Discounted Cash Flow) Assessment Method

The Net Present Value methodology is widely used for taking investment decisions, (Alberto, 2005). It is has been accepted as a sound indices for making investment decisions and suggested in many corporate finance books (Copeland & Weston, 1988; Bierman & Smidt, 1992; Rao, 1992; Damodaran, 1999; Copeland, Koller & Murrin, 2000; Brealey & Myers, 2000; Fernández, 2002).

In TEA, NPV method has been used a lot and considered to be reliable in giving sound judgement. It accounts for the fact that capital investment is disbursed at the start of a project/investment, but returns take some time to pay back during which their value may have diminished in real terms of money of the day since the income comes in later. By which stage their value, in real terms has diminished (1 pound today is more valuable than the promise that 1 pound will be paid in five years' time) (Alberto, 2005).

According to Max (2008), it is calculated by discounting the cash flows by the discount rate and by the entire addition over the project period. In typical techno-economic project analysis, the discount rate should be at least two percent above the interest rate of the source of loan.

Equation / Calculation

According to Max (2008), the net present value of every year is discounted to the year 0 by the discount rate using the formula in equation 2-1 below. For example the equation can be: the net present value of the project NPV_{tot} is the sum of the discounted cash flows for every year of the project period.

$$NPV_n = \frac{NCF}{(1+d)^n}$$

Equation 3-1

$$NPV_{tot} = \sum nNPVn$$

Equation 3-2

Practically these calculations are done using the same worksheet as it is established for calculating the net cash flow table. It is a very good tool for comparing different ranges of projects. Because this is mostly built as models using excel packages or software, the impact of data variation and input parameters/data information can be evaluated in a sensitivity assessment.

3.3.5 IRR Assessment Method

The Internal Rate of Return (IRR) is the average annual return rate on the primary investment when considering all costs and paybacks over the given project period (Max, 2008). It is calculated on the present value of money or cash flows from the investor and into the investment (Stevens, 2013).

The IRR has been seen as an important factor used for the assessment of the economic viability and health of a project. In a situation where you have one or more project scenarios than one possible project to be compared to each other, the internal rate of return (IRR) gives an indication on the most profitable scenario, independent of project size and technology (Max, 2008). It is a favoured way to measure the performance of an investment (Robert, 1996).

Various computer programs compute IRR including Microsoft Excel, Lotus spreadsheets and some personal finance software. Also, some other specialised software programs (Robert, 1996). Hence, this research has also used the IRR in the Excel for the Model development and also a calculation approach.

Calculating IRR is important as it can be easily used to help point you to an investment direction. For example, it will help you establish in strong terms if you are better off leaving your money in the Bank or investing it somewhere else. Where the IRR is less than what you could get from the bank, it will not make any sense investing in a project that your money is not secured and the return not guaranteed for you to get a return lower than the bank rate. So, this will also help us know the technology that will give us the best return.

“For a project to be an attractive investment the IRR should be higher than other options the investor has for investing that money, taking into account the degree of risk associated with the investment’’, Max (2008).

3.3.6 TEA Method of Best Fit

From the above review, the TEA method relevant to this research is the NPV Discounted Cash Flow (DCF) Assessment Method. The UZO-MARG Model is built on MS Excel 2007 and will also provide Internal Rate of Return (IRR) as an output result.

The IRR is better off when it is been used to compare projects, however the DCF method looks at the entire spectrum of a field or an opportunity. The Cash Flow Table is only looking at cash flow and not key economic parameters required for investment decision. The DCF method is relevant to this research and the case studies that will be carried out. Hence UZO-MARG is built on DCF.

4 Economic and Financial Model Design

4.1 Introduction

Typically, models are used when it is either not possible or practical to create experimental situations in which an outcome can be directly measured. Through the use of a model, different scenarios of a situation or conditions can be produced. In addition, models enables the impact and effect of changes in policy options, fiscal regimes like in oil and gas, and various sensitivities to be transparently observed and evaluated.

Economic and Financial modelling is at the centre of economic and financial theory. A Model no doubt provides a systematic logical approach to help the person carrying out the economic analysis to think in a structured and organized manner with the aim of isolating and sorting out complicated chains of cause and effects in the system been analysed (Evans, 1997).

4.2 Model Objective

According to (Macmoran, 2015) a financial/economic model is built to be able to carry out computations which can help determine for a business the following:

- Financing (Debt or Equity) and Buy vs. Lease
- Valuation and Budgeting (leading to investment decisions)
- Business Plans and Strategic Plans (leading to investment decisions)
- Expansion and Merger / Acquisition (leading to investment decisions)
- Lost Profits and Business Interruption
- Litigation Support and Start-ups
- Contraction / Closure

Specifically for Marginal fields, the following can be derived from the model:-

- Estimates of the cash flows from the field or facility
- Comparison of different fiscal terms on the viability of the field. This is especially good for both the ‘farmor’ and ‘farmee’
- Estimate of bidding cost for the asset (leading to investment decisions)

- Quick evaluation of sensitivities on changes in economic parameters on earnings
- Impact of bidding cost on the cash flows from the field or facility
- Economic and financial indices which are derivable from the cash flows

In addition to the above, a Financial / Economic model will help reveal the economic and financial factors such as Net Present Value (NPV), Value Investment Ratio (VIR) etc. and financial indices such as Return on Average Capital Employed (ROACE), Return on Capital Employed (ROCE) etc including demonstrating to an intense depth what the business is going to do, how it will do it and how it is shown in the financial analysis (Macmoran, 2015).

4.3 Types of Models

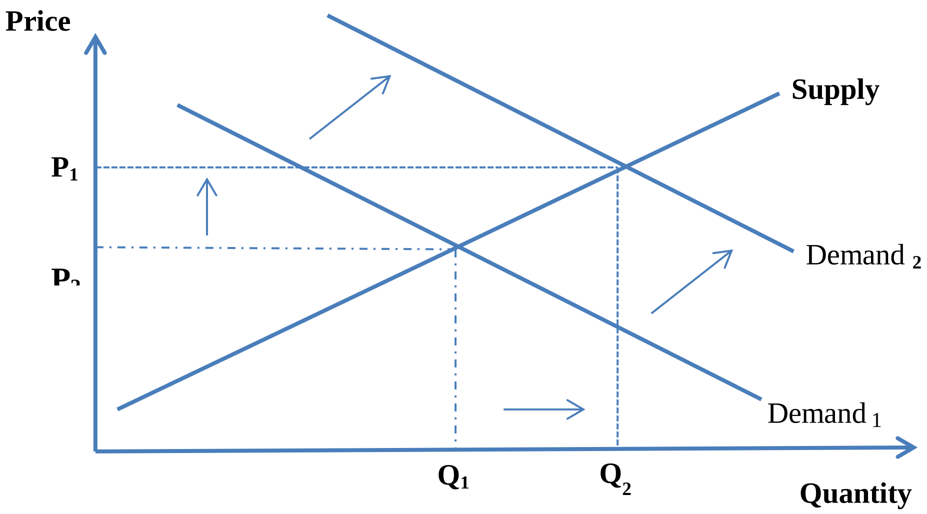
The four fundamentally model types that have formed the foundation upon which models are designed and developed are:

- Visual Models
- Mathematical Models
- Empirical Models
- Simulation Models

4.3.1 Visual Models

Visual models are centred on visual illustrations as the name suggests. For example, It could be a pictorial illustration of an abstract economy using graphs and lines that communicate an economic and financial story of a situation or condition been evaluated see below Figure 4-1 showing demand and supply curve.

Most visual models are diagrammatic expressions of mathematical models. The foundations of visual models are mathematical models (Evans, 1997).



1) The first demand curve represents demand prior to the formation of inflationary expectations
2) The second demand curve represents the effects of inflationary expectations upon demand
3) Prices and output finally settle at P2 and Q2, higher in both cases

Figure 4-1: Effect of inflationary Expectations on price and output

These models do not require an extensive understanding of mathematics but still allow the presentation of complicated relationships between economic and financial models. They are easily understood but limited in scope.

4.3.2 Mathematical Models

These models are formal in nature and can appear abstract. For example, they can be a system of simultaneous equations with equal or more number of financial and economic variables. Some of the equations governing the models can be quite large with over six equations and many unknown variables. The use of and the working of this models requires a sound understanding of mathematics (Evans, 1997).

The mathematical equation below shows the mathematical model of the visual model shown above in Figure 4-1 with the variables representing economic activities.

$$(1)\ S = a + bP$$

$$(2)\ D = c - dP + eIE$$

$$(3)\ S = D = Q^{0}$$

$$(4)\ P^{0} = \frac{(c + eIE - a)}{(b + d)}$$

$$(5)\ Q^{0} = a + bP^{0}$$

S = Supply; P = Price; D = Demand; Q = Quantity; IE = Inflationary Expectations;

a, b, c, d, e = constants

Figure 4-2: Mathematical model of the Visual model shown in Figure 4-1

Mathematical models have so many advantages which are as shown below:

- Mathematics is a very precise language. This helps us to formulate ideas and identify underlying assumptions.
- Mathematics is a concise language, with well-defined rules for manipulations.
- All the results that mathematicians have proved over hundreds of years are at our disposal.
- Computers can be used to perform numerical calculations.

4.3.3 Empirical Models

Empirical models are more or else mathematical models designed to be used with variables in form of data. Data is normally gathered for the variables and applying approved statistical methods, the data is used to calculate and provide estimated model values. It is normally not easy to understand empirical models except where the user has a deep understanding of statistics and they are largely built from mathematical models (Evans, 1997).

4.3.4 Simulation Models

Simulation models are used with computers, they are normally mathematical models defined in computer language and evaluated by computers. The user does not need to be over proficient with computers depending on the level and type of model been built. The mathematical equations can be written in Excel, C++ or other applicable programming language. In the simulation model, the user most times alters most of the variables (Evans, 1997). The figure 4-3 below gives a process flow of Simulation Model Design.

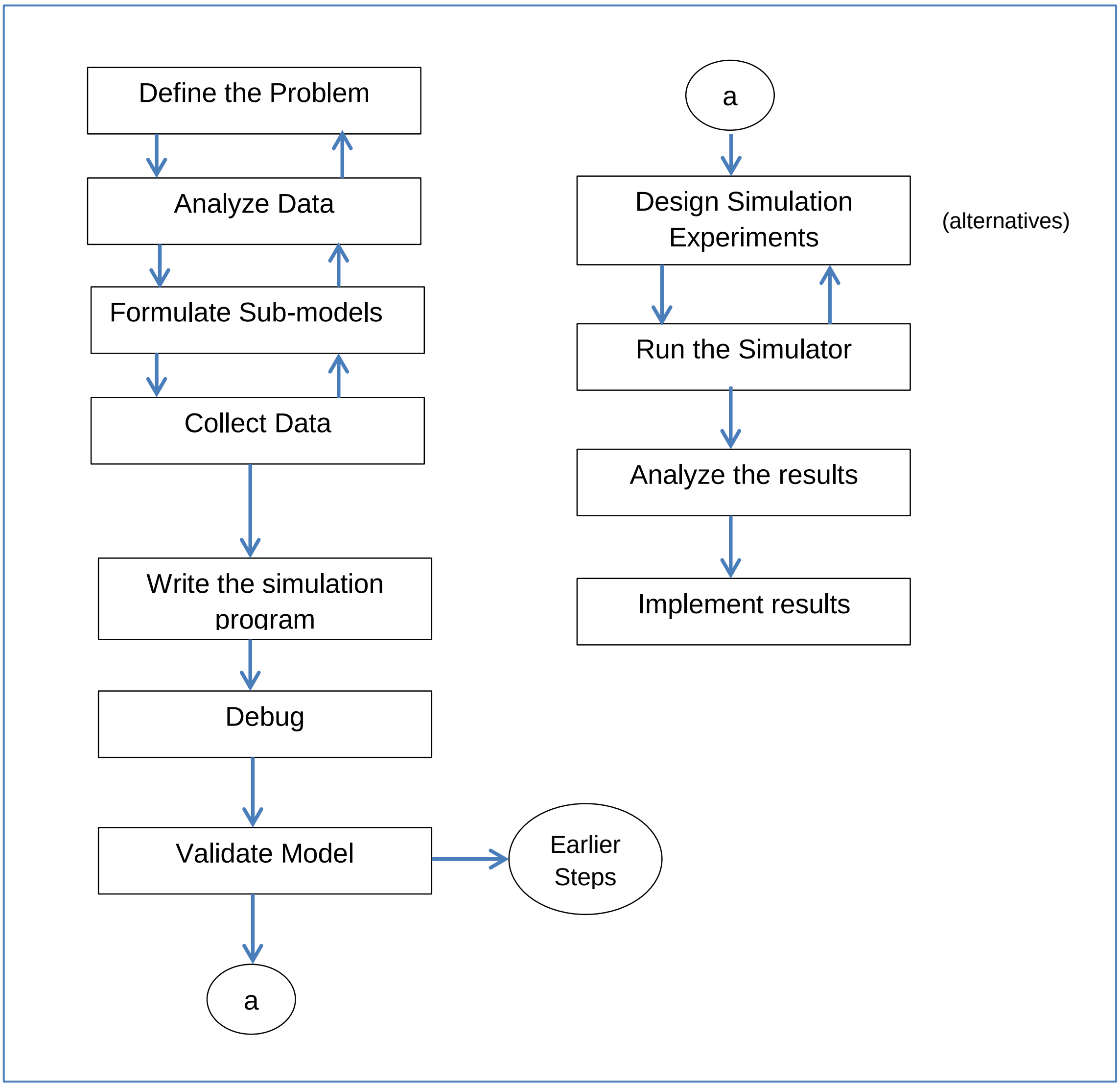


Figure 4-3: Steps involved in carrying out a simulation study (Perros, 2009)

Generally, simulation models are used to study real life systems mostly which do not currently exist. It is specifically used when the interest is about establishing the performance of a system with various input variables or what the resultant output/outcome of a system study or situation evaluation under different or varying input data (Perros, 2009).

In simulation models study exercises, relevant variables are categorized into two, the ones that are not manipulated (uncontrollable variables) and the ones that can be manipulated to produce an outcome or a solution is known as (controllable variables).

4.3.5 Model Method of Best Fit

All the models listed above have their respective areas of best fit. Considering what the model is to be used for, the level of data complication the model is to handle, the financial analysis and the integrated nature of the model, the Simulation Model Type is identified to be the model of best fit for the design and development of the model.

The model will also be deployed to run various Techno-Economic Analysis (TEA) which is best handled through a computer simulation model. In addition to the above justification for the selection of the Simulation Model to be used, listed below are other attributes of the simulation model type that makes it the selected choice:

1. They can be used with computers, which most people are conversant with as far as the program is already written and functioning
2. All the mathematical functions written in computer language can easily be retained and where there is a change in the plant design, the simulation model can easily be updated, adjusted to produce new results and outputs
3. Model can be built on Excel function of the Microsoft Office, no special software is required, and however, designed model can later be transferred into other programming languages.

4. The present and future case studies UZO-MARG will be used for are both predictive and validation cases to aid investment decisions and allowable error margin is small.
5. Ease of verification and validation with reduced margin for error.
6. Can be used as a dependable tool for plant operation (easily transferable)
7. The Financial Analysis the model will process can only be easily handled by a computerised system with capacity for simulation.
8. The Techno-Economic Assessment method selected is the NPV (Discounted Cash Flow Method). This aligns with the simulation method of model design.

Having identified the model type, designing and building the model is what follows. The model to be built will have the capacity and robustness to carry out economic and financial analysis for investment decisions, be able to carry out valuation of oil fields assets for both already developed assets and exploration assets. Also be able to carry out the financial health check of a Marginal Oil Field company. To achieve this, there is need to understand how to build an economic and financial model.

4.4 Model Design and Development

In designing and developing of a model, it is important to decide whether it is a One-Off Model design or a Template Model design.

4.4.1 One-off or Unique Model Design Type

Developing a unique or one-off model means that the model is been built for a specific use i.e. in a project or an evaluation, just for that purpose only. Although it can be used again when required but may be exposed to substantial errors as a result of the level of modifications that is required for it to be used on another project or situation (Tjia, 2009).

4.4.2 Template or Pattern Model Design Type

Another model design is the Template Model design type; this is a model design type that will become like a pattern that will be used numerous times. It can become the analytical tool for a company or organisation for carrying out the studies or case studies leading to major organisational or investment decisions.

It is understood that not all the time will a model design type be easily replicable, however, for a template model design type that is well built; it should be over 80% ready for any analytical work with minor modifications or updates to bring to full performance. One smart way to increase the reach and performance of a template model design type is to have enabled and included additional sheets where the base programme is Excel Ms Office. The sheets can be added in front of the analytical master sheet as inputs (which are the model) so that they can be made more detail and the back of the model as outputs see figure 4-4 below.

A harmonised template model can be an excellent business decision tool for an organization. Because it is designed to be used consistently, the designer, developer and the users can continue to work it and bring other several improvements to it while it is still been used to deliver value to the organisation or users. One major advantage of the template design model type is that because of the level of granularity of the inputs, several users can use the model at different times and locations. Also, it can be updated to fit into different situations in little time (Tjia, 2009).

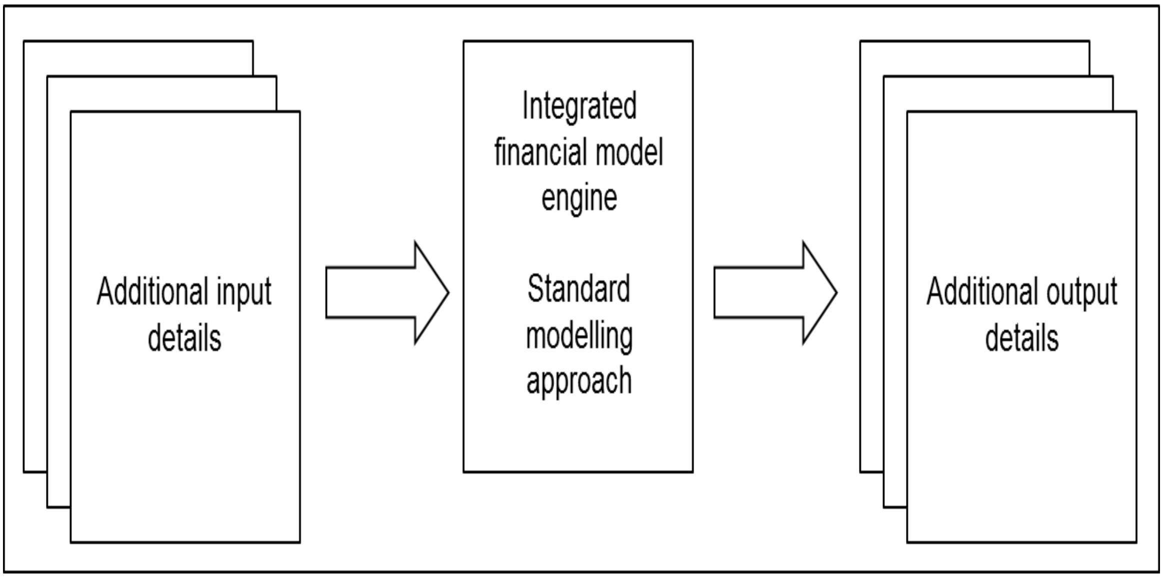


Figure 4-4: Standardized Template Model for Pattern Design (Tjia, 2009)

4.4.3 Modelling Life Cycle

The design and development of computer models go through different life cycle stages, knowing and appreciating the way the life cycles through which models evolve and grow surely contributes to the development of robust and credible models (Read and Batson, 1999). The design and development of a model go through six different stages as shown in figure 4-5 below:

The modelling life cycle stages are

- Scope
- Specification
- Design
- Build
- Test
- Use

Figure 4-5: The six stages of the modelling life cycle (Read & Batson, 1999)

4.4.3.1 Scope Definition Stage

In the design and development of a model, it is important to have a well-defined scope before start-up. This scope will further define the objectives and the boundaries of the model viz a viz,

- The objectives of the model will help define what the model will do and what it will not deliver
- The level of complexity that should be entertained and the assumptions that will be made
- The data requirements for the model, quality and availability of the data
- Using workshops to build a common understanding of the model scope;
- The contents of the scope document; and
- How to estimate timescales for model development

4.4.3.2 Specification Stage

At the centre of any software that will be used for model design and development is the definition of the formula that will be used to calculate the model's results. The specification of the formula can be termed as the most important part of the model design and development.

For developers, formulas are written during the build stage, working out what each formula should be at the same time populating the software. It is recommended that the process of specifying the model calculations and formulas be separated from model design and development.

The specification stage is also about defining the outputs and inputs to the model.

4.4.3.3 Design Stage

In every structure been built, the Layout is very important. It can drive ease of use; hence, good model design is one of the prominent features of a very good spreadsheet model. An easy to use and understand model is a well-designed model. It is less likely to be error free and easy to identify mistakes that the designer and developer have made.

It is also easier to be improved upon by another user when the model is well designed. Part of the design of a model is about understanding when a spreadsheet should be used for a modelling challenge and if other software will be used. Agree on methods for consolidating data in a spreadsheet and how to use macro in the spreadsheet.

4.4.3.4 Spread Sheet Model Design

Amongst other packages, the spreadsheet package is very good when dealing with numbers as variables as it has a wide spread of financial and mathematical functions. Most times it is easier to present calculations in such a way that it could be readable with informative graphical display. Over time, spreadsheets have become very popular, broadly available and comfortable to use.

The spreadsheet is also a flexible software package. It very important to note that before a spreadsheet is modelled, the model designer and developer have to be sure that spreadsheet is the most appropriate, see below in Table 4-1 comparing different modelling software packages.

According to (Kumiega and Van Vliet, 2008), there are other reasons the use of spreadsheet is acceptable towards the development of financial and economic Models, this ranges from:

- Availability of pre-built and standardized functions in spreadsheets that can easily handle complex calculations particularly MS Excel.
- Organisations embrace and accept spreadsheet, including universities and colleges as the main tool for financial and economic model development.

The table below compares the strengths and weaknesses of a number of different modelling packages.

Table 4-1: Comparison of Modelling Software

Software type	**Strengths**	**Weaknesses**
Spreadsheets e.g.: Microsoft Excel, Lotus 123	• numeric manipulation; • financial functions; • user interface; • graphical reports; • easy to learn; and • time series modelling.	• handling large quantities of data; • multi-dimensional data; • systems with feedback or circularity; • looping and branching; and • can develop "black box" systems.
Databases e.g.: Microsoft Access	• handling large volumes of data; • user interface; • can develop "black box" systems; and • multi-dimensional data.	• complex calculations; • complex report structures; • graphical reports; and • time series modelling.
Statistical software e.g.: SAS	• handling large volumes of data; and • complex statistical functions.	• expensive; and • more difficult to learn.
Multi-dimensional packages e.g.: Oracle Financial Analyser	• multi-dimensional data; • handling large volumes of data; • "slice and dice" reporting; and • aggregation of data.	• specialised use; • more difficult to learn; • expensive; and • used more for information reporting than modelling.
System Dynamics packages e.g.: Vensim, Powersim	• systems with feedback or circularity; • "soft" variables such as staff morale; • multi-dimensional data; and • graphical representation of the model structure.	• producing financial statements; • difficult to understand and accept the processes; and • specialised skills required to develop and maintain.
Rules based packages e.g.: Applications Manager	• can develop "black box" systems; and • looping and branching.	• specialised use; and • more difficult to learn.

4.4.3.5 Build Stage

In the Build stage, the coding of the model is undertaken. This stage is easier, quicker and less prone to errors if the specification and design stages are successfully completed. It is always tempting to start coding the model too soon, especially when you are under pressure to produce results from the model quickly. Taking time to understand the problem and how you are going to solve it makes building the model:

- Quicker and easier, because you have a model specification that describes what the model will do rather than having to work it out as you go along;
- Less prone to errors if you have a written description of how the model works; and
- Less likely to have to be reworked, if you have taken some time to build a common understanding of the requirement of the model.

4.4.3.6 Tests Stage

At best practice, spreadsheet model can be relied upon for important decisions. This is only possible if you have confidence that the results produced by the model are reliable. It is not possible to guarantee that even a moderately complex model is error free. Testing can, however, substantially reduce the risk of significant errors in the model.

If testing is skipped or done poorly, errors are likely to be discovered after the model has been put into use. Errors at this stage can undermine the credibility of both the model and its developer. The value of testing can be measured against the potential cost of a wrong decision: if a model is being used for an important and expensive business decision, the time and resource spent testing the model is time and money well spent.

4.5 Programming Tool and Language

Excel 97 has a wide range of add-in functions that allow you to do a lot of unusual calculations. Many of these can be very useful, but if you find that you are using them a lot, it may suggest that you are better off using a specialist package. For example, if you are using a lot of the database functions, you probably should be using database software.

4.6 Model Input

On the definition of the Model calculation, the inputs required in the model should be implicit (Read and Batson, 1999). It is important that that models need to balance simplicity and ease of use; accuracy, precision, and representativeness; and data granularity (Gifford et al., 2011).

4.7 Model Output

The model of a business system normally will consist of three phases namely, inputs, processes (calculations) and outputs which is mostly known as the results. The information from the output system is also used as a control mechanism to manage the deviations from the expected or planned business performance (Barlow, 2005). Outputs can be final outcome or results from the analysis or calculations (Saxena et al., 2010).

The model is designed to carry out a number of calculations to arrive at economic and financial indices relevant for making investment decisions, and this is clearly shown in the output page of the model. The evaluations covered by this model are described in the sub-sections below.

In excel based models; the input section is not used for the output section or sheet. Separate output pages are normally created, especially for the financial statements; each output sheet references the calculated results inly for a neater outlook (Tjia, 2009).

According to Ecklund, 2006, an output is about what you are trying to solve, find, show or optimise; it is more or else the bottom line from the calculation of the input.

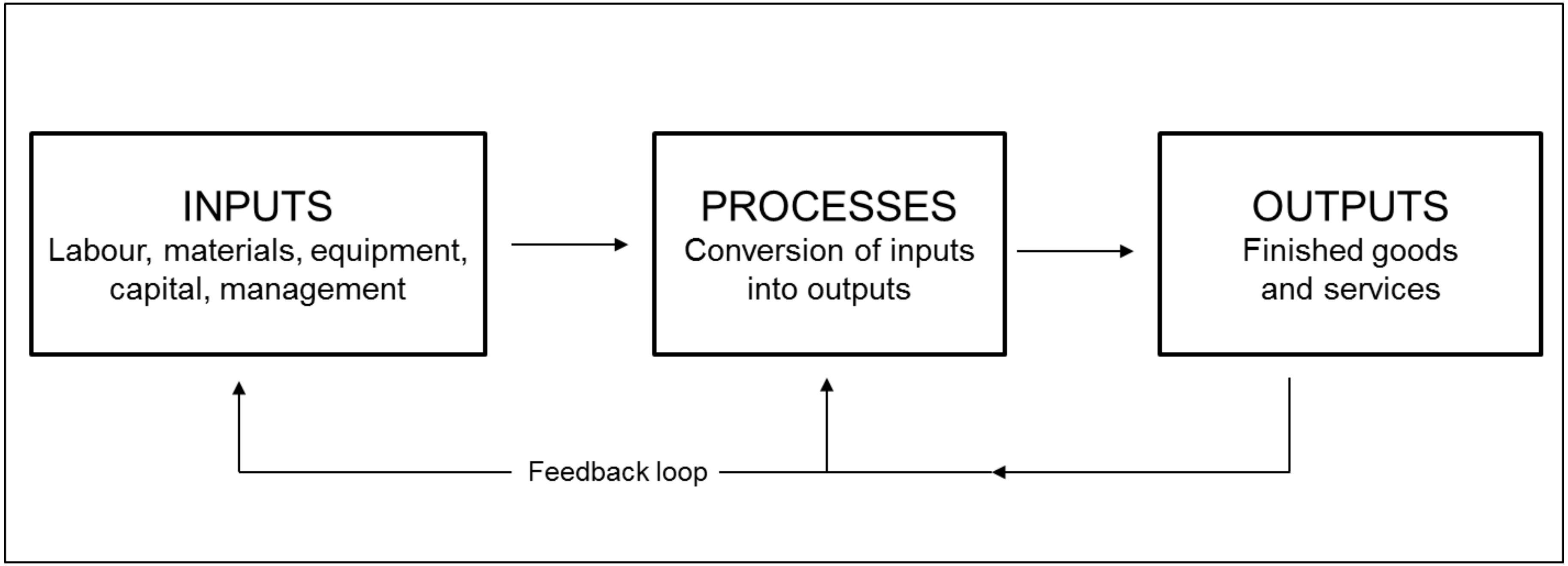


Figure 4-6: Business System View (Model System View)

(Excel Models for Business and Operations Management, 2005)

4.8 Verification and Validation of Models

4.8.1 Introduction

One important question that any one designing a model is likely to be asked is has the model been verified and validated? This is very important if the Model is to be trusted and relied upon for decision making (Macal, 2005).

Validation is about confirming if the model represents the reality of what is been sort for or what it is designed to deliver Computer Model Validation with Functional Output (Bayarri et al., 2007). The development of models is usually for analysing focused problems for different systems (Hillston, 2003).

4.8.1.1 Model Validation Objective

The main objective of model validation is to confirm that the model meets its planned requisites in terms of the methodology applied and results output. Ultimately, it is about making the model create the intended value by providing accurate information from it to aid decision making.

Reasons we do modelling and simulation (Macal, 2005):

- We are constrained by linear thinking: We cannot understand how all the various parts of the system interact and add up to the whole
- We cannot imagine all the possibilities that the real system could exhibit
- We cannot foresee the full effects of cascading events with our limited mental models
- We cannot foresee novel events that our mental models cannot even imagine
- We model for insights, not numbers
- As an exercise in “thought space” to gain insights into key variables and their causes and effects
- To construct reasonable arguments as to why events can or cannot occur based on the model
- We model to make qualitative or quantitative predictions about the future

4.8.2 Validation Processes

There are six process steps for model validation that is defined (Bayarri et al, 2007). The process is particularly designed to treat the issues associated with the validation process, quantifying multiple sources of error and uncertainty in models; combining multiple sources of information; and being able to adapt to different, but related scenarios. These steps are described as a framework for model validation and they are:

1. Defining the problem (inputs, outputs, initial uncertainties);
2. Establishing evaluation criteria;
3. Designing experiments;
4. Approximating computer model output;
5. Analysing the combination of field and computer run data;
6. Feeding back to revise the model, perform additional experiments, and so on.

4.8.3 Verification and Validation Processes

When carrying out a verification and validation of a model, it is critical to begin by identifying the key principles and techniques to be applied for that model. Planning of the verification and validation process is very necessary to have a good outcome (Kennedy et al., 2005).

A hierarchy of verification and validation methods that can be used for economic and financial models is shown below in Figure 4-7 below:

4.8.4 Choice of Validation Methods

Different quantitative and qualitative methods of validation of models are available as shown in the Figure 4-7 below, a number have also been described below.

The selection of the method to be used, especially for this research, is based on the model's methodology, its complexity, data availability and type, and the scale of potential business impacts when the Model is used for business decisions.

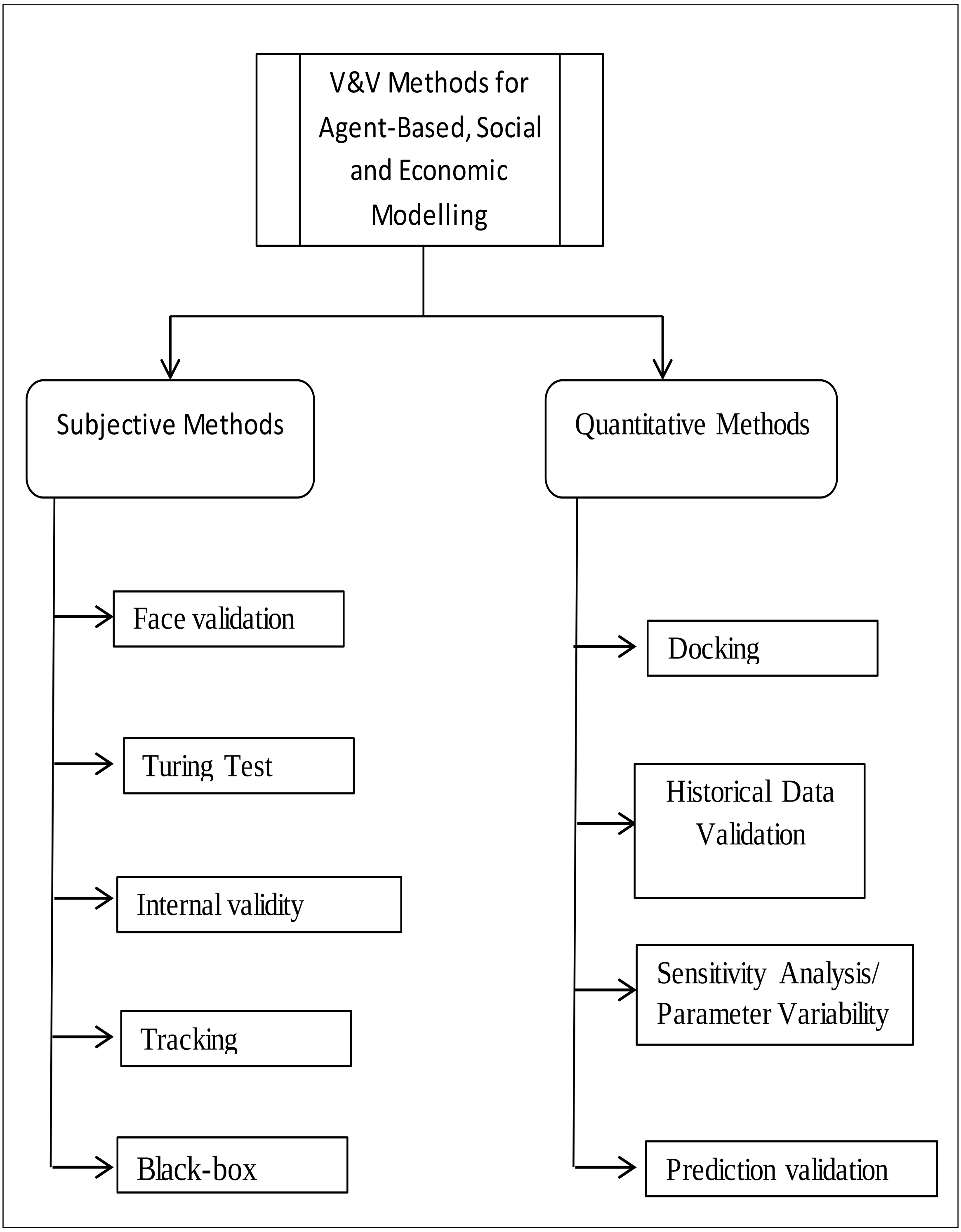


Figure 4-7: Verification and Validation Methods (Kennedy et al., 2005)

4.8.5 Subjective Methods

As the word suggests, subjective methods of verification and validation rely on judgement of subject matter experts. They are often used for models that are not too risky for decision making. This method requires less efforts compared to the quantitative methods of verification and validation. One key advantage is that errors can be detected early in the simulation process and is often the method applied when a newly design simulation model is been built.

According to (Kennedy et al., 2005), the following are subjective verification and validation methods often applied in science and business environment.

1. **Face validation:**

   This is an introductory process to validation and it entails asking subject matter experts (SMEs) how well the model is behaving and the level of accuracy been recorded. This is often worked by assessing the model output.

2. **Turing test:**

   This is achieved by asking SMEs to evaluate and confirm the difference between real life situation and model outputs.

3. **Internal validity:**

   This entails the comparison between several model replications of a simulation. Where inconsistencies in model output are observed, the validity of the model can be challenged.

4. **Tracing:**

   In this case, the behaviour of units in the model is followed to determine if the logic of the model is acceptable.

5. **Black-box testing:**

   This technique entails how precisely the model converts the input to output in a system.

4.8.6 Quantitative Methods

Integrating quantitative or statistical methods validation process can increase the acceptance and credibility of the model. Statistical techniques can be used to compare the model output result with the output data of other models run with the same data.

The first step commencing quantitative analysis is to determine appropriate outputs measures that be used to respond to questions the user may have (Kennedy et al., 2005).

After a series of output measures has been determined, various statistical techniques can be applied to complete the validation process. Aggregations of the different output results can be used to plot graphs and charts for result reading and interpretation.

It is important to note that robust and credible results are achieved when tests are carefully selected according to the model design, type and objective. The below according (Balci, 1998) have outlined quantitative techniques that are relevant to this research and the case studies carried out.

1. **Docking (Model to Model Comparison):**
   Docking or model to model comparison/alignment is applied when there is a real practical data in existence or can be created. Also in a situation when another model is available that models the same occurrence (or can be generated).

   It helps to establish if two or more models can generate the same results (Axtell, R., Axelrod, R., Epstein, J.M., Cohen, M.D., "Aligning Simulation Models: A Case Study and Results," Computational and Mathematical Organization Theory, 1996).

   The key matter here is that model confidence in terms of credibility is significantly improved when two or more models generate the same outcome, especially if the models were developed independently and with different system approach.

2. **Historical data validation:**
   This is the type of validation where historical data exists or can be obtained; the model is then built with this obtained data and the remaining data then used to establish if the model behaves as the system does.

3. **Sensitivity analysis/parameter variability:**
   This validation is such that changes are made to the input values and the internal factors of a model to establish the impact upon the model and its output. The relationship in the real-world situation is imitated in the model.

   Before using this model, especially for decision making, sensitive factors that could lead to major changes in the model behaviour ought to be made adequately accurate before using the model.

4. **Predictive validation:** This type of validation is normally used to compare the models prediction with real system performance. The system information may be obtained or derived from an operational system or focused experiments from laboratories or field experiments.

4.8.7 Validation Method of Best Fit.

For this PhD research, the chosen Validation method is the Quantitative method with two approaches namely Docking and Sensitivity Analysis/Parameter Variability Validation because of the following reasons :

1. Real data exists for this research both costs and hydrocarbon data
2. Practical and real outcome data for an operating company is available to compare output from model i.e. Lekoil Energy studies report and performance report.
3. Changes are made to the input values to see if confirmable results are obtained from the output.

5 Oil and Gas Property Valuation

5.1 Introduction

Determining upstream oil and gas facility/property value could be challenging because of the high potential of failure, the technical uncertainties and non-technical risks, so quantifying value of the oil and gas assets is important for investment decisions (Moore, 2009).

A lot of people wonder why oil and gas companies have challenges towards buying or selling their fields (assets); many times the challenge is what is the asset worth, especially for the already producing fields, why it should not be more or less from the actual costs been offered (Rashed, 2013). The oil and gas properties are classified into three categories namely; exploration properties, development properties and production properties and they are normally appraised in this other.

Most appraisal firms are generalists and do not have all the required skills necessary to assess oil and gas assets. Most times the valuation tools applied are not usually adequate for oil and gas leading to loss of value by the purchaser. This is because significant scientific and technical know-how is required (Howard and Harp, 2009).

5.2 Objective

Petroleum property valuation is an analytical procedure or process by which the commercial value of oil and gas fields is assessed to support an investment decision. This assessment helps the prospective buyers, sellers, and other investors to be aware of the true estimate of the fair procurement value of the buried hydrocarbon, especially the reserves (Smith, 2003).

The exploration and production of oil and gas assets over its entire life changes with time. For example, before a well is drilled, the value depends on the quantity of commercially viable hydrocarbon in the reservoir, this drives the decision to develop the reservoir; the value is based on the producible streams over time and the economic performance of the produced asset before abandonment (Moore, 2009).

It is important to always remember that production will decline overtime and new costs may be required to improve production from the wells and this can inform when the assets will stop producing positive cash flow. This is the main driver for valuation, how long will the asset be profitable, and will it cover the expenditures that will go into the asset development and production? This will also determine the valuation method and technique that should be applied to oil and gas assets.

Given that decline and production is inevitable over time, valuation techniques based on either replacement cost or net book values are not suitable for oil and gas assets.

Exploration, production, mining and metals are amongst the best priced equities in the world. However, the drastic in prices natural resources such as oil, gas and other mineable resources, economic recessions coming without notice, demand reduction are confusing investors.

This has made investments in this kind of commodities to become more attractive as a long term investment, thus it has become very important and useful than ever before to know how to value this resources (Baurens, 2010). This is more needed for marginal fields since they are already existing operating assets/properties or properties that have already been bought and not developed for some time.

The most widely utilised and preferred method for valuing oil and gas properties is Discounted Cash Flow (DCF) analysis. DCF analysis entails projecting the future costs and revenues to which the interest holder is entitled (Moore, 2009).

Projected cash flow is decreased by a discount factor that is applied to account for the time value money. The total sum of these discounted annual cash flows through the entire life of the asset is called the Net Present Value (NPV).

5.3 Valuation Methodology

The value of a natural resource asset or property can be most times complex. There are various methods for determining the value but many are not applicable. The reason is because of the specific nature of the natural resource industry which oil and gas is one of them. Apart from the risk associated with financing, discovery of hydrocarbon in the case of exploration, there are things like oil and gas price volatility, changes and variation in CAPEX and OPEX (Baurens, 2010).

Amongst other valuations methods, there are three distinct standard ones that are used for oil and gas asset/property valuation; they are the COST APPROACH, SALES COMPARISON or MARKET SALES APPROACH and INCOME APPROACH (Miller, 2002). It should be stated that these valuation methods all compensate for one another depending on the information and the data available.

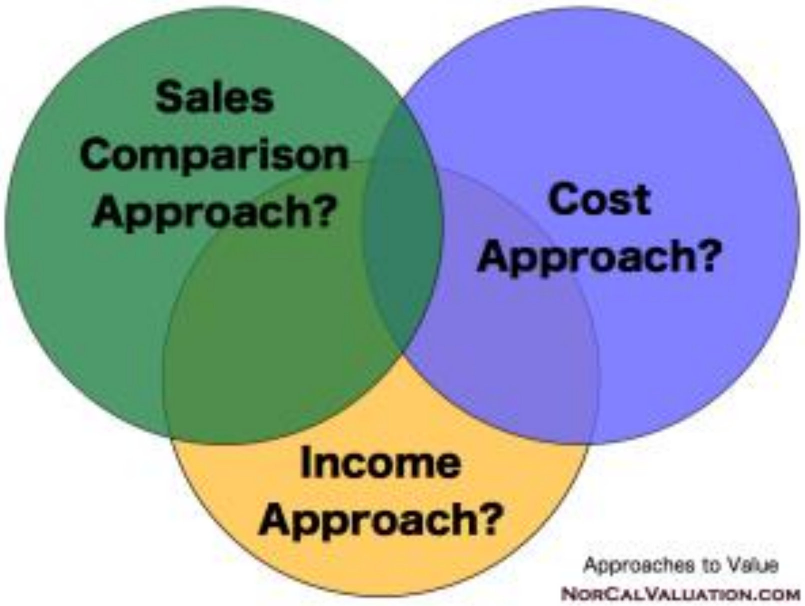


Figure 5-1: 3 Ways to Determine Equipment Value (Young, 2015)

These three approaches should not be seen as autonomous from each other since they pull from the same data source but the data are analysed using different valuation methods. The strategy is such that the three valuation methods should complement the outcome from each other.

5.4 Valuation Methodology Classification

Valuation of an oil and gas asset/property can be divided into three categories depending on what stage the asset to be valued is, and this also goes to further define the type of valuation method that is best applied to appraise the asset. The categories are Exploration, Development and Production (Baurens, 2010).

To further define this category, we have them as shown below:

5.4.1 Exploration Properties

This are properties or assets that are still been studied based on seismic data. There is yet to be a near full proof that the property been evaluated will have positive economics. The value is premised on the potential that a viable discovery has been made keeping in mind that until an exploration well is drilled and tested, the value is not yet quantified and huge risk still exists. Hence, the valuation method to be used will be different from that of others.

5.4.2 Development Properties

At this stage of oil and gas maturation, it is known that some more studies have been done on the opportunity by way of pre-feasibility or feasibility studies and the outcomes suggest strongly that the opportunity is economically viable. However, no investment decision has been taken to execute the opportunity or turn it into a full blown project. Also, there is enough and adequate quality information to value the opportunity using discounted cash flow methods of Valuation. This quality information includes proven reserves, production forecast, costs estimates, etc (Baurens, 2010).

5.4.3 Production Properties

Production Properties are hydrocarbons assets that are in production or already in production but abandoned. This can also be fields that are already been produced and made available for sale. Marginal oil and gas fields fall into this category because most are already proven and producing fields. Where they are not already producing fields, they most times are proven fields (CIM, 2009; Baurens, 2010).

5.5 Cost Approach (Appraised Value Method)

The cost approach is a well-known method of valuing oil and gas properties. This method is premised on a relationship between cost and value i.e. the cost to develop a property or hydrocarbon asset is compared with the value of the existing property or a property of similar scope (Miller, 2002). This method also assumes that the cost of the property is related to its value (Baurens, 2010)

Table 5-1: Types of Mineral Properties (CIM, 2009)

Table : Valuation Approaches and Methods for Different types of Mineral Properties					
Valuation Approach	Description	Valuation Method	Exploration Properties	Development Properties	Production Properties
Income or Cash flow	Relies on the 'value-in-use' principle and requires determination of the present value a	Discounted Cash flow	Not generally used	Widely Used	Widely used
		Real Options	Less widely used	Quite sidely used	Quite sidely used
		Monte Carlos Analysis	Less widely used	Less widely used	Less widely used
		Probablistic methods	Not widely used	Not widely used	Not widely used
Market	Relies on the principle of substitution. The Mineral property being valued is compared with the transaction value of similar Mineral properties transacted in an open market	Comparable Transactions	Widely Used	Widely Used	Widely Used
		Option Agreement Terms	Widely Used	Widely Used	Quite Widely Used
		Gross in-situ Metal value	Not Acceptable		
		Net Metal Value per unit of metal	Widely Used rule of Thumb		
		Value per Unit Area	Widely Used	Not Widely Used	Not Widely Used
		Market Capitalization	More applicable to single property asset junior companies		
Cost	Relies on historical and/or future amounts spent on the Mineral Asset	Appraised Value	Quite Widely Used	Not Widely Used	Not generally Used
		Multiples	Quite Widely Used	Quite Widely Used	Widely Used
		Geoscience factor	Not Widely Used	Not Widely Used	Not generally Used

5.6 Comparable Transactions (Market Approach)

The sales Comparison Approach also known as the Market Sales Approach is the technique for valuing oil and gas properties and other natural resources by analysing and comparing the market for similar properties and assets have recently been purchased or sold. The technique has various steps; the appraiser carries out a market research or survey of similar hydrocarbon assets or characteristics similar to the one been valued. It is more of comparative analysis of the hydrocarbon assets and where there are differences factors are included to bring the similarity closer (Miller, 2002).

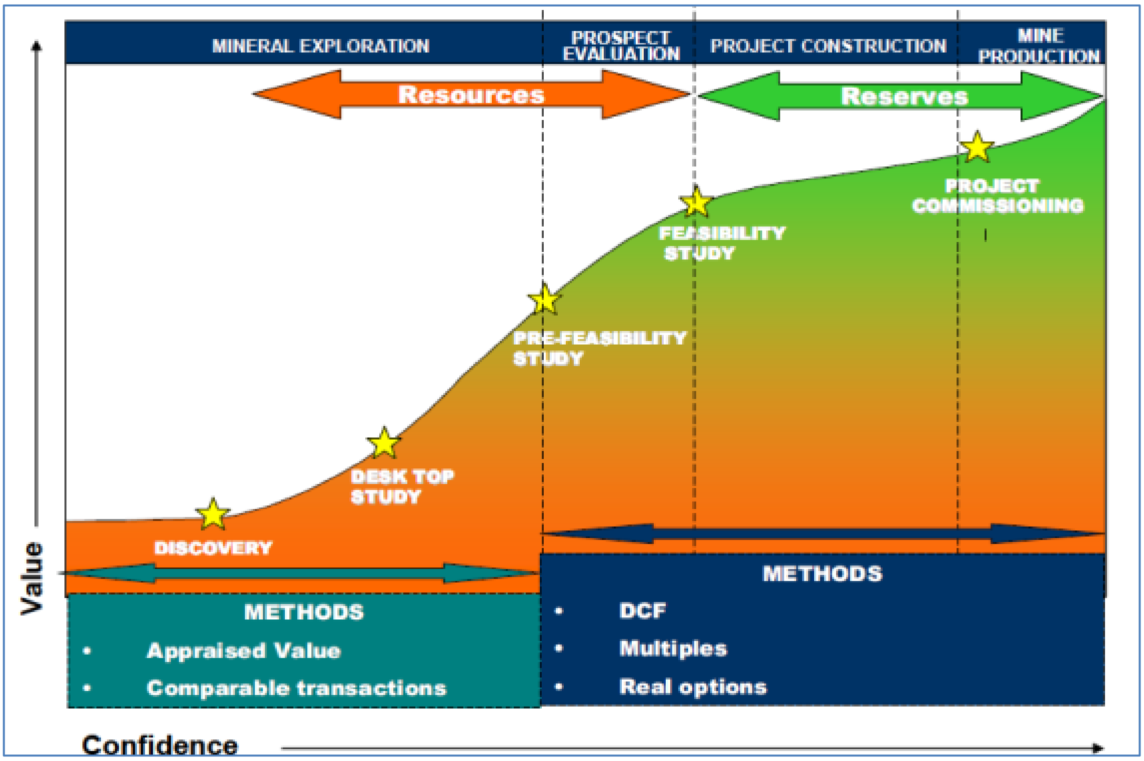


Figure 5-2: Mineral resource study and execution trend (Baurens, 2010)

Figure 5-2 above shows different valuation methods; this can be applied depending on the different stages of development of the oil and gas property (CIM, 2009).

Comparable methods allow the value estimated for the focused project to be benchmarked against other projects with costs already established in the market (Roberts, 2006).

This approach is good in situations where there is not enough information to perform reasonable NPV analysis (Davis, 2002).

5.7 The Income Approach

Oil and Gas assets/properties are developed and operated for future income stream that is normally obtained from the sale of the produced oil. Where the principal driver is about using the asset to earn income overt time (t), the income approach is recommended (Miller, 2002). While other methods can be used to support the income approach where possible, it still remains the most used for oil and gas properties.

Under the income valuation approach, future amounts (cash flows or earnings) are converted to a single present amount (discounted) known as the present value (PV). The measurement is premised upon the amount indicated by the current market about the future amounts. Most companies in the oil and gas industry use the income approach by building or using an already built Discounted Cash Flow Model (DCF), the Market Approach can also be an alternative to the income Approach and it is used most times to confirm the robustness of the DCF Model (Deloitte, 2015).

As a result of the above, the Income Approach (Discounted Cash Flow-DCF was selected for this research. The UZO-MARG Model for marginal oil and gas field model have been built with the DCF.

5.7.1 Inputs Parameters for Income Approach (DCF) Analysis

The important factors in Discounted Cash Flow method are the following: -

1. Risk Factors
2. Profitability Index
3. Initial NPV
4. Hydrocarbon Reserve
5. Revenue (volume x price)
6. Production costs
7. Operating Costs
8. Capital Expenditure
9. Taxes and Royalties

5.7.2 Valuation Method of Best Fit

The Income Approach as described above is the Valuation Method of best fit. The major advantage it has is its ability to capture future revenues and earnings in the form of Cash Flow. When compared to the Market Approach, it differentiates itself as a method because of the market approach one spot comparison and you will hardly find exactly the same situation of true comparable assets. The Cost Approach is also in appropriate as it does not capture future returns on the asset been valued. Figure 5-4 shows a summary of the different approaches, their respective hierarchy and advantages.

