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Development and Evaluation of an Economic Model for a Libyan Oil Field Development with an EPSA Agreement

Mohamed S BenZeglam

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Development and Evaluation of an Economic Model for a Libyan Oil Field Development with an EPSA Agreement

Mohamed S. BenZeglam

**Thesis submitted
to the Benjamin M. Statler College of Engineering and Mineral Resources
at West Virginia University**

**in partial fulfillment of the requirements for the degree of
Master of Science in
Petroleum and Natural Gas Engineering**

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2018

Keywords: economics, oil production, Monte Carlo, reservoir variables

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Abstract

Development and Evaluation of an Economic Model for a Libyan Oil Field Development with an EPSA Agreement

Mohamed BenZeglam

Economic evaluation of any project is an essential part of the process of studying available investment opportunities and supporting decision-making, by using special methodology and scientific analysis to select best options. It is a decision-making tool. The evaluation of petroleum projects has general features which are similar to those in other industries. To be able to carry out a detailed economic evaluation study on an upstream petroleum project it is essential to be familiar with the applied petroleum fiscal regime.

An International Oil Company (IOC) operating in Libya has recently made a significant undersaturated oil discovery inside one of its designated concession areas within the Sirte Basin in the northern part of the Sahara Desert. The company is considering to develop this discovery under the existing Exploration & Production Sharing Agreement (EPSA-IV) with the Libyan National Oil Corporation (NOC). This agreement is a special case of the widely applied Production Sharing Contracts (PSC).

An economic model is developed with a set of basic (rough) data obtained from the company through NOC. NOC wants to determine the feasibility of developing this discovery based on the available data through the construction of an economic model. However, NOC does not have such a model. As a result, this study focuses on the construction of an economic model that incorporates the EPSA-IV terms and conditions to be used for evaluating the economics of development projects under this agreement. Further, the study determines the impact of variations in input parameters. The results indicate that the project will be profitable.

Dedication

“to my parents, my sisters, my wife, and my daughter”

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I also thank members of the National Oil Corporation who provided me with the necessary data on the recent discovery and expressed their need to carry out this economic evaluation study and to acquire an economic model based on EPSA-IV agreement to enable them to evaluate similar future projects.

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Table of Content

Abstract.....	ii
Dedication	iii
Acknowledgement.....	iv
List of tables	vi
List of figures.....	vii
List of Abbreviations	1
Executive Summary	2
Background	4
Literature review.....	6
Economic Evaluation Study.....	13
1. Input/Output:.....	14
2. Cash Flow Calculation:	16
3. Economic Indicators:	32
4. Sensitivity Analysis	38
5. Monte Carlo Simulation	44
Summary of Results.....	66
Conclusions.....	68
Recommendations	70
References.....	71
Appendix A- MATLAB Code.....	73
Appendix B- Definitions and Equations	85

List of tables

Table1 : Economic indicators for the project and each party.....	2
Table2 : Monte Carlo Simulation Worst/Best-Case scenario.....	3
Table3 : "A" Factor (Index Factor)	10
Table4 : "B" Factor (Base Factor).....	10
Table5 : Calculated annual production rate, price and revenue for each product	17
Table6 : The expected cumulative production after 20 years of production	18
Table7 : The annual capital and operating expenditures.....	19
Table8 : Expected cumulative capital and operating expenditures after 20 years	20
Table9 : The project annual net cash flow.....	21
Table10 : The second party abandonment provision:.....	23
Table11 : The second party cost recovery profile.....	24
Table12 : "A" factor profile.....	25
Table13 : "B" Factor and the combined factor profiles	26
Table14 : The second party net cash flow profile	27
Table15 : First party net cash flow calculation using method 1	29
Table16 : First party net cash flow calculation using method 2	30
Table17 : The economic indicators for the project and for each party	34
Table18 : Production cost per barrel equivalent calculations for each party based on constant and escalated costs	35
Table19 : The average constant and nominal costs per barrel equivalent for the project and each party	36
Table20 : The calculated NPV's and IRR's for the project and for each party for each parameter variation	39
Table21 : Economic Indicator for the Project (MATLAB vs Spreadsheet)	44
Table22 : Monte Carlo Simulation Worst/Best-Case scenario.....	65
Table23 : Monte Carlo results	67
Table24 : Decline curves (Model, Exponential and Linear Decline)	84
Table25 : Decline curves (Model, Harmonic and Hyperbolic Decline).....	84

List of figures

Figure 1: Cost and production share of each party according to EPSA-IV	11
Figure 2: Costs and revenues share among the two parties	11
Figure 3: Input data as displayed in the Input / Output section.....	15
Figure 4: The annual oil, gas and condensate production rates.....	18
Figure 5: The annual capital and operating expenditures.....	20
Figure 6: The project cash flow profile.....	22
Figure 7: The project net cash flow profile for each party.....	31
Figure 8: The project NCF allocation for each party	31
Figure 9: The Internal Rate of Return for the project and for each party.	33
Figure 10: The payback time for the project and for each party	33
Figure 11: Production cost per barrel equivalent profile for the project and for each party based on constant costs.....	36
Figure 12: Production cost per barrel equivalent profile for the project and for each party based on Escalated costs	37
Figure 13: First party NPV Spider diagram.....	39
Figure 14: Second party NPV Spider diagram	40
Figure 15: Project NPV Spider diagram	40
Figure 16: Project NPV Tornado Diagram.....	41
Figure 17: Project IRR Spider diagram.....	42
Figure 18: First Party IRR Spider diagram	42
Figure 19: Second party IRR Spider diagram.....	43
Figure 20: Second Party IRR Tornado Diagram.....	43
Figure 21: Production Forecast using Different Decline Curve.....	45
Figure 22: Production Forecast using Different Decline Curve (Semi-Log)	46
Figure23 : Distribution of Production Rate and NPV Distribution Functions	47
Figure24 : Net Present Value vs Production Rate	48
Figure 25: Distribution of Oil Price and NPV Distribution Functions	49
Figure 26: Net Present Value vs Oil Price	49
Figure 27: Distribution of Gas Price and NPV Distribution Functions	50

Figure 28: Net Present Value vs Gas Price	51
Figure 29: Distribution of Condensate Price and NPV Distribution Functions	52
Figure 30: Net Present Value vs Condensate Price	52
Figure 31: Distribution of Number of Wells and NPV Distribution Functions	53
Figure 32: Net Present Value vs Number of Wells	54
Figure 33: Distribution of Cost Contingency and NPV Distribution Functions	55
Figure 34: Net Present Value vs Cost Contingency	55
Figure 35: Distribution of Gas Oil Ratio and NPV Distribution Functions	56
Figure 36: Net Present Value vs Gas Oil Ratio	57
Figure 37: Discount Rate and NPV Distribution Functions	58
Figure 38: Net Present Value vs Discount Rate	58
Figure 39: Inflation Rate and NPV Distribution Functions	59
Figure 40: Net Present Value vs Inflation Rate	60
Figure 41: NPV Probability and Cumulative Distribution Functions (All Key Parameters Change)	61
Figure 42: NPV Histogram (All key parameters change).....	61
Figure 43: NCF Histogram (All key parameters change).....	62
Figure 44: IRR Histogram (All key parameters change)	62
Figure 45: Payout Histogram (All key parameters change)	63
Figure 46: CPI Histogram (All key parameters change)	63
Figure 47: ME value Histogram (All key parameters change)	64
Figure 48: ME Time Histogram (All key parameters change).....	64

List of Abbreviations

viations

BOE	Barrels of Oil Equivalent
CAPEX	Capital Cost, \$
CCF	Cumulative (Net) Cash Flow, \$
CPI	Capital Productivity Index
DEPSA	Development and Production Sharing Agreement
EPSA	Exploration and Production Sharing Agreement
IOC	International Oil Companies
IRR	Internal Rate of Return
M	1,000
ME	Maximum Exposure
MM	1,000,000
n	Year
NCF	Net Cash Flow, &
NOC	National Oil Company
NPV	Net Present Value, \$
OPEX	Operational Expenses, \$
PSC	Production Sharing Contract
PO	Profit Oil
ROI	Return on Investment
SCF	Standard Cubic Feet
STB	Stock Tank Barrel
\$	US Dollar
\$MM	Million US Dollars

Executive Summary

The Libyan NOC wishes to acquire a spreadsheet economic model to be able to study the feasibility of oil development projects under the EPSA-IV agreement, including a recent discovery made by an IOC in the Sirte Basin.

This study consists of developing an economic model to study the feasibility of oil development projects under the EPSA-IV agreement for the Libyan NOC, including a recent discovery made by an IOC in the Sirte Basin.

A set of basic (rough) data of this discovery has been obtained from the IOC through NOC. A spreadsheet economic model was built to accommodate this data and to carry out a detailed economic evaluation study to determine the viability of developing this discovery, for the project as a whole and for each involved party, namely NOC (1st Party) and IOC (2nd Party).

The study included calculating cash flow profile, determining the economic indicators and analyzing the sensitivity of key indicators to varying certain parameters.

The following table summarizes the economic indicators for the project as a whole and for each party according to EPSA-IV terms and conditions for an assumed production life of 20 years.

Table1 : Economic indicators for the project and each party

Economic Indicator	Project	1st Party	2nd Party	Units
Net Cash Flow (NCF)	24,197	22,275	1,923	\$MM
Net Present Value (NPV)	7,141	6,787	354	\$MM
Internal Rate of Return (IRR)	55.5%	76.4%	18.5%	
Payback Period (Payout)	4.83	4.49	6.86	Years
Capital Productivity Index (CPI)	5.84	10.47	0.61	\$\$
Cumulative Production	367	327	40	MMBOE
Cost per Barrel Equivalent (Constant)	8.12	6.18	24.02	\$/BOE
Cost per Barrel Equivalent (Escalated)	9.86	7.71	27.46	\$/BOE

Each of these indicators confirms the economic viability of developing this discovery for each party. The sensitivity analysis indicated that the project economics is highly sensitive

to the production rate, selling prices and the assumed discount rate, while less sensitive to the capital and operating expenses.

Monte Carlo simulation results confirm the project profitability with worst-case scenario of 3,000 \$MM, and best scenario of 12,000 \$MM. Additionally, the rest of the economic indicators show the project remain feasible in all cases.

The following table summarizes the results obtained from conducting the Monte Carlo simulation by showing the best and worst possible scenario using the selected probability distributions for each key parameter.

Table2 : Monte Carlo Simulation Worst/Best-Case scenario

Monte Carlo Simulation								
Worst-Case			Base-Case			Best-Case		
NCF	11,200	\$MM	NCF	24,197	\$MM	NCF	38,000	\$MM
NPV	3,000	\$MM	NPV	7,141	\$MM	NPV	12,000	\$MM
IRR	33	%	IRR	55.5	%	IRR	77	%
Payout	5.8	Years	Payout	4.83	Years	Payout	4.5	Years
CPI	2	\$/	CPI	5.84	\$/	CPI	10.9	\$/
ME Value	-1,890	\$MM	ME Value	-1,462	\$MM	ME Value	-1,100	\$MM
Year of ME	2022		Year of ME	2022		Year of ME	2022	

Background

Libya gained its independence in 1951. Its economy was dependent on simple trades in addition to the rents derived from US and UK military bases operating on the Libyan soil. In the 1960's Libya became a major oil producer after the discovery of giant oil fields. However, its economy ever since has been dependent almost entirely on the oil & gas revenues. A number of IOCs, such as Esso, Occidental, Texaco, British Petroleum, Total, Agip and others were actively operating under the concession agreement that was in effect then. They were granted concession blocks at the Sirte Basin and made giant oil discoveries. These discoveries were quickly developed and produced. Under the terms of this agreement the IOCs were granted the right to explore, produce and market the minerals located on the country's various blocks or concession areas. They were granted full control, including technical and commercial control, over all aspects of the oil and gas production. The government intake was then 16.67% royalties and 65% production tax.

During the 1970's a partial nationalization came into effect where the government issued a decree acquiring 51% of most of the IOC's assets. Under this decree the government started paying 51% of the operating costs and receiving 51% of the revenues. The companies were still paying the government royalties and taxes on its remaining revenues. The National Oil Corporation was then established representing the government in receiving its share of the petroleum revenues.

As a result of this decree many operating companies suffered from low profits and decided to withdraw from the country. Their assets were bought by the government and a number of local companies were established to continue their operations. In addition, oil embargo was imposed and the country's economy severely suffered from lack of expertise and funds. Consequently, the country's exploration activities were declined rapidly and its oil reserves were being depleted without adding new discoveries. The Libyan oil industry dramatically suffered from lack of fund and technology.

NOC then decided to encourage foreign companies to return under a Production Sharing Contracts (PSC) regime. Under the PSC, NOC is relieved from bearing the risk of finding new discoveries while benefiting from the technology brought by the international oil

companies. It introduced the Exploration and Production Sharing Agreement (EPSA) which is a special case of the PSC. In 1979 the introduction of EPSA-I was enacted. Libya continued to issue new versions of EPSA hoping to attract more investors in the oil industry. EPSA-II was introduced in the 1980's followed by EPSA-III in 1990's, and finally EPSA-IV in 2005. The main difference between EPSA-IV and the previous versions is that under EPSA-IV for IOC to win the bid it should accept the lowest share of profits. A number of major companies such as Exxon-Mobil, Occidental, Shell and others won EPSA-IV bids and were granted open blocks to carry out exploration activities.

