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A New Progressive and Efficient Royalty Model for Upstream Petroleum Industry

Ibrahim S. Mohamed*, Hamid M. Khttab, Said K. Elsayed, Mohsen G. El-Noby, Shady G. Elrammah

Department of Petroleum Engineering, Faculty of Petroleum and Mining Engineering, Suez University, Suez, Egypt.
*Email: i.salah@suezuni.edu.eg

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ABSTRACT

In this research paper, a new methodology to design a progressive and win-win royalty model for upstream fiscal systems is developed. The proposed royalty model is designed as a function of different boundary conditions of the market and the productive resources. These boundary conditions include the associated exploration and production risks, commodity prices, the extraction costs, besides the expected production and depletion rate. The behavior of the proposed royalty model under different oil prices, development costs, production rates, and exploration risks is investigated using deterministic and stochastic analysis. Our results prove that the applicable royalty rate increases with both the price and production rate while it decreases with increasing the development costs and the associated exploration and production risks. In addition, the proposed royalty model provides the contractor with sufficient incentives to develop marginal or low profitability fields and the development of deep offshore or frontier fields with high development and operating costs.

Keywords: Fiscal Systems, Royalty, Tax Policy, Petroleum Industry
JEL Classifications: F38, Q47

1. INTRODUCTION

Upstream Petroleum Agreement includes all the contractual, legal, and fiscal aspects that determine the framework of the financial agreement between the host government and investor or the foreign oil companies. The essence of these systems is how the oil wealth is shared between the investors and the host government and how the costs are recovered. For the fiscal system to be efficient, it should provide a stable business environment, provide a balance between risk and reward, minimize sovereign risk, provide the potential for a fair return to both the host government and investors, incorporate flexibility for changing economic conditions, minimize complexity and administrative burdens and finally promote competition and market efficiency (Mian, 2010). For the fiscal system to be attractive, the host government should adopt a progressive fiscal system in which the government take increases with the price or production rate while its take decreases during periods of economic recession (Dongkun and Na, 2010; Echendu and Iledare, 2016; Echendu et al., 2015; Mian, 2010; Swe and Emodi, 2018).

Each government developed its fiscal instruments to capture the appropriate rent from its non-renewable resources. Royalty is one of the key fiscal instruments developed by the host government to maximize its economic rents from its non-renewable resources. Royalty is a payment made by the license holder to the government either in cash or kind as a specified percentage of the gross revenue before any deductions. This percentage may be defined by the regulations or negotiated with the oil and gas companies. Host governments developed various mechanisms to determine the royalty percentage. The simplest mechanism is fixed-rate royalty other mechanisms include variable-rate royalty. Variable-rate royalty is determined by changes in production volumes, commodity prices, measures of profitability, or some combination of these factors (Iledare, 2004a, 2004b, Isehunwa and Ifeoma, 2011, Kanshio, 2020).

Modern fiscal systems link the royalty with project or investor profitability using what is called the ratio method or simply the R factor. Each government defines the economic basis for calculating its R factor. The most used R factor is the ratio between the cumulative revenue to the cumulative costs. When the R factor is zero, the contractor incurred a cost with no revenue, which usually happens before production starts. When the contractor breaks even or the cumulative costs equal to the cumulative revenue, the R factor becomes one. Investors begin to make a profit when the R factor is greater than one (Luo and Yan, 2010; Mian, 2010).

Since royalty is one of the top deductions before any deductions or cost recovery, it greatly affects the economic life of the field and the survival of upstream oil companies, especially during periods of low crude prices. Ogolo and Nzerem proposed a delayed royalty framework to increase the survival of the contractors during periods of low crude prices (Ogolo and Nzerem, 2021). They proved through deterministic and stochastic analysis that the delayed royalty framework increases the contractor's revenue and decreases the government take.