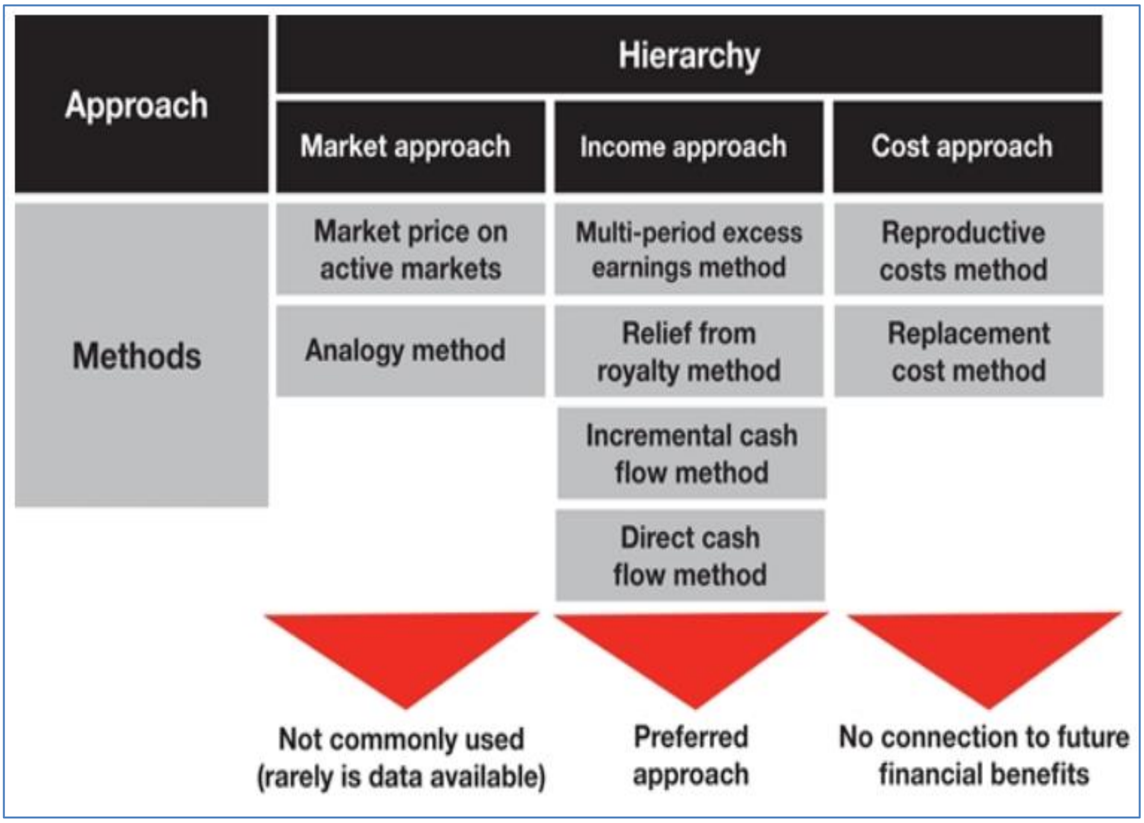


Figure 5-3: The Three Valuation Approaches (Duff & Phelps)

5.8 Integrated Risk Management

For any robust investment decision, a risk assessment must be carried out on the opportunity. Risk Management helps you understand the uncertainties that are associated with the Marginal Fields, oil and gas been a high-risk investment itself (Hawkins, 2003).

According to Hawkins (2003), the key areas contributing to project failures include the following:

- Technical definition has not been adequately completed for the decisions being taken
- Too little attention has been made to the upside and downside cases
- Too little attention in looking for innovative or aggressive angles and strategies
- Insufficient number of staff and competencies to deliver project
- Organisation structure and interfaces are unrealistic for the project complexity
- Non-alignment of stakeholders
- Project objectives poorly communicated to project team and stakeholders
- Poor quality opportunity and risk management systems
- Plans are incomplete and / or not fully integrated
- Reviews have been too late
- Assurance and Review teams/individual were not independent

Often risks analysis is carried out in two different stages, the first been a preliminary screening of the risks and opportunities using qualitative techniques followed by a more quantitative approach lending themselves to quantification however, it should be noted that not all risks are quantifiable (Deloitte & Touche, 2012).

5.9 Risk Categorisation

Risks are categorised to assist in the qualitative assessment and qualitative analysis (see figure 5-5 below). Opportunities and risks are grouped according to categories to assist in the identification, quantification, response development and control. The risk areas have been consolidated into TECOP (Woodside Energy Ltd 1999) i.e., Technical, Economic, Commercial, Organisational and Political.

To be able to manage both pending and upending risks, a risk factor should be applied as shown in figure 5-4 below. In this research, it has been applied to the cost estimates as a contingency to deliver the total project estimate costs using the TECOP approach as described above. Risk Factors are applied in situations where there are uncertainties or unproven systems. Risks factors are easy to apply to the Discounted Cash Flow approach.

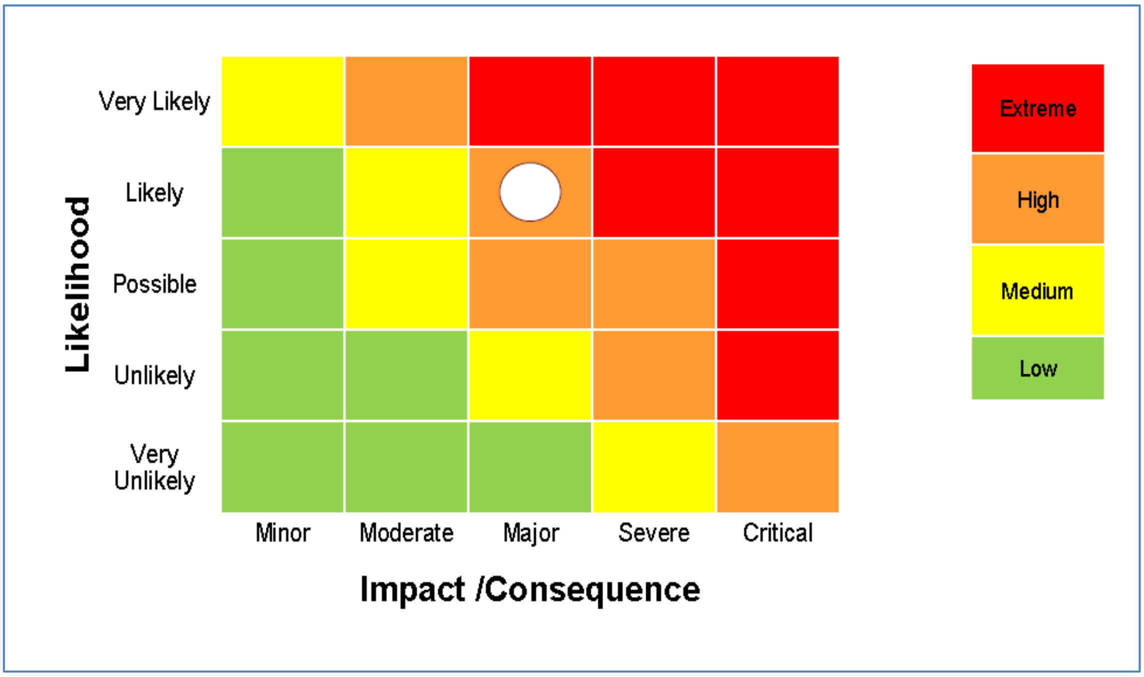


Figure 5-4: Sample of Risk Analysis (Glazer, 2013)

Figure 5-5: TECOP Model for Risk Evaluation (Glazer, 2013)

5.9.1 Risk Factor

A risk factor is defined as a measurable characteristic, a change that can affect the value of an asset, such as exchange rate, interest rate, market price, environmental factors, offshore location, onshore location, regulatory, geopolitical challenges, government involvement, energy prices etc. To determine the risks factor, there is a need to categorise the risks as described in section 5.9 above and carry out both quantitative and qualitative assessments of the risks.

Category	Topics that underly cost risk	Low risk (1)	High risk (5)	Topic Scores (1-5)	Average Score (1-5)	Weighting	Weighted Score	Comments
Technical	Project Location	Heartland	New Frontier	4	3	3	9	
	Climate	Temperate	Arctic	3				
	Onshore Environment	Level/ Open	Swamp/ Mountainous	4				
	Offshore Environment	Shallow Water	Ultra Deepwater	2				
	Subsurface	Well defined with good well coverage	Based on seismic only					
	Scope Definition at Project Phase	Well defined	Poorly defined	2				
	Existing Infrastructure	Good/ Reliable	Non existent	2				
	Project Complexity	Simple	Complex	3				
	Technology	Conventional	New/Unproven	3				

Figure 5-6: Risk Factor Table

The risk model uses various categories in the categorisation spectrum; this is broken down into topics that underlie low and high risks. The risks are quantified using a range 1 to 5 for risk rating (1- very low risk; 3-average; 5-very high risk), and a range 1 to 5 for weighting (1 – very low cost; 3 – average; 5–very high cost). A sample risk analysis is shown in Figure 5-6 above.

5.9.2 RISK Management / Risk Factor Application

The risk categorisation and risk factor derived is used as the contingency multiplier for deriving actual costs estimate. The assurance that all technical risks have been well covered for the investment is obtained through this process.

6 Cost Estimation

6.1 Introduction

Cost Estimation is the iterative process of building an approximation of the monetary resources required to execute and deliver a project (PMBOK, 2008). This is not limited to Labour, Materials, Equipment, Services, Software, Hardware, Facilities and Contingency Costs.

6.2 Cost Estimation Methods (CEMs)

There are various cost estimating techniques or methods used in project cost estimation (Oyedele, 2015; PMBOK, 2008). Fundamentally, there are three main, cost estimation methods (CEMs) form the mainstay of tools applied for cost estimation within the technology industry namely Engineering Bottom-up, Analogy and Parametric approaches (Trivailo et al., 2012) and they are discussed in more details below.

6.2.1 Bottom-Up Cost Estimation Method

The bottom-up estimation method comprises of the synonymous methods of engineering build-up, grassroots and detailed cost estimations. Bottom up method is carried out using specifications and engineering drawings to determine the quantities of materials needed for the project (Oyedele 2015). PMBOK, 2008, clearly states that the accuracy of this method is defined by the accuracy of the specifications, drawings and packages including activities.

6.2.2 Analogy Cost Estimation Method

Analogy and parametric cost estimation methods are part of the top-down methods or ‘’statistical approaches and can be classed as gross estimation methods’’ (Trivailo et al., 2012). The Analogy methods are the use of metrics from similar projects that have been executed as a premise for the estimation. It takes the completion costs of similar projects when compared to the one been planned and modify to capture scope changes, complexities, time, exchange rates, duration for execution, sizes etc. (PMBOK, 2008).

6.2.3 Parametric Cost Estimation Method

The Parametric cost estimation method is used quite well in various industries and governments.it motivates the development of costs estimates in an economic manner. It is commonly used during budgeting and planning phase of any project (DoD, 1995).

It is also the base rock of various important models and software used for early phase of cost estimation technology intense projects (Smith, 2002). If used correctly, this cost estimation method can produce very high accuracy cost estimate.

6.2.4 Expert Judgement Cost Estimation Method

Expert Judgment (EJ) is another cost estimation method that is in use. One can argue whether it is an officially acceptable method despite the fact that it is well in use officially (Hughes, 1996). This method is known to be subjective in nature since it is built around the experience and knowledge of the estimator (Trivailo et al., 2012) It is deemed to be the fourth cost estimation method (Greves and Schreiber, 1995). It is described as one that is more of a guessing work (Kitchenham, 1991). There is a feeling in the industry that the EJ method is sensitive to political pressure since it is primarily based on personal knowledge (Hughes, 1996).

This approach can be very beneficial when historical data is scarce for that very project. Other than the Analogy method, various more advanced techniques have been designed with Expert Judgement method as their premise.

6.3 Cost Estimation Methodology Selection

To be able to have a robust cost estimate that can be trusted in the development of an economic and financial model, it is important to have an appropriate Cost Estimating Method (CEM) which can indicate a realistic cost estimate for the different project/case studies that will be used to develop the economic and financial model for marginal field development. The selected method for the development of the cost estimate is essential to the accuracy and relevance of the estimate (NASA, 2002).

The various CEMs mentioned are to different degrees appropriate for use during the different project phases for case studies used in developing the techno-economic model. This appropriateness and flexibility of the different CEMs with respect to time and therefore phase is qualitatively shown in figure 6-1.

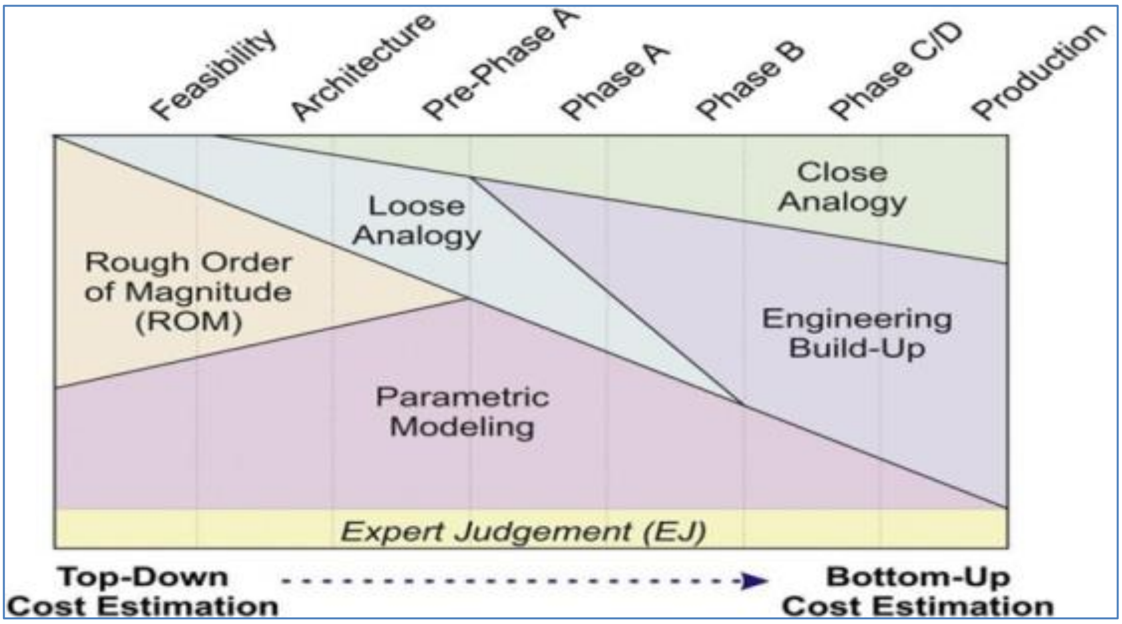


Figure 6-1: Cost Estimation (Lillie and Thompson, 2012)

Several of the CEMs can also be strategically combined to formulate a hybrid estimate. Alternatively, if this is possible, an existing tool or model can be taken and potentially 'tailored' to particular project specifications through manual input or calibration (Trivailo et al., 2012).

This cost estimate has been developed with the aim to provide a consistent and transparent basis for estimating the cost of Marginal Oil & Gas facilities. These are key costs input for the development of the UZO-MARG Techno-Economic model. The estimating methodology used tends to progress is a combination of

6.3.1 Cost Estimate Method of Best Fit

The cost estimate Method selected for this research is both the Analogy and Parametric method. Being Marginal fields, there exists already costs estimates from similar projects. However, since there are few changes that impact projects differently such as location, technology, exchange rate etc., a parametric method also had to be applied to ensure increase in estimate accuracy level. This entails the statistical analysis of the Analogous Estimate outcome to bring the estimate to money of the value.

6.4 Basis for Cost Estimates

The basis for the cost estimates is premised on the development of the case study on Marginal Fields - Shekinah and Otakikpo Fields. The cost estimates are priced costs from equipment lists generated from engineering studies and process simulations carried out with UNISIM (formerly HYSIS) software on the various concepts considered for the two fields.

The estimates also include the costs for different renewable energy types which could be used for development of Marginal fields, particularly where the power required does not exceed 5-10MWand in some occasions when it exceeds. In this research, conventional fossil fuel and renewable energy has been evaluated to use as the primary energy source for the different oil and gas production facility concepts to replace fossil fuel energy systems.

The intent of applying renewable energy cost estimates is to evaluate the economic and financial impact of using renewable energies for Marginal field development. This is important because of the global clamour for green facilities and CO_2 reduction, which is driving the industry to think more about using renewable energy for power generation.

6.4.1 Cost Estimate Accuracy

The level of accuracy in a cost estimate will determine how well the estimate will deliver its intent; the more exact an estimate is, the better it can meet its objectives. The basis for this cost estimate is to establish components of an estimate that when applied will give a probable cost that can complete a project. According to Aibinu and Pasco, 2008, “Inaccuracy in the estimate of a project may arise from two sources, namely, bias associated with the project itself and bias associated with the estimating techniques used and the operating environment”.

Construction cost estimates are built using direct costs, indirect costs, fixed costs and variable costs. These costs can be on material, labour, plant and machineries, and others. These are factors that can affect quality of costs estimates.

6.5 Factors that can Influence the Accuracy of Estimates

The accuracy of a cost estimate is highly dependent on the level of details known at the point when the estimate is been developed and the level of clarity and definition of the scope of the project or work. They are definitions of the client's requirements for space, function, and quality of the proposed project (Akintoye, 2000; Trost and Oberlender, 2003; Babalola and Aladegbaiye, 2006; Dysert, 2006; Liu and Zhu, 2007: and Odusami and Onukwube, 2008).

In many countries, factors that can affect accuracy of estimates include:

1. Political factor: Costs Estimates are more accurate in time of political stability than in time of instability.
2. Economic factors: Interest rate regime, inflation and forces of demand and supply.
3. Government policy: Government policy bordering on procurement, importation, the use of local content, expatriate quota etc can also affect construction cost estimate.
4. Time: Construction is season-sensitive. Estimates can be affected by weather. Dry seasons are more suitable for construction than rainy season.
5. Location of the project: Estimates are based on inputs like materials, labour and plant. Location will determine the costs of these items.

Environmental factors like topography and geology of the site will also affect the estimate.

6. Legal factors like litigation and government policies including taxes and other statutory payments.
7. Security: Risks which include both the insurable and non-insurable are factored into construction estimates and can affect them. For example a construction project in Jos will be estimated higher than a construction job in a peaceful city.
8. Year of project: There are good years and bad years for construction. For example, any year preceding election year in Nigeria is usually a good year. Politicians spend money on capital projects in election years than in non-election years. These are due to two reasons; one, they want to use the projects as a campaign tool and two; they want to empower loyalists who will finance their campaigns.
9. Nature of job (whether public or private): Public projects have more interests to be protected than private projects. There are factors like political party of the state awarding the contract that must be taken care of, party members are also encouraged to serve as sub-contractors or their interest factored in the cost estimate. In the public sector, estimates are carried out bearing in mind the interest of awarding the contract. In some cases it is 10% which, at times, have to be paid in advance.
10. Complexity of job: The simpler the working/engineering drawings of a project, the more accurate the cost estimate tend.
11. Experience of the contractor also counts in determining the accuracy of construction cost estimates.
12. Detail of project brief given the consultants by the client also influence accuracy of cost estimate.
13. Corruption: High level of corrupt practices will affect the accuracy of estimates. For jobs to be done on time, the estimator in a corrupt environment has to set aside some amount for “public relation’, “mobilization” and “tipping” which are not receipted.

The estimates are real costs have been subjected to upward and downward variations due to time and changes in the global economy, especially with the current low oil price been experienced globally. This variation in costs helped demonstrate the profitability potential from the techno-economic models if prices change, so that investment decisions can be managed in a more conservative manner.

The cost estimate is grouped into a number of buckets – capital expenditure and operating expenditure.

6.5.1 Contingency

A contingency is a pre-set amount or percentage of the contract held for unforeseen changes in the project (Hart, 2005). It is a strategy that can be used to manage any risk that may show up during a project execution, especially risk that have not been foreseen during the planning stages of the project and makes the project financial robust. It helps to manage design changes in scope.

Further defining contingency, projects costs can easily be overrun in construction works (Touran, 2003). “Cost contingency is normally added to a budget estimate so that the budget represents the total financial requirement by the project owners, hence the estimation of cost contingency is important to have in any project development and execution (Baccarini, 2004).

For this case studies cost estimation a 38% contingency has been allowed. This is premised on the risk analysis carried out on the two case studies used in this research.

6.5.2 Project Management and Indirect Costs

Project Management costs in this research consist mainly of manpower costs, salaries, office management, travels, pre-commissioning and commissioning costs. The costs of Project management range from 5% to 15% of the other estimated project costs, depending on the nature of the project and the scope of what is covered under project management (Cost Estimating Guide, 2011).

The key component of the project management costs for the Shekinah field comprises of construction management, Design and Engineering (including travels), commissioning, and salaries, labour costs, office and travels etc., shown below.

6.6 Operating Cost Estimate (OPEX)

OPEX costs are categorised into two – Fixed OPEX and Variable OPEX (Anderson, 2009):

6.6.1 Fixed OPEX (Project OPEX)

This is a large amount which necessarily has to be incurred on a one-off basis to maintain existing facilities yearly. These expenditures are not capitalised and are mostly like fixed OEM costs for maintenance; major parts replacement can sometimes be capitalised. Please see attachment for the Fixed OPEX Costs for the two case studies (Anderson, 2009).

6.6.2 Variable OPEX (Recurrent)

These are annually recurring expenditures of small amounts necessary to keep existing facilities running (Anderson, 2009). Please see attachment for the Variable OPEX Costs for the two case studies

6.7 Methods of Best Fit Combinations

The combination of several methods of best fit like the selection of Microsoft Excel as a platform, the use of NPV (Discounted Cash Flow) Assessment Method for the TEA, selection of the Simulation Method instead of Visual, Mathematical Methods or Empirical methods for design of the tool operating method has defined the model foundation and design. For the input data such as cost estimates, amongst several methods, the Income Approach was found to be the best of them to build the economic and financial model, basically any method that supports cash flow method or discounted cash flow was found to be suitable for building the model. For the Model validation process, subjective and quantitative processes were reviewed upon which the qualitative method was selected.

7 UZO-MARG Techno-Economic and Financial Model

7.1 Introduction

One of the major deliverable of this PhD research/Project is the UZO-MARG Economic and Financial Model. It can also be referred to as a Techno-Economic Model", it is a one-stop-shop for a wide range of analysis meant to aid investment decisions. This model is ideal for all kinds of fiscal arrangements as available in Nigeria for oil field operators but can be used for any fiscal regime anywhere in the world.

Evaluation of fields is comprised of technical, economic and financial analysis and it is a mandatory requirement in every oil and gas development not withstanding whether it is a Marginal Field or fields that are beyond marginal field criteria definition. Most investment decisions are made out of the robustness of the technical, economic and financial outlook of the opportunity. This research has developed a flexible and integrated Model for carrying out both economic and financial analysis of Marginal Fields. This Model is called UZO-MARG.

Developing this Model is with the support of others disciplines including experts in the industry ranging technical experts in economists, Information Technology (IT), Commercial Reservoir and Petroleum Engineers. The Computer Simulation method of model development was used for building the model.

The computer back bone of the model is premised on Microsoft Excel Package with macros and a wide of first principle MS Excel definition for ease of model development, upgrade and future adaptability to packages like Microsoft Visual Basic studio 2010 that has been used to develop software since it ensures quality code throughout the entire application life cycle, from design to deployment (Adamu et al., 2013).

Although the Model has not been transformed into software, the results from it can be fully relied upon. One major difference between this model and others around including software is its ability to look beyond economic analysis but also financial analysis that enables robust investments decisions to be reached.

The UZO-MARG Model has been built to be able to evaluate economic and financial outlook of an investment not limited to both Greenfield and Brownfield investments. It does evaluate and investigate the changes in financial and economic attributes of an investment when indices such as cost, fiscal regimes, production profile, discount rates etc changes. It is also important to state that this model has been built with the flexibility to evaluate both Marginal and complete fields both anywhere in the world.

The economic factors include Net Present Value (NPV), Value Investment Ratio (VIR), Cash Surplus Unit Operating Cost (UOC), Unit Development Cost (UDC), Unit Technical Cost (UTC), Govt. Take etc while the financial factors evaluated are Return on Capital Employed (ROCE), Return on Average Capital Employed (ROACE), Earning Before Interests and Taxes (EBIT) and Earnings After Interests and Taxes (EAIT), Revenue etc (Gifford et al., 2011).

The Uzo- MARG Model has provision for input factors such as production profile, Capital Costs (CAPEX), Operating Costs (OPEX), Fiscal Regimes for different contracts and agreements such as the PSC and JV, discount rates etc. It also has an input selection for equity sharing if more than one company is on the investment under study or review.

The Model has been found to be robust with the validation using a real life Marginal Field known as Otakikpo (see section 7.8).

7.2 Model Objective

The UZO-MARG Techno-Economic model has been built to evaluate the economic viability and financial strength of prospective fields with particular focus on buyers of marginal fields. The model is able to carry out computations of the returns on investment with and without the amount to be paid to the 'farmor' as cost for the field. The following can be derived from the model:

- Estimates of the cash flows from the field or facility
- Comparison of different fiscal terms on the viability of the field. This is especially good for both the 'farmor' and 'farmee'
- Estimate of bidding cost for the asset

- Quick evaluation of sensitivities on changes in economic parameters on earnings
- Impact of bidding cost on the cash flows from the field or facility
- Economic and financial indices which are derivable from the cash flows

7.3 Model Description

The UZO-MARG Techno-Economic model is a macro-enabled workbook with a full-scale economic evaluation, project valuation and financial analysis of a prospect project/field. The model has several worksheets which serves as inputs (orange coloured tabs) and outputs (green coloured tabs) with lots of embedded formulas and links between cells and named ranges. The named ranges have been defined to be as clear as possible from the given names e.g. Abandonment_Cost, Education_Tax_Rate, Gas_Royalty_Rate, etc.

The following tabs in the model are explained under the headings - output tabs and input tabs:

7.3.1 Output Tabs

- Financials: Financial model of the project/field
- Financialsv2: Financial model of the project/field with initial cost of asset
- Model Data Output Page-Results: Economic model of the project/field
- CashFlow-Economics Model – Data extract from model for plots and charts
- Results Chart Page – Plots and Charts of relevant economic metrics
- Oil Asset Valuation – Asset valuation calculations
- Model Data Output Page-Resultsv2: Economic model of the project/field with cost of asset included

7.4 Model Input

- Production profile – The hydrocarbon forecast provides the revenue generating stream which essentially translates to cash flows. Provision has been made for a range of forecasts to accommodate the uncertainties associated with subsurface modelling and the assumptions that went into it.

These have been defined as P90_Lowcase, P50_Basecase and P10_Highcase for the pessimistic case, expectation case and optimistic case forecasts respectively. (Mireault and Dean, 2008).

- Operating Expense (OPEX) – An OPEX forecast constitutes one of the cost elements into an economic/financial model. It is made up of two parts:
  - Fixed OPEX – This is fixed and independent of production volumes unless additional facilities requiring additional capital spend is appended to the existing facility. It includes things like lease cost, periodic facility maintenance cost, etc. (Bridgwater, 1975)
  - Variable OPEX – This varies with production. It is associated with the expenditure that increases or reduces as production changes. (Adamu et al., 2013).

- Capital Expense (CAPEX) – A CAPEX profile is the second cost element incorporated in the model. This is associated with new projects or investments and every other expense that involves creating assets. Capital cost is normally split into drilling and facilities due to incentives that may be available for either or both of these.

  A cost breakdown structure for different elements of capital cost was implemented in the model. These elements include: project management and indirect cost, facilities and equipment cost, well engineering cost and pipelines cost (Jacobs, 2009).

- Exploration Expense (EXPEX) – An EXPEX profile is the third cost element incorporated in the model. EXPEX includes all expenses incurred on getting a commercial discovery and appraising the structure (Mireault and Dean, 2008).

- Abandonment Cost – This cost is associated with the abandonment and decommissioning of physical structures that were created for the project. It also includes cost for restoring the environment back to pre-start up levels

(Decommissioning in the UK Continental Shelf: a Litigator's Perspective Michael Davar Associate Solicitor, Squire Patton Boggs, Gideon Shirazi Barrister, 4 Pump Court, 2015).

- CO_2 Cost – This refers to the charges levied on companies for carbon emissions as part of their operations. The imposition of this penalty or tax is meant to discourage the use of fossil fuels and encourage the development of renewable resources as part of project/facility design. CO_2 penalty usually takes the form of carbon tax or a requirement to purchase permits to emit. With the imposition of CO_2 cost, operators are forced to consider the economics of running their planned facilities on non-fossil fuel alternatives (Gavenas et al., 2015).

- Fiscal Terms – This refers to the terms of agreement, laws and regulations which govern the economic benefits derived from a petroleum production enterprise. It regulates the sharing formula of the revenue and profit between legal and commercial entities.
  In the Nigerian context, the fiscal terms that exist include the: Joint Venture (JV), Marginal Field (Onshore/Offshore) and the Production Sharing Contract (PSC). Fiscal terms which were built into the model are defined in Table 7-1. (David-West, 2013).

- Royalty – This is defined as payment made by a "licensee" to a "licensor" for the right for continued use if an asset. It is typically agreed as a percentage of gross or net revenue. For the Nigerian JV, royalty is 20% of gross revenue. For marginal fields, this varies with production rate while for PSC, it varies with water depth. The different royalty rates used in the model are defined in Table 7-1.

- Tax rate – This refers to the petroleum profit tax payable for revenue generated from a petroleum related venture. The different tax rates for the fiscal regimes used in the model are provided in the table below. A special tax exemption is granted for “pioneer status” which is a zero-tax payment for the first five years of production.

- Investment tax allowance/ credit (ITA/ITC) – ITA and ITC are an effective means of stimulating and encouraging investment through tax reductions. These are applied to the capex spend for the year. ITA is deducted from the taxable income before tax computations, while ITC on the other hand is deducted directly after tax computation for the year. The different rates for the fiscal regimes used in the model are provided in Table 7-1.
- Education tax – This tax is levied on oil producing companies operating in Nigeria. It requires the annual payment of 2% of assessable profit. This levy is tax deductible.

- Niger Delta Development Charge – This is a charge levied on oil producing companies operating in Nigeria. It requires the payment of an annual contribution of 3% of the total annual budget to the Niger Delta Development Commission (NDDC). This charge is fixed and independent of operator’s fiscal terms. This levy is tax deductible.

The fiscal terms defined below, extracted from relevant materials [1 & 2], have been incorporated in the UZO-MARG model.

Table 7-1: Parameters

Fiscal Parameter	**Marginal Field Onshore**	**Marginal Field Offshore**	**Joint Venture**	**Production Sharing Contract**
Oil Royalty	By Production rate < 5kbopd → 2.5% < 10kbopd → 7.5% < 15kbopd → 12.5% < 25kbopd →18.5% > 25kbopd → 25%	By Production rate < 5kbopd → 2.5% < 10kbopd → 7.5% < 15kbopd → 12.5% < 25kbopd →18.5% > 25kbopd → 25%	20%	By water depth 0m → 20% <100m → 18.5% <200m → 16.67% <500m → 12% <800m → 8% <1000m→ 4% >1000m→ 0
Gas Royalty	2.5%	2.5%	7%	5%
Oil Tax Rate	55%	50%	85%	50%
Gas Tax Rate	0%	0%	30%	0%
Investment Incentive	Oil ITA – 20% Gas ITA – 0%	Oil ITA – 20% Gas ITA – 0%	Oil ITA – 5% Gas ITA – 5%	Oil ITA – 50% Gas ITA – 0%
Education Tax Rate	2%	2%	2%	2%
NDDC	3%	3%	3%	3%

Charge Rate				
Capital Allowance	5-year depreciation (20/20/20/20/19%)	5-year depreciation (20/20/20/20/19%)	5-year depreciation (20/20/20/20/19%)	Cost Oil 100% cost recovery from revenue less royalty
Profit Oil	Not applicable	Not applicable	Not applicable	Cumulative Production (MMstb) 0 – 350 → 20% 351 – 700 → 35% 701 – 1000 → 45% 1001 – 1500 → 50% 1501 – 2000 → 60% > 2000 → negotiable
Pioneer Status	Applicable	Applicable	Applicable	Applicable

7.5 Model Output

The UZO-MARG Techno-Economic model carries out a number of calculations to arrive at economic and financial indices relevant for making investment decisions. The evaluations covered by this model are described in the sub-sections below.

7.5.1 Economic Evaluation

The UZO-MARG Techno-Economic model incorporates two modules for estimating economic parameters for the asset both before initial investment and after initial investment. These are represented in the 2 output worksheets - Model Data Output Page-Results and Model Data Output Page-Resultsv2 respectively.

- **Revenue** – Revenue from oil and gas operations is derived from the sales of hydrocarbon. In oil fields, revenue is derived from the oil, while the gas by-product is flared, used as fuel gas or compressed for sales to a gas distribution network. The sale of the gas however depends on the availability of a gas sales agreement. In gas fields however, revenue is derived from the sale of both the gas stream and condensate which drops out of the gas stream.

$$Revenue = (Oil\ Production\ Rate * Oil\ Price + Gas\ Production\ Rate * Gas\ Price) * (Days\ in\ the\ year)$$

Equation 7-1

- **Pre-Tax Cashflows MOD** – Pre-tax cash flow is calculated as revenue less royalty and total costs. Total costs here is the summation of all cost including: opex, capex, expex and abex.

$$Pre - tax\ cashflows = (Revenue - Royalty - Total\ Cost)\ where\ Total\ Cost = Opex + Capex + Expex + Abex$$

Equation 7-2

- **Economic Cut-off Year** – This is the year in which the annual net cash flow turns negative and remains negative. It is an indication of the time where the project or field is no longer economic i.e. the revenue generated can no longer support the operating cost incurred.

- **Capital Allowance** – The computation of capital allowance varies based on the fiscal terms at play. Joint venture and marginal field operations use the depreciation on the capital asset. PSC on the other hand uses the cost oil recovery.
  In the PSC arrangement, capital allowance is limited to a percentage of the revenue less royalty, with the balance carried forward to the subsequent year. This percentage can be up to 100% in deepwater operations where usually government participation is limited and corporations bear 100% of the risk on their investment.

- **Taxable Income** – Taxable income is computed as revenue less costs (opex, abandonment cost, exploration, CO_2 Cost), less statutory charges (NDDC and education tax) and less applicable investment tax allowance (ITA).

$$Taxable\ Income = (Revenue - Royalty - Total\ Opex - CO2\ Cost - Capital\ Allowance - Exploration\ Capex - Abandonment\ Capex - NDDC - Education\ Tax - ITA)$$

Equation 7-3

- **Tax** – Tax computation is carried out as a percentage of the taxable income less applicable investment tax credit (ITC).

$$Tax = (Taxable\ Income * Tax\ Rate - ITC)$$

Equation 7-4

- **Post-Tax Cash flows MOD/RT/PV** – Post tax Cashflows is computed in a similar manner to the taxable income, except that the ITA which was included in the taxable income as tax incentive is replaced with the tax paid.

$$\begin{aligned} Post-tax\ cashflows \\ &= (Revenue - Royalty - Total\ Opex - CO2\ Cost \\ &- Capital\ Allowance - Exploration\ Capex \\ &- Abandonment\ Capex - NDDC - Education\ Tax - Tax) \end{aligned}$$

Equation 7-5

Since the economic evaluation was based on MOD, assumed inflation and discount rates were applied to translate the Cashflows to RT and PV respectively.

- **Economic Indices** –
  - **Net Present Value** – NPV, measures the value of an investment as the sum of the present value of post-tax cash flows up to the economic cut-off year. This is normally used to make screening decisions to eliminate bad projects.

$$NPV = \sum_{i=1}^{n^*} PV\ Cashflows$$

$$where\ n^*\ is\ the\ economic\ cut-off\ year$$

Equation 7-6

  - **Value-Investment-Ratio** – VIR (also known as profitability index), measures the relative returns on a project to the investment made. It is the ratio of the NPV to the investment cost. VIR is normally used to rank projects in the presence of limited capital.

$$VIR = \frac{NPV}{Present\ Value\ of\ Total\ Capex}$$

Equation 7-7

Real Term Earning Power **– RTEP measures the discount rate at which the NPV based on discounted RT Cashflows is zero. Also used for screening decisions.**

$$RTEP = IRR^{*}(Total\ RT\ Cashflows, discount\ rate)$$

** An excel function*

Equation 7-8

- **Internal Rate of Return (IRR)** – IRR measures the discount rate at which the NPV based on discounted MOD Cashflows is zero. This is also used to make screening decisions.

$$IRR = IRR^{*}(Total\ MOD\ Cashflows, discount\ rate)$$

** An excel function*

Equation 7-9

- **Unit Finding Cost** – This measures the unit cost of finding hydrocarbon. It is estimated as the ratio of the exploration cost to the total reserves anticipated to be produced in the field or by the project.

$$Unit\ Finding\ Cost = \frac{Finding\ Cost}{Reserves}$$

Equation 7-10

- **Unit Development Cost** – This measures the unit cost of developing the field. It is estimated as the ratio of the capital cost to the total reserves anticipated to be produced in the field or by the project.

$$Unit\ Development\ Cost = \frac{Capital\ Cost}{Reserves}$$

Equation 7-11

- **Unit Operation Cost** – This measures the unit cost of operating the field. It is estimated as the ratio of the operating cost to the total reserves anticipated to be produced in the field or by the project.

$$Unit\ Operating\ Cost = \frac{Operating\ Cost}{Reserves}$$

Equation 7-12

- **Unit Total Cost** – This measures the unit total cost of developing and operating the field. It is estimated as the ratio of the sum of the capital cost and operating cost to the total reserves anticipated to be produced in the field or by the project.

$$Unit\ Total\ Cost = \frac{Total\ Cost}{Reserves}$$

Equation 7-13

- **Payout Year** – This index measure how long in time is required for the investment cost to be recovered. This time is indicative of how long project capital is at risk. It is the time at which the cumulative net cash flow moves from the negative region to the positive.

$$Payout\ Year = PAYBACK^{*}(Total\ Cashflow, Years)$$

** An excel function*

Equation 7-14

- **Maximum Exposure** – This measures the maximum amount of capital that is placed at risk in relation to the project. It is indicative of the risk rating of the investment in relation to the amount of capital employed. It is the minimum amount on the cumulative net cash flow curve.

- **Breakeven Price** – This index is calculated as the oil price at which the project achieves an NPV of zero. It is indicative of the minimum price required for the investment to be viable.

The interface for the economic evaluation is as shown in Appendix Figure A.

The figure below shows the flowchart for the model:

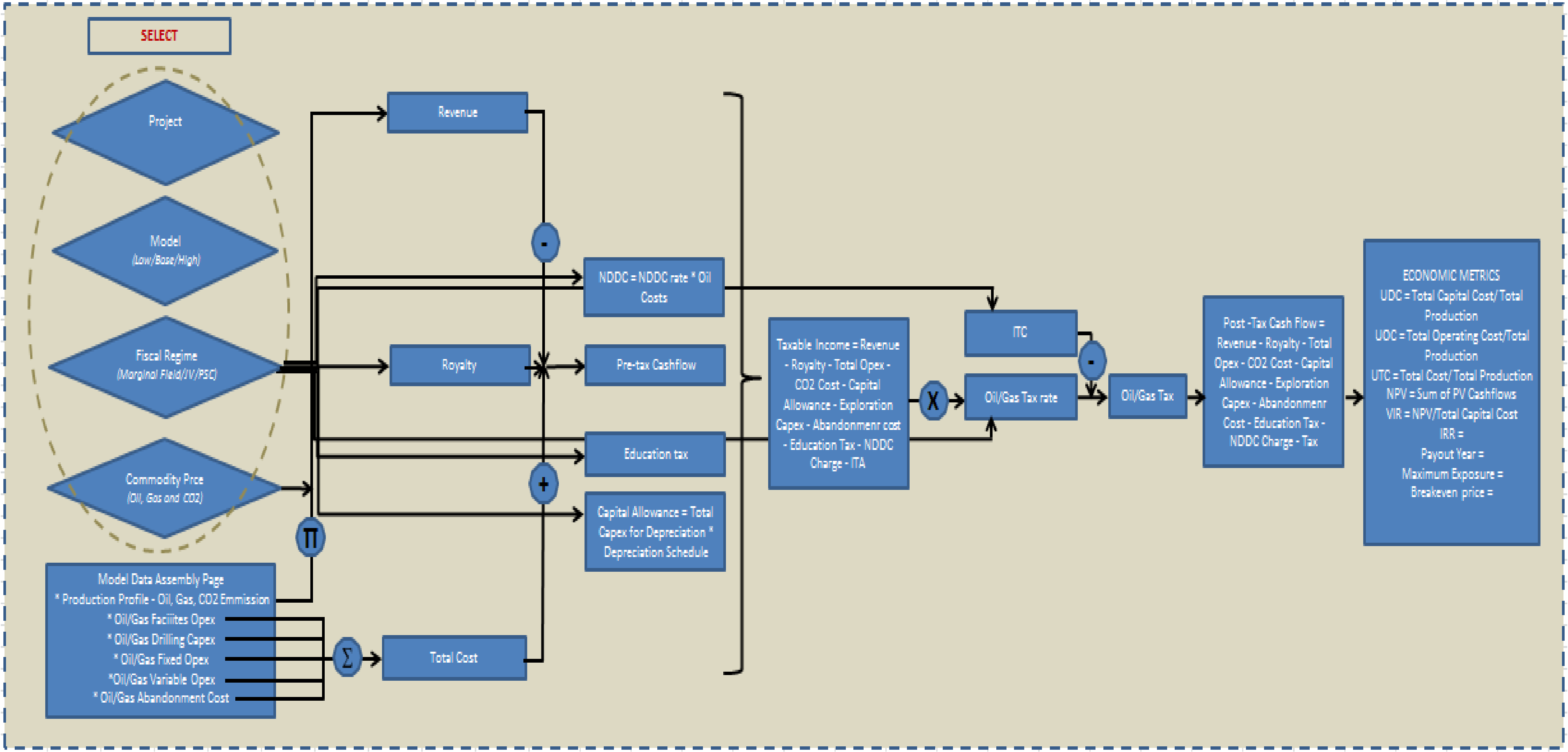


Figure 7-1: UZO-MARG Model Flowchart

The flowchart provides an overview of the model calculations. First, the user selects the project, model type, fiscal regime and commodity price for consideration. The content of the "Model Data Assembly Page" which includes the production profiles and costs are reproduced in the model.

Revenue is calculated using the production profiles combined with the commodity prices. Royalty is calculated using the rate carried in the fiscal regime applied to the revenue. "Total costs" is calculated as the sum of all the costs elements (capex, opex, abandonment and exploration).

Other fiscal calculations except the petroleum profits tax are computed as defined in the fiscal parameters. This includes: NDDC charge, education tax, capital allowance, flares charge and investment tax allowance.

These are all discounted from the Royalty to obtain the taxable income. Post – tax cash flows are subsequently calculated using the tax rate specified for the fiscal regime after the application of any investment tax credit accruable to the venture.

This post tax cash flow provides the basis for the computation of the economic metrics which have been defined in the preceding section.

7.5.2 Asset Valuation

The UZO-MARG Techno-Economic model also incorporates a module for estimating the fair value for an asset to be purchased i.e. the valuation of the asset. The valuation module evaluates a number of parameters, these include: NPV before initial investment, risk factor and assumed profitability index to estimate the range of price that can be negotiated for the asset and the true NPV of the asset post investment cost (NPV after initial investment).

- Profitability Index – Profitability index here is not the same as the calculated PI or VIR of the asset in the previous section, rather it is the median rate of return in the industry. This is usually based on analog data from similar fields and investments within the same operating region. If there are no good analogs from the same operating region, the search can be spread further.

- Cost of Purchasing Asset/Initial Investment - This is a range of cost that can be put forward for negotiating for the asset. The range of cost is based on the assumed PI and risk factor as well as the NPV before initial investment.

$$Cost\ of\ Purchasing\ Asset$$
$$= \frac{NPV\ Before\ Initial\ Investment * Risk\ factor}{(1 + Profitability\ Index)}$$
$$where;\ Lower\ End\ of\ Cost\ \leftrightarrow Low\ Profitability\ Index$$
$$Upper\ End\ of\ Cost\ \leftrightarrow Median\ Profitability\ Index$$

Equation 7-15

- NPV after Initial Investment – This is the true NPV of the asset being negotiated. Here, the cost of purchasing the asset is fed back into the whole economic evaluation as incremental capital cost to derive true NPVs which now incorporate the bid cost. To ensure a robust evaluation, the weighted average cost of capital is applied in the form of interest on loan over the investment cost. This analysis is done in a separate worksheet named "Model Data Output Page-Resultv2". The NPV results here can also be derived for different oil price scenarios.

The interface for the asset valuation is as shown in the figure below for a sample valuation for an asset with P50 production profile, 10% discount rate, oil price sensitivity between \$40 and \$120, 18% profitability index, 38% risk factor and 10% interest rate on loan.

ASSET VALUATION

Selected Discount Rate	10%										
Investment Year	2015	*(Enter year between 2012 and 2015)*									
Oil Price	$40	$60	$80	$100	$120						
NPV Before Initial Investment ($'mln)											
P50_BaseCase	100.11	192.75	285.58	378.54	471.50						
LOWER RANGE OF COST						**UPPER RANGE OF COST**					
Profitability Index	18%	*(Median Rate of Return in Industry)*				Profitability Index	0%	*(Break-Even Assumptions)*			
Risk Factor	38%					Risk Factor	38%				
Cost of Purchasing Asset/Initial Investment ($' mln)						Cost of Purchasing Asset/Initial Investment ($' mln)					
Upper	32.24	62.07	91.97	121.90	151.84	Upper	38.04	73.24	108.52	143.84	179.17
Oil Price for Investment Decisio	$40					Oil Price for Investment Decisio	$40				
Expected Value of Asset ($'mln	32.24					Expected Value of Asset	38.04				
Cost Range	**32.24**	To	**38.04**								
Agreed Cost	32.24										
Interest rate on Loan	10%										
NPV After Initial Investment ($'mln)											
P50_BaseCase	21.32										

Figure 7-2: Asset Valuation

The flowchart below shows the flowchart for the model:

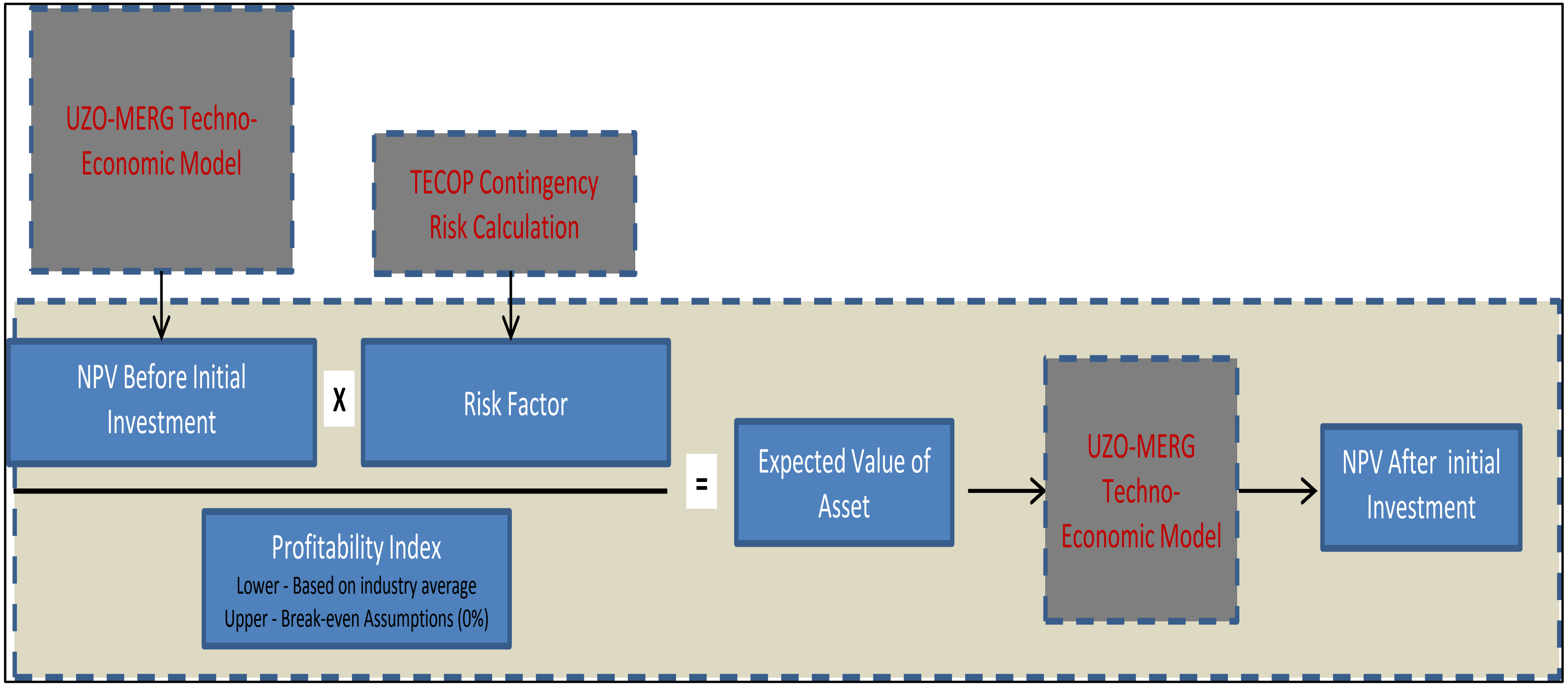


Figure 7-3: Model Flowchart

7.6 Financial Evaluation

The UZO-MARG Techno-Economic model has a module for financial evaluation for both the economic model before initial investment and the economic model after initial investment. In this module, a number of financial metrics are evaluated.

These metrics are defined in the section below, they include: capital employed, average capital employed, earnings before interest and taxes (EBIT), earning after interest and tax (EAIT), return on capital employed (ROCE) and return on average capital employed (ROACE).

- **Capital Employed** – This is the sum of all capital and operating expenditure on a project/asset in the year of interest.

$$Capital\ Employed = Capex + Opex$$

Equation 7-16

- **Average Capital Employed** – Average capital employed is defined as average of the opening and closing capital employed for the time period.

$$Average\ Capital\ Employed = \frac{Opening\ Capital\ Employed + Closing\ Capital\ Employed}{2}$$

Equation 7-17

- **Earnings Before Interest and Tax (EBIT)** – EBIT are a financial term that also means net operating profit. As the name implies, it is the return on a project before tax is applied. Net operating profit (EBIT) is calculated as Revenue less Royalty less Operating cost less capital allowance based on capital asset depreciation.

$$EBIT = (Revenue - Royalty - Capital\ Allowance - \ Opex)$$

Equation 7-18

- **Earnings After Interest and Tax (EAIT)** – A step further from EBIT is the financial term called EAIT. This term measures the true earning, since tax liability is statutory and unavoidable. It includes other statutory charges alongside the applicable tax. In the UZO-MARG Techno-Economic model, EAIT has been calculated as follows:

$$EAIT = EBIT - Tax - NDDC\ Charge - Education\ Tax - CO2\ Cost$$

Equation 7-19

- **Return on Capital Employed (ROCE)** – ROCE measures how efficiently a company can generate profits from the capital it employs by comparing its net operating profit to capital employed. In the UZO-MARG Techno-Economic model, ROCE has been built in from the year production starts till the end of the project. This has been implemented as follows:

$$ROCE = \sum_{i=0}^{n} \frac{EBIT}{Capital\ Employed}; where\ i = project\ years$$

NB
$- Instantaneous\ ROCE\ is\ available\ per\ year, while\ project\ ROCE\ is\ based\ on\ project\ lifetime$

Equation 7-20

It is important to note that EBIT is used here rather than EAIT, because different companies have different contractual tax obligations which can impact significantly on the ROCE analysis and give a false representation. The higher the ROCE, the more efficient a company is using capital. Note that capital is always sourced from equity and debt.

