IMPACT OF THE 2012 PETROLEUM INDUSTRY BILL ON OFFSHORE E&P ECONOMICS

A group project on:

ADVANCED PETROLEUM ECONOMICS

By:

Members of Group 3

2016/2017 AUST Advanced Petroleum Economics Project,

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ABSTRACT

Petroleum has been the chief support of the Nigerian economy accounting for about 35% of the Gross Domestic Product (GDP) and over 80% of government revenue. The government with the intension to make the Petroleum Industry generate the kind of economic development it ought to has sent a Petroleum Industry Bill (PIB) to the National Assembly which seeks to restructure the Petroleum Industry. The fiscal provisions of the 2012 PIB give the government greater access to gross revenue and this will have an impact on the economics and profitability of oil and gas investments, especially for deepwater which is already very capital intensive. A fiscal model is developed using Microsoft Excel spreadsheet. The fiscal model developed is an integration or coding of the elements of the fiscal provisions of the PIB. The model generates cash flow and profitability indices for both investor and government using the investment profile and expected production profile. Sensitivity analysis is also carried out to establish the relationships between these indices and key decision variables. This understanding of the financial instruments will help the International Oil Companies (IOCs) to improve profitability. The results show that Royalty Rates and the Nigerian Hydrocarbon Tax (NHT) have great impacts on a company's profitability. However, the sliding scale royalty system of 2012 PIB ensures profitability for both the marginal and giant producers. It is also discovered that the government surrenders part of its take at low oil prices while its take increases with an increase in oil price. If the IOCs can reduce CAPEX incurred abroad, the fiscal incentives in the PIB and the volume of hydrocarbon in deepwater Nigeria would make investments in deepwater remain attractive.

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INTRODUCTION

To attract investors, the Nigerian Oil and Gas industry must have dynamic, efficient and stable fiscal arrangements to facilitate optimal hydrocarbon resource management. A dynamic and stable fiscal system must include terms that would willingly give a significant proportion of economic rents from the host government to investors to guarantee sustainable upstream investment flow. High exploration risk and low prospective regions must balance government take with attractive financial returns to investors.

There are three broad production sharing contracts in Nigerian terms of unique fiscal instruments. The first is the PSC 1993 which is characterized as the most progressive in terms of its contract terms and fiscal instruments. The cost recovery limit is 100% with a royalty rate of zero percent beyond 1000 meters of water depth. The PSC 2000 is noted for the introduction of Value Added Tax (VAT). The PSC 2005 limited the cost recovery limit to a maximum of 80%. In the fall of the year 2012, a new PIB was submitted to the Nigerian National Assembly. PIB 2012 draws its provisions extensively from the 2009 final memoranda of the IAT on PIB 2008 and the technical committee report submitted to the then Minister of Petroleum Resources. The royalty and fees are stipulated in the PIB 2012 as regulatory provisions rather than being determined legislatively as recommended in both the interagency memorandum and the technical committee report (PIB, 2012; Echendu, 2014).

This report evaluates the economics of Exploration and Production projects using the fiscal provisions of the PIB 2012.

METHODOLOGY

To evaluate the economics of investment under the PIB 2012, a fiscal model was developed using Excel spreadsheet. The model developed is an integration of the elements of the fiscal provisions of the PIB. Elements such as royalty schedule, Company Income Tax (CITA), Nigerian Hydrocarbon Tax (NHT), Cost Recovery Limit, Profit Oil and Profit Gas Split are featured.

The model converted the texts in the fiscal provisions of the PIB into mathematics and coded them in Excel. The model required the investor to supply data such as times of obtaining the different licenses, expenditure forecast, (CAPEX, OPEX), reserves and expected production profile during the life of the field. A price forecast of the products was used with the model to generate cash flows for both the investor and the host government.

Analysis of Deepwater Economics under PIB 2012

All contract types for deepwater under the PIB would be Production-sharing contracts (PSCs). PSCs are types of contract where the contractor bears the exploration risk alone and share the rewards with the host government if there is fund.

Royalty is paid directly to the government as a percentage of gross revenue. There are two types of royalty payments in the PIB; royalty by volume and royalty by value. Both are subjected to sliding scale and the rate to be paid by each type of royalty depends on the price of oil and monthly average daily production. Royalty rates based on value are organized into 5 tranches while those based on volume are organized into 3 tranches. The dollar values would have to be adjusted every year based on the US Consumer Price Index (CPI). The revenue left after the royalty has been paid is referred to as working revenue or gross revenue after royalty. The working revenue is usually split into two; cost oil and profit oil. It is from the cost oil that cost recovery is made. There is usually a ceiling or limit on the cost oil and it is 80% in the PIB. This is necessary to ensure that there is profit oil to be shared with the host government every year from the year the field comes on stream. If the cost oil limit for a given year cannot cover the contractor's CAPEX and OPEX, what is left is carried over to the following years. What is left of cost oil limit when all contractor's CAPEX and OPEX have been recovered is referred to as excess cost recovery and under PIB, this is split between the host government and contractor in the same ratio as the profit oil which itself is subjected to a sliding scale based on the cumulative volume of production.

Mathematically,

$$Gross\ Revenue\ (GR) = Price\ of\ oil * Volume\ of\ production \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 1$$

$$Working\ Revenue = GR - Royalty\ (ROY) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2$$

$$Working\ Revenue = Cost\ Recovery + Profit\ Oil\ (PO) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3$$

$$Contractor\ PO\ Share\ (PO_c) = (Contractor\ \%\ share) * PO \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 4$$

$$Government\ PO\ Share\ \left(PO_g\right) = (Government\ \%\ share) * PO \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5$$

$$Cost\ Recover\ (CR) = Cost\ Oil\ limit * Working\ Revenue \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 6$$

$$Cost\ to\ Recover_{year(n)} = Cost\ to\ Recovery_{year(n-1)} + CAPEX + OPEX - CR \ldots\ldots\ldots\ldots\ldots 7$$

$$If\ Cost\ to\ Recover\ is > 0, Excess\ Cost\ Recovery\ (ECR) = 0 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 8$$

$$If\ Cost\ to\ Recover\ is < 0, ECR = \big(-(Cost\ to\ Recover)\big) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 9$$

$$Contractor\ Share\ of\ ECR\ (ECR_c) = (Contractor\ \%\ share) * ECR \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 10$$

$$Government\ Share\ of\ ECR\ \left(ECR_g\right) = (Government\ \%\ share) * ECR \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 11$$

For a complete analysis, it is also important to take a look at how cost is treated in the PIB. Only 80% of the cost incurred abroad are eligible for recovery while 100% of the cost incurred locally are eligible for recovery. Geographical and exploration costs are allowed to be expensed while development costs are depreciated.