Under the EPSA-IV agreement the IOC is responsible for all exploration activities such as seismic surveys, wildcat and appraisal well drilling during a fixed period (normally five years). If no commercial discovery is found the company leaves without any compensation from NOC. However, in case of a commercial discovery the capital and operating costs of the field development project are shared between both parties and the company receives a portion of the total production to recover its past costs (including exploration) plus adequate profit. Under this agreement the IOC is exempted from taxes, custom duties and rental fees. So, the EPSA-IV agreement was attractive to both IOC and NOC.

Under the EPSA-IV agreement the IOC does not grant ownership of the oil as in the case of the concession agreement. It acts as a contractor and only grants the right to receive a share of the production. However, it bears the risk of exploration costs. As a result, the company must insure that its income is consistent with the risk. With regards to the government the introduction of the EPSA-IV agreement was attractive. In addition to receiving an adequate profit it benefits from attracting foreign investments, job creation, technology transfer and the development of infrastructure. So, at the end it is a win-win situation.

At the turn of the century a number of companies failed to find commercial discoveries and had to withdraw while others were fortunate enough to find significant discoveries. They submitted development plans to obtain NOC's approval for projects commerciality. Once granted they developed these discoveries jointly with NOC and started production under EPSA-IV terms and conditions.

Literature review

Petroleum Economic Evaluation:

Economic evaluation of any project is an essential part of the process of studying available investment opportunities and supporting decision-making, by using special methodology and scientific analysis to select best options. It is a decision-making tool. The evaluation of petroleum projects has general features which are similar to those in other industries. However, there are special and distinguished issues, essentially linked to the nature and conditions of petroleum projects that require special skills and experiences (Yas, 2010). The upstream petroleum projects are characterized by:

- High Risk in finding hydrocarbon resources
- High Degree of Uncertainty in predicting future prices/costs/production rate/reserves.
- Capital Intensive due to huge amounts spent for exploration and to produce sufficient oil reserves.
- Long Period between start of Project until Profit
- Limited Production Period (Contract)
- High Technology.
- High Reward/Return

To be able to carry out a detailed economic evaluation study on an upstream petroleum project it is essential to be familiar with the applied petroleum fiscal regime.

Petroleum Fiscal Regime:

The petroleum fiscal regime is a set of laws, regulations and agreements which govern the economic benefits derived from the upstream petroleum projects (Johnston, 1994). The regime dictates how the costs and the profits will be shared among the involved parties; the National Oil Corporation and the International Oil Company.

Because each country has distinctive legislation, there are theoretically just as many different fiscal regimes as there are countries in the world with petroleum resources, but

the regimes can still be categorized based on their common characteristics. So there is no ideal Fiscal Regime or One-Regime-Fits-All.

Within fiscal regimes where the government owns the mineral rights, the governments have generally selected one of two types of licensing systems: a concession agreement or a contractual (production sharing) agreement.

Concession Agreement:

All oil companies within the Libyan Oil Industry were operating under the concession agreement which was in effect since the 1960's. Under the concession agreement, IOCs were granted the right to explore, produce and market the minerals located on one of the country's various blocks or concession areas. A concession agreement granted the IOC full control, including technical and commercial control, over all aspects of the oil and gas production for a limited time (Karbal, 2015). The economic evaluation of the Libyan upstream projects under the concession agreement is relatively simple and does not require a rigorous software.

By the 1980's following the economic downturn of the Libyan Oil Industry which resulted from the withdrawal of many IOC's and the imposed US embargo, NOC decided to encourage foreign investments by introducing the Exploration and Production Sharing Agreement (EPSA) which is a special case of the Production Sharing Contracts.

Production Sharing Contracts (PSCs)

Production sharing contracts are a common type of contract signed between NOC and IOC. Today they dominate most of the oil companies in the Middle East and Central Asia. In production sharing contracts, the NOC awards the execution of exploration and production activities to IOC which bears the mineral and financial risk of the initiative and explores, develops and ultimately produces the field as required. When successful, IOC is permitted to use the money from produced oil to recover capital and operational expenditures, known as "cost recovery". The remaining money is known as "profit oil",

and is split between the government and the company in accordance with the EPSA terms and conditions.

However, the split of the profit between NOC and IOC is relatively complex as IOC share of the profit oil follows a sliding scale. As a result, IOC's make the decision to invest in a certain petroleum project based on economic models. These models are constructed as spreadsheets prepared by internal economists in the company or by external experts. As a result, each petroleum company has developed its own economics model (Shereih, 2015).

EPSA-IV

Compared to the Concession Agreement, the EPSA-IV which is the latest version of the EPSA agreement was preferred by both parties. In 2008, NOC decided to convert all IOC contracts from concession to special version of EPSA-IV agreements called Development and Production Sharing Agreement (DEPSA) (Palmer, 2016). On 17 July 2008, NOC continued their policy of redefining contracts in line with the new rubric by renegotiating the contract for an international consortium operated by Spain's Repsol, in partnership with France's Total, Austria's OMV and Norway's Saga Petroleum. In 2011, NOC continued negotiating a DEPSA with the Waha Group, consisting of US oil majors Marathon, ConocoPhillips and Hess ("EPSA IV," n.d). However, these negotiations were suspended due to the political unrest following the Arab Spring. Currently NOC is back negotiating with Germany's Wintershall to convert its existing Concession Agreement to DEPSA.

NOC has been responsible for negotiating new EPSA-IV agreements with prospective IOC's. Because of the complexity of the agreement, it has been relying on IOC's to present their project economics and sometimes verify it with the help of a third party economic consultant.

Recent Discovery

A few years ago an IOC signed an EPSA-IV agreement with NOC whereby an open block at the Sirte Basin was granted. It then carried out an extensive exploration activity

including a seismic survey, wild cats and appraisal wells drilling before declaring an oil discovery. It is currently in the process of preparing a comprehensive development plan to obtain NOC's approval of the commerciality of the discovery. Some data was received from NOC and used in determining the economics of developing this discovery for each party under the existing EPSA-IV terms and conditions.

It has always been the case that NOC would like to be able to run its own economic evaluation on all EPSA-IV projects. A number of economics software's are being acquired by NOC and other petroleum companies in Libya to determine upstream project profitability including Schlumberger's Merak PEEP. However, these softwares can carry out standard economic analyses including production forecasting and portfolio management but they cannot simulate the complexity of the cost recovery, sliding scale factors and the abandonment provision calculations detailed in the agreement. These softwares are currently used by NOC and most of the local oil companies on relatively simple projects and for training purposes. As a result, it is decided to conduct this study for the development of an economic spreadsheet model specially designed for EPSA-IV projects and further use it for determining the profitability of this new EPSA-IV project.

EPSA-IV Description

The EPSA-IV agreement clearly dictates how the costs and the production will be shared among the parties. In terms of costs, 100% of the exploration costs, 50% of the capital costs and 15% of the operating costs are to be paid by IOC. NOC will pay the remaining costs. In the case of production, 15% of the production will be entitled to IOC (as a cost stop) to recover its past costs including the exploration and the development capital and operating costs (cost recovery). Once its past costs are recovered its remaining entitled production (called profit oil) will be shared with NOC. IOC share of profit oil will follow a sliding scale intended to limit its withdrawal. This sliding scale is a function of two factors; namely the Index or "A" Factor and the Base or "B" Factor. The "A" Factor is calculated based on the ratio "R" of IOC's cumulative revenue divided by its cumulative costs as of the previous year. The higher the ratio "R", indicating that IOC is receiving additional revenue, the lower the "A" Factor. The Base or "B" Factor is a function of the total fluid production rate (oil and condensate). The production rate is divided into segments. A

specific "B" factor is assigned to each segment so that the higher the rate the lower the overall "B" factor.

The following tables describe these factors (NOC v. IOC, 2006), and the allocation of the costs and revenues of each party:

Table3 : "A" Factor (Index Factor)

"A" Factor (Index Factor)	
Is a function of $R = \text{Company's (Cum Revenue / Cum Costs)}$	
"R" Ratio	"A" Factor
≤ 1.0	90%
$> 1.0 \text{ to } \leq 3.0$	70%
$> 3.0 \text{ to } \leq 4.0$	50%
> 4.0	30%

Table4 : "B" Factor (Base Factor)

"B" Factor ("Base" Factor)	
Is a function of Project's Daily Production	
Oil Prod. Rate (MBD)	"Base" Factor per Segment
≤ 20	100%
$> 20 - \leq 30$	80%
$> 30 - \leq 60$	50%
$> 60 - \leq 85$	30%
> 85	20%

The following Figure-1 describe the cost and production shares of each party according to EPSA-IV:

Figure 1: Cost and production share of each party according to EPSA-IV

The following flow chart (Figure-2) describes how costs and revenues are shared among the two parties:

Figure 2: Costs and revenues share among the two parties

Economic Model Development:

In order to carry out a detailed economic evaluation on IOC discovery, an economic model was built using Spreadsheet (Excel). The model is capable of performing the following functions:

1. Calculation of basic input parameters based on the acquired data. These parameters will consist of oil, gas and condensate production forecasts, capital and operating expenditure profiles for an assumed production life of 20 years.
2. Carry out a detailed nominal cash flow analysis of the entire project regardless of the parties involved. This analysis included the calculation of the annual revenue, capital and operating expenditure profiles after applying an assumed cost contingency and an annual inflation rate. The annual net cash flow profile resulted from deducting the annual costs from the annual revenues.
3. Determination of the project's key economic indicators such as Net Present Value, Internal Rate of Return, Payback Period, Capital Productivity Index and Maximum Exposure using an assumed discount rate.
4. Based on the EPSA-IV terms and conditions, detailed cash flow calculation for each party applying a sliding scale for the IOC to control its production withdrawal. This sliding scale is consisted of two factors; the "A" and the "B" Factors as defined earlier. The cash flow calculation for the revenue, cost recovery and profit oil followed by the calculation of the Net Cash Flow of each party.
5. Determination of each party key economic indicators.
6. Carry out sensitivity analysis to determine the effect of varying some input parameters on key economic indicators. This analysis is carried out for the entire project and for each party. It included the construction of the spider and tornado diagrams. Important information are obtained from the spider diagram such as breakeven data.

Economic Evaluation Study

The economic study consists of the following sections:

1. Input/Output
2. Cash flow calculations
3. Economic Indicators
4. Sensitivity Analysis

1. Input/Output:

This section lists the input data of the project as received from NOC. Then it displays the results of the study.

In case this model is to be used for other projects that may have a different set of data then this section could be modified to accommodate new data. In many cases, NOC receives refined data that could be directly inserted in the cash flow section.

Figure-3 shows the input data as displayed in the Input / Output section (Input Output Sheet). Note that the data on the shaded cells indicate variables. So in case any of this data is changed the resulting output data will change automatically.

Past Exploration Costs			
Seismic Survey	60	\$MM	
Wildcats	80	\$MM	
Appraisal Wells	50	\$MM	
Production Data			
Oil production rate in year 5	60	MBD	
Decline rate	5%	per year	
Gas/Oil Ratio	1200	SCF/STB	
Condensate/Gas Ratio	0.08	Bbl/MCF	
Investment Data as of Year 0 (2018)			
Number of wells	70	wells	
Drilling cost	10	\$MM/well	
Length of pipelines	120	Kilometer	
Diameter of oil pipeline	20	inches	
Diameter of gas pipeline	24	inches	
Cost of pipeline	30,000	\$/inch-kilometer	
Cost of production facilities	250	\$MM	
Cost of camp	50	\$MM	Inflation rate (per year)
Abandonment Costs	60	\$MM	
Capex in Year 1	15%	of Total Capex	2%
Capex in Year 2	30%	of Total Capex	
Capex in Year 3	40%	of Total Capex	
Capex in Year 4	15%	of Total Capex	
Operating Cost Data (@ year 0)			
Fuel & Consumables	10	\$MM/year	2%
Spare parts	8	\$MM/year	2%
Maintenance Requirements	15	\$MM/year	2%
Salaries	2000	\$/person/month	2%
Catering & Services	150	\$/person/day	2%
Overhead costs	5	\$MM/year	2%
Well services & workovers	0.25	\$MM/year/well	2%
Number of personnel	100	People	
Cash Flow Data (@ Year 0)			
Crude Selling Price	60	\$/barrel	2%
Gas Selling Price	8	\$/MCF	2%
Condensate Selling Price	70	\$/barrel	2%
Discount Rate	10%		
Cost Contingency	20%		
1 MMSCF of gas	176	BOE	

Figure 3: Input data as displayed in the Input / Output section

2. Cash Flow Calculation:

Calculation of Main Parameters:

A detailed cash flow calculation was performed to determine the stream of Net Cash Flow (NCF) for the project and for each party (Cash Flow Sheet).

Table-5 summarizes the calculated annual production rate, price and revenue for each product. The year column starts at year 2018 (year 0) and continues to year 2042 (year 24). It is assumed that the project will be executed starting year 1 for 4 years, and production will start in year 5 for 20 years. Abandonment of the project will take place in year 25. The year number (n) indicates the number of years after starting the project. All calculated terms in each column are defined in Appendix B.