- **Return on Average Capital Employed (ROACE)** – ROACE is a more preferred metric to several analysts and investors than ROCE. In ROACE, the average capital employed is used in place of the capital employed at an arbitrary point in time. It can be defined using the formula below.

$$ROACE = \sum_{i=0}^{n} \frac{EBIT}{Average\ Capital\ Employed}; where\ i = project\ years$$

Equation 7-21

7.7 UZO-MARG Model Validation

The UZO-MARG Techno-Economic model has been validated with the Otakikpo marginal field (OML 11) which was farmed out by the Shell Petroleum Development Company Joint Venture operations to Green Energy International Limited ("Green Energy"). Lekoil Oil and Gas Investments Limited "Lekoil Oil and Gas") thereafter executed a farm-in agreement with Green Energy to acquire a 40% interest in Otakikpo. Lekoil Nigeria Limited ("Lekoil") holds a 90% economic interest in Lekoil Oil and Gas, with the remainder held by other minority interests.

The economic evaluation for the prospect by Lekoil oil and Gas was carried out by AGR TRACS and the report details the economic cut-off and NPVs for various scenarios of discount rates and oil price. The report also compares the NPV with marginal field terms with the NPVs with pioneer status granted.

7.7.1 Input Tabs

- Production Profile – Production Profile of the project/field
- Cost Estimate Summary – Aggregation of all input costs – CAPEX and OPEX
- Project Input Data Page – Aggregation of costs and production profiles
- Model Input Data Page – Aggregation of costs and production profiles by cases
- Model Data Assembly Page – Selective aggregation sheet per case
- Fiscal Parameters – Structure of the different fiscal parameters
- Project Management and Indirect – Details of the individual cost elements related to project management and indirect costs
- Facilities and Equipment – Details of the individual cost elements related to facilities and equipment costs. This is a deliverable from the conceptual engineering studies carried out as part of the research
- Well Engineering – Details of the individual cost elements related to well engineering cost

- Pipeline Onshore – Details of the individual cost elements related to onshore pipeline cost
- Pipeline Offshore – Details of the individual cost elements related to offshore pipeline cost
- Risk Factor Calculation – Detail analysis of risk quantification under the categories: Technical, Economic, Commercial, Organizational and Political
- Cost Estimate Summaryv2 – Aggregation of all input costs – CAPEX and OPEX with cost of asset included
- Project Input Data Pagev2 – Aggregation of costs and production profiles with cost of asset included
- Model Input Datav2 – Aggregation of costs and production profiles by cases with cost of asset included

The flow chart below provides an overview of the model:

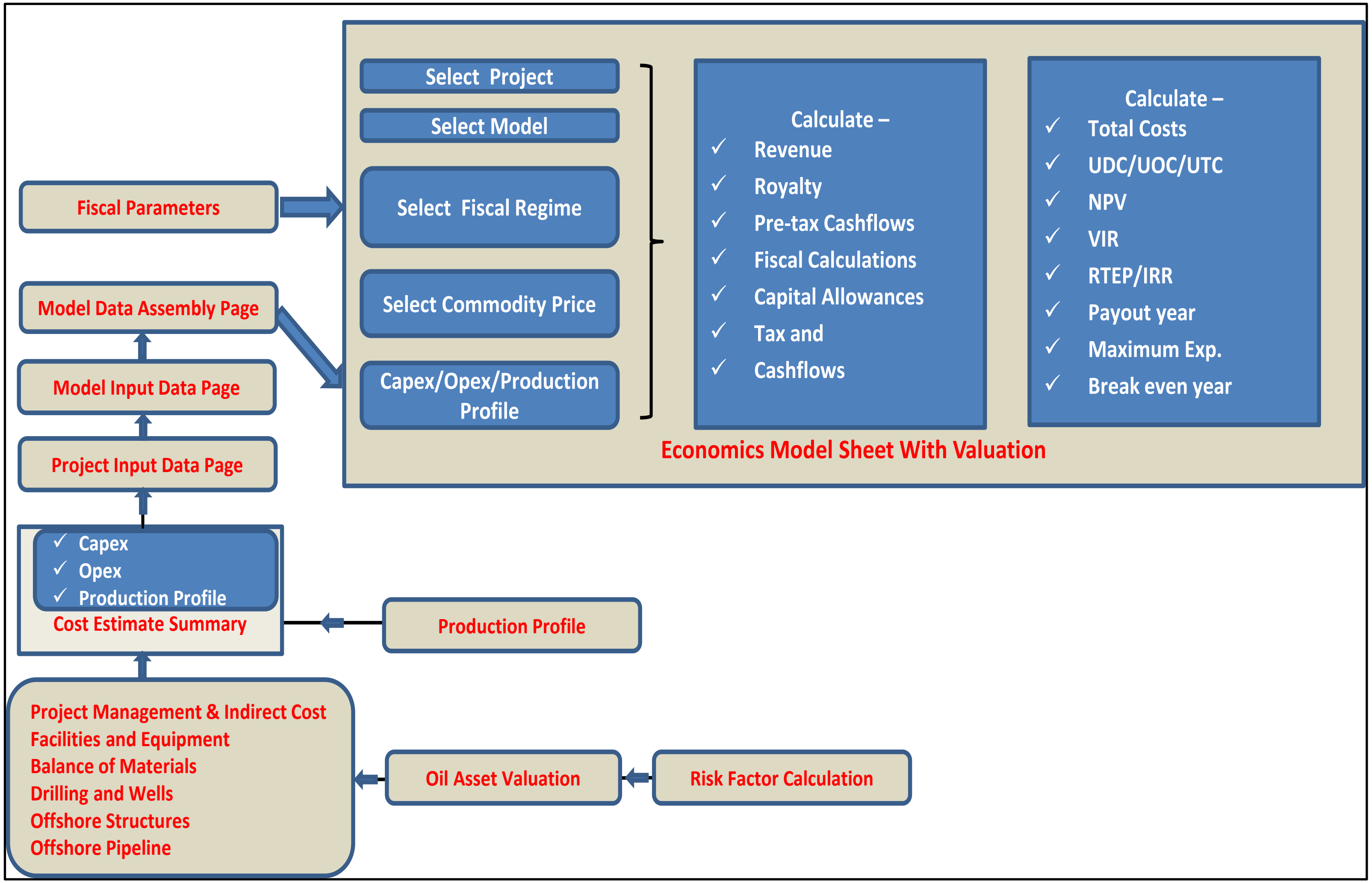


Figure 7-4: UZO-MARG Techno-Economic Model

The flowchart shows the worksheets which collate the inputs required by the model in red font. These worksheets ensure that inputs like production profile, costs, fiscal parameters and asset valuation costs are fed into the appropriate sections of the model.

The “Model Data Assembly Page” collates all the production profiles and costs; the “Fiscal Parameters” worksheet ensures that the fiscals of any production agreement selected are correctly populated in the model for the calculations. In the “Model Data Output Page”, the user selects the project scenario using the list box provided; selects the model type and fiscal regime being investigated.

The user can also select the appropriate discount rate and commodity prices (oil and gas) for the analysis. The model computes the economic limit, cash flow before and after tax as well as the economic indices (UDC/UOC/UTC, NPV, VIR, IRR, payout time, maximum exposure and break-even price).

7.8 Case Study 1: UZO-MARG Model Validation- Otakikpo Field

7.8.1 Introduction

Otakikpo is an onshore Marginal Field Development. This field was used in the validation of the Model, UZO-MARG. It is based on the economic outcome of the results which were shared in ‘Addendum to AGR TRACS Competent Persons Report on Otakikpo Marginal Field, OML 11, Nigeria, for Lekoil’ by Liam Finch, Simon Moy, Bjon Smidt-Olsen (January 2015).

In the report referenced above, the detailed cost estimates is not included but the final estimate costs was given. This research work detailed out/ break down the cost estimates to actual numbers which corresponded with the given cost estimates. This approach is in line with the Analogy and Parametric approach of cost estimation (Oyedele, 2015; Trivailo et al, 2012).

The broken down/detailed estimate allowed the performance of a dynamic simulation of the techno-economic & financial model and sensitivity analysis of various costs in the estimates such that different parts of the estimates could be replaced or varied for different financial and economic conditions and outcomes.

This costs estimate for the Otakikpo Marginal field is from actual bids and tenders submitted by vendors (Lekoil Oil and Gas CPR-2014). This costs were also used in running the economic evaluations of the field, hence the estimates was used in the validation of the Techno-Economic & Financial Model.

7.8.2 Field Description

Otakikpo is sited in a coastal swamp location in oil mining lease (OML) 11, adjacent to the shoreline in the south-eastern part of the Niger Delta. Lekoil Nigeria exercises the rights and benefits of its 40% participating and Economic interest in Otakikpo via the Farm-in Agreement and Joint Operating

An agreement was signed on 17th May, 2014 with Green Energy International Limited ("GEIL").

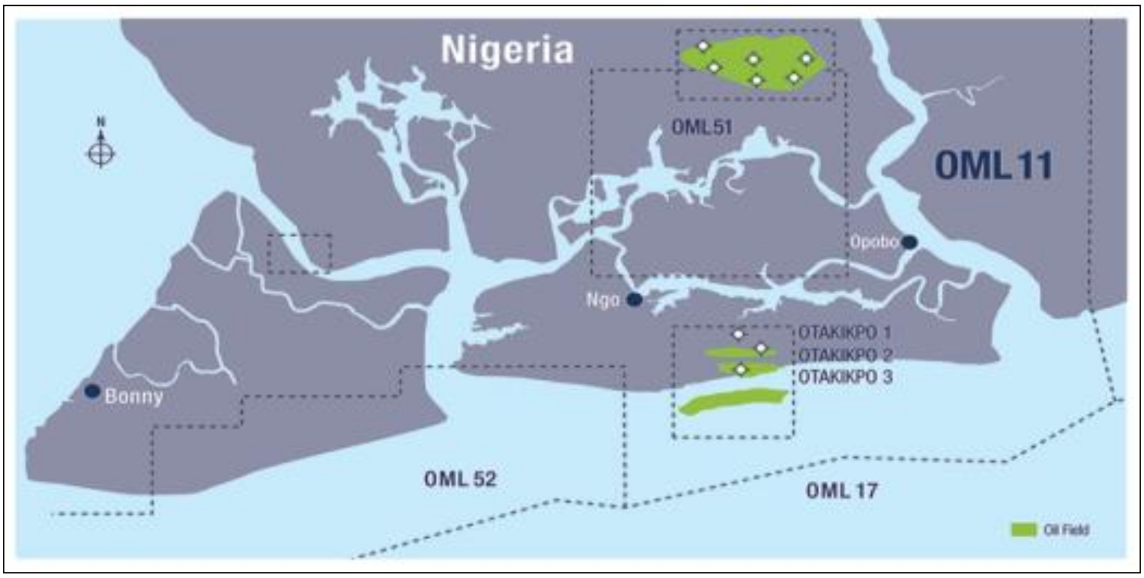


Figure 7-5: Lekoil Map (UBS Oil and Gas Conference, March 17, 2016)

The Company holds 90% of the economic interests in Lekoil Nigeria. Lekoil Limited's economic interest in Otakikpo therefore equates to 36%. The Otakikpo Joint Venture (Lekoil as Financial and Technical Partner to GEIL) began operations in December 2014. Ministerial consent was granted by the Honourable Minister of Petroleum Resources of Nigeria in June 2015.

The Otakikpo Field Development Plan consists of two phases. Phase 1 comprises the recompletions of two wells, Otakikpo-002 and Otakikpo-003, with the installation of an Early Production Facility of 10,000 bopd capacity and export via shuttle tanker. Phase 2 covers the subsequent incremental development of the rest of the field with a new Central Processing Facility and seven new wells expected to come on stream during 2017.

7.8.3 Production Profile

A dynamic modelling was carried out on the field which produced the production forecast shown below. The existing notional production profiles were edited and separated to represent the Phase 1 Recompletions (wells 002 and 003) on stream in Q2/2015 (see Figure 7-6) and the planned Phase 2 Full-field Development based on 7 new wells coming on stream from 1.1.2017 onwards (see Figure 7-6 below). The combined Phase 1 and Phase 2 production profiles are provided in Figure 6-7 below.

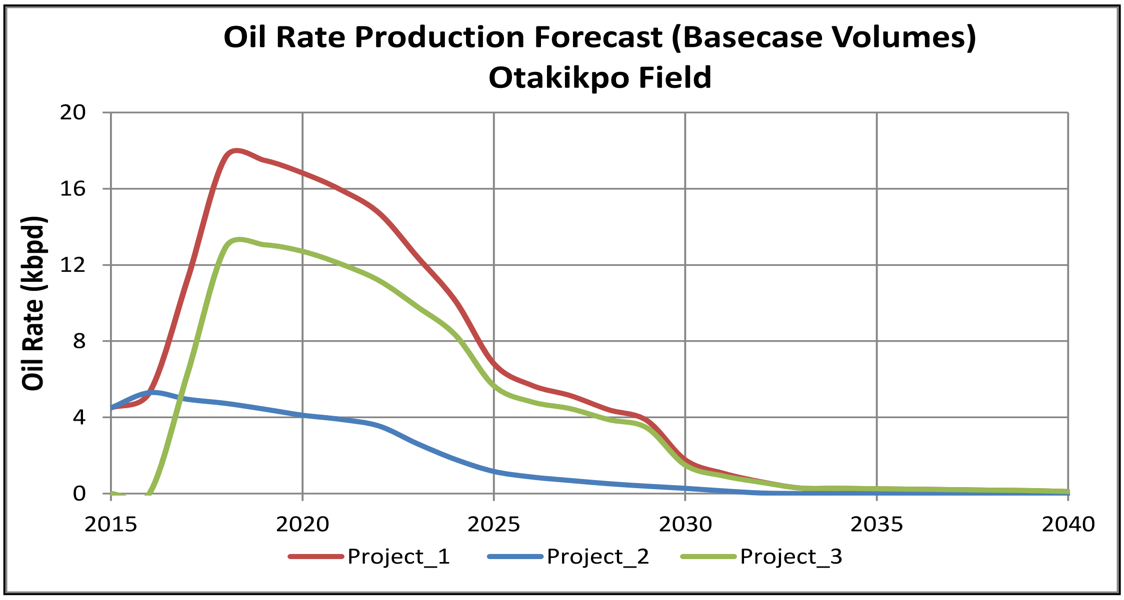


Figure 7-6: Production Profile

7.8.4 Process Description

Phase-1 is premised on the use of Early Production Facility (EPF), the initial recompletion of two wells (002 and 003) with produced hydrocarbon transported via a 6'' x 4.5km temporary onshore and offshore pipeline to an offshore storage and shuttle tanker.

The produced stabilized crude will be transferred first to the onshore tanks and subsequently to the offshore shuttle tanker for export/sale.

The production facility shown in Figure 7-7 below consists of 3-phase test separators for each well, rated to a back pressure of 3 barg. Associated gas will be passed through a scrubber to gas-fired generators for power generation, while the produced water will be sent to a water disposal unit.

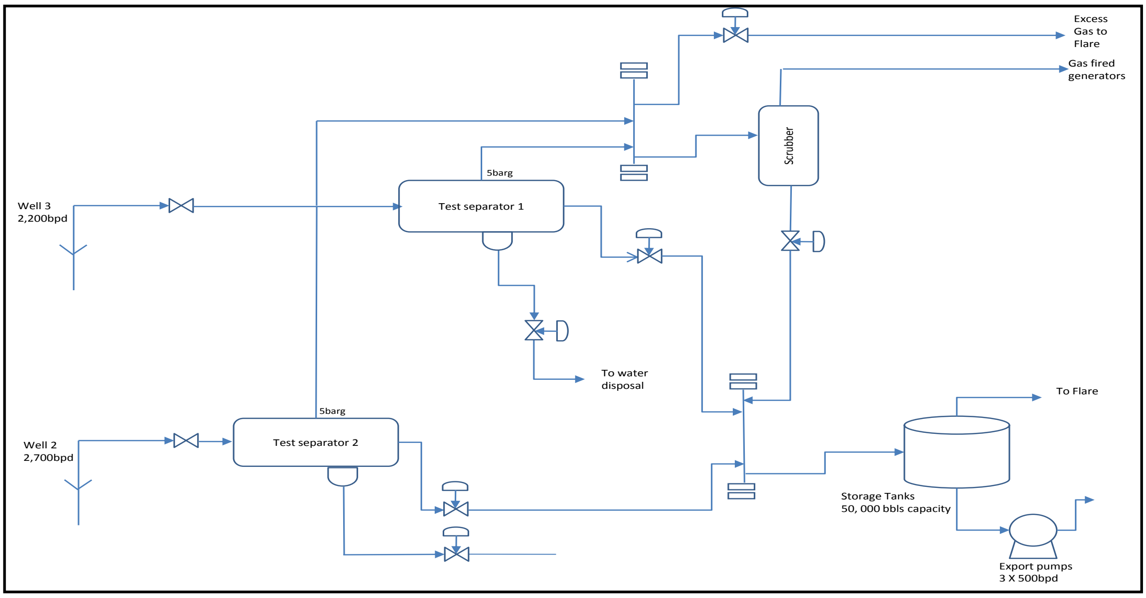


Figure 7-7: Otakikpo EPF Process Flow Diagram (Lekoil, 2015)

The maximum daily rate is assumed to be 6,000bbls/d, with 50,000bbls storage capacity on-site. The Offshore scope of the development consists of laying a pipeline to buoy that will be used for tanker loading.

This concept definition study helped the delivery of the equipment list, selection of pipeline types and process flow scheme for the opportunity. It also helped create a systematic path that allowed the determination of the cost, probable execution schedule, ease of execution and economic viability of the opportunity.

In summary, the concept engineering study has been used to do the following:-

- Carry out an engineering study that has produced the required deliverables which helped define the boundaries in the development of building a techno-economics model required for Marginal Field development.
- Development of Cost Estimates that have been used in the building of the Model and Validation of the Model as mentioned above.

- Definition of the risks approach for the Model development because of the different complexities peculiar to each opportunity.
- Demonstration of the systematic approach of how a proper opportunity should be evaluated.

Below are the various concept scopes that were evaluated for the conceptual engineering study.

Otakikpo Scope-1: Completion of two existing (Brownfield) wells with the installation of an Early Production Facility (EPF) as the production facility with a temporary Onshore and Offshore split pipeline scope. Focus was on the Otakikpo Field.

Otakikpo Scope-2: Drilling and completion of 7 new wells and the construction of a new and permanent pipeline with a split Onshore and Offshore scopes - Focused field was on the Otakikpo Field.

The concept proposed for the planned Otakikpo Early Production Facility (EPF) is the initial completion of two wells (002 and 003) with produced hydrocarbon transported via a 6’’ x 4.5km temporary onshore and offshore pipe line to an offshore storage and shuttle tanker.

The dual strings in Otakikpo-02 will be tested to their optimum potential. The produced stabilized crude will be transferred first to the onshore tanks and subsequently to the shuttle tanker for export/sale.

The shuttle tanker is expected to have a total capacity of 75,000 - 150,000 barrels. Production will be monitored for two months inn Otakikpo 02 and thereafter well testing and production of Otakikpo-02 will commence.

The production facility will consist of 3-phase test separators for each well rated to a back pressure of 3 barg. Associated gas will be passed through a scrubber to gas fired generators for power generation, while the produced water will be sent to a water disposal unit.

The maximum daily rate is assumed to be 6,000bbls/d, with 50,000bbls storage capacity on-site.

7.8.5 Phase-1 and Phase-2 Work scope (Model Validation Field)

1. Lease an Early Production Facility (EPF) to produce newly completed wells.
2. Carry out site preparation for the location of the EPF
3. Recomplete wells 002 and 003 with a work over rig.
4. Install new Well Heads on the two wells.
5. Install flow lines to transport crude oil from the wells to the EPF
6. Install temporary Onshore and Offshore pipelines.

7.8.5.1 Gas Injection and Gas gathering

This concept involves separation of oil and gas at the Central Processing Facility (CPF) or Gas Gathering Facility and installation of gas gathering lines for collection of the separated gas from the field at Shekinah Field Production Platform where it is compressed and re-injected into a suitable reservoir for storage.

The collected gas will also pass through minimal treatment to render it suitable for injection into the target reservoir. Produced liquids from the gas facility will be routed to the oil (condensate and water) flowstation through an evacuation line from the gas facility to the oil production.

Gas will be collected from Surge Vessel, Low Pressure (LP) separator, High Pressure (HP) separator and compressed to very high injection pressure for injection into the reservoir offshore.

The scope of work will entail the following:

1. Installation of gas gathering pipelines from the wells to the Production Platform.
2. Installation of Booster/High Injection Pressure Compression Modules/Systems on the Production Platform.
3. Gas Treatment Facilities.
4. Gas Injection Lines.
5. Identification or Drilling of Gas Injection well(s).

7.8.6 Booster Compression

This option is similar to the above option except that in this option gas will be exported and not re-injected into a reservoir as the case is in the above section. This concept involves separation of oil and gas at the production at Shekinah and installation of gas gathering lines to transport gas from the production platform to onshore domestic gas pipeline after treatment.

The development of this concept will entail the following:

1. Installation of a gas export line from the Shekinah Production Platform to riser platform
2. Installation of gas gathering pipelines from Benisede, Ogbotobo and Opukushi to Tunu flowstation.
3. Installation of Booster Compression Modules/Systems at each of the flowstations.
4. Installation of high pressure Main Compressors for gas export.
5. Gas Treatment Facilities.

7.8.7 Otakikpo Phase-1 Development Cost Estimate

The Estimate for Phase -1 is categorised as shown below:

Table 7-2: Cost Estimate Summary, Otakikpo

CAPEX Cost Estimate Category	OPEX Cost Estimate
	Fixed OPEX Costs
Project Management and Indirect	OEM Costs
Facilities and Equipment Costs	Staff Costs
Drilling and Well Costs	Material Spares
Balance of Plant Costs (Not Required- EPF)	Office and Logistics
Onshore Pipeline Costs	Maintenance Costs
Offshore Pipeline Costs	**Variable OPEX**
Onshore Structures	
Asset Costs	
HSE	

The key difference to note in this cost estimate is the non-inclusion of offshore structures and major offshore pipelines compared with the Shekinah field which is purely located offshore. The offshore pipelines in this case are mainly for offloading since the facility is located on the coast of the river. See below Tables 7-3, 7-4, 7-5, OPEX & CAPEX cost estimate breakdown, used for the evaluation.

Three different scenarios as defined below were presented.

1. Otakikpo Phase 1 involving planned recompletion of 2 wells in the field, the installation of an Early Production Facility (EPF) of 6,000bpd capacity, export via shuttle tankers with project on-stream date of 2015. This has been tagged Project_2 in the UZO-MARG model.
2. Otakikpo Phase 2 which involves Incremental development of the rest of the field with a new Central Processing Facility (CPF), the drilling of 7 new wells with project on-stream date of 2017. This has been tagged Project_3 in the UZO-MARG model.
3. Combined Otakikpo Phases 1 and 2, representing the planned full field development. This has been tagged Project_1 in the UZO-MARG model.

7.8.8 Otakikpo Phase-1 Development Expenditure

1. Operating Expenditure

Table 7-3: Fixed OPEX

Fixed Opex ($mln/yr)	2015	2016	2017	2018	2019	2020	2021	2022	2023
Project_1	18.08	18.08	20.20	20.20	20.20	20.20	20.20	20.20	20.20
Project_2	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08
Project_3	-	-	20.20	20.20	20.20	20.20	20.20	20.20	20.20

Table 7-4: Variable OPEX

Variable Opex ($/bbl)	P90	P50	P10
Project_1	3	2.73	2.6
Project_2	3	2.73	2.6
Project_3	3	2.73	2.6

2. Capital Expenditure

Table 7-5: Capital Expenditure

Capex ($mln)	2015	2016	2017	End of econ. Life
Project_1	48.79	177.87	136.38	104.19
Project_2	48.79	-	-	
Project_3	-	177.87	136.38	104.19

3. Fiscal Term – Marginal field onshore
4. Inflation rate – 2.5%
5. Oil price scenarios - $40-$60-$80-$100-$120/bbl
6. Discount rates – 0%-10%-15%-20%

7.8.9 Results

The results for the model shows a good match of the economic cut-offs reported. The NPV for the varied scenarios were also matched to reasonable levels (+5%). This margin difference can be attributed to the manner of application of the abandonment cost which was not clearly specified in the report. Model results and that of the AGR TRACS report are shown in Table 7-6 to Table 7-8.

Table 7-6: Model vs AGR TRACS Report NPV result – Project 1

	P90_LowCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	47.44	56.1	27.17	30.8	12.82	12.8
$60	126.79	137.4	92.09	96.8	67.24	67.8
$80	206.62	218.6	157.24	161.9	121.78	121.7
$100	286.61	298.7	222.47	225.6	176.37	173.8
$120	366.7	379	287.75	289.3	230.97	225.9
	P50_BaseCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	72	77.2	45.2	45.8	26.4	23.8
$60	161.7	169.1	117.2	118.5	85.9	83.2
$80	251.6	260.8	189.4	190.7	145.5	142
$100	341.5	351.3	261.6	261.3	205.1	198.9
$120	431.6	442	333.8	332.1	264.7	255.9
	P10_HighCase - NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	86.02	93	54.43	56.2	32.86	31.2
$60	184.14	194.8	131.78	134.8	95.93	94.3
$80	282.49	296.1	209.24	212.5	159.04	156.4
$100	380.85	396.5	286.69	289.1	222.15	217.1
$120	479.3	497.1	364.18	365.1	285.27	277.8

Table 7-7: Project 2

	P90_LowCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	23.67	21.3	19.77	16.1	16.66	11.9
$60	54.56	51.3	46.73	43.6	40.6	37.2
$80	85.95	73.2	73.99	63.9	64.73	56.1
$100	117.33	94.2	101.25	83.2	88.86	73.9
$120	148.81	115.1	128.56	102.3	113.02	91.5
	P50_BaseCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	31.5	37.4	26.2	28.5	22.1	21.5
$60	63.8	72.1	54.4	59.2	47	49.1
$80	96.6	105.4	82.8	87.9	72.1	74.3
$100	129.7	138.3	111.4	115.7	97.3	98.4
$120	163	171.3	140.1	143.6	122.6	122.5
	P10_HighCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	33.97	39.8	28.27	30.5	23.8	23.2
$60	67.84	76	57.6	62.2	49.67	51.6
$80	102.07	110.8	87.14	92.1	75.68	77.7
$100	136.51	145.1	116.81	121	101.76	102.6
$120	171.14	179.5	146.59	149.9	127.91	127.6

Table 7-8: Project 3

	P90_LowCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	12.83	-	-1.22	-	-10.9	-
$60	65.54	-	40.53	-	22.93	-
$80	118.97	-	82.65	-	56.95	-
$100	172.56	-	124.84	-	91.01	-
$120	226.25	-	167.08	-	125.08	-
	P50_BaseCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	35.7	-	15.3	-	1.4	-
$60	98.1	-	63.6	-	39.8	-
$80	160.8	-	112.1	-	78.3	-
$100	223.6	-	160.6	-	116.7	-
$120	286.4	-	209.1	-	155.3	-
	P10_HighCase – NPV ($mln)					
Oil Price	10%		15%		20%	
	Model	Report	Model	Report	Model	Report
$40	47.59	-	22.92	-	6.5	-
$60	117.62	-	75.86	-	47.87	-
$80	187.87	-	128.88	-	89.27	-
$100	258.13	-	181.92	-	130.67	-
$120	328.48	-	234.98	-	172.09	-

Model validation was carried out using the economic indices summary stated in the “ADDENDUM to AGR TRACS Competent Persons Report (CPR) on Otakikpo for Lekoil” report.

In general, the model was found to be very comparable with the CPR based on the quoted NPVs. The differences can be ascribed to the manner in which the abandonment capex were applied, which were not clearly stated in the CPR. A few scenarios have been provided below to compare the results from both sources:

Scenario 1:

Model Type – BaseCase; Fiscal Regime – Marginal Field Onshore; Oil Price @ $60/bbl; 10% discount rate

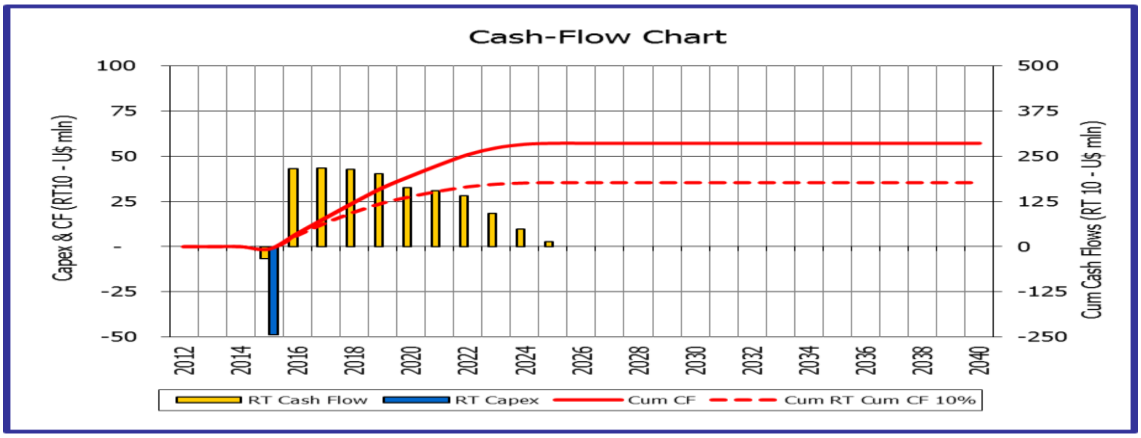


Figure 7-8: Phase 1

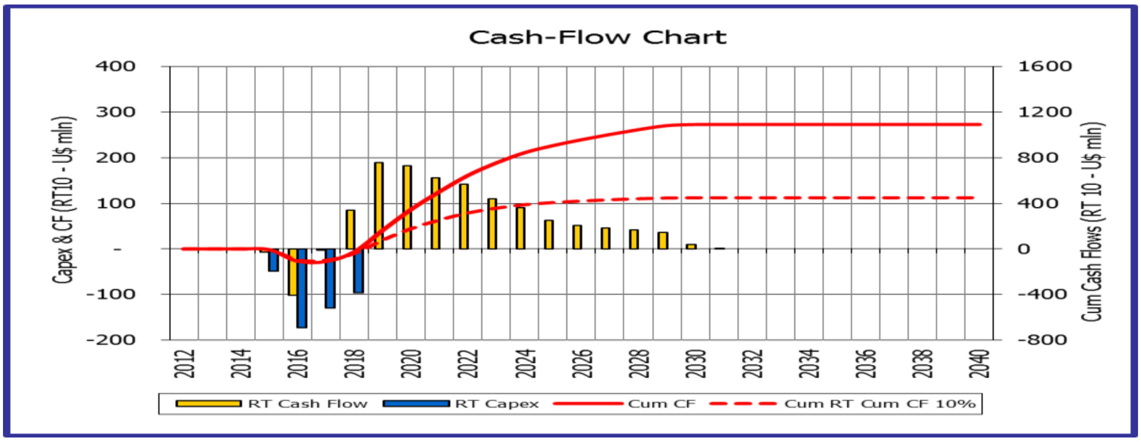


Figure 7-9: Phase 1 & 2

Table 7-9: Scenario 1 Comparison

Scenario 1	NPV (US$ mln) - 36%*		NPV (US$ mln) – 100%		% Difference
	Report	Model	Report	Model	
Phase 1	72.1	63.8	200.3	177.2	-11.5
Phase 1 & 2	169.1	161.7	469.7	449.2	-4.3

* Lekoil's working interest for Otakikpo field is 36%

The upper chart shows the maximum exposure of ca. US$50mln with the Phase 1 recompletions of the 002 and 003 wells and the installation of an Early Production Facility (EPF). With onset of production a year afterwards, the project achieves payout and steady cash flows until production fizzles out after 10 years. The lower chart however shows the impact of continued investment with the subsequent development of the Phase 2 aspects which covers the drilling of 7 new wells with on-stream date of 2017 and a new Central Processing Facility (CPF).

The maximum exposure occurs in 2016 where most of the spend on the CPF construction and 4 new wells are drilled. Pay out occurs in the third year from production commencement (2015). From 2019 onwards, the cash flow declines from the maximum to the lowest in sync with production rate after which the annual net cash flow turns negative in 2031, signalling the end of economic life of the field.

Scenario 2:

Model Type – LowCase; Fiscal Regime – Marginal Field Onshore; Oil Price @ $60/bbl; 10% discount rate

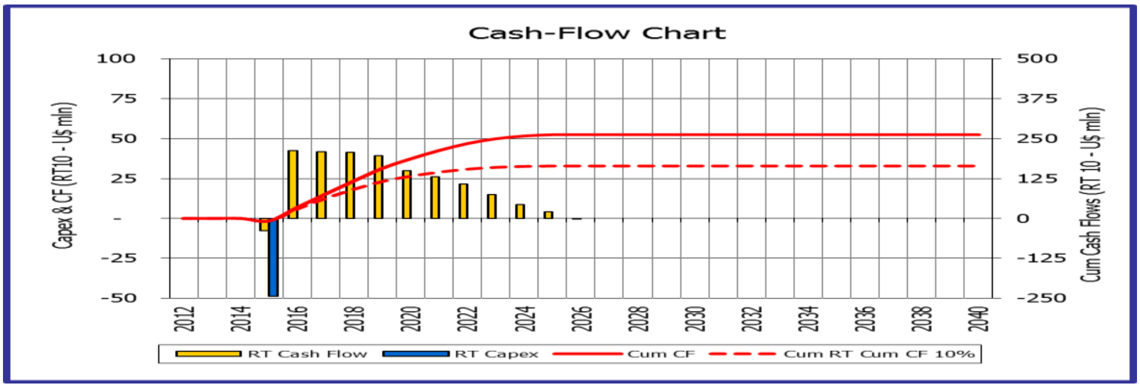


Figure 7-10: Phase 1

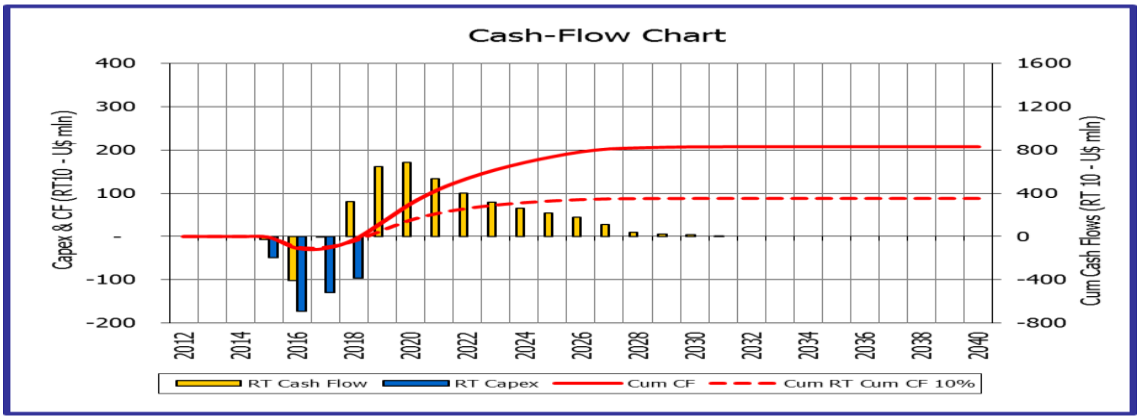


Figure 7-11: Phase 1 & 2

Table 7-10: Scenario 2 Comparison

Scenario 2	**NPV (US$ mln) - 36%***		**NPV (US$ mln) – 100%**		**% Difference**
	Report	**Model**	**Report**	**Model**	
Phase 1	51.3	59.1	142.5	164.2	-13.2
Phase 1 & 2	137.4	131.9	381.7	366.4	-4

* Lekoil's working interest for Otakikpo field is 36%

The low case model which uses the low case production profile and costs for the Phase 1 project shows the same maximum exposure of ca. US$50mln with the recompletions of wells 002 and 003 and the installation of an Early Production Facility (EPF).

Payout time remained the same as one year from investment year. Positive cash flows continue proportional to the production rate until the field goes out of production after 10 years. In the combined Phases 1 and 2 project case, where 7 new wells are planned to be drilled (alongside the 2 well recompletions) with on-stream date of 2017 and a new Central Processing Facility (CPF), the reduced production volumes result into reduced cash flows. Pay out occurs in the third year from production commencement (2015). From 2019 onwards, the cash flow declines from the maximum to the lowest in sync with production rate after which the annual net cash flow turns negative in 2031, signalling the end of economic life of the field.

Scenario 3:

Model Type – HighCase; Fiscal Regime – Marginal Field Onshore; Oil Price @ $60/bbl; 10% discount rate

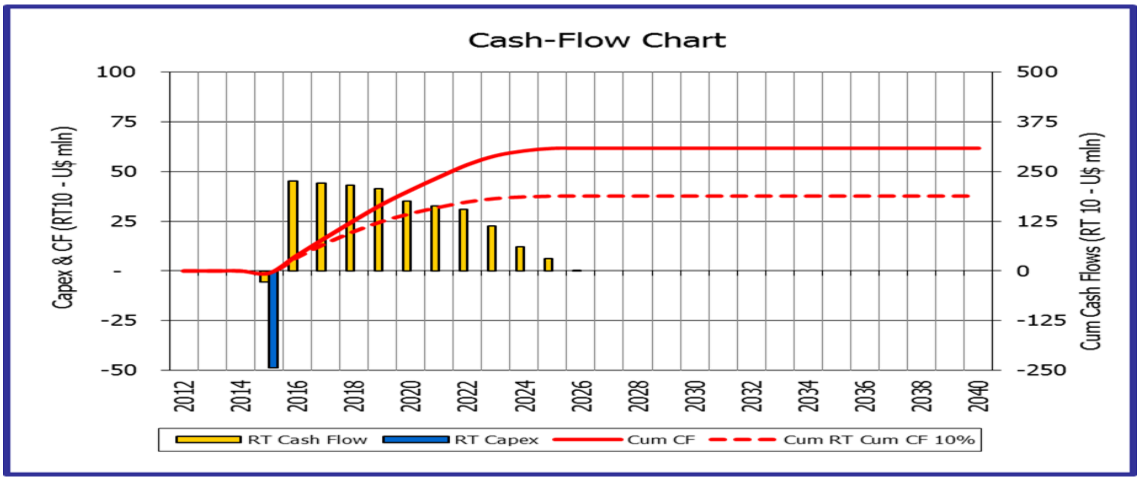


Figure 7-12: Phase 1

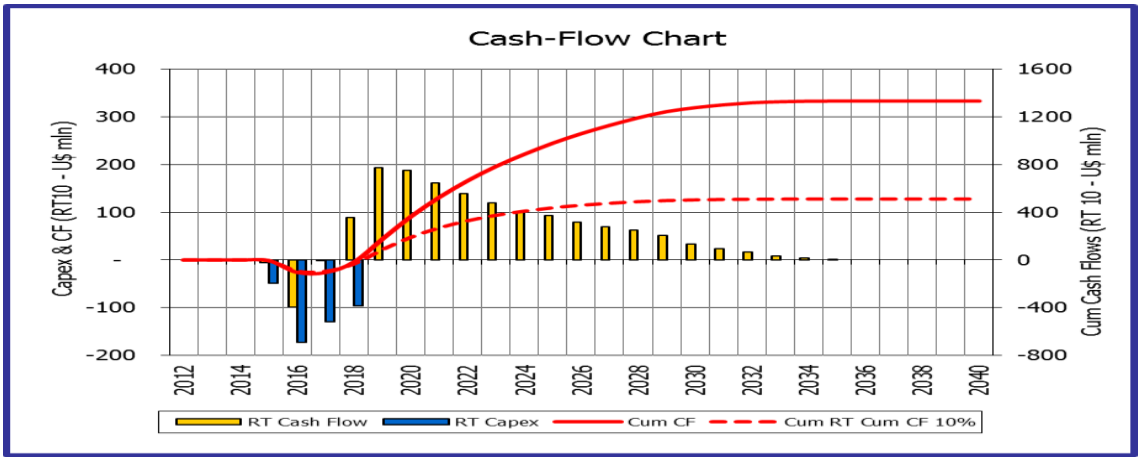


Figure 7-13: Phase 1& 2

Table 7-11: Scenario 3 Comparison

Scenario 3	NPV (US$ mln) - 36%*		NPV (US$ mln) – 100%		% Difference
	Report	Model	Report	Model	
Phase 1	76.0	67.8	211.1	188.3	-10.8
Phase 1 & 2	194.8	184.1	541.1	511.4	-5.5

The high case model which uses the high case production profile and costs for the Phase 1 project shows the same maximum exposure of ca. US$50mln with the recompletions of wells 002 and 003 and the installation of an Early Production Facility (EPF).

Payout time remained the same as one year from investment year. Positive cash flows continue proportional to the production rate until the field goes out of production after 10 years, howbeit with a flatter profile. In the combined Phases 1 and 2 project case, where 7 new wells are planned to be drilled (alongside the 2 well recompletions) with on-stream date of 2017 and a new Central Processing Facility (CPF), the improved production volumes result into higher cash flows.

Pay out occurs in the third year from production commencement (2015). From 2019 onwards, the cash flow declines from the maximum to the lowest in sync with production rate after which the annual net cash flow turns negative in 2035, signalling the end of economic life of the field.

This comparison shows a very good match between the model NPV results and that from the AGR TRACS report. As earlier mentioned, the discrepancies observed between both results can be attributed to the handling of the abandonment cost which was not stated in the AGR TRACS report.

This validity check has therefore provided confidence in the further maturation of the model for full-scale economic evaluation, financial evaluation, asset valuation, risk analysis and project costing.

7.9 Marginal Field Financial and Economic Indices

With the UZO-MARG Model developed, tested, validated and assured, it is important to run a full scale of the Model with a Case Study of an existing field-Shekinah Field (name disguised) with a demonstration of all the financial and economic indices that are required for investment decision leading to the development of a marginal oil and gas field.

The economic and financial indices comprise of Net Present Value (NPV), Present Value Rate (PV), Internal Rate of Return (IRR), Unit Development Cost (UDC), Unit Operating Cost (UOC), Cash Flow at defined discount rate. Analysis. For the financials, ROACE, ROCE, EBIT, EBAT, also, the impact of development costs, fiscal regimes, oil prices, Operating costs on marginal field profitability. The impact of associated risks and uncertainties using TECOP on the field/economic viability was also considered. The fiscal regimes considered ranges are PSC, JV, Marginal Field Offshore and Marginal Field Onshore.

Also demonstrated through the case study is how to evaluate the economic and financial viability of a Marginal field with the application of different technologies, in this case the use of renewable energy or a combination of conventional energy and renewable energy for power generation in Marginal Field development was evaluated.

7.10 Case Study 2: Shekinah Marginal Fields

7.10.1 Introduction

Shekinah field was discovered in 1995 by a major oil company. The exploration well, flowed 5,200 b/d. Another well was requested to be drilled as a proof of reserves the same year. After the field was discovered, nothing was done on this field.

A major Marginal Oil Field license sale took place and the government requested that the license be sold to a local company in 2010. The field is located 20km to the Waka town and is at a water depth of 50m.

Shekinah field is owned by 2 companies in a Joint venture and they have in place a Joint Venture Operating Agreement managing their respective venture splits of 60% to Kedu Inc. and 40% to Odinma Inc.

7.10.2 Field Description

The high case scenario for the field based on reservoir and geological studies is estimated at 160 million bbl. of oil and 120 bcf of gas. Kedu Inc. is the operator of this joint venture.

Because of the need to get quick return on investment, Kedu Inc. developed an execution strategy that will increase the chance of an early return on investment with a quick upstream date, thereby reducing the period between exploration well completion and on stream production by at least 4years.

The first exploration well was drilled and completed in 2013 and the target is to begin production by 2017. If this comes out successful, the template from commercial, finance through engineering to production could become a standard approach to Marginal Oil Field Development in many locations.

In 2015 Kedu commenced drilling activities to have at least 2-3 wells drilled. At the end of the drilling program in 2016, they had two wells drilled and completed. The field has an estimated gas reserve volume of 100bcf of gas for the duration of the field life.

Due to the increased global pressure for climate change, gas emission management and the requirement to stop gas flaring, the produced gas from the wells have to be captured, treated and sold where possible. The law in place is total elimination of all produced associated gas hence no routine flaring will go without penalties after 5years. An opportunity to treat produced gas and sell to others may also present itself during the field development.

7.10.3 Production Profile

The concept evaluation for the Shekinah field is based on the below production profile for both oil and gas stream.

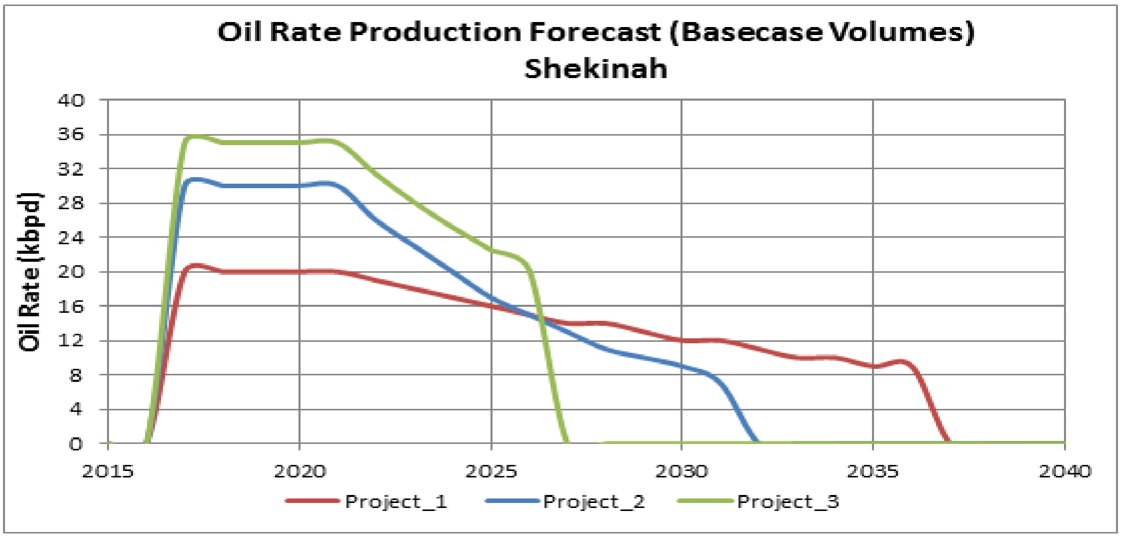


Figure 7-14: Ultimate Recovery

The recoveries for the production profile are based on the below definitions and assumptions.

The production profile below assumes that the drilling of new wells commences in 2015-2016. The production profile has been defined in three different production years' scenarios, 10years categorised as Project-3, 15 years as Project-2 and 20years production categorised as Project-1.

7.10.4 Concept Engineering Studies

Concept engineering studies approach was used to define the technical requirements for the development and maturation of the Shekinah field, at the same time used for the confirmation of the Otakikpo field as an opportunity that can be used to validate the study outcome of the Shekinah field because of its similarity in development strategy.

This concept definition study helped the delivery of the equipment list, selection of pipeline types and process flow scheme for the opportunity. It created a systematic path that allowed the determination of the cost, probable execution schedule, ease of execution and economic viability of the opportunity.

In summary, the concept engineering study has been used to do the following:-

- Carry out an engineering study that has produced the required deliverables which helped define the boundaries in the development of building a techno-economics model required for Marginal Field development.
- Development of Cost Estimates that have been used in the building of the Model and Validation of the Model as mentioned above.
- Definition of the risks approach for the Model development because of the different complexities peculiar to each opportunity.
- Demonstration of the systematic approach of how a proper opportunity should be evaluated.

Below are the various concept scopes that were evaluated for the conceptual engineering study.

Shekinah Scope: Installation of an Oil and Gas Facility (Greenfield) 20km Offshore-focused field was on the Shekinah Field.

7.10.5 Process Description

7.10.5.1 Introduction: UNISIM Process Engineering Software

UNISIM process engineering tool is the software that was used in carrying out the study. It is simulation software developed as an improved version of the popular HYSIS process engineering software with special features and capability to carry out dynamic simulations.

Apart from UNISIM, there are other process simulation tools available in the industry that can be used; they all have their merits and demerits but share similar features which include a data bank of thermodynamic and physical properties of pure components and mixtures and a module oriented library that can simulate the plant or facilities to be used or designed. The process simulator package used is a hybrid simulator called UniSim Design R390TM licensed by Honeywell.

7.10.5.2 UNISIM Design

The objective of this section is to highlight design steps; it does not discuss in detail the whole simulation process from start to finish.

The first thing you do in constructing a process simulation is identifying and selecting the chemical components that are required. Thereafter a set of reactions are defined depending on what the objectives are (Tijhuis, 2013). Then one or more input streams are defined i.e. defining the temperature, pressure and composition of the streams. Then you have the unit operations installed, linked together and defined, and then the built design with all the input parameters defined can then be simulated. The result output from the simulation model can be read from the property view display.

As an example a property view is shown below. The view displays the conditions of the connected streams.

