TECHNO ECONOMIC ANALYSIS OF HEAVY OIL FIELD DEVELOPMENT IN NIGERIA

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By

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ABSTRACT

The main challenge of heavy oil (bitumen) is the high viscosity making it not flow easily to production wells at normal reservoir conditions. Thermal recovery methods are used to exploit heavy oil reservoirs, where oil viscosity is very high and mobility low at the reservoir temperature. It is desirable to reduce the oil viscosity by increasing its temperature. The main processes that use thermal methods for heavy oil recovery are Steam methods, like Cyclic Steam Stimulation (CSS), and Steam Assisted Gravity Drainage (SAGD). Nigeria is blessed with high reserve of heavy oil (bitumen), yet it is not commercially produced. These recovery methods are capital intensive and as such need intensive studies and forecast about their outcomes therefore the need to have an effective or the most economical EOR for high viscous oil reservoir cannot be over emphasized. The primary objectives of this study are to evaluate existing EOR methods for heavy oil, conducting economic analysis for selected EOR methods for heavy oil and selecting the most productive EOR method for heavy oil.

An economic analysis was carried out to evaluate if the two methods are economically profitable by building an economic model. Projected production along with price, royalty and tax were the input data fed into the economic model. The results of the economic analysis indicated for SAGD a payback period of about 5years with an Internal Rate of Return of 34% and a Net Present Value of $51.69 million USD using a 10% discount rate, While that of CSS a payback period of 7.5years with an Internal Rate of Return of 14% and a Net Present Value of $4.84 million USD using a 10% discount rate. The major finding of this study is that investment in exploration and production of bitumen in Nigeria is a wise economic decision because it is profitable.

Keywords: Heavy oil (bitumen), economic evaluation, EOR**.**

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DEDICATION

I dedicate this thesis study to my late parent Mr. and Mrs. Joseph Odeyanro.
God remains faithful…

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CHAPTER ONE

INTRODUCTION

1.1 OVERVIEW

Heavy or extra-heavy oils are highly viscous oils that cannot easily flow to production wells at normal reservoir conditions. ‘‘Heavy” is defined because the density or specific gravity is higher than that of lighter oils (i.e., conventional oils). It is widely accepted to adopt the specific gravity and viscosity as two standards to classify light, heavy and extra-heavy oils Specific gravity is measured based on the American Petroleum Institute in units called API degrees (API); the lower the number of API degrees, the higher the specific gravity of the oil. Viscosity is measured in centipoises (CP) that represents the oil’s resistance to flow; the higher the value, the higher the viscosity.(Guo, Li, & Yu, 2016).

The heavy oil recovery is very connected to the application of techniques known as enhanced oil recovery methods, from where stand out the thermal recovery methods. The process of producing hydrocarbons by methods other than the normal methods is called enhanced oil recovery (EOR). It also includes re-pressurizing schemes with gas and water. An EOR method should generate an incremental oil recovery. Incremental oil is designated as oil produced higher than the projected production from the reservoir without the EOR method (Ezekwe 2011). Heavy oil and oil sands that cannot be produced by conventional methods can be produced by applications of EOR methods such as thermal process, which improve oil recovery from these types of reservoirs.

According to Speight (2019), Heavy oil is a viscous type of crude oil that contains higher level of sulfur than conventional crude oil and which occurs in similar locations to crude oil. The nature of heavy oil is a problem for recovery operations and for refining the viscosity of the oil may be too high, thereby leading to difficulties in recovery and/or difficulties in refining the oil. However, tar sand bitumen, in terms of properties and behavior, are a world apart from conventional crude oil.

Success with this material and with extra heavy oil depends as much on understanding the fluid (or no fluid) properties of the material and the behavior of the fluids in the deposit in which they occur as it does on knowing the geology of the deposit. For example, heavy oil is considered (arbitrarily) to be those crude oils that had gravity somewhat less than 20° API with the heavy oil falling into the API gravity range 10–15°. For example, Cold Lake heavy crude oil has an API gravity equal to 12°, and extra heavy oil, such as tar sand bitumen, usually has an API gravity in the range 5–10° (Athabasca bitumen ¼ 8° API). Residue would vary depending upon the temperature at which distillation was terminated, but usually vacuum residue are in the range 2–8° API.

Here are different **Oil Class and °API;**

- Light - °API $\geq$ 31,
- Medium - 22 $\leq$ °API < 31
- Heavy - 10 $\leq$ °API < 22 ,
- Extra-heavy - °API $\leq$ 10.

Heavy oil has a much higher viscosity (and lower API gravity) than conventional crude oil, and the recovery of heavy oil usually requires thermal stimulation of the reservoir (Speight, 2015). The generic term heavy oil is often applied to a crude oil that has less than 20° API The reason is that the chemical and physical differences between heavy oil, extra heavy oil, and tar sand bitumen oil ultimately affect the viscosity and other relevant properties that in turn, influence the individual aspects of recovery and refining operations.

According to Green and Willhite (1998). Unconventional oils - mainly heavy oils, extra heavy oils and bitumen - represent a significant share of the total oil world reserves. Oil companies have expressed interest in unconventional oil as alternative resources for the energy supply. These resources are composed usually of viscous oils and, for this reason, their use requires additional efforts to guarantee the viability of the oil recovery from the reservoir and its subsequent transportation to production wells and to ports and refineries. This review describes the main properties of high-viscosity crude oils, as well as compares traditional and emergent methods for their recovery and transportation(Santos & Lo, 2014)

According to Santos & Lo (2014), unconventional oils cannot be recovered in their natural state by the exclusive application of typical production methods, and further they generally require heating and dilution during transport, which increases recovery costs. Another important aspect is the high flow resistance displayed, that normally impacts their natural flow. In addition, in contrast with conventional oils, these unconventional oils present a higher density, a higher content of nitrogen, oxygen, sulfur and heavy metals and a wider quantity of heavier oil fractions. Furthermore, the refining of unconventional oils requires great specificity and produces lower proportions of high added value products, such as liquefied petroleum gas (LPG), gasoline, kerosene, and diesel oil. Recent studies estimate that unconventional oil reserves, including heavy oils, extra-heavy oils and bitumen exceed 6 trillion barrels.

Thermal methods are common in technologies used for the production of heavy and ultraviscous oils (van Poolen, 1981; Farouq Ali, 2003; Shah et al., 2010). Thermal methods are the most advanced EOR method because of the wide experience in the test field and the technology developed during the many years (almost 6 decades) of their application. Thermal methods are based on supplying heat to the reservoir. In this way, the improvement in oil recovery is mainly due to the reduction of the oil viscosity and, consequently, to the improvement of the mobility ratio. Besides, the heating of the reservoir induces the expansion of solid and fluid phases, steam distillation and visbreaking (Donaldson, 1985; Lake, 1989; Farouq Ali, 2003; Thomas, 2008), which affect the recovery efficiency. Heat may be supplied to the reservoir through either steam or water injection and also by means of petroleum combustion inside the reservoir (Lake, 1989; Triggia et al., 2001) and should ensure an economically viable oil flow. The main processes that use thermal methods for heavy oil recovery are Steam methods, like Cyclic Steam Stimulation (CSS), Steam Flooding (SF) and Steam Assisted Gravity Drainage (SAGD), In-situ combustion (ISC) and Hot water flood.

Thermal recovery methods are used to exploit heavy oil reservoirs, where oil viscosity is very high and mobility low at the reservoir temperature. It is desirable to reduce the oil viscosity by increasing its temperature(Rangel-German, 2006)

1.2 PROBLEM DEFINITION

Generally heavy oil or extra heavy oil reservoirs are not easily produced because of the high viscosities that either slow or stop mobility of the hydrocarbons therefore enhanced oil recovery like thermal recovery method is used to help decrease the viscosity drag effect of the hydrocarbons. These recovery methods are capital intensive and as such need intensive studies and forecast about their outcomes therefore the need to have an effective or the most economical EOR for high viscous oil reservoir cannot be over emphasized. Though from previous works done by many researchers, they did economic analysis of a particular type of thermal EOR, this thesis will use same parameter to evaluate different type of thermal EOR method for a heavy reservoir and compare to see the most effective and economical method, because economics is one of the important aspect in the crude oil business.

1.3 AIM

This study aims to develop an economic model for the evaluation of heavy oil Enhanced Oil Recovery project performance under risk uncertainly inherent oil price dynamics.

1.4 OBJECTIVES

The objectives of this project are to evaluate existing EOR methods for heavy oil, conducting economic analysis for selected EOR methods for heavy oil and selecting the most productive EOR method for heavy oil.

1.5 SCOPE AND LIMITATION OF THIS WORK

Collection of data for economic evaluation for the project would be gotten from reliable sources, then economic evaluation of, steam assisted gravity drainage and cyclic steam stimulation. After which sensitivity analysis would be carried out to determine key parameters that influences the output using Monte Carlo simulation. This work is limited to the development of an economic model for heavy oil reservoir.

1.6 RESEARCH QUESTIONS

- What are the different types of EOR for heavy crude oil? Knowing the different methods of enhanced oil recovery for heavy crude oil.
- What parameters are needed for the economic evaluation? To build an economic model and evaluate some key parameters are needed.
- Which is the most effective and economical for heavy oil? After building a model and evaluating, using key profitability indicators we will know the most effective.

1.7 OVERVIEW OF THESIS

This research work will be structured in the format below:

» Chapter l (Introduction) discusses the thesis via a background and the problem statement. The objectives of the research that led to the specific research/problem statement will be presented.

» Chapter 2 (Literature review) will examined valid literature for availability of bitumen/oil and tar sands in commercial quantity and its geology in Nigeria, the geology and quality of the Nigeria tar sand and available technology for the exploration and development of bitumen.

» Chapter 3 presents the methodology employed in this study like the cash flow model formulation, petroleum production forecasting and some fiscal system-based modelling.

» Result of findings in chapter three will be documented in chapter four.

» In chapter five, the findings will be discussed and interpreted to pinpoint the credence they give to the thesis and with a view to drawing inferences and conclusion.

» Finally, in chapter six, conclusion relating to the stated research statement will be presented and recommendation for further research will be made.

CHAPTER TWO

LITERATURE REVIEW

2.1 HEAVY OIL

Heavy oil is a type of petroleum that is different from conventional petroleum insofar as they are much more difficult to recover from the subsurface reservoir. Heavy oil, particularly heavy oil formed by biodegradation of organic deposits, are found in shallow reservoirs, in unconsolidated sands. This characteristic, which brings about difficulties during well drilling and completion operations, may become a production advantage due to higher permeability(Unconsolidated sediments tend to have higher porosity than consolidated ones because they have no cement, and most have not been strongly compressed). Heavy oil has a much higher viscosity (and lower API gravity) than conventional petroleum, and recovery of these petroleum types usually requires thermal stimulation of the reservoir (Speight, 2015).

When petroleum occurs in a reservoir that allows the crude material to be recovered by drilling, pumping and compression techniques as a free-flowing dark to light colored liquid, it is often referred to as *conventional petroleum*. During the past three decades the term *black oil* has been introduced into the petroleum lexicon. The global demand for energy in rapidly increasing and conventional oil reserves will not be able to meet up the increasing energy demand. The need to exploit unconventional resources is being considered globally.(Ogiriki & Agunloye, 2018)

Heavy oil is a type of crude oil which is very viscous and does not flow easily. The common characteristic properties (relative to conventional crude oil) are high specific gravity, low hydrogen to carbon ratios, high carbon residues, and high contents of asphaltenes, heavy metals, sulfur, and nitrogen. Heavy oil is an oil resource that is characterized by high viscosities (i.e., resistance to flow) and high densities compared to conventional oil. Most heavy oil reservoirs originated as conventional oil that formed in deep formations, but migrated to the surface region where they were degraded by bacteria and by weathering, and where the lightest hydrocarbons escaped (Speight, 2015) .There are large resources of heavy oil in Canada, Venezuela, Russia, the United States, and many other countries. In fact, heavy oil accounts for more than double the resources of conventional oil in the world and heavy oil offers the potential to satisfy current and future oil demand. However, heavy oil is more difficult to recover from the subsurface reservoir than conventional or light oil. Heavy oil has a much higher viscosity (and lower API gravity) than conventional petroleum and recovery of heavy oil usually requires thermal stimulation of the reservoir.

These heavy oils fall into a range of high viscosity (Fig. 2.1), from the figure we can see that viscosity is inversely proportional to API and the viscosity is subject to temperature effects, (Fig. 2.2), from the figure we see that that temperature is inversely proportional to viscosity (the higher the temperature the lower the viscosity) which is the reason for the application of thermal methods to heavy oil recovery. Finally, the formation of stable emulsions of water and oil is a phenomenon frequently found in the production of heavy oils. Emulsions are formed during simultaneous flow of oil and water, although it is also supposed to occur while still in the reservoir.

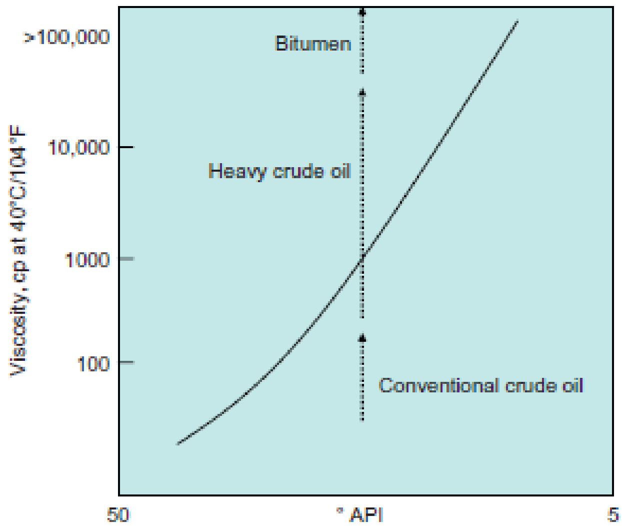


Figure 2.1 General Relationship Of Viscosity To API Gravity(Speight, 2015)

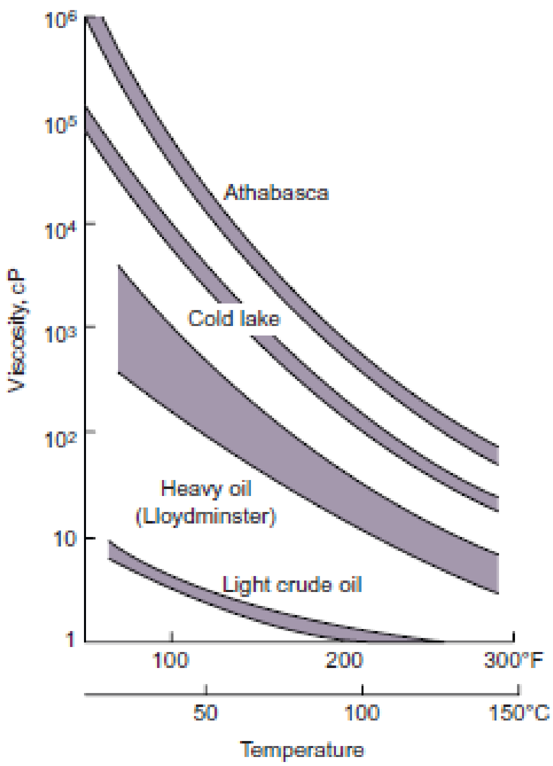


Figure 2.2 Variation Of Viscosity With Temperature.(Speight, 2015)

2.2 DESCRIPTION OF TAR SAND AND ITS ORIGIN

By definition, tar sands are sedimentary rocks (consolidated or unconsolidated) that contains bitumen (solid or semisolid hydrocarbons) or other heavy petroleum that, in natural state, cannot be recovered by conventional petroleum recovery methods. Technically, tar sand is not a combination of tar and sand as the name implies, since tar is a viscous liquid; black in colour with adhesive properties, obtained by the destructive distillation of coal, wood, shale, etc., and such an origin for tar in tar sands are rarely implied. On the other hand, “bitumen” is the name given to viscous liquids or solid materials black or dark brown in colour having adhesive properties, consisting essentially of hydrocarbons derived from petroleum or occurring in natural asphalt and soluble in carbon disulphide. Bitumen is found mixed with other components such as clay, water, etc., in sand known as “tar sand” by name, which is a misnomer or an inappropriate term and should rightly have been called “bitumen sand” since it is bitumen and not tar from destructive distillation of coal that is intermingled with the sand deposits. Bitumen is simply the name of the oil found in tar sands and until recently, Alberta’s bitumen deposits were known as tar sand but are now called “oil sands”. Tar sands is not only made up of bitumen but also consist of feldspar, Mica clay minerals in minor amount and quartz as the dominant mineral constituting over 90% of the entire assemblage of mineral grains. Tar sands are water wet by nature. In Nigerian, the tar sand belts fall within the Eastern Dahomey basin which is a coastal sedimentary basin filled with over 2500 meters of cretaceous and younger sediments unconformity overlying the block faulted basement complex rocks (Ogiriki & Agunloye, 2018)

The term tar sand, also known as oil sand (in Canada), or (more correctly) Bituminous sands, commonly describes sandstones or friable sand (quartz) Impregnated with viscous bitumen (a hydro carbonaceous material soluble in carbon disulfide). Significant amounts of fine material, usually largely or completely clay, are also present. The degree of porosity varies from deposit to deposit and is an important characteristic in terms of recovery processes. The bitumen makes up the desirable fraction of the tar sand from which liquid fuels can be derived (Speight, 2013d, 2014a). However, the bitumen is usually not recoverable by conventional petroleum production techniques. Furthermore, the properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the tar sands that are recognized as being water-wet (rather than bitumen-wet) in the Athabasca deposit, a layer of water surrounds the sand grain, and the bitumen partially fills the voids between the wet grains. On the other hand, the Utah tar sands lack the water layer and the bitumen is directly in contact with the sand grains without any intervening water. Typically, more than 99% w/w of the mineral matter is composed of quartz and clay minerals. The Utah deposits range from largely consolidated sands with low porosity and permeability to, in some cases, unconsolidated sands. High concentrations of heteroatoms tend to increase viscosity, increase the bitumen–sand reactions and bitumen–minerals reactions making processing more difficult. Tar sands are sedimentary rocks containing bitumen, a viscous hydro carbonaceous mixture. Tar sand deposits may be divided into two major types:

(1) A breached reservoir where erosion has removed the capping layers from a reservoir of relatively viscous material, allowing the more volatile petroleum hydrocarbons to escape; and

(2) Deposits that formed when liquid petroleum seeps into a near-surface reservoir from which the more volatile constituents escaped.