Table5 : Calculated annual production rate, price and revenue for each product

Year		Annual Production			Price			Revenue			
		Oil MMB	Gas BCF	Cond. MMB	Oil \$/bbl.	Gas \$/MCF	Cond. \$/bbl.	Oil \$MM	Gas \$MM	Cond. \$MM	Total \$MM
2018	0										
2019	1										
2020	2										
2021	3										
2022	4										
2023	5	21.9	26.3	2.1	66.24	8.83	77.29	1,451	232	162	1,845
2024	6	20.8	25.0	2.0	67.57	9.01	78.83	1,406	225	157	1,788
2025	7	19.8	23.7	1.9	68.92	9.19	80.41	1,362	218	153	1,733
2026	8	18.8	22.5	1.8	70.30	9.37	82.02	1,320	211	148	1,679
2027	9	17.8	21.4	1.7	71.71	9.56	83.66	1,279	205	143	1,627
2028	10	16.9	20.3	1.6	73.14	9.75	85.33	1,239	198	139	1,577
2029	11	16.1	19.3	1.5	74.60	9.95	87.04	1,201	192	135	1,528
2030	12	15.3	18.4	1.5	76.09	10.15	88.78	1,164	186	130	1,480
2031	13	14.5	17.4	1.4	77.62	10.35	90.55	1,128	180	126	1,434
2032	14	13.8	16.6	1.3	79.17	10.56	92.36	1,093	175	122	1,390
2033	15	13.1	15.7	1.3	80.75	10.77	94.21	1,059	169	119	1,347
2034	16	12.5	14.9	1.2	82.37	10.98	96.09	1,026	164	115	1,305
2035	17	11.8	14.2	1.1	84.01	11.20	98.02	994	159	111	1,265
2036	18	11.2	13.5	1.1	85.69	11.43	99.98	963	154	108	1,225
2037	19	10.7	12.8	1.0	87.41	11.65	101.98	934	149	105	1,187
2038	20	10.1	12.2	1.0	89.16	11.89	104.02	905	145	101	1,151
2039	21	9.6	11.6	0.9	90.94	12.13	106.10	877	140	98	1,115
2040	22	9.2	11.0	0.9	92.76	12.37	108.22	849	136	95	1,080
2041	23	8.7	10.4	0.8	94.61	12.62	110.38	823	132	92	1,047
2042	24	8.3	9.9	0.8	96.51	12.87	112.59	798	128	89	1,014
2043	25										
Total		281	337	27				21,869	3,499	2,449	27,818

The following bar chart (Figure-4) summarizes the annual oil, gas and condensate production rates.

Figure 4: The annual oil, gas and condensate production rates

Table-6 below summarizes the expected cumulative production after 20 years of production.

Table6 : The expected cumulative production after 20 years of production

Product	Oil (MMB)	Gas (BCF)	Condensate (MMB)
Cumulative Production (20 years)	281	337	27

Table-7 summarizes the annual capital and operating expenditures. Annual capex profile is calculated from assumed data and allocated for each of the first 4 years by incorporating capex percentage allocation for each year. Cost contingency and the inflation rate are then incorporated using equations given in Appendix B. Note that the spreadsheet model can accommodate a different inflation rate for each of the operating cost items as well as the capital cost and the selling price of each of the different products. However, for this study it is assumed to equal 2% per year for all cost and price items.

Table7 : The annual capital and operating expenditures

Year	Capex	Opex							
	\$MM	Fuel \$MM	Spares \$MM	Maint. \$MM	Salaries \$MM	Serv. \$MM	O/H \$MM	Wells \$MM	Total \$MM
2018									
2019	213								
2020	434								
2021	590								
2022	226								
2023		11.04	8.83	16.56	2.65	6.04	5.52	19.32	83.97
2024		11.26	9.01	16.89	2.70	6.17	5.63	19.71	85.64
2025		11.49	9.19	17.23	2.76	6.29	5.74	20.10	87.36
2026		11.72	9.37	17.57	2.81	6.41	5.86	20.50	89.10
2027		11.95	9.56	17.93	2.87	6.54	5.98	20.91	90.89
2028		12.19	9.75	18.28	2.93	6.67	6.09	21.33	92.70
2029		12.43	9.95	18.65	2.98	6.81	6.22	21.76	94.56
2030		12.68	10.15	19.02	3.04	6.94	6.34	22.19	96.45
2031		12.94	10.35	19.40	3.10	7.08	6.47	22.64	98.38
2032		13.19	10.56	19.79	3.17	7.22	6.60	23.09	100.35
2033		13.46	10.77	20.19	3.23	7.37	6.73	23.55	102.35
2034		13.73	10.98	20.59	3.29	7.52	6.86	24.02	104.40
2035		14.00	11.20	21.00	3.36	7.67	7.00	24.50	106.49
2036		14.28	11.43	21.42	3.43	7.82	7.14	24.99	108.62
2037		14.57	11.65	21.85	3.50	7.98	7.28	25.49	110.79
2038		14.86	11.89	22.29	3.57	8.14	7.43	26.00	113.01
2039		15.16	12.13	22.73	3.64	8.30	7.58	26.52	115.27
2040		15.46	12.37	23.19	3.71	8.46	7.73	27.05	117.57
2041		15.77	12.62	23.65	3.78	8.63	7.88	27.60	119.92
2042		16.08	12.87	24.13	3.86	8.81	8.04	28.15	122.32
2043	118								
	1,580	268	215	402	64	147	134	469	2,040

The following chart (Figure-8) summarizes the annual capital and operating expenditures.

Figure 5: The annual capital and operating expenditures

Table-8 summarizes the expected cumulative capital and operating expenditures after 20 years:

Table8 : Expected cumulative capital and operating expenditures after 20 years

Costs (\$MM)	Constant (Year 2018 Costs)		Escalated Costs	
	CAPEX	OPEX	CAPEX	OPEX
Cumulative Cost (25 years)	1,462	1,521	1,580	2,040

Project annual net cash flow is given in Table-9.

Table9 : The project annual net cash flow

Year	Total Project Cash Flow					Payback Years
	Revenue \$MM	Capex \$MM	Opex \$MM	NCF \$MM	Cum NCF \$MM	
2018						
2019		213		-213	-213	0.00
2020		434		-434	-647	0.00
2021		590		-590	-1,237	0.00
2022		226		-226	-1,462	0.00
2023	1,845		84	1761	299	4.83
2024	1,788		86	1703	2,002	0.00
2025	1,733		87	1645	3,647	0.00
2026	1,679		89	1590	5,237	0.00
2027	1,627		91	1536	6,773	0.00
2028	1,577		93	1484	8,257	0.00
2029	1,528		95	1433	9,690	0.00
2030	1,480		96	1384	11,074	0.00
2031	1,434		98	1336	12,410	0.00
2032	1,390		100	1290	13,699	0.00
2033	1,347		102	1245	14,944	0.00
2034	1,305		104	1201	16,145	0.00
2035	1,265		106	1158	17,303	0.00
2036	1,225		109	1117	18,420	0.00
2037	1,187		111	1077	19,496	0.00
2038	1,151		113	1038	20,534	0.00
2039	1,115		115	1000	21,534	0.00
2040	1,080		118	963	22,496	0.00
2041	1,047		120	927	23,423	0.00
2042	1,014		122	892	24,316	0.00
2043	0	118	0	-118	24,197	0.00
	27,818	1,580	2,040	24,197		4.83

The project cash flow profile is shown in Figure-6.

Figure 6: The project cash flow profile

IOC Net Cash Flow:

NCF is determined for each party according to the EPSA-IV terms and conditions. To determine the second party Net Cash Flow the following parameters have to be calculated:

1. Abandonment Provision
2. Cost Recovery
3. "A" Factor
4. "B" Factor
5. Profit Oil

1. Abandonment Provision

The EPSA-IV agreement defines IOC Abandonment Provision. Since the abandonment cost is a capital item then it should be equally paid by both parties. The IOC share of the abandonment cost is to be deposited in a saving account designated to NOC. This abandonment provision will start when the IOC recovers its past costs and will be calculated based on the Units-of-Production depreciation method. At the end of the contract period NOC has the option either to combine IOC's deposited amount to its share of the abandonment costs and abandon the project, or it can decide to solely continue production.

Table-10 summarizes the second party abandonment provision:

Table10 : The second party abandonment provision:

Year	Calculating Second Party Abandonment Provision						
	Abandonment \$MM	Production MMB	Cum Prod. MMB	Rem. Res. MMB	Cum AP \$MM	AP@Y25 \$MM	PV of AP \$MM
2018							
2019							
2020							
2021							
2022							
2023		22	22	281	0.0	0.0	0.0
2024		21	43	259	0.0	0.0	0.0
2025		20	62	238	0.0	0.0	0.0
2026		19	81	219	0.0	0.0	0.0
2027		18	99	200	5.3	5.3	1.1
2028		17	116	182	10.3	5.0	1.2
2029		16	132	165	15.0	4.8	1.3
2030		15	147	149	19.6	4.5	1.3
2031		15	162	134	23.9	4.3	1.4
2032		14	176	119	27.9	4.1	1.4
2033		13	189	105	31.8	3.9	1.5
2034		12	201	92	35.5	3.7	1.6
2035		12	213	80	39.0	3.5	1.6
2036		11	224	68	42.3	3.3	1.7
2037		11	235	57	45.5	3.2	1.8
2038		10	245	46	48.5	3.0	1.9
2039		10	255	36	51.3	2.9	1.9
2040		9	264	26	54.0	2.7	2.0
2041		9	273	17	56.6	2.6	2.1
2042		8	281	8	59.1	2.4	2.2
2043	59						
	59	281				59	26

2. Cost Recovery

The cost recovery is calculated to determine the amount of revenue to be received by the second party to recover its costs; namely the past exploration costs, its share of capex including the abandonment provision and its share of the operating cost. According to EPSA-IV the second party entitled revenue is the cost recovery ceiling. To calculate the cost recovery, the second party cumulative costs and cumulative entitled revenue have to be calculated first. Table-11 summarizes the second party cost recovery profile.

Table11 : The second party cost recovery profile

Year	Calculating Cost Recovery							
	Revenue \$MM	Capex \$MM	Opex \$MM	PV of AP \$MM	Cost \$MM	Cum Rev \$MM	Cum Cost \$MM	Cost Rec. \$MM
							190	
2018								
2019		106			106		296	
2020		217			217		513	
2021		295			295		808	
2022		113			113		921	
2023	277	0	13	0.0	13	277	934	277
2024	268	0	13	0.0	13	545	947	268
2025	260	0	13	0.0	13	805	960	260
2026	252	0	13	0.0	13	1,057	973	168
2027	244	0	14	1.1	15	1,301	988	15
2028	236	0	14	1.2	15	1,537	1,003	15
2029	229	0	14	1.3	15	1,766	1,018	15
2030	222	0	14	1.3	16	1,989	1,034	16
2031	215	0	15	1.4	16	2,204	1,050	16
2032	208	0	15	1.4	16	2,412	1,067	16
2033	202	0	15	1.5	17	2,614	1,084	17
2034	196	0	16	1.6	17	2,810	1,101	17
2035	190	0	16	1.6	18	3,000	1,118	18
2036	184	0	16	1.7	18	3,183	1,136	18
2037	178	0	17	1.8	18	3,362	1,155	18
2038	173	0	17	1.9	19	3,534	1,174	19
2039	167	0	17	1.9	19	3,701	1,193	19
2040	162	0	18	2.0	20	3,863	1,213	20
2041	157	0	18	2.1	20	4,021	1,233	20
2042	152	0	18	2.2	21	4,173	1,253	21
2043								
	4,173	731	306	26	1,063			1,253

3. The Index "A" Factor

To calculate the Index or "A" Factor it is important to first calculate the "R" ratio which is the ratio of the second party cumulative received revenue over its cumulative costs as of the previous year. The following Table-12 summarizes the "A" Factor profile.

Table12 : "A" factor profile

Year	Calculating "A" Factor								"A" Factor
	Received Revenue	Cum Rev \$MM	Cum Cost \$MM	R Ratio	R<1.0 1.0	1.0<R<3.0 3.0	3.0<R<4.0 4.0	R>4.0 100.0	
					90%	70%	50%	30%	
2018			190						
2019			296						
2020			513						
2021			808						
2022			921						
2023	277	277	934	0.00	90%	0%	0%	0%	90%
2024	268	545	947	0.30	90%	0%	0%	0%	90%
2025	260	805	960	0.58	90%	0%	0%	0%	90%
2026	223	1,028	973	0.84	90%	0%	0%	0%	90%
2027	134	1,162	988	1.06	0%	70%	0%	0%	70%
2028	132	1,294	1,003	1.18	0%	70%	0%	0%	70%
2029	130	1,425	1,018	1.29	0%	70%	0%	0%	70%
2030	129	1,554	1,034	1.40	0%	70%	0%	0%	70%
2031	127	1,681	1,050	1.50	0%	70%	0%	0%	70%
2032	126	1,807	1,067	1.60	0%	70%	0%	0%	70%
2033	124	1,931	1,084	1.69	0%	70%	0%	0%	70%
2034	123	2,054	1,101	1.78	0%	70%	0%	0%	70%
2035	122	2,176	1,118	1.87	0%	70%	0%	0%	70%
2036	121	2,297	1,136	1.95	0%	70%	0%	0%	70%
2037	120	2,417	1,155	2.02	0%	70%	0%	0%	70%
2038	119	2,535	1,174	2.09	0%	70%	0%	0%	70%
2039	116	2,652	1,193	2.16	0%	70%	0%	0%	70%
2040	114	2,766	1,213	2.22	0%	70%	0%	0%	70%
2041	111	2,877	1,233	2.28	0%	70%	0%	0%	70%
2042	109	2,986	1,253	2.33	0%	70%	0%	0%	70%
2043									
		2,986							

From this table the calculated "A" Factor is 70% once the "R" ratio exceeds 1. It will remain at this rate till the end of the production life as long as the "R" ratio is between 1 and 3.