Name	Prop Oxide	Water Feed	Mixer Out
Vapour	0.0000	0.0000	0.0000
Temperature [F]	75.00	75.00	75.00
Pressure [psia]	16.17	16.17	16.17
Molar Flow [lbmole/hr]	150.0	610.6	760.6
Mass Flow [lb/hr]	8712	1.100e+004	1.971e+004
Std Ideal Liq Vol Flow [USGPM]	20.83	22.01	42.84
Molar Enthalpy [Btu/lbmole]	-5.203e+004	-1.225e+005	-1.086e+005
Molar Entropy [Btu/lbmole-F]	-5.768	1.499	0.8824
Heat Flow [Btu/hr]	-7.804e+006	-7.481e+007	-8.262e+007

Figure 7-15: The Property View of a Unit Operation (Tijhuis, 2013)

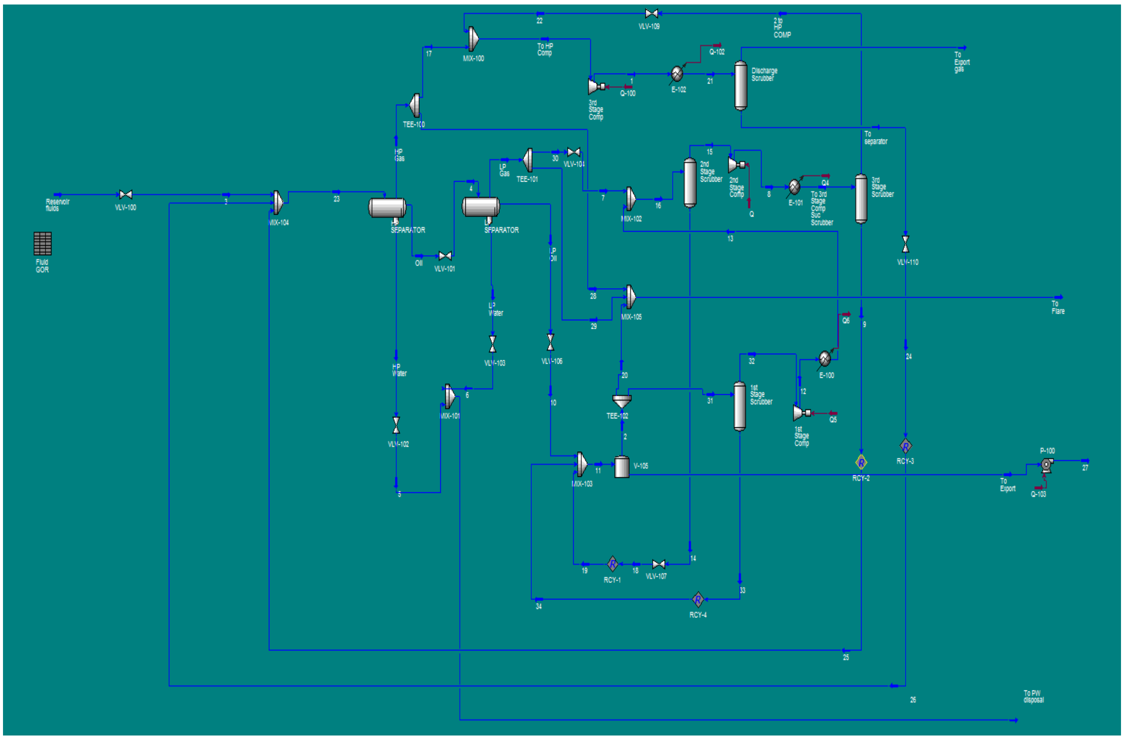


Figure 7-16: UNISIM Process Engineering Software

It has incorporated in it rotating machinery features which many process engineering tools do not have built into them. UNISIM was used for the process evaluation of the Shekinah field. Above figure 7-16 is the UNISIM screen shot of the Shekinah Field, the actual facilities been designed. It is important to note that the Otakikpo field looked very much similar like the Shekinah field from the PFS found in the Lekoil report; hence it was used for validation.

Substantially, UNISIM improves simulation of online and off-line process unit design and optimization applications and helps determine the workflow, equipment needs and implementation requirements for a particular process. Users can easily capture and share process knowledge, improve plant profitability, and maximize the return on their simulation investments.

7.10.5.3 Process Flow Description

Reservoir fluid at the Shekinah field will be processed in an integrated oil & gas facility which stabilize the crude from the wells and gather the associated gas.

The well fluid will be stabilized using the standard flowstation processes of staged pressure let down. The well fluid flows into a three-phase HP separator which operates at about 12barg. The separator separates the well fluid into gas, water and oil streams.

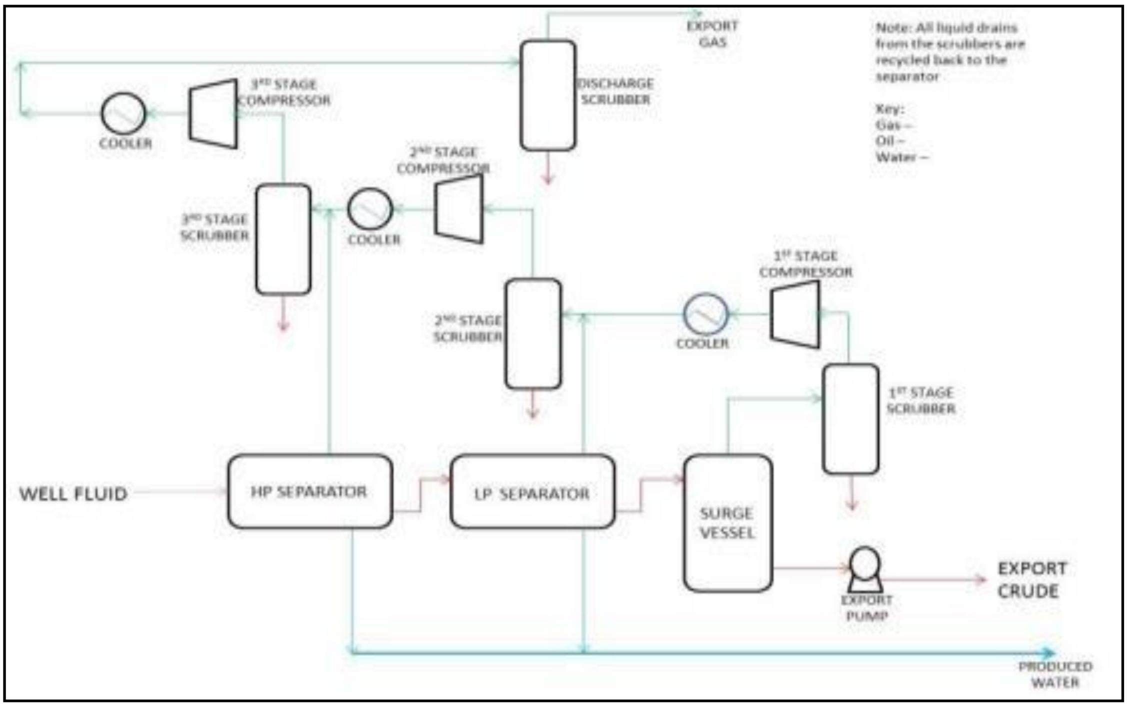


Figure 7-17: Integrated Oil and Gas Facility

The oil is further stabilized in a three phase LP separator which operates at 3barg. The oil is then sent to the surge vessel which operates at atmospheric pressure and then exported. The produced water from both separators is disposed accordingly.

The gas from the 3 stages of separation is gathered using a 3-stage compression system. The 1st stage compressor compresses the surge vessel to LP pressure.

Gas flashed from the LP separator combines with the gas from the 1st stage compression and is fed into the 2nd stage compressor to be compressed to HP pressure.

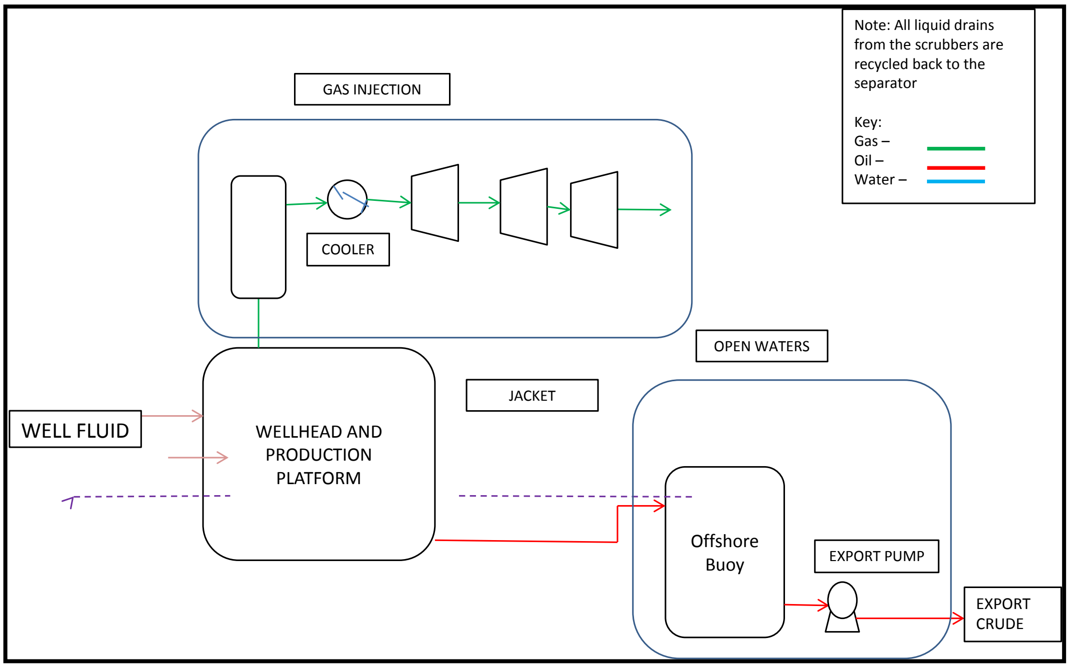


Figure 7-18: Flowline Profile

The gas from this stage is then combined with the gas flashed from the HP separator and is fed into to the 3rd stage compressor to compress the gas to export pressure to be exported to the customer.

Provision is made for the gas to be routed to the flare should the gas gathering facility be down so that oil production can continue.

An Offshore Jacket will be used for the drilling activity and at the same time used as a production platform for the production operation facilities. A dedicated Offshore Buoy will be installed and used as both holding tank for the stabilised crude and evacuation tank for ocean loading vessels.

7.10.5.4 Pipeline Sizing

Table 7-12: Flowline Profile

Elevation	Distance
0	0
0	-43.001
4999.9	-48
13000	-30
14000	-35
20000	-20
20000	0

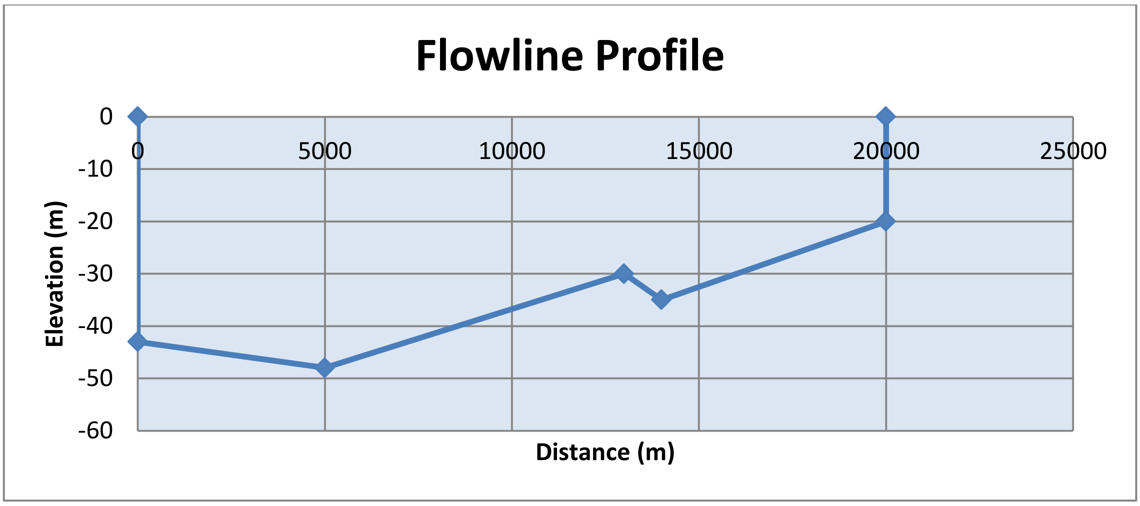


Figure 7-19: Flowline Profile

Dry trees are used at the wellhead platform. The flowline goes to the sea bed from the tree towards shore where it enters the processing plant. Based on the elevation profile, pipe sizing calculation was done, looking at 4 pipe IDs.

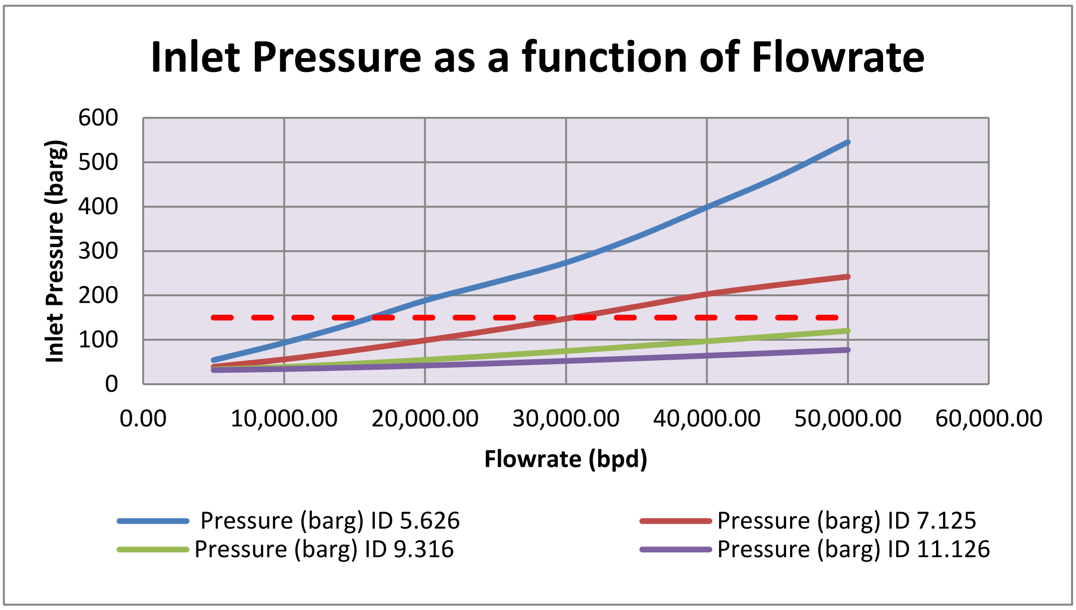


Figure 7-20: Inlet Pressure vs. Flowrate

The figure 7-20 shows the inlet pressure as a function of flowrate. This inlet pressure is the pressure at which the flow leaves the pump from the facility into the pipeline to its destination.

Various inlet pressure profiles were developed for the pipeline sizing and selection, considering the two concepts for the Shekinah field. As can be seen from the figure 7-20 above, the maximum tubing head pressure (THP) is also shown and the inlet pressure must not exceed this pressure.

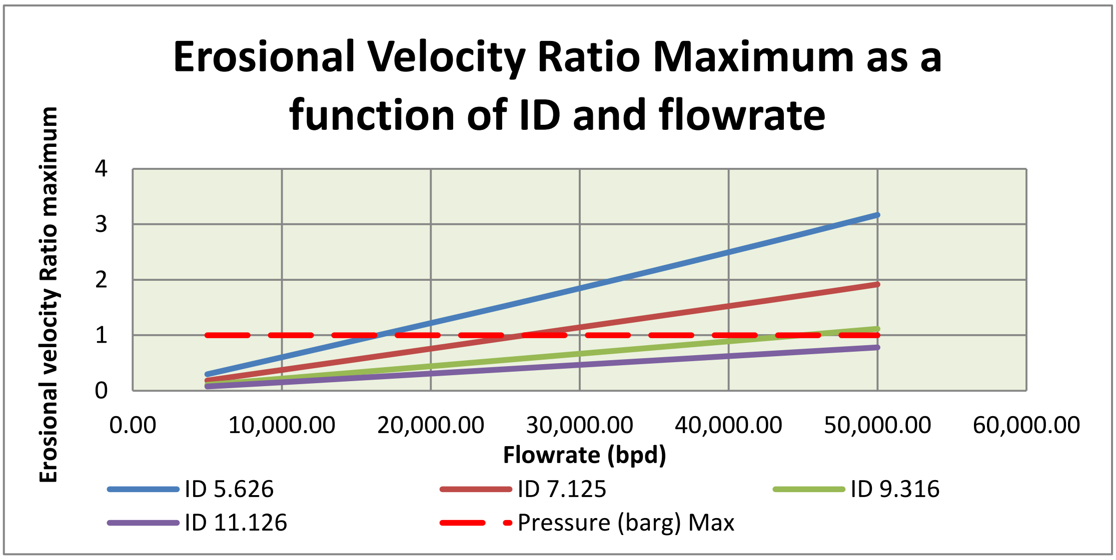


Figure 7-21: Erosional Velocity Ratio Max vs. Flowrate

The Erosional Velocity Ratio Maximum as a function of pipeline internal diameter and flowrate chart is shown in figure 7-21. This helped in the selection of the pipeline. The erosional velocity for any pipeline that will be selected must be less than 1.

The two lines that are below this cut off line of 1.0 erosional velocity are ID (9.316 and 11.126). All these have been considered for the pipeline selection which helped determine actual pipeline size.

Table 7-13: Erosional Velocity Ratio Max vs. Flowrate

	Internal Diameter							
	5.626inch		7.125inch		9.316inch		11.126inch	
(bpd)	Required Inlet pressure (Barg)	Erosional Velocity Ratio	Required Inlet pressure (Barg)	Erosional Velocity Ratio	Required Inlet pressure (Barg)	Erosional Velocity Ratio	Required Inlet pressure (Barg)	Erosional Velocity Ratio
10000	100	0.6	50	0.4	50	0.3	50	0.2
20000	200	1.2	100	0.8	60	0.5	58	0.3
30000	280	1.8	300	1.1	80	0.7	60	0.5
40000	400	2.5	200	1.5	100	0.9	75	0.6
50000	550	3.2	250	1.9	120	1.1	90	0.9

A combination of the two Figures 7-20 and 7-21 as shown in the above Table 7-13 provided the necessary technical basis for the selection of the pipeline size and also the determination of pump duty for the two concepts. Maximum Tubing Head Pressure (THP) and Erosional Velocity Ratio was used as the selection criteria for the pipeline, this means that all the sized pipelines as shown in Figure 7-20 must have a THP above 150bar and a Erosional Velocity Ratio above 1.0.

From the aforementioned criteria and as shown in Table 6-5 the pipeline size in this range is a 9.316inc pipeline which is an outcome of a 100bar THP (inlet Pressure) and Erosional Velocity Ratio = 0.9.

The next tubing head pressure of 120bar could not be used because of the high erosional velocity ratio of 1.1. However, the 9.316inch is not a standard pipeline size, the nearest line size to it is a 10inch size and that was selected.

7.10.5.5 Sizing Criteria

Erosional velocity ratio of < 1.0

The 10inch line size is the optimum line size for the expected flowrates putting into consideration that velocity decreases as diameter increases.

Pump duty required to achieve inlet pressure required to flow from offshore facility to the terminal as obtained from Unisim is 906.3kW for a base case of 40000bpd.

7.10.6 Shekinah Field Equipment Lists

Table 7-14 below shows the equipment list drawn from the process simulation carried out towards the development and production of the Shekinah field.

EQUIPMENT	TAG	DESCRIPTION	CAPACITIES	OPERATING PRESSURE	OPERATING TEMP.	DIAMETER	LENGTH	DUTY	Delta T (degC)
				(barg)	(oC)	(m)	(m)	KW	
HP SEPARATOR	V-100	3-PHASE HORIZONTAL SEPARATOR WITH WIREMESH INTERNAL		12	48.3	3.00	9.00		
LP SEPARATOR	V-101	3-PHASE HORIZONTAL WITH WIREMESH INTERNAL		3	47.3	3.00	8.00		
SURGE VESSEL	V-102	VERTICAL KNOCKOUT VESSEL		0.5	45.9				
1ST STAGE SUCTION SCRUBBER	V-103	VERTICAL KNOCKOUT VESSEL		0.5	45.5	1.00	3.00		
2ND STAGE SUCTION SCRUBBER	V-104	VERTICAL KNOCKOUT VESSEL		3	39.9	1.50	6.00		
3RD STAGE SUCTION SCRUBBER	V-105	VERTICAL KNOCKOUT VESSEL		11.5	35.0	1.00	3.00		
DISCHARGE SCRUBBER	V-106	VERTICAL KNOCKOUT VESSEL		100	35.0	1.00	3.00		
EXPORT PUMP	P-100	CENTRIFUGAL PUMP						53.6	
1ST STAGE COMPRESSOR	K-100	COMPRESSOR						84.04	
2ND STAGE COMPRESSOR	K-101	COMPRESSOR						143.74	
3RD STAGE COMPRESSOR	K-102	COMPRESSOR						940.8	
HEAT EXCHANGER	E-100	AIR COOLER						105.2	66.8
HEAT EXCHANGER	E-101	AIR COOLER						234.3	66.3
HEAT EXCHANGER	E-102	AIR COOLER						1510	166.5

Table 7-14: List of Facilities and Equipment

As already mentioned, the Equipment list forms part of the basis for the costs estimate development especially the Facilities and Equipment.

7.10.7 Exporting Options

The Shekinah field development considered two export evacuation options.

7.10.7.1 Offloading offshore to vessels 2km from facility

This option entails the separation of oil and gas on the production platform and storing in an atmospheric operated vessel near the production platform. An offshore buoy is also installed few meters from this tank. Been that the production facility is a platform and not an FPSO, a retaining tank is required from which crude will be loaded through the offshore bouy to the offshore vessel.

The offshore loading point is 2km away from the production platform. The export pressure and pump duty required to carry out the offshore loading is as shown below:

Table 7-15: Offloading Offshore

Export pressure (barg)	6
Duty (KW)	60

7.10.7.2 Offloading to terminal 20km from facility

Table 7-16: Pipeline Sizes

Pipeline Size	8 inch	10 inch	12 inch
Export pressure (barg)	97	34	15
Duty (KW)	1320	460	200

This export option involves the transportation of the stabilised crude to a terminal 20km onshore from Shekinah Field. The crude from the terminal is now transported to a refinery where it is refined and used locally.

The option to use the produced gas locally also exists however; it will be re-injected into a selected reservoir to help maintain downhole pressure.

Table 7-16 above shows the various pipeline sizes that were evaluated. From 8inch to 12inch pipelines, any of these pipelines can be used for the planned process, 8inch, 97bar and a 1320kw pump duty was selected. This selection offers the best pump pressure for this service.

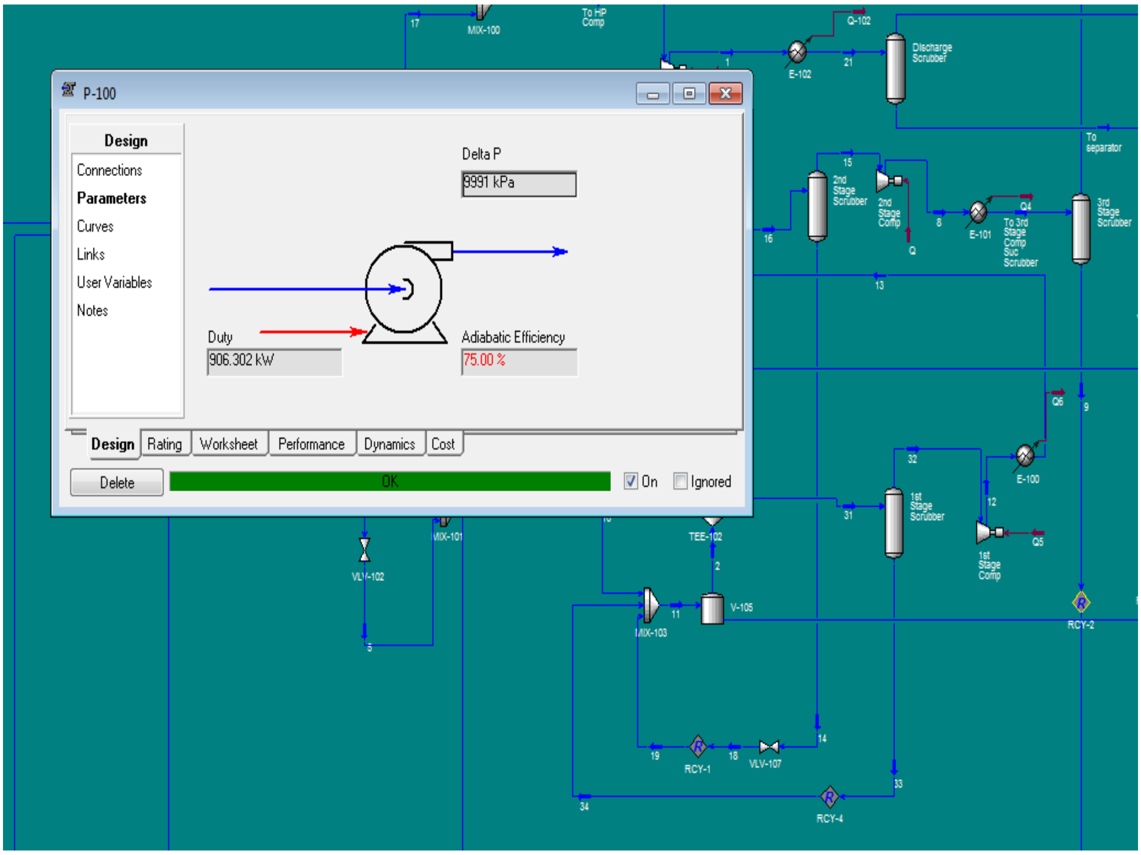


Figure 7-22: Pump Sizing using the UNISIM Model

7.10.8 Summarized Work Scope Definition

Premised on all the above technical studies and evaluation, below is the summarised work scope and cost estimate upon which the economic and financial evaluation have been done. This can be categorised as major work scope for the Shekinah Field.

1. Design and installation of topside facilities for the oil and gas processing.
2. Design and fabrication of offshore structures for production systems.
3. Installation of a Power Generation Package for Electricity Supply.

4. Procurement and installation of offshore flowlines from the wells to offshore production topsides.
5. Procurement and installation of Offshore Umbilical (Bulkline) that will be used to transport oil from holding tank (surge vessel) to the terminal 20km away from the offshore platform and Laying of fibre optics from the offshore platform to the wellheads, terminal, around topsides of facility.
6. Procurement and installation of Manifolds for the well heads.
7. Installation of gas injection facilities on the platform (future), but designed.

7.10.9 Cost Estimate

Table 7-17: Cost Estimate

S/N	Description	Unit	Amount
1	Total Oil Facilities CAPEX	$ USD Million	741.06
2	Total Oil Facilities OPEX	$ USD Million	731.60
3	Total Gas Facilities Costs	$ USD Million	40.60
4	CO_2 Cost	$ USD Million	4.10

7.11 Shekinah Model Critical templates

7.11.1 Production Profile

The economics for this field was based on forecast profiles associated with three projects defined as “Project_1”, “Project_2” and “Project_3”. Each project forecast had low case, base case and high case profiles with their respective initial rate, plateau production period and volumes for development. The projects were based on scenarios development phasing resulting in accelerated or delayed production profiles; with “Project_1” implying project development spaced-out, “Project_2” implying optimum development spacing and “Project_3” implying accelerated development. See Appendix Figure B for template.

7.11.2 Cost Estimate Summary Sheet

This sheet, as shown in Appendix Figure C, collates the cost estimates from the six different capex elements including: Project Management and Indirect, Facilities and Equipment, Bulk Materials, Drilling and Wells, Offshore Structure and Platform as well as Pipeline Offshore. Each of these elements were worked out in detail in their respective work breakdown sheet with options for changes influenced by the choice of energy mix being utilized. The individual sheets have thus been linked with this summary sheet. The key thing to note here is that the Capex applied is the same for all the scenarios of development phasing and for all uncertainty cases.

7.11.3 Project Input Data Page

This collates all the economics inputs used in the model (see Appendix Figure D). Inputs here include: Production rates (oil and gas), Capex, Opex, abandonment costs and CO_2 Emission cost. The variable Opex was calculated in this sheet using the combination of the production profile and variable Opex rates.

7.11.4 Fiscal Parameters

The Shekinah field is located offshore Nigeria and its commercial terms are as defined in the Petroleum Tax laws of Nigeria. The Fiscal Parameters sheet defines the different fiscal regimes operating in Nigeria. For each regime, the royalty rate is either flat (as with the JV and PSC) or a function of production rate (as with the marginal field onshore and onshore). Other parameters defined are the depreciation schedule, tax rate, investment incentive (ITA or ITC) rate, education and NDDC tax. See Appendix Figure E for the fiscal parameters.

7.11.5 Cash Flow – Economic Model Sheet

The cash flow – economic model sheet (see Appendix Figure F) extracts data from the techno-economic model for display as charts/plots in the "Results Chart Page". This sheet has embedded macros for sensitivity runs of economic outputs over different oil prices and fiscal regimes to enable quick analysis and decision making. For the Shekinah field which has a defined fiscal regime, it provides a basis for analysis for negotiations with the government for incentives that can support or encourage marginal field operators.

7.11.6 Results Chart Page

This sheet provides graphical illustration of the data contained in the "Cash Flow Economics Model Sheet". It highlights pictorially the impact of oil price on the economic indices, impact of fiscal regime changes and the impact of other changes to the economics inputs including efforts at decreasing costs of asset building or operational costs. These charts also help in conveying the outcomes of these sensitivities to decision makers for a cost benefit analysis. It is shown in Appendix Figure G.

7.12 Sensitivity Analysis

Like most global businesses, they come with uncertainties which mean that some of the assumptions made during the economic and financial analysis have been done with the best available information at that time. Hence, it is important to change some of the applied parameters one at a time to see what the profitability indicators will still be in case it changes in real life situation, this process is known as Sensitivity Analysis, i.e. with changing capital & operating costs, change in oil price and the different fiscal regimes. It is important to note that a change in CAPEX will also mean a change in OPEX; they can also be done one at a time.

The UZO-MARG Model was built with the intricacies of several business environments in mind. This model has the capacity and capability to run not just cost variations but different fiscal regimes, some of which include the following: Production Sharing Contract (PSC), Joint Venture (JV) agreement, Onshore Marginal Fields, Offshore Marginal Fields, etc.

The model has been built to calculate on a 100% equity share with the flexibility to calculate any percentage share as required. The model also gives allowance for several assumptions to be made, while carrying out a sensitivity analysis to determine how different values of an independent variable impact a number of dependent variables.

7.12.1 Definitions

<u>Joint Venture (JV) and Production Sharing Contract (PSC) agreements</u>:

The fiscal regime parameters assumed are as listed below –

Table 7-18: JV and PSC Terms

Parameters	**JV**	**PSC**
Oil_Royalty_Rate	20.0%	20.0%
Gas_Royalty_Rate	7.0%	5.0%
Oil_Depreciation_Schedule	20% (over 5years)	100%
Gas_Depreciation_Schedule	20% (over 5years)	100%
Start_of_Depreciation	At_Spend	At_Spend
Oil_Tax_Rate	85%	50%
Gas_Tax_Rate	30%	
Oil_ITA_ITC_Rate	5%	50%
Gas_ITA_ITC_Rate	5%	
Education_Tax_Rate	2%	2%
NDDC_Rate	3%	3%

Project 1**:** Production life of the field is expected to be 20 years.

Project 2: Production life of the field is expected to be 15 years.

Project 3: Production life of the field is expected to be 10 years.

P50_Base Case: In this case, a 50% probability has been assigned to the occurrence of this scenario. That is, a neutral view is taken of interactions within the model and no extreme event is expected in the case of the production profile.

P90_Low Case: In this case, a 90% probability has been assigned to the occurrence of this scenario. That is, conditions are presumed to be less than favourable and the worst possible outcome is expected in the case of the production profile.

P10_High Case: In this case, a 10% probability has been assigned to the occurrence of this scenario. That is, conditions are presumed to be very favourable and the best possible outcome is expected in the arrangement of the production profile.

New Comer Status: This organization enjoys a 5-year tax holiday with Petroleum Profit Tax (PPT) set at 0% from the date of 1st oil production, before the 50% rate comes into action. The cost recovery of CAPEX and OPEX during the 0% PPT time period could possibly be deferred until the end of the 5-year period, such that all accrued costs are recovered under the 50% PPT rate fiscal regime.

Tax Payer Status: This organization DOES NOT enjoy any tax holiday, as they already exist in the industry.

Pioneer Status: The model has an option to select YES or NO; where YES implies that the organization will enjoy a 5-year tax holiday and NO implies that no tax holiday will be applicable.

Investment Incentive: It comes in the form of an Investment Tax Allowance (ITA) or an Investment Tax Credit (ITC) used to encourage investment in the oil and gas industry.

Money of the Day (MOD): This refers to money that is quoted in current prices or nominal terms.

Real Term (RT): This refers to money that is adjusted for general price level changes over time, i.e., inflation or deflation.

Inflation Rate: The model allows for any figure to be inputted. For this analysis we use 2.5%.

Nominal Discount Rate: The model allows for medication to the discount rate, which is also known as the Cost of Capital.

Oil prices: A range of prices have been computed into the model for robustness, they are graduated by $10 and range from $10bbl to $120bbl.

Gas prices: Taking cognizance of the effect of gas on overall economics, a range of gas prices have been computed into the model as well. These prices are quoted in Mscf and include the following: $1.0, $2.0, $2.3, $2.5, $3.0 $3.5 and $4.0.

CO_2 Price (penalty charges): Given that the industry has increased the awareness for cleaner energy, the model takes the penalty charges that could be applicable into consideration.

7.12.2 Categories of sensitivity analysis carried out

The following analysis were carried out:

1. Oil price sensitivities
2. CAPEX sensitivities
3. OPEX sensitivities
4. Projects sensitivities
5. Low Case, Base Case and High Case sensitivities
6. Sensitivities on Taxes and Modified Fiscal Regime

Only the Production Sharing Contract (PSC) and Joint Venture (JV) fiscal regimes were considered while carrying out these analyses.

Assumptions made in carrying out the sensitivities highlighted above are listed with the explanations that go along with each set of analysis.

7.12.3 Oil Price Sensitivities

This evaluates changes in the Economic parameters that are as a result in changes in OIL prices only.

Assumptions: The following assumptions were made in carrying out the Oil Price sensitivity analysis: Start year 2015; Base Case; Project 1; Inflation rate 2.5%; Discount rate 10%; Equity share 100%.

New Comer, Pioneer Status – Yes

At $20/bbl: There is a negative cash flow for the new comer JV and PSC fiscal regimes, resulting in a negative NPV and VIR. While the economic cutoff for both regimes is 2036, the payback for investment in the JV fiscal regime will take place after 18years, which is rather close to the end of the project life. Hence, it is not advisable to carry out either project if the oil price remains $20/bbl, as all the economic indicators return negative values for both the JV and PSC fiscal regimes.

At $50/bbl: While the new comer JV fiscal regime returns a negative cash flow, the PSC shows a positive return. Both regimes have positives NPVs which implies that both projects can be undertaken, however the PSC regime has a payback period of only 2 years while that of the JV regime is about 10years.

At $100/bbl: At this price, cash flow and revenue are very attractive for both regimes; with impressive NPV, VIR, RTEP, IRR and both projects paying back in 2017. Consequently, in the event that oil prices are $100/bbl, it will be acceptable to carry out a project in either fiscal regime; albeit the PSC fiscal regime is more attractive.

Tax Payer, Pioneer Status – No

At $20/bbl: Both fiscal regimes return a negative cash flow; however, given the less stringent conditions attached to the PSC (where the share of revenue that accrues to the government comes to only 32%, as against 54% in the JV fiscal regime), a positive NPV is recorded. While the JV regime did not return any value for IRR, the 6% returned in the PSC regime is lower than the Discount Factor (cost of capital) of 10%. Furthermore, the breakeven price for any project in this analysis is $30/bbl. Hence carrying out this project at an oil price of $20/bbl is not economically feasible.

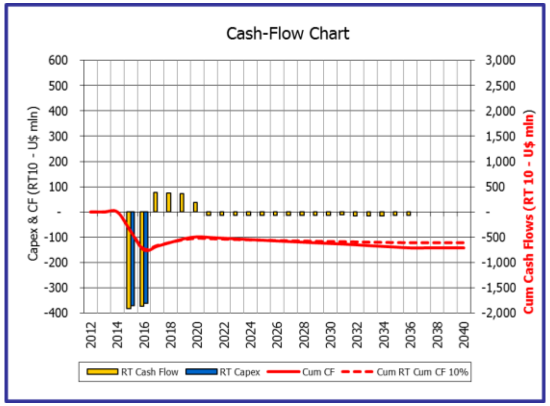
At $50/bbl: At a value that is $20 higher than the breakeven price, the PSC regime returns a positive cash flow while the JV regime remains in the negative. Here, the PSC regime is the more attractive investment to pursue given that its VIR is greater than 1, its IRR at 46% is greater than the prevailing cost of capital, and its payback period is only 2years. One of the main reasons why the PSC regime is more favorable is because government share of the revenue generated comes to 48%, which is much lower than the 72% in JV regime.

At $100/bbl: The JV fiscal regime returns a positive cash flow, albeit only 14% of what the PSC regime returns at the same oil price level. The VIR, RTEP and IRR for the PSC regime are impressive and much higher than those returned for the JV regime. Hence, of the two regimes, investing in a project within the PSC regime will yield a higher return.

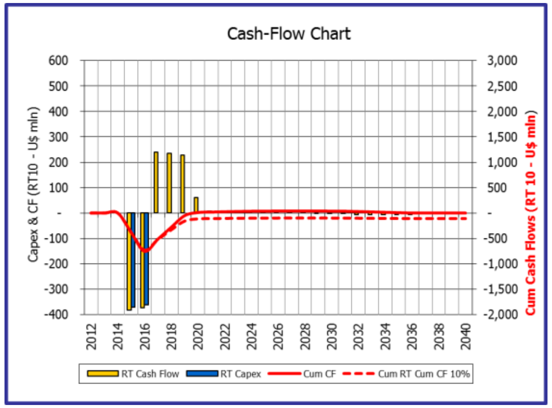
Table 7-19: Result of Oil Price Sensitivities

S/N	Description	Unit	New Comer, Poineer Status - Yes						Tax Payer, Poineer Status - No					
			$20		$50		$100		$20		$50		$100	
			JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC
1	Oil Cash Flow	$ USD	- 889.13	- 472.88	- 65.70	1,069.55	1,306.69	3,640.25	- 565.59	- 76.91	- 180.16	1,207.86	462.23	3,349.16
2	Revenue	Mln$	2,388.65	2,388.65	5,664.83	5,664.83	11,125.13	11,125.13	2,388.65	2,388.65	5,664.83	5,664.83	11,125.13	11,125.13
3	Royalty	Mln$	451.14	447.05	1,106.38	1,102.29	2,198.44	2,194.35	451.14	447.05	1,106.38	1,102.29	2,198.44	2,194.35
4	Govt Take	Mln$	1,613.93	1,149.14	4,066.67	2,882.90	8,154.59	5,772.49	1,290.39	753.18	4,181.14	2,744.58	8,999.05	6,063.59
5	Cash Surplus	Mln$	- 788.16	- 323.37	35.27	1,219.05	1,407.66	3,789.76	- 464.62	72.59	- 79.19	1,357.36	563.20	3,498.66
6	UDC	$/bbl	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79
7	UOC	$/bbl	7.53	7.53	7.53	7.53	7.53	7.53	7.53	7.53	7.53	7.53	7.53	7.53
8	UTC	$/bbl	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31
9	NPV	Mln$	- 788.16	- 323.37	35.27	1,219.05	1,407.66	3,789.76	- 464.62	72.59	- 79.19	1,357.36	563.20	3,498.66
10	VIR	Ratio	- 1.06	- 0.44	0.05	1.65	1.90	5.11	- 0.63	0.10	- 0.11	1.83	0.76	4.72
11	RTEP	%	N/A	-21%	0%	16%	36%	44%	N/A	3%	N/A	42%	13%	85%
12	IRR	%	N/A	-12%	2%	18%	40%	47%	N/A	6%	N/A	46%	16%	90%
13	Payout Year	Year	2033	2022	2025	2017	2017	2017	2033	2022	2025	2017	2017	2017
14	Max Exposure	Mln$	- 788.16	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 523.93	- 196.38	- 523.93	- 196.38	- 523.93	- 196.38
15	Breakeven Price	$/bbl	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

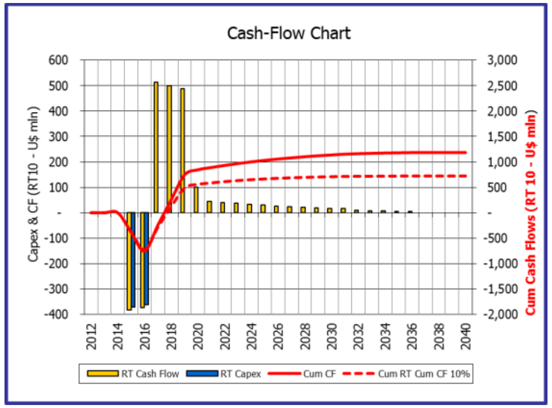
Figure 7-23: Oil Price Sensitivities: JV New Comer, Pioneer Status – Yes



At $20

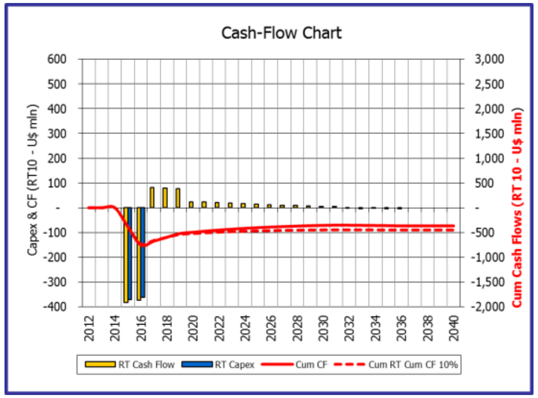


At $50

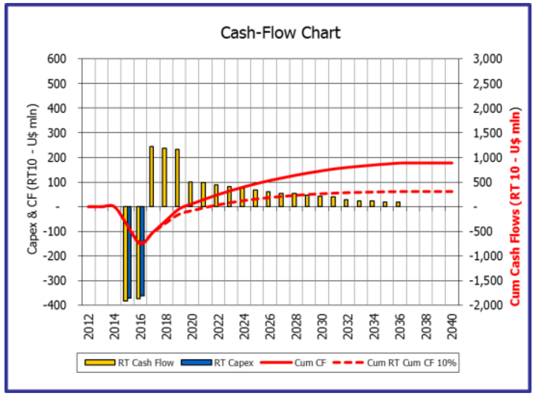


At $100

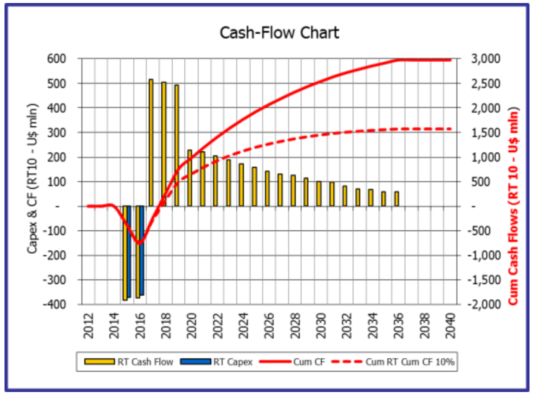
Figure 7-24: Oil Price Sensitivities: PSC New Comer, Pioneer Status – Yes



At $20



At $50



At $100

7.12.4 Oil Price at $50/bbl

To carry out the other sensitives, oil price was assumed to be $50/bbl taking a conservative view of the forecasts that are illustrated in the graphs below:

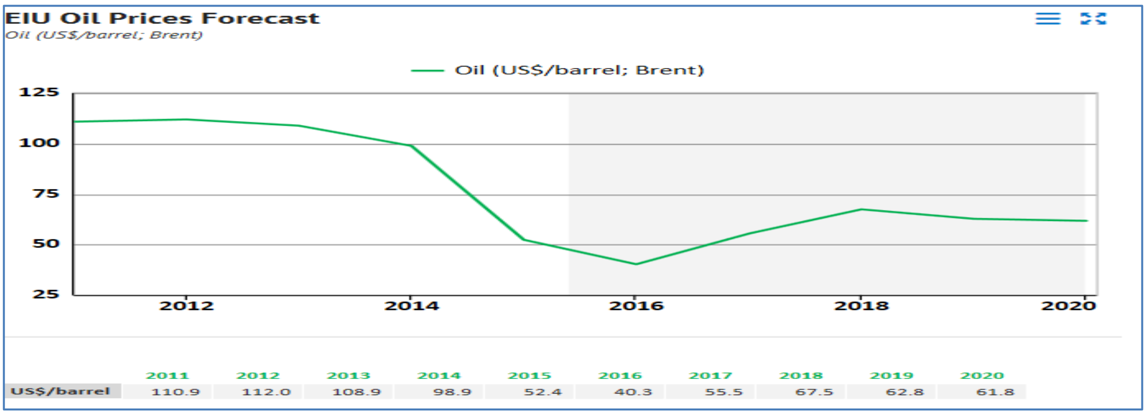


Figure 7-25: EIU Oil Prices Forecast

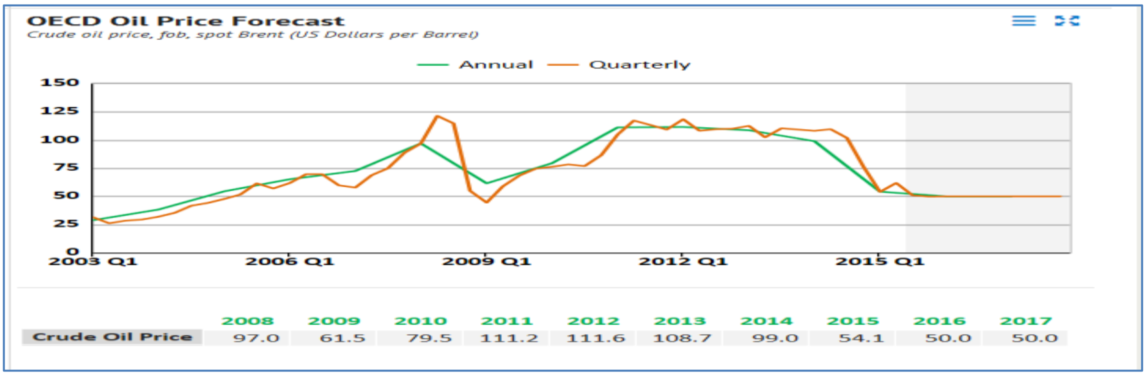


Figure 7-26: OECD Oil Price Forecast

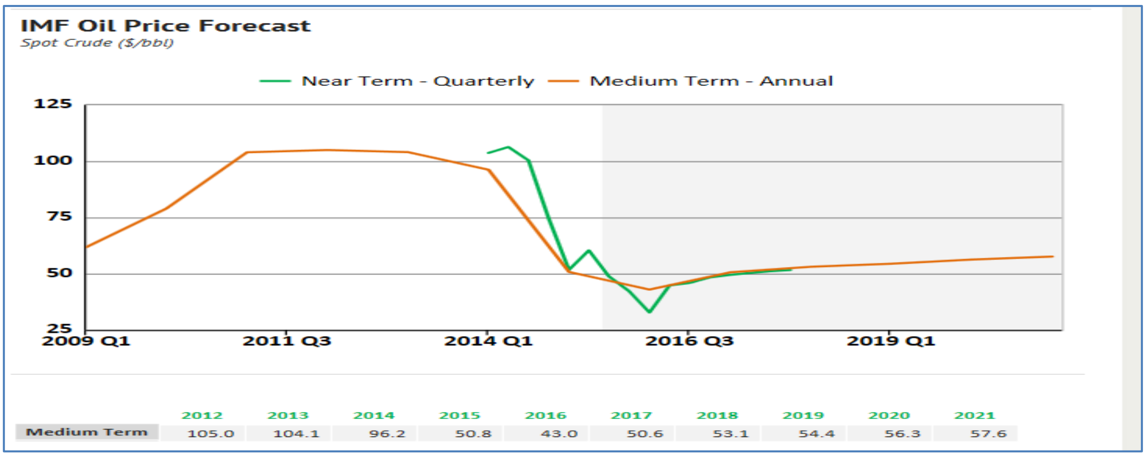


Figure 7-27: IMF Oil Price Forecast,

Source: Knoema Crude Oil Price Forecast

7.12.5 Capital Expenditure (CAPEX) Sensitivities

This evaluates changes in the economic parameters that are as a result of a 20% increase/decrease in the capital expenditure of oil production.

Assumptions: The following assumptions were made in carrying out the CAPEX sensitivity analysis: Start year 2015; Base Case; Project 1; Inflation rate 2.5%; Discount rate 10%; Equity share 100%; Oil price $50/bbl; Base CAPEX $741.1 million.

New Comer, Pioneer Status – Yes

CAPEX -20%: For this sensitivity, the capital expenditure came to $594.97 million. Results show that a 20% decrease in capital expenditure induced a reduction of 20%, 1% and 10% respectively in UDC, UOC and UTC respectively. Both regimes return positive cash flows, but the terms of the PSC make its returns higher than that of the JV. Though the JV regime returns values that are significantly lower than that of the PSC regime, investing in a JV project can also be accepted because at 12% its IRR is greater than the 10% cost of capital.

Base CAPEX: This was used to portray the base effect of having a capital expenditure of $741.1 million while oil trades at $50/bbl. The JV regime returns a negative cash flow, while the PSC regime returns a positive cash flow which is 12% less than what was returned when CAPEX was reduced by 20%. At 72%, the share of revenue that goes to the government in the JV regime is considerably more than the 51% seen in the PSC regime. Given the results, it is better to invest in a project within the PSC regime, as the VIR is greater than 1, RTEP is 16%, IRR is 18% and its payback period is only 2 years.

CAPEX +20%: Increasing the capital expenditure by 20% brings the cost value to $887.1 million and results in an erosion of cash flow. In addition, the UDC, UOC and UTC increased by 16%, 1% and 9% respectively when compared with the values reported in the Base CAPEX. Nonetheless, the NPV, VIR, RTEP and IRR in the PSC regime are positive, implying that an investment in this regime will be profitable.

Tax Payer, Pioneer Status – No

CAPEX -20%: With the capital expenditure reduced to $594.97 million, the JV regime returns a negative cash flow while the PSC regime returns a positive cash flow. The government's share of the revenue generated within the JV and PSC regimes are 76% and 50% respectively, this leaves the JV regime in a CSD negative position. On the other hand, the PSC regime shows impressive NPV, VIR, RTEP and IRR; all these point to a highly profitable return if investment is made within this regime.

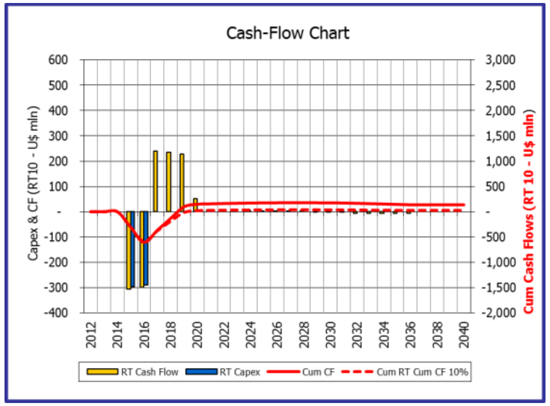
Base CAPEX: At the base capital cost of $741.1 million, the JV regime returns a negative cash flow while the PSC regime returns a positive cash flow. Regardless of the 25%, 1% and 11% increase in UOC, UDC and UTC respectively, the PSC regime continues to return impressive VIR, RTEP and IRR. In addition, the maximum financial exposure of investing in a project within the PSC regime is only 37% of the financial exposure in the JV regime. This makes investing in the PSC regime more attractive.

CAPEX +20%: An increased capital cost of $887.1 million results in a negative cash flow in the JV regime, which translates to an equally negative NPV and VIR. This makes investing in a project within the JV regime unattractive. On the contrary, investing in a project within the PSC regime is attractive given the positive cash flow and NPV, along with a VIR that is greater than 1 and an IRR that is greater than the cost of capital (that is, 10%).