As there's no ideal fiscal system that is suitable for all countries or projects, the aim and the novel work of the present research is to propose a novel methodology to design a progressive and stable royalty model. The proposed model is designed as a function of different boundary conditions of the market and the productive resources. These boundary conditions are the associated exploration and production risks, commodity prices, the extraction costs, besides the expected production and depletion rate. It is believed that the new proposed royalty model will benefit the policymakers, contract negotiators, decision-makers, academics, new entrants to the upstream petroleum industry, and institutions concerning fiscal stability under different price volatilities.

2. THEORY

2.1. Royalty Modelling

The following assumptions are used to design the proposed royalty model:

1. For each accounting period, the royalty percentage is confined between two limits: minimum (Roy_{min}) and maximum royalty (Roy_{max}) percentage. These two limits are negotiated between the host government and the contractor
2. The royalty percentage for any accounting period is a function of the following:
   - The level of maturity or risk associated with the licensed block
   - The commodity prices
   - The extraction costs, and
   - The production or the depletion rate of the field
3. Royalty increases as the commodity prices mark upon the extraction costs to allow the government to capture higher economic rent during periods of high prices and low costs
4. To extend the economic life of the field, royalty decreases as the production rate decreases or when the reservoir depletion increases.

The proposed royalty percentage is given by Eq. (1).

$$\text{Royalty} = \begin{cases} Roy_{max} RI \geq x_2 \\ a_1 * RI + b_1 x_2 \geq RI \geq x_1 \\ Roy_{min} RI \leq x_1 \end{cases} \quad (1)$$

where:

Roy_{min} and Roy_{min} are the maximum and minimum royalty percentages respectively.

x_1 and x_2 are the triggering numbers for Roy_{min} and Roy_{min} respectively.

RI is called the royalty index and is given by Eq. (2).

$$RI = \left[\frac{EP}{EC} * (1 - \frac{\sum Q_i}{N}) \right]^{(1-r_f)} \quad (2)$$

where:

$\sum Q_i$ is the cumulative production rate at the end of each accounting period.

N is the estimated reserves bbl.

$\frac{\sum Q_i}{N}$ represents the reservoir depletion rate at the end of each accounting period

Table 1: The risk depreciation profile for illustration example

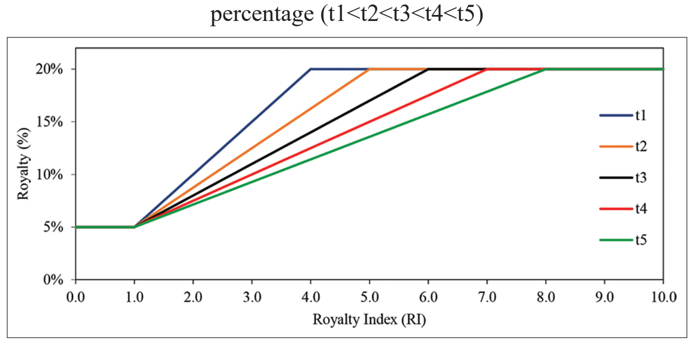
Year	1*	2	3**	4	5	6	7	8	9	10
r_{fi}	20%	20%	20%	17%	14%	11%	8%	5%	5%	5%
r_{fr}	20%	20%	17%	14%	11%	8%	5%	5%	5%	5%

*Project start year, ** Production start year

Table 2: The input fiscal data to the proposed royalty model

Maximum Royalty	20%
Minimum Royalty	2.5%
Estimated Risk Factor	90%
Remaining Risk	10%
Risk Relief Period	5 years
Depreciation	Straight line over 5 years

Figure 1: The impact of production time on the applicable royalty percentage (t1<t2<t3<t4<t5)



EP is the average price per equivalent barrel of oil for each accounting period $/BOE.

EC is the cost per equivalent barrel of oil $/BOE and given by Eq. (3).

$$EC = \frac{Cumulative(DepreciatedTangibleCAPEX + ExpensedIntangibleCAPEX + OPEX)}{\sum Q_i} \quad (3)$$

r_f: is called risk factor %.

2.2. Risk Factor Modeling (r_f)

Risk factor is proposed to reflect the level of maturity of the sedimentary basin and the associated exploration risk of