4. Base "B" Factor

The Base "B" Factor is calculated based on the total project fluid production rate (oil + condensate). This production rate is divided into segments and for each segment a designated "B" Factor is applied as per the previously mentioned "B" factor table. The following Table-13 summarizes the "B" Factor and the combined factor profiles.

Table13 : "B" Factor and the combined factor profiles

Year	Calculating Base Factor						"Base" Factor	Combined Factor
	Fluid Prod.	P<20	20<P<30	30<P<60	60<P<85	P>85		
	20	30	60	85	85	20%		
	(MBD)	100%	80%	50%	30%	20%		
2018								
2019								
2020								
2021								
2022								
2023	65.8	20.0	10.0	30.0	5.8	0.0	68.0%	61.2%
2024	62.5	20.0	10.0	30.0	2.5	0.0	70.0%	63.0%
2025	59.3	20.0	10.0	29.3	0.0	0.0	71.9%	64.7%
2026	56.4	20.0	10.0	26.4	0.0	0.0	73.1%	65.8%
2027	53.6	20.0	10.0	23.6	0.0	0.0	74.3%	52.0%
2028	50.9	20.0	10.0	20.9	0.0	0.0	75.5%	52.9%
2029	48.3	20.0	10.0	18.3	0.0	0.0	76.9%	53.8%
2030	45.9	20.0	10.0	15.9	0.0	0.0	78.3%	54.8%
2031	43.6	20.0	10.0	13.6	0.0	0.0	79.8%	55.9%
2032	41.4	20.0	10.0	11.4	0.0	0.0	81.4%	57.0%
2033	39.4	20.0	10.0	9.4	0.0	0.0	83.0%	58.1%
2034	37.4	20.0	10.0	7.4	0.0	0.0	84.8%	59.3%
2035	35.5	20.0	10.0	5.5	0.0	0.0	86.6%	60.6%
2036	33.8	20.0	10.0	3.8	0.0	0.0	88.5%	62.0%
2037	32.1	20.0	10.0	2.1	0.0	0.0	90.5%	63.4%
2038	30.5	20.0	10.0	0.5	0.0	0.0	92.7%	64.9%
2039	28.9	20.0	8.9	0.0	0.0	0.0	93.8%	65.7%
2040	27.5	20.0	7.5	0.0	0.0	0.0	94.5%	66.2%
2041	26.1	20.0	6.1	0.0	0.0	0.0	95.3%	66.7%
2042	24.8	20.0	4.8	0.0	0.0	0.0	96.1%	67.3%
2043								

From this table the "B" Factor increases as the field production rate declines. Since the "A" Factor remains constant starting year 2027 when the ratio "R" exceeds 1, then the combined ratio will increase from 52% in year 2027 to 67% in year 2042. IOC share of the Profit Oil will be based on this combined ratio.

5. Profit Oil

Note that the second party entitled revenue will all be allocated to its Cost Recovery during the first 4 years of production. After that the remaining entitled revenue will be shared between the two parties based on the calculated combined factor. Table-14 summarizes the second party net cash flow profile.

Table14 : The second party net cash flow profile

Year	Second Party Cash Flow									
	Cost Rec.	Profit Oil	Share of PO	Revenue	Cost	NCF	Cum NCF	Payback	Max Exposure	
	\$MM	\$MM	\$MM	\$MM	\$MM	\$MM	\$MM	Years	Year	Time
2018										
2019					106	-106	-106	0.00	0	0
2020					217	-217	-323	0.00	0	0
2021					295	-295	-618	0.00	0	0
2022					113	-113	-731	0.00	2022	4
2023	277	0	0	277	13	264	-467	0.00	0	0
2024	268	0	0	268	13	255	-212	0.00	0	0
2025	260	0	0	260	13	247	35	6.86	0	0
2026	168	84	55	223	13	210	245	0.00	0	0
2027	15	229	119	134	15	119	364	0.00	0	0
2028	15	221	117	132	15	117	481	0.00	0	0
2029	15	214	115	130	15	115	596	0.00	0	0
2030	16	206	113	129	16	113	709	0.00	0	0
2031	16	199	111	127	16	111	821	0.00	0	0
2032	16	192	109	126	16	109	930	0.00	0	0
2033	17	185	108	124	17	108	1,038	0.00	0	0
2034	17	179	106	123	17	106	1,143	0.00	0	0
2035	18	172	104	122	18	104	1,248	0.00	0	0
2036	18	166	103	121	18	103	1,351	0.00	0	0
2037	18	160	101	120	18	101	1,452	0.00	0	0
2038	19	154	100	119	19	100	1,552	0.00	0	0
2039	19	148	97	116	19	97	1,649	0.00	0	0
2040	20	142	94	114	20	94	1,743	0.00	0	0
2041	20	137	91	111	20	91	1,834	0.00	0	0
2042	21	132	89	109	21	89	1,923	0.00	0	0
2043							1,923	0.00	0	0
	1,253	2,919	1,733	2,986	1,063	1,923		6.86	2022	4

NOC Net Cash Flow:

The first party net cash flow profile is calculated using two different methods:

Method 1:

$$\text{First party NCF} = \text{Cash Inflow} - \text{Cash Outflow}$$

$$\begin{aligned} \text{First party NCF} = & \text{Project gross revenue} \times \text{Its share} + \text{the remaining profit oil} + \\ & \text{second party abandonment provision} - \text{its share of capex (including abandonment costs)} - \\ & \text{its share of Opex} \end{aligned}$$

Method 2:

$$\text{First party NCF} = \text{Project NCF} - \text{Second party NCF}$$

The following Table-15 summarizes first party net cash flow calculation using method 1:

Table15 : First party net cash flow calculation using method 1

Year	First Party Cash Flow (Method 1)								
	Revenue Share \$MM	Remaining PO \$MM	2nd Party Aband.	Revenue \$MM	Capex \$MM	Opex \$MM	NCF \$MM	Cum NCF \$MM	Payback Years
2018									
2019					106		-106	-106	0.00
2020					217		-217	-323	0.00
2021					295		-295	-618	0.00
2022					113		-113	-731	0.00
2023	1,569	0	0.0	1,569		71	1,497	766	4.49
2024	1,520	0	0.0	1,520		73	1,447	2,213	0.00
2025	1,473	0	0.0	1,473		74	1,399	3,612	0.00
2026	1,427	29	0.0	1,456		76	1,380	4,992	0.00
2027	1,383	110	1.1	1,494		77	1,417	6,409	0.00
2028	1,340	104	1.2	1,446		79	1,367	7,775	0.00
2029	1,299	99	1.3	1,398		80	1,318	9,094	0.00
2030	1,258	93	1.3	1,353		82	1,271	10,364	0.00
2031	1,219	88	1.4	1,308		84	1,225	11,589	0.00
2032	1,181	83	1.4	1,266		85	1,180	12,769	0.00
2033	1,145	78	1.5	1,224		87	1,137	13,906	0.00
2034	1,109	73	1.6	1,184		89	1,095	15,001	0.00
2035	1,075	68	1.6	1,144		91	1,054	16,055	0.00
2036	1,042	63	1.7	1,106		92	1,014	17,069	0.00
2037	1,009	58	1.8	1,070		94	975	18,044	0.00
2038	978	54	1.9	1,034		96	938	18,982	0.00
2039	948	51	1.9	1,000		98	903	19,885	0.00
2040	918	48	2.0	969		100	869	20,753	0.00
2041	890	46	2.1	938		102	836	21,589	0.00
2042	862	43	2.2	908		104	804	22,393	0.00
2043					118		-118	22,275	0.00
	23,645	1,187	26	24,858	849	1,734	22,275		4.49

The following Table-16 summarizes first party net cash flow calculation using method 2:

Table16 : First party net cash flow calculation using method 2

Year	First Party Cash Flow (Method 2)		
	Project NCF \$MM	2nd Party NCF \$MM	NCF \$MM
2018			
2019	-213	-106	-106
2020	-434	-217	-217
2021	-590	-295	-295
2022	-226	-113	-113
2023	1,761	264	1,497
2024	1,703	255	1,447
2025	1,645	247	1,399
2026	1,590	210	1,380
2027	1,536	119	1,417
2028	1,484	117	1,367
2029	1,433	115	1,318
2030	1,384	113	1,271
2031	1,336	111	1,225
2032	1,290	109	1,180
2033	1,245	108	1,137
2034	1,201	106	1,095
2035	1,158	104	1,054
2036	1,117	103	1,014
2037	1,077	101	975
2038	1,038	100	938
2039	1,000	97	903
2040	963	94	869
2041	927	91	836
2042	892	89	804
2043	-118	0	-118
	24,197	1,923	22,275

The following diagrams in Figure 7 and Figure-8 summarize the project net cash flow profile and NCF allocation for each party.

Figure 7: The project net cash flow profile for each party

Figure 8: The project NCF allocation for each party

3. Economic Indicators:

A number of key economic indicators were calculated for the entire project and for each party. The following indicators were calculated:

- **Net Cash Flow (NCF)**
- **Net Present Value (NPV)**
- **Internal Rate of Return (IRR)**
- **Payback Period (or Payout)**
- **The Capital Productivity Index (CPI) or Return on Investment (ROI)**
- **Maximum Exposure (ME)**

The definition of indicators are given in Appendix B. The IRR is determined by using a spreadsheet built-in function, by trial & error or graphically by plotting the NPV versus discount rate. The following Figure-9 demonstrates the IRR for the project and for each party.

Figure 9: The Internal Rate of Return for the project and for each party.

Figure-10 demonstrates the payback time for the project and for each party:

Figure 10: The payback time for the project and for each party

Economic indicators for the project and for each party are summarized in Table-17.

Table17 : The economic indicators for the project and for each party

Economic Indicator	Project	1st Party	2nd Party	Units
Net Cash Flow (NCF)	24,197	22,275	1,923	\$MM
Net Present Value (NPV)	7,141	6,787	354	\$MM
Internal Rate of Return (IRR)	55.5%	76.4%	18.5%	
Payback Period (Payout)	4.83	4.49	6.86	Years
Capital Productivity Index (CPI)	5.84	10.47	0.61	\$\$
Maximum Exposure Value	-1,462	-731	-731	\$MM
Year of ME	2022	2022	2022	

The following Tables-18 and Table-19 together with Figure-11 and Figure-12 summarize the average production cost per barrel equivalent (\$/BOE) and its profile for the project and for each party based on constant (fixed) and escalated costs.

Table18 : Production cost per barrel equivalent calculations for each party based on constant and escalated costs

Year	Cost/BOE (\$/BOE)					
	Constant			Escalated		
	1st Party	2nd Party	Project	1st Party	2nd Party	Project
2018						
2019						
2020						
2021						
2022						
2023	5.51	18.84	7.51	5.94	19.96	8.04
2024	5.80	19.83	7.91	6.31	21.07	8.53
2025	6.11	20.88	8.32	6.71	22.25	9.04
2026	6.30	24.80	8.76	6.99	26.51	9.59
2027	6.27	42.14	9.22	7.03	45.18	10.17
2028	6.61	43.57	9.71	7.49	46.86	10.79
2029	6.97	45.02	10.22	7.97	48.57	11.44
2030	7.35	46.50	10.76	8.50	50.33	12.14
2031	7.75	48.00	11.32	9.06	52.13	12.88
2032	8.18	49.53	11.92	9.65	53.97	13.67
2033	4.16	7.20	4.44	5.59	9.69	5.97
2034	4.38	7.42	4.67	6.02	10.19	6.41
2035	4.62	7.65	4.92	6.48	10.71	6.88
2036	4.88	7.88	5.17	6.97	11.25	7.39
2037	5.15	8.11	5.45	7.50	11.82	7.94
2038	5.43	8.35	5.73	8.07	12.40	8.52
2039	5.73	8.67	6.04	8.68	13.14	9.15
2040	6.04	9.04	6.35	9.33	13.97	9.82
2041	6.36	9.42	6.69	10.03	14.86	10.55
2042	6.71	9.82	7.04	10.78	15.79	11.32
2043						
Average	6.18	24.02	8.12	7.71	27.46	9.86

Table19 : The average constant and nominal costs per barrel equivalent for the project and each party

Description	First Party	Second Party	Project	Units
Cum. Production	327	40	367	MMBOE
Real Costs (Constant 2018 Costs)				
Capex	731	731	1,462	\$MM
Opex	1,293	228	1,521	\$MM
Total Cost	2,024	959	2,983	\$MM
Capital Cost/bbl.	2.23	18.31	3.98	\$/BOE
Operating Cost/bbl.	3.95	5.71	4.14	\$/BOE
Total Cost/bbl.	6.18	24.02	8.12	\$/BOE
Nominal Costs (Escalated)				
Capex	790	790	1,580	\$MM
Opex	1,734	306	2,040	\$MM
Total Cost	2,524	1,096	3,621	\$MM
Capital Cost/bbl.	2.41	19.79	4.30	\$/BOE
Operating Cost/bbl.	5.30	7.66	5.55	\$/BOE
Total Cost/bbl.	7.71	27.46	9.86	\$/BOE

Figure 11: Production cost per barrel equivalent profile for the project and for each party based on constant costs

Figure 12: Production cost per barrel equivalent profile for the project and for each party based on Escalated costs

In general the upward trend of the cost per barrel profiles results from the gradual production decline. The odd shape of the second party cost per barrel profile can be explained as follows:

- During the first 4 years of production: Cost per barrel starts lower than its average rate at about \$20/BOE due to receiving all its entitled revenue for cost recovery, and increases gradually as field production declines.
- During the following 6 years: Cost per barrel jumps to around \$45/BOE resulting from allocating a portion of its entitled revenue to NOC as its share of profit oil.
- During the remaining 10 years: Cost per barrel drops to around \$10/BOE after all Capex is depreciated.