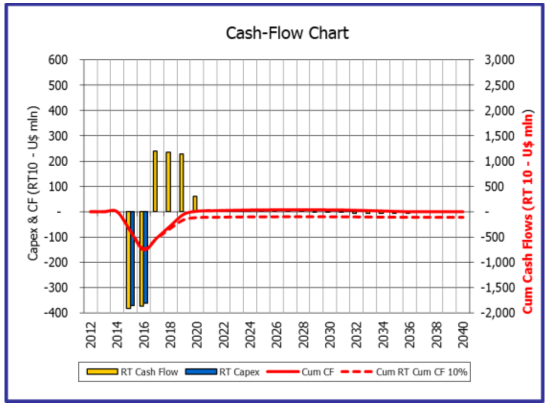
Table 7-20: Result of CAPEX Sensitivity Analysis

S/N	Description	Unit	New Comer, Poineer Status - Yes						Tax Payer, Poineer Status - No					
			CAPEX -20%		Base CAPEX		CAPEX +20%		CAPEX -20%		Base CAPEX		CAPEX +20%	
			JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC
1	Oil Cash Flow	Mln$	72.89	1,219.93	- 65.70	1,069.55	- 204.28	919.17	- 162.57	1,246.53	- 180.16	1,207.86	- 197.75	1,169.19
2	Revenue	Mln$	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83
3	Royalty	Mln$	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29
4	Govt Take	Mln$	4,078.56	2,882.98	4,066.67	2,882.90	4,054.79	2,882.81	4,314.01	2,856.38	4,181.14	2,744.58	4,048.26	2,632.79
5	Cash Surplus	Mln$	173.86	1,369.43	35.27	1,219.05	- 103.31	1,068.67	- 61.60	1,396.03	- 79.19	1,357.36	- 96.78	1,318.69
6	UDC	$/bbl	5.45	5.45	6.79	6.79	8.12	8.12	5.45	5.45	6.79	6.79	8.12	8.12
7	UOC	$/bbl	7.49	7.49	7.53	7.53	7.57	7.57	7.49	7.49	7.53	7.53	7.57	7.57
8	UTC	$/bbl	12.93	12.93	14.31	14.31	15.69	15.69	12.93	12.93	14.31	14.31	15.69	15.69
9	NPV	Mln$	173.86	1,369.43	35.27	1,219.05	- 103.31	1,068.67	- 61.60	1,396.03	- 79.19	1,357.36	- 96.78	1,318.69
10	VIR	Ratio	0.29	2.30	0.05	1.65	- 0.12	1.20	- 0.10	2.35	- 0.11	1.83	- 0.11	1.49
11	RTEP	%	9%	22%	0%	16%	N/A	11%	N/A	52%	N/A	42%	N/A	35%
12	IRR	%	12%	25%	2%	18%	N/A	14%	N/A	55%	N/A	46%	N/A	39%
13	Payout Year	Year	2025	2017	2025	2017	2025	2017	2025	2017	2025	2017	2025	2017
14	Max Exposure	Mln$	- 612.82	- 612.82	- 763.29	- 763.29	- 913.76	- 913.76	- 420.65	- 157.67	- 523.93	- 196.38	- 627.21	- 235.09
15	Breakeven Price	$/bbl	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

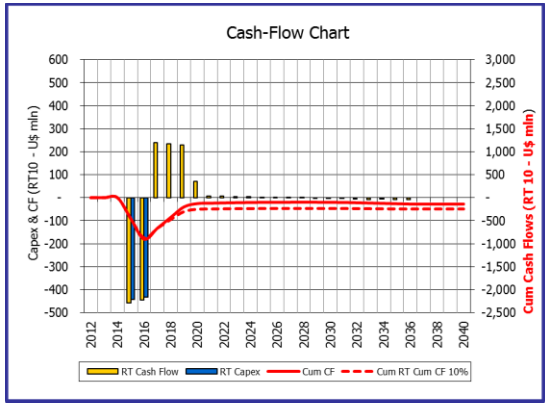
Figure 7-28: CAPEX Sensitivities: JV New Comer, Pioneer Status – Yes



CAPEX -20%

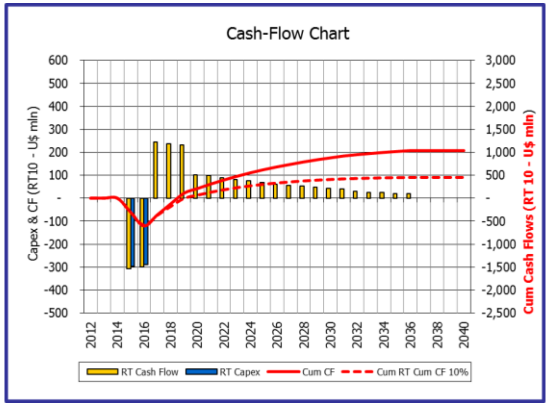


Base CAPEX

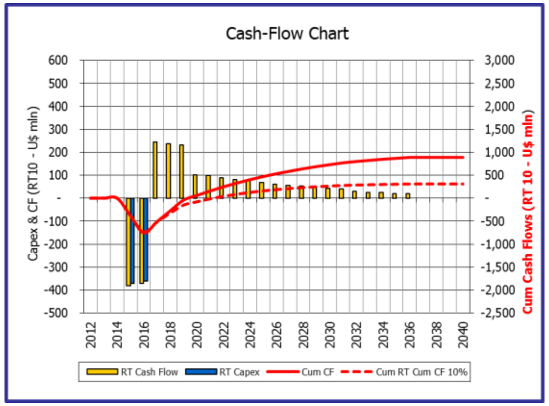


CAPEX +20%

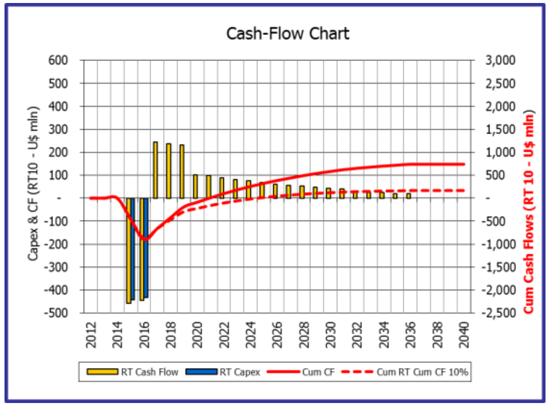
Figure 7-29: PSC New Comer, Pioneer Status – Yes



CAPEX -20%



Base CAPEX



CAPEX +20%

7.12.6 Operating Expenditure (OPEX) Sensitivities

This evaluates changes in the economic parameters that are as a result of a 20% increase/decrease in combined fixed and variable operating expenditure of oil production.

Assumptions: The following assumptions were made in carrying out the OPEX sensitivity analysis: Start year 2015; Base Case; Project 1; Inflation rate 2.5%; Discount rate 10%; Equity share 100%; Oil Price $50/bbl; Base OPEX $731.62 million.

New Comer, Pioneer Status – Yes

OPEX -20%: Reducing the operating cost by 20% brings OPEX to $585.29 million, which leads to a positive cash flow for both JV and PSC regimes. While the UDC remains unchanged, there is an 18% and 10% reduction in UOC and UTC respectively, compared to the values returned in the base case. Though the JV regime returns a positive NPV which makes investing in the project acceptable, its IRR at 7% is less than the cost of capital at 10%. Hence, investing in a project within the JV regime is not acceptable. On the other hand, carrying out a project in the PSC regime is acceptable given its positive NPV and an IRR that is higher than the discount factor.

Base OPEX: At an operating cost of $731.62 million, the JV regime returns a negative cash flow while the PSC regime returns a positive cash flow. The government’s share of revenue in the JV and PSC regimes comes to 72% and 51% respectively, causing the PSC regime to return a cash surplus that is significantly higher than what derives in the JV regime. Though both regimes return a positive NPV, only an investment in the PSC regime is considered acceptable given that its IRR is greater than the discount factor of 10%.

OPEX +20%: Increasing the operating cost by 20% brings OPEX to $877.94 million and causes a decline in the cash flow for both regimes. While the JV regime returns a negative cash flow, the positive cash flow return in the PSC regime is 14% less than what was returned in the base case. Negative NPV and VIR in the JV regime makes carrying out a project within the regime unattractive, while investing in a project within the PSC regime remains attractive given its positive NPV, VIR and an IRR that is greater than the discount factor of 10%.

Tax Payer, Pioneer Status – No

OPEX -20%: While the JV regime cash flow goes into the red, a 20% reduction in operating cost to $585.29 million results in an 11% increase in the cash flow returned within the tax payer PSC regime, as against what was reported in the new comer PSC regime. Though the NPV for both regimes return positive values, the 4% IRR for the JV regime is less than the discount factor of 10%. On the other hand, the 49% IRR in the PSC regime makes investing in a project in this regime acceptable.

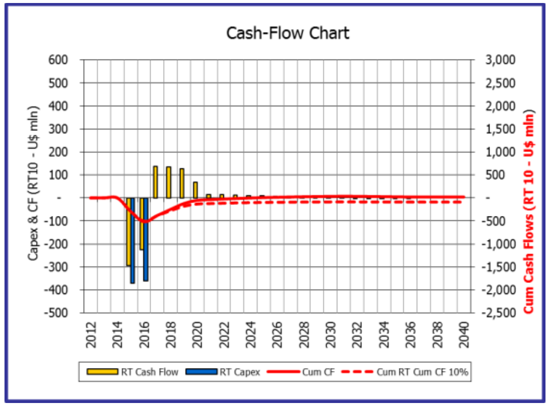
Base OPEX: With a base operating cost of $731.26 million, a negative cash flow, NPV and VIR is reported in the JV regime. While the PSC regime returns a positive cash flow, NPV and VIR, all of this makes investing in a project within this regime acceptable.

OPEX +20%: A 20% increase in operating cost to $877.94 million results in a negative cash flow in the JV regime and a positive cash flow in the PSC regime, albeit at a value that is 12% less than what was recorded in the base case. Nonetheless, the VIR, RTEP and IRR values in the tax payer PSC regime are far greater than those reported in the new comer PSC regime; this makes investment in this regime very attractive.

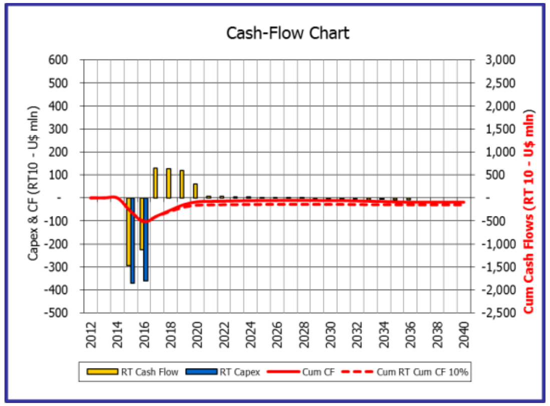
Table 7-21: Result of OPEX Sensitivity Analysis

S/N	Description	Unit	New Comer, Poineer Status - Yes						Tax Payer, Poineer Status - No					
			OPEX -20%		Base OPEX		OPEX +20%		OPEX -20%		Base OPEX		OPEX +20%	
			JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC
1	Oil Cash Flow	Mln$	81.05	1,216.71	- 65.70	1,069.55	- 212.45	922.38	- 33.62	1,354.90	- 180.16	1,207.86	- 326.70	1,060.82
2	Revenue	Mln$	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83
3	Royalty	Mln$	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29	1,106.38	1,102.29
4	Govt Take	Mln$	4,070.64	2,886.45	4,066.67	2,882.90	4,062.71	2,879.35	4,185.31	2,748.26	4,181.14	2,744.58	4,176.96	2,740.91
5	Cash Surplus	Mln$	182.02	1,366.22	35.27	1,219.05	- 111.47	1,071.89	67.35	1,504.41	- 79.19	1,357.36	- 225.72	1,210.32
6	UDC	$/bbl	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79	6.79
7	UOC	$/bbl	6.15	6.15	7.53	7.53	8.91	8.91	6.15	6.15	7.53	7.53	8.91	8.91
8	UTC	$/bbl	12.93	12.93	14.31	14.31	15.69	15.69	12.93	12.93	14.31	14.31	15.69	15.69
9	NPV	Mln$	182.02	1,366.22	35.27	1,219.05	- 111.47	1,071.89	67.35	1,504.41	- 79.19	1,357.36	- 225.72	1,210.32
10	VIR	Ratio	0.25	1.84	0.05	1.65	- 0.15	1.45	0.09	2.03	- 0.11	1.83	- 0.30	1.63
11	RTEP	%	5%	17%	0%	16%	N/A	14%	1%	45%	N/A	42%	N/A	39%
12	IRR	%	7%	20%	2%	18%	N/A	17%	4%	49%	N/A	46%	N/A	43%
13	Payout Year	Year	2022	2017	2025	2017	2032	2017	2022	2017	2025	2017	2032	2017
14	Max Exposure	Mln$	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 523.93	- 196.38	- 523.93	- 196.38	- 523.93	- 196.38
15	Breakeven Price	$/bbl	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

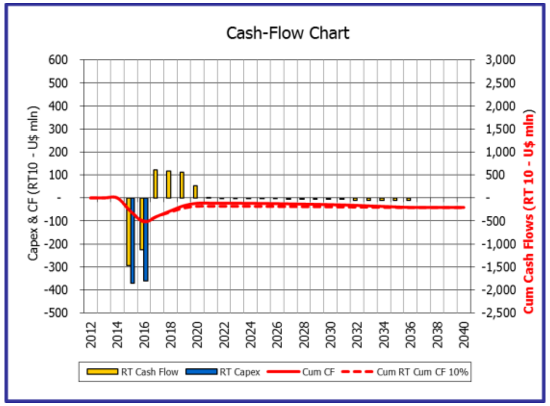
Figure 7-30: OPEX Sensitivities: JV Tax Payer, Pioneer Status – No



OPEX -20%

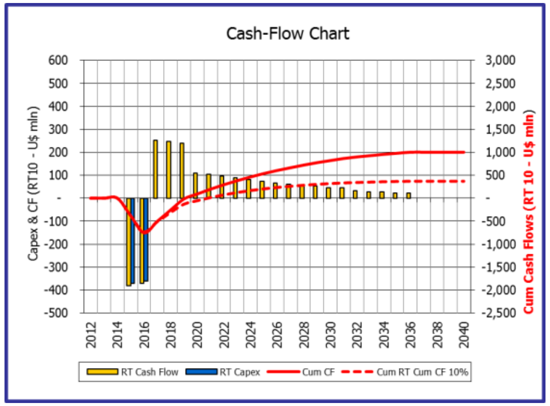


Base OPEX

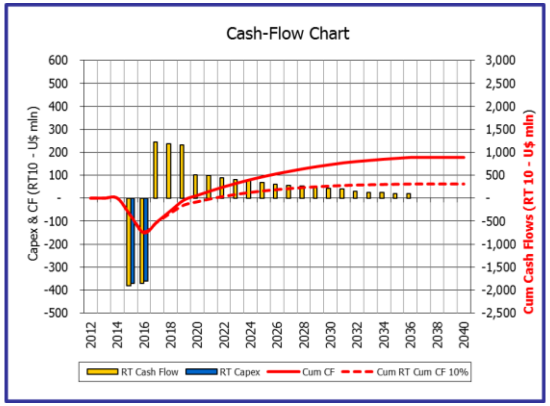


OPEX +20%

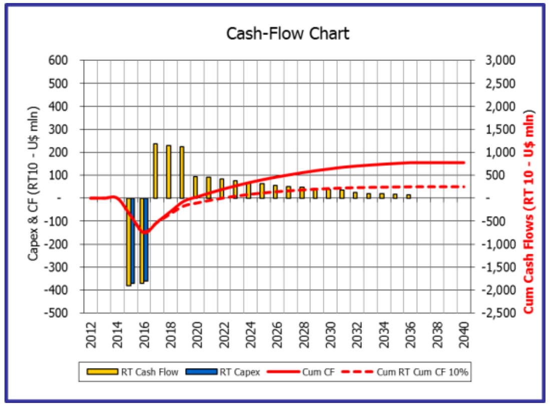
Figure 7-31: OPEX Sensitivities: PSC Tax Payer, Pioneer Status – No



OPEX -20%



Base OPEX



OPEX +20%

7.12.7 Projects Sensitivities

This evaluates changes in the economic parameters that are as a result of varying the production life of the field (named: Project 1, Project 2 & Project 3).

Assumptions: The following assumptions were made in carrying out the Projects sensitivity analysis: Start year 2015; Base Case; Inflation rate 2.5%; Discount rate 10%; Equity share 100%; Oil price $50/bbl.

New Comer, Pioneer Status – Yes

Project 1: At a field production life of 20years, cash flow from the JV regime returns a negative value while that of the PSC regime returns a positive value. The UDC, UOC and UTC in this scenario are 1%, 22% and 11% greater than what obtains in Project 2. Though both regimes have positive NPVs, the 0% RTEP and 2% IRR in the JV regime makes carrying out a project in that regime unattractive. However, the 2year payback period coupled with an IRR that is greater than the cost of capital makes investing in the PSC regime attractive.

Project 2: This field has a production life of 15years, within which both the JV and PSC regimes have positive cash flows, better revenue and reduced UDC, UOC and UTC when compared to the field with 20years production life. Furthermore, both regimes have positive NPV and VIR that makes carrying out a project in either regime acceptable; however, the JV regime has a longer payback period of 7years as against the 2year period in the PSC regime.

Project 3: Given a production life of only 10years, both JV and PSC regimes return positive cash flows and NPVs. The UDC, UOC and UTC are 0.4%, 16% and 8% less than the values that were obtained in Project 2. Investing in a project within either the JV regime or the PSC regime is acceptable, as both have impressive VIR, RTEP and IRR.

Tax Payer, Pioneer Status – No

Project 1: The field production life of 20years shows a JV regime that returns negative cash flow, NPV and VIR which makes investing in this regime unacceptable. The share of revenue to the government comes to 74% and 48% for the JV and PSC regimes respectively. This further augments a favorable PSC regime to return positive cash flow, NPV and VIR, thereby making for an attractive investment case.

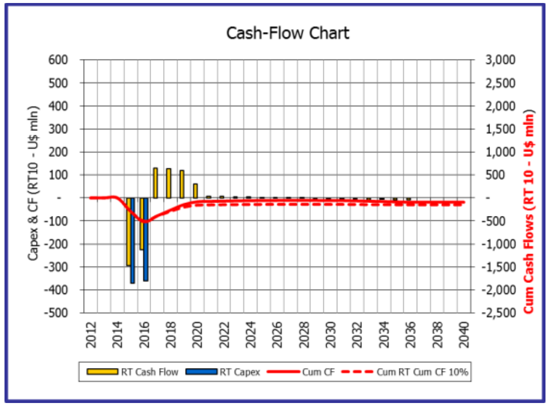
Project 2: A field with 15year production life shows the JV regime returning a negative cash flow while the PSC regime returns a positive cash flow. Though the NPV for the JV regime is in the green, its rather low VIR coupled with an IRR that is less than the cost of capital does not make for an attractive investment case. On the contrary, the PSC regime makes for an attractive investment case given its impressive VIR, RTEP and IRR.

Project 3: With a 10year production life, the JV and PSC regimes both return positive cash flows and NPVs. However, the 8% IRR for the JV regime is still lower than the 10% cost of capital, thus it makes investment unattractive when compared to the PSC regime where all the investment indicators return impressive values.

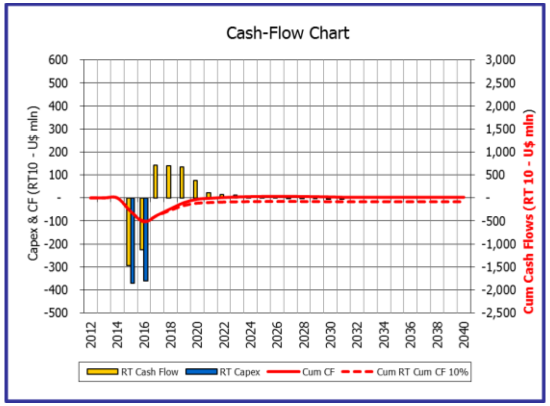
Table 7-22: Result of Projects Sensitivity Analysis

S/N	Description	Unit	New Comer, Poineer Status - Yes						Tax Payer, Poineer Status - No					
			Project 1		Project 2		Project 3		Project 1		Project 2		Project 3	
			JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC
1	Oil Cash Flow	Mln$	- 65.70	1,069.55	401.86	1,397.28	686.63	1,614.06	- 180.16	1,207.86	- 76.95	1,321.27	25.61	1,430.87
2	Revenue	Mln$	5,664.83	5,664.83	5,704.47	5,704.47	5,727.72	5,727.72	5,664.83	5,664.83	5,704.47	5,704.47	5,727.72	5,727.72
3	Royalty	Mln$	1,106.38	1,102.29	1,113.83	1,109.67	1,118.63	1,114.49	1,106.38	1,102.29	1,113.83	1,109.67	1,118.63	1,114.49
4	Govt Take	Mln$	4,066.67	2,882.90	3,751.53	2,693.97	3,593.29	2,604.05	4,181.14	2,744.58	4,230.34	2,769.98	4,254.31	2,787.24
5	Cash Surplus	Mln$	35.27	1,219.05	533.55	1,591.11	817.60	1,806.84	- 79.19	1,357.36	54.74	1,515.10	156.58	1,623.65
6	UDC	$/bbl	6.79	6.79	6.74	6.74	6.71	6.71	6.79	6.79	6.74	6.74	6.71	6.71
7	UOC	$/bbl	7.53	7.53	6.17	6.17	5.21	5.21	7.53	7.53	6.17	6.17	5.21	5.21
8	UTC	$/bbl	14.31	14.31	12.91	12.91	11.93	11.93	14.31	14.31	12.91	12.91	11.93	11.93
9	NPV	Mln$	35.27	1,219.05	533.55	1,591.11	817.60	1,806.84	- 79.19	1,357.36	54.74	1,515.10	156.58	1,623.65
10	VIR	Ratio	0.05	1.65	0.72	2.15	1.10	2.44	- 0.11	1.83	0.07	2.04	0.21	2.19
11	RTEP	%	0%	16%	19%	29%	27%	35%	N/A	42%	1%	63%	5%	73%
12	IRR	%	2%	18%	22%	32%	30%	39%	N/A	46%	3%	67%	8%	77%
13	Payout Year	Year	2025	2017	2022	2017	2017	2017	2025	2017	2022	2017	2017	2017
14	Max Exposure	Mln$	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 523.93	- 196.38	- 523.93	- 196.38	- 523.93	- 196.38
15	Breakeven Price	$/bbl	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00

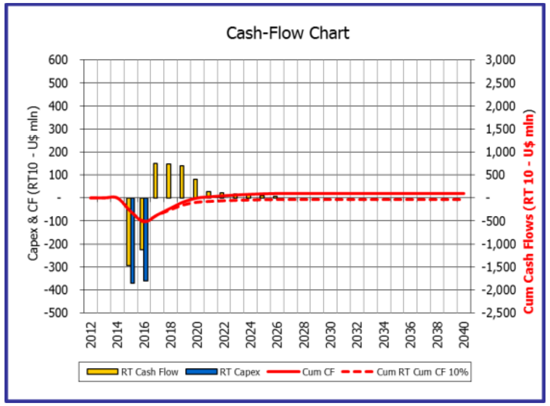
Figure 7-32: Projects Sensitivities: JV Tax Payer, Pioneer Status – No



Project 1

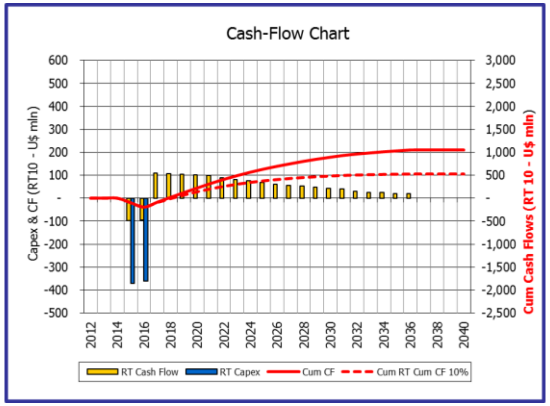


Project 2

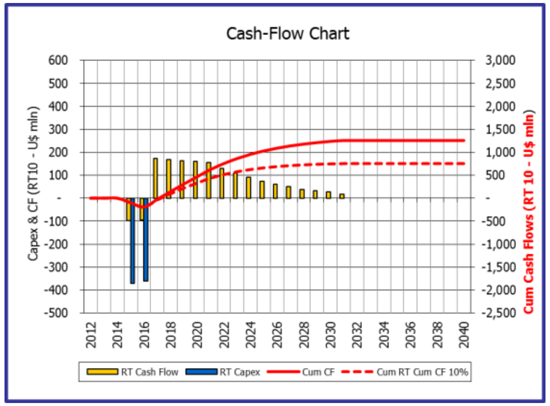


Project 3

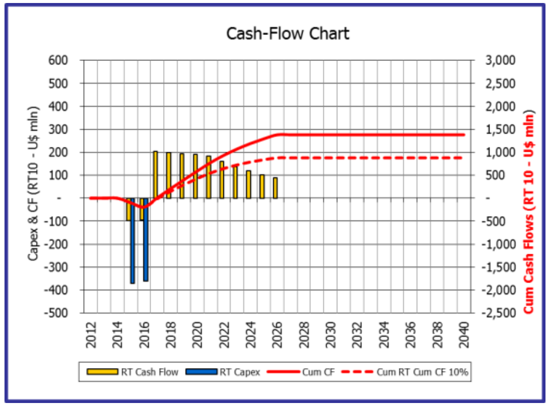
Figure 7-33: Projects Sensitivities: PSC Tax Payer, Pioneer Status – No



Project 1



Project 2



Project 3

7.12.8 Low Case, Base Case and High (LBH) Case Sensitivities

This evaluates changes in the economic parameters that are as a result of changes in scenarios, that is: Low Case, Base Case or High Case.

Assumptions: The following assumptions were made in carrying out the Low case, Base case and High case sensitivity analysis: Start year 2015; Project 1; Inflation rate 2.5%; Discount rate 10%; Equity share 100%; Oil price $50/bbl.

New Comer, Pioneer Status – Yes

Low Case: The UDC, UOC and UTC values returned in this scenario are 82%, 42% and 61% higher than the values reported in the base scenario. These high costs impact the cash flow in both regimes, with the JV returning a negative value while the PSC returned a positive value which is remarkably low. Investing in a project within either regime is not attractive given the negative indicators in the JV regime and the 6% IRR in the PSC regime (a value less than the 10% cost of capital). In addition, the breakeven price of oil for this scenario is more than double the price in the base scenario.

Base Case: Here, the cash flow for both regimes returns values that are better than what was returned in the low case analysis, though the cash flow for the JV regime continues to stay in the red. Of the two regimes, only the PSC regime returns an IRR that is greater than the cost of capital, making an investment in this regime acceptable.

High Case: Both regimes return significantly higher positive cash flows than what was seen in the other two scenarios. In addition, there is a marked reduction of 32%, 16% and 24% in the UDC, UOC and UTC of this scenario compared to the base case. Overall, investing in either regime is acceptable.

Tax Payer, Pioneer Status – No

Low Case: The JV regime returns a negative cash flow, negative NPV and government share of the revenue generated is 64%, as against the 40% in the PSC regime. However, a positive cash flow, NPV and an IRR that is greater than the cost of capital makes investing in the PSC regime attractive.

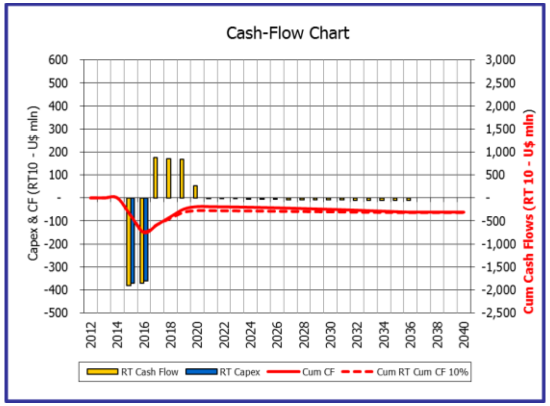
Base Case: There is a marked improvement in the cash flow for both regimes, though that of the JV regime remains in the red. Given the less than impressive investment indicators in the JV regime, it is more acceptable to make an investment in a project within the PSC regime.

High Case: The JV cash flow remains in the red, though its NPV has now turned green. Nonetheless, its IRR at 5% remains lower than the 10% cost of capital. On the contrary, the PSC regime with its positive NPV and impressive VIR, RTEP and IRR makes for an attractive investment case.

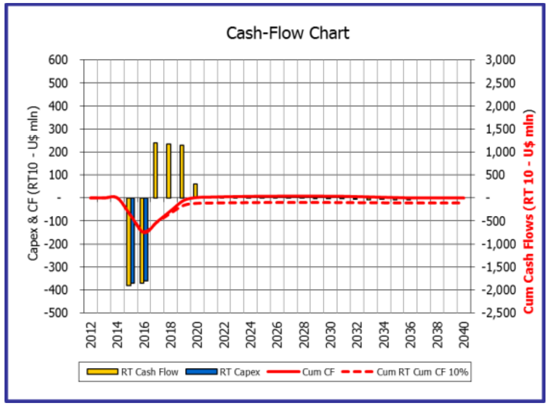
Table 7-23: Result of LBH Case and High Case Sensitivity Analysis

S/N	Description	Unit	New Comer, Poineer Status - Yes						Tax Payer, Poineer Status - No					
			Low Case		Base Case		High Case		Low Case		Base Case		High Case	
			JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC	JV	PSC
1	Oil Cash Flow	$ USD	- 389.50	145.12	- 65.70	1,069.55	265.45	2,036.33	- 321.79	390.59	- 180.16	1,207.86	- 31.19	2,067.49
2	Revenue	Mln$	3,106.19	3,106.19	5,664.83	5,664.83	8,356.75	8,356.75	3,106.19	3,106.19	5,664.83	5,664.83	8,356.75	8,356.75
3	Royalty	Mln$	606.76	604.53	1,106.38	1,102.29	1,631.94	1,625.88	606.76	604.53	1,106.38	1,102.29	1,631.94	1,625.88
4	Govt Take	Mln$	2,053.73	1,490.25	4,066.67	2,882.90	6,192.28	4,353.24	1,986.01	1,244.78	4,181.14	2,744.58	6,488.92	4,322.09
5	Cash Surplus	Mln$	- 329.02	234.46	35.27	1,219.05	406.53	2,245.57	- 261.30	479.93	- 79.19	1,357.36	109.90	2,276.72
6	UDC	$/bbl	12.37	12.37	6.79	6.79	4.60	4.60	12.37	12.37	6.79	6.79	4.60	4.60
7	UOC	$/bbl	10.69	10.69	7.53	7.53	6.31	6.31	10.69	10.69	7.53	7.53	6.31	6.31
8	UTC	$/bbl	23.06	23.06	14.31	14.31	10.91	10.91	23.06	23.06	14.31	14.31	10.91	10.91
9	NPV	Mln$	- 329.02	234.46	35.27	1,219.05	406.53	2,245.57	- 261.30	479.93	- 79.19	1,357.36	109.90	2,276.72
10	VIR	Ratio	- 0.44	0.32	0.05	1.65	0.55	3.03	- 0.35	0.65	- 0.11	1.83	0.15	3.07
11	RTEP	%	N/A	3%	0%	16%	12%	24%	N/A	26%	N/A	42%	2%	54%
12	IRR	%	N/A	6%	2%	18%	15%	27%	N/A	29%	N/A	46%	5%	58%
13	Payout Year	Year	2033	2019	2025	2017	2022	2017	2033	2019	2025	2017	2022	2017
14	Max Exposure	Mln$	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 763.29	- 523.93	- 196.38	- 523.93	- 196.38	- 523.93	- 196.38
15	Breakeven Price	$/bbl	90.00	90.00	30.00	30.00	50.00	50.00	90.00	90.00	30.00	30.00	50.00	50.00

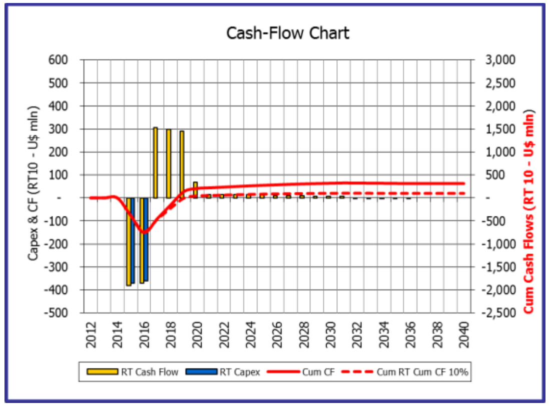
Figure 7-34: LBH Case Sensitivities: JV New Comer, Pioneer Status – Yes



Low Case

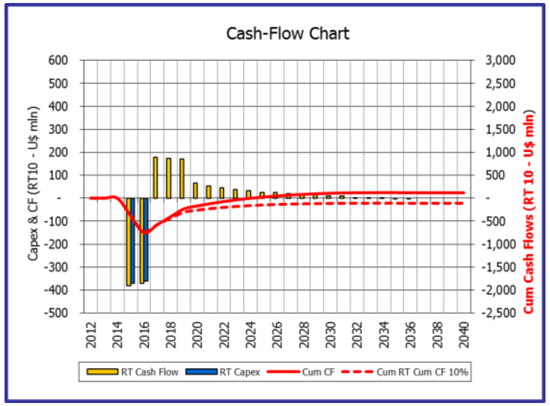


Base Case

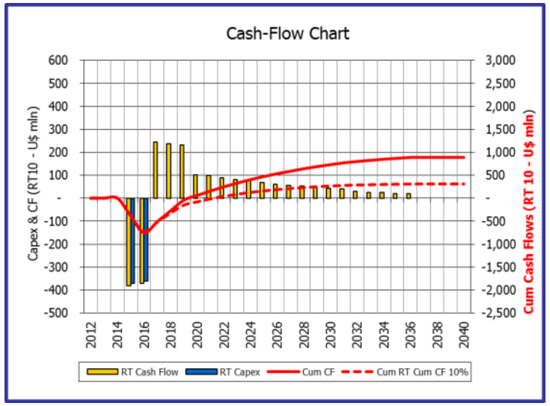


High Case

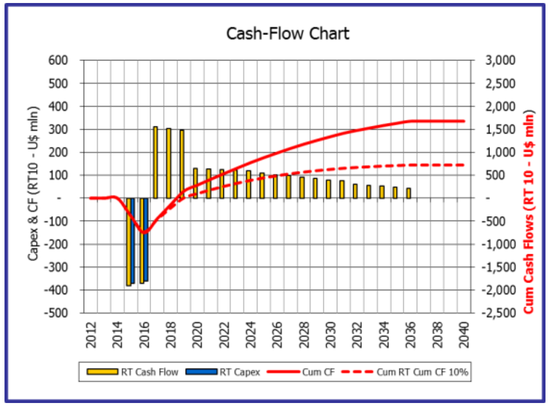
Figure 7-35: LBH Sensitivities: PSC New Comer, Pioneer Status – Yes



Low Case



Base Case



High Case

7.12.9 Sensitivities on Taxes and Modified Fiscal Regimes

From the analysis done so far, the terms of the PSC regime seem to be very attractive for investment. In recent times, the PSC has become the agreement of choice for the government, as it incurs zero cost on the exploration and production of oil; leaving the contractor to bear all the risk. However, the portion of the revenue that accrues to the government in the PSC regime is lower than what the government would have gotten in a JV regime. Hence, there arises a need to restructure the fiscal terms of both regimes such that it can attract investment and still deliver great value to the government.

Using certain assumptions, a critical evaluation of each fiscal regime (JV and PSC) was carried out and the derived results are referred to as “Current Terms (Base)” in Table 7-27 and Table 7-28 below. Thereafter, adjustments were made to production based taxes, revenue based taxes, Education and NDDC taxes, and a combination of all three categories of taxes. Results derived from these adjustments are also recorded in Table 7-27 and Table 7-28 below.

7.12.9.1 Joint Venture (JV) Fiscal Regime

General assumptions: Start year 2015; New Comer, Pioneer Status – Yes; Base case; Project 1; Inflation rate 2.5%; Discount rate 10%; Oil price $50/bbl; Gas Price $2.5/MMscf

<u>Current Terms (Base)</u>

The prevailing taxes within the JV fiscal regime, as shown in table 7-27 below, indicates that the government’s share of the total revenue generated is about 72%. This leaves the investor with only about 0.6% of the total revenue after taxes have been deducted, while the oil cash flow returns a negative value. Though the project NPV is positive, a very low VIR, an IRR that is less than the discount rate of 10%, coupled with a payback period of about 10years will not attract an investment. Going by this analysis, it can be inferred that a project within this regime will not be attractive to investors.

This, therefore, informed the decision to carry out several adjustments on the taxes with the JV fiscal regime, in a bid to see what can be done to make this regime attractive to investors.

Production-based Taxes (decreased)

This refers to the royalty levied on the production of oil and gas. Keeping other tax rates constant, the Oil Royalty and Gas Royalty rates were reduced by 5% and 2% respectively. There was a 25% reduction in the value of royalty, bringing about some difference in the revenue split between the government and the investor. The government's share of revenue came to 70%, while that of the investor came to 2%; compared to the results generated in the base case, the government's share only took a cut of about 2% while the investor's share saw a two-fold increase of its base value. In addition, the oil cash flow moved into the positive zone, albeit marginally. However, a low VIR and an IRR that is less than the discount rate continues to make this project unattractive, in spite of the adjustments done to the production-based taxes.

Revenue-based Taxes (decreased)

In this scenario, it was assumed that the Oil tax and Gas tax rates were reduced by 10% respectively, in order to see what the implication will be on the revenue split between the government and the investor. This resulted in the government's share of the revenue coming down to 66% and the investor's share climbing up to about 7%. With a positive oil cash flow, a positive NPV, an IRR that is greater than the discount factor and a payback period of only 2years, this project is likely to be attractive to would-be investors. Meanwhile, the government too does not lose too much revenue in the process.

Education Tax and Niger Delta Development Commission (NDDC) Tax

These taxes are assessed alongside the Petroleum Profit Tax (PPT) or income tax liability of a company. Education tax is assessed at 2%, while the NDDC tax is assessed at 3%. For this analysis both tax rates were set to 0% in order to view what the effect of their removal might mean for an investor. Compared to the base case, there is an improvement in the oil cash flow (though still negative), a slight decrease in government's share of the revenue but a marked 1.5 time increase in the value of the investor's revenue. However, with an IRR that is less than the discount rate and a payback period of about 10years, the removal of only the Education and NDDC tax will still not make this project attractive to investors.

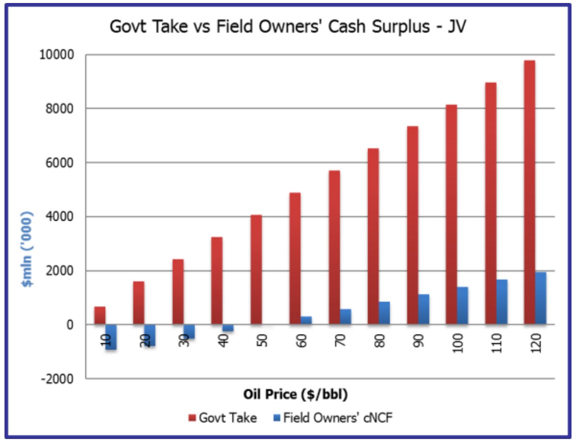
Adjusting all three categories of taxes

In order to attract investment to projects in the JV fiscal regime, this scenario was used to analyze the combined effect of adjusting all three categories of taxes at once. There is a marked increase in cash flow from Oil and the investor's share of the revenue rises to 10%, as against the less than 1% share that was observed in the base case. Government's share of the revenue drops to 63%, representing a cut of about 9% when compared to the base value. Overall, the positive NPV, 12% RTEP and an IRR that is greater than 10% makes this an attractive project for investment; while keeping in mind that the government does not compromise too much on the amount of revenue that would have accrued to it.

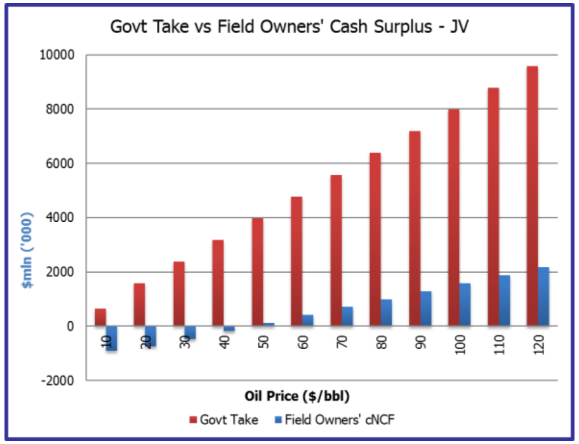
Table 7-24: Result of adjusting taxes within the JV fiscal regime

S/N	Description	Unit	Current Terms (Base) Amount	Production based Taxes (Decreased) Amount	Revenue based Taxes (Decreased) Amount	Education & NDDC tax (Adjusted) Amount	All three adjustments combined Amount
Fiscal Terms							
1	Oil_Royalty_Rate	%	20%	**15%**	20%	20%	**15%**
2	Gas_Royalty_Rate	%	7%	**5%**	7%	7%	**5%**
3	Oil_Tax_Rate	%	85%	85%	**75%**	85%	**75%**
4	Gas_Tax_Rate	%	30%	30%	**20%**	30%	**20%**
5	Education_Tax_Rate	%	2%	2%	2%	**0%**	**0%**
6	NDDC_Rate	%	3%	3%	3%	**0%**	**0%**
Economics							
1	Pre-_Tax Cash Flow	$ USD	3,041.09	3,318.20	3,041.09	3,041.09	3,318.20
2	Oil Cash Flow	$ USD	- 65.70	20.08	268.72	- 14.31	436.86
3	Gas Cash Flow	$ USD	100.97	103.75	115.81	104.73	122.97
4	Revenue	Mln$	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83
5	Royalty	Mln$	1,106.38	829.27	1,106.38	1,106.38	829.27
6	Govt. Take	Mln$	4,066.67	3,978.12	3,717.42	4,057.05	3,587.64
7	Cash Surplus	Mln$	35.27	123.83	384.53	90.42	559.83
8	UDC	$/bbl	6.79	6.79	6.79	6.79	6.79
9	UOC	$/bbl	7.53	7.53	7.53	7.11	7.11
10	UTC	$/bbl	14.31	14.31	14.31	13.89	13.89
11	UTC	$/boe	12.67	12.67	12.67	12.31	12.31
12	NPV	Mln$	35.27	123.83	384.53	90.42	559.83
13	VIR	Ratio	0.05	0.17	0.52	0.12	0.76
14	RTEP	%	0%	4%	8%	3%	12%
15	IRR	%	2%	7%	11%	6%	15%
16	Payout Year	Year	2025	2024	2017	2025	2017
17	Max. Exposure	Mln$	- 763.29	- 763.29	- 763.29	- 741.06	- 741.06

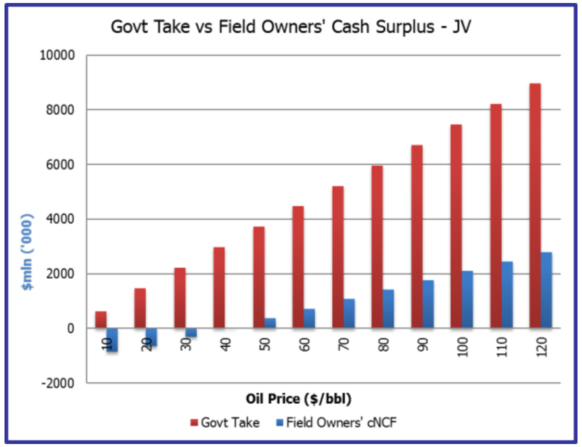
Figure 7-36: Adjusted JV taxes: Govt. Take vs. Investor's Take



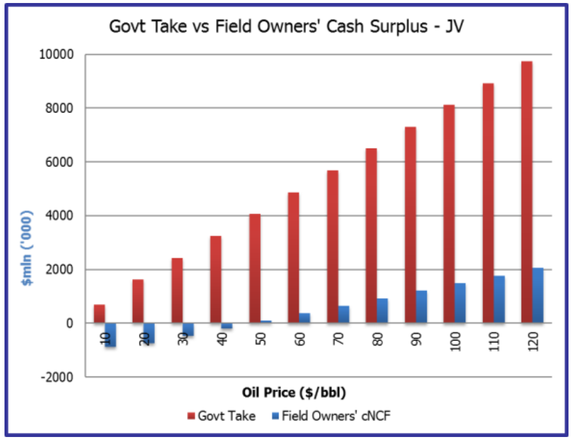
Current Terms



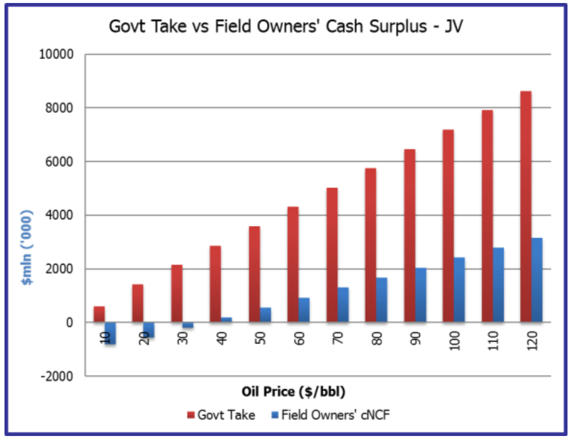
Reduce Production-based Taxes



Reduce Revenue-based Taxes

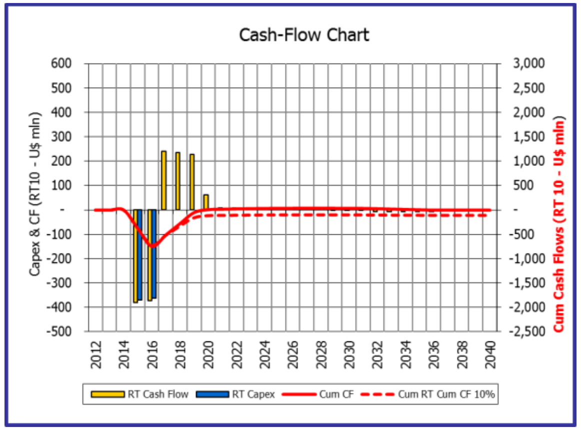


Remove Education & NDDC Taxes

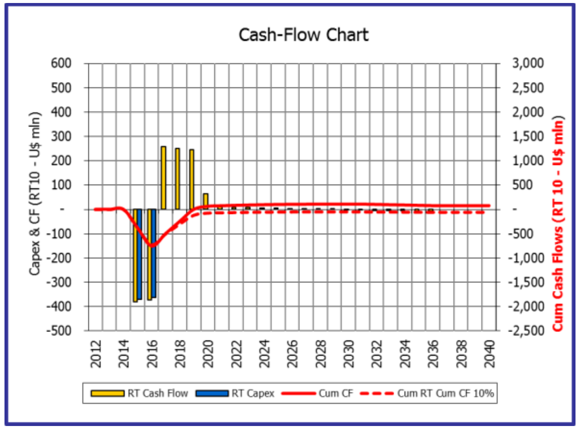


Adjust all three categories

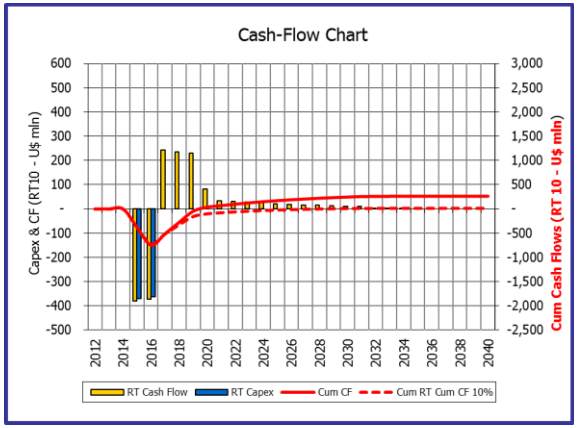
Figure 7-37: Cash-flow charts based on different JV tax adjustments



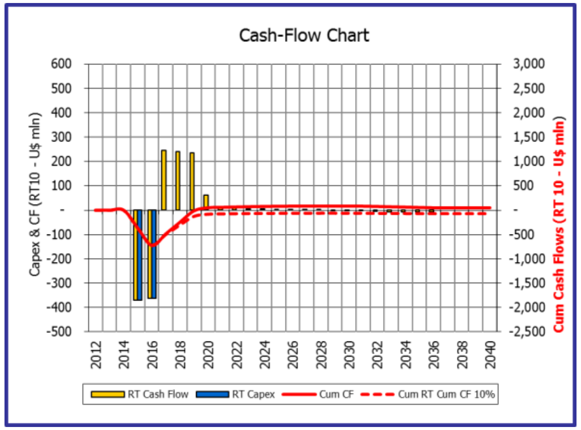
Current Terms



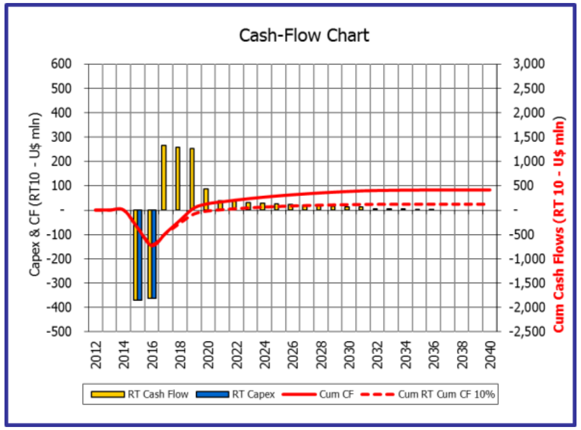
Reduce Production-based Taxes



Reduce Revenue-based Taxes



Remove Education & NDDC Taxes



Adjust all three categories

7.12.9.2 Production Sharing Contract (PSC) Fiscal Regime

General assumptions: Start year 2015; New Comer, Pioneer Status – Yes; Base case; Project 1; Inflation rate 2.5%; Discount rate 10%; Oil price $50/bbl; Gas Price $2.5/MMscf.

Current Terms (Base)

The existing terms of the PSC regime makes the government's share of the entire revenue amount to only 51%; this is less than the 72% that would otherwise have accrued to the government if it were the JV regime. In this PSC regime, the investor gets 22% of the revenue; a far cry from the 0.6% that would otherwise have accrued to the investor if it were the JV regime. A positive cash flow, positive NPV, a VIR that is greater than 1 and an IRR that is higher than the cost of capital, all make this project attractive to an investor.

However, the contention lies in the fact that the government is of the opinion that its share of the revenue generated within this regime should be higher than what currently obtains. In order to test for how the government's desire for more revenue can be accommodated, while not jeopardizing the attractiveness of the project to investors, some of the taxes in the PSC were increased as shown in Table 7-28 below and an analysis of each category is provided below.

Production-based Taxes (Increased)

This refers to the royalty levied on the production of oil and gas. Keeping other tax rates constant, the Oil Royalty and Gas Royalty rates were increased by 10% and 5% respectively. Though this adjustment brought about a marked reduction in the cash flow from oil and gas, it also made the amount to be paid as royalty increase by 50% and government's share of the revenue also rose to 57%. The investor's share of revenue, on the other hand, was reduced to 16%. Nonetheless, this project can still attract investment as its NPV remains positive, its IRR is greater than the cost of capital and its payback period is only 2years.

Revenue-based Taxes (decreased)

Here, it was assumed that the tax rate on Oil was increased by 10% and a 20% tax was introduced on Gas. This resulted in 32% and 20% reduction of the oil cash flow and the gas cash flow respectively, compared to the values that were seen in the base case. Government's share of revenue came to 57%, while that of the investor came to 15%. As revealed in the analysis done earlier, this project continues to remain attractive due to its positive NPV and an IRR that is greater than the cost of capital.