Various forms of taxes such as CITA, NHT, education tax, NDDC charge are paid by the contractor from what accrues to it as part of profit oil and excess cost recovery. What is left of these is the contractor's net revenue (Oyekunle, 2011).

Data Simulation

To account for the uncertainties inherent in the economic data assumptions, @RISK simulation tool was used to quantify the impact of selected stochastic variables on the economic indicators, NPV, IRR, HGT and CT using Monte Carlo simulation approach. The stochastic variables used are crude oil price, peak capacity and discount rate. The crude oil price and the discount rate are assumed to be triangularly distributed, and the peak capacity is assumed to be log-normally distributed (Echendu, 2014).

RESULTS AND DISCUSSION

This section analyzes results and attempts to give explanations and clarification on observed trends and values.

A sound production forecast is a basis for any project-based resource estimate and any business or development decisions. After the exploratory activities on the field, a discovery of 200MMbbl was found.

Figure 1 shows a production forecast of the deep offshore field. The production began in the year 2020 and rose steadily at a build-up rate of 1.3/year till 2023 where it reached a peak value of 50,000 BOPD and remained at the plateau for two years and declined afterwards at an instantaneous rate of 0.133/year. From the Figure, the cumulative production rose steadily and 20 years after production had begun, 168.5 MMbbls of oil had been produced out of 186.9 MMbbls of reserves leaving 18.4 MMbbls at the time of sale. This is just about the size of a marginal field and could still be economical to produce other things being equal.

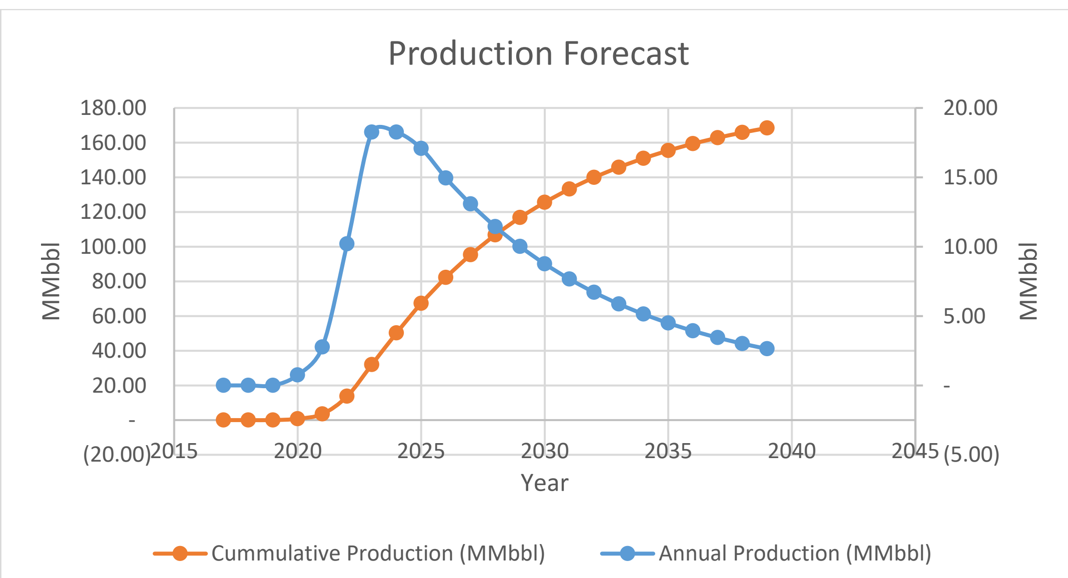

Figure 1: Deepwater Offshore Production Forecast

Figure 2 shows the cost outlay of the deep offshore project with projections showing the gross revenue, technical cost, net cash flow, discounted government and contractor take. At the early years of the project (Exploration and Development period), the gross revenue was zero and rose when production began in 2020 until 2023 when it began to decline correspondingly to the production rate. Ceteris Paribus, the revenue is the multiplication of price and quantity produced.

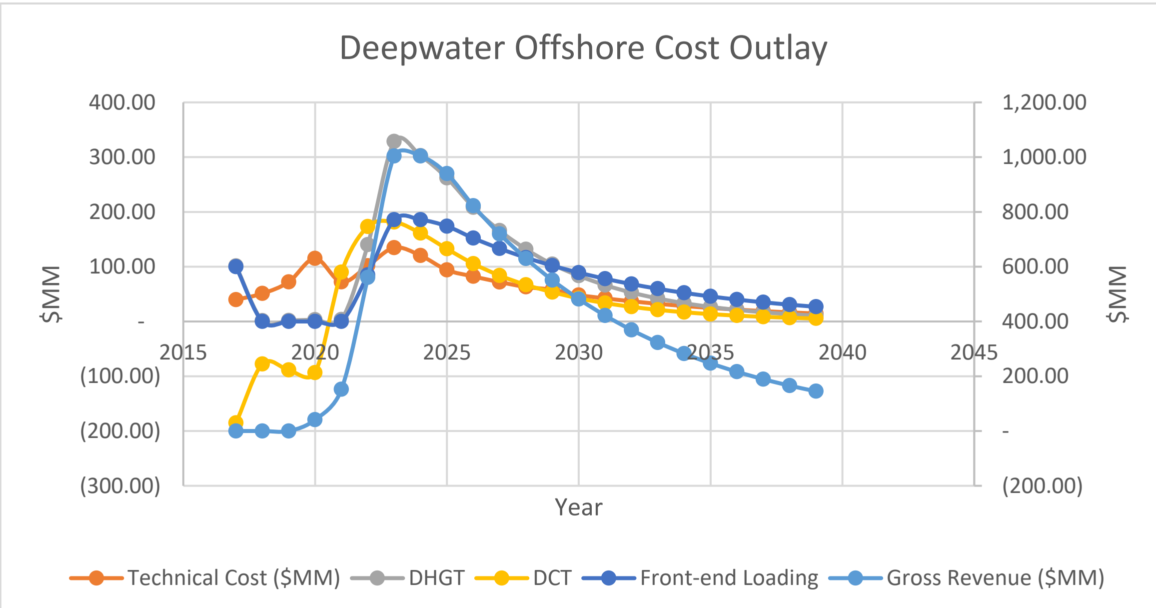

Figure 2: Deepwater Offshore Cost Outlay

Figure 2 also shows the after-income tax net cash flow contractor take, which also shows the payout year to be 6 years. Discounted government and contractor takes is also shown to increase respectively.