4. Sensitivity Analysis

Since the calculated economic indicators are based on future predictions then there is always a high degree of data uncertainty. To answer "What If" questions a sensitivity analysis was performed for the project as well as for each party. These analyses determine what would happen to project profitability in case a number of key parameters vary from their base case assumptions. The economic sensitivity is demonstrated by constructing spider and tornado diagrams.

For example, to determine how the NPV will change when varying the operating cost (such as by $\pm 50\%$) from its base case assumption, two spreadsheets are duplicated from the base case "Cash Flow" sheet. On the first copy the operating cost is increased by 50% and on the other sheet it is decreased by 50%. The resulting NPV's are then plotted versus the percentage variation of OPEX. The same calculation is repeated for each additional key parameter such as the production rate, selling prices, Capex and the assumed discount rate. The advantage of this method is that the spider diagram will be automatically updated whenever an input data is changed from its base case assumption.

The degree of the sensitivity of the NPV will depend on the slope of each line. The larger the slope the more sensitive the NPV to variation of this parameter. This sensitivity analysis investigated the effect of varying each of the mentioned parameter on the NPV's and IRR's separately.

The following Table-20 summarizes the calculated NPV's and IRR's for the project and for each party for each parameter variation.

Table20 : The calculated NPV's and IRR's for the project and for each party for each parameter variation

NPV Sensitivity (\$MM)	1st Party			2nd Party			Project		
	-50%	0%	50%	-50%	0%	50%	-50%	0%	50%
Prod. Rate	2,754	6,787	10,953	-43	354	618	2,711	7,141	11,571
Selling Price	2,768	6,787	10,848	-57	354	723	2,711	7,141	11,571
Capex	7,166	6,787	6,416	555	354	145	7,721	7,141	6,561
Opex	7,040	6,787	6,533	380	354	328	7,420	7,141	6,862
Discount Rate	11,791	6,787	4,167	849	354	103	12,641	7,141	4,270
IRR Sensitivity	1st Party			2nd Party			Project		
	-50%	0%	50%	-50%	0%	50%	-50%	0%	50%
Prod. Rate	48.3%	76.4%	96.4%	8.9%	18.5%	24.3%	33.0%	55.5%	71.5%
Selling Price	48.3%	76.4%	96.2%	8.4%	18.5%	25.9%	33.0%	55.5%	71.5%
Capex	110.1%	76.4%	60.2%	32.7%	18.5%	12.5%	83.2%	55.5%	42.4%
Opex	77.5%	76.4%	75.3%	19.0%	18.5%	18.0%	56.4%	55.5%	54.6%

The resulting spider diagrams for the sensitivity of the NPV's are given in Figure-13 thru Figure-15.

Figure 13: First party NPV Spider diagram

Figure 14: Second party NPV Spider diagram

Figure 15: Project NPV Spider diagram

The following tornado diagram (Figure-16) demonstrates the range of the project NPV's resulting from varying some parameters in a descending order.

Figure 16: Project NPV Tornado Diagram

The resulting spider diagrams to investigate the sensitivity of the IRR are given in Figure-17 thru Figure-19.

Figure 17: Project IRR Spider diagram

Figure 18: First Party IRR Spider diagram

Figure 19: Second party IRR Spider diagram

The following tornado diagram (Figure-20) demonstrates the range of the second party IRR's resulting from varying some parameters in a descending order.

Figure 20: Second Party IRR Tornado Diagram

5. Monte Carlo Simulation

Monte Carlo simulations are applied to simulate the probability of different outcomes when several variables are taking place. Using Monte Carlo simulations makes it viable to comprehend the effect of risk and uncertainty in forecasting models.

The constructed sensitivity analysis is used to study the project profitably when varying key parameters individually. The advantage of using Monte Carlo is to observe the project profitability when varying several parameters at the same time. Additionally, this approach provides the probability distribution function of several key parameters and their effect on the resulted Net Present Value.

Since it is challenging to perform Monte Carlo simulation of the economic model using spreadsheet, it is decided to perform Monte Carlo simulation using MATLAB software. To insure the accuracy of the simulation, the base case model is build using MATLAB. The economic indicators of the MATLAB model and the spreadsheet model are compared and their results are found identical (Table-21).

Table21 : Economic Indicator for the Project (MATLAB vs Spreadsheet)

Economic Indicators for the Project					
Using Matlab			Using Spreadsheet		
NCF	24,197	\$MM	NCF	24,197	\$MM
NPV	7,141	\$MM	NPV	7,141	\$MM
IRR	55.5	%	IRR	55.5	%
Payout	4.83	Years	Payout	4.83	Years
CPI	5.84	\$/	CPI	5.84	\$/
ME Value	-1,462	\$MM	ME Value	-1,462	\$MM
Year of ME	2022		Year of ME	2022	

After it was determined that the MATLAB model is valid, several key parameters were chosen to perform Monte Carlo simulation by changing them. The selected key parameters are: Production rate, oil price, gas price, condensate price, number of wells, cost contingency, gas oil ratio, discount rate, and inflation rate.

In order confirm the accuracy of the forecasted production rate. It is determined to try several decline curve analyses and carry on the study with the worst possible decline case scenario. The investigated decline curve analyses are:

1. Model decline (Constant 5% decline).
2. Exponential decline (similar to the model decline).
3. Linear decline.
4. Harmonic decline.
5. Hyperbolic decline.

The following Figure-21 and Figure-22 illustrate the production forecast using each decline curve method.

Figure 21: Production Forecast using Different Decline Curve

Figure 22: Production Forecast using Different Decline Curve (Semi-Log)

From the observed decline curves, it is seen that the worst-case scenario is the model decline (5% constant decline) when compared to the other decline curves. The linear decline is eliminated from the comparison since it does not represent a realistic decline curve. Therefore, the model decline curve is being used in the following Monte Carlo simulation study as the worst case.

Before performing Monte Carlo simulation, it is important to understand the effect of each key parameter on the resulting net present value in addition to understanding the probability distribution of the parameter itself. Both normal and uniform distributions are used by defining the mean, standard deviation, and limits for each parameter. Most of the selected key parameters follows a normal probability distribution, such as inflation

rate and selling price, while other parameters use uniform distribution, such as manufacturing costs (Monte Carlo Simulation, n.d.).

The following plots describes the results of changing each of the key parameters on the net present value.

Production rate

Production rate is following a normal probability distribution with a mean of 60 MBD (Figure-23). The resulted net present value remains positive with a minimum value of 4000 \$MM and maximum value of 11,000 \$MM. The relationship shown in Figure-24 between production rate and net present value is directly proportional. Moreover, net present value is highly sensitive to production rate.

Figure23 : Distribution of Production Rate and NPV Distribution Functions

Figure24 : Net Present Value vs Production Rate

Oil Price

Oil Price is following a normal probability distribution with a mean of 60 \$/bbl (Figure-25). The resulted net present value remains positive with a minimum value of 4500 \$MM and maximum value of 9,800 \$MM. Figure-26 shows that the relationship between oil price and net present value is directly proportional. Moreover, net present value is highly sensitive to oil price.

Figure 25: Distribution of Oil Price and NPV Distribution Functions

Figure 26: Net Present Value vs Oil Price

Gas Price

Gas Price is following a normal probability distribution with a mean of 8 \$/MCF (Figure-27). The resulted net present value remains positive with a minimum value of 6,800 \$MM and maximum value of 7,500 \$MM. Figure-28 shows that the relationship between gas price and net present value is directly proportional. Moreover, net present value is not very sensitive to gas price.

Figure 27: Distribution of Gas Price and NPV Distribution Functions

Figure 28: Net Present Value vs Gas Price

Condensate Price

Condensate Price is following a normal probability distribution with a mean of 70 \$/bbl (Figure-29). The resulted net present value remains positive with a minimum value of 6,800 \$MM and maximum value of 7,500 \$MM. Figure-30 shows that the relationship between condensate price and net present value is directly proportional. Moreover, net present value is not very sensitive to condensate price.

Figure 29: Distribution of Condensate Price and NPV Distribution Functions

Figure 30: Net Present Value vs Condensate Price

Number of Wells

Number of wells is following a uniform probability distribution with upper and lower limits of 50 and 90 wells (Figure-31). The resulted net present value remains positive with a minimum value of 6,900 \$MM and maximum value of 7,380 \$MM. Figure-32 shows that the relationship between number of wells and net present value is inversely proportional. Moreover, net present value is not very sensitive to number of wells.

Figure 31: Distribution of Number of Wells and NPV Distribution Functions

Figure 32: Net Present Value vs Number of Wells

Cost Contingency

Cost contingency is following a uniform probability distribution with upper and lower limits 10 and 30 percent (Figure-33). The resulted net present value remains positive with a minimum value of 7,000 \$MM and maximum value of 7,290 \$MM. Figure-34 shows that the relationship between cost contingency and net present value is inversely proportional. Moreover, net present value is not very sensitive to cost contingency.

Figure 33: Distribution of Cost Contingency and NPV Distribution Functions

Figure 34: Net Present Value vs Cost Contingency

Gas Oil Ratio

Gas oil ratio is following a normal probability distribution with a mean of 1.2 SCF/STB (Figure-35). The resulted net present value remains positive with a minimum value of 6,850 \$MM and maximum value of 7,400 \$MM. Figure-36 shows that the relationship between gas oil ratio and net present value is directly proportional. Moreover, net present value is not very sensitive to gas oil ratio.

Figure 35: Distribution of Gas Oil Ratio and NPV Distribution Functions

Figure 36: Net Present Value vs Gas Oil Ratio

Discount Rate

Discount rate is following a normal probability distribution with a mean of 10% (Figure-37). The resulted net present value remains positive with a minimum value of 6,000 \$MM and maximum value of 8,500 \$MM. Figure-38 shows that the relationship between discount rate and net present value is inversely proportional. Moreover, net present value is moderately sensitive to discount rate.

Figure 37: Discount Rate and NPV Distribution Functions

Figure 38: Net Present Value vs Discount Rate

Inflation Rate

Inflation rate is following a normal probability distribution with a mean of 2% (Figure-39). The resulted net present value remains positive with a minimum value of 5,800 \$MM and maximum value of 8,600 \$MM. Figure-40 shows that the relationship between inflation rate and net present value is directly proportional. Moreover, net present value is moderately sensitive to inflation rate.

Figure 39: Inflation Rate and NPV Distribution Functions

Figure 40: Net Present Value vs Inflation Rate

The results show that the project would remain profitable when any of the key parameters changes. However, these analyses do not show the project profitability when these parameters changes simultaneously. This is when Monte Carlo simulation takes place and becomes an effective method of project profitability investigation.

The results of Monte Carlo study of all the economic indicators are given in Figure-41 thru Figure-48 when the selected key parameters change concurrently following a normal distribution.

Figure 41: NPV Probability and Cumulative Distribution Functions (All Key Parameters Change)

Figure 42: NPV Histogram (All key parameters change)

Figure 43: NCF Histogram (All key parameters change)

Figure 44: IRR Histogram (All key parameters change)

Figure 45: Payout Histogram (All key parameters change)

Figure 46: CPI Histogram (All key parameters change)

Figure 47: ME value Histogram (All key parameters change)

Figure 48: ME Time Histogram (All key parameters change)

Monte Carlo simulation results indicate that the project net present value remains positive (profitable) with a worst-case scenario of 3,000 \$MM, and best scenario of 11,200 \$MM. Additionally, the rest of the economic indicators show the project remains feasible even with all the worst-case scenarios.

The following Table-22 summarizes the results obtained with the Monte Carlo simulation for the best and worst possible scenarios using the selected probability distributions for each key parameter.