Education Tax and Niger Delta Development Commission (NDDC) Tax

These taxes are assessed alongside the Petroleum Profit Tax (PPT) or income tax liability of a company. Education tax is assessed at 2%, while the NDDC tax is assessed at 3%. For this analysis both tax rates were set to 0% in order to gauge its effect on the revenue split between the government and the investor. Result of this analysis shows that the removal of these set of taxes alone will stand to favour the investor alone. This defeats the purpose of trying to see how the government's ambition for more revenue can be accommodated while not jeopardizing the project's attractiveness.

Adjusting all three categories of taxes

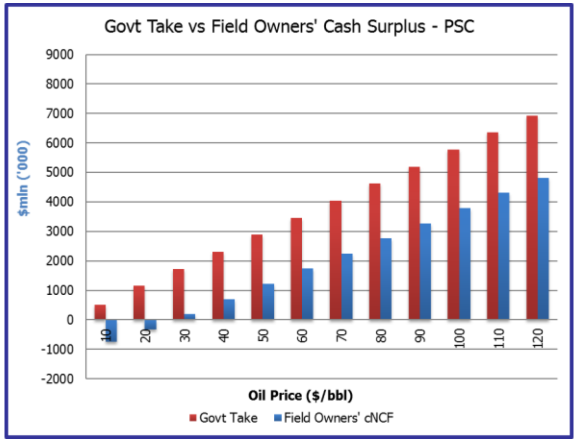
This scenario was used to analyze the combined effect of adjusting all three categories of taxes at once. Government's share of revenue increased to 62%, a marked improvement from the 51% that was recorded in the base case. The investor's take of the revenue came to 11%, though this is the lowest percentage arrived at of all the adjustments done in the PSC regime, it is still higher than what was obtainable in the JV regime even after adjusting all three categories of taxes. The project continues to be attractive given its positive NPV, VIR, IRR that is greater than the cost of capital and a payback period of only 2years.

All these analyses imply that there is room for taxes within both the JV and PSC fiscal regimes to be adjusted, such that it's a win-win situation for government and the investor.

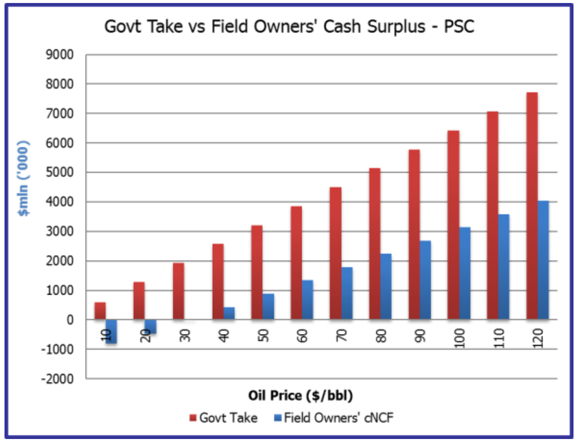
Table 7-25: Result of adjusting taxes within the PSC fiscal regime

			Current Terms (Base)	Production based Taxes (Increased)	Revenue based Taxes (Increased)	Education & NDDC tax (Adjusted)	All three adjustments combined
S/N	**Description**	**Unit**	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**
Fiscal Terms							
1	Oil_Royalty_Rate	%	20%	**30%**	20%	20%	**30%**
2	Gas_Royalty_Rate	%	5%	**10%**	5%	5%	**10%**
3	Oil_Tax_Rate	%	50%	50%	**60%**	50%	**60%**
4	Gas_Tax_Rate	%	0%	0%	**20%**	0%	**20%**
5	Education_Tax_Rate	%	2%	2%	2%	**0%**	**0%**
6	NDDC_Rate	%	3%	3%	3%	**0%**	**0%**
Economics							
1	Pre-_Tax Cash Flow	$ USD	3,045.18	2,488.93	3,045.18	3,045.18	2,488.93
2	Oil Cash Flow	$ USD	1,069.55	748.21	728.10	1,146.99	513.98
3	Gas Cash Flow	$ USD	149.50	139.48	119.00	153.71	114.79
4	Revenue	Mln$	5,664.83	5,664.83	5,664.83	5,664.83	5,664.83
5	Royalty	Mln$	1,102.29	1,658.54	1,102.29	1,102.29	1,658.54
6	Govt. Take	Mln$	2,882.90	3,214.26	3,254.85	2,846.77	3,518.70
7	Cash Surplus	Mln$	1,219.05	887.69	847.10	1,300.70	628.77
8	UDC	$/bbl	6.79	6.79	6.79	6.79	6.79
9	UOC	$/bbl	7.53	7.53	7.53	7.11	7.11
10	UTC	$/bbl	14.31	14.31	14.31	13.89	13.89
11	UTC	$/boe	12.67	12.67	12.67	12.31	12.31
12	NPV	Mln$	1,219.05	887.69	847.10	1,300.70	628.77
13	VIR	Ratio	1.65	1.20	1.14	1.76	0.85
14	RTEP	%	16%	11%	13%	17%	10%
15	IRR	%	18%	14%	15%	20%	12%
16	Payout Year	Year	2017	2017	2017	2017	2017
17	Max. Exposure	Mln$	- 763.29	- 763.29	- 763.29	- 741.06	- 741.06

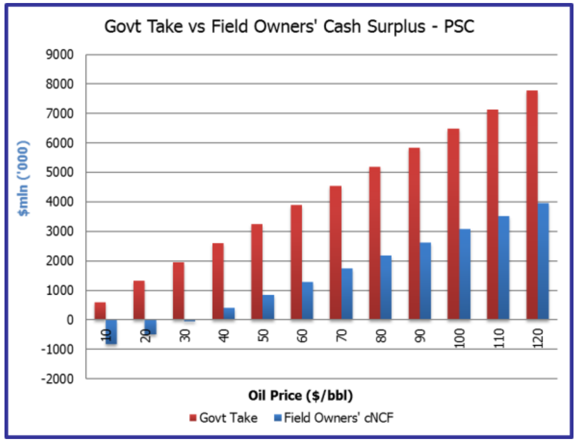
Figure 7-38: Adjusted PSC taxes: Govt. Take vs. Investor's Take



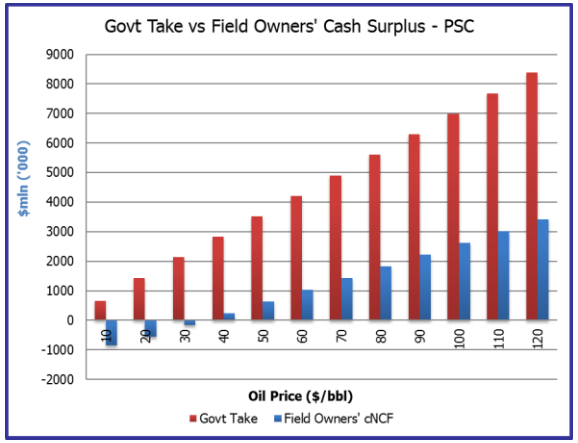
Current Terms



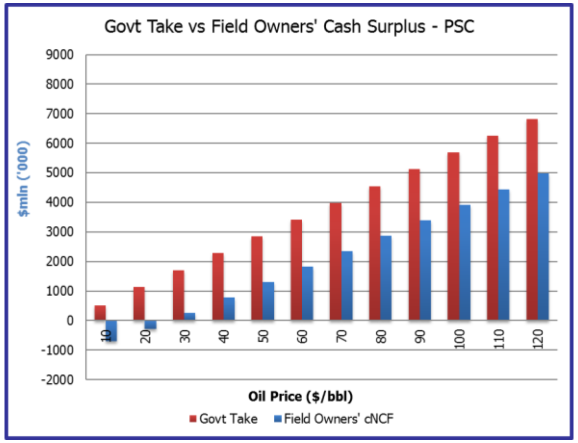
Increase Production-based Taxes



Increase Revenue-based Taxes

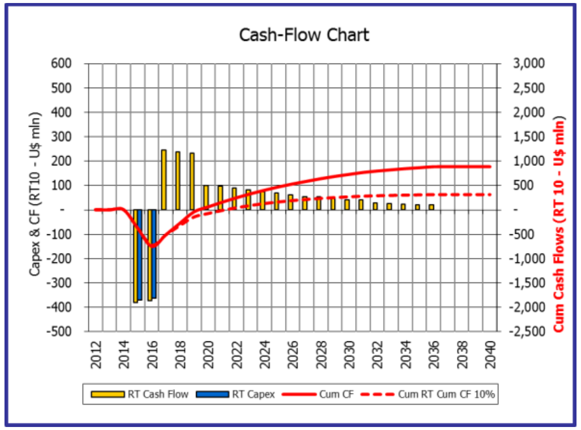


Remove Education & NDDC Taxes

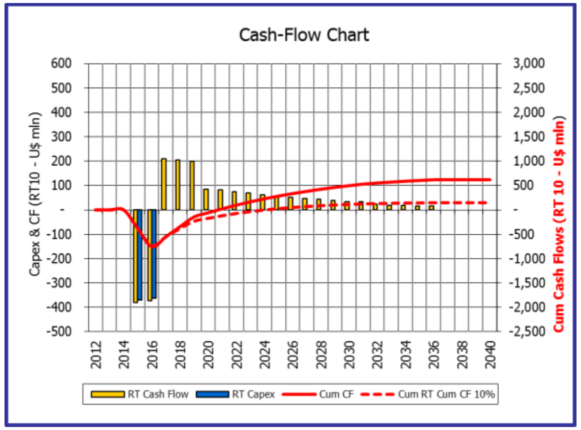


Adjust all three categories

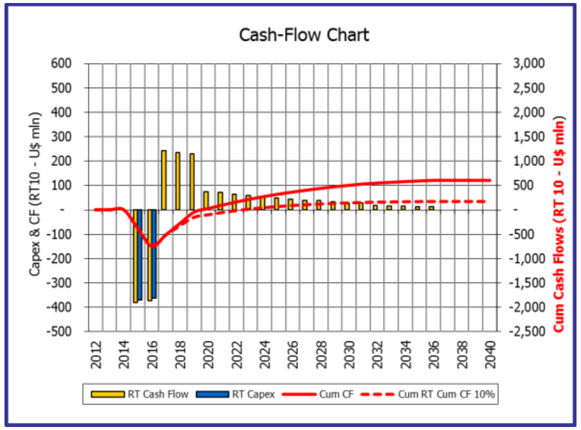
Figure 7-39: Cash-flow charts based on different PSC tax adjustments



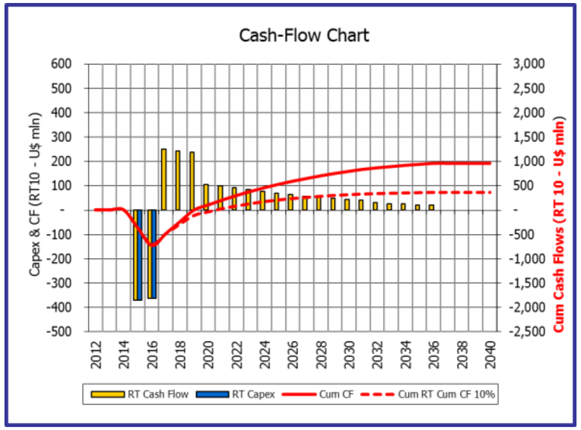
Current Terms



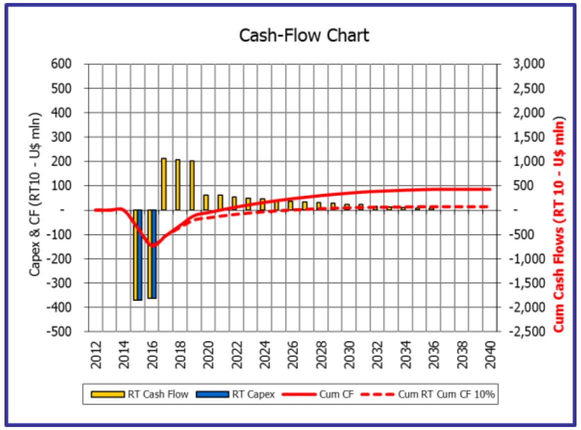
Increase Production-based Taxes



Increase Revenue-based Taxes



Remove Education & NDDC Taxes



Adjust all three categories

8 Marginal Field Sustainable Power Generation

8.1 Introduction

The purpose of power generators is to transform one energy type to electrical energy efficiently. Hence the type of energy generation technology that can be selected is largely dependent on the primary energy sources that are available at the location or point of power generation (Height, 2000). For example, where fuel gas is available a conventional energy technology type can be considered, where sunlight, water, wind is readily available, renewable energy systems can be considered as an option since it will reduce carbon emission, earn revenue through carbon taxes and sometimes a cheaper option to run the facility.

These power generators are required to keep oil and gas facilities profitable by driving and supporting the continuous uninterrupted operation of the plant with minimal planned outages. To achieve this, a key requirement is to have in place a sustainable Power Generation system that can drive pumps, compressors, electrical heating systems, light loads & HV Loads, and other electrical systems in the facility but with a very low total cost of ownership.

On energy types, apart from the conventional fossil fuel power generation system, renewable energy systems are becoming popular and cheaper on a daily basis to be used where possible, in addition to the global demand and pressure for reduced CO_2 emission due to climate change. Scenarios and sensitivities evaluation of various renewable and conventional energy type application to the Shekinah field have been carried out by this research using the Discounted Cash Flow Methodology of Techno-Economic Analysis in the UZO-MARG model. This is to show if there are opportunities for the use of renewable energy for power generation in oil and gas facilities, especially where the opportunity presents itself.

Hybrid Power Generation type, as it is often called is the combination of different Power Generation technologies or energy sources (conventional and renewable energies) for ultimate generation of power, It can also be a combination of different renewable or conventional energy types. It can be very reliable, efficient and lower total cost of ownership compared to others (Ingole and Rakhonde, 2015).

8.2 Power Generation Technologies

In these research two types of Power Generation technologies have been considered namely, Conventional (fossil fuels) and Renewable Energy Power Generation.

8.2.1 Conventional Power Generation

Conventional Power Generation types that are used in the oil and fields ranges from Gas Turbine- single cycle and combined cycle type technologies, Diesel and Gas Fired Reciprocating Engines. All these generation technologies run on fossil fuel turned into fuel gas.

8.2.1.1 Gas Turbines

The fuel gas which could be natural gas or other forms of gas burns at very high temperatures.

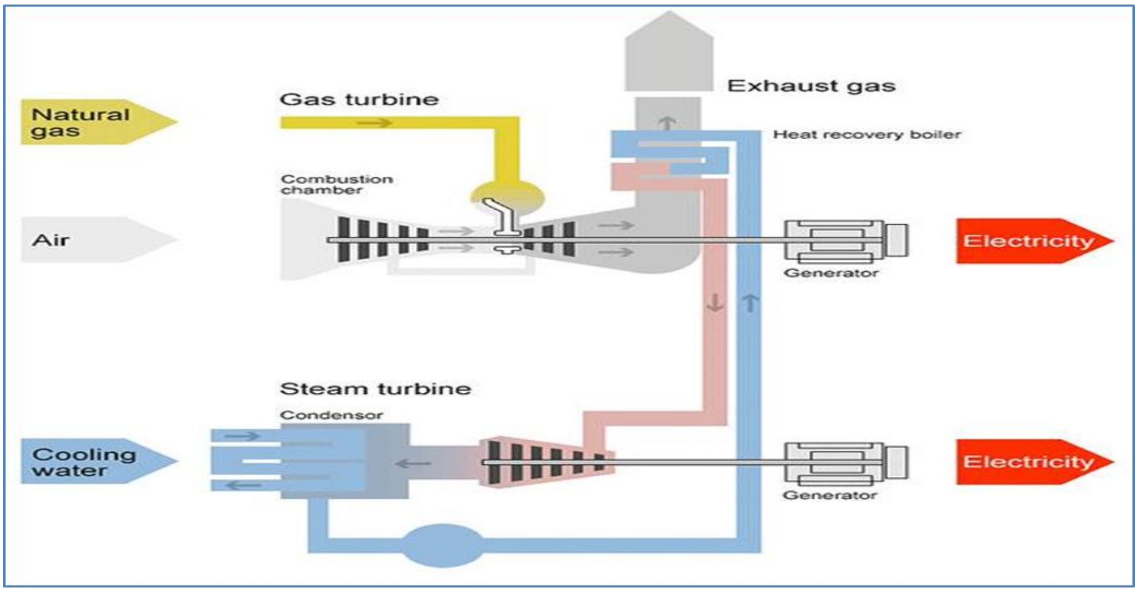


Figure 8-1: Combined Cycle Gas Turbine

This high temperature becomes an opportunity for increased power generation with the use of combined cycle system where it is used to produce steam that drives another turbine (steam turbines), which is what makes combined cycles to be a highly efficient gas turbine arrangement (Idachaba et al., 2014).

Maintenance costs for Gas Turbines can vary depending on utilisation, operating conditions of the equipment. Maintenance cost. The costs can triple for a Gas turbine that is cycled every hour versus a turbine that is operated every 1000 hours or more.

It is important to note that when Gas turbines are operated above their design and rated capacity, they attract more variable and fixed costs because of the impact on the hot gas path (Energy, 2000).

8.2.1.2 Reciprocating and fossil fuel engine

Most times, these are diesel and gas engines. Known to be highly utilised in remote locations but involves constant supply of diesels and fuel gas where possible which will need constant shipping or trucking of the diesel fuel and gas treatment (in case of a gas fired) to the location.

8.2.2 Renewable Energy Technologies

As already discussed in the literature review, shown below are renewable energy systems that can be deployed in the oil and gas industry, especially towards the development of Marginal hydrocarbon fields. They are all environmentally friendly and compliant solutions for power generation. They include:

- Solar energy (Photovoltaic systems)
- Wind energy (Wind turbines) Offshore and Onshore
- Biomass
- Biofuels
- Hydro

In the past, one major limitation with renewable energy systems range from limited capacity, high cost, low efficiency in performance due to nature's conditions i.e. wind speed, wave movement, sunlight intensity etc. However, these challenges are being overcome by innovations such as power bank to store generated energy, mostly applied to Solar system (Lloyd et al., 2000).

One important aspect of the improvements observed in the renewable energy technology space is the reduced costs of these technologies. Their costs continue to drop as the years go by due to improved innovation and cheaper manufacturing processes.

8.2.3 Hybrid Power Generation Systems

The global push for clean energy and reduction in CO_2 emission has led to the need for renewable energy. However, these renewable energies are environmentally friendly but with unpredictable availability due to varying weather and naturel conditions i.e. with a dark cloud, solar power is limited and with low wind, the wind technologies have a challenge. Though the reliability and availability of fossil fuel technologies also continues to grow, they remain environmentally unfriendly.

To solve this challenge of sustainable power generation using renewable energies, one already identified solution is the combination of the best advantages offered by the (fossil fuel) diesel technology and also renewable energy to generate power. This combination is known as the Hybrid Power Generation System figure 8.2 and 8.3.

The hybrid system can further be defined as a Power Generation systems that entail the combination of different other power generation systems, i.e. combination of conventional power & renewable energy systems or combination of different renewable energies, have proven to be extremely reliable as the demand for CO_2 reduction increases.

This is aimed at maximizing the advantages of each system. It can easily be used in remote locations and has better efficiency and availability than conventional energy resources, where the combination is purely based on renewable energy it is friendly to the environment.

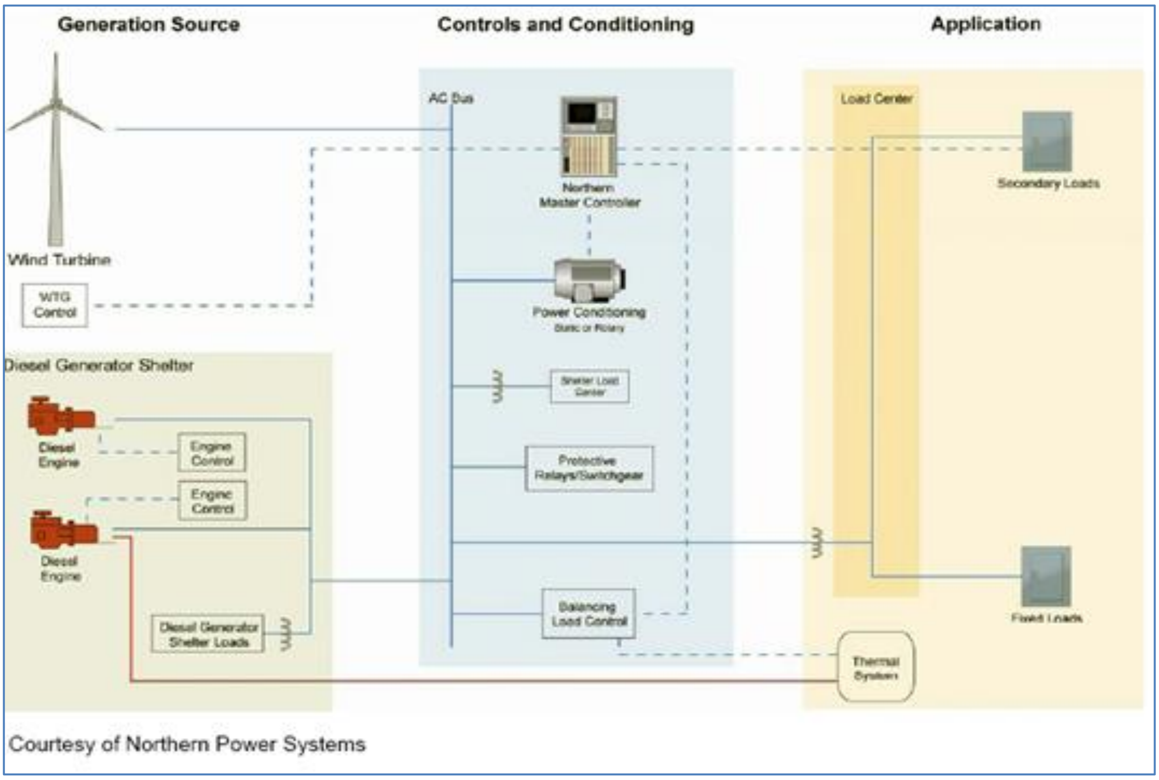


Figure 8-2: Hybrid Power Systems (Source – Northern Power Systems)

Figure 8-3: Hybrid Power Plant (Kräutle, 2016)

8.3 Case Study: Shekinah Field Power Generation

8.3.1 Technical Evaluation

Electrical Load Definition

This section details the work completed as part of the electrification study for the production flowstation. The evaluation and sizing of the Power Generator for the plant including the gas compression plant was also carried out. Shekinah field power demand was used as the basis for the study. This is irrespective of whether it will be a conventional Power Generating technology or a Renewable Energy Power Generating technology. Now that the actual size of Power required has been established, it will further help to determine if Renewable Energy Technology is a viable technology to be considered for use in both Marginal or Normal Oil and Gas development.

In carrying out the electrification study, a major consideration is noting that most of the rotating machineries are electric motor driven except for the emergency generators that are gas driven. For the electric motors, the impact of the starting currents on the electrical system was considered.

Motor starting studies were performed to assess the system response when starting one of the Export pumps (1200KW), the largest directly fed HV motors on the network. The motor was started with one generator supplying the normal running load and the future load of the system. The motor started successfully running up in approximately 4.8s. The voltage drop during starting was within acceptable range in accordance to IEC standard.

The studies carried out to determine actual size of the power generator required to operate the Shekinah Field ranges from Load Flow Studies, Fault Level Studies, and Motor Starting Studies

The calculated & specified loads are from the process simulation carried out for the Shekinah field using the UNISIM software.

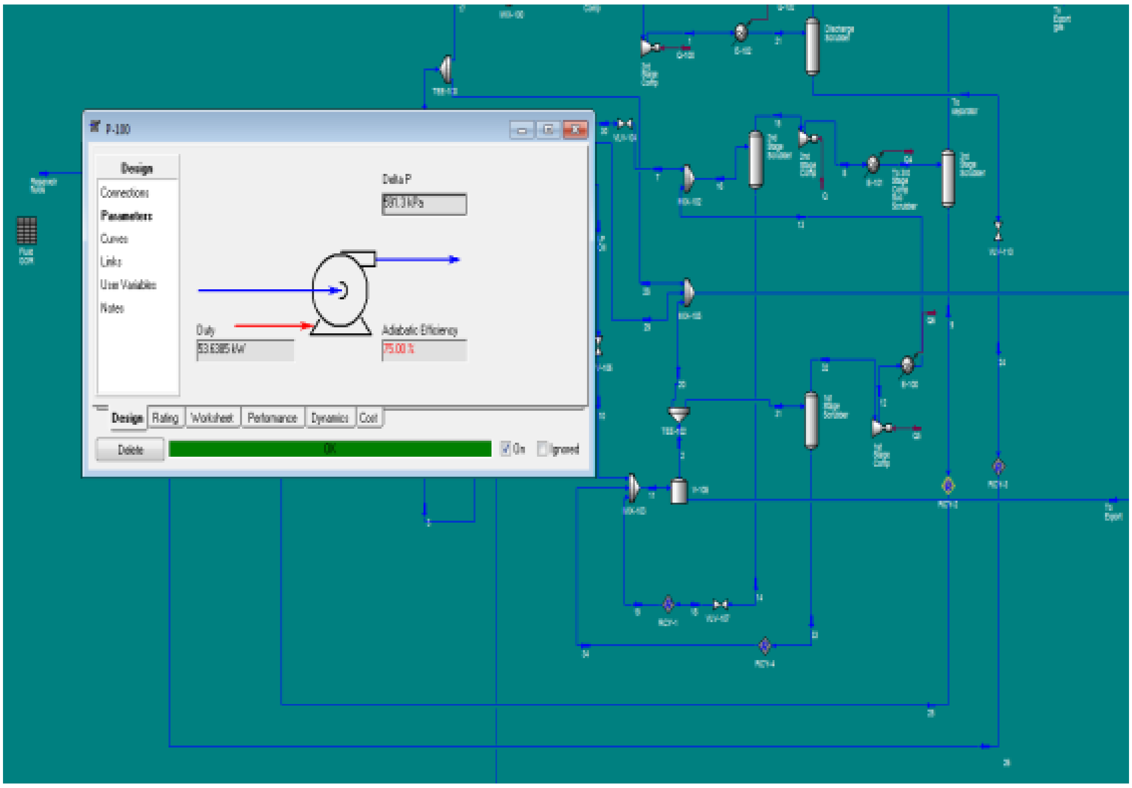


Figure 8-4: Pump UNISIM Stimulation

Premised on the loads, the electrical systems definition and requirement was done and the load lists developed as shown below in Table 8-1. In the definition of the electrical loads requirement, the following was considered.

- Identification/definition of Heavy Load (HV) Table 8-1 and the Light Loads (LV) Table 8-2 for the plant/facilities.
- Design of a Single Line Diagram for the facilities as shown in Figure 8-5 below
- Determination of plant/facility total loads for power generator sizing
- Establishment of the required maximum for power demand specification
- Emergency load determination and operating definition
- Transformer sizing

The loads are based on the peak production rate and total flowrate of gas from the gas compression plant for gathering and transporting the associated gas from the oil. The gas gathering facilities will be installed later after 5years of tax holiday for new investors.

For future growth, 10% of the total load has been added to the total sum of the load required to run the facility.

An allowance of 1 MW was allowed for electrical supply to the Field Logistic Base near the production platform. The field logistics base consists mainly of the living quarters.

Allowances have been made for lighting, HVAC, power socket outlets, battery chargers, Uninterruptible Power Supplies (UPS) and impressed cathodic protection, etc. which are not given on the equipment lists.

There are two different load levels considered in the plant simulation design in Figure 8-5. Total Load required if the concept of the Shekinah Field is to do the following: -

1. Pumping the crude 20km away from offshore to Onshore.
2. Pumping the Crude 2km from the Production Platform.

For this research, the load list below is premised on transporting the fluid for 20km. This is based on evaluating the worst case scenario in terms of load calculation for the base case production.

8.3.2 Shekinah Field – High Voltage Loads (HV)

Table 8-1: Shekinah Field Load List (HV)

Description	Vital	Essential	Absorbed Load (KW)	Motor Rating (KW)	Continuous (KW)
Export Pump A		X	1128	1200	1327
Export Pump B		X	1128	1200	1327
Booster compressor Pump		X	356	400	419
HVAC-1	X		182	200	194
HVAC-2	X		182	200	194
HVAC-3	X		182	200	194

The other concept of lifting the crude 2km away from the platform does not require much of pumping power, entire power demand will only be less by 1.33MW (Been the power requirement for the export pump-when pumping 20km away from the platform).Table 8-2: Shekinah Field Low Voltage Loads (LV)

Description	Vital	Essential	Absorbed Load (kW)	Continuous (kW)
Chemical Injection Pump A		X	1.66	1.77
Chemical Injection Pump B		X	1.66	1.77
Glycol Pump A		X	3.04	3.23
Glycol Pump B		X	3.04	3.23
Glycol Pump C		X	3.04	3.23
Glycol Pump D		X	3.04	
Glycol Pump E		X	3.04	
Export Comp Lube Oil Pump A		X	10.23	10.55
Export Comp Lube Oil Pump B		X	10.23	10.55
Corrosion Inhib Pump A		X	12.45	14.82
Corrosion Inhib Pump B		X	12.45	14.82
Corrosion Inhib Pump C		X	12.45	
Corrosion Inhib Pump D		X	12.45	
MeOH Injection Pump A		X	16.53	18.57
MeOH Injection Pump B		X	16.53	18.57
Water Wash Pump A		X	32.3	36.7
Water Wash Pump B		X	32.3	36.7
Water Wash Pump C		X	32.3	36.7
Water Wash Pump D		X	32.3	
Water Wash Pump E		X	32.3	
Air Compressor A	X		138	150
Air Compressor B	X		138	150
Plant Light (Normal)		X	130	138.3

Plant Light (Emergency)	X		70	73.68
Auxiliary Loads		X	300	326.09
Cathodic Protection			200	219.78
Power Sockets and UPS		X	70	77.78

The load calculation was split into two, the High Voltage (HV) Power requirement shown in Table 8-1 above and the Low Voltage (LV) power requirement also shown in the Table 8-2 above. The power requirement for the HV is 4567.2MVA while that of LV is 1683.6. The loads were also categorised into continuous, intermittent and standby loads. This helped to determine what the peak load during the plant operation will be.

The combination of both the High Voltage and Low Voltage power requirement analysis is shown above in Figure 8-5 below in a single line diagram. The evaluation was carried out using the Software for electrical systems study. Considering 80% efficiency, the calculated site rating for the required generator to power and drive the defined load is 9MVA pf 0.83ph 6.6kv, this amount to 9MVA x 0.83 = 7.47MW.

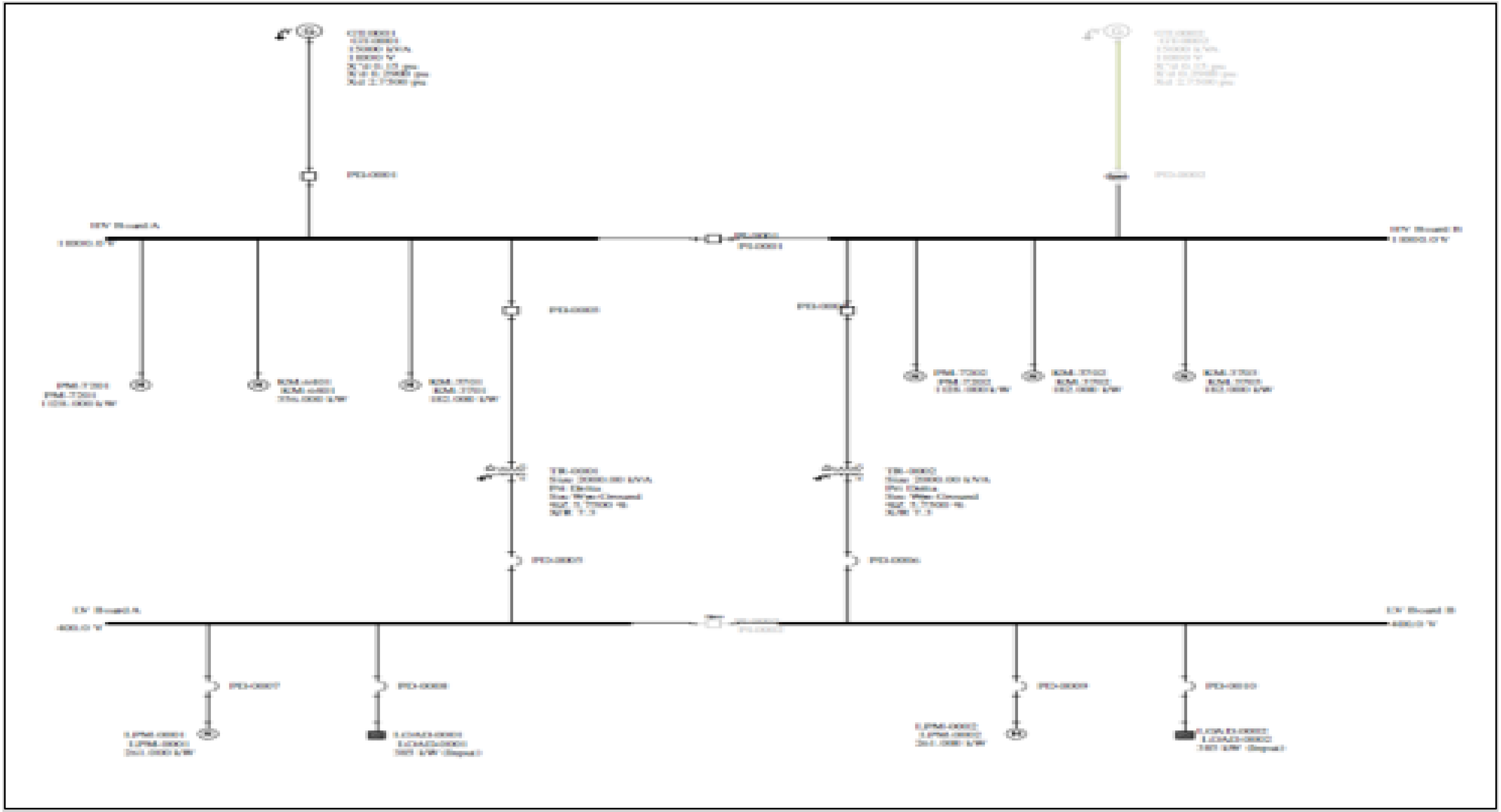


Figure 8-5: Single Line Diagram

8.3.3 Electrical Systems Studies

8.3.3.1 Load Flow Studies

The results of the load flow studies indicated that the generating capability of one 11kV gas turbine generator is sufficient to supply the demand of the flow station under peak load.

At base loading, the peak demand of the flow station system is 6.25MVA increasing to 6.9MVA when supplying the planned future load. The system operates with N+1 when at the future loading with one generator in service loaded to 55.8% of its 12MW ISO rating.

The voltage at all switchboards in the flow station is within ±5% of nominal in the investigated scenarios.

8.3.3.2 Fault Level Studies

The fault studies considered the in-service switchboards loaded for normal running load and future load. The result shows that the switchboards are sufficiently rated to withstand the expected fault current for balanced and unbalanced fault.

8.3.3.3 Motor Starting Studies

Motor starting studies were performed to assess the system response when starting one of the Export pumps (1200KW), the largest directly fed HV motors on the network.

The motor was started with one generator supplying the normal running load and the future load of the system. The motor started successfully running up in approximately 4.8s. The voltage drop during starting was within acceptable range in accordance to IEC standard.

8.3.3.4 Site Rated Power

The outcome of the power system design studies, after the Load flow studies, Fault Level studies and Motor starting current shows that the site rated power for the Shekinah field is 12MW: Figure 8-6 LV and HV load calculation analysis.

The power generation package/plant will consist of two 12MW, 11kV power generation technology.

Loads at the oil and gas production station are supplied by 11kV high voltage switchboard and a 400V low voltage switchboard fed by 2MVA 11/0.4kV step down transformers.

The operating philosophy of the generators is such that only one generator is running while the other is on standby to support N+1 philosophy.

LV		kW	kVAr	kVA	Diversity Factors		kW	kVAr						
400V	Continuous	1346.9	1010.1	1683.6	100%		1346.86	1010.14						
400V	Intermittent	0	0	0.0	30%		0.0	0.0						
					Normal running LV load		1347	1010	=	1684	kVA			
										0.80	pf			
400V	Standby	109.5	82.1	136.9	10%		11	8						
					Peak LV Load		1358	1018						
DECISION: Add 10% for future growth.					10%		136	102				**Transformer Selection**		
												kVA	**Amps**	**Load (A)**
					Firm Design Capacity at 400 V		**1494**	**1120**	**=**	**1867**	**kVA**	**2000**	**2887**	2694.84
										0.80	**pf**			
HV														
6.6kV	Continuous	3653.79	2740.34	4567.2	100%		3653.79	2740.34						
6.6kV	Intermittent	0	0	0.0	30%		0.0	0.0						
					Normal running HV Motor load		3654	2740	=	4567	kVA			
										0.80	pf			
DECISION: Feed 400V from 6.6kV.					Add Normal LV load		1347	1010						
					Normal running HV load		5001	3750	=	6251	kVA			
										0.80	pf			
400V	Standby	109.5	82.1	136.9	10%	0	11	8						
6.6kV	Standby	0	0	0	10%		0	0						
					Peak HV load		5012	3759						
DECISION: Add 10% for future growth.					10%		501	376				**Transformer Selection**		
												kVA	**Amps**	**Load (A)**
					Firm Design Capacity at 6.6 kV		**5513**	**4135**	**=**	**6891**	**kVA**	**7200**	**630**	602.82
										0.80	**pf**			
Generator Size:														
Considering 80% effieciency														
Site Rating of generator is 9MVA pf 0.8 3ph 6.6kV														

Figure 8-6: LV and HV Calculation/Analysis

8.3.4 Power Generation Cost Estimate

8.3.4.1 Conventional Power Generation

As shown in the Black, 2012 Cost Report, the cost estimate for the natural gas fired combustion turbine generator is premised on typical industrial heavy duty gas turbine, GE Frame 7FA or equivalent of the 211-net-MW size.

The cost of selective catalytic reduction technology (SCR) / carbon monoxide (CO) reactor for NOX and CO reduction is normally not included in this package.

However, the cost estimates for Gas Turbine Power Generation technology shown in Table 8-3 below includes the cost of CO_2 and NOX management/reduction/treatment facilities.

The various gas turbine generator cost estimate calculations are shown below and summarised in a table. This cost estimate becomes the power generation package costs for the Shekinah oil and gas facilities with the typical gas turbine as a base case.

Profitability charts are also generated to demonstrate the economic and financial position of the Shekinah field with the conventional Gas Turbine. Similar charts will also be provided for the for the combined Cycle Gas turbine with and without carbon capture.

Table 8-3: Gas Turbine Power Plant Costs (Black, 2012)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	671	–	–	–	–
2010	651	29.9	5.26	10,390	30
2015	651	29.9	5.26	10,390	30
2020	651	29.9	5.26	10,390	30
2025	651	29.9	5.26	10,390	30
2030	651	29.9	5.26	10,390	30
2035	651	29.9	5.26	10,390	30
2040	651	29.9	5.26	10,390	30
2045	651	29.9	5.26	10,390	30
2050	651	29.9	5.26	10,390	30

Table 8-4: Combined-Cycle Gas Turbine Power Plant Costs (Black, 2012).

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	1250	–	–	–	–
2010	1230	3.67	6.31	6,705	41
2015	1230	3.67	6.31	6,705	41
2020	1230	3.67	6.31	6,705	41
2025	1230	3.67	6.31	6,705	41
2030	1230	3.67	6.31	6,705	41
2035	1230	3.67	6.31	6,705	41
2040	1230	3.67	6.31	6,705	41
2045	1230	3.67	6.31	6,705	41
2050	1230	3.67	6.31	6,705	41

Table 8-5: Combined-Cycle Gas Turbine Power Plant Costs (Black, 2012).

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	3860	–	–	–	–
2010	-	-	-	-	-
2015	-	-	-	-	-
2020	3750	10	18.4	10,080	44
2025	3750	10	18.4	10,080	44
2030	3750	10	18.4	10,080	44
2035	3750	10	18.4	10,080	44
2040	3750	10	18.4	10,080	44
2045	3750	10	18.4	10,080	44
2050	3750	10	18.4	10,080	44

8.3.4.2 Cost Estimate Calculation with the 2 x 12MW power generation package

Apart from the manual calculation shown in Equation 8-1 below, a spreadsheet model was also developed for quick calculation of the power generation cost estimate with the costs from Black, 2012 as the premise for the estimation. This model is known as a power generator calculator. The output result page of the spreadsheet model is as shown in the Table 8-7: Power Generation Cost Calculator. This calculator is also used for estimating the costs for renewable energy technologies that have been considered in this research.

Table 8-6: For Gas Turbine (Single Shaft)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	671	–	–	–	–
2010	651	29.9	5.26	10,390	30
2015	651	29.9	5.26	10,390	30
2020	651	29.9	5.26	10,390	30

TCo= Capital Cost + Variable Cost (O&M) + Fixed Cost (O&M)

Equation 8-1

Size of Power Generator = 2X12MW

Duration of Plant = 20years

Availability = 90%

Required Gas Turbine for the Shekinah field

$651/kw x 12 x 1000kw + 29.9 x12 x20 x 365x 24 (0.9) MW + 5.26 x 12 x 1000 x 20kw

= $6.51Mln + $52.38Mln + $1.05Mln

= $69.0Mln (**For 2 power generation package = $138Mln)**

Table 8-7: Power Generation Cost Calculator

Input	**KW**	**MW**	**Hrs**	**Year**	
Coversion Factors	1000	1	24	365	
Required Gas Turbine Rating (MW)	12				
Plant Life (Production Years)	20				
Availability	0.95				
Capital Cost ($/kW)	671				
Variable Cost ($/MWh)	29.9				
Fixed O&M ($/kW-yr)	5.26				
Output					
Capital Cost (MW)	671,000	8,052,000			
Variable Cost O&M (MW)	248,828	59,718,672			
Fixed O & M (MW) For Plant Life	105,200	1,262,400			
Total Cost		**69,033,072**		**For 2**	**138,066,144**

Table 8-8: For a combined Cycle Power Generator

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	1250	–	–	–	–
2010	1230	3.67	6.31	6,705	41
2015	1230	3.67	6.31	6,705	41
2020	1230	3.67	6.31	6,705	41

Table 8-9: For Combined Cycle Gas Turbine

Input	KW	MW	Hrs	Year	
Coversion Factors	1000	1	24	365	
Required Gas Turbine Rating (MW)	12				
Plant Life (Production Years)	20				
Availability	0.95				
Capital Cost ($/kW)	1230				
Variable Cost ($/MWh)	3.67				
Fixed O&M ($/kW-yr)	6.31				
Output					
Capital Cost (MW)	1,230,000	14,760,000			
Variable Cost O&M (MW)	30,542	7,330,018			
Fixed O & M (MW) For Plant Life	126,200	1,514,400			
Total Cost		**23,604,418**		**For 2**	**47,208,835**

<u>Total cost for 2x12 Power Generator = $47.21Mln</u>

Table 8-10: Combined Cycle Gas Turbine

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)
2008	3860	–	–	–	–
2010	-	-	-	-	-
2015	-	-	-	-	-
2020	3750	10	18.4	10,080	44

Table 8-11: For Combined Cycle Gas Turbine

Input	KW	MW	Hrs	Year	
Coversion Factors	1000	1	24	365	
Required Gas Turbine Rating (MW)	12				
Plant Life (Production Years)	20				
Availability	0.95				
Capital Cost ($/kW)	3750				
Variable Cost ($/MWh)	10				
Fixed O&M ($/kW-yr)	18.4				
Output					
Capital Cost (MW)	3,750,000	45,000,000			
Variable Cost O&M (MW)	83,220	19,972,800			
Fixed O & M (MW) For Plant Life	368,000	4,416,000			
Total Cost		**69,388,800**		**For 2**	**138,777,600**

<u>Total cost for 2x12 Power Generator = $138Mln</u>

Table 8-12: Summary Table for Conventional Power Generation

Description	**Cost for 2 x 12MW ($Mln)**
Gas Turbine	138.06
Combined Cycle Gas Turbine	47.21
Combined Cycle Gas Turbine with Carbon	138.8

8.3.5 Shekinah Field Profitability with Conventional Power Generator

<u>Gas Turbine</u>

Table 8-13: Summarised table for Gas Turbine Investment Performance

Gas Turbine		**Fiscal Regime (New Comer)**			
Premise Description	**Definition**	**PSC**	**JV**	**Marginal Field Offshore**	**Marginal Field Onshore**
Project 1	Production (Duration)	20years	20years	20years	20years
Pro. Profile Likely Case	P50 Base Case	P50	P50	P50	P50
Fiscal Regime	Fiscal Regime	Yes	Yes	Yes	Yes
Nominal Discount	10%	10%	10%	10%	10%
Equity Share	100%	100%	100%	100%	100%
Inflation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Oil Price ($/bbl)	$50	50%	50%	50%	50%
Gas Price ($/Mscf)	$2.5	2.5%	2.5%	2.5%	2.5%
First Production (Year)	2017	2017	2017	2017	2017
Economic Cut off Year	2036	2036	2036	2036	2036
Break Even Price ($)	$	30	80	40	40
NPV (Net Present Value)	$	527	-150	382	321
Maximum Exposure	$	-196	-518.3	-669	-661
Value Investment Ratio	Ratio	0.75	-0.21	0.54	0.45

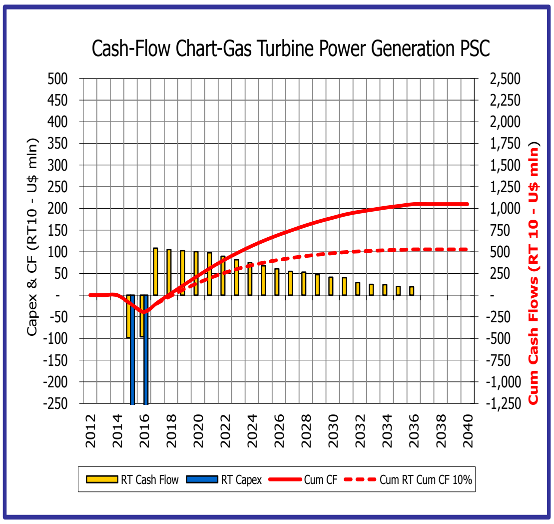


Figure 8-7: PSC Cash Flow (CF)

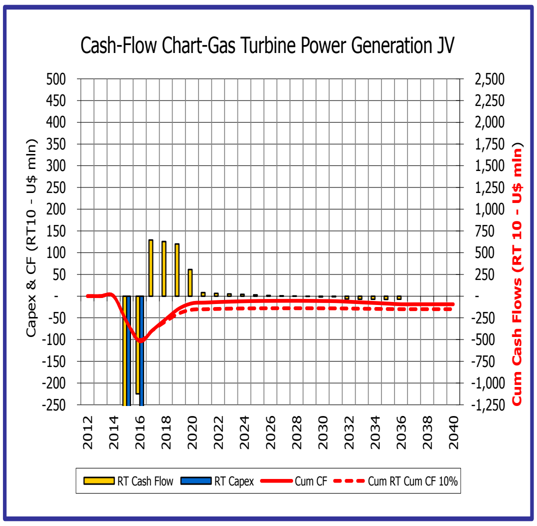


Figure 8-8: JV Cash Flow (CF)

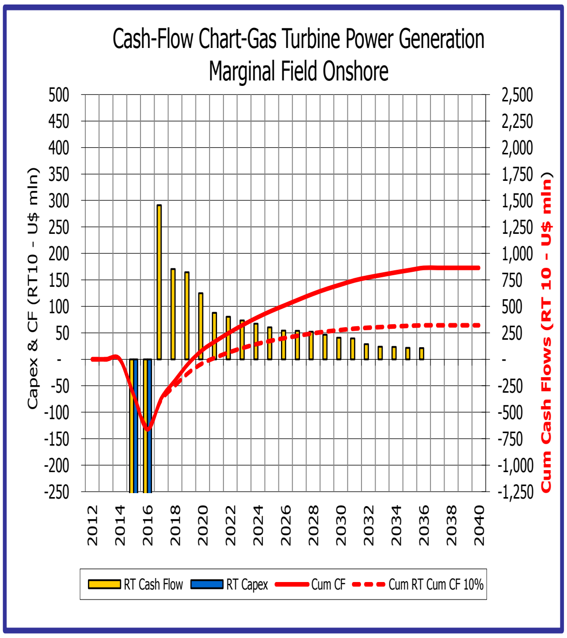


Figure 8-9: Marginal Field Onshore (CF)

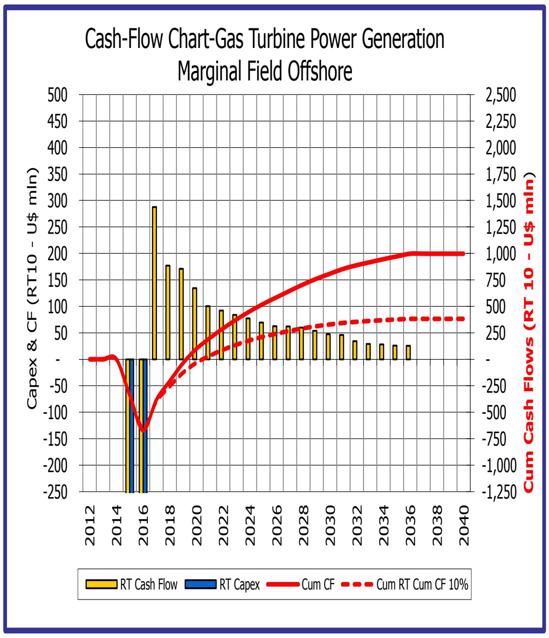


Figure 8-10: Marginal Field Offshore (CF)

Tax Payer outcome in this research has no change as the government is using the marginal field as a stimulus to activate investments and encourage local and new comers into the industry.

8.4 Renewable Power Generation Technologies

This section details out the cost estimate and performance data for renewable energy technologies that could be used to develop Marginal oil fields (Black, 2012). The interesting thing about the technologies covered here is that they may fit into the unpopular locations where Marginal Oil fields are mostly located. These technologies are not limited to the following: -

1. Biomass (standalone)
2. Geothermal (hydrothermal and enhanced geothermal systems)
3. Hydropower, Ocean energy technologies (wave and tidal)
4. Solar energy technologies (photovoltaics and concentrating solar power)
5. Wind energy technologies (onshore and offshore).

8.4.1 Biomass (standalone) Power Generating Plant

While Biomass is most likely not to be considered easily for Marginal Fields except where it already exists as a power plant and has spare power that can be purchased or used by the Marginal Oil Field operator. In this case, it has been evaluated for use in Marginal Field Development since the raw materials i.e. Biological materials required can sometimes potentially be easily found at Marginal oil field locations. For this research, a Biomass standalone plant was considered for evaluation.

A Standard Rankine cycle housing wet mechanical draft cooling tower producing 50 MW net is initially assumed for the standalone biomass generator. The cost estimate is premised on 2010 capital cost to be 3,830 $/kW, 25% and +50%.

Table 8-14: Stand-Alone Biomass Power Plant Cost (Black, 2012)

Year	Capital Cost $/kW	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Heat Rate (Btu/KWh)	Constr. Schedule (Months)
2008	4,020	–	–	–	–
2010	3,830	15	95	14,500	36
2015	3,830	15	95	14,200	36
2020	3,830	15	95	14,000	36
2025	3,830	15	95	13,800	36
2030	3,830	15	95	13,500	36
2035	3,830	15	95	13,200	36
2040	3,830	15	95	13,000	36
2045	3,830	15	95	12,800	36
2050	3,830	15	95	12,500	36

8.4.2 Geothermal Power Generating Technology

The quality of geothermal resources are site and resource specific, therefore costs of geothermal resources can vary significantly from region to region.