For the capital budgeting, management needs objective measures of the economic worth of investment proposals. They should be able to rank, accept, reject, compare, or choose among them and select those most beneficial to the company's long-term prosperity. The estimated deterministic profitability indicators which measure the worth of an investment for this deep offshore project are as shown in Table 1.

TABLE 1: PROFITABILITY INDICATORS

Parameter	NPV ($MM)	IRR (%)	GRR (%)	PI	UTC
Value	788.27	29	16	3.26	8.055

The project has a net present value of 788.3 $MM, which indicates that at a discount rate of 10%, it can pay for the cost of financing the investment and generate revenue. The rate at which the NPV is zero referred to as internal rate (IRR) was found to be 29%. The result implies that the earning power of the investment in the Deepwater offshore in Nigeria is significantly higher than the cost of capital, thus, showing how efficient the investment is given that the assumptions are favourable. The use of NPV and IRR as criteria fails to reflect the size of the initial investment. These yardsticks pose problems when an analyst has to choose among several alternative investments of different sizes. Thus, the need for another indicator (Profitability Index) which overcomes the drawbacks of NPV and IRR. Profitability index answers the question of how much value benefits has been added per dollar of investment. For the project under consideration with a PI of 3.26, it means that for every dollar investment made, $3.26 is received as return on investment. The unit technical cost also referred to as the cost of discovery was estimated to be $8.1/bbl.

Government take reflects the total receipts of the host government from a project, including, all taxes, bonuses, profit oil, levy and other forms of rent extraction. The estimated discounted takes for the deepwater offshore project executed under PIB 2012 fiscal arrangement was 73% and 27% for the HG ad Contractor respectively. This means for every $1 gain per barrel, the host government keeps 73 cents and the contractor keeps 27cents, *ceteris paribus,* in offshore E & P projects in Nigeria under the PIB 2012.

Joseph *et.al.,* 2014, reported discounted government take values under different fiscal arrangements to be 88%, 100% and 84% for PSC 1993, PSC 2005 and IAT 2009 respectively. The estimated HGT under consideration is close to the value of 78% reported by Joseph *et. al.,* 2014. The FLI is shown in Table 2 for different fiscal regimes. The difference in the estimated FLI value for the project under consideration and that reported by Joseph *et. al.,* 2014, is due to the different discount rates used. This makes the PSC 2005 with the highest FLI the most regressive and 2009 the least regressive.

TABLE 2: FRONT –END LOADING INDEX OF DIFFERENT FISCAL REGIMES

Fiscal Regime	**PSC 1993**	**PSC 2005**	**IAT 2009**	**PIB 2012 (Joseph *et. al.*, 2014)**	**PIB 2012 onsidered**
DHGT	88	100	84	78	73
DCT	12	0	16	22	27
FLI	0.32	0.4	0.14	0.15	0.07

SENSITIVITY ANALYSIS

Sensitivity analysis is a method used to assess how sensitive a model is to changes in its input parameters. If small changes in an input parameter result in relatively large changes in a model's output, the model is said to be sensitive to the parameter. Sensitivity analyses are usually conducted to understand how the conclusions and inferences drawn from a calculation or an assessment depend on its inputs.

Sensitivity Analysis 1

Sensitivity analysis of the impact of tax rate, instantaneous production rate, peak production rate and current oil price on the profitability of the project was evaluated to ascertain the performance of the project under this fiscal regime. The input values are as shown in Table 3.

TABLE 3: INPUT PARAMETERS FOR SENSITIVITY ANALYSIS

PARAMETERS	Low	Base	High
TAX RATE (%)	15	25	35
Q_i (MBOPD)	0.5	1	1.5
Q_{peak} (MBOPD)	30	50	70
Oil Price ($/bbl.)	28	55	70

Table 4 shows that the NPV of the project is positively sensitive to rising oil price, instantaneous production rate and peak production rates. However, the NPV is negatively sensitive to the tax rate as the value decreases with increasing tax rate. IRR increases with increase in the oil prices and peak production rate, but decrease with increase in the tax rate. However, at an instantaneous production rate of 1000 BOPD, the IRR remains constant. The host government take showed a positive increase as tax rate and discount rate increases but decreases with increasing values of peak production rate and oil price. But unaffected by changes in the value of instantaneous production. Discounted takes are used as criteria instead of undiscounted takes as the major pitfall in using the government take percentage as means of comparing different international fiscal regimes, is that government takes does not take into consideration the timing of the payment to the government neither does it consider the timing of revenues and cost which may be negative for quite some time over the project life. The discounted payout showed reverse response to impact of the sensitivity parameters as does IRR as portrayed in Table 4.