Table22 : Monte Carlo Simulation Worst/Best-Case scenario

Monte Carlo Simulation								
Worst-Case			Base-Case			Best-Case		
NCF	11,200	\$MM	NCF	24,197	\$MM	NCF	38,000	\$MM
NPV	3,000	\$MM	NPV	7,141	\$MM	NPV	12,000	\$MM
IRR	33	%	IRR	55.5	%	IRR	77	%
Payout	5.8	Years	Payout	4.83	Years	Payout	4.5	Years
CPI	2	\$/ \$	CPI	5.84	\$/ \$	CPI	10.9	\$/ \$
ME Value	-1,890	\$MM	ME Value	-1,462	\$MM	ME Value	-1,100	\$MM
Year of ME	2022		Year of ME	2022		Year of ME	2022	

Summary of Results

- The overall project economics indicate that:
 - Its 20 years cumulative production is 367MMBOE
 - Its 20 years net profit is \$24,197MM.
 - The net present value of its profit is \$7,141MM assuming 10% annual discount rate.
 - Its Internal Rate of Return is 55.5%.
 - Its Payback Period is 4.83 years from project start.
 - Its Capital Productivity Index (or its Return on Investment) is \$5.84 for each dollar invested in term of its present value.
 - Its Maximum Exposure is \$1,462MM in year 2022
 - Its average cost per barrel equivalent is \$8.12/BOE (2018 costs) or \$9.86/BOE (escalated costs)
- The economics of the first party indicates that:
 - Its 20 years cumulative production is 327MMBOE
 - Its 20 years net profit is \$22,275MM.
 - The net present value of its profit is \$6,787MM assuming 10% annual discount rate.
 - Its Internal Rate of Return is 76.4%.
 - Its Payback Period is 4.49 years from project start.
 - Its Capital Productivity Index (or its Return on Investment) is \$10.47 for each dollar invested in term of its present value.
 - Its Maximum Exposure is \$731MM in year 2022
 - Its average cost per barrel equivalent is \$6.18/BOE (2018 costs) or \$7.71/BOE (escalated costs)
- The economics of the second party indicates that:
 - Its 20 years cumulative production is 40MMBOE
 - Its 20 years net profit is \$1,923MM.
 - The net present value of its profit is \$354MM assuming 10% annual discount rate.

- Its Internal Rate of Return is 18.5%.
- Its Payback Period is 6.86 years from project start.
- Its Capital Productivity Index (or its Return on Investment) is \$0.61 for each dollar invested in term of its present value.
- Its Maximum Exposure is \$731MM in year 2022
- Its average cost per barrel equivalent is \$24.02/BOE (2018 costs) or \$27.46/BOE (escalated costs)
- Conducting Monte Carlo simulation indicates that the project remains profitable even if worst case scenario accrued as displayed on the following table.

Table23 : Monte Carlo results

Monte Carlo Simulation								
Worst-Case			Base-Case			Best-Case		
NCF	11,200	\$MM	NCF	24,197	\$MM	NCF	38,000	\$MM
NPV	3,000	\$MM	NPV	7,141	\$MM	NPV	12,000	\$MM
IRR	33	%	IRR	55.5	%	IRR	77	%
Payout	5.8	Years	Payout	4.83	Years	Payout	4.5	Years
CPI	2	\$/	CPI	5.84	\$/	CPI	10.9	\$/
ME Value	-1,890	\$MM	ME Value	-1,462	\$MM	ME Value	-1,100	\$MM
Year of ME	2022		Year of ME	2022		Year of ME	2022	

Conclusions

Based on the results of this study, the followings are concluded:

- A new spreadsheet model is developed to study the economics of an Exploration and Production Sharing Agreement for an oil field in Libya. The results of the spreadsheet is verified with a Monte Carlo model.
- The sensitivity of NPV indicates that the project economics is highly sensitive to variations in the production rate, selling prices and the assumed discount rate, while less sensitive to variations in the capital and operating expenditures.
- The sensitivity of IRR indicates that the project economics is highly sensitive to variations in the capital cost, moderately sensitive to variations in the production rate and selling prices and less sensitive to variations in the operating cost.
- The second party considers IRR a critical indicator as it should not fall below its chosen limit rate which is normally higher than the assumed discount rate.
- The overall project is economically viable provided that:
 - Its production rate does not fall below 20% of the assumed value (or a reduction of not more than 80%)
 - The selling prices do not fall below 20% from the assumed values (or a reduction of not more than 80%).
 - The discount rate does not exceed 55.5% (Its IRR%)
 - Its capital costs do not exceed 715% of the assumed values (or increase by more than 615% above the assumed values).
 - Its operating costs do not exceed 1,378% of the assumed values (or increase by more than 1,278% above the assumed values).
- For the first party the project is economically viable provided that:
 - Its production rate does not fall below 15% of the assumed value (or a reduction of not more than 85%).
 - The selling prices do not fall below 15% of the assumed values (or a reduction of not more than 85%).
 - The discount rate does not exceed 76.4% (Its IRR%)

- Its capital costs do not exceed 1,205% of the assumed values (or increase by more than 1,105% above the assumed values).
- Its operating costs do not exceed 1,463% above the assumed values (or increase by more than 1,363% above the assumed values).
- For the second party the project is economically viable provided that:
 - Its production rate does not fall below 55% of the assumed value (or a reduction of not more than 45%).
 - The selling prices do not fall below 57% of the assumed values (or a reduction of not more than 43%).
 - The discount rate does not exceed 18.5% (Its IRR%)
 - its capital costs do not exceed 182% of the assumed values (or increase by more than 82% above the assumed values)
 - Its operating costs do not exceed 805% of the assumed values (or increase by more than 705% above the assumed values).
- Based on the received data from NOC the proposed development project appears economically feasible for both parties.
- The results of Monte Carlo simulation show that the project remains positive (profitable) even with a worst-case scenario for all economic indicators.

Recommendations

Based on the results of this study, the followings are recommended:

- Data received from NOC is to be verified before deciding to implement the project to guarantee the project viability.
- The project is to be implemented as planned as project delay normally has a negative impact on the project profitability.
- Since NPV is highly sensitive to production rate, IOC should carry out additional well testing to ensure the accuracy of the assumed well production rate.
- The economic model should be updated when any of the input data is changed.
- NOC should adopt the spreadsheet model to be able to evaluate the economics of other EPSA-IV projects.

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- **Appendix A- MATLAB Code**

This appendix displays the MATLAB codes that were used to build the economic model and perform the Monte Carlo simulation. The results for different decline curve values are displayed in Table-24 and Table-25.

The MATLAB Code (Base Case Model-Project)

```

clc
clear all
%% Production Data.....
Rate_Oil=60; %MBD
Rate_Decline=0.05; %per year
GOR=1.2; %SCF/STB
CGR=0.08; %BBL/MCF

%% Investment Data as of Year 0 (2018).....
No_Wells=70; %wells
Cost_Drill=10; %MM/well
L_Pipe=120; %Kilometer
D_Oil=20; %inches
D_Gas=24; %inches
Cost_Pipe=30000; %$/inch-kilometer
Cost_Facility=250; %$MM
Cost_Camp=50; %$MM
Cost_Abon=60; %$MM
Capex_Perc=zeros(25,1);
Capex_Perc(1)=.15; Capex_Perc(2)=.3; Capex_Perc(3)=.4;
Capex_Perc(4)=.15;
Rate_Inf=.02;

%% Cash Flow Data (@ Year 0)
Oil_Price_0=60; %$/bbl
Gas_Price_0=8; %$/MCF
Cond_Price_0=70; %$/bbl
Rate_Discount=0.1; %percentage
Cost_Contingency=.2;

%% Operating Cost Data (@ year
0.....
Cost_Fuel=10; %$MM/year

```

```

Cost_Spare=8; %$MM/year
Cost_Maintenance=15; %$MM/year
Cost_Salary=2000; %$/person/month
Cost_Service=150; %$/person/day
Cost_Overhead=5; %$MM/year
Cost_Workover=0.25; %MM/year/well
No_Personnel=100; %people

%%
%-----Calculation-----
%
%% CAPEX
delta_year=[1:25];
CAPEX_Total=No_Wells*Cost_Drill+L_Pipe*Cost_Pipe*D_Oil/1000
000+L_Pipe*Cost_Pipe*D_Gas/1000000+Cost_Camp+Cost_Facility;
CAPEX=zeros(25,1);
for i=1:25

CAPEX(i)=CAPEX_Total*(1+Cost_Contingency)*Capex_Perc(i)*(1+
Rate_Inf)^i;
    if i==25

CAPEX(i)=Cost_Abon*(1+Cost_Contingency)*(1+Rate_Inf)^i;
        end
    end
%% Production
Oil=zeros(25,1);
Gas=zeros(25,1);
Cond=zeros(25,1);
for i=5:24
    Oil(i)=Rate_Oil*.365*(1-Rate_Decline)^(i-5);
    Gas(i)=Oil(i)*GOR;
    Cond(i)=Gas(i)*CGR;

end

%% Price
Oil_Price=zeros(25,1);
Gas_Price=zeros(25,1);
Cond_Price=zeros(25,1);
for i=5:24
    Oil_Price(i)=Oil_Price_0*(1+Rate_Inf)^(i);
    Gas_Price(i)=Gas_Price_0*(1+Rate_Inf)^(i);
    Cond_Price(i)=Cond_Price_0*(1+Rate_Inf)^(i);

```

```

end

%% Revenue
Oil_Revenue=Oil.*Oil_Price;
Gas_Revenue=Gas.*Gas_Price;
Cond_Revenue=Cond.*Cond_Price;
Revenue=Oil_Revenue+Gas_Revenue+Cond_Revenue;

%% OPEX
OPEX=zeros(25,1);
for i=5:24

OPEX(i)=(Cost_Fuel+Cost_Spare+Cost_Maintenance+Cost_Salary*
No_Personnel*12/1000000+Cost_Service*No_Personnel*365/10000
00+Cost_Overhead+Cost_Workover*No_Wells)*((1+Cost_Contingen
cy))*(1+Rate_Inf)^(i);

end

%% NCF
NCF=Revenue-OPEX-CAPEX;
Cum_NCF= cumsum(NCF);

%% Payback
Payback=zeros(25,1);
for i=2:24
    if Cum_NCF(i)*Cum_NCF(i-1)<0
        Payback(i)=(i-1)+abs(Cum_NCF(i-1)/NCF(i));
        Payout_Index=i;
    end
end

%% Economic

NPV = pvvar([0;NCF],Rate_Discount);
IRR = irr([0;NCF]);
CPI=NPV/pvvar([0;CAPEX([1:4,end])],Rate_Discount);

%% Report
Net_Cash_Flow=sum(NCF)
NPV
IRR
Payout=Payback(Payout_Index)
CPI

```

```
[Max_Exposure, Index_Exposure] = min(Cum_NCF);  
Max_Exposure  
Year_ME=Index_Exposure+2018
```

The MATLAB Results (Base Case Model-Project)

Net_Cash_Flow =

2.4197e+04

NPV =

7.1408e+03

IRR =

0.5550

Payout =

4.8302

CPI =

5.8400

Max_Exposure =

-1.4623e+03

Year_ME =

2022

The MATLAB Code to perform Monte Carlo including all the key parameters

```
clc
clear all
% creating the range
% Uniform Distribution
% Rate_Inf_Range=linSPACE(0.01,0.05,10000);
% Rate_Oil_Range=linSPACE(30,100,10000); %MBD
No_Wells_Range=linSPACE(50,90,10000); %wells
% Oil_Price_0_Range=linSPACE(30,100,10000); %$/bbl
% Gas_Price_0_Range=linSPACE(2,15,10000); %$/MCF
% Cond_Price_0_Range=linSPACE(30,100,10000); %$/bbl
% Rate_Discount_Range=linSPACE(0.09,0.11,10000);
%percentage
% Cost_Maintenance_Range=linSPACE(10,30,10000); %$MM/year
% GOR_Range=linSPACE(1,1.4,10000); %SCF/STB
Cost_Contingency_Range=linSPACE(0.1,0.3,10000);

% Normal Distribution
Rate_Inf_Range=0.005*randn(1,10000)+0.02; %percentage
Rate_Oil_Range=6*randn(1,10000)+60; %MBD
% No_Wells_Range=7*randn(1,10000)+70; %Wells
Oil_Price_0_Range=6*randn(1,10000)+60; %$/bbl
Gas_Price_0_Range=0.7*randn(1,10000)+5; %$/MCF
Cond_Price_0_Range=6*randn(1,10000)+70; %$/bbl
Rate_Discount_Range=0.005*randn(1,10000)+0.1; %percentage
Cost_Maintenance_Range=3*randn(1,10000)+15; %$MM/year
GOR_Range=0.05*randn(1,10000)+1.2; %SCF/STB
% Cost_Contingency_Range=0.02*randn(1,10000)+0.2;

for j=1:10000
    % parameters
    Rate_Inf=datasample(Rate_Inf_Range,1);
    Rate_Inf_values(j)=Rate_Inf;

    Rate_Oil=datasample(Rate_Oil_Range,1); %MBD
    Rate_Oil_values(j)=Rate_Oil;

    No_Wells=datasample(No_Wells_Range,1); %wells
    No_Wells_values(j)=No_Wells;

    Oil_Price_0=datasample(Oil_Price_0_Range,1); %$/bbl
    Oil_Price_0_values(j)=Oil_Price_0;
```

```

Gas_Price_0=datasample(Gas_Price_0_Range,1); %$/MCF
Gas_Price_0_values(j)=Gas_Price_0;

Cond_Price_0=datasample(Cond_Price_0_Range,1); %$/bbl
Cond_Price_0_values(j)=Cond_Price_0;

Rate_Discount=datasample(Rate_Discount_Range,1); %$/bbl
Rate_Discount_values(j)=Rate_Discount;

Cost_Maintenance=datasample(Cost_Maintenance_Range,1);
%$/bbl
Cost_Maintenance_values(j)=Cost_Maintenance;

GOR=datasample(GOR_Range,1); %$/MCF
GOR_values(j)=GOR;

Cost_Contingency=datasample(Cost_Contingency_Range,1);
Cost_Contingency_values(j)=GOR;

%% Production
Data.....
Rate_Decline=0.05; %per year
CGR=0.08; %BBL/MCF

%% Investment Data as of Year 0
(2018).....
Cost_Drill=10; %MM/well
L_Pipe=120; %Kilometer
D_Oil=20; %inches
D_Gas=24; %inches
Cost_Pipe=30000; %$/inch-kilometer
Cost_Facility=250; %$MM
Cost_Camp=50; %$MM
Cost_Abon=60; %$MM
Capex_Perc=zeros(25,1);
Capex_Perc(1)=.15; Capex_Perc(2)=.3;
Capex_Perc(3)=.4; Capex_Perc(4)=.15;

%% Operating Cost Data (@ year
0.....
Cost_Fuel=10; %$MM/year
Cost_Spare=8; %$MM/year