In either type of deposit, the lighter, more volatile constituents have escaped to the environment, leaving the less volatile constituents in place which are altered by contact with air, bacteria, and groundwater. Because of the very viscous nature of the bitumen in tar sands, tar sands cannot be processed by the typical petroleum production techniques (Speight, 2013d, 2014a). Tar sand deposits occur throughout the world and the largest deposits occur in Alberta, Canada (the Athabasca, Wabasca, Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the United States, with the larger individual deposits in Utah, California, New Mexico, and Kentucky.

The term bitumen (also, on occasion, referred to as native asphalt, and extra heavy oil), which is the organic component of tar sand, includes a wide variety of reddish brown to black materials of semisolid, viscous to brittle character that can exist in nature with no mineral impurity or with mineral matter contents that exceed 50% by weight. Bitumen is frequently found filling pores and crevices of sandstone, limestone, or argillaceous sediments, in which case the organic and associated mineral matrix is known as rock asphalt (Abraham, 1945). However, bitumen from different deposits (eg, deposits in the United States and Canada, exhibit a variety of properties (Speight, 2015).

According to Ohenhen et al., (2015). Tar sands (also known as oil sand and bituminous sand) is a sand deposit that is impregnated with dense, viscous material called bitumen. The sand makes up about 84% of tar sand by weight and consist predominantly of quartz, with traces of mica, rutile, zircon, tourmaline and pyrite.

Bitumen is typically found surrounding sand grains encased in water and clay, which is where it gets its alternative name, oil sands. The bitumen must be removed from the sands and processed before it can be refined like conventional oil. Unlike the light, sweet crude found in the Niger Delta, extra-heavy oil and bitumen are viscous and dense. To convert this tar-like substance into lighter oil, called synthetic crude that can be used for petroleum products such as petrol, the bitumen must be removed from the sands and processed.

Nigeria's former Ministry of Mines and Steel Development has identified three potential methods of bitumen extraction in Nigeria:

(1) Small-scale surface mining

(2) Large-scale surface mining and

(3) in-situ extraction .(christina, 2015)

Also according to Ogiriki & Agunloye, (2018) The basin sedimentary fill was subdivided into three intervals by Durham Pickect namely:

- Sand and sandstone at the base.
- Alternating sand and shale.
- Upper shales which correspond to the three formations of Ise, Afowo and Araromi respectively.

The grain size of the tar bearing sands vary from fine to coarse grained. The quartz sand forms a bulk of the material with either the bitumen i.e. Oil wet (as in the case of some US deposits - Utah), or water wet (as for the Athabasca in Canada and Okitipupa in Ondo State of Nigeria), forming the continuous phase, generally depending on the grade of the oil sand.

The microscopic examination of the Athabasca tar sand shows that the thin film of water is about 10mm thick. The similarity of the grain/water relationship of both the Nigerian and Canadian tar sand makes it characteristically easy to derive comparative studies on processing Nigerian tar sand from the Canadian experience. Although, the Nigerian tar sand has been discovered since the dawn of the past two decades, they have largely remained unexploited due to the availability of the conventional oil in the neighbouring oil rich Niger Delta of the country. According to Adegoke *et al.* the lithology, hydrocarbon contents area and spatial distribution of the bituminous sands have been well documented. Adegoke *et al.* recommended that bitumen be exploited by open cast mining in areas where the bituminous sands outcrop or where they are overlain by less than 50 – 75 metres of over burden while heavy oil be exploited by the use of in-situ techniques in all areas south of the tar sand mine zone, especially where the over burden thickness is in excess of 100 meters.

Bitumen and extra-heavy oils are unconventional oils that generally require additional processing to extract, transport, and refine into petroleum products than lighter, conventional oils. These additional steps typically incur additional costs - including investment costs as well as environmental and social costs. As conventional oil reserves decline, international companies are increasingly turning their attention towards unconventional oils to meet rising global demand for petroleum products. Nigeria has an estimated 38 billion barrels of extra-heavy oil and bitumen reserves. While this amount is significant, and roughly equivalent to its present conventional oil reserves, this amount is much, much smaller than Canada's 2.4 trillion barrels and venezuela's 2.1 trillion barrels1, as shown in Figure 1,. Geologists and engineers predict that Nigeria would use similar methods to extract bitumen as Canada, as the reserves are geologically similar. (christina, 2015)

2.3 GEOLOGY AND STRATIGRAPHY

From the work done by (Adeyemi, Akinmosin, Aladesanmi, & Badmus, 2013), The tar sand belt falls within the Nigerian sector of the eastern Dahomey basin. The stratigraphy of the basin was studied by Billman (1976) but was reviewed by Omatsola & Adegoke (1981) on the basis of new subsurface data. The Dahomey basin is a coastal sedimentary basin filled with over 2500m of cretaceous and younger sediments uncomfortably overlying the block faulted Basement Complex rocks. The basin's sedimentary fill was subdivided into three intervals by Durham Picket (1966) namely (a) Sand and sandstones at the base (b) alternating sands and shale and (c) upper shales which correspond to the three formations of Ise, Afowo and and Araromi respectively (Omatsola &Adegoke,1981).

Ise Formation: This formation is the oldest, and overlies the weathered basement complex. It is comprised of conglomeratic sands showing upward fining variation into finer grained sands. Kaolinitic clays are quite obvious as interbeds and at the sediment/basement contact ,Quartz is the major constituent of the sands although some other minerals (mica, heavy minerals) have been reported in the stratigraphic record as most of it had been eroded following the Santonian tectonics that affected the basement complex, rocks. A Niccomian age is assigned to Ise formation.

Afowo Formation: Afowo sediments indicate the commencement of deposition in a transitional environment after the entirely basal and continental Ise formation. The sediments are composed of interbedded sands, shales and clays. The sands are tar-bearing whilst the shales are organic–rich. Outcrops of this formation are commonly encountered within the tar sand belt and are easily recognizable because of the presence of sticky and viscous tar seeping out of the sandy portions of the Afowo Formation. The age is Maastrichitian.

Araromi Formation: Sediments of the Araromi formation represent the youngest and topmost sedimentary sequence in the subbasin. They are comprised of shales, fine grained sands, thin interbeds of limestone, clay and lignitic bands. It is attributed an age range of Maastrichitian to Paleocene (Billman 1976,Omatsola and Adegoke,1981).

Solid bituminous sand (tar sand) is formed in a number of ways. These include thermal attraction, microbial degradation, water washing or gas de-asphalting of the fluidly hydrocarbon. Irrespective of its formational mode, bituminous sand is a sedimentary rock attest of the former presence of fluid hydrocarbon in the environment. The occurrence of these deposits in Nigeria has been known since early last century, however intense investigation had commenced and continued from mid-

70’s till date. A reservoir is therefore defined as subsurface rock Containing Commercially exploitable quantities of oil and gas because of its porosity and permeability. These parameters are the two major factors that influence a reservoir quality.

2.3.1 Occurrence

Bitumen occurs as extra heavy crude. The remains of organisms like foraminifera, algae, corals, etc. are naturally buried in the soil. The remains change to light crude at certain depth. In the crust, rise by capillarity could cause the light crude to migrate upward and in doing so is fed upon by bacteria in aquifers. The process removes the lighter components of the crude and leaves the heavier parts behind. As the crude migrates further up, the heavier crude is turned to bitumen. This event could take millions of years.

2.3.2 Properties Of Nigerian Tar Sand

Oil sand (tar sand) consists of an initiate mixture of bitumen, water, quart sand and clays and other minerals which is either oil or water wet. The case of oil sands in Utah in U.S.A is oil-wet but the oil sands in Canada and Okitipupa in Ondo State of Nigeria are water-wet. This makes the Nigerian and Canada tar sand similar. The Nigerian and Canadian tar sand are also similar in the area of mean value of chemical composition (Montgomery 1981), as shown on Table 2.1

Other similarities between Nigeria and Canada tar sand properties on the bases of characteristics is in the area of having similar texture parameter, oil saturation, chemistry and water-wet nature of grains. However, the Nigerian tar sand are more asphalthenic and lesser in trace metals as shown below.

Table 2.1 Chemical Composition Of Nigerian And Canadian Oil Sands (Montgomery 1981)

Element	**Nigeria's composition (%)**	**Canada's composition (%)**
Carbon	85	83.4
Hydrogen	10.7	10.4
Nitrogen	0.5	0.4
Oxygen	1.7	1.0

Table 2.2 Metal Composition Of Nigeria's And Athabasca's Tar Sands (Montgomery 1981)

Element	Nigeria's composition (ppm)	Athabasca' composition (ppm)
Vanadium	35	75
Nickel	33	198

The close similarity of the characteristics of the tar sands of Nigeria and Athabasca suggest that the Canadian experience can be used as a model for the development of Nigerian tar sand. The similarities make it characteristically easy to derive comparative studies on processing of the Nigerian deposits, easy determination of similar techniques for exploitation and draws the difference from those oil wet deposits of California, New Mexico and Utah (Ogiriki & Agunloye, 2018).

2.3.3 Distribution And Classification

Oil is classified according to its API (American Petroleum Institute) number. Based on the API number, oil is divided into three categories;

- 5° - 11 ° as bitumen
- 12° - 25° as heavy crude

- >26° as light crude.

Bitumen is found in Ondo, Lagos, Ogun, Edo and Enugu States. In these areas, five types of hydrocarbon occurrence are known within the tar sand belt in these States. The occurrences are: "Outcrops, Rich sands, Lean sands, Shale and Deep seated heavy crude" (Professor E.A Fayose 2004: Bitumen in Ondo State)

The term "tar sand" is only applicable to the first three types of occurrence that have bitumen content above 10%wt. They are composed basically of sand, bitumen, water and some mineral accessories. The tar sands with 5-10%wt of bitumen are designated as good or medium grade" (Professor E.A Fayose 2004: Bitumen in Ondo State).

Nigeria ranks #6 globally in heavy oil and bitumen reserves, with an estimated 38 billion barrels of oil in place. While this remains a significant quantity of oil, it is substantially less than Canada and Venezuela, who hold the number one and two spots, respectively(christina, 2015).

2.4 CHARACTERISTICS OF NIGERIA BITUMEN AND TAR SAND

Results of the characterization are compared with results in literature for tar sand bitumens and petroleum. Comparison of the results with the Utah and the Athabasca bitumens provides a basis for the evaluation of the Nigerian bitumen because considerable information about the processing characteristics of the Athabasca bitumen have been reponed by many researchers.(Ukwuoma, 1999)

Table 2.3 Characteristics Of Nigerian Tar Sand Bitumen (Ukwuoma, 1999)

Characteristics of Nigerian tar sand bitumen	
Specific gravity 60°F	1.008
API gravity	8.7
Viscosity(cst) at 100°F	323,834
Viscosity(cst) at 210°F	364
Sulphur, wt %	3.57
Ash, wt %	0.24
Conrodson carbon residue, wt %	14.8
Asphaltenes (heptane insoluble) wt %	10.6
Saturates wt %	33.1
Aromatics, wt %	21.9
Polar Compounds, wt %	24.0
Total hydrocarbons, wt %	55.0
Distillate yield (<538°C), wt %	65.2

Figure 2.3: Top 10 Countries With Bitumen And Extra-Heavy Oil Reserves**.** (Christina, 2015)

2.5 CHALLLENGES IN PRODUCING HEAVY OIL

- The main challenge to the in situ production of the bitumen is finding an economical way to increase the fluidity of the bitumen, which is very viscous. The viscosity of the bitumen can be decreased by increasing the temperature or by dissolving the bitumen in a light solvent. Once the bitumen is fluid enough, it can be recovered from an oil well, analogous to conventional crude oil recovery. The need to decrease viscosity and improve fluidity is therefore primarily an issue related to bitumen recovery and transport. (de Klerk, Gray, & Zerpa, 2013)

There are numerous flow assurance and processing challenges associated with the production of heavy oil. These heavy and extra heavy oil processing challenges include the following:

- The need for artificial lift to produce such viscous oils from wells onshore and offshore
- Difficult handling issues with respect to flow, separation, emulsions handling, storage and transportation.
- High heating demand for processing and traditionally large equipment required (residence times)
- Very often solid production will be associated with the processing of heavy oil.
- When such oils are refined they generate more of the less valued products and are more prone to cause.
- Problems, like Cat Cracker catalyst poisoning by high Calcium content in such oils.

(Georgie & Smith, 2012)

2.6 DEFINITION OF EOR

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Historically, these stages described the production from a reservoir in a chronological sense. Primary production, the initial production stage, resulted from the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of operations, usually was implemented after primary production declined. Traditional secondary recovery processes are water flooding, pressure maintenance, and gas injection, although the term secondary recovery is now almost synonymous with water flooding. Tertiary recovery, the third stage of production, was that obtained after water flooding (or whatever secondary process was used). Tertiary processes used miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process became uneconomical. (Don W. Green, 1998)

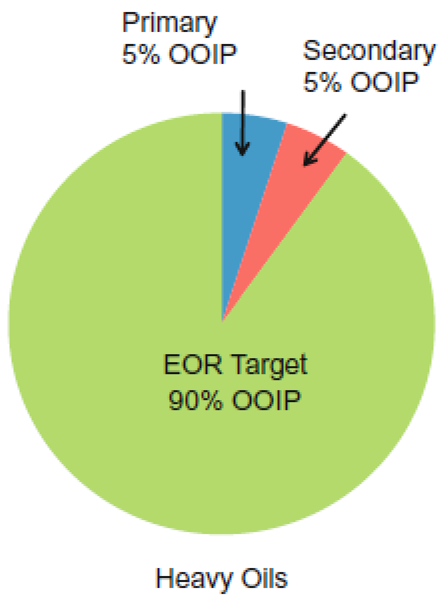


Figure 2.4 Target For Heavy Crude Oil System(Ahmed & Meehan, 2012)

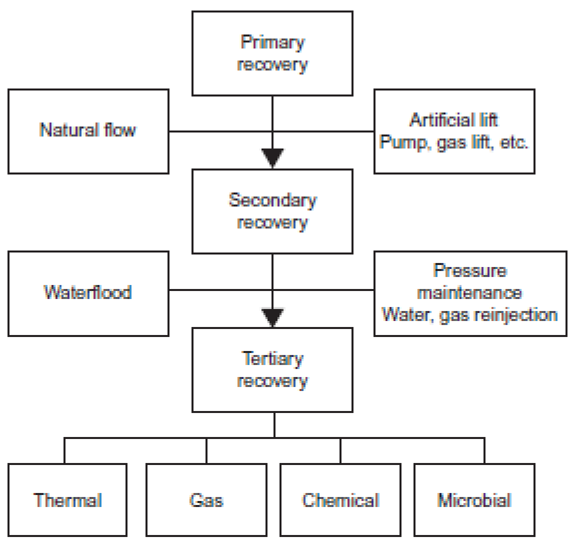


Figure 2.5 Methods For Oil Recovery (Ahmed & Meehan, 2012)

2.6.1 Enhanced Oil Recovery Methods

EOR technologies can be broadly grouped into the following four categories:

• Thermal;

• Chemical;

• Miscible;

• Others.

Each of the four categories contains an assortment of injection schemes and a different variety of injection fluids (Ahmed & Meehan, 2012)

2.6.1.1 Gas Flood Recovery Methods

Miscible fluid displacement involves the injection of gas (e.g., natural gas, enriched natural gas, a liquefied petroleum slug driven by natural gas, carbon dioxide, nitrogen, or flue gas) or alcohol into the reservoir at pressure levels such that the gas or alcohol and reservoir oil are miscible.

2.6.1.2 Chemical Flood Recovery Methods

This enhanced oil recovery processes involve the use of chemicals such as caustic, surfactant/polymer, and polymer.

Surfactant flooding is a multiple-slug process involving the addition of surface-active chemicals to water (Reed and Healy, 1977). These chemicals reduce the capillary forces that trap the oil in the pores of the rock. *Surfactant-polymer flooding,* also known as *micro emulsion flooding,* involves injection of a surfactant system to enhance the displacement of oil toward producing wells.