TABLE 4: RESULT OF SENSITIVITY ANALYSIS

INPUT VARIABLES		OUTPUT PARAMETERS					
		IRR (%)	NPV CT (MM$)	PI	DGT (%)	DPO (yrs)	FLI (%)
TAX RATE (%)	15	32	1025.3	3.95	65	5.9	7
	25	29	788.3	3.26	73	6.0	7
	35	25	551.27	2.58	81	6.4	6
Q_i (MBOPD)	0.5	28	760.2	3.18	73	6.2	7
	1	29	788.3	3.26	73	6.0	7
	1.5	29	809.4	3.33	73	5.98	7
Q_{peak} (MBOPD)	30	21	66.533	2.1	78	7.1	12
	50	29	788.3	3.26	73	6.0	7
	70	35	1218.7	4.5	71	5.7	5
Oil Price	28	18	232.7	1.67	82	8.3	16

($/bbl.)	55	29	788.3	3.26	73	6.0	7
	70	33	1095	42	71	5.7	5
Discount rate (%)	5	29	1398.4	4.71	70	5.7	3
	10	29	788.3	3.26	73	6	7
	15	29	430.8	2.33	77	6.5	13

STOCHASTIC SIMULATION

To account for the uncertainty inherent in the economic model assumptions, we applied Oracle Crystal Ball and Palisade @RISK simulation tools to quantify the impact of selected stochastic variables on the economic indicators NPV, IRR, PI, HGT and FLI using Monte Carlo simulation approach. The stochastic variables invoked are oil price, peak and instantaneous production rates and discount rate. The variables are assumed to be triangularly distributed. Table 5 presents the descriptive statistics of selected stochastic variables used in this project and they form the basis for the stochastic output values reported in table 6.

Stochastic Model Results

TABLE 5: PROBABILITY DISTRIBUTION OF PARAMETERS FOR THE STOCHASTIC ANALYSIS

PARAMETERS	PROBABILITY DISTRIBUTION	Min	Medium	Max
Tax Rate (%)	Triangular	15	10	35
Q_i (MBOPD)	Triangular	0.5	1	1.5
Q_{peak} (MBOPD)	Triangular	30	50	70
Oil Price ($/bbl.)	Triangular	28	55	70

TABLE 6: SUMMARY OF P50, MODE, MEDIAN, MAXIMUM AND MEAN OF STOCHASTIC ECONOMIC INDICATOR INDICES

Percentile	NPV CT (MM$)	IRR (%)	PI	DGT	Disc. PO	FLI	UTC
P50	656.39	26.64	2.91	74.6	6.22	7.74	7.93
Mode	928.06	26.17	2.50	81.40	5.98	8.20	6.95
Mean	703.49	26.78	3.00	74.8	6.4	8.50	7.86
Minimum	147.57	15.92	1.44	63.8	5.25	2.81	4.92
Maximum	1832.31	39.45	6.61	87.4	9.29	20.9	9.95

TABLE 7.0: LIST OF 3 MOST INFLUENTIAL INPUT PARAMETERS ON PROJECT PROFITABILITY INDICATORS

MOST INFLUENTIAL PARAMETERS	PROFITABILITY INDICATORS			
	NPV	IRR	FLI	Disc. POP
	(i) Oil Price ($/bbl)	(i) Oil Price ($/bbl)	(i) Oil Price ($/bbl)	i) Oil Price (MOD)
	(ii) Peak Production Rate	(ii) Discount rate	(ii) Discount rate	ii) Peak Production Rate
	(iii) Discount rate	(iii) Peak Production Rate	(iii) Peak Production Rate	iii) Discount rate

MOST INFLUENTIAL PARAMETERS	PROFITABILITY INDICATORS		
	Disc. Take Statistics	**GROR**	**PI**
	i) Oil Price (MOD)	i) Discount rate	i) Oil Price (MOD)
	ii) Peak Production Rate	ii) Oil Price (MOD)	ii) Peak Production Rate
	iii) Discount rate	iii) Peak Production Rate	iii) Discount rate

Table 6 reports the Monte Carlo simulation result. The stochastic results show that the project NPV base case scenario is consistent with the result obtained in the deterministic analysis. The most likely NPV at 10% discount rate is $928.06 under the PIB 2012 fiscal arrangement. It's observed that for a viable deepwater project, the unit technical cost (UTC) has to be within the range of $6.15 and $9.21 per bbl.; this will enable the contractor to have higher IRR. This result is in agreement with values reported by Joseph *et. al.*, 2014 and showing the viability of projects in the anticipated PIB 2012 fiscal terms.

The minimum, maximum and most likely IRR are 15.92%, 39.45% and 26.17% respectively. This shows a positive outlook for the anticipated PIB 2012 as compared to the hurdle rate of 10%. The PI of the project indicates a viable project and a most likely return on investment of $2.5 per One dollar invested. However, a high value of IRR can be attributed to the low FLI of the fiscal regime.

The maximum realizable value of HGT is $84.7MM, with the most likely being $81.4MM and the minimum estimate of $63.8MM. The resulting HGT for the proposed PIB 2012 is in agreement with deterministic estimates and is also favourable to both the HG and contractors. It is estimated that the UTC ranges from a low value of $4.92 to a high value of $9.95 per bbl. and most likely estimated UTC being $6.95 per bbl.

Figure 3 through 10, shows the stochastic distributions of the variables and their sensitivity analysis too. It is worth mentioning that the discounted payout period for the 20 years production is 6 years. This guarantees early possible breakeven of investment.

Table 6 shows a summary of stochastic output for P50 value of the economic indicators described above. There is a 50% confidence that the project NPV would be $656.39 million

CONCLUSION

The economics of petroleum E & P projects under PIB 2012 was evaluated. As seen, a project is not viable at higher UTC, it is, therefore, necessary that the cost of oil production be within the $6.15 to $9.21 per bbl. for deepwater projects in Nigeria. According to Joseph *et. al.,* 2014, lower UTC could be achieved if the Nigerian government curtails the nefarious activities of illegal oil bunkering and pipeline vandalization to eliminate high cost expended in securing the facilities and personnel. Contractors also need to cut down their foreign expenditure and key into the local content of the nation to improve the efficiency of deepwater projects. This will amount to capacity development and purposeful engagement of indigenes, hereby curtailing vices and subsequently, lowering UTC.

The favourable economic metrics obtained from both the deterministic and stochastic results for the anticipated PIB, if passed into law should encourage huge investment into offshore deepwater projects that could lead to new reserve finding and possibly encourage the repetition of the effect of PSC 1993 in growing Nigeria's reserve. This investment drive will aid to increase Nigeria's proved oil reserves to the anticipated 40.0 billion barrels and production capacity of 4.0 million barrels per day from its undulating 2.5 million barrels per day (Joseph *et. al.*, 2014). With 10.0% opportunity cost of capital, he discounted HGT obtained depicts a viable project investment option for any investor. The low FLI and this fiscal regime is an additional encouragement for investment and provide an avenue for sharing of risk between the HG and contractor, thereby mitigating the associated risk.