```

```

Cost_Salary=2000; %$/person/month
Cost_Service=150; %$/person/day
Cost_Overhead=5; %$MM/year
Cost_Workover=0.25; %MM/year/well
No_Personnel=100; %people

%%
%-----Calculation-----
%
%% CAPEX
delta_year=[1:25];

CAPEX_Total=No_Wells*Cost_Drill+L_Pipe*Cost_Pipe*D_Oil/1000
000+L_Pipe*Cost_Pipe*D_Gas/1000000+Cost_Camp+Cost_Facility;
CAPEX=zeros(25,1);
for i=1:25

CAPEX(i)=CAPEX_Total*(1+Cost_Contingency)*Capex_Perc(i)*(1+
Rate_Inf)^i;
    if i==25

CAPEX(i)=Cost_Abon*(1+Cost_Contingency)*(1+Rate_Inf)^i;
        end
    end
%% Production
Oil=zeros(25,1);
Gas=zeros(25,1);
Cond=zeros(25,1);
for i=5:24
    Oil(i)=Rate_Oil*.365*(1-Rate_Decline)^(i-5);
    Gas(i)=Oil(i)*GOR;
    Cond(i)=Gas(i)*CGR;

end

%% Price
Oil_Price=zeros(25,1);
Gas_Price=zeros(25,1);
Cond_Price=zeros(25,1);
for i=5:24
    Oil_Price(i)=Oil_Price_0*(1+Rate_Inf)^(i);
    Gas_Price(i)=Gas_Price_0*(1+Rate_Inf)^(i);
    Cond_Price(i)=Cond_Price_0*(1+Rate_Inf)^(i);
end

```



```

%% Revenue
Oil_Revenue=Oil.*Oil_Price;
Gas_Revenue=Gas.*Gas_Price;
Cond_Revenue=Cond.*Cond_Price;
Revenue=Oil_Revenue+Gas_Revenue+Cond_Revenue;

%% OPEX
OPEX=zeros(25,1);
for i=5:24

OPEX(i)=(Cost_Fuel+Cost_Spare+Cost_Maintenance+Cost_Salary*
No_Personnel*12/1000000+Cost_Service*No_Personnel*365/10000
00+Cost_Overhead+Cost_Workover*No_Wells)*((1+Cost_Contingen
cy))*(1+Rate_Inf)^(i);

end
%% NCF
NCF=Revenue-OPEX-CAPEX;
Cum_NCF= cumsum(NCF);

%% Payback
Payback=zeros(25,1);
for i=2:24
    if Cum_NCF(i)*Cum_NCF(i-1)<0
        Payback(i)=(i-1)+abs(Cum_NCF(i-1)/NCF(i));
        Payout_Index=i;
    end
end

%% Economic
NPV = pvvar([0;NCF],Rate_Discount);
IRR = irr([0;NCF]);
CPI=NPV/pvvar([0;CAPEX([1:4,end])],Rate_Discount);

%% Report
Net_Cash_Flow(j)=sum(NCF);
Net_Present_Value(j)=NPV;
Internal_Rate_Return(j)=IRR;
Payout(j)=Payback(Payout_Index);
Capital_PI(j)=CPI;
[Max_Exposure(j),Index_Exposure] = min(Cum_NCF);

```

```

        Max_Exposure;
        Year_ME(j)=Index_Exposure+2018;

end

% figure(1)
% plot(Rate_Inf_values,Net_Present_Value,'*')
% xlabel('Inflation Rate')
% ylabel('NPV $MM')
% title('NPV vs Inflation Rate')
%
% figure(2)
% plot(Rate_Oil_values,Net_Present_Value,'*')
% xlabel('Production Rate MBPD')
% ylabel('NPV $MM')
% title('NPV vs Production Rate')
%
% figure(3)
% plot(No_Wells_values,Net_Present_Value,'*')
% xlabel('Number of Wells')
% ylabel('NPV $MM')
% title('NPV vs Number of Wells')
%
% figure(4)
% plot(Oil_Price_0_values,Net_Present_Value,'*')
% xlabel('Oil Price $/bbl')
% ylabel('NPV $MM')
% title('NPV vs Oil Price')
%
% figure(5)
% plot(Gas_Price_0_values,Net_Present_Value,'*')
% xlabel('Gas Price $/MCF')
% ylabel('NPV $MM')
% title('NPV vs Gas Price')
%
% figure(6)
% plot(Cond_Price_0_values,Net_Present_Value,'*')
% xlabel('Condensate Price $/bbl')
% ylabel('NPV $MM')
% title('NPV vs Condensate Price')
%
% figure(7)
% plot(Rate_Discount_values,Net_Present_Value,'*')
% xlabel('Discount Rate')

```

```

% ylabel('NPV $MM')
% title('NPV vs Discount Rate')
%
% figure(8)
% plot(Cost_Maintenance_values,Net_Present_Value,'*')
% xlabel('Maintenance Cost $MM/year')
% ylabel('NPV $MM')
% title('NPV vs Maintenance Cost')
% Rate_Inf_values
%
% figure(9)
% plot(GOR_values,Net_Present_Value,'*')
% xlabel('GOR SCF/STB')
% ylabel('NPV $MM')
% title('NPV vs GOR')

figure(10)
hist(Net_Present_Value,50);
xlabel('NPV $MM')
ylabel('Frequency')
title('NPV Histogram')
%%

figure(11)
subplot(2,1,1)
[f,x]=hist(Net_Present_Value,50);
PDF=f/trapz(x,f);
bar(x,PDF);
xlabel('NPV $MM')
ylabel('Probability')
title('Probability Distribution Function')
xlim([min(Net_Present_Value) max(Net_Present_Value) ])

subplot(2,1,2)
CDF=cumsum(PDF);
CDF=CDF/max(CDF);

plot(x,CDF,'color','red','linewidth',4)
xlim([min(Net_Present_Value) max(Net_Present_Value) ])

xlabel('NPV $MM')
ylabel('Probability')
title('Cumulative Distribution Function')

```

```

figure(12)
hist(Internal_Rate_Return,50);
xlabel('IRR')
ylabel('Frequency')
title('IRR Histogram')

figure(13)
hist(Net_Cash_Flow,50);
xlabel('NCF $MM')
ylabel('Frequency')
title('NCF Histogram')

figure(14)
hist(Payout,50);
xlabel('Payout Years')
ylabel('Frequency')
title('Payout Histogram')

figure(15)
hist(Capital_PI,50);
xlabel('CPI $/$')
ylabel('Frequency')
title('CPI Histogram')

figure(16)
hist(Max_Exposure,50);
xlabel('ME Value $MM')
ylabel('Frequency')
title('Maximum Exposure Value Histogram')

figure(17)
hist(Year_ME,50);
xlabel('ME Time Year')
ylabel('Frequency')
title('Maximum Exposure Time Histogram')

```

Table24 : Decline curves (Model, Exponential and Linear Decline)

Time (years)		Model Decline			Exponential Decline			Linear Decline		
Cash Flow	Production	Daily (BOPD)	Annual (BO)	Cumulative (BO)	Daily (BOPD)	Annual (BO)	Cumulative (BO)	Daily (BOPD)	Annual (BO)	Cumulative (BO)
5	0	60,000	21,900	21,900	60,000	21,900	21,900	60,000	21,900	21,900
6	1	57,000	20,805	42,705	57,074	20,832	42,732	57,000	20,805	42,705
7	2	54,150	19,765	62,470	54,290	19,816	62,548	54,000	19,710	62,415
8	3	51,443	18,777	81,246	51,642	18,850	81,397	51,000	18,615	81,030
9	4	48,870	17,838	99,084	49,124	17,930	99,328	48,000	17,520	98,550
10	5	46,427	16,946	116,030	46,728	17,056	116,383	45,000	16,425	114,975
11	6	44,106	16,099	132,128	44,449	16,224	132,607	42,000	15,330	130,305
12	7	41,900	15,294	147,422	42,281	15,433	148,040	39,000	14,235	144,540
13	8	39,805	14,529	161,951	40,219	14,680	162,720	36,000	13,140	157,680
14	9	37,815	13,802	175,753	38,258	13,964	176,684	33,000	12,045	169,725
15	10	35,924	13,112	188,866	36,392	13,283	189,967	30,000	10,950	180,675
16	11	34,128	12,457	201,322	34,617	12,635	202,602	27,000	9,855	190,530
17	12	32,422	11,834	213,156	32,929	12,019	214,621	24,000	8,760	199,290
18	13	30,801	11,242	224,398	31,323	11,433	226,054	21,000	7,665	206,955
19	14	29,260	10,680	235,078	29,795	10,875	236,929	18,000	6,570	213,525
20	15	27,797	10,146	245,225	28,342	10,345	247,274	15,000	5,475	219,000
21	16	26,408	9,639	254,863	26,960	9,840	257,114	12,000	4,380	223,380
22	17	25,087	9,157	264,020	25,645	9,360	266,475	9,000	3,285	226,665
23	18	23,833	8,699	272,719	24,394	8,904	275,379	6,000	2,190	228,855
24	19	22,641	8,264	280,983	23,204	8,470	283,848	3,000	1,095	229,950
Total			280,983			283,848			229,950	

Table25 : Decline curves (Model, Harmonic and Hyperbolic Decline)

Time (years)		Model Decline			Harmonic Decline			Hyperbolic Decline		
Cash Flow	Production	Daily (BOPD)	Annual (BO)	Cumulative (BO)	Daily (BOPD)	Annual (BO)	Cumulative (BO)	Daily (BOPD)	Annual (BO)	Cumulative (BO)
5	0	60,000	21,900	21,900	60,000	21,900	21,900	60,000	21,900	21,900
6	1	57,000	20,805	42,705	57,143	20,857	42,757	57,109	20,845	42,745
7	2	54,150	19,765	62,470	54,545	19,909	62,666	54,422	19,864	62,609
8	3	51,443	18,777	81,246	52,174	19,043	81,710	51,920	18,951	81,559
9	4	48,870	17,838	99,084	50,000	18,250	99,960	49,587	18,099	99,659
10	5	46,427	16,946	116,030	48,000	17,520	117,480	47,407	17,304	116,962
11	6	44,106	16,099	132,128	46,154	16,846	134,326	45,369	16,560	133,522
12	7	41,900	15,294	147,422	44,444	16,222	150,548	43,459	15,862	149,384
13	8	39,805	14,529	161,951	42,857	15,643	166,191	41,667	15,208	164,593
14	9	37,815	13,802	175,753	41,379	15,103	181,294	39,983	14,594	179,187
15	10	35,924	13,112	188,866	40,000	14,600	195,894	38,400	14,016	193,203
16	11	34,128	12,457	201,322	38,710	14,129	210,023	36,909	13,472	206,674
17	12	32,422	11,834	213,156	37,500	13,688	223,711	35,503	12,959	219,633
18	13	30,801	11,242	224,398	36,364	13,273	236,984	34,176	12,474	232,107
19	14	29,260	10,680	235,078	35,294	12,882	249,866	32,922	12,016	244,123
20	15	27,797	10,146	245,225	34,286	12,514	262,380	31,736	11,583	255,707
21	16	26,408	9,639	254,863	33,333	12,167	274,547	30,612	11,173	266,880
22	17	25,087	9,157	264,020	32,432	11,838	286,385	29,548	10,785	277,665
23	18	23,833	8,699	272,719	31,579	11,526	297,911	28,537	10,416	288,081
24	19	22,641	8,264	280,983	30,769	11,231	309,142	27,578	10,066	298,148
Total			280,983			309,142			298,148	

Appendix B- Definitions and Equations

Cash Flow Equations: The following key equations (Petroconsultants. 1995) were used in the spreadsheet model to calculate the Net Cash Flow and the Economic Indicators:

- **Net Cash Flow (NCF):** is the amount of net profit that results from deducting the annual total costs from the annual total revenue. This represents the total net profit expected to be earned during the life of the project in terms of money-of-the-day. NCF is calculated using the following equation:

$$\text{NCF} = \text{Cash Inflow} - \text{Cash Outflow} = \text{Revenue} - \text{Capex} - \text{Opex}$$

- **Net Present Value (NPV):** is the present value of the stream of future net cash flows. It is calculated by incorporating the assumed discount rate of 10%. In other words it represents how much extra profit will be earned in terms of the present value compared to investing in a bank that offers 10% annual interest rate. NPV is calculated using the following equation:

$$\text{NPV} = \sum_{i=1}^n \frac{\text{NCF}_i}{(1+r)^i} \text{ where } r = \text{discount rate, } n = \text{number of years}$$

- **Internal Rate of Return (IRR):** is the interest rate the project will generate on its investment. It also means that the project will earn the same profit as a bank that will offer the same annual interest on the invested amount. Mathematically the IRR is the discount rate that yields NPV=0.