Table 8-15 presents cost estimate information and performance data for enhanced geothermal systems, respectively, based on these single value estimates while Table 8-16 details the CAPEX estimate breakdown.

Table 8-15: Stand-Alone Geothermal Power Plant Cost (Black, 2012)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Constr. Schedule (Months)
2008	10,400	31	0	36
2010	9,900	31	0	36
2015	9,720	31	0	36
2020	9,625	31	0	36
2025	9,438	31	0	36
2030	9,250	31	0	36
2035	8,970	31	0	36
2040	8,786	31	0	36
2045	8,600	31	0	36
2050	8,420	31	0	36

8.4.3 Hydropower Technologies

Just like geothermal technologies, the cost of hydropower technologies can be site specific, depending on the location. This fits well into power generating technologies that can be used for Marginal Fields that are located in the swamps, river and shallow offshore Marginal Field locations.

There are various options available for hydroelectric generation; repowering an existing dam or generator, or installing a new dam or generator, are options. As such, the cost estimates (Black, 2012) shown in this report are single value estimates. 2010 capital cost for a 500 MW hydropower facility was estimated at 3,500 $/kW +35%. Table 8-16 presents cost and performance data for hydroelectric power technology.

Table 8-16: Stand-Alone Hydropower Tech Power Plant Cost (Black, 2012)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Constr. Schedule (Months)
2008	3,600	–	–	–
2010	3,500	6	15	24
2015	3,500	6	15	24
2020	3,500	6	15	24
2025	3,500	6	15	24
2030	3,500	6	15	24
2035	3,500	6	15	24
2040	3,500	6	15	24
2045	3,500	6	15	24
2050	3,500	6	15	24

8.4.3.1 Solar Photovoltaic Technologies

Choosing the non-tracking utility PV with a 100 MW (DC) size as a representative case, a 35% reduction in cost was expected through 2050. Table 8-17 shows cost and performance data for a wide range of PV systems that can be used in the Oil and Gas Marginal Fields. Table 8-17 includes 2008 costs to illustrate the impact (in constant 2009 dollars) of the commodity price drop that occurred between 2008 and 2010.

For most generation technologies, the decline in commodity prices over the two years results in a 3%–5% reduction in capital cost. As seen in Table 8-17, the drop in PV technology costs is significantly greater. For PV, the 2008 costs were based on actual market data adjusted to 2009 dollars. Over these two years, PV experienced a drastic fall in costs, due to technology improvements, economies of scale, increased supply in raw materials, and other factors.

In the 2012 Cost Report by Black, estimated capital costs was 4,910 $/kW -35% and +15% without storage and 7,060 $/kW -35% and +15% with storage for

2010. There is greater downside potential than upside cost growth due to the expected emergence of new technology options.

Table 8-17: Solar Power Technology Cost (Black, 2012)

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Construction Schedule (months)
2008	7280	–	–	–
2010	7060	0	50	24
2015	6800	0	50	24
2020	6530	0	50	24
2025	5920	0	50	24
2030	5310	0	50	24
2035	4700	0	50	24
2040	4700	0	50	24
2045	4700	0	50	24
2050	4700	0	50	24

8.4.3.2 Wind Energy Technologies

Significant understanding of the details of wind cost estimates was obtained by performing 300 MW of detailed design and 300 MW of construction services in 2008. Cost estimates as shown in Table 8-17 are provided for onshore, fixed bottom offshore and floating platforms as well as offshore wind turbine installations.

8.4.3.3 Onshore Technology

The cost is estimated at a capital cost at 1,980 $/kW +25%. Cost certainty is relatively high for this maturing technology and no cost improvements were assumed through to 2050.

Table 8-18: Onshore Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kWyr)	Construction Schedule (Months)
2008	2,060	–	–	–

2010	1,980	0	60	12
2015	1,980	0	60	12
2020	1,980	0	60	12
2025	1,980	0	60	12
2030	1,980	0	60	12
2035	1,980	0	60	12
2040	1,980	0	60	12
2045	1,980	0	60	12
2050	1,980	0	60	12

8.4.3.4 Fixed Bottom Offshore Technology

Fixed bottom offshore wind projects were assumed to be at depths which allow the erection of a tall tower with a foundation that touches the sea floor.

The capital cost estimate is based on historical figures. Reviewed engineering studies and published data for European projects estimate the costs at a capital expenditure of 3,310 $/kW +35%.

Table 8-19: Fixed Bottom Offshore Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)
2008	3,410	–	–	–
2010	3,310	0	100	12
2015	3,230	0	100	12
2020	3,150	0	100	12
2025	3,070	0	100	12
2030	2,990	0	100	12
2035	2,990	0	100	12
2040	2,990	0	100	12
2045	2,990	0	100	12
2050	2,990	0	100	12

8.4.3.5 Floating Platform Offshore Technology

Floating platform offshore wind technology was assumed to be needed in water depths where a tall tower and foundation are not cost effective/feasible.

Taking a baseline data cost estimate as shown in the below table, a 2020 capital cost at 4,200 $/kW +35%. Cost improvements of 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes until 2030.

Table 8-20: Floating Platform Offshore Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)
2020	4,200	0	130	12
2025	4,090	0	130	12
2030	3,990	0	130	12
2035	3,990	0	130	12
2040	3,990	0	130	12
2045	3,990	0	130	12
2050	3,990	0	130	12

Table 8-21 below shows the model spreadsheet for the calculation of Power Generation costs for Renewable energy. The cost of $163Mln in the sample spreadsheet below is that of Wind Energy installed in a floating platform offshore. This spread sheet was used for calculating all the renewable energy costs detailed in Table 8-22. It has Biomass, Geothermal Energy, Solar, Wind-Onshore, Wind-Offshore, Wind –Offshore platform and Hydropower.

Table 8-21: Calculation of Power Generation costs for Renewable energy

Input	**KW**	**MW**	**Hrs**	**Year**	
Coversion Factors	1000	1	24	365	
Required Gas Turbine Rating (MW)	12				
Plant Life (Production Years)	20				
Availability	0.95				
Capital Cost ($/kW)	4200				
Variable Cost ($/MWh)	0				
Fixed O&M ($/kW-yr)	130				
Output					
Capital Cost (MW)	4,200,000	50,400,000			
Variable Cost O&M (MW)	-	-			
Fixed O & M (MW) For Plant Life	2,600,000	31,200,000			
Total Cost		**81,600,000**		**For 2**	**163,200,000**

Table 8-22: Renewable Energy Costs

Description	Cost for 2 x 12MW ($Mln)
Biomass	197.4
Geothermal	354.831
Hydropower	115.2
Solar	180.7
Wind- Onshore	76.320
Wind-Offshore (Fixed Bottom)	127.4
Wind- Floating Platform	163.2

All the Renewable Energy Technologies evaluated in this research will be assessed by comparative economics with each other.

8.4.4 Biomass

The Economics of BIOMASS Technology has been evaluated using the cost estimate shown in Table 8-22: Stand-Alone Biomass Power Plant Cost (Black, 2012).

The evaluation was run with a sense that what if the BIOMASS Technology is what will be deployed in the Shekinah oil and gas field for its power generator keeping in mind that the load calculation had estimated the use of (2x12MW) power generator while applying the N+1 philosophy for increased availability.

The production profile remains the same for the Shekinah field and the electrical load calculation as shown in Table 8-22 remains the basis for the calculation.

This was not run in Isolation of all the required factors like depreciation etc necessary for a robust economic analysis. Below shows the outcome of the profitability factors for BIOMASS Technology.

The cost estimate used for this analysis is as shown in the above table Summary Costs of Renewable Energy. For BIOMASS the cost is $197.4Mln for (2x12MW) power generation package as calculated.

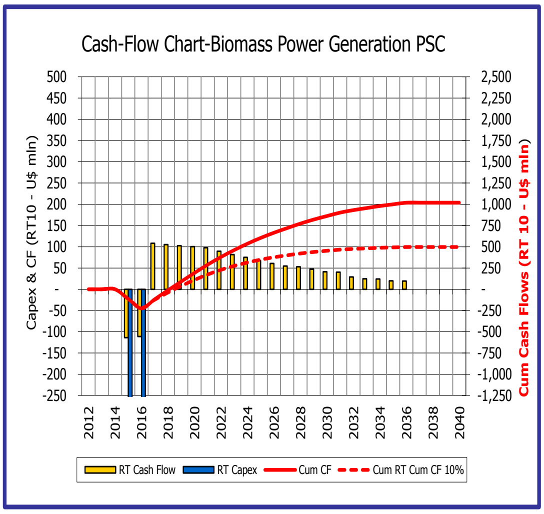
8.4.5 Biomass Sensitivity Analysis

Table 8-23: Economic Analysis Result of BIOMASS

Biomass		Fiscal Regime (NewComer)			
Premise Description	**Definition**	**PSC**	**JV**	**Marginal Field Offshore**	**Marginal Field Onshore**
Project 1	Production (Duration)	20years	20years	20years	20years
Pro. Profile Likely Case	P50 Base Case	P50	P50	P50	P50
Fiscal Regime	Fiscal Regime	Yes	Yes	Yes	Yes
Nominal Discount	10%	10%	10%	10%	10%
Equity Share	100%	100%	100%	100%	100%
Inflation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Oil Price ($/bbl)	$50	$50	$50	$50	$50
Gas Price ($/Mscf)	$2.5	$2.5	$2.5	$2.5	$2.5
Frst Production (Year)	2017	2017	2017	2017	2017
Economic Cut off Year	2036	2036	2036	2036	2036
Break Even Price ($)	$	30	90	40	40
NPV (Net Present Value)	$	497	-179	323.5	268
Maximum Exposure	$	-224	-600	-776.5	-766
Value Investment Ratio	Ratio	0.61	-0.22	0.39	0.33

The economic analysis was carried out on four different fiscal regimes, Production Sharing Contract (PSC), Joint Venture (JV), Marginal Field Offshore, and Marginal Field Onshore. The Net Present Value, Value Investment Ratio, Maximum exposure and the respective Breakeven Price is shown in Table 8-23 above.

One thing that is very evident is the high project maximum exposure as a result of the BIOMASS Technology deployment in the Marginal oil and gas field. It ranges from PSC ($222 Mln), JV ($600 Mln), Marginal Field Offshore ($776.5Mln), and Marginal Field Onshore ($766). The exposure has to do with how much will be lost if at any time the investors stops the project.



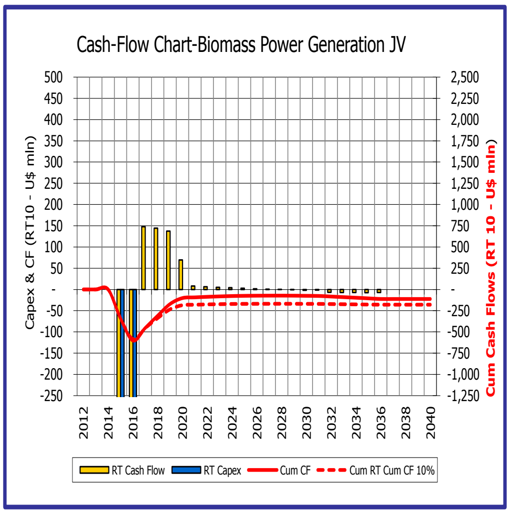
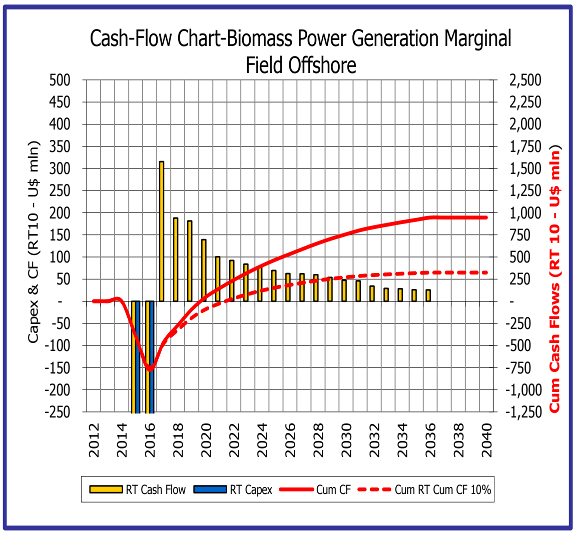


Figure 8-11: Cash Flow (PSC)

Figure 8-12: Cash Flow (JV)



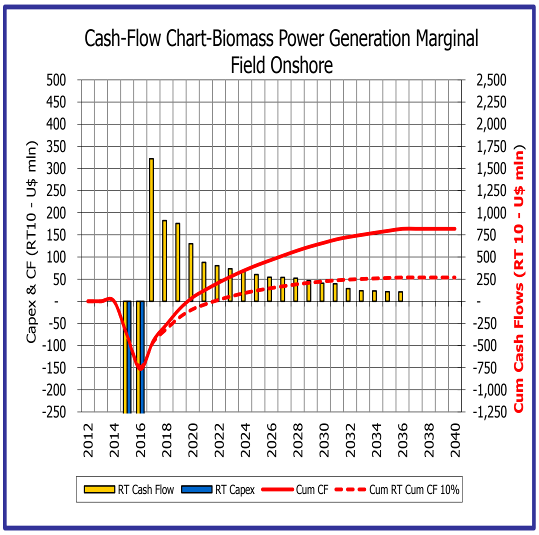


Figure 8-13: Cash Flow (Offshore)

Figure 8-14: Cash Flow (Onshore)

8.4.6 Hydropower

The Economics of Hydropower Technology has been evaluated using the cost estimate shown in Table 8-22: Stand-Alone Biomass Power Plant Cost (Black, 2012).

Hydropower has been assumed to be installed in this marginal field for a power generation of (2x12MW) power generator while applying the N+1 philosophy for increased availability. The production profile for the Shekinah Marginal Field still remains unchanged and the electrical load requirement is also unchanged.

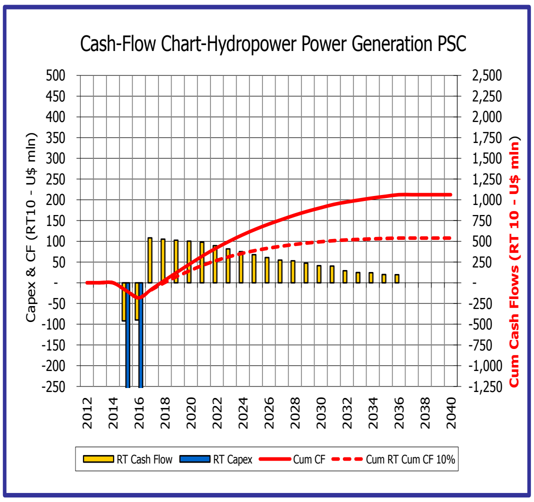
The cost of the hydropower was used in the model calculation sheet as the basis for the economic analysis for this scenario. Cost is shown in the facilities power generation package with all other factors such as the depreciation rates remaining the same.

It is important to note that the costs of Hydropower is most times lower than that of conventional energy, but the challenge remains the opportunity to have adequate water resources and the required environment to have it installed. For this scenario the cost estimate used is $115.2Mln for (2x12MW) power generation package (see Table 8-22).

8.4.7 Hydropower Sensitivity Analysis

Table 8-24: Summary Costs of Renewable Energy

Gas Turbine		Fiscal Regime (New Comer)			
Premise Description	**Definition**	**PSC**	**JV**	**Marginal Field Offshore**	**Marginal Field Onshore**
Project 1	Production (Duration)	20years	20years	20years	20years
Pro. Profile Likely Case	P50 Base Case	P50	P50	P50	P50
Fiscal Regime	Fiscal Regime	Yes	Yes	Yes	Yes
Nominal Discount	10%	10%	10%	10%	10%
Equity Share	100%	100%	100%	100%	100%
Inflation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Oil Price ($/bbl)	$50	50%	50%	50%	50%
Gas Price ($/Mscf)	$2.5	2.5%	2.5%	2.5%	2.5%
First Production (Year)	2017	2017	2017	2017	2017
Economic Cut off Year	2036	2036	2036	2036	2036
Break Even Price ($)	$	30	80	30	40
NPV (Net Present Value)	$	538	-138.6	404	341
Maximum Exposure	$	-184	-486	-628	-620
Value Investment Ratio	Ratio	0.81	-0.21	0.61	0.51



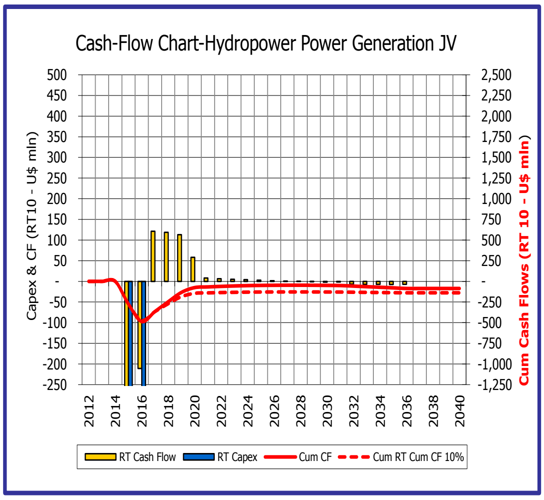
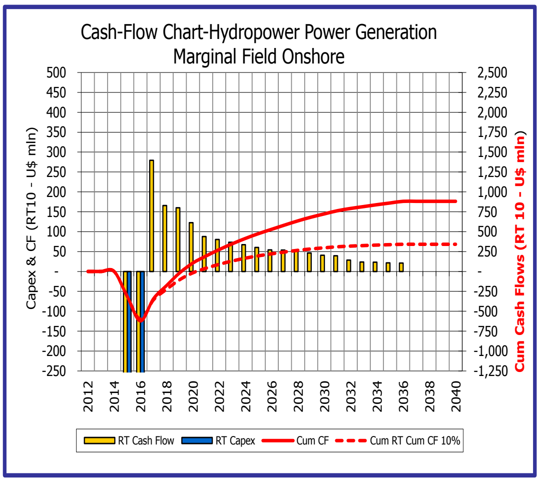


Figure 8-15: Hydropower (PSC)

Figure 8-16: Hydropower (JV)



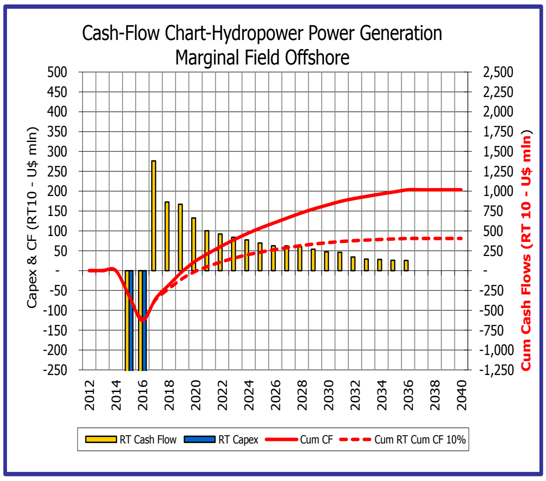


Figure 8-17: Hydropower (Onshore)

Figure 8-18: Hydropower (Offshore)

Figures 8-14 to 8-17 shows the fiscal regimes for the PSC, JV, Marginal Field Onshore and Marginal Field Offshore. The exposures still show clearly that the JV is more expensive to deploy this renewable energy.

One thing that is very evident is the high project maximum exposure as a result of the BIOMASS Technology deployment in the Marginal oil and gas field.The exposure has to do with how much will be lost if at any time the investors stops the project.

8.4.8 Solar Power

The Economics of Solar Power Technology has been evaluated using the cost estimate shown in Table 8-22: Stand-Alone Biomass Power Plant Cost (Black, 2012).

The evaluation was run with a sense that what if the BIOMASS Technology is what will be deployed in the Shekinah oil and gas field for its power generator keeping in mind that the load calculation had estimated the use of (2x12MW) power generator while applying the N+1 philosophy for increased availability.

The production profile remains the same for the Shekinah field and the electrical load calculation as shown in Table 8-21 remains the basis for the calculation.

This was not run in Isolation of all the required factors like depreciation etc necessary for a robust economic analysis. Below shows the outcome of the profitability factors for BIOMASS Technology.

The cost estimate used for this analysis is as shown in the above Table 8-22 For BIOMASS the costs is $197.4Mln for (2x12MW) power generation package as calculated.

8.4.9 Solar Power Sensitivity Analysis

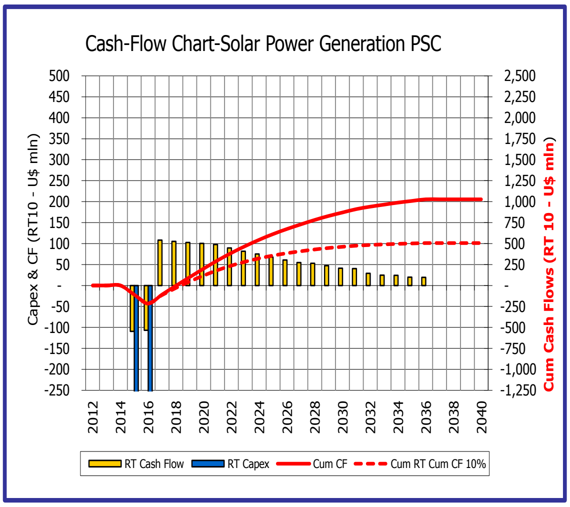


Figure 8-19: Solar (PSC)

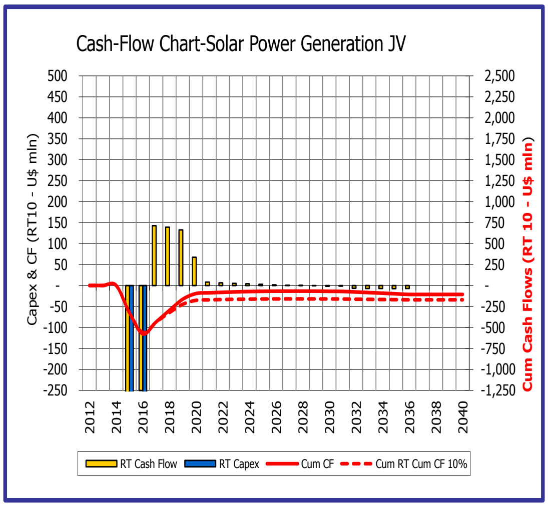
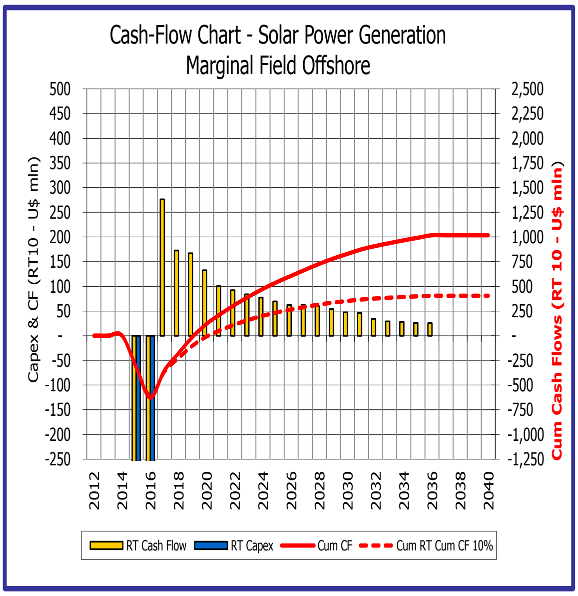


Figure 8-20: Solar (JV)



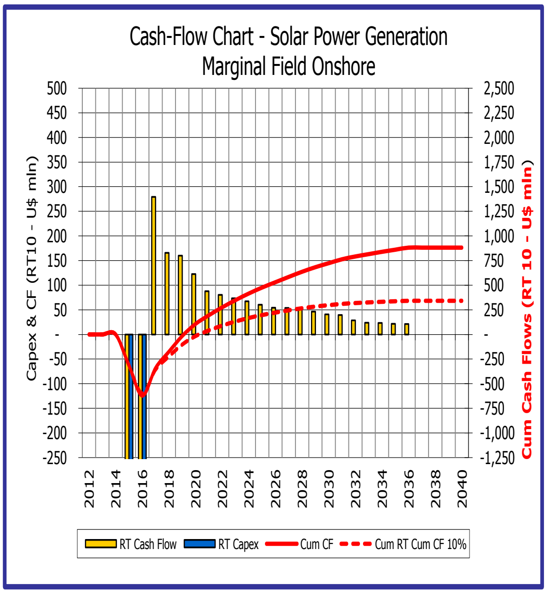


Figure 8-21: Solar (Offshore)

Figure 8-22: Solar (Onshore)

The economic analysis was carried out under four different fiscal regimes, Production Sharing Contract (PSC), Joint Venture (JV), Marginal Field Offshore, Marginal Field Onshore. The Net Present Value, Value Investment Ratio, Maximum exposure and the respective Breakeven Price is shown in the above Table 8-24.

8.4.10 Wind-Onshore

The Economics of BIOMASS Technology has been evaluated using the cost estimate shown in Table 8-22: Stand-Alone Biomass Power Plant Cost (Black, 2012).

The evaluation was run with a sense that what if the BIOMASS Technology is what will be deployed in the Shekinah oil and gas field for its power generator keeping in mind that the load calculation had estimated the use of (2x12MW) power generator while applying the N+1 philosophy for increased availability.

The production profile remains the same for the Shekinah field and the electrical load calculation as shown in Table 8-21 remains the basis for the calculation.

This was not run in Isolation of all the required factors like depreciation etc necessary for a robust economic analysis. Below shows the outcome of the profitability factors for BIOMASS Technology.

The cost estimate used for this analysis is as shown in table 8-22 above. For BIOMASS the cost is $197.4Mln for (2x12MW) power generation package as calculated.

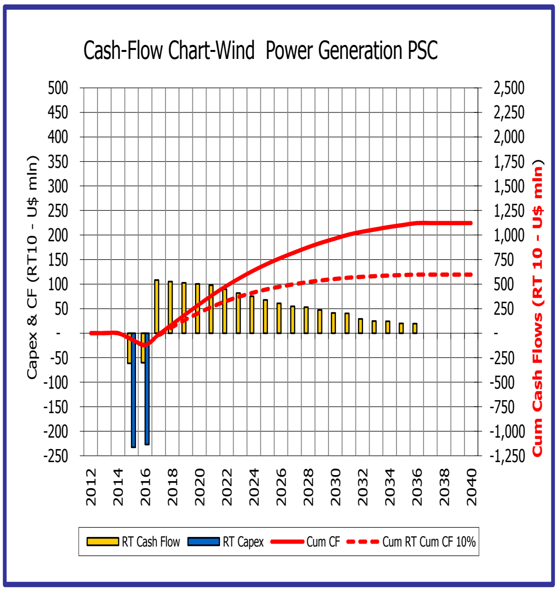


Figure 8-23: Wind (PSC)

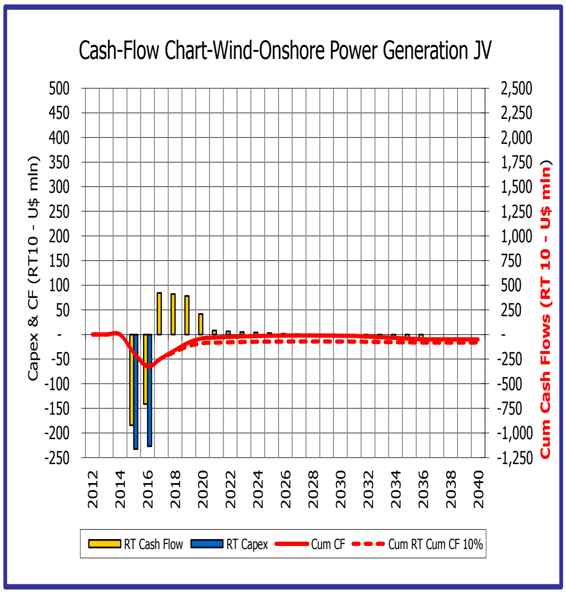


Figure 8-24: Wind (JV)

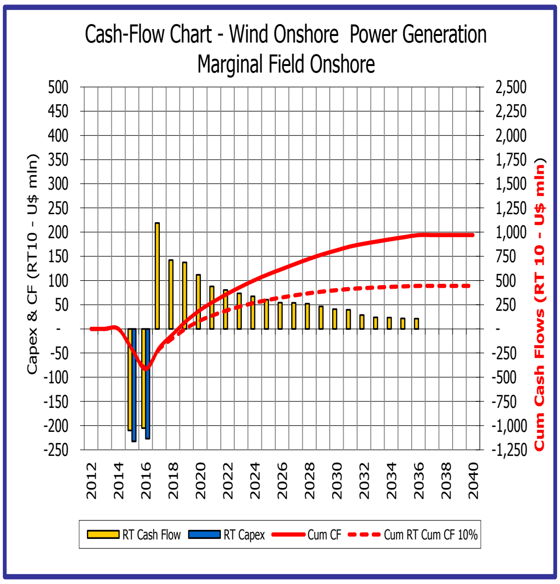


Figure 8-25: Wind (Onshore)

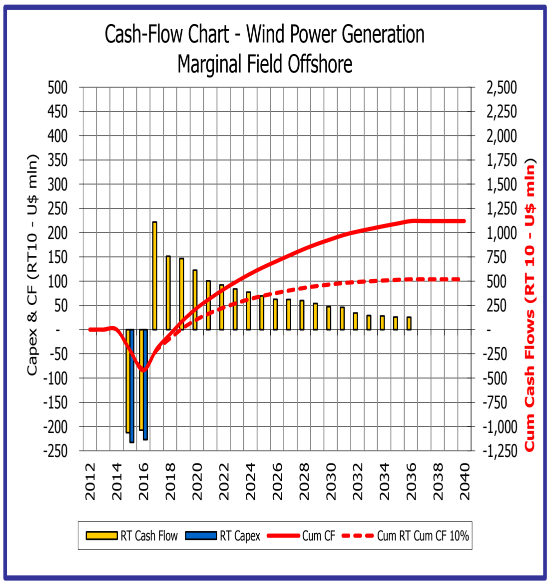


Figure 8-26: Wind (Offshore)

The Wind-Onshore (fixed Bottom) and Wind- floating platform have not been considered.

The economic analysis was carried out under four different fiscal regimes, Production Sharing Contract (PSC), Joint Venture (JV), Marginal Field Offshore, Marginal Field Onshore. The Net Present Value, Value Investment Ratio, Maximum exposure and the respective Breakeven Price is shown in the above Table 8-24.

8.4.11 Hybrid System Power Generation

This section analyses two different combinations of hybrid power system for supplying electricity to the oil and gas production facility. The hybrid system consists of renewable energy (solar photovoltaic cells & wind- energy system).

These Hybrid systems consist of the combination of two or more different options power generation systems integrated together. For the purpose of this research, the following combinations have been considered.

1. All Renewable Technology Combination (Wind Onshore and Solar Energy Technology)
2. Renewable Energy and Conventional Energy (Wind Onshore Energy and Conventional Gas Turbine)

The main power source in this scenario is the Renewable Energy which is heavily controlled by nature depending on the renewable energy type.

The summarised costs table for the different Hybrid system combination is detailed below in Table 8-25.

The sizing of the different renewable energy sources leads to different costs as shown in the below table. This power is calculated based on total cost and generating units required per annum. With respect to a typical combination of Wind and Solar power generation system, the energy produced profile is shown in Figure 8-27 below. This depends a lot on the environmental conditions like wind, sunlight etc.

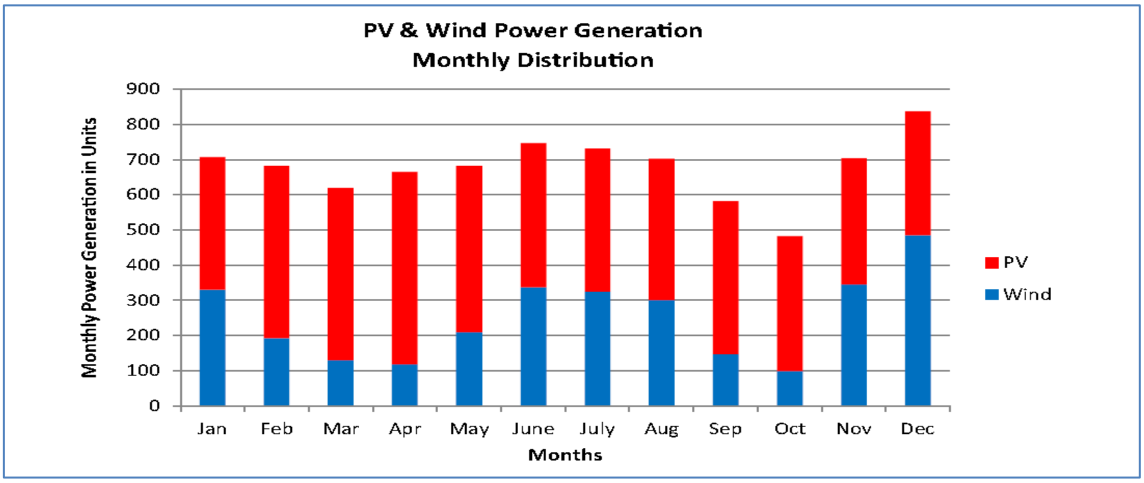


Figure 8-27: PV &Wind Power Generation (Source: Nagaraj et al, 2016)

The above profile shows the different months helps the in the selection of best energy required combination for the hybrid system. The performance in terms of nature is also demonstrated, hence making a case for the Hybrid Solution.

8.4.12 Energy Combination (Wind-Onshore + Solar Energy)

The main power source in this scenario is the Renewable Energy which is heavily controlled by nature depending on the renewable energy type.

The economic analysis of this Hybrid Technology system has been done not as an isolated or standalone power generation system but as an integrated part of an oil and gas investment which helps the per unit cost of power production from the technology also achieving the reduced CO_2 emission from the environment. This approach has already taken into cognisance depreciation factor, cost of equipment etc.

Cost Estimate for the Wind and Solar Power Combination

Table 8-25: Cost Estimate

Description	Costs ($Mln)
Solar	90.35 (1 X 12MW)
Wind-Onshore	76.3 (2 x 12MW)
Total	**166.67**

The above table shows the cost estimate of the combined solution of using Hybrid Technology Power generation system. This costs already has in it the capital costs of the power generation system, fixed cost, the variable cost and the running costs as part of it, please see (section 8.3.4 Power Generation Cost Estimate).

Table 8-26: Summary Cost of Hybrid Technology

Hybrid (Wind + Solar Power)		Fiscal Regime (New Comer)			
Premise Description	**Definition**	**PSC**	**JV**	**Marginal Field Offshore**	**Marginal Field Onshore**
Project 1	Production (Duration)	20years	20years	20years	20years
Pro. Profile Likely Case	P50 Base Case	P50	P50	P50	P50
Fiscal Regime	Fiscal Regime	Yes	Yes	Yes	Yes
Nominal Discount	10%	10%	10%	10%	10%
Equity Share	100%	100%	100%	100%	100%
Inflation Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Oil Price ($/bbl)	$50	50%	50%	50%	50%
Gas Price ($/Mscf)	$2.5	2.5%	2.5%	2.5%	2.5%
First Production (Year)	2017	2017	2017	2017	2017
Economic Cut off Year	2036	2036	2036	2036	2036
Break Even Price ($)	$	30	80	30	30
NPV (Net Present Value)	$	554.9	-122.8	436	554.9
Maximum Exposure	$	-165.2	-441.4	-570.4	-165.2
Value Investment Ratio	Ratio	0.92	-0.2	0.72	0.92

Figures 8-27 to 8-30 describes the Cash flow for the hybrid solution for Renewable Technology Combination of Wind-Onshore and Solar Energy system when applied to a marginal field or to an oil field under the different fiscal regime such PSC, JV, Marginal Offshore and Marginal Onshore. The cost of all the facilities and the production profile for this case remains the same but with different costs for the power generation technologies been Wind-Onshore Mill and Solar Power Systems.

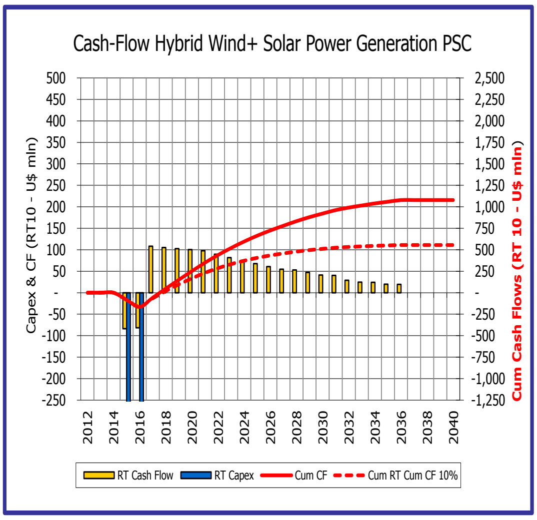


Figure 8-28: Hybrid (PSC)

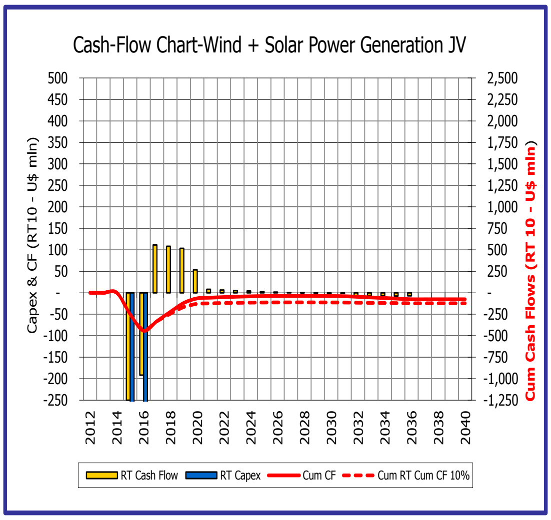


Figure 8-29: Hybrid (JV)

The power required is premised on the energy requirement as defined by the process simulation to be 2x12MW. Where the wind energy is the primary energy driver for the facility, a 2x12MW Wind-Onshore technology power generator has been selected to increase the availability of the power in the facility while 1x12 MW Solar Power system is also selected for this concept.

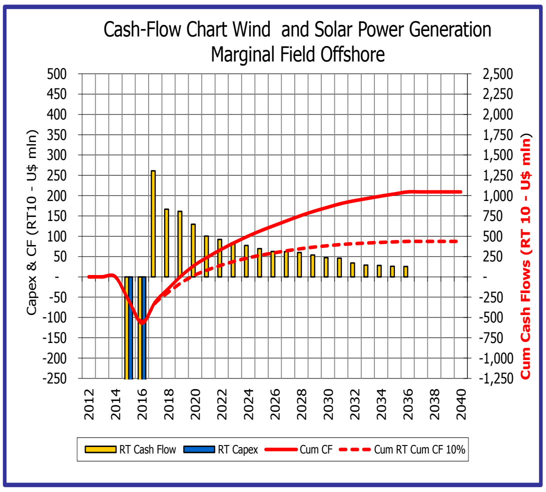


Figure 8-30: Hybrid (Offshore)

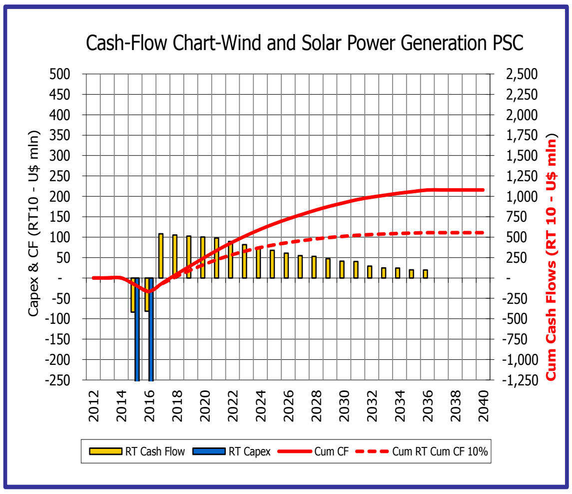


Figure 8-31: Hybrid (Onshore)

Under the different fiscal regimes, it is clear that the Joint Venture (JV) is the worst fiscal regime to apply a Hybrid Technology Solution when compared to others. The reason for the worst case in JV with a negative Net Present Value (NPV) and VIR is not because of the power generation type but more of the taxes that are associated to the JV.

However, one thing is very clear, under the Joint Venture (JV), the use of Hybrid Technology solution does not make the investment profitable. But for the other fiscal regimes, the Hybrid Technology Solution still application to the investment still has it with impressive NPV and VIR as can be seen in Table 8-26 and Figures 8-28 to 8-31. Hence climate change management can be supported by the application of this technology while still maintaining impressive production and cash flow from the investment.

8.4.12.1 Renewable Energy and Conventional Energy (Wind Onshore + Gas Turbine)

This combination is a Hybrid Technology system involving the use of a renewable energy; in this case the hybridization is between Wind-Onshore and Fossil Fuel technology known as Gas Turbine. Hybrid Wind Energy-Fossil power plants can be only the first step towards a 100% sustainable power supply for oil and gas marginal fields.

Table 8-27: Renewable Energy and Conventional Energy Cost

Description	Costs ($Mln)
Wind-Onshore	76.320 (2 X 12MW)
Gas Turbine	69.03 (1 x 12MW)
Total	**145.35**

As a result of the fluctuating wind resources availability which could make the wind turbine sometimes not operate optimally, it's combination with a fossil fuel technology such as a Gas Turbine appears economically robust as can be seen in the below cash flow Figures 8-32 to 8-35, most times irrespective of the fiscal regime been operated.

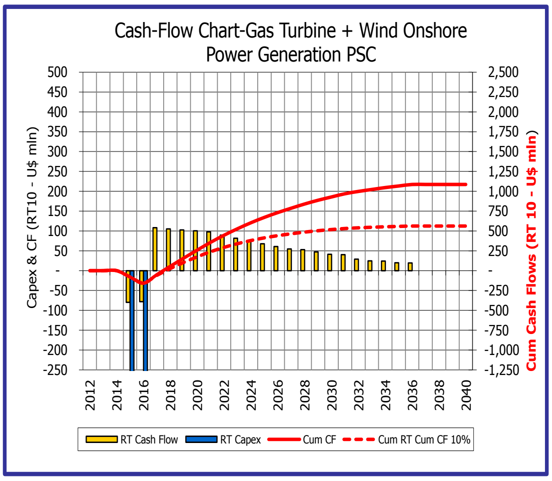


Figure 8-32: Gas + Wind (PSC)

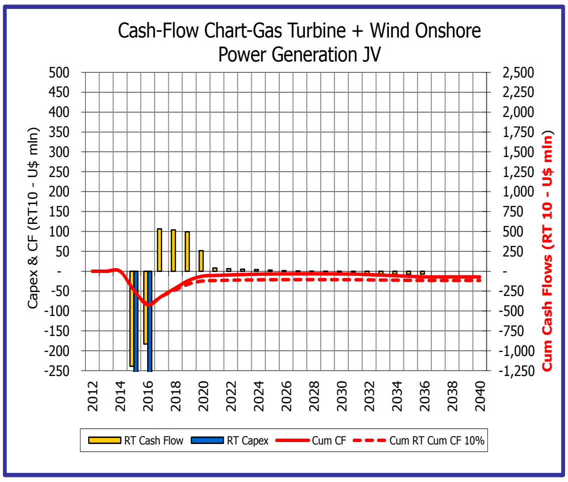


Figure 8-33: Gas + Wind (JV)

This economic assessment is an integrated one i.e with production profile, capital costs, depreciation and fiscal regimes considered. This shows the true value from the Wind Energy and Gas Turbine hybridization.

From the plotted Cash Flows in Figures 8-31 to 8-34 derived from the cost estimates shown in Table 8-27 above, it still demonstrates that oil and gas investment has huge potential to remain profitable with the application of a Hybrid Technology solution and still helps reduce carbon deposit in the Ozone layer, thereby support a clean environment.

The Joint Venture fiscal regime still remains a challenge for profitability in Marginal fields, while it is still important to note that it’s none profitability is not as a result of the hybrid technology solution for power generation.

However, the economic analysis which also has considered deeply the Total Cost of Ownership is compared for the different technologies using the PSC terms. The advantage of this approach of using the UZO-MARG model is that it takes cognisance and evaluates equipment in terms of financial, commercial and economic viability of the field. As mentioned above, using the PSC terms as calculated for each equipment is as shown below:

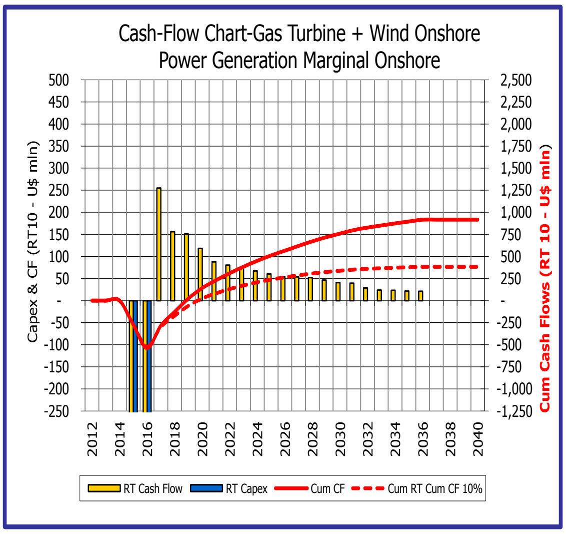


Figure 8-34: Gas + Wind (Onshore)

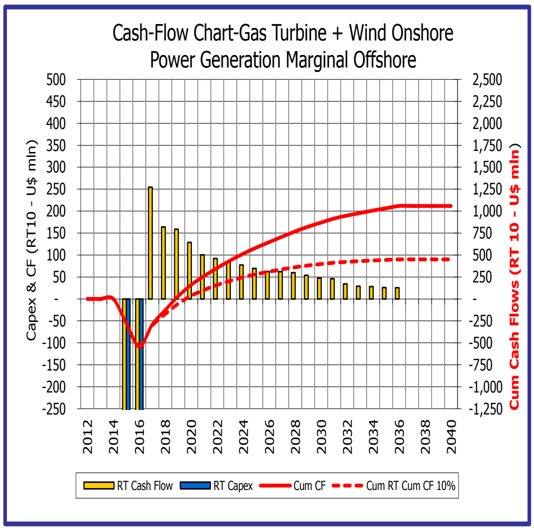


Figure 8-35: Gas + Wind (Offshore)

The above cash flow for Marginal Onshore and Marginal Offshore still shows impressive profitability with the hybrid solution. This implies that it does not impact negatively the investment decision to use a Hybrid solution where required.

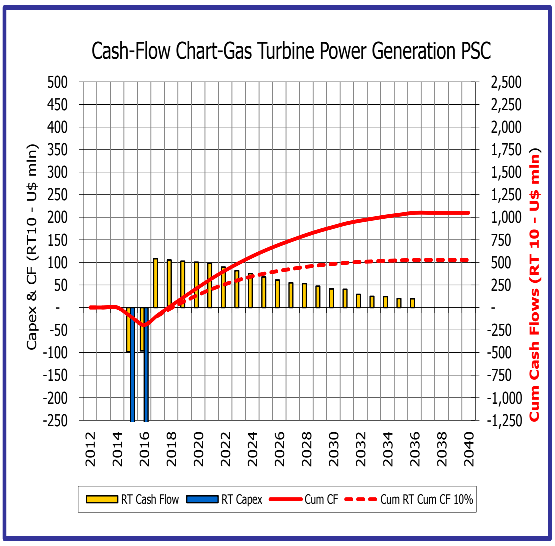


Figure 8-36: Gas Turbine

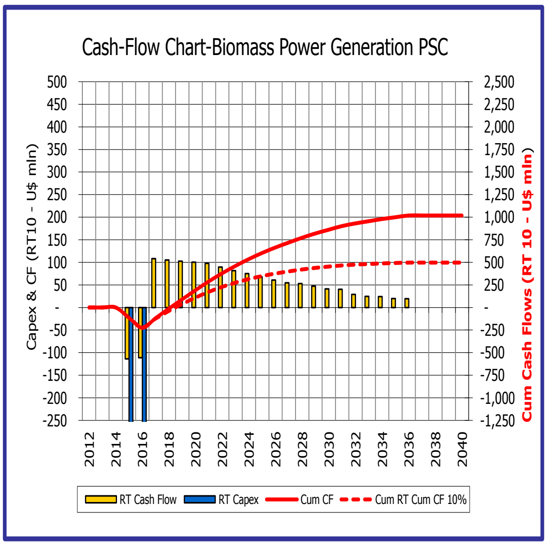


Figure 8-37: BIOMASS

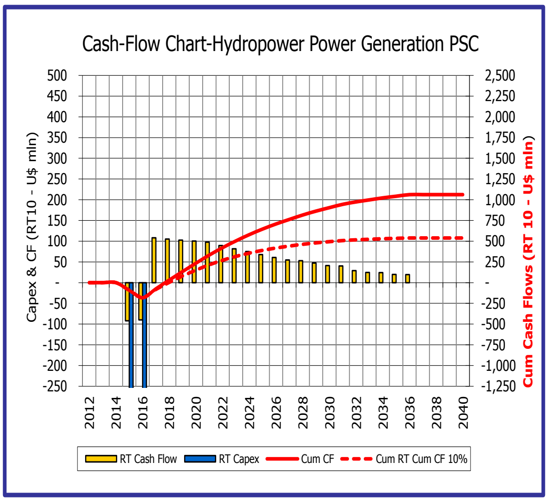


Figure 8-38: Hydropower

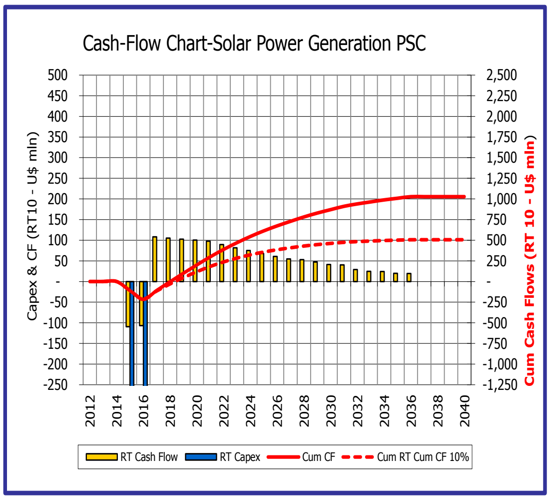


Figure 8-39: Solar

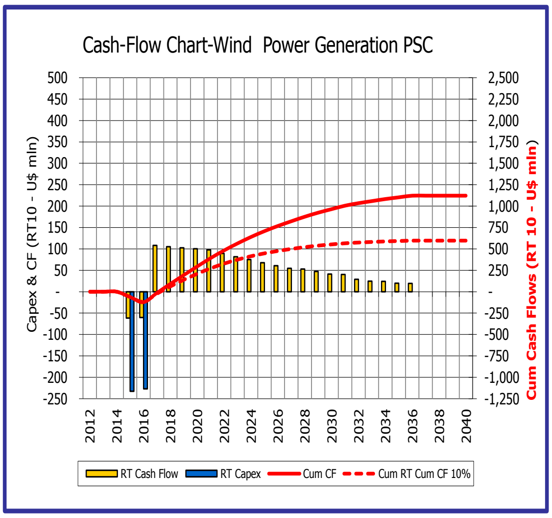


Figure 8-40: Wind-Onshore

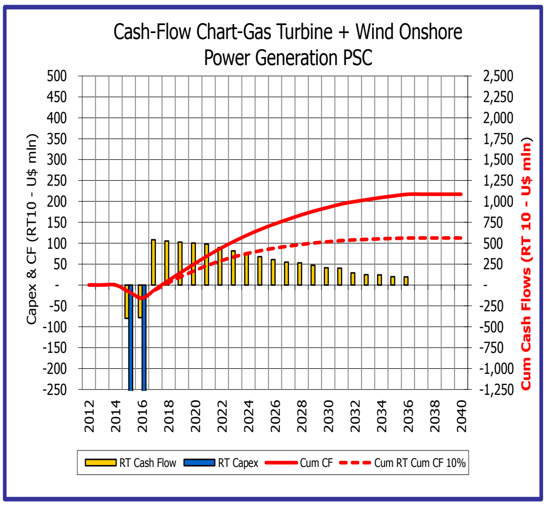


Figure 8-41: Hybrid (Wind+ Gas)

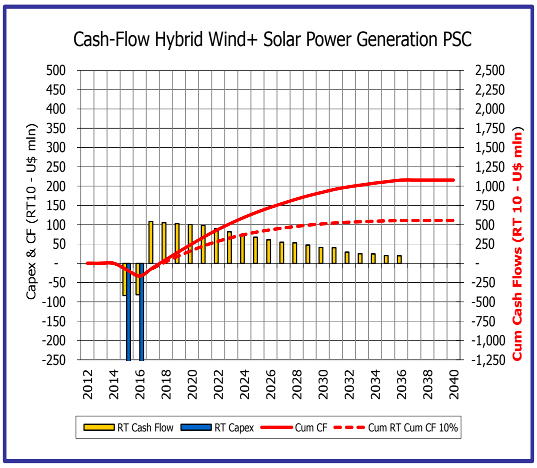


Figure 8-42: Hybrid (Wind + Solar)

9 Conclusion

The main aim of this thesis was achieved, as an integrated Techno-Economic and financial tool for the evaluation of Marginal Oil and Gas fields with different fiscal regimes was developed and its versatility was demonstrated with different case studies. The tool is flexible enough to accommodate any kind of fiscal regime.