Polymer augmented waterflooding (sometimes called *polymer flooding*) involves the injection of polymeric additives with water to improve the areal and vertical sweep efficiencies of the reservoir by increasing the viscosity and decreasing the mobility of the water injected.

Alkaline flooding involves the use of aqueous solutions of certain chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate that are strongly alkaline.(Speight, n.d.)

2.6.1.3 Thermal Recovery Methods

Thermal enhanced oil recovery processes add heat to the reservoir to reduce oil viscosity and/or to vaporize the oil. In both instances, the oil is made more mobile so that it can be more effectively driven to producing wells. In addition to adding heat, these processes provide a driving force (pressure) to move oil to producing wells.

Steam injection is the most common form of thermally enhanced oil recovery and is used extensively to increase oil production. In situ combustion is another form; instead of using steam to reduce the crude oil viscosity, some of the oil is burned to heat the surrounding oil. Thermal methods have been used for those heavy-oil reservoirs that cannot be produced in any other way because the oil is too viscous to flow without the application of heat and pressure. To be produced at profitable rates, then ands must have a high permeability and oil saturations must be high at the start of the process..(Taber, Martin, & Seright, 1997)

Thermal methods for oil recovery have found most use when the oil in the reservoir has a high viscosity (Eremin, 2001).

For example, heavy oil is usually highly viscous, with a viscosity ranging from approximately 100 centipoises to several million centipoises at the reservoir conditions.

In recent years, thermal methods has acquired a major role in the tertiary recovery of crude oils. (People are tending towards tapping into unconventional oil, and thermal is one of the best method of producing unconventional oil)Thermal EOR methods are generally applicable to heavy, viscous and paraffinic crudes. It involve the introduction of thermal energy or heat into the reservoir to raise the temperature of the oil and reduce its viscosity. Steam (or hot water) injection and in-situ combustion are the popular thermal recovery methods used in EOR (Ikiensikimama, 2019)

For the purpose of this research (Heavy oil). Thermal is the best method for heavy oil, so we will focus more on thermal recovery methods.

2.7 SCREENING CRITERIA FOR THERMAL METHOD

Taber et al. (1997) proposed screening criteria for enhanced oil recovery methods that were developed by compiling numerous data from EOR projects around the world. As a first step in selecting and implementing an enhanced oil recovery method, a screening study should be conducted to identify the appropriate EOR technique and evaluate its applicability to the reservoir. Based on extensive analysis of the collected data, the authors listed the optimum reservoir and oil characteristics that are required for implementing a successful EOR project in a particular field in Table 2.4 (Taber et al., 1997).

Thermal methods account for the biggest share of the world's enhanced oil production. The largest EOR operations in many countries (e.g., Canada, Colombia, Germany, Indonesia, Trinidad, the U.S., and Venezuela) are either steamfloods or surface-mining operations. In the past, the production of bitumen from tar sands has not normally been included in EOR screening criteria or surveys, perhaps because the mining operations are not considered a part of reservoir engineering. However, the resource is so important that hydrocarbon recovery from tar sands should be included in listings of EOR or IOR processes. There is a very strong effort to try to recover these extremely viscous oils by in-situ methods to avoid the cost of surface mining and to open vast deeper reserves.

Table 2.4 Summary Of Screening Criteria For Eor Methods (Taber Et Al., 1997)

OIL PROPERTIES				
	Gravity ^{o}API	**Viscosity (cp)**	**Composition**	**Oil saturation Oil saturation**
combustion	**<40(10-25 normally)**	**<1000**	**Some asphaltic components**	**>40-50% pv**
steamflooding	**<25**	**>20**	**N/c**	**>40-50% pv**
RESERVOIR CHARACTERISTICS				
Formation Type%	**Net thickness(ft)**	**Average permeability(md)**	**Depth(ft)**	**Temp(^{o}F)**
Sand or sandstone with high porosity	**>10**	**>10**	**>500**	**>150 preferred**
Sand or sandstone with high porosity	**>20**	**>200**	**300-50000**	**N/c**

Where

N/c- Not critical and PV- pore volume.

2.8 BITUMEN EXPLORATION AND EXTRACTION TECHNOLOGIES

Various technologies have been proposed, developed and tested for the recovery of bitumen from oil and tar sands. There have also been modifications of some of these technologies. Pioneering these inventions are the United States, Canada and Venezuela. The drive to pioneer these inventions is connected to the fact that larger percentages of world bitumen deposit are found in these countries. Another drive is the fact that world economy and power are deeply rooted in petroleum products trade. For the purpose of this research work however, these technologies vis-a-vis steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

2.8.1 Steam Assisted Gravity Drainage SAGD

For SAGD production two horizontal wells are drilled in the oilsands ore layer, one about 5 m above the other. The top well is used for steam injection and the bottom well is used for bitumen recovery. The wells are equipped with a slotted liner or a fine wire mesh screen to limit the entrance of small particulates into the well. Production from a SAGD well pair involves the continuous injection of steam through the injection well. As the temperature of the surrounding oilsands deposit increases, the bitumen becomes less viscous and it can flow by gravity drainage into the production well. The bitumen is recovered as a mixture with water and fine mineral matter that passed through the well screens.

The mixture typically contains (25_30) % bitumen, (70_75) % water and 1 % mineral matter. After separation of the bitumen from the water, the water is cleaned and part of the water is recycled. The estimated production life of a SAGD well pair is around 15 years, with an ultimate bitumen recovery of (70_80) % for continuous steam feed production. The steam to oil ratio required for SAGD bitumen production is typically (2_3) m3_m23 on a liquid volume basis(de Klerk et al., 2013).

SAGD was initially developed to recover bitumen from the Canadian oil sands. The key element of SAGD is that the two wells need to be parallel and horizontal. It is only in the last 10 to 15 years that directional drilling technology has been able to achieve these two characteristics with any degree of certainty. In the simplest form, the SAGD technology requires the drilling of two parallel horizontal wells through the oil-bearing formation. Into the upper well, steam is injected creating a high-temperature steam chamber. The increased heat loosens the thick crude oil causing it to flow downward in the reservoir to the second horizontal well. This second well is located parallel to and below the steam injection well. This heated, thinner oil is then pumped to the surface via the second horizontal, or production well. Water is injected into the bitumen-drained area to maintain the stability of the deposit.(Orire, 2009).

2.8.2 Cyclic Steam Stimulation (CSS)

The method involves the thinning of reservoir oil so that it will move more easily from the injection to the production wells. It could also be used as a single well procedure. This method, also known as the Huff and Puff method, consists of 3 stages: injection, soaking, and production. Steam is first injected into a well for a certain amount of time to heat the oil in the surrounding reservoir to recover approximately 20% of the Original Oil in Place (OOIP). It is quite common for wells to be produced in the cyclic steam manner for a few cycles before being put on a steam flooding regime with other wells.

The mechanism proceeds through cycles of steam injection, soak, and oil production. First, steam is injected into a well at a temperature of 300 to 340° Celsius for a period of weeks to months. Next, the well is allowed to sit for days to weeks to allow heat to soak into the formation. Finally, the hot oil is pumped out of the well for a period of weeks or months (Speight, 2015).

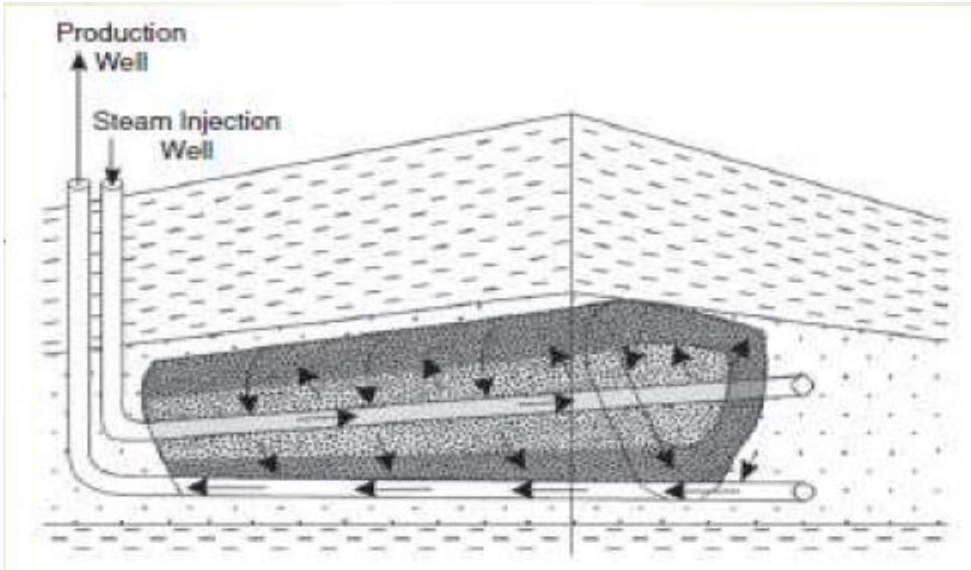


Figure 2.6: Sagd Process Diagram

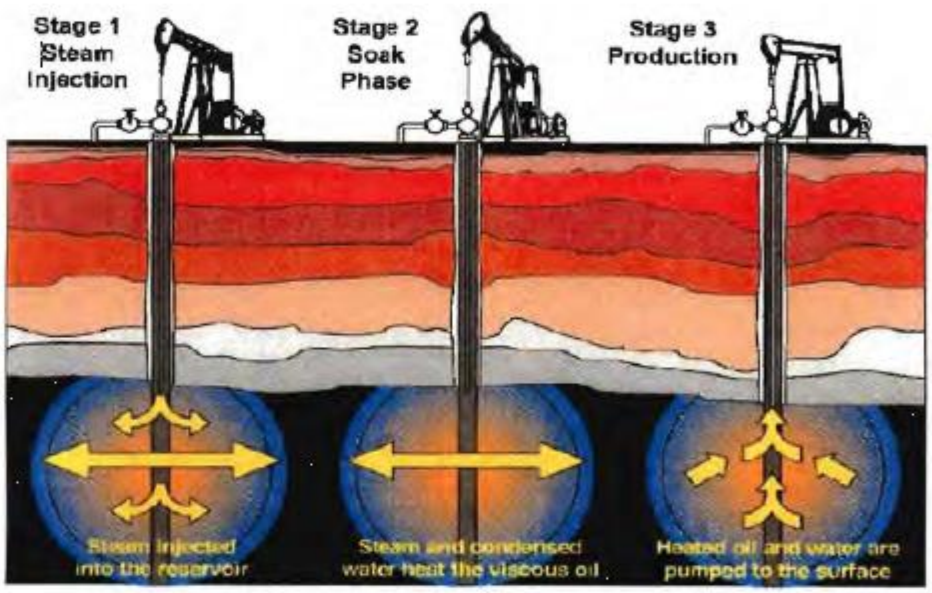


Figure 2.7: Cyclic Steam Stimulation Process (Alberta Energy Research Institute, Calgary. October, 2004)

According to Orire, (2009), who cited Dr Oluropo Rufus Ayodele (August 2006), wrote the following, bitumen and heavy oil as shown above can be recovered through any thermal -based recovery technique like SAGD, steam flooding, and *CSS* techniques. These techniques, although a bit specialized, are much cheaper than implementing surface mining operation. Some multinational oil companies in Nigeria, like ExxonMobil, Shell, Chevron and ConocoPhillips are already operating in situ techniques in Canada, Venezuela and some other locations around the world. He also reported that because the costs are cheaper, these companies can easily implement such operations in Nigeria and so transfer the technical know-how to the country through their other operating subsidiaries around the world. Such in situ operations will also present few barriers to indigenous investors who want to get into heavy oil and bitumen exploration and production activities.

CSS VS SAGD: Note that the choice between CSS and SAGD technology is dictated by the geology of the reservoir. The Cold Lake deposit lends itself better to CSS while oil sands in the Athabasca region responds better to SAGD.(Www.oilsandsmagazine.com/technical/in-situ, 2019)

2.9 INVESTMENT ADVANTAGES IN BITUMEN EXPLORATION AND DEVELOPMENT IN NIGERIA

The country alongside ECOWAS sub-region has a large market (about *15,000/20,000* metric tonnes per annum). The market has the capacity to grow as the present government has promised to open up the rural areas in order to decongest the cities. In order to make investment in bitumen attractive to developers, the federal government has offered many incentives in the form of waivers on tax and has also allowed foreign companies to buy into domestic companies. (Nigeria Investment Promotion Committee report, June 2004). Other investment advantages will be in the form of technology transfer. Most of the technologies for exploration and development of bitumen ore are foreign to the country. This will ultimately benefit the country. The federal government has also promised tax reduction for equipment imported into the country for the purpose of bitumen exploration. Other form of investment advantage is in the other sectors, vis-a-vis power and transport sectors. These sectors of the country are so poor that it has become issues of serious concern to all. The potential of the development of bitumen ore to positively affect these sectors is not in doubt. Power is one of the core requirements for bitumen exploration and development. Access to the deposit must be created. Also asphalt that is one of the main by-products of bitumen is presently being imported by the country due to the fact that the Kaduna refinery that was supposed to produce bitumen/asphalt has been out of order since 1986. (Orire, 2009)

2.10 ECONOMIC EVALUATION

The purpose of petroleum engineering is to examine, define, and implement methods and procedures for developing and extracting oil, gas and associated products so as to;

(1) Optimize profits

(2) Obtain a return-on-investment that is commensurate with the risk incurred in making the investment.

Economic evaluation consists of two major objectives:

● Estimation of the amount of producible oil and/or gas attributable to a property or project and prediction of a schedule of recovery of the producible volume

● Estimation of the economic value of the predicted future production (Brimhall, 2016).

2.10.1 Review Of Statistics And Risk Analysis

Uncertainty and risk are two terms which we commonly come across when analyzing any exploration prospect or oil field investment project. Risk arises because there is uncertainty about the course of future events. Risk analysis tries to quantify uncertainty by treating uncertain input parameters of a problem as random variables, which are distributed according to quantifiable statistical distribution functions. Different outcomes can then be simulated by letting a computer recalculate the model many times, using different randomly selected sets of values for the input parameters. This is like trying all valid combinations of values of the input parameters to simulate all possible outcomes. The net result of this process would be to specify the model output as a statistical distribution of probable values. This process is also sometimes called Monte-Carlo simulation(Joshi, 1998).

2.10.2 Discounted Cash Flow Model

The first basic principle of finance is that a dollar received today is worth more than a dollar received in the future, because the dollar today can be invested to earn interest and thus will be worth more than a dollar received in the future. This principle is fundamental in analyzing the economic feasibility of any oilfield project, since a future oil production rate schedule must be translated into future cash flows, which in turn must be related to an investment decision in the present. Therefore a method is needed to convert a delayed payoff into a value today, a *present value* (PV). This is done by multiplying the delayed payoff by a *discount factor*, which is less than 1. If there are a series of delayed cash flows *Ci* at times *ti* then their PV is given by

$$PV = \sum_{i=1}^{n} DF_i \times C_i \qquad (2.1)$$

where DF_i is the discount factor at time t_i .

The discount factor is given by

$$DF_i = \frac{1}{(1+r_i)^{t_i}} \qquad (2.2)$$

In Equation 2.1, r_i is the rate of return that would be offered by other comparable investments (at time t_i). This rate of return is also called by various names; the *discount rate*, *hurdle rate* or *opportunity cost of capital.* The term opportunity cost arises because it is the return that is foregone by not investing in safe securities. The Net Present Value (NPV) is obtained by adding the initial cash flow for the project (usually a negative number, since it is a cash outflow) to the PV equation

$$NPV = Co + PV \tag{2.3}$$

One important point to be noted about the NPV rule is that it is stated in terms of cash flows. Cash flows are, simply stated, just the difference between dollars received and dollars paid out. Cash flows must not be confused with accounting profits. They must, however, be estimated on an after-tax basis, as tax payments are real cash out-flows. Therefore, for most analyses, we can estimate cashflows using the general equation

$$CF = NOI - TAX \tag{2.4}$$

where CF is cashflow, NOI is net operating income and TAX is taxes paid. Here,

NOI = Gross Income - Expenses.

The main criterion to be used, when evaluating any project by the NPV method, is that the NPV must be greater than zero. This simply implies that the present value of any future payoffs from the project is greater than the initial and future (discounted) cash outflows required for the project.

Another related number, which is sometimes used, is the Internal Rate of Return (IRR). The IRR is simply that rate of return which makes the NPV equal to zero. Thus the IRR is the rate of return at which the PV of future payoffs is equal to the initial cash outflow for the project. However the IRR is less useful than the NPV because sometimes a project may not have a unique IRR and in some cases an IRR may not even exist. (Joshi, 1998)

CHAPTER 3

RESEARCH METHODOLOGY

This chapter describes the methodology used in this study. It includes data acquisition, analysis and evaluation of the economic model.

3.0 INTRODUCTION

Making the decision to invest in petroleum exploration and production projects is always a very complicated endeavor. These projects are impacted by many high risk factors associated with the petroleum industry, such as relatively high initial investment requirements, long term investment horizons (projects may take up to 20 years or more) and negative cash flow during the first few years, sometimes also during the last years of the project life. These factors, coupled with dangerously volatile price levels, makes the number of uncertainties in the data utilized in decision making to invest in petroleum projects very high, and this therefore weighs heavily on the minds of decision makers (Shereih, 2017).