The IRR is determined by using a spreadsheet built-in function, by trial & error or graphically by plotting the NPV versus discount rate.

- **Payback Period (or Payout):** is the amount of time required for the net cash flow projection to recover the invested amount. It is determined when the cumulative net cash flow equals 0.

- **The Capital Productivity Index (CPI) or Return on Investment (ROI):** is the amount of profit the project will earn for each dollar invested in terms of the present value. It is calculated using the following equation:

$$\text{Capital Productivity Index} = \frac{\text{Net Present Value of Future Cash Flow}}{\text{Present Value of the Capital Costs}}$$

Annual Oil Production: calculates the annual oil production rate in MMB @ year 5 using this equation:

$$\text{Production in year 5} = \text{Daily production rate} \times 0.365$$

From year 6 onwards annual production is calculated using the assumed exponential decline rate:

$$\text{Production in year (n)} = \text{production in year (n - 1)} \times (1 - \text{decline rate})$$

Annual Gas Production: calculates the annual gas production in (BCF) using the assumed Gas/Oil Ratio:

$$\text{Annual gas production in year (n)} = \text{Oil production in year (n)} \times (\text{Gas/Oil Ratio}) \div 1000$$

Annual Condensate Production: calculates the annual condensate production in (MMB) using the assumed Condensate/Gas Ratio:

$$\text{Annual condensate production in year (n)} = \text{Gas production in year (n)} \times (\text{Condensate/Gas Ratio})$$

Oil Price: calculates oil selling price in (\$/bbl.) using the assumed oil price in year 0 and the assumed inflation rate:

$$\text{Oil price in year (n)} = \text{Oil price in year (0)} \times (1 + \text{Inflation Rate})^n$$

Gas Price: calculates gas selling price in (\$/MCF) using the assumed gas price in year 0 and the assumed inflation rate:

$$\text{Gas price in year (n)} = \text{Gas price in year (0)} \times (1 + \text{Inflation Rate})^n$$

Condensate Price: calculates condensate selling price in (\$/bbl.) using the assumed condensate price in year 0 and the assumed inflation rate:

$$\text{Condensate price in year (n)} = \text{Condensate price in year (0)} \times (1 + \text{Inflation Rate})^n$$

Oil Revenue: calculates the annual oil revenue in (\$MM) using this equation:

$$\text{Oil revenue in year (n)} = \text{Oil production in year (n)} \times \text{Oil price in year (n)}$$

Gas Revenue: calculates the annual gas revenue in (\$MM) using this equation:

$$\text{Gas revenue in year (n)} = \text{Gas production in year (n)} \times \text{Gas price in year (n)}$$

Condensate Revenue: calculates the annual condensate revenue in (\$MM) using this equation:

$$\text{Condensate revenue in year (n)} = \text{Condensate production in year (n)} \times \text{Condensate price in year (n)}$$

Total Revenue: calculates the total revenue in (\$MM) by summing the revenues of the individual products using this equation:

$$\text{Total revenue in year (n)} = \text{Oil revenue in year (n)} + \text{Gas revenue in year (n)} + \text{Condensate revenue in year (n)}$$

Capex: calculates the annual capex profile from the assumed data, then calculates capex allocated for each of the first 4 years by incorporating capex percentage allocation for each year. Cost contingency and the inflation rate are then incorporated as per these equations:

$$\begin{aligned} \text{Total Capex} = & \text{Number of wells} \times \text{Cost of each well} + \text{Oil pipeline length} \times \text{its diameter} \times \\ & \text{Pipeline cost} + \text{Gas pipeline length} \times \text{its diameter} \times \text{Pipeline cost} + \\ & \text{Cost of surface facilities} + \text{Cost of camp} \end{aligned}$$

$$\text{Capex Allocated to year (n)} = \text{Total Capex} \times \text{percentage of capex allocation for year (n)} \times (1 + \text{inflation rate})^n \times (1 + \text{cost contingency})$$

$$\text{Abandonment cost in year (25)} = \text{Abandonment cost in year (0)} \times (1 + \text{Inflation Rate})^{25} \times (1 + \text{contingency})$$

Opex (Fuel): calculates the annual fuel consumptions in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Fuel consumptions in year (n)} = \text{Fuel consumption in year (0)} \times (1 + \text{Inflation Rate})^n \times (1 + \text{contingency})$$

Opex (Spares): calculates the annual Spares costs in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Spare costs in year (n)} = \text{Spare costs in year (0)} \times (1 + \text{Inflation Rate})^n \times (1 + \text{contingency})$$

Opex (Maintenance): calculates the annual maintenance costs in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Maintenance costs in year (n)} = \text{Maintenance costs in year (0)} \times (1 + \text{Inflation Rate})^n \times (1 + \text{contingency})$$

Opex (Salaries): calculates the annual salaries in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Salaries in year (n)} = \text{Monthly salary of each person in year (0)} \times \text{number of people} \times (1 + \text{Inflation Rate})^n \times 12 \div 1,000,000 \times (1 + \text{contingency})$$

Opex (Services): calculates the annual catering and services costs in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Services in year (n)} = \text{Services cost per person per day in year (0)} \times \text{number of people} \times 365 \times (1 + \text{Inflation Rate})^n \div 1,000,000 \times (1 + \text{contingency})$$

Opex (O/H): calculates the annual Overhead costs in (\$MM) by incorporating the inflation rate and using this equation:

$$\text{Overhead Costs in year (n)} = \text{Overhead costs in year (0)} \times (1 + \text{Inflation Rate})^n \times (1 + \text{contingency})$$

Total Opex: calculates the total annual operating costs in (\$MM) by using this equation:

$$\text{Operating Costs in year (n)} = \text{Summation of individual operating costs in year(n)}$$

Project net cash flow: is calculated using these equations:

$$\text{Project Net Cash Flow in year (n)} = \text{Cash inflow in year (n)} - \text{Cash outflow in year (n)}$$

$$\text{Project Net Cash Flow in year (n)} = \text{Project revenue in year (n)} - \text{Capex in year (n)} - \text{Opex in year (n)}$$

Cumulative net cash flow: is calculated using the following equation:

$$\text{Cumulative Net Cash Flow in year (n)} = \sum_{i=0}^{i=n} \text{NCF}_i$$

Payback Period: is calculated and inserted when the cumulative net cash flow (CCF) becomes positive using the following equation:

If $CCF_n \times CCF_{n-1}$ is negative, then $PB_n = (n - 1) + ABS\left(\frac{CCF_{n-1}}{NCF_n}\right)$, otherwise = 0

$$\text{Project Payback} = \sum_{i=0}^{i=25} PB_i$$

Net Cash Flow (NCF): is the amount of net profit that results from deducting the annual total costs from the annual total revenue. This represents the total net profit expected to be earned during the life of the project in terms of money-of-the-day. NCF is calculated using the following equation:

$$NCF = \text{Cash Inflow} - \text{Cash Outflow} = \text{Revenue} - \text{Capex} - \text{Opex}$$

Net Present Value (NPV): is the present value of the stream of future net cash flows. It is calculated by incorporating the assumed discount rate of 10%. In other words it represents how much extra profit will be earned in terms of the present value compared to investing in a bank that offers 10% annual interest rate. NPV is calculated using the following equation:

$$NPV = \sum_{i=1}^n \frac{NCF_i}{(1 + r)^i}, \text{ where } r = \text{discount rate, } n = \text{number of years}$$

Internal Rate of Return (IRR): is the interest rate the project will generate on its investment. It also means that the project will earn the same profit as a bank that will offer the same annual interest on the invested amount. Mathematically the IRR is the discount rate that yields $NPV=0$.

Payback Period (or Payout): is the amount of time required for the net cash flow projection to recover the invested amount. It is determined when the cumulative net cash flow equals 0.

The Capital Productivity Index (CPI) or Return on Investment (ROI): is the amount of profit the project will earn for each dollar invested in terms of the present value. It is calculated using the following equation:

$$\text{Capital Productivity Index} = \frac{\text{Net Present Value of Future Cash Flow}}{\text{Present Value of the Capital Costs}}$$

Maximum Exposure (ME): is the minimum (or the maximum negative) cumulative cash flow. It normally takes place when the entire Capex is spent prior to generating any profit. It also indicates the maximum loss in case of project failure.

Second Party Abandonment Cost: is calculated for year 25 using this equation:

$$\text{Second party abandonment cost in year 25} = \text{Inflated abandonment cost} \times \text{Second party share of capex} \times (1 + \text{contingency})$$

Cumulative Production: is calculated using this equation:

$$\text{Cumulative oil production in year (n)} = \sum_{i=0}^{i=n} (\text{Annual oil production})_i$$

Remaining Reserves: is calculated using this equation:

$$\text{Remaining oil reserves in year (n)} = \text{Cumulative oil production in year 25} - \text{Cumulative oil production in year (n - 1)}$$

Second Party Inflated Abandonment Provision: is calculated using the units-of-production depreciation method when the "R" ratio exceeds 1 using this equation:

$$\begin{aligned} &\text{Second party abandonment provision in year (n)} = \\ &\text{Remaining abandonment cost as of year (n)} \times \frac{\text{Annual oil production in year (n)}}{\text{Remaining reserves as of year (n)}} \end{aligned}$$

The calculated second party abandonment provision is inflated for year 25. To calculate its present value at the year it will be paid to the first party this equation is used:

$$\begin{aligned} &\text{Present value of second party abandonment provision at year (n)} = \\ &\text{Inflated abandonment provision at year (n)} \div (1 + \text{Assumed discount rate})^{(25-n)} \end{aligned}$$

Second Party Entitled Revenue: is calculated from the total project revenue based on the second party entitled share of 15% according to EPSA-IV using this equation:

$$\text{Second party entitled revenue} = \text{Total project revenue} \times \text{second party share}$$

$$\text{Cumulative entitled revenue in year (n)} = \sum_{i=0}^{i=n} (\text{Entitled annual revenue})_i$$

The second party costs at year n is the summation of its share of payable Capex, Opex and its abandonment provision using this equation:

$$\text{Second party costs} = \text{Its share of Capex} + \text{Its share of Opex} + \text{Its abandonment provision}$$

$$\text{Second party cumulative costs in year (n)} = \text{Its past exploration costs} + \sum_{i=0}^{i=n} (\text{its costs})_i$$

Cost Recovery: is calculated based on the annual and cumulative costs and the annual and cumulative entitled revenue. If the cumulative cost exceeds the cumulative revenue then all the entitled revenue is used for cost recovery. Otherwise only the amount of the annual cost is received from the revenue. In this case the remaining revenue is considered Profit Oil as per this equation:

$$\text{Profit Oil in year (n)} = \text{Second party entitled revenue in year(n)} - \text{Cost recovery in year(n)}$$

Index “A” Factor: is calculated with the following equations:

$$\text{Second party received revenue} = \text{Cost recovery} + \text{its share of profit oil}$$

$$\text{Second party share of profit oil} = \text{Profit oil} \times \text{"A" factor} \times \text{"Base" factor}$$

$$\text{"R" Ratio at year(n)} = \frac{\text{Second party cumulative revenue as of year (n - 1)}}{\text{Second party cumulative costs as of year (n - 1)}}$$

Base “B” Factor: is calculated using this equation:

$$\text{Base Factor} = \frac{\sum \text{Each segment production rate} \times \text{its designated factor}}{\text{Total field production rate}}$$

A combined factor is calculated by multiplying the "A" factor with the "B" factor:

$$\text{Combined Factor} = \text{"A" factor} \times \text{"B" factor}$$

Profit Oil: is calculated by deducting the Cost Recovery from second party entitled revenue as per this equation:

$$\text{Profit Oil} = \text{Second party entitled revenue} - \text{its cost recovery}$$

Second party share of Profit Oil: is calculated using this equation:

$$\text{Second party share of profit oil} = \text{Profit Oil} \times \text{Combined factor}$$

Second Party Net Cash Flow Profile: is calculated by deducting its cash out-flow from its cash in-flow as per the following equation:

$$\text{Second party NCF} = \text{Its received revenue} - \text{Its total costs}$$

$$\begin{aligned} \text{Second party NCF} = & \text{Cost Recovery} + \text{Its share of profit oil} - \text{Its share of Capex} - \\ & \text{Its share of Opex} - \text{Its abandonment provision} \end{aligned}$$