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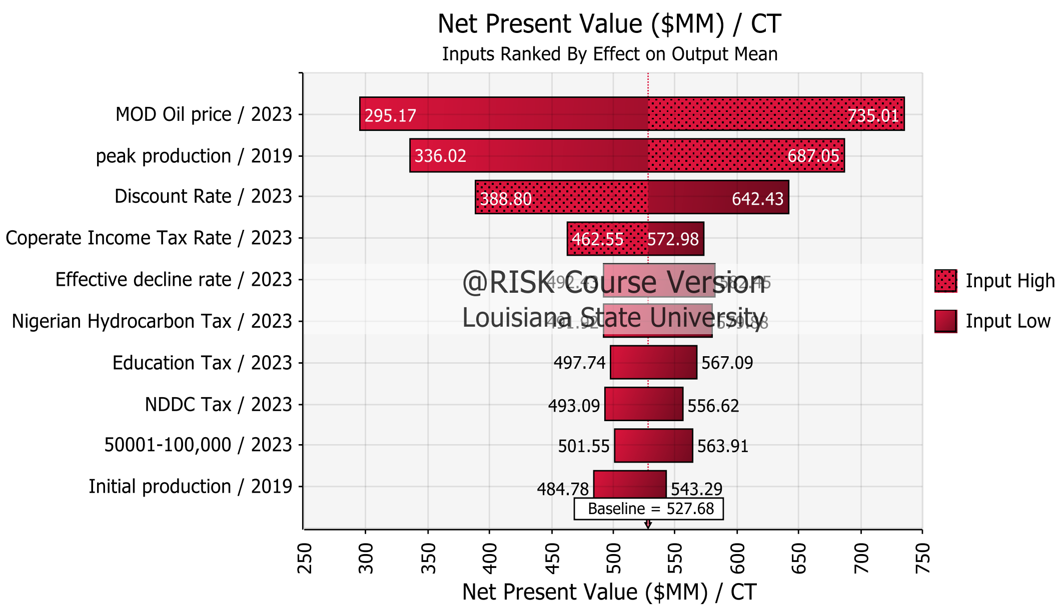
APPENDIX



Net Present Value ($MM) / CT
Inputs Ranked By Effect on Output Mean
MOD Oil price / 2023
peak production / 2019
Discount Rate / 2023
Coperate Income Tax Rate / 2023
Effective decline rate / 2023
Nigerian Hydrocarbon Tax / 2023
Education Tax / 2023
NDDC Tax / 2023
50001-100,000 / 2023
Initial production / 2019
295.17
735.01
336.02
687.05
388.80
642.43
462.55
572.98
497.74
567.09
493.09
556.62
501.55
563.91
484.78
543.29
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@RISK Course Version
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Input Low
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600
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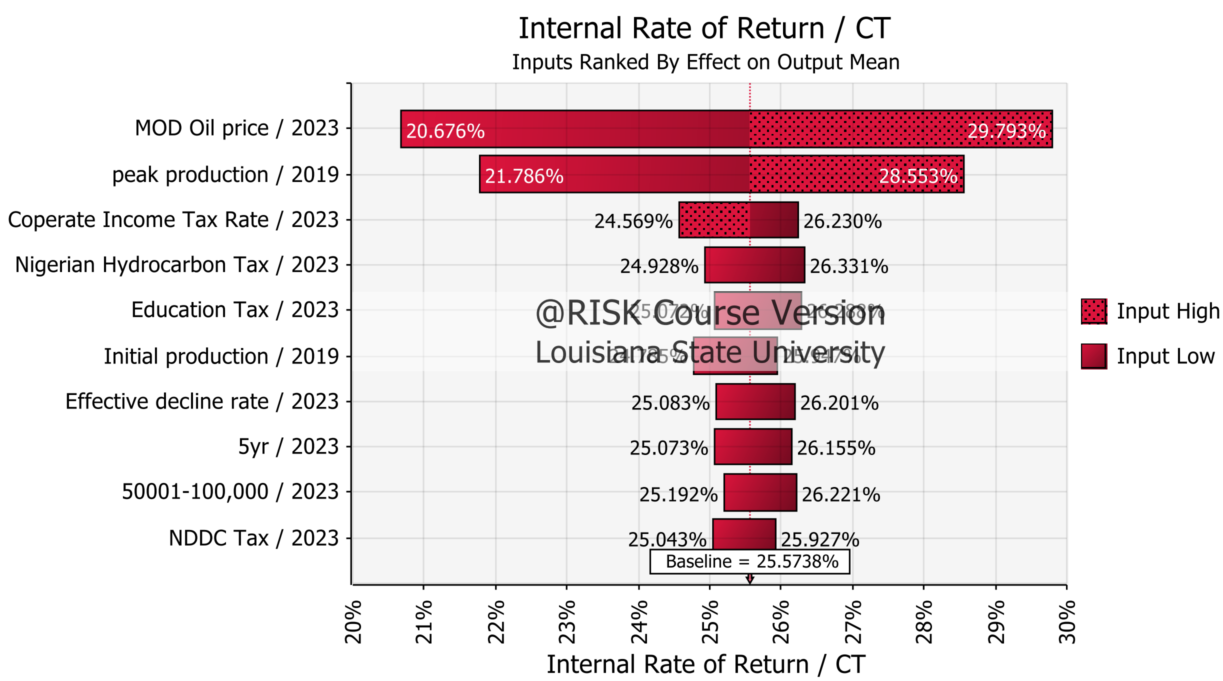
Net Present Value ($MM) / CT