Most petroleum companies make the decision to invest in a certain petroleum project based on economics models, which are constructed as spreadsheets prepared by internal economists in the company or by external experts based on data available from different sources (such as petroleum engineers, geologists etc.). As a result, each petroleum company has developed its own economics model. These models are characterized by unclear definitions of input variables and the way they are related to the output parameters. Energy policy analyst, investors, or developers use varieties of figures to predict the cost effectiveness of a project. They often include capital cost, projected output, annual revenue, operating cost and deductions. For the purpose of this research, however, these primary figures were identified. The methods needed for petroleum project evaluation in other to determine the profitability is described in this chapter. The model approach adopted would be spreadsheet based and are similar to those presented by Mian M.A (2002) and (Iledare, 2019).

To build a complete economic model, it is vital that the production profile of the field be first established. Estimating the quantity of the proved reserves is the beginning of investment decision in petroleum industry.

This is a useful way of determining reserves and the associated production forecast, specifically for the fields/wells with insufficient information. The method is widely used on new wells drilled in a developed field and/or exploratory wells (wildcats). The analogy used for wells drilled in a developed field is expected to constitute the reservoir characteristics in the wells producing in the adjacent sections. For wildcats, the analogy can be used from other fields producing from the same type of expected hydrocarbon accumulations. The closer the analogous properties are to the properties to be evaluated, the better and more reliable the estimates will be.

Analogous information can be used to determine average recovery factor, ultimate oil and/or gas reserves, and the most likely production behavior. Note that analogy must be from the same type of reservoirs with approximately the same geological age, reservoir drive mechanism, and petrophysical properties.(Mian, 2002).

For the purpose of this project since Nigeria has not fully started Bitumen production we will use production parameter from Athabasca field in Canada to get production data by modeling(using hyperbolic decline), as it is similar in property to that of Nigerian heavy oil (Orire, 2009).

3.2 PETROLEUM PRODUCTION FORECASTING

Three typical phases were adopted in this work, for production forecasting. Which are:

- ✓ Build-up phase

- ✓ Plateau phase
- ✓ Decline phase

3.2.1 Build-Up Phase

This phase of the model indicates the initial conditions of reservoir production. It is the earliest stage of reservoir depletion in mostly new fields. During this stage, the wells are being drilled and the production facilities are being put in place, hence the wells cannot flow at full capacity. This condition was factored into the model by first flowing the wells at a low instantaneous production rate. Gradually, the flow was increased at a specific build up rate, for some time, t, until peak production rate, as reached. How this increase in rate was achieved remained a function of the reservoir and fluid properties. The reservoir properties might necessitate linear increment of the flow rates until peak level is attained. However, this model used Arp's equations to reflect the different rates decline and buildup patterns. This was to establish uniformity in the behavioral assumptions in the build-up as well as the decline phases of this investigation. Arps (1945) presented different equations for the decline patterns that are prevalent during production. These equations are for exponential, hyperbolic and harmonic decline patterns as summarized in Table 3.1 below.

Table 3.1 Arp's Equations

	EXPONENTIAL	HYPERBOLIC	HARMONIC
DECLINE RATE, (a_i)	$\frac{q_i - q_t}{N_p}$	$\frac{\left(\frac{q_i}{q_t}\right)^b - 1}{bt} = \left\{\frac{q_i}{N_p(1-b)}\right\}\left\{1 - \left\|\left(\frac{q_i}{q_t}\right)^{(1-b)}\right\|\right\}$	$\frac{\frac{q_i}{q_t} - 1}{t} = \frac{q_i}{N_p} \ln \frac{q_i}{q_t}$
PROD. RATE, (q_t)	$q_i \exp(-a_i t)$	$\frac{q_i}{\{1 + b\, a_i\, t\}^{\frac{1}{b}}}$	$\frac{q_i}{\{1 + a_i\, t\}}$
CUM. PROD, (N_p)	$\frac{q_i - q_t}{a_i\|}$	$\left\{\frac{q_i}{a_i(1-b)}\right\}\left\{1 - \left\|\left(\frac{q_i}{q_t}\right)^{(1-b)}\right\|\right\}$	$\frac{q_i}{a_i} \ln \frac{q_i}{q_t}$

where

$a_i =$ Decline rate in per unit time.

q_i& q_t are flow rates in bbl per unit time.

b = the hyperbolic exponent. This could be obtained by Newton Ralphson's Iterations (Ahmed, 2000)

t = time in days, months or years: care was taken to maintain consistency in time units

N_p = the cumulative production in bbls

The build-up rate could be viewed as the reverse of decline rate, as changing the sign convention of one would reflect the behavior of the other. The build-up stage of the production profile was generated by using and transforming the Arp's equations as presented in the second and the third rows of Table 3.1.

Buildup rate, $d = -a = -\frac{q_i - q_p}{N_p} = {(ln\frac{q_p}{q_i})}\Big/{t}$ ----------------------- 3.1

Production rate at any time, t, before plateau phase

$q_t = q_i \exp(dt)$--- 3.2

Cumulative production,$N_p = \frac{q_t - q_i}{d}$-- 3.3

Annual production,$N_a = \frac{q_{t+1} - q_t}{d}$-- 3.4

For hyperbolic build-up behavior, the following were the governing equations used in the coding of the model:

Buildup rate, $d = \frac{(\frac{q_i}{q_t})^b - 1}{bt}$ -- 3.5

Production rate at any time, t, before plateau phase, was obtained by the equation

$q_t = \frac{q_i}{\{1+b\,d\,t\}^{\frac{1}{b}}}$ -- 3.6

Cumulative production, $N_p = \frac{\left(\frac{q_i}{q_t}\right)^b - 1}{bt} = \left\{\frac{q_i}{N_p(1-b)}\right\}\left\{1 - \left|\left(\frac{q_i}{q_t}\right)^{(1-b)}\right|\right\}$--------- 3.7

Annual production, $N_a = N_{p(t+1)} - N_{p(t)}$-- 3.8

For harmonic build-up behavior, the following were the governing equations used in the coding of the model:

Buildup rate, d=$\frac{\frac{q_i}{q_t} - 1}{t}$-- 3.9

Production rate at any time, t, before plateau phase, was obtained by the equation

$\frac{q_i}{\{1+dt\}}$-- 3.10

Cumulative production,$N_p = \frac{q_i}{d} \ln \frac{q_i}{q_t}$-- 3.11

Annual production, $N_a = N_{p(t+1)} - N_{p(t)}$-- 3.8

3.2.2 Plateau Phase

This phase in the life of a field starts as soon as the build-up period is over. Many wells would have been completed and the facilities for production and transportation would have been duly put in place. Therefore, the wells could flow up to full acceptable capacity. The production rate is at its peak throughout the life of this phase. The operators are interested in maintaining this phase for as long as it is technically and economically feasible. Strong pressure support is observed in the reservoir within this period. During this period it is expected that the bulk of the investment made by the contractor will have been recovered. In the model, this was easy to incorporate. Consider the production profile represented in Fig 3.1. The area of the rectangle covered by the plateau phase is given by the peak rate, q_p multiplied by the time duration, t, of the phase. This is the cumulative production for that period. Hence, cumulative production, N_p was obtained in the model by using equation 3.12a below.

Cumulative production, $N_p = q_p t$ -- 3.12a

Annual production, , $N_a = q_p t$ -- 3.12b

where t in eq. 3.12b is the monthly or yearly time within the plateau phase.

Equation 3.12 remained the same for all the decline regimes (exponential, hyperbolic and harmonic) used in the model.

3.2.3 Decline Phase

This is the last phase in the life of the reservoir. It starts as soon as the plateau production is over. During this period the reservoir pressure is constantly on the decrease, which is reflected by gradual fall in the rate of production. The contractor embarks upon a lot of pressure maintenance and enhanced hydrocarbon recovery projects to keep up production and increase the life of the field before economic limit. Economic limit could be driven by different factors which range from sociopolitical to real economic issues.

Depending on the physical and fluid properties of the reservoir, decline could manifest in three ways:

- ✓ Exponential
- ✓ Hyperbolic
- ✓ Harmonic

This research assumes that the production decline pattern in this phase is similar to what was done in the build-up stage.

Decline rate, $a_i = \frac{q_p - q_{ei}}{N_p}$ --3.13

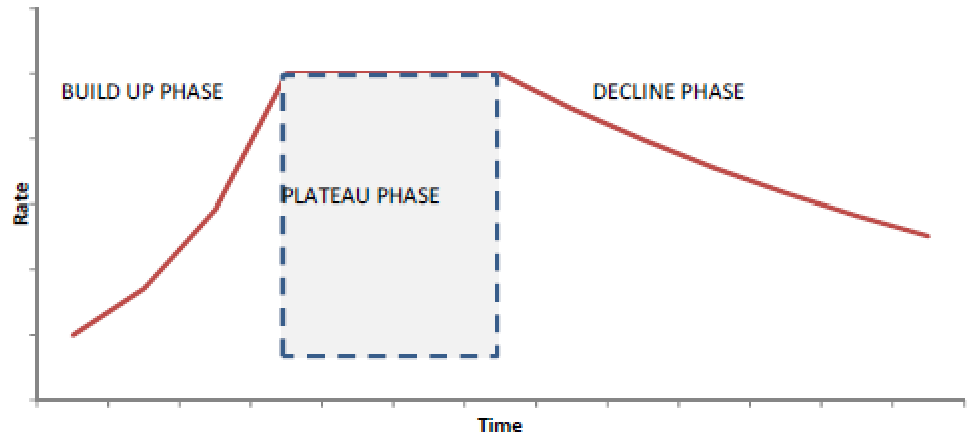


Figure 3.1 - Typical Production Profile Showing Build-Up, Plateau And Decline Phases.

Where q_{ei} is the economic limit rate. This rate was considered to be zero in order to calculate the decline rate, a_i since exponential decline rate is a constant percentage and N_p is the total ultimate recovery during the decline period. However, if cumulative production in the decline region up to economic limit was known as an input, equation 3.13 could accurately be used.

Care was taken to maintain unit consistency between flow rate and decline rate.

Production rate at any time, t, after the plateau phase, was obtained by the equation

$q_t = \exp(-a_i t)$-- 3.14

Cumulative production, $N_p = \frac{q_p - q_t}{a_i}$ --- 3.15

Annual production, $N_a = \frac{q_t - q_{t+1}}{a_i}$ ---3.16

For hyperbolic decline behavior, the following were the governing equations used in the coding of the model:

Decline rate, $a_i = \left\{\frac{q_p}{N_p(1-b)}\right\}\left\{1 - \left|\left(\frac{q_{ei}}{q_p}\right)^{(1-b)}\right|\right\}$-------------------------------------3.17

Where b is the hyperbolic decline curve exponent.

Production rate at any time, t, after plateau phase, was obtained by the equation

$$q_t \frac{q_p}{\{1+b\, a_i\, t\}^{\frac{1}{b}}} \text{--} \quad 3.18$$

Cumulative production, $N_p = \left\{\frac{q_p}{a_i(1-b)}\right\}\left\{1 - \left|\left(\frac{q_t}{q_t}\right)^{(1-b)}\right|\right\}$ ---------------------------- 3.19

This is strictly the cumulative production within the decline period only. For total cumulative production, addition to that before decline phase was effected.

Annual production, $N_a = N_{p(t+1)} - N_{p(t)}$-- 3.8

For harmonic decline behavior, the following were the governing equations used in the coding of the model:

Decline rate, $a_i = \frac{q_p}{N_p} \ln \frac{q_p}{q_{et}}$ -- 3.20

It should be noted also that the N_p used was that for decline phase only.

Production rate at any time, t, after plateau phase, was obtained by the equation.

$$q_t = \frac{q_p}{\{1+ a_i\, t\}} \text{--} \quad 3.21$$

Cumulative production $N_p = \frac{q_p}{a_i} \ln \frac{q_{p_i}}{q_t}$ --------------------------------------- 3.22

This is strictly the cumulative production within the decline period only. For total cumulative production, addition to that before decline phase was effected.

Annual production, $N_a = N_{p(t+1)} - N_{p(t)}$-- 3.8

For the purpose of this thesis which is heavy oil hyperbolic decline rate will be used.

Table 3.2: Production Data For CSS: Source (Cash Flow Model)

Year Begin	Oil (BOPD)	Annual MM(STB)	Cumulative at year end MM(STB)
2019	-	-	-
2020	100	-	-
2021	128	41,448.10	41,448.10
2022	165	53,172.08	94,620.18
2023	211	68,212.31	162,832.50
2024	271	87,506.81	250,339.31
2025	347	112,258.94	362,598.25
2026	703	256,440.00	619,038.25
2027	703	256,440.00	875,478.25
2028	703	256,440.00	1,131,918.25
2029	703	256,440.00	1,388,358.25
2030	703	256,440.00	1,644,798.25
2031	703	256,440.00	1,901,238.25
2032	703	256,440.00	2,157,678.25
2033	703	256,440.00	2,414,118.25
2034	703	256,440.00	2,670,558.25
2035	520	221,536.84	2,892,095.09
2036	385	164,100.21	3,056,195.31
2037	286	121,554.86	3,177,750.17
2038	212	90,040.01	3,267,790.18
2039	157	66,695.84	3,334,486.01
2040	116	49,403.98	3,383,889.99
2041	86	36,595.28	3,420,485.27
2042	64	27,107.43	3,447,592.70
2043	47	20,079.43	3,467,672.13
2044	35	14,873.55	3,482,545.68
2045	26	11,017.37	3,493,563.05
0	-	-	-
0	-	-	-

Table 3.3: Production Data For SAGD: Source (Cash Flow Model)

Year Begin	Oil (BOPD)	Annual MM(STB)	Cumulative at year end MM(STB)
2019	-	-	-
2020	100	-	-
2021	138	43,119.27	43,119.27
2022	191	59,651.29	102,770.57
2023	265	82,521.73	185,292.29
2024	366	114,160.73	299,453.02
2025	507	157,930.20	457,383.22
2026	2,810	1,025,760.00	1,483,143.22
2027	2,810	1,025,760.00	2,508,903.22
2028	2,810	1,025,760.00	3,534,663.22
2029	2,810	1,025,760.00	4,560,423.22
2030	2,810	1,025,760.00	5,586,183.22
2031	2,810	1,025,760.00	6,611,943.22
2032	2,810	1,025,760.00	7,637,703.22
2033	2,810	1,025,760.00	8,663,463.22
2034	2,810	1,025,760.00	9,689,223.22
2035	2,810	1,025,760.00	10,714,983.22
2036	503	489,494.72	11,204,477.95
2037	90	87,608.91	11,292,086.85
2038	16	15,680.09	11,307,766.94
2039	3	2,806.39	11,310,573.34
2040	1	502.28	11,311,075.62
0	-	-	-
0	-	-	-

3.3 DATA REQUIREMENT

The model building will involve two fold and there are the technical aspect and the non-technical aspect. The technical aspect involved the production forecasting of a typical onshore field in Nigeria.

The non-technical part involved the Nigerian fiscal system (NMMA 2007) and cost assumptions typical of a Nigerian onshore lease. However, these costs could be made user-specific to reflect true individual realities. The oil price would reflect the lease acquisition year constant dollar-per-barrel. This price could still be made variable, real or nominal as desired by the user and the prevailing conditions. To build a complete economic model, it is vital that the production profile of the field be first established. This work will assume a huge heavy oil (bitumen) reserve typical to those in Athabasca with good recovery factor, reasonable instantaneous and peak production rates that would bring about good build up period, Sustained plateau period and the economic life of the field could vary based on the decline method to be applied. The fiscal systems used in this work were made to reflect those which govern operations in Nigeria. The fiscal system invoked in this work was NMMA 2007. Based on these fiscal systems, royalties were deducted from the gross revenue and bonuses were treated as costs.

The profitability criteria adopted in the work were NPV at a certain hurdle rate, internal rate of return and profitability index. Sensitivity analyses were invoked or employed to determine the impact of decline rate, reservoir size, oil price, cost depreciation and the corporate income tax on the profitability criteria using @RISK. However, the model has been automated to allow for input data variation.

3.4 FISCAL TERMS

Fiscal terms for upstream investment refer to the agreement between a government and an oil and gas exploration company to explore, develop and produce hydrocarbons (Centre for Energy Economics, Univ. of Texas). A fiscal system contains definitions of the relationship between mineral owners (host government) and the oil and gas companies (IOC, NOC & DOC). This relationship could range from taxation, legislations, contracts, whether or not costs are recoverable and how to share profit between host government and oil and gas companies. From the foregoing, it could be deduced that a fiscal system is location specific, as each country has a unique system that works for her. Nigeria has practiced both the R/T and PSC fiscal systems. This research focused on the R/T system as is prevalent in the onshore terrains of the Nigerian territory. The R/T systems modelled include the current NMMA 2007. This was to bring out a basis of analysis for this investigation.