Using the tool, the following deductions were made:

1. With the different fiscal regimes considered in this research, it is evident that the government makes more money from Joint Venture Agreements (JV) than the Production Sharing Contracts (PSC) because of the various taxes applies.

2. Under the range of Marginal fields considered in this study and assuming that the player is a new comer, for a hydrocarbon volume of 123.3MMboe at an oil price of $50bbl, with CAPEX of $741.1million, OPEX of $731.6million and a production life of 20 years – a JV agreement returns a NPV of $35.27million, VIR of 0.05, IRR of 2% and in the first 5years ROACE of -40%, -26.7%, 19.9%, 19.9% and 20.4% (breaking even in the third year of production); while a PSC agreement returns a NPV of $1,219.05million, VIR of 1.65, IRR of 18% and in the first 5years ROACE of -200%, -66.7%, 39.9%, 39.9% and 39.9% (breaking even in the third year). This shows the PSC agreement returning better VIR, NPV and ROACE, compared to the JV agreement.

3. Renewable Energy Technology has the potential to be used as a power generation technology to supply power to oil and gas facilities, especially where power generation infrastructure is not available and still have the facility remain profitable.

4. The use of Renewable Energy, particularly the Hybrid solution type of integrating a Solar Power solution and a Gas turbine solution to manage

carbon emission has been found not to impact the cash flow under the PSC compared to the JV. It has also been established that this solution will give you the required power and still meet the CO_2 emission limits if load distribution is well managed.

5. It is the conclusion of this research that during low oil price scenario, of say $40bbl, marginal oil and gas fields can still be profitable if operated with lower CAPEX and OPEX. At a lower CAPEX of $595.0million and a lower of OPEX $585.3million for a new comer field operator, NPV is $1,002.46million, VIR is 1.68 and the first 5years ROACE of -200%, -66.76%, 43.7%, 43.7% and 43.7% (with a breakeven in the third year) in a PSC regime; and for a JV regime, the NPV is $46.13million, VIR is 0.08, and the 5years ROACE of -40%, -26.7%, 23.7%, 23.7% and 24.2% (with a breakeven in the third year).

6. This thesis further concludes that the developed Integrated Techno-economic and financial tool can be used to optimise the revenue and profitability from an operating plant. This is established from the analysis of the increased and reduced CAPEX scenario, increased and reduced OPEX scenario analysis carried out in this research. Where the OPEX and CAPEx outlay in a plant can help define the profitability envelope of the plant before the investment is made i.e plant upgrade, expansion, remodelling etc.

7. For a robust PhD research outcome, a research/project Opportunity Framing should be adopted. Helps identify all that should be considered for credible PhD outcome.

8. Fiscal Regimes and taxes can be the deciding factor during the purchase and operation of a Marginal field, especially the commercial viability of the field to either the owner or the investor. Where the taxes and fiscal

regime favours exceedingly the field owner making the Government take too be too high or vice versa, an investment decision can be annulled.

9. Oil Price is not the only and sometimes the main factor that can establish commercial viability of a Marginal field. There are other factors if well negotiated and managed, can lead to commercial viable fields instead of losing the opportunity.

10. During Low oil price and where Tax is reduced, Marginal field has the potential to keep remaining commercially viable.

9.1 Future Work

1. The UZO-MARG model should be further developed into a full blown template software to support oil and gas field operators, especially Marginal Field Operators.

2. A subsurface oil and gas recovery model with capability to evaluate production forecast as part of the integrated software should be included into the model. This can be worked during the conversion of the model into software and it will improve the versatility of the UZO-MARG.

3. The capability of the model currently cannot handle technical concept evaluations like equipment sizing for both conventional and renewable energies. This should be included in the Model.

4. Detailed analysis of renewable energy economic and financial analysis capabilities is still required and this should be evaluated. The outcome should also be into the Model that eventually becomes part of software development.

5. Integrate the developed Renewable Energy Model into the UZO-MARG model and have them become one model that is connected to each other with various libraries defined in them.

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APPENDICES

Figure A: UZO-MARG Economic Model Result

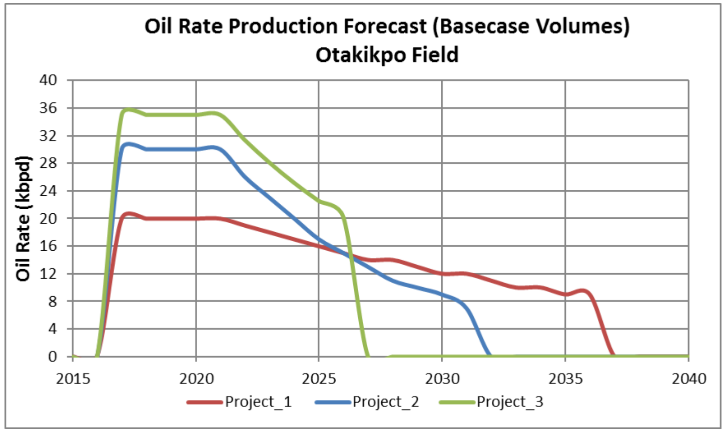
UZO-MERG Economics Model			1	2	3	4	5	6	7	8	9	10	11	12	13	14
Years			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Project	**Project_1**															
Select Model	**P50_BaseCase**															
P50_BaseCase	**Units**	**Totals**														
Model_Start_Year			2015													
RT_Year	year		2015													
PV_Year	year		2015													
LookForward_Year	year		2015													
Manual_Eval_CutOff_Year	year		2075	Check and Correct		??										
Economics Parameters																
Inflation_Rate	%		2.50%													
Nominal_Discount_Rate (Cost of Capital)	%		10.00%													
Fiscal Regime Parameters	Marginal Field Onshore	NewComer														
Pioneer Status			No													
Prices																
Oil_Price	$MOD/bbl		40	MOD												
Gas_Price	$MOD/mlnbtu		2.5	MOD												
CO2_Price (for penalty costs)	$RT/tCO2		80	RT												
Pre-Tax Cashflow																
Pre_Tax_Cashflow	mln$MOD	848.5				-7.3	-129.5	-23.9	68.4	170.5	163.8	153.7	153.3	126.1	99.1	65.1
Cum_Pre_Tax_Cashflow	mln$MOD					-7.3	-136.8	-160.7	-92.2	78.3	242.1	395.8	549.0	675.2	774.2	839.3
Economic_Cutoff_Year	year		2030													
Oil_Cashflow_MOD	mln $MOD	476.1				-20.7	-114.7	-34.0	32.9	125.9	116.8	93.0	78.0	55.2	43.3	28.4
Gas_Cashflow_MOD	mln $MOD															
Real Term and Discounted Cashflow																
Oil_Cashflow_RT	mln $RT	588.5				-20.7	-117.6	-35.8	35.5	138.9	132.2	107.9	92.8	67.3	54.1	36.3
Gas_Cashflow_RT	mln $RT															
Oil_Cashflow_PV	mln $RT	200.1				-20.7	-104.3	-28.1	24.8	86.0	72.5	52.5	40.0	25.8	18.4	10.9
Gas_Cashflow_PV	mln $RT															
			MOD	RT	PV10											
Discount_Rates_MOD				2.50%	10.00%											
Discount_Rates_RT			-2.44%		7.32%											
Production_Oil	mln bbl		56.2	56.2	29.0											
Production_Gas	bcf															
Total_Production_Boe	mlnBoe		56.2	56.2	29.0											
Revenue	mln$		2248.3	2630.1	1313.5											
Exploration_Cost	mln$															
Capital_Cost	mln$		467.2	486.6	401.5											
Operating_Cost	mln$		347.1	418.8	189.6											
Abandonment_Cost	mln$		153.4	179.5	89.6											
Royalty	mln$		302.7	347.4	184.7											
Tax	mln$		473.4	576.4	231.3											
Govt_Take	mln$		804.4	956.8	432.7											
Cash_Surplus	mln$		476.1	588.5	200.1											
		Check	OK	OK	OK											
			MOD	RT	PV10											
UFC	$/bbl															
UDC	$/bbl		8.3	8.7	13.8											
UOC	$/bbl		8.9	10.6	9.6											
UTC_Oil	$/bbl		17.2	19.3	23.4											
UTC_Boe	$/boe		17.2	19.3	23.4											
			MOD	RT	PV10											
Govt_Take_Perc	%		35.8%	36.4%	32.9%		NPV (36% WI)									
NPV	mln$		476.1	588.5	200.1		72.0422961									
VIR	ratio		1.02	1.21	0.50											
RTEP	%			35.39%												
IRR	%		32.09%													
Payout Year	Year		N/A	N/A												
Maximum Exposure	mln$		-169.4	-174.0												
Breakeven Price	$/bbl_$/mlnBtu															

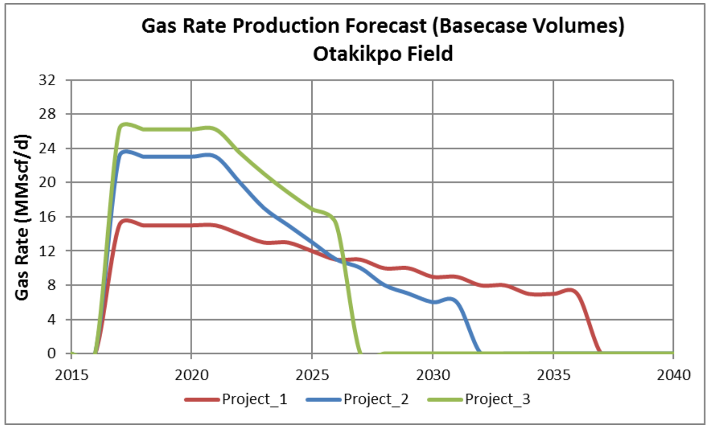
Figure B: Production Profile

Selected Project	Oil rate (kb/d)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	15	15	15	14	12	11	10	9	8	8	7	6	6	5	5	4	4	4	3	3	0	0	0	0
	P50	Base	0	0	0	0	0	20	20	20	20	20	19	18	17	16	15	14	14	13	12	12	11	10	10	9	9	0	0	0	0
	P10	High	0	0	0	0	0	25	25	25	25	25	25	25	25	24	23	23	22	21	20	20	19	18	18	17	16	0	0	0	0
20 Year Forecast	**Year Forecast**																														
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	15.00	15.00	15.00	14.00	12.00	11.00	10.00	9.00	8.00	8.00	7.00	6.00	6.00	5.00	5.00	4.00	4.00	4.00	3.00	3.00	0	0	0	0
	P50	Base	0	0	0	0	0	20.00	20.00	20.00	20.00	20.00	19.00	18.00	17.00	16.00	15.00	14.00	14.00	13.00	12.00	12.00	11.00	10.00	10.00	9.00	9.00	0	0	0	0
	P10	High	0	0	0	0	0	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	24.00	23.00	23.00	22.00	21.00	20.00	20.00	19.00	18.00	18.00	17.00	16.00	0	0	0	0
15 Year Forecast	**Year Forecast**																														
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	20.00	20.00	20.00	17.00	15.00	13.00	11.00	9.00	8.00	7.00	6.00	5.00	4.00	4.0	3.0	0	0	0	0	0	0	0	0	0
	P50	Base	0	0	0	0	0	30.00	30.00	30.00	30.00	30.00	26.00	23.00	20.00	17.00	15.00	13.00	11.00	10.00	9.0	7.0	0	0	0	0	0	0	0	0	0
	P10	High	0	0	0	0	0	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	28.00	19.00	13.00	9.00	6.0	4.0	0	0	0	0	0	0	0	0	0
10 Year Forecast	**Year Forecast**																														
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	25.00	25.00	25.00	20.88	17.44	14.57	12.17	10.16	8.49	7.09	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	P50	Base	0	0	0	0	0	35.00	35.00	35.00	35.00	35.00	31.35	28.09	25.16	22.54	20.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	P10	High	0	0	0	0	0	45.00	45.00	45.00	45.00	45.00	45.00	45.00	45.00	41.13	37.59	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Assumptions

Low Case: (i) plateau rate of 25 kbpd (ii) Plateau length of 3 years (iii) Decline rate of 18% per annum
Base Case: (i) plateau rate of 35 kbpd (ii) Plateau length of 5 years (iii) Decline rate of 11% per annum
High Case: (i) plateau rate of 45 kbpd (ii) Plateau length of 8 years (iii) Decline rate of 9% per annum
Same GOR assumed for the low, base and high cases





Selected Project	Gas rate (MMscf/d)		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	11	11	11	10	9	8	8	7	6	6	5	5	4	4	4	3	3	3	2	2	0	0	0	0
	P50	Base	0	0	0	0	0	15	15	15	15	15	14	13	13	12	11	11	10	10	9	9	8	8	7	7	7	0	0	0	0
	P10	High	0	0	0	0	0	19	19	19	19	19	19	19	19	18	17	17	16	16	15	15	14	14	13	13	12	0	0	0	0
20 Year Forecast	**Year Forecast**																														
Selected Project			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	11.00	11.00	11.00	10.00	9.00	8.00	8.00	7.00	6.00	6.00	5.00	5.00	4.00	4.00	4.00	3.00	3.00	3.00	2.00	2.00	0	0	0	0
	P50	Base	0	0	0	0	0	15.00	15.00	15.00	15.00	15.00	14.00	13.00	13.00	12.00	11.00	11.00	10.00	10.00	9.00	9.00	8.00	8.00	7.00	7.00	7.00	0	0	0	0
	P10	High	0	0	0	0	0	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	18.00	17.00	17.00	16.00	16.00	15.00	15.00	14.00	14.00	13.00	13.00	12.00	0	0	0	0
15 Year Forecast	**Year Forecast**																														
Selected Project			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	15.00	15.00	15.00	13.00	11.00	10.00	8.00	7.00	6.00	5.00	5.00	4.00	3.00	3.0	2.0	0	0	0	0	0	0	0	0	0
	P50	Base	0	0	0	0	0	23.00	23.00	23.00	23.00	23.00	20.00	17.00	15.00	13.00	11.00	10.00	8.00	7.00	6.0	6.0	0	0	0	0	0	0	0	0	0
	P10	High	0	0	0	0	0	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	21.00	14.00	10.00	7.00	5.0	3.0	0	0	0	0	0	0	0	0	0
10 Year Forecast	**Year Forecast**																														
Selected Project			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
	Case	Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	P90	Low	0	0	0	0	0	18.75	18.75	18.75	15.66	13.08	10.93	9.13	7.62	6.37	5.32	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	P50	Base	0	0	0	0	0	26.25	26.25	26.25	26.25	26.25	23.52	21.07	18.87	16.91	15.14	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	P10	High	0	0	0	0	0	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75	30.85	28.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure C: Cost Estimate Summary

Oil Facilities CAPEX	Project_SF		
Description	P90_LowCase	P50_BaseCase	P10_HighCase
Project Management & Indirects	63.01	63.01	63.01
Facilities and Equipment	306.32	306.32	306.32
Bulk Materials	29.64	29.64	29.64
Drilling and Wells	54.45	54.45	54.45
Offshore Structures/Platform	200.13	200.13	200.13
Pipeline Offshore	87.50	87.50	87.50
Sub-Total	741.06	**741.06**	**741.06**

Oil Facilities Capex	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	300	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2 Emmission	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0.00	0.00	0.00	0.00	0.00	0.27	0.27	0.27	0.27	0.27	0.26	0.24	0.24	0.22	0.20	0.20	0.18	0.18	0.16	0.16	0.15	0.15	0.13	0.13	0.13	0.00	0.00	0.00	0.00
Oil Exploration Capex	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oil Fixed Operating Costs (opex)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
(M$)	0	0	0	0	0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	0	0	0	0
Oil Drilling Capex	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	70.98	70.98	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Exploration Capex																													
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Facilities Capex																													
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Drilling CAPEX																													
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Operating OPEX																													
Year	2012	2013	2012	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Abandoment OPEX																													
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Costs ($M)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure D: Project Input Data

Oil Production

Oil Rate (kb/d)

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	15	15	15	14	12	11	10	9	8	8	7	6	6	5	5	4	4	4	3	3	0	0	0	0
Base	0	0	0	0	0	20	20	20	20	20	19	18	17	16	15	14	14	13	12	12	11	10	10	9	9	0	0	0	0
High	0	0	0	0	0	25	25	25	25	25	25	25	25	24	23	23	22	21	20	20	19	18	18	17	16	0	0	0	0

GasProduction

Gas Rate (MMscf/d

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	11	11	11	10	9	8	8	7	6	6	5	5	4	4	4	3	3	3	2	2	0	0	0	0
Base	0	0	0	0	0	15	15	15	15	15	14	13	13	12	11	11	10	10	9	9	8	8	7	7	7	0	0	0	0
High	0	0	0	0	0	19	19	19	19	19	19	19	19	18	17	17	16	16	15	15	14	14	13	13	12	0	0	0	0

CO2 Emmission

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0.273938	0.273938	0.273938	0.273938	0.273938	0.255675	0.237413	0.237413	0.21915	0.200888	0.200888	0.182625	0.182625	0.164363	0.164363	0.1461	0.1461	0.127838	0.127838	0.1278375	0	0	0	0
Base	0	0	0	0	0	0.273938	0.273938	0.273938	0.273938	0.273938	0.255675	0.237413	0.237413	0.21915	0.200888	0.200888	0.182625	0.182625	0.164363	0.164363	0.1461	0.1461	0.127838	0.127838	0.1278375	0	0	0	0
High	0	0	0	0	0	0.273938	0.273938	0.273938	0.273938	0.273938	0.255675	0.237413	0.237413	0.21915	0.200888	0.200888	0.182625	0.182625	0.164363	0.164363	0.1461	0.1461	0.127838	0.127838	0.1278375	0	0	0	0

Oil Exploration CAPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Oil Facilities CAPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	300	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	300	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	300	300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Oil Drilling CAPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Oil Fixed Operating OPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	0	0	0	0
Base	0	0	0	0	0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	0	0	0	0
High	0	0	0	0	0	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	0	0	0	0

Oil Variable Operating OPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0.00	0.00	0.00	0.00	0.00	16.43	16.43	16.43	15.37	13.14	12.05	10.95	9.88	8.76	8.76	7.67	6.59	6.57	5.48	5.48	4.39	4.38	4.38	3.29	3.29	0.00	0.00	0.00	0.00
Base	0.00	0.00	0.00	0.00	0.00	21.90	21.90	21.90	21.96	21.90	20.81	19.71	18.67	17.52	16.43	15.33	15.37	14.24	13.14	13.14	12.08	10.95	10.95	9.86	9.88	0.00	0.00	0.00	0.00
High	0.00	0.00	0.00	0.00	0.00	27.38	27.38	27.38	27.45	27.38	27.38	27.38	27.45	26.28	25.19	25.19	24.16	23.00	21.90	21.90	20.86	19.71	19.71	18.62	17.57	0.00	0.00	0.00	0.00

Oil Abandonment

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Exploration Capex

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Facilities Capex

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Drilling Capex

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Fixed Operating OPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Gas Variable Operating OPEX

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	3.294	3.285	3.285	2.19	2.196	0	0	0	0
Base	0	0	0	0	0	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	8.784	8.76	7.665	7.665	7.686	0	0	0	0
High	0	0	0	0	0	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	15.372	15.33	14.235	14.235	13.176	0	0	0	0

Gas Abandonment

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure E: Fiscal Parameters

Marginal Field Onshore							
Cut Off Rates for Royalty Rate		0	5	10	15	25	1000000
Oil_Royalty_Rate		2.5%	7.5%	12.5%	18.5%	12.5%	12.5%
Gas_Royalty_Rate		2.5%					
Oil_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Gas_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Start_of_Depreciation	Flag	Prod_Start					
Oil_Tax_Rate	%	55%					
Gas_Tax_Rate	%	0%					
TaxPayer_NewComer		NewComer					
Investment_Incentive		ITA					
Oil_ITA_ITC_Rate		20%					
Gas_ITA_ITC_Rate		0%					
Education_Tax_Rate		2%					
NDDC_Rate		3%					

Marginal Field Offshore							
Cut Off Rates for Royalty Rate		0	5	10	15	25	1000000
Oil_Royalty_Rate		2.5%	7.5%	12.5%	18.5%	12.5%	12.5%
Gas_Royalty_Rate		2.5%					
Oil_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Gas_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Start_of_Depreciation	Flag	Prod_Start					
Oil_Tax_Rate	%	50%					
Gas_Tax_Rate	%	0%					
TaxPayer_NewComer		NewComer					
Investment_Incentive		ITA					
Oil_ITA_ITC_Rate		20%					
Gas_ITA_ITC_Rate		0%					
Education_Tax_Rate		2%					
NDDC_Rate		3%					

JV							
Cut Off Rates for Royalty Rate		n/a					
Oil_Royalty_Rate		20.0%					
Gas_Royalty_Rate		7%					
Oil_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Gas_Depreciation_Schedule	%	20%	20%	20%	20%	19%	
Start_of_Depreciation	Flag	At_Spend					
Oil_Tax_Rate	%	85%					
Gas_Tax_Rate	%	30%					
TaxPayer_NewComer		NewComer					
Investment_Incentive		ITA					
Oil_ITA_ITC_Rate		5%					
Gas_ITA_ITC_Rate		5%					
Education_Tax_Rate		2%					
NDDC_Rate		3%					

PSC

Cut Off Rates for Royalty Rate			n/a
Oil_Royalty_Rate			20.0%
Gas_Royalty_Rate			5%
Oil_Depreciation_Schedule	%		100%
Gas_Depreciation_Schedule	%		100%
Start_of_Depreciation	Flag		At_Spend
Oil_Tax_Rate	%		50%
Gas_Tax_Rate	%		0%
TaxPayer_NewComer			TaxPayer
Investment_Incentive			ITA
Oil_ITA_ITC_Rate			50%
Gas_ITA_ITC_Rate			0%
Education_Tax_Rate			2%
NDDC_Rate			3%

Water Depth (m)	Royalty
0	20%
100	18.50%
200	16.67%
500	12%
800	8%

Figure F: Cash flow – Economic Model

Cash Flow

Inflation Rate	0.025
Nominal Discount Rate	0.1
Reference year is	2015

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
RT Cash Flow	-	-	-	-382	-372	517	504	491	227	221	204	188	173	157	143	129	126	113	101	98	81	70	69	59	58	-	-	-	-
Cum CF	-	-	-	-382	-754	-237	267	758	985	1,207	1,411	1,598	1,771	1,928	2,071	2,200	2,326	2,439	2,540	2,638	2,719	2,790	2,858	2,918	2,975	2,975	2,975	2,975	2,975
RT CF 10%	-	-	-	-382	-347	449	408	371	160	145	124	107	92	78	66	55	50	42	35	32	24	20	18	14	13	-	-	-	-
Cum RT Cum CF 10%	-	-	-	-382	-729	-280	128	498	658	803	927	1,034	1,125	1,203	1,269	1,324	1,374	1,416	1,451	1,483	1,507	1,527	1,545	1,560	1,573	1,573	1,573	1,573	1,573
MOD CAPEX	0	0	0	371	371	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RT Capex	-	-	-	-371	-361	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RTEP Life Cycle	43%																												
RTEP LF (10)	44%																												
Deflation Factor (DF)	108%	105%	103%	100%	98%	95%	93%	91%	88%	86%	84%	82%	80%	78%	76%	74%	73%	71%	69%	67%	66%	64%	63%	61%	60%	58%	57%	55%	54%
Discount Factor (DF)	133%	121%	110%	100%	91%	83%	75%	68%	62%	56%	51%	47%	42%	39%	35%	32%	29%	26%	24%	22%	20%	18%	16%	15%	14%	12%	11%	10%	9%
Revenue	0	0	0	0	0	730	730	730	732	730	693.5	657	622.2	584	547.5	511	512.4	474.5	438	438	402.6	365	365	328.5	329.4	0	0	0	0
Total Opex	0	0	0	0	0	42.1	42.1	42.1	42.16	42.1	41.005	39.91	38.866	37.72	36.625	35.53	35.572	34.435	33.34	33.34	32.278	31.15	31.15	30.055	30.082	0	0	0	0
Production	0	0	0	0	0	20	20	20	20	20	19	18	17	16	15	14	14	13	12	12	11	10	10	9	9	0	0	0	0
Total Capex	0	0	0	370.52904	370.52904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	LOWCASE			BASECASE			HIGHCASE		
Fiscal Terms	NPV MOD	NPV RT	NPV 10%	NPV MOD	NPV RT	NPV 10%	NPV MOD	NPV RT	NPV 10%
JV	5810	1045	2035	13043	2017	4069	21403	3024	6281
PSC	16397	2245	4902	38028	4448	10282	63275	6757	16228
Marginal Field Offshore	19097	2527	5590	41437	4703	11006	65273	7214	17009
Marginal Field Onshore	17350	2335	5124	37608	4342	10070	59251	6668	15567

Financial Model Results	Project_1	P50_BaseCase		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CapEmp	0	0	0	370.53	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06
AVCapEmp	0	0	0	185.26	555.79	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06	741.06
EBIT	0	0	0	-370.53	-370.53	541.90	541.90	541.90	543.44	541.90	513.80	485.69	458.89	429.48	401.38	373.27	374.35	345.17	317.06
EAIT	0	0	0	-381.64	-381.64	530.20	529.76	529.76	244.55	243.83	230.63	217.42	204.82	191.00	177.80	164.59	165.10	151.38	138.18
ROCE	0	0	0	-100%	-50%	73%	73%	73%	73%	73%	69%	66%	62%	58%	54%	50%	51%	47%	43%
ROACE	0	0	0	-200%	-67%	73%	73%	73%	73%	73%	69%	66%	62%	58%	54%	50%	51%	47%	43%

Generate

	JV												PSC											
Oil Price ($)	10	20	30	40	50	60	70	80	90	100	110	120	10	20	30	40	50	60	70	80	90	100	110	120
Total Gross Revenue ($)	11059	20366	29672	38978	48285	57591	66898	76204	85510	94817	104123	113430	11059	20366	29672	38978	48285	57591	66898	76204	85510	94817	104123	113430
Total Cost ($)	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517
Total Post-tax Cashflow ($)	983	2323	3663	5003	6343	7683	9023	10363	11703	13043	14383	15723	3884	7678	11472	15265	19059	22853	26647	30441	34234	38028	41822	45616
IRR	6%	14%	21%	28%	36%	44%	51%	59%	66%	73%	79%	86%	15%	24%	32%	40%	47%	54%	61%	68%	75%	81%	87%	93%

Generate

	Marginal Field Offshore												Marginal Field Onshore											
Oil Price ($)	10	20	30	40	50	60	70	80	90	100	110	120	10	20	30	40	50	60	70	80	90	100	110	120
Total Gross Revenue ($)	11059	20366	29672	38978	48285	57591	66898	76204	85510	94817	104123	113430	11059	20366	29672	38978	48285	57591	66898	76204	85510	94817	104123	113430
Total Cost ($)	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517	1517
Total Post-tax Cashflow ($)	4295	8422	12549	16676	20803	24929	29056	33183	37310	41437	45564	49690	3916	7660	11403	15147	18890	22634	26377	30121	33864	37608	41351	45095
IRR	16%	25%	33%	41%	48%	56%	63%	69%	76%	82%	88%	94%	15%	24%	32%	40%	47%	55%	62%	68%	75%	81%	88%	93%

Oil Price for Analysis	100																					
YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
JV	-382	-763	10	934	2037	2275	2495	2748	3037	3369	3744	4164	4637	5200	5827	6516	7338	8228	9197	10339	11572	13043
PSC	-382	-763	16	947	2057	2715	3499	4388	5391	6526	7792	9202	10771	12634	14689	16938	19610	22511	25644	29343	33309	38028
Marginal Field Offshore	-382	-763	32	981	2113	2819	3619	4526	5549	6706	7997	9434	11149	13185	15430	17887	20804	23972	27393	31433	36002	41437
Marginal Field Onshore	-382	-763	32	981	2113	2754	3474	4290	5211	6254	7417	8714	10260	12097	14123	16341	18976	21835	24925	28572	32698	37608

Annual NCF

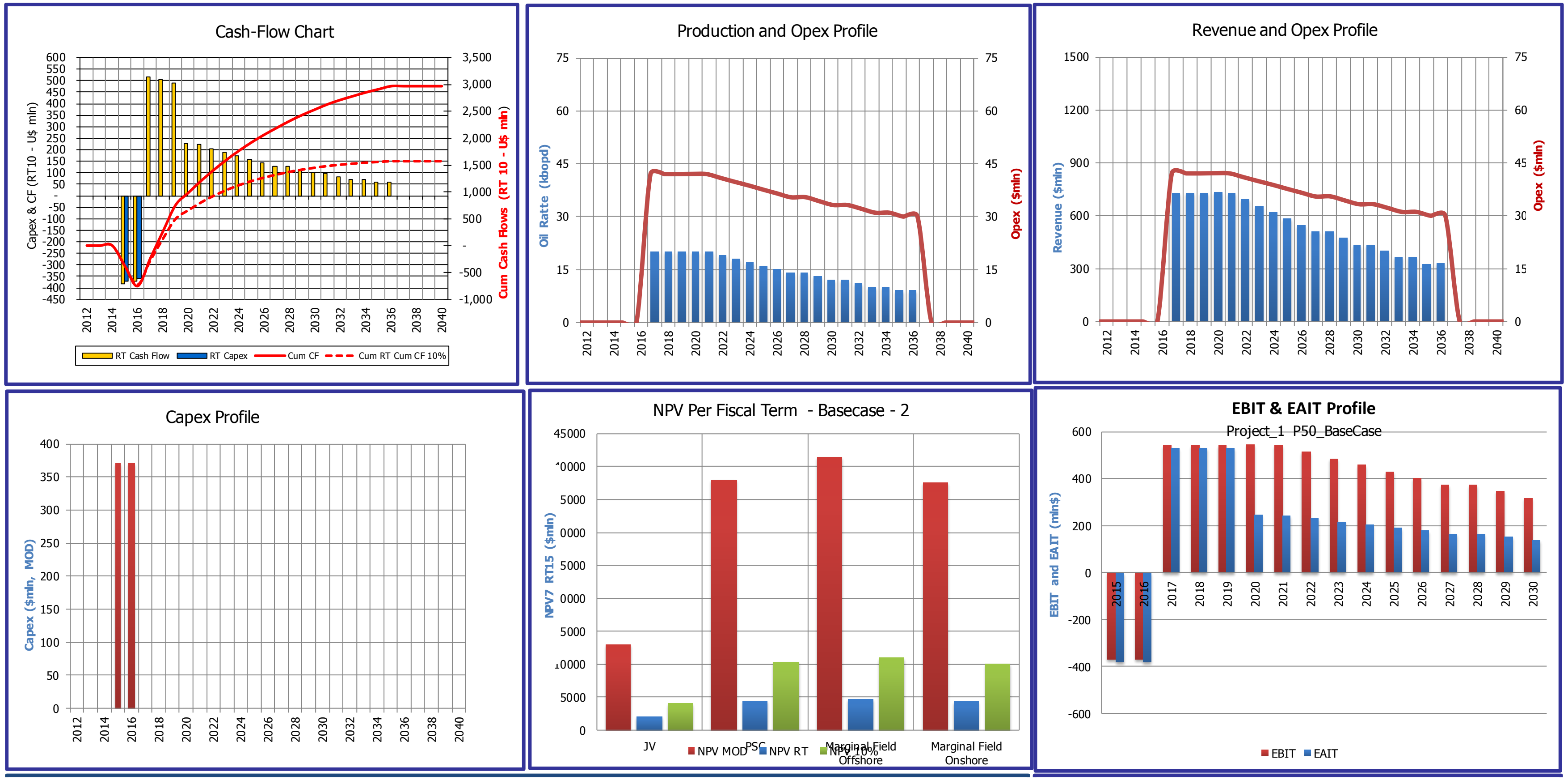
JV	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Govt Cashflow	11.1	11.1	228.1	270.6	320.6	1459.7	1795.4	2020.6	2267.7	2545.6	2830.5	3143.5	3478.0	4129.0	4532.7	4956.3	5872.3	6391.05	6870.3	8132.37	8678.83	10311.3
Field Owners' Cashflow	-381.6	-381.6	773.5	923.9	1102.5	238.9	219.3	252.8	289.3	332.4	374.4	420.3	473.0	563.3	627.1	688.5	821.9	890.335	969.241	1141.55	1232.79	1471.24
PSC	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Govt Cashflow	11.1	11.1	222.3	263.8	312.5	1041.1	1230.1	1384.5	1553.9	1743.7	1939.1	2153.7	2381.9	2829.3	3104.6	3395.2	4022.7	4380.65	4706.41	5574.56	5945.55	7063.55
Field Owners' Cashflow	-381.6	-381.6	779.3	930.7	1110.5	657.5	784.7	889.0	1003.1	1134.3	1265.9	1410.0	1569.0	1863.0	2055.2	2249.5	2671.5	2900.73	3133.12	3699.36	3966.07	4718.98
Marginal Field Offshore	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Govt Cashflow	11.1	11.1	206.8	245.4	290.7	992.5	1214.3	1366.7	1534.0	1721.4	1914.2	2126.1	2236.3	2656.5	2914.9	3187.8	3776.8	4113.04	4418.62	5234.13	5342.88	6347.55
Field Owners' Cashflow	-381.6	-381.6	794.8	949.1	1132.4	706.1	800.5	906.7	1023.0	1156.7	1290.8	1437.6	1714.6	2035.8	2245.0	2457.0	2917.3	3168.34	3420.92	4039.78	4568.74	5434.98

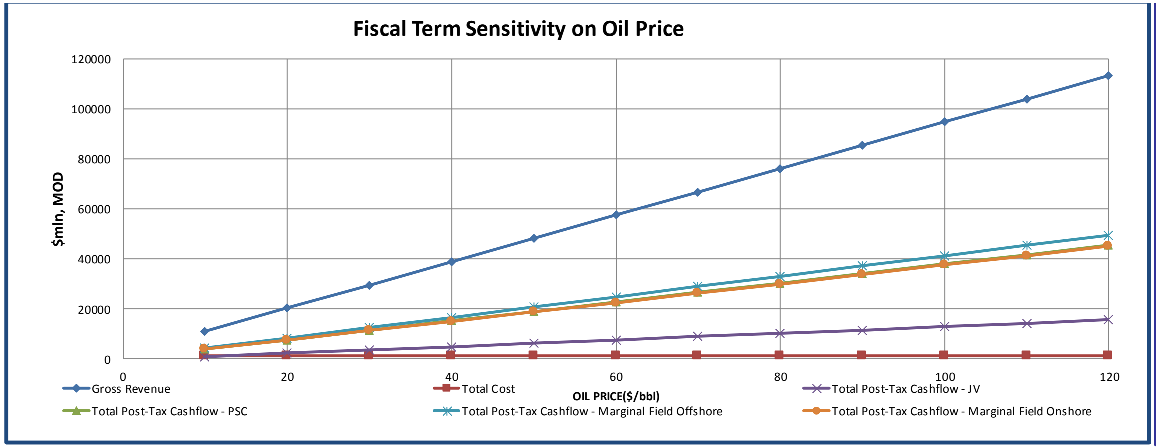
Oil Price ($) -	10	20	30	40	50	60	70	80	90	100	110	120
Govt Take	8514	16480	24446	32413	40379	48346	56312	64278	72245	80211	88178	96144
Field Owners' cNCF	983	2323	3663	5003	6343	7683	9023	10363	11703	13043	14383	15723
Govt Cashflow	5612	11125	16637	22150	27663	33175	38688	44201	49713	55226	60738	66251
Field Owners' cNCF	3884	7678	11472	15265	19059	22853	26647	30441	34234	38028	41822	45616
Govt Cashflow	5201	10381	15560	20740	25919	31099	36279	41458	46638	51817	56997	62176
Field Owners' cNCF	4295	8422	12549	16676	20803	24929	29056	33183	37310	41437	45564	49690
FRACTIONAL												
Govt Take	0.90	0.88	0.87	0.87	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Field Owners' cNCF	0.10	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Govt Cashflow	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.59
Field Owners' cNCF	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Govt Cashflow	0.55	0.55	0.55	0.55	0.55	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Field Owners' cNCF	0.45	0.45	0.45	0.45	0.45	0.44	0.44	0.44	0.44	0.44	0.44	0.44

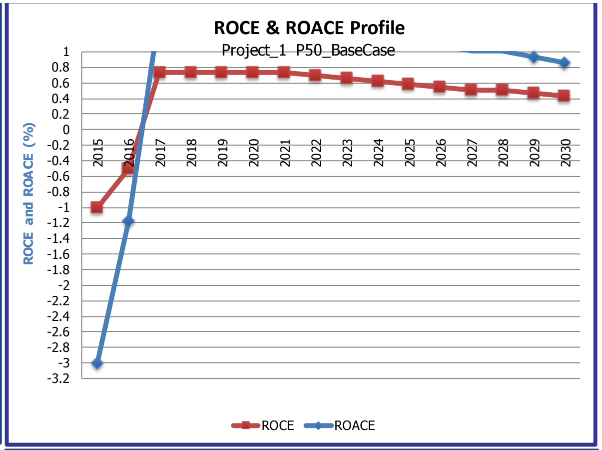
Govt Cashflow	5580	11143	16706	22269	27832	33395	38958	44521	50083	55646	61209	66772
Field Owners' cNCF	3916	7660	11403	15147	18890	22634	26377	30121	33864	37608	41351	45095
FRACTIONAL												
Govt Cashflow	0.59	0.59	0.59	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Field Owners' cNCF	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

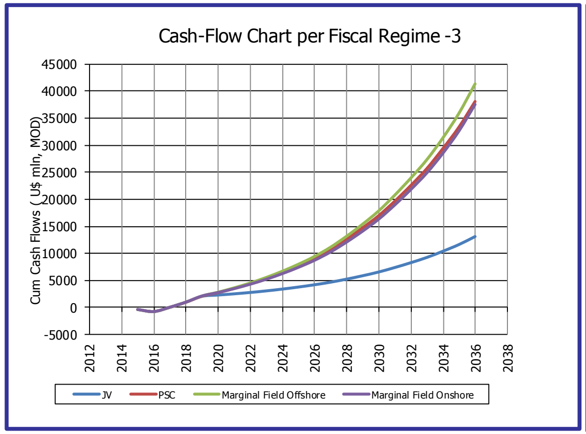
Marginal Field Onshore	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Govt Cashflow	11.1	11.1	206.8	245.4	290.7	1057.2	1294.9	1457.5	1635.9	1835.7	2041.3	2267.3	2404.0	2855.7	3133.4	3426.8	4060.1	4421.49	4749.94	5626.69	5785.39	6873.28
Field Owners' Cashflow	-381.6	-381.6	794.8	949.1	1132.4	641.4	719.8	815.9	921.1	1042.4	1163.6	1296.4	1547.0	1836.6	2026.4	2218.0	2634.1	2859.89	3089.6	3647.23	4126.23	4909.25

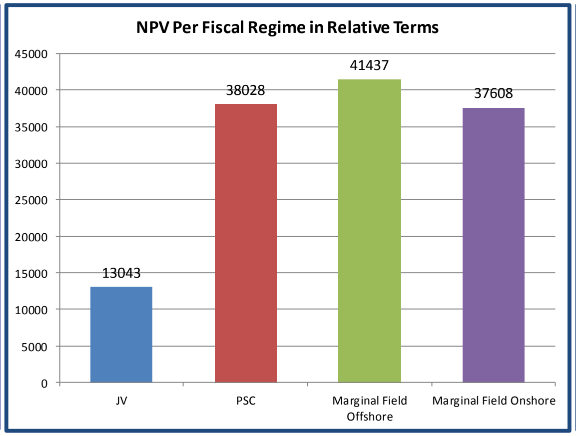
Figure G: Result Chart Page

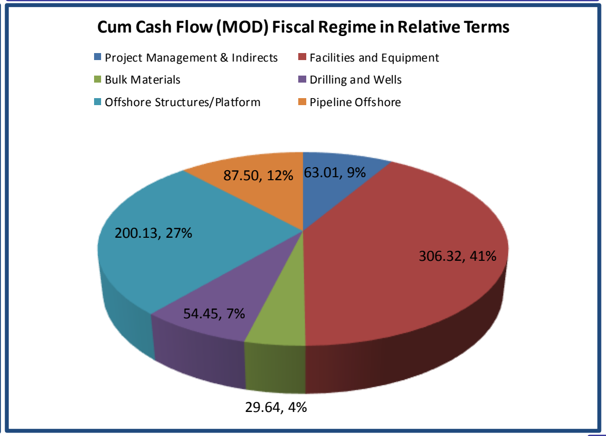


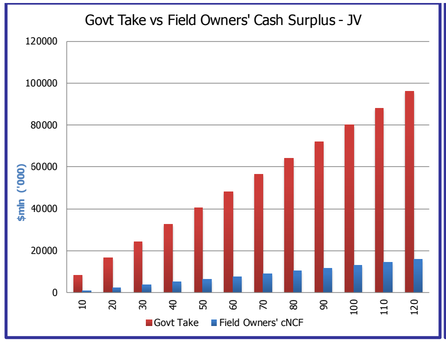

Fiscal Term Sensitivity on Oil Price
$mln, MOD
OIL PRICE($/bbl)
Gross Revenue
Total Cost
Total Post-Tax Cashflow - JV
Total Post-Tax Cashflow - PSC
Total Post-Tax Cashflow - Marginal Field Offshore
Total Post-Tax Cashflow - Marginal Field Onshore

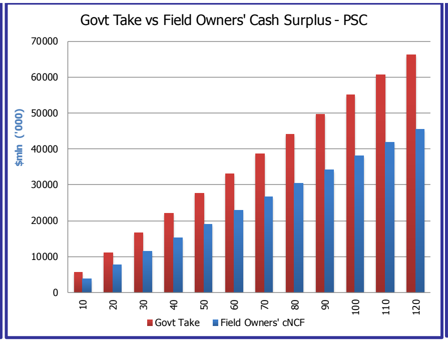

ROCE & ROACE Profile
Project_1 P50_BaseCase
ROCE and ROACE (%)
ROCE
ROACE

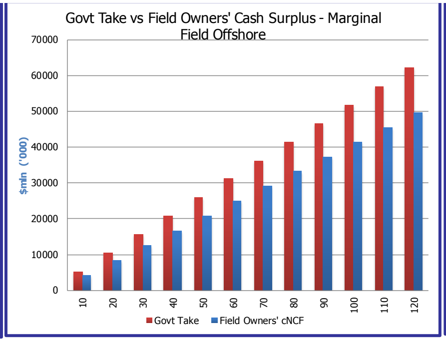

Cash-Flow Chart per Fiscal Regime -3
Cum Cash Flows (U$ mln, MOD)
JV
PSC
Marginal Field Offshore
Marginal Field Onshore

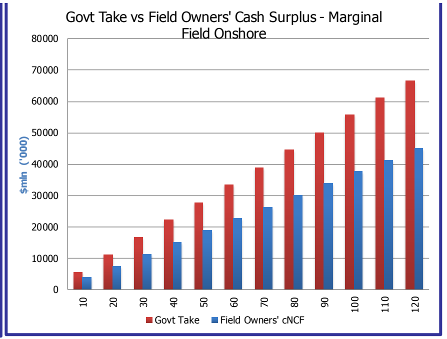

NPV Per Fiscal Regime in Relative Terms
13043
38028
41437
37608
JV
PSC
Marginal Field Offshore
Marginal Field Onshore

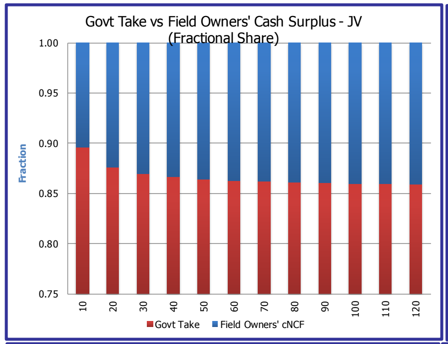

Cum Cash Flow (MOD) Fiscal Regime in Relative Terms
Project Management & Indirects
Facilities and Equipment
Bulk Materials
Drilling and Wells
Offshore Structures/Platform
Pipeline Offshore
87.50, 12%
63.01, 9%
200.13, 27%
306.32, 41%
54.45, 7%
29.64, 4%

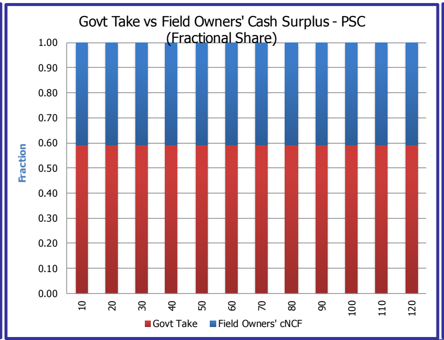

Govt Take vs Field Owners' Cash Surplus - JV
$mln ('000)
Govt Take
Field Owners' cNCF

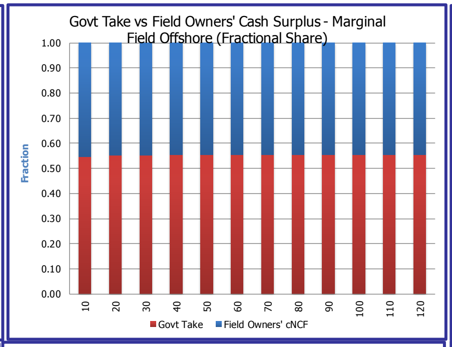

Govt Take vs Field Owners' Cash Surplus - PSC
$mln ('000)
Govt Take
Field Owners' cNCF

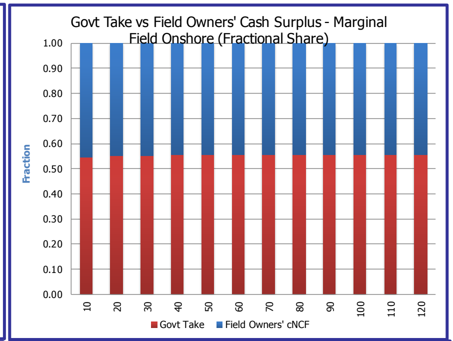

Govt Take vs Field Owners' Cash Surplus - Marginal Field Offshore
$mln ('000)
Govt Take
Field Owners' cNCF

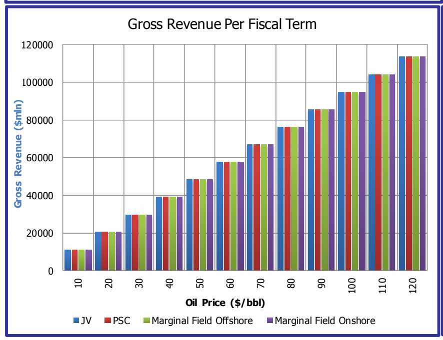

Govt Take vs Field Owners' Cash Surplus - Marginal Field Onshore
$mln ('000)
Govt Take
Field Owners' cNCF

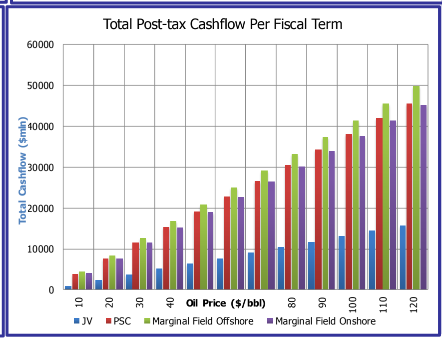

Govt Take vs Field Owners' Cash Surplus - JV (Fractional Share)
Fraction
Govt Take
Field Owners' cNCF

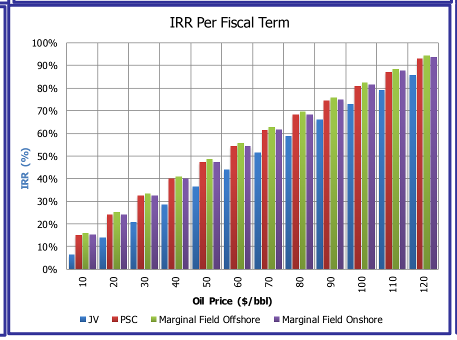

Govt Take vs Field Owners' Cash Surplus - PSC (Fractional Share)
Fraction
Govt Take
Field Owners' cNCF

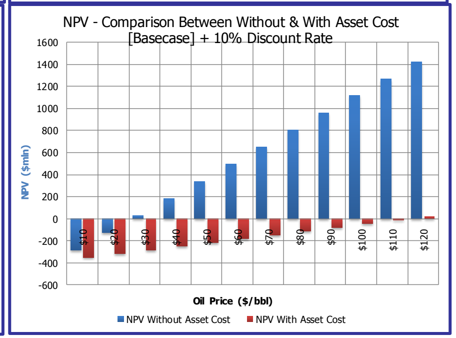

Govt Take vs Field Owners' Cash Surplus - Marginal Field Offshore (Fractional Share)
Fraction
Govt Take
Field Owners' cNCF


Govt Take vs Field Owners' Cash Surplus - Marginal Field Onshore (Fractional Share)
Fraction
Govt Take
Field Owners' cNCF


Gross Revenue Per Fiscal Term
Gross Revenue ($mln)
Oil Price ($/bbl)
JV
PSC
Marginal Field Offshore
Marginal Field Onshore


Total Post-tax Cashflow Per Fiscal Term
Total Cashflow ($mln)
Oil Price ($/bbl)
JV
PSC
Marginal Field Offshore
Marginal Field Onshore


IRR Per Fiscal Term
IRR (%)
Oil Price ($/bbl)
JV
PSC
Marginal Field Offshore
Marginal Field Onshore


NPV - Comparison Between Without & With Asset Cost [Basecase] + 10% Discount Rate
NPV ($mln)
Oil Price ($/bbl)
NPV Without Asset Cost
NPV With Asset Cost