Internal Rate of Return / CT
Inputs Ranked By Effect on Output Mean
MOD Oil price / 2023
peak production / 2019
Coperate Income Tax Rate / 2023
Nigerian Hydrocarbon Tax / 2023
Education Tax / 2023
Initial production / 2019
Effective decline rate / 2023
5yr / 2023
50001-100,000 / 2023
NDDC Tax / 2023
20.676%
29.793%
21.786%
28.553%
24.569%
26.230%
24.928%
26.331%
25.083%
26.201%
25.073%
26.155%
25.192%
26.221%
25.043%
25.927%
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Louisiana State University
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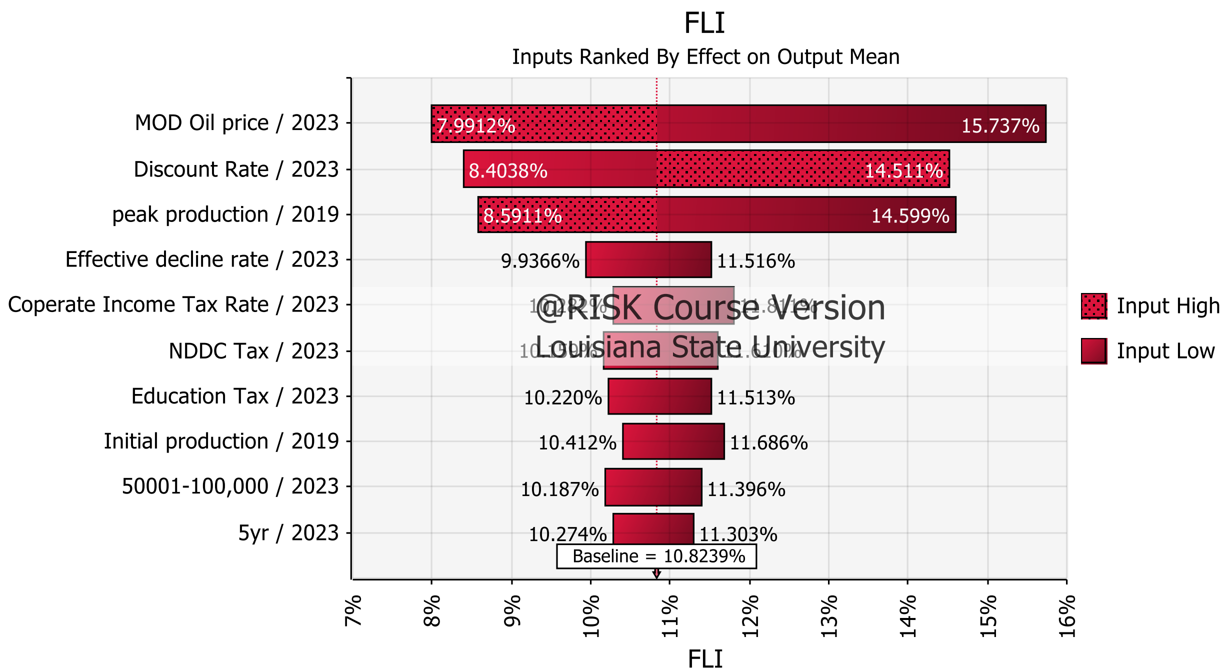
Internal Rate of Return / CT


FLI
Inputs Ranked By Effect on Output Mean
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Discount Rate / 2023
peak production / 2019
Effective decline rate / 2023
Coperate Income Tax Rate / 2023
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Education Tax / 2023
Initial production / 2019
50001-100,000 / 2023
5yr / 2023
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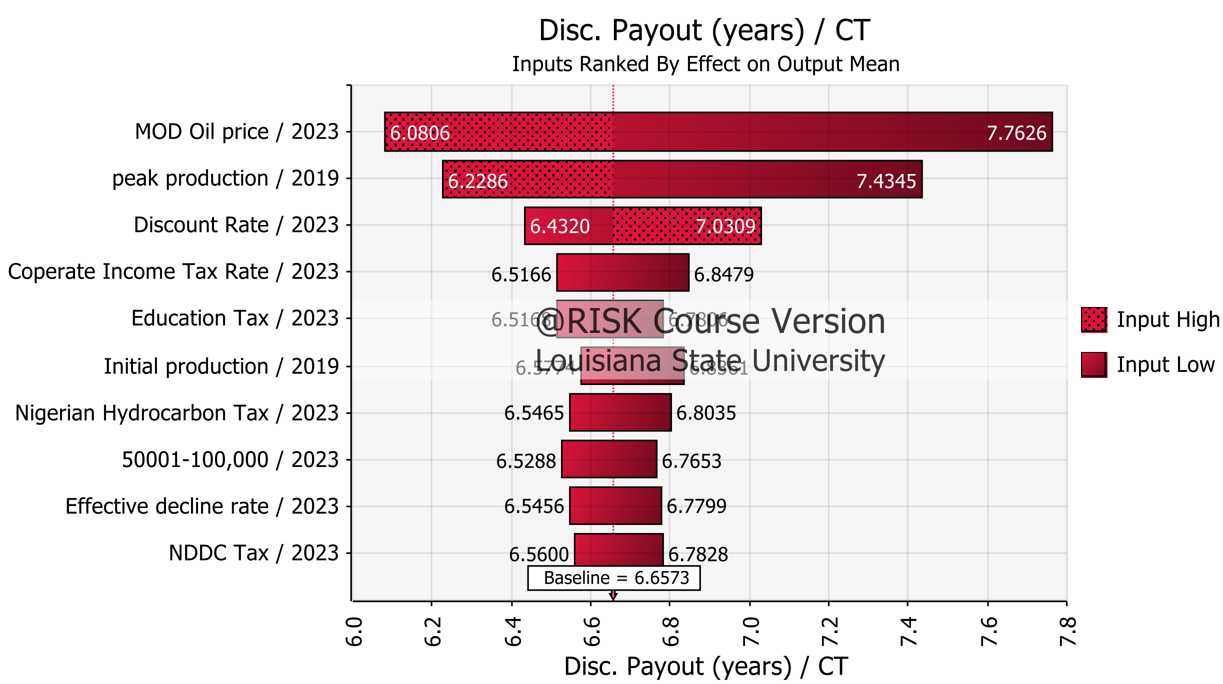
FLI