According to Akintayo Lawal (2011), Presently, three independent tax regimes exist in the upstream sector of the Nigerian petroleum industry. These are corporate (PPT, 1990), Petroleum Technology Development Fund (PTDF, 1990) and Education Trust Fund (ETF,1993). The reference-case fiscal terms are presented in the Table below. At present, the royalty rate varies from one basin to the other. For the inland basins, to which the bitumen-bearing Dahomey Basin belongs, the royalty rate is 10% (PPT,1990). Considering that Nigeria is yet to have a dedicated policy for the exploitation of her heavy oil and bitumen resources, we apply the laws currently guiding the exploitation of her light crude and gas. However, where data gap exists and for the sake of sensitivity studies, we make reasonable assumptions from information available on the well-established industries in Canada and elsewhere (Gaspar Ravagnani *et al.*, 2009; Shin and Polikar, 2006; Edwards, 2000).

As a comparison, the rate for the onshore sector of the Niger Delta is 20% (PPT, 1990). The disparity of fiscal rates is currently one of a number of efforts at attracting investors to this bitumen belt. In the calculation of the annual net cash flow, we assume that the prospective project developer is not an existing taxpayer (i.e. new investor) hence does not pay tax in the years when fiscal costs exceed gross revenue. However, we implement the three-year tax holiday which is

Table 3.4: Fiscal-Term Components

Item	**Rate**
Corporate tax	40 % (Vanguard, 2010; PPT, 1990; 1999 Decree Nos. 9, 26).
PTDF tax	3 % (PTDF, 1990).
ETF tax	2 % (ETF, 1993).
Discount (inflation)	10 % / year (Yang *et al.*, 2009).
Depreciation	20 % / year (NIPC, 2010).
Royalty	10 % (PPT, 1990).
Tax relief period	3 years
Income tax	20% (NMMA 2007)

3.5 COST TREATMENT AND ASSUMPTIONS

These costs are in two folds: technical and nontechnical. Technical costs include CAPEX, OPEX and abandonment costs. CAPEX could either be tangible or intangible.

3.5.1 Capital Cost (CAPEX)

Companies expend capital cost in order to obtain capital assets used to produce the petroleum. Usually, it is paid only once at the beginning of the project, although sometimes CAPEX occurs during the economic life of the project; for example, if the project applies new techniques and facilities in order to increase petroleum production.

The assumptions for the capital expenditures for this thesis are given below

Table 3. 5: Capex Estimates (Source: Birrell (2003) And Infomine Cost Data Centre, (2018))

Description	Cyclic steam stimulation(CSS)	Steam assisted gravity drainage(SAGD)
CAPEX	$1.7492500million USD	$2.0405000million USD
License	$2500 USD	$2500 USD
Steam generation	$5.11 million USD	$5.11 million USD
Bitumen treatment	$4.38 million USD	$4.38 million USD
Drilling cost	$8 million thousand USD	$ 10.912500 million USD

3.5.1.1 Depreciation

Depreciation is the loss in the value of asset over the time it is being used (Mian, 2002). The purpose of fiscal depreciation expense is to spread investment costs over time, for income tax and financial report purposes. It is a method for capital recovery of the costs of fixed assets over the estimated useful life of the asset according to the underlying rules set by tax legislation.

3.5.1.2 Types Of Depreciation Methods.

- Straight line depreciation (SLN)
- Declining balance depreciation (DB)
- Double declining balance depreciation (DDB)
- Sum-of-the-years'-digits depreciation (DDB)

$$SLD = \frac{DEPRECIATION\ COST - SALVAGE\ VALUE}{USEFUL\ LIFE} \qquad \text{3.23}$$

$$SYD = \frac{NUMBER\ OF\ REMAINING\ YEARS\ OF\ LIFE}{SYD}(DEPRECIATION\ COST - SALVAGE\ COST)$$

…3.2

$$SYD = \frac{N(N+1)}{2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 3.24$$

N=Useful Life Of Asset

For the purpose of this thesis the straight line depreciation (SLN) will be adopted, as stipulated by the Nigerian government (NIPC, 2010), the straight-line method of depreciation is used to provide for the depreciable assets. Specifically, the CAPEX elements are depreciated in equal amounts over the first 5 years of incurring the costs (NIPC, 2010).

3.5.2 OPEX

This is also called lease operating expenditure (LOE). It is a direct cost associated with production. OPEX together with CAPEX make up technical cost. No operating costs if there is no ongoing production or injection. OPEX could be divided into variable and fixed costs.

Other model Input Data

The input data fed into the model are price, projected production, royalty, mineral tax.

Assuming an exponential function, the production history data was used to forecast production for the projected period of 10years

$$Gross\ Revenue = Annual\ Production\ \times Price \ldots\ldots\ldots\ldots\ldots 3.4$$

For the purpose of this thesis the prices used were randomly selected using excel, but within a range of low price($20.41-$29.23) gotten from (Birrell, Aherne, & Seleshanko, 2005),

3.6 KEY BUSINESS INDICATORS OF PETROLEUM PROJECTS

According to Shereih (2017), Key business indicators of petroleum projects present tools utilized in the improvement of the decision making process. The most common used indicators for evaluation of petroleum projects are net cash flow; discounted cash flow; net present value; internal rate of return and payback period.

3.6.1 Net Cash Flow (NCF)

The net cash flow of a project is defined as the cash remaining after covering all the expenses during one year or one period (Mian, 2011). In order to express the annual NCF associated with a petroleum project, the cash disbursements should be subtracted from cash receipts for the given period.

NCF = cash inflows (revenue) – cash outflows (cost)………………………………… 3.24

Babusiaux & Pierru (2005) classified net cash flow as net cash flow before tax payments and net cash flow after tax payments; also operating cash flow generated only from petroleum sales and associated costs and other net cash flow generated from other unusual cash inflows or outflows such as asset sales or wastage.

A negative cash flow for one year is not necessarily bad for the total investment; it could mean that the company makes a large investment at this period which earns a high return later.

For example, the first years of the petroleum project where a lot of money is paid for exploration and development but no reward is achieved.

After all required information was collected; the construction of net cash flow started.

3.6.2 Discounted Cash Flow

Discounted cash flow is a technique which translates the time value of money by discounting the future cash flow to a present value reference (Kruschwitz & Leoffler, 2005). The discounted cash flow in the end of the year a is given as:

$$DCF_a = \frac{NCF_a}{(1+i)^a} \qquad 3.25$$

where,

NCF_a: Net cash flow at the end of year a

i: The discount rate

a: Number of the year a = 0, 1, 2…A

The above equation assumes that the cash flow has occurred at the end of the year, which is also what use in this thesis was.

3.6.3 Net Present Value

The net present value (NPV) value is the algebraic sum of discounted annual cash flows associated with the project (Mian, 2011). The NPV is given as:

$$NPV = \sum_{a=0}^{A} \frac{NCF_a}{(1+i)^a} \quad \text{……………………………………………………….………..3.26}$$

When the NPV of an investment at a certain discount rate is positive, the project is acceptable. By evaluating mutually exclusive projects, the project with the highest NPV should be accepted. A negative NPV indicates that the investment is not generating any earnings and the project should be rejected. If the NPV is zero, then the decision maker will be undecided because the investment is generating the same return as the alternative use of the money. The decision should then be based on other criteria, e.g. the degree of risk associated with each project.

3.6.4 Internal Rate Of Return

The internal rate of return of a project is the value of the discount rate which equates the project's NPV to zero.

$$0 = \sum_{a=0}^{A} \frac{NCF_a}{(1+IRR)^a} \quad \text{……………………………………………………………....3.27}$$

If the IRR is greater than the weighted average cost of capital then the NPV is positive, and if the IRR is less than the weighted average cost of capital then the NPV is negative. The NPV is equal to zero when the IRR is equal to the weighted average cost of capital.

An Internal Rate of Return (IRR) was then used to measure and evaluate the ability of the projected investment to generate income relative to revenue, capital cost and operating cost.

3.6.5 Payback Period

The payback of a project identifies the expected number of years which the company needs to recover its project investments. At this point, the cumulative net cash flow is equal to the total investment. The payback can be defined by using the following equation:

$\sum_{a=0}^{b} NCF_a \geq 0$……….3.28

where b represents the payback point at which the cumulative net cash flow is positive for the first time in the project life.

3.7 SENSITIVITY ANALYSIS OF FACTORS AFFECTING NET REVENUE AND COST

Using Monte Carlo simulation via @RISK software, sensitivity analysis was carried out to determine the level of impact annual production, price, capital cost and operating cost had on net revenue as well as how annual cost outlay is affected by changes in capital and operating costs. These Profitability indicators were used as outputs to perform sensitivity analysis on various input parameters using Monte Carlo simulation via @RISK.

The above methodology was followed and Details and results were as presented in chapter four of this work and the Appendix.

CHAPTER FOUR

4.0 INTRODUCTION

This chapter presents the details of all the result gotten from the model that was developed in chapter 3. The base case study is done by incorporating all the available data (reservoir size, production rates, type of decline, type of depreciation, CAPEX, OPEX, oil price etc.) into the developed cash flow model. The results obtained in the base case study are deterministic. Sensitivity analysis was performed on the base case variables to obtain probabilistic results. Consequently, stochastic perspective is given to the model using an MS Excel add-in, @RISK. This was use to account for the uncertainties inherent in some of the input data used in the base case of the models.

4.1 ESTIMATED DETERMINISTIC RESULT

The study analyzed and compared two methods of heavy oil EOR (SAGD AND CSS) using the following decision metrics,

- Internal Rate of Return (IRR)
- Payout Time (DPO)
- Net Present Value (NPV)

The above profitability indicators allow various investors the opportunity to make decision from suitable criteria of preference.

4.2 MODEL ASSUMPTIONS

- An assumed discount rate of 10% is used for all discounting purposes in the model.
- Reserve estimation using decline curve analysis are only estimates, it does not necessarily mean that estimates of remaining reserves will become closer to truth as more production data becomes value.
- Modeling is done in years rather than in days or months.

- Guided by production forecast, the timing of future investments in this model was at the beginning of the year regardless of the problem statement.

4.3 ECONOMIC FEASIBILITY ANALYSIS AND FIELD DEVELOPMENT INPUT

Exponential decline was used for the field development. The basic input variables are summarized in table 4.1 below. With the assumptions made in the input variable as seen in table 4.1, the estimated reserves calculated for SAGD and CSS were 25.644 MMBBL and 6.411 MMBBL respectively, as a result of the 60% (SAGD) and 15% (CSS) recovery of STOIIP assumed (de Klerk et al., 2013). Given the data discussed in the methodology, the economic model was developed. The model was used to perform economic feasibility analysis of SAGD and CSS EOR. This analysis was used to determine whether an investment in either of the 2 methods is attainable within an estimated cost and as well profitable. The model assumed capital costs and operating costs. The input data into the model were bitumen price, projected annual production, royalty and taxes. The model output were Net Present Value, Internal Rate of Return and Payout Period which were then used to make economic decisions. The results of the economic model are presented in appendix. The estimated plateau rate (Q_{tp}) is 2810 BOPD for SAGD and 703 BOPD for CSS.

Table 4.1: Bitumen Field Development Input For SAGD and CSS

	SAGD	CSS	
STOIIP	42.74	42.74	MMbbls
Recovery Factor	60.0	15.0	%
Time to Plateau	5	5	Years
Well rate	100	100	BOPD
Wells to drill	40	40	
Minimum rate	100	100	BOPD
Discount factor	10%	10%	
Average well cost	10912500	8000000	MM$
Facility size	1000	1000	BOPD
Initial Oil Price	20	20	$/bbl
Final Oil Price'	35	35	$/bbl
Plateau ends at	40%	40%	of reserves
Plateau rate	4%	4%	of reserves annually
Production start year	2020	2020	
Economic life	20	25	

Table 4.2: Calculated Results For SAGD And CSS

Calculated values	SAGD	CSS	
Reserves	25.644	6.411	MMbbls
Max plateau rate $Q(t_p)$	2810	703	BOPD
Plateau rate	2810	703	BOPD
Buildup production	1.48	0.56	MMSTB
Plateau production	8.77	2	MMSTB
Plateau ends at	10	9	Years
Decline factor	1.720	0.30	Fraction

4.3.1 Economic Feasibility For SAGD

The plateau rate is reached after 5 years of starting production, the plateau period is estimated to last for 10 years ending after 14 years of production. It was estimated that a total of 0.97 MMSTB of bitumen have been produced during the 5 years of buildup and 9.29MMSTB of bitumen produced during the 10 years of constant (plateau) peak rate. As a result of the cumulative production after 14 years, the decline factor is calculated using the remaining reserves of 15.384 MMBBL. A decline rate of 1.720 is calculated in this case. The total time it will take to economically and technically produce the 25.644 MMBBL estimated is about 20 years. The results gotten from this development field plan were used as input in this economic model analysis.

The computed internal rate of return (IRR) is 28%. From literature we know that if a project has a high IRR then it is a good project. However, this IRR must be referred to some benchmark. This benchmark is the cost of capital. This cost of capital also refers to the rate of return (NPV discount rate) required to convince an investor to make a given investment. Since the computed IRR of 28% is greater than the discount rate of 10% used and the NPV (42.10) is positive, it is a good project to pursue.

To obtain the payback period, the cumulative cash flows was plotted against time as shown in Figure 4.1.

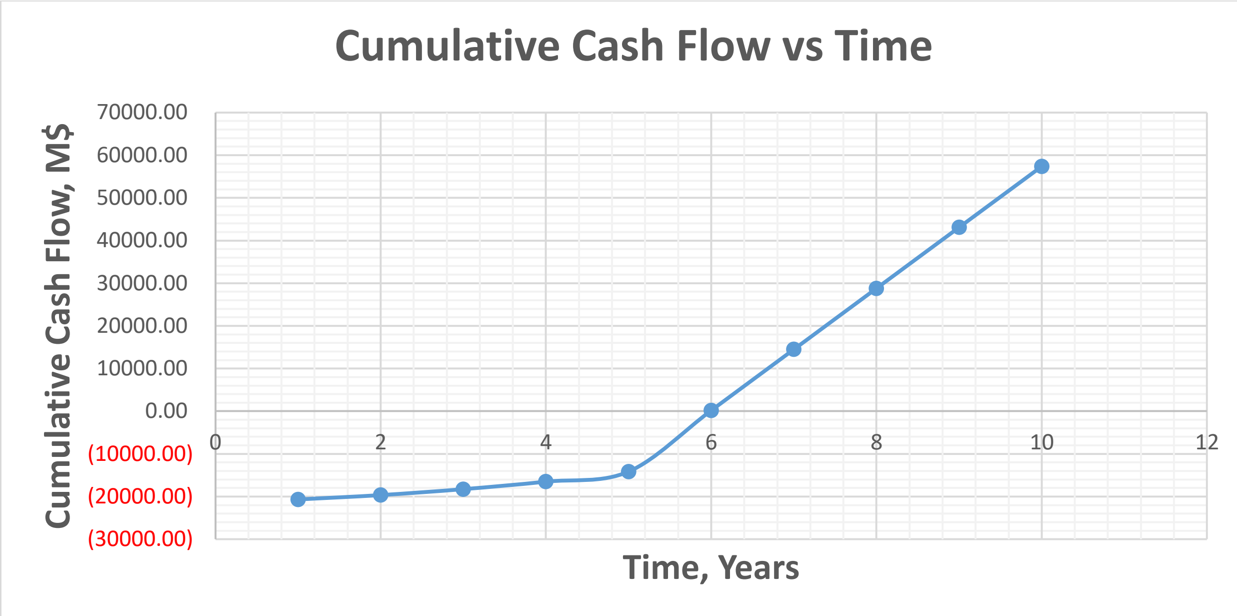


Figure 4. 1: Plot Of Cumulative Cash Flows Vs Time (SAGD)

From Figure 4.1 it can be seen that the payback period is about six (6) years. This indicates that it will take about 6 years to earn back the amount invested in this proposed project from the net cash flows. Payback period helps to evaluate the risk associated with a project. This relatively short payback period makes the project appealing because it shows that the investor's initial outlay is at a risk only for a relatively short period of time, which is appealing.

4.3.2. Economic Feasibility For CSS

The plateau rate is reached after 5 years of starting production, the plateau period is estimated to last for 9 years ending after 13 years of production. It was estimated that a total of 0.48 MMSTB Of bitumen have been produced during the 5 years of buildup and 2.08 MMSTB of bitumen produced during the 9 years of constant (plateau) peak rate. As a result of the cumulative production after 13 years, the decline factor is calculated using the remaining reserves of 3.851 MMBBL. A decline rate of 0.3 is calculated in this case. The total time it will take to economically and technically produce the 6.411 MMBBL estimated is about 25 years. The results gotten from this development field plan were used as input in this economic model analysis.

The computed internal rate of return (IRR) is 12%. From literature we know that if a project has a high IRR then it is a good project. However, this IRR must be referred to some benchmark. This benchmark is the cost of capital. This cost of capital also refers to the rate of return (NPV discount rate) required to convince an investor to make a given investment. Since the computed IRR of 12% is greater than the discount rate of 10% used and the NPV (2.97) is positive, it is a good project to pursue. Compared to that of SAGD, this is not as economical as it. To obtain the payback period, the cumulative cash flows was plotted against time as shown in Figure 4.2.

From Figure 4.2 it can be seen that the payback period is about 8.2 years. This indicates that it will take about 8.2 years to earn back the amount invested in this proposed project from the net cash flows. Payback period helps to evaluate the risk associated with a project. This relatively long payback period makes the project a bit not appealing because it shows that the investor's initial outlay is at a risk only for a relatively long period of time, which some investors cannot wait.

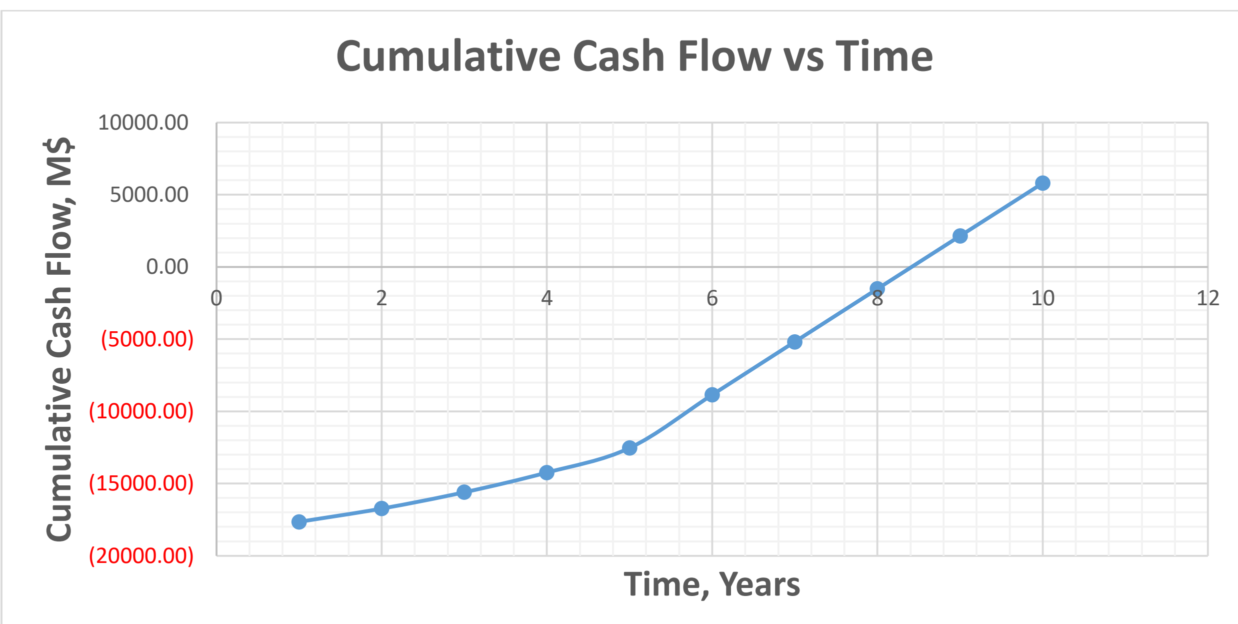


Figure 4.2: Plot Of Cumulative Cash Flows Vs Time (CSS)

4.4 MODEL SIMULATION AND ANALYSIS

4.4.1 Stochastic Simulation

The problem of high risk and uncertainty associated with high capital intensive industry which could make success rate to be relatively low is analyzed with the stochastic simulation using (Monte Carlo) on the SAGD and CSS EOR. In decision making the use of probabilistic models helps provide better estimate.

@RISK was used in the stochastic simulation for the economic model. Risk analysis in @RISK is a quantitative method that seeks to determine the outcomes of a decision situation as a probability distribution. @RISK uses Monte Carlo simulation in its risk analysis to describe uncertain values and present results in the model. (Echendu, 2011)

Ten thousand (10000) iterations in one simulation were performed on both the SAGD and CSS EOR and applied to three (3) measures of profitability indicators.

4.5 MONTE CARLO SIMULATION ANALYSIS FOR SAGD

From the result gotten from the @RISK Monte Carlo simulation, the SAGD and CSS EOR stochastic analysis will be done with the following objective functions with 95% confidence level consideration; IRR, NPV and payback period.

4.5.1 IRR Of SAGD

There is 90% chance that the IRR value will be between 23.64% and 32.95%. There's 5% chance that the IRR will be less than 23.64% and there's 95% chance that the IRR would be less than 32.95% as shown in Figure 4.3.

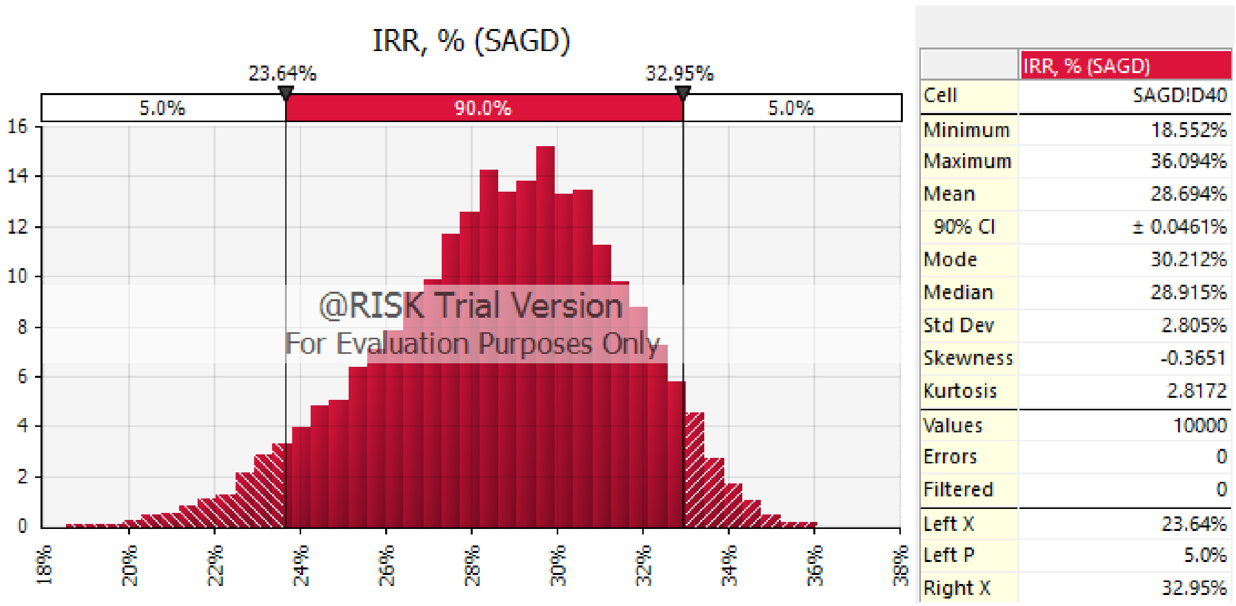


Figure 4.3: Probabilistic Distribution For IRR (SAGD)

From the spider chart in Figure 4.4, it is seen that price, plateau (peak) rate and recovery rate have positive impact on the IRR with plateau (peak) rate having the greatest impact. Hence an increase in any of the factors will increase the IRR. Same level of sensitivity also applied to the Tornado chart.

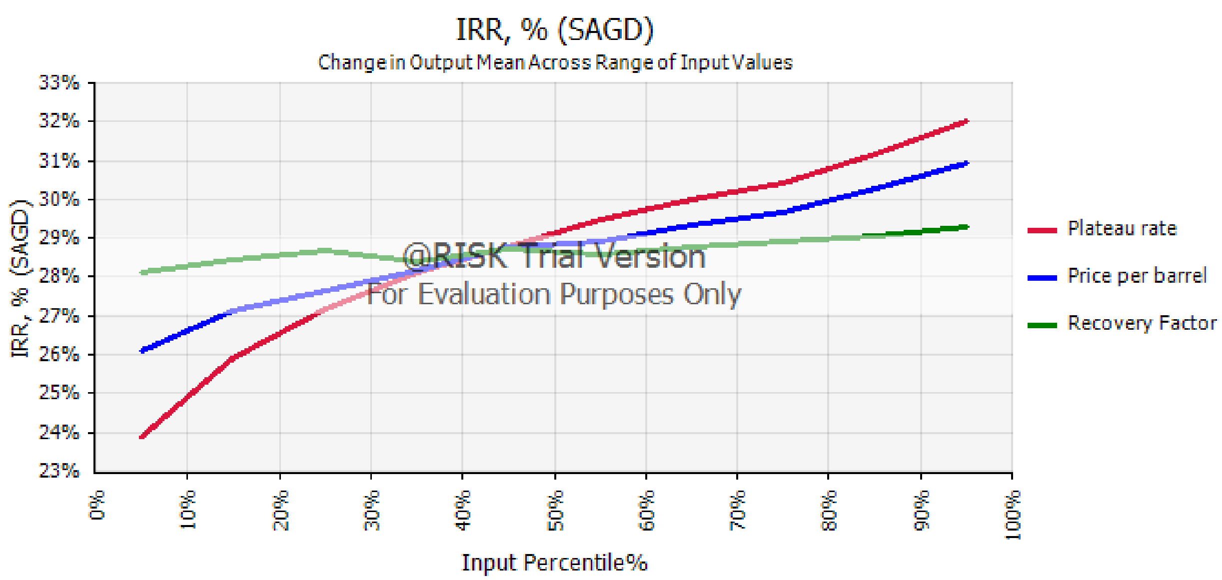


Figure 4.4: Spider Chart For IRR (SAGD)

From the correlation coefficient in Figure 4.5, we also see that plateau rate (0.83), recovery factor (0.10) and price per barrel (0.50) have positive correlation with the IRR, which implies that an increase in any of the factors will increase IRR.

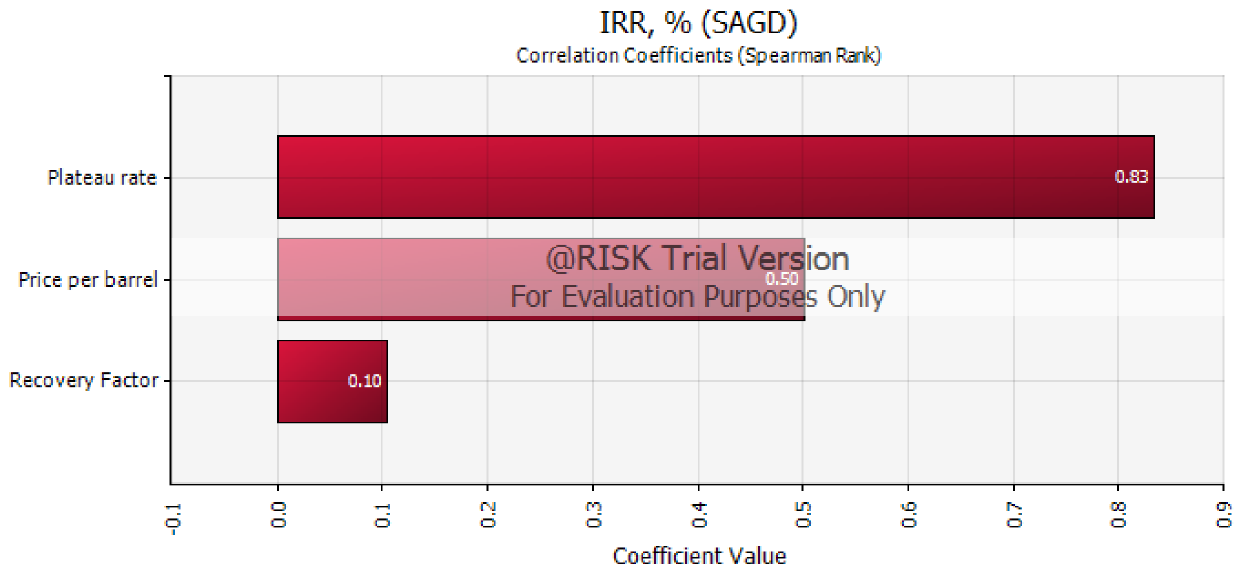


Figure 4.5: Correlation Coefficients For IRR (SAGD)

4.5.2 NPV Of SAGD

There is 90% chance that the NPV value will be between \$30.74MM and \$56.08MM. There's 5% chance that the NPV will be less than \$30.74MM and there's 95% chance that the IRR would be less than \$56.08MM as shown in figure 4.6.

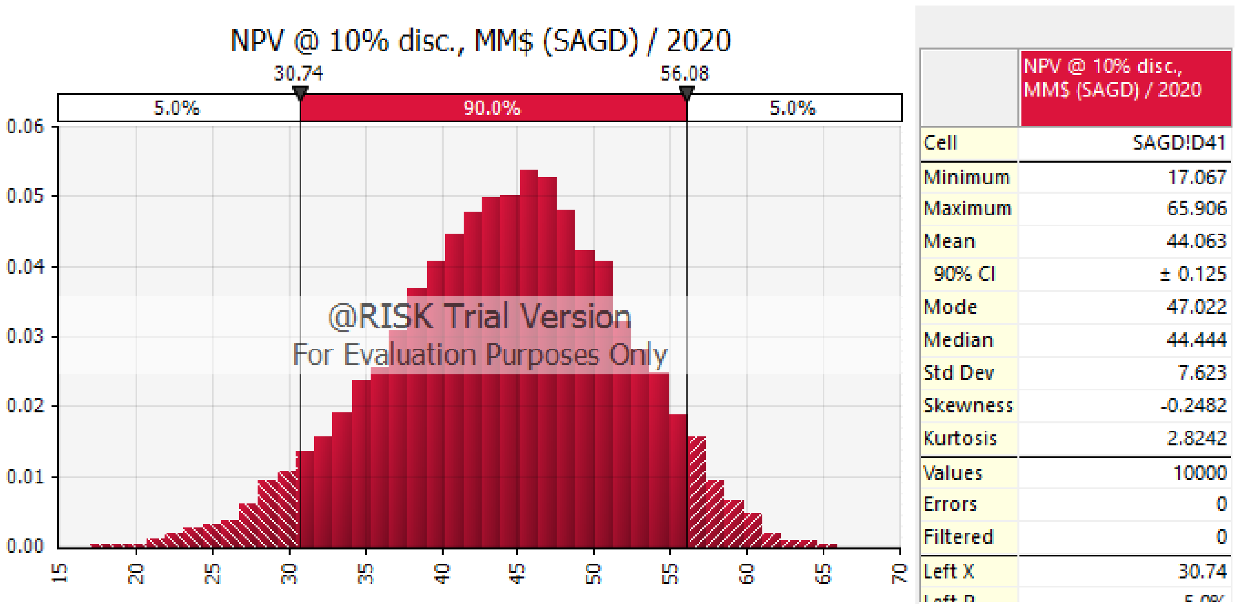


Figure 4.6: Probabilistic Distribution For NPV (SAGD)

From the spider chart in table 4.7, it is seen that price, plateau (peak) rate and recovery rate have positive impact on the IRR with plateau (peak) rate having the greatest impact. Hence an increase in any of the factors will increase the NPV. Same level of sensitivity also applied to the Tornado chart.

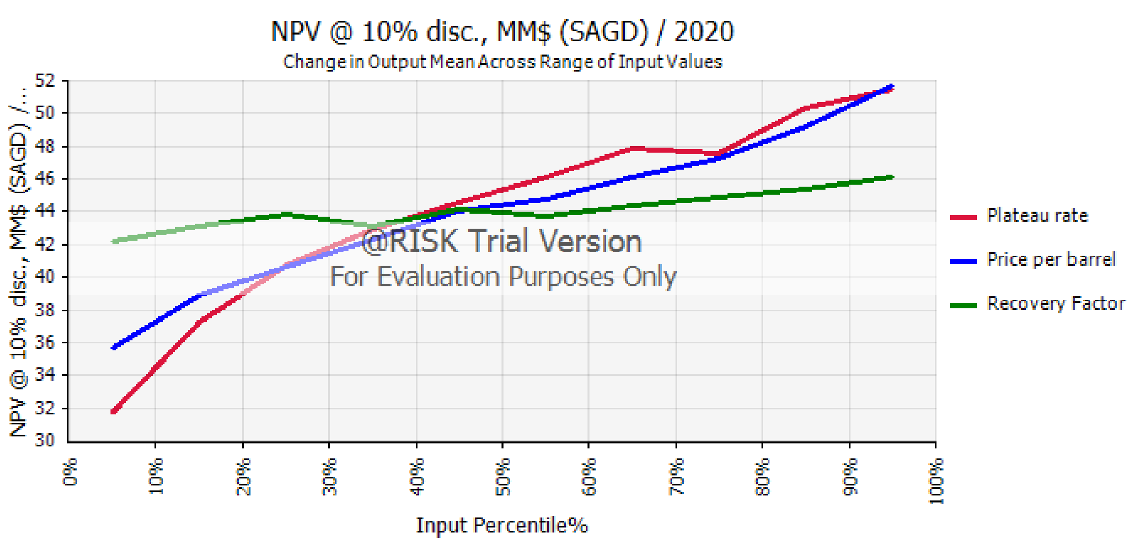


Figure 4.7: Spider Chart For NPV (SAGD)

From the correlation coefficient in Figure 4.8, we also see that plateau rate (0.73), recovery factor (0.14) and price per barrel (0.61) have positive correlation with the NPV, which implies that an increase in any of the factors will increase NPV.

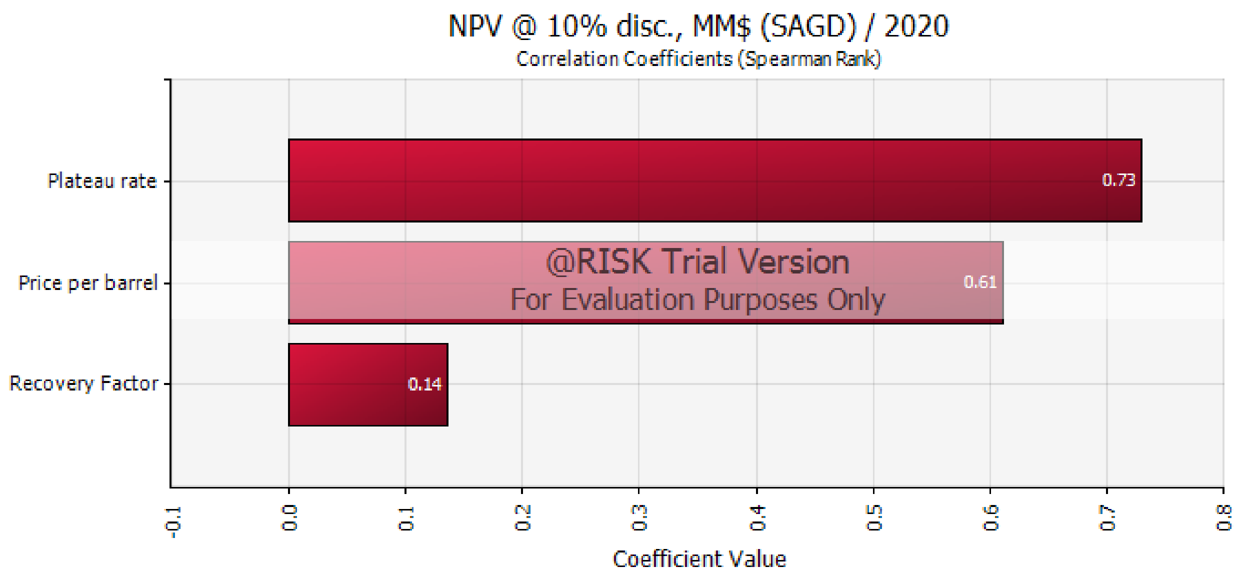
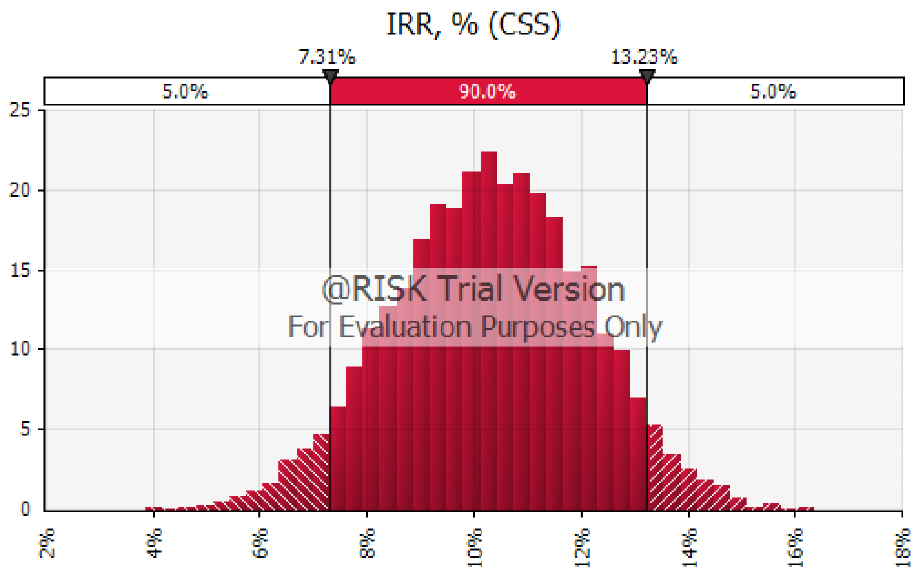


Figure 4.8: Correlation Coefficients For NPV (SAGD)

4.5.3 IRR Of CSS

There is 90% chance that the IRR value will be between 7.31% and 13.23%. There's 5% chance that the IRR will be less than 7.31% and there's 95% chance that the IRR would be less than 13.23$ as shown in Figure 4.9.



	IRR, % (CSS)
Cell	CSS!D40
Minimum	3.874%
Maximum	16.367%
Mean	10.315%
90% CI	± 0.0297%
Mode	10.362%
Median	10.344%
Std Dev	1.805%
Skewness	-0.0500
Kurtosis	2.7855
Values	10000
Errors	0
Filtered	0
Left X	7.31%
Left P	5.0%
Right X	13.23%

Figure 4.9: Probabilistic Distribution FOR IRR (CSS)

From the spider chart in Figure 4.10, it is seen that price, plateau (peak) rate and recovery rate have positive impact on the IRR with recovery factor having the greatest impact. Hence an increase in any of the factors will increase the IRR. Same level of sensitivity also applied to the Tornado chart.

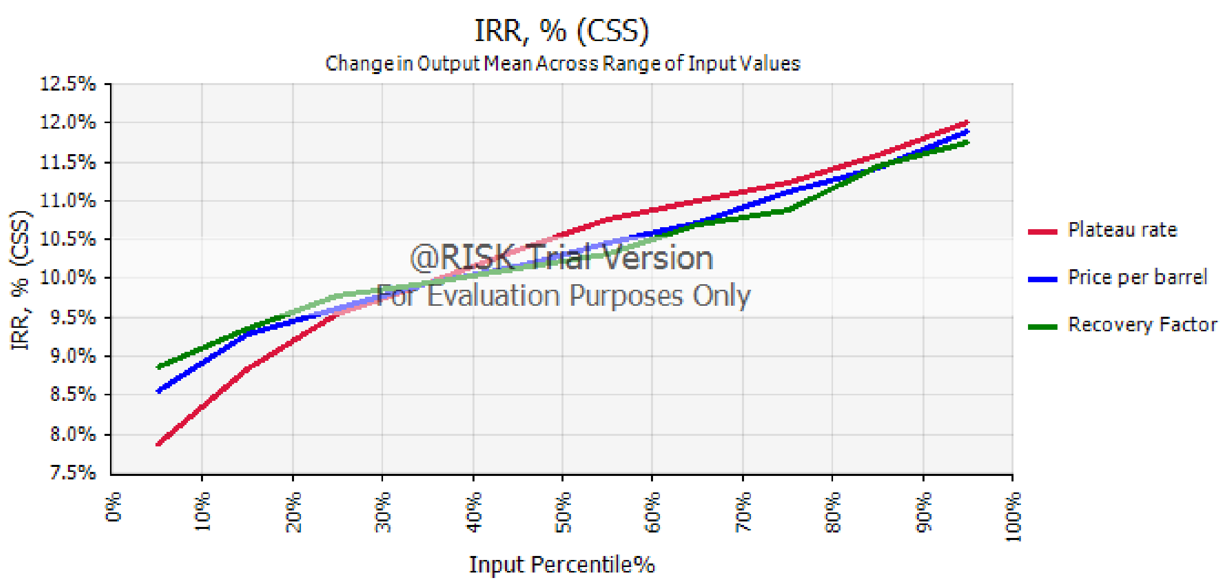


Figure 4.10: Spider Chart For IRR (CSS)

From the correlation coefficient in Figure 4.11, we also see that recovery factor (0.46), price per barrel (0.53) and plateau rate (0.66) have positive correlation with the IRR, which implies that an increase in any of the factors will increase IRR.

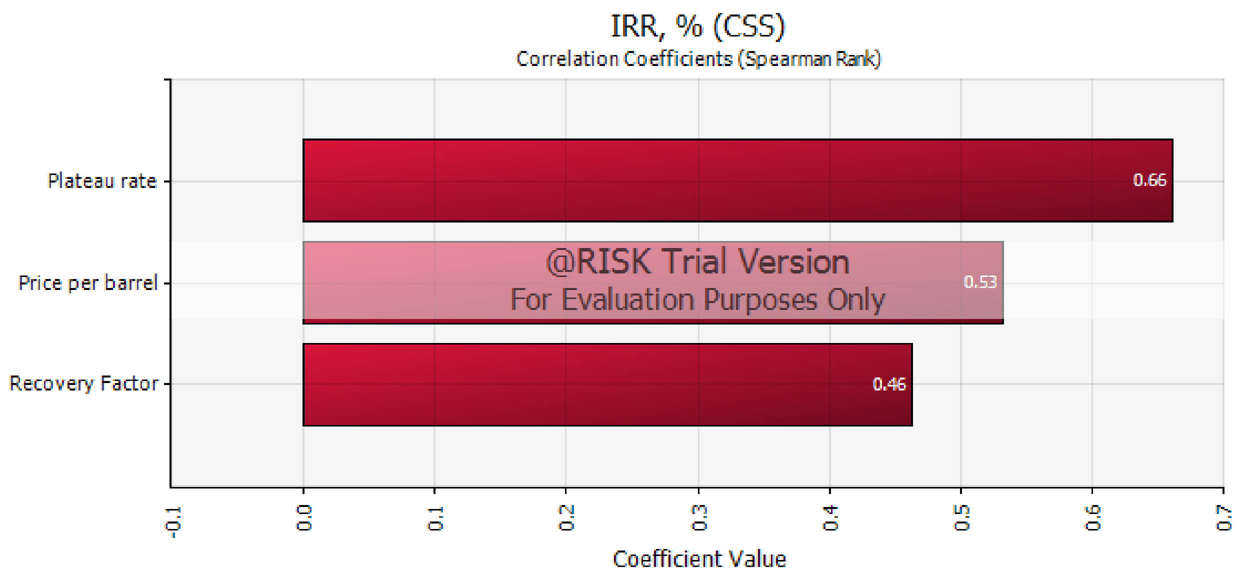


Figure 4.11: Correlation Coefficients For IRR (SAGD)

4.5.4 NPV Of CSS

There is 90% chance that the NPV value will be between \$-3.17MM and \$4.04MM. There's 5% chance that the NPV will be less than \$-3.17MM and there's 95% chance that the NPV would be less than \$4.04MM as shown in figure 4.10.

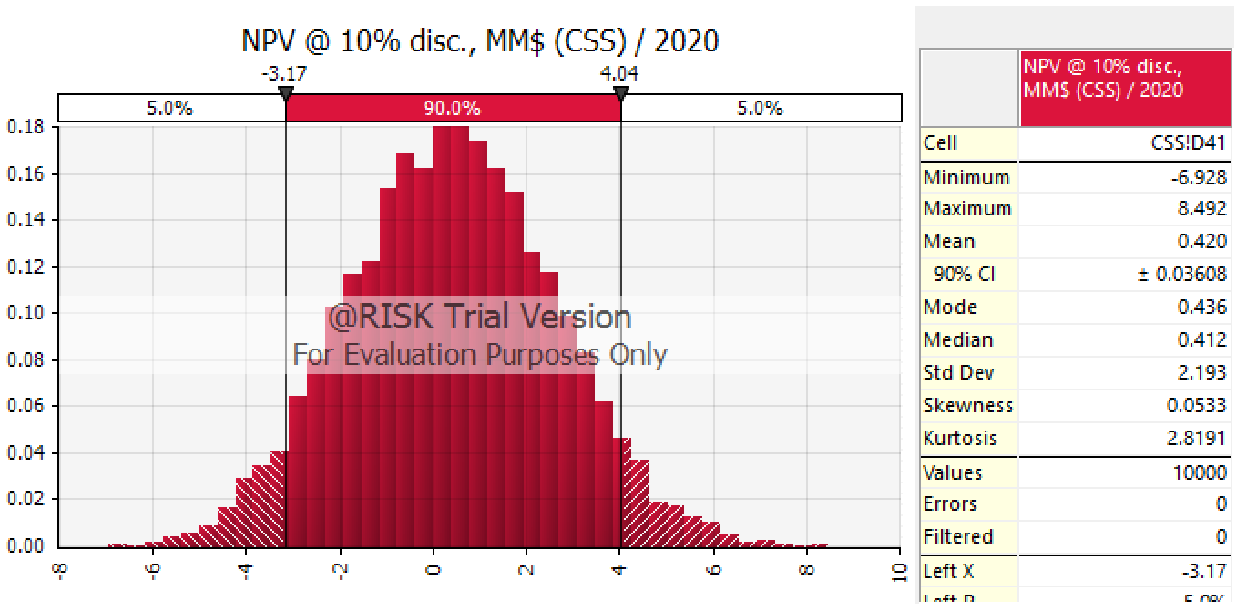


Figure 4.12: Probabilistic Distribution For NPV (CSS)

From the spider chart in Figure 4.13, it is seen that price, and recovery rate have positive impact on the NPV with recovery rate having the greatest impact. Hence an increase in any of the 2 factors will increase the NPV.

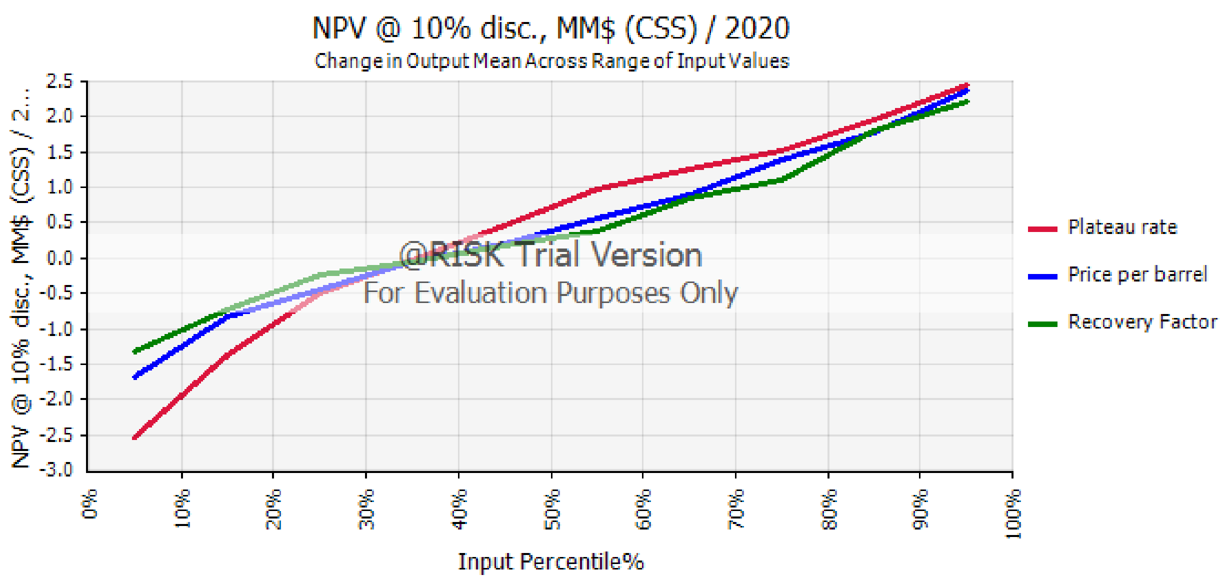


Figure 4.13: Spider Chart For NPV (CSS)

From the correlation coefficient in Figure 4.14, we also see that plateau rate (0.66), recovery factor (0.46) and price per barrel (0.53) have positive correlation with the NPV, which implies that an increase in any of the factors will increase NPV.

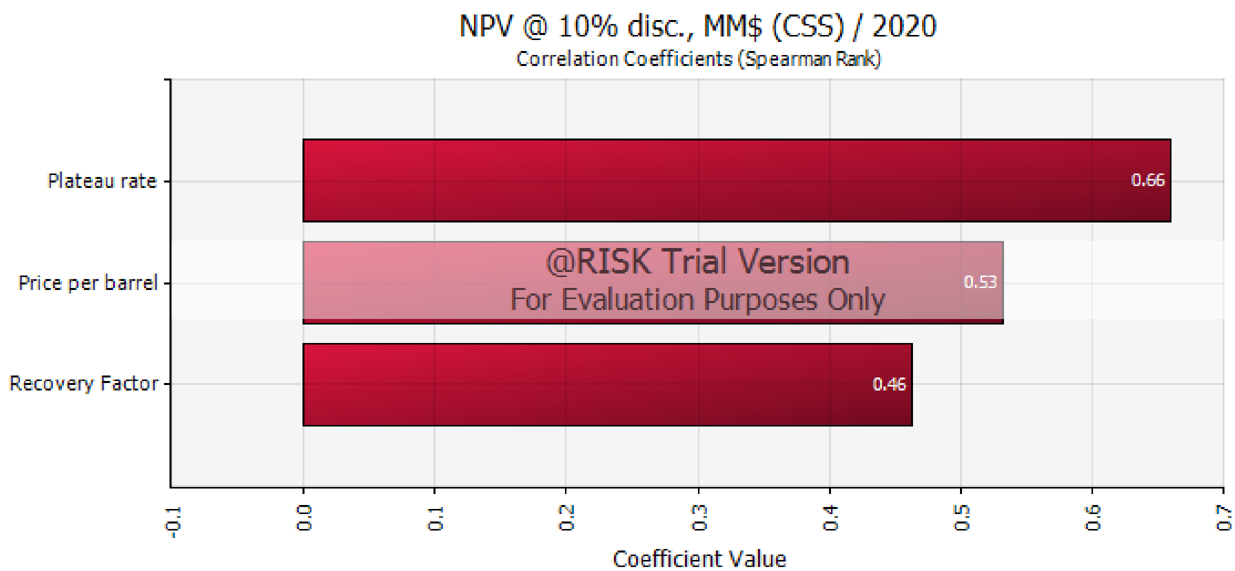


Figure 4.14: Correlation Coefficients For NPV (CSS)

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 SUMMARY

In this study, methods of EOR for heavy oil and the economic evaluation was discussed. General overview of two EOR methods for heavy oil (SAGD and CSS) and economic evaluation for building a model is highlighted. The aim is to develop an economic model for the evaluation of heavy oil Enhanced Oil Recovery project performance under risk uncertainty inherent oil price dynamics. The economic model accounts for risks and uncertainties using @RISK for its stochastic simulation for appropriate decision making.

The economic model is formulated in an Excel spread sheet with @RISK add-in for stochastic modeling. The methodology adopted for the study involves:

- Data gathering to build economic model: Which includes production data, technical cost data, fiscal policy of NMMA 2007, and Oil price forecast.
- Forecasting production field development plan
- Formulating yearly cost outlay plan for the venture
- Developing the cash flow model with 3 different profitability indicators(NPV, IRR and Payback period)

5.2 CONCLUSIONS

At the end of this research, the following conclusions were drawn:

- A programmed economic model was successfully developed for heavy oil field development in Nigeria for economic evaluation or analysis.
- Investors can use the economic model in making decisions using any of the three (3) profitability indicators of choice such as NPV, IRR, and payback period.
- The economic model can also estimate peak production rate, reserves, production period, and decline factor based on few basic input parameters like STOIIP, percentage recovery, instantaneous production rate, and facility size.
- Stochastic simulation to account for uncertainties and risks was successfully added in the model.
- For SAGD the computed internal rate of return (IRR) is 28%. While for CSS the computed internal rate of return (IRR) is 12%. Both were greater than the discount rate of 10% used which is good.
- For SAGD the NPV (42.10) which is high and positive, while for the CSS the NPV (2.97) is positive, both are good project to pursue.
- The payback period for SAGD was 6years while that of CSS was 8.2years. That of SAGD which was also within the range an investor can wait is relatively appealing compared to that of CSS.
- Lastly, deterministic and stochastic results showed that both methods were profitable, and also proved what was in the literature, that's SAGD is more profitable in Areas like Athabasca and Nigeria than CSS. CSS is still important in places of poor vertical permeability.

5.3 RECOMMENDATIONS

Since no commercial production of bitumen in Nigeria yet, production data was the issue. Instead of modelling for production data, simulation using either eclipse or a higher simulator that can simulate heavy oil (bitumen) should be use. I believe it will reduce assumptions and increase the quality of the work.

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NOMENCLATURE

API	American Petroleum Institute
BBL	Barrel
BOPD	Barrels of Oil per Day
CAPEX	Capital Expenditure
CF	Cash Flows
CSS	Cyclic Steam Stimulation
IRR	Internal Rate of Return
NPV	Net Present Value
NMMA	Nigeria Mineral Mining Acts
OPEX	Operating Expenditure
R/T	Royalty/Tax
SAGD	Steam Assisted Gravity Drainage
STB	Stock Tank Barrel
S.G.	Specific Gravity

APPENDIX

APPENDIX A: OTHER MODEL EQUATIONS

Below are other equations incorporated into the economic model

Net Income Before Tax (NIBT):

$$NIBT = Gross\ Revenue - Royalty - OPEX - Depreciation - Amortization$$

$$Income\ Tax = 20\% \times Net\ Income\ Before\ Tax$$

$$Net\ Income\ After\ Tax = Net\ Income\ Before\ Tax - Income\ Tax$$

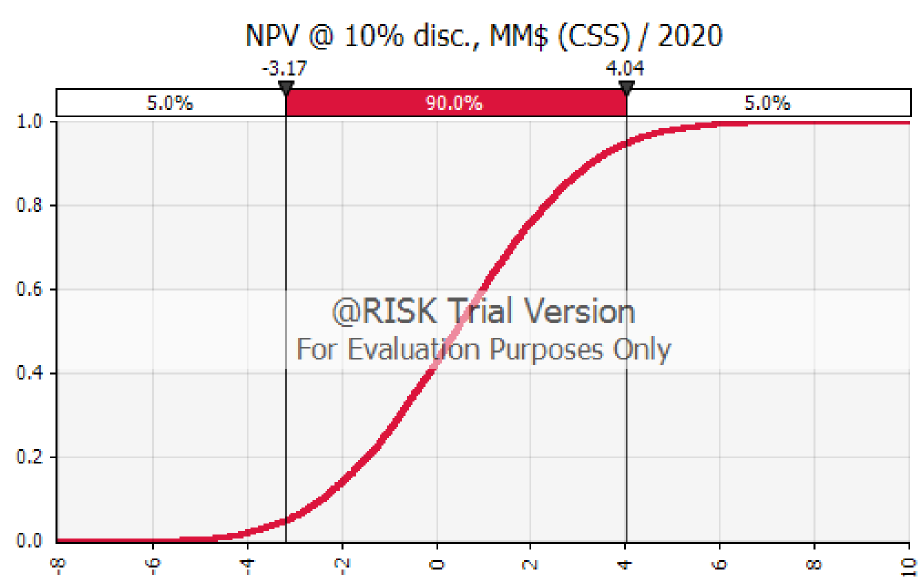
$$Net\ Cash\ Flow = Net\ Income\ After\ Tax + Depreciation + Amortization - CAPEX$$

APPENDIX B: MODEL FOR SAGD

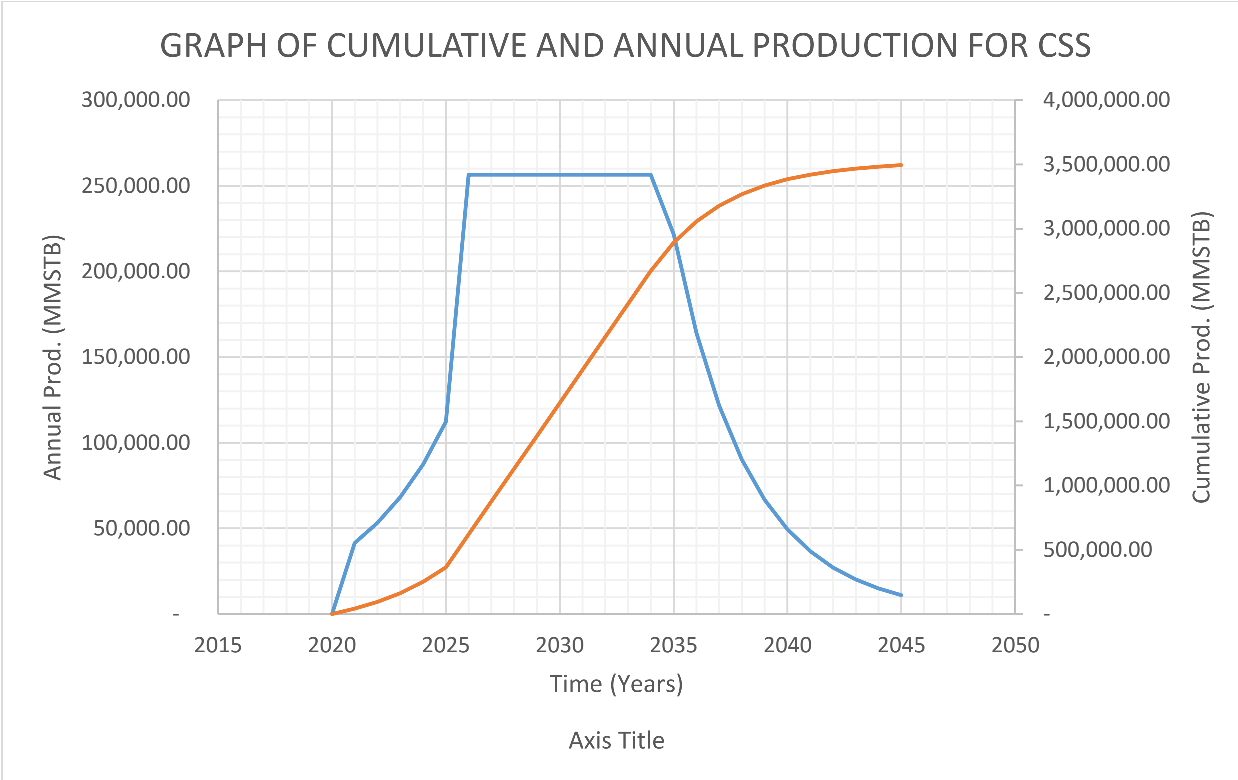
SAGD												
Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Price, $			23	23	23	23	23	23	23	23	23	23
Annual Prod., barrels		0	43119	59651	82522	114161	157930	1025760	1025760	1025760	1025760	1025760
Gross Revenue, M$			991.74	1371.98	1898.00	2625.70	3632.39	23592.48	23592.48	23592.48	23592.48	23592.48
Royalty, M$		0.00	49.59	68.60	94.90	131.28	181.62	1179.62	1179.62	1179.62	1179.62	1179.62
Capital Expenditure												
License, M$			2.5	0	0	0	0	0	0	0	0	
Steam generation, M$			5110	0	0	0	0	0	0	0	0	
Bitumen treatment, M$			4380	0	0	0	0	0	0	0	0	
Drilling cost, M$			10912.5	0	0	0	0	0	0	0	0	
Total Capital Expenditure, M$			20405	0	0	0	0	0	0	0	0	
Operating Expenditure												
Fixed Operating Expenditure, M$			1020.25									
Variable Operating Expenditure, M$			198.35	274.40	379.60	525.14	726.48	4718.50	4718.50	4718.50	4718.50	4718.50
Depreciation, M$				1020.13	969.12	920.66	874.63	830.90	789.35	749.89	712.39	676.77
Amortization, M$				0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125
Total Depreciation, M$			0.00	1020.13	969.12	920.66	874.63	830.90	789.35	749.89	712.39	676.77
Net Income Before Tax, M$			(276.44)	8.86	454.38	1048.61	1849.67	16863.46	16905.01	16944.47	16981.97	17017.59
Loss carried forward				-276.44	-267.58							

MODEL FOR CSS

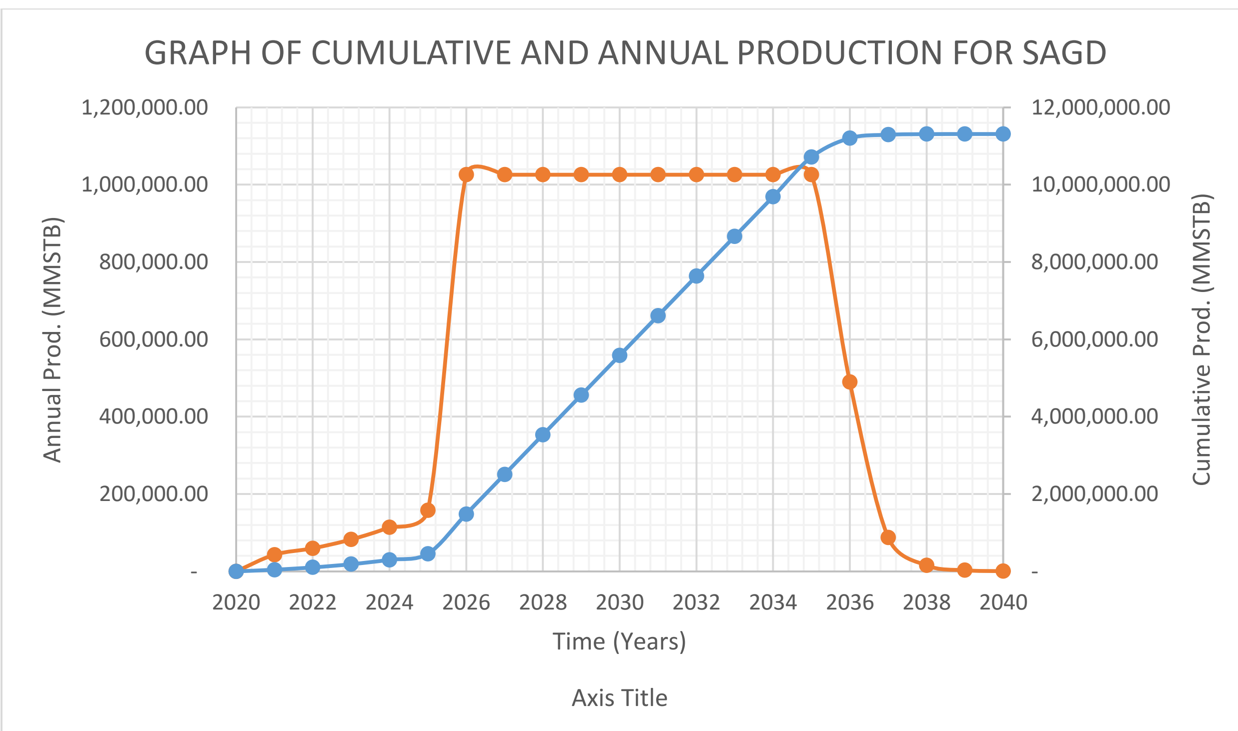
CSS																
Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20
Price, $			23	23	23	23	23	23	23	23	23	23	23	23	23	
Annual Prod., barrels		0	41448	53172	68212	87507	112259	256440	256440	256440	256440	256440	256440	256440	256440	256
Gross Revenue, M$			953.31	1222.96	1568.88	2012.66	2581.96	5898.12	5898.12	5898.12	5898.12	5898.12	5898.12	5898.12	5898.12	5898
Royalty, M$		0.00	47.67	61.15	78.44	100.63	129.10	294.91	294.91	294.91	294.91	294.91	294.91	294.91	294.91	294
Capital Expenditure																
License, M$			2.5	0	0	0	0	0	0	0	0					
Steam generation, M$			5110	0	0	0	0	0	0	0	0					
Bitumen treatment, M$			4380	0	0	0	0	0	0	0	0					
Drilling cost, M$			8000	0	0	0	0	0	0	0	0					
Total Capital Expenditure, M$			17492.5	0	0	0	0	0	0	0	0					
Operating Expenditure																
Fixed Operating Expenditure, M$			874.63													
Variable Operating Expenditure, M$			190.66	244.59	313.78	402.53	516.39	1179.62	1179.62	1179.62	1179.62	1179.62	1179.62	1179.62	1179.62	1179.
Depreciation, M$				874.50	830.78	789.24	749.77	712.29	676.67	642.84	610.70	580.16	551.15	523.60	497.42	472.
Amortization, M$				0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.125	0.1
Total Depreciation, M$			0.00	874.50	830.78	789.24	749.77	712.29	676.67	642.84	610.70	580.16	551.15	523.60	497.42	472.
Net Income Before Tax, M$			(159.65)	42.72	345.89	720.26	1186.69	3711.30	3746.92	3780.75	3812.89	3843.43	3872.44	3899.99	3926.17	3951.
Loss carried forward				-159.65	-116.93											
Taxable Income			(159.65)	(116.93)	228.96	720.26	1186.69	3711.30	3746.92	3780.75	3812.89	3843.43	3872.44	3899.99	3926.17	3951.(
Income Tax, M$			0.00	0.00	(45.79)	(144.05)	(237.34)	(742.26)	(749.38)	(756.15)	(762.58)	(768.69)	(774.49)	(780.00)	(785.23)	(790.
Net Income After Tax, M$			(159.65)	(116.93)	183.17	576.21	949.35	2969.04	2997.53	3024.60	3050.32	3074.74	3097.95	3120.00	3140.94	3160.
(+) Depreciation, M$			0.00	874.50	830.78	789.24	749.77	712.29	676.67	642.84	610.70	580.16	551.15	523.60	497.42	472.
(+) Loss Carried Forward				159.65	116.93											



	NPV @ 10% disc., MM$ (CSS) / 2020
Cell	CSS!D41
Minimum	-6.928
Maximum	8.492
Mean	0.420
90% CI	± 0.03608
Mode	0.436
Median	0.412
Std Dev	2.193
Skewness	0.0533
Kurtosis	2.8191
Values	10000
Errors	0
Filtered	0
Left X	-3.17
Left P	5.0%



GRAPH OF CUMULATIVE AND ANNUAL PRODUCTION FOR CSS
300,000.00
250,000.00
200,000.00
150,000.00
100,000.00
50,000.00
-
Annual Prod. (MMSTB)
4,000,000.00
3,500,000.00
3,000,000.00
2,500,000.00
2,000,000.00
1,500,000.00
1,000,000.00
500,000.00
-
Cumulative Prod. (MMSTB)
2015
2020
2025
2030
2035
2040
2045
2050
Time (Years)
Axis Title



GRAPH OF CUMULATIVE AND ANNUAL PRODUCTION FOR SAGD
1,200,000.00
1,000,000.00
800,000.00
600,000.00
400,000.00
200,000.00
-
Annual Prod. (MMSTB)
12,000,000.00
10,000,000.00
8,000,000.00
6,000,000.00
4,000,000.00
2,000,000.00
-
Cumulative Prod. (MMSTB)
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Time (Years)
Axis Title