Disc. Payout (years) / CT
Inputs Ranked By Effect on Output Mean
MOD Oil price / 2023
peak production / 2019
Discount Rate / 2023
Coperate Income Tax Rate / 2023
Education Tax / 2023
Initial production / 2019
Nigerian Hydrocarbon Tax / 2023
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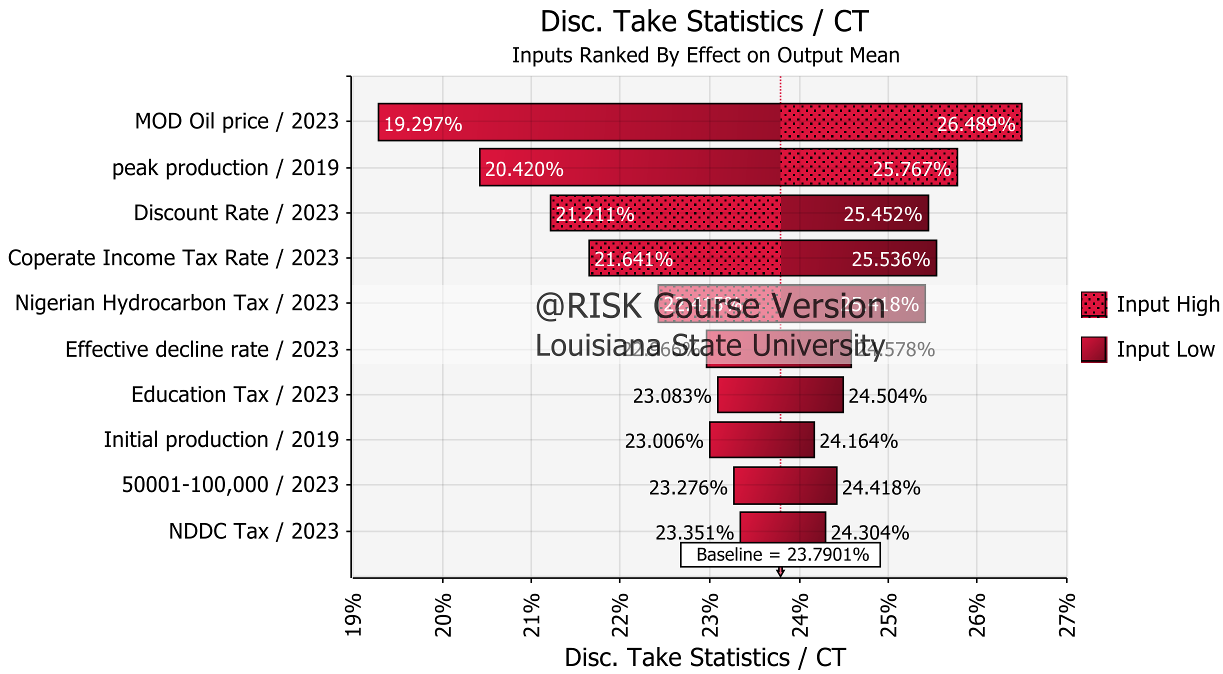
Disc. Take Statistics / CT
Inputs Ranked By Effect on Output Mean
MOD Oil price / 2023
peak production / 2019
Discount Rate / 2023
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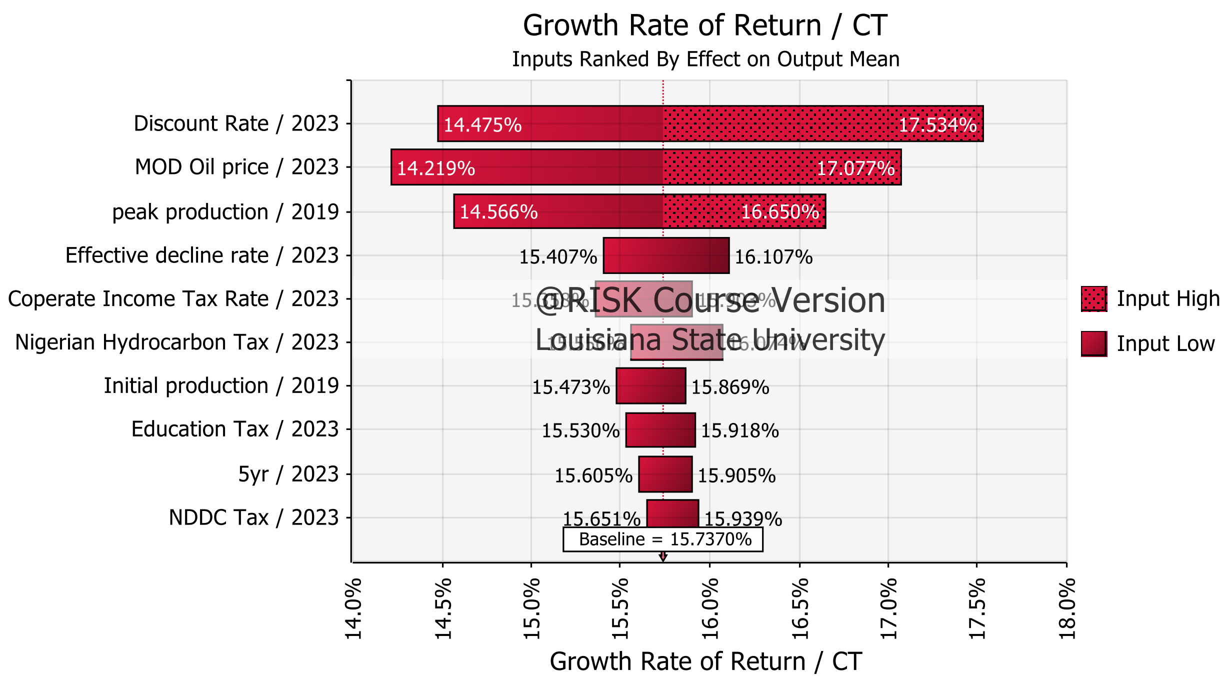
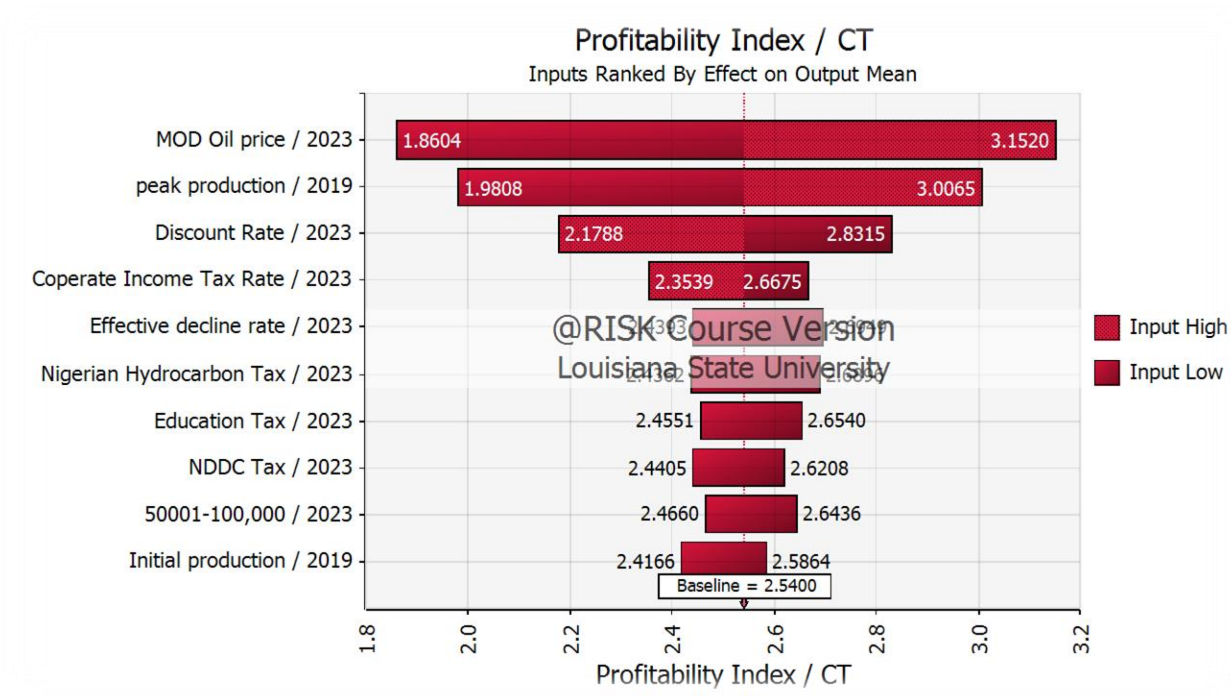
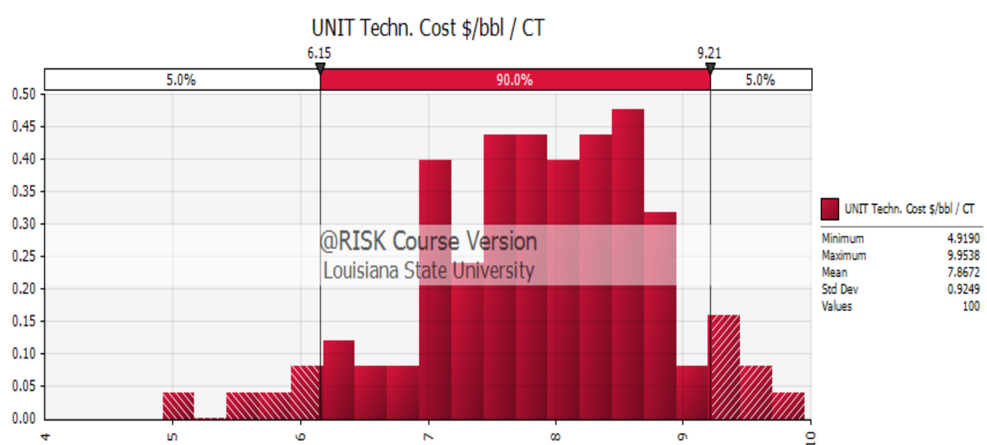
Nigerian Hydrocarbon Tax / 2023
Effective decline rate / 2023
Education Tax / 2023
Initial production / 2019
50001-100,000 / 2023
NDDC Tax / 2023
19.297%
26.489%
20.420%
25.767%
21.211%
25.452%
21.641%
25.536%
24.578%
23.083%
24.504%
23.006%
24.164%
23.276%
24.418%
23.351%
24.304%
Baseline = 23.7901%
@RISK Course Version
Louisiana State University
Input High
Input Low
19%
20%
21%
22%
23%
24%
25%
26%
27%
Disc. Take Statistics / CT


Growth Rate of Return / CT
Inputs Ranked By Effect on Output Mean
Discount Rate / 2023
MOD Oil price / 2023
peak production / 2019
Effective decline rate / 2023
Coperate Income Tax Rate / 2023
Nigerian Hydrocarbon Tax / 2023
Initial production / 2019
Education Tax / 2023
5yr / 2023
NDDC Tax / 2023
14.475%
17.534%
14.219%
17.077%
14.566%
16.650%
15.407%
16.107%
15.473%
15.869%
15.530%
15.918%
15.605%
15.905%
15.651%
15.939%
Baseline = 15.7370%
@RISK Course Version
Louisiana State University
Input High
Input Low
14.0%
14.5%
15.0%
15.5%
16.0%
16.5%
17.0%
17.5%
18.0%
Growth Rate of Return / CT


Profitability Index / CT
Inputs Ranked By Effect on Output Mean
MOD Oil price / 2023
peak production / 2019
Discount Rate / 2023
Coperate Income Tax Rate / 2023
Effective decline rate / 2023
Nigerian Hydrocarbon Tax / 2023
Education Tax / 2023
NDDC Tax / 2023
50001-100,000 / 2023
Initial production / 2019
1.8604
3.1520
1.9808
3.0065
2.1788
2.8315
2.3539
2.6675
2.4551
2.6540
2.4405
2.6208
2.4660
2.6436
2.4166
2.5864
Baseline = 2.5400
@RISK Course Version
Louisiana State University
Input High
Input Low
1.8
2.0
2.2
2.4
2.6
2.8
3.0
3.2
Profitability Index / CT


UNIT Techn. Cost $/bbl / CT
6.15
9.21
5.0%
90.0%
5.0%
@RISK Course Version
Louisiana State University
UNIT Techn. Cost $/bbl / CT
Minimum 4.9190
Maximum 9.9538
Mean 7.8672
Std Dev 0.9249
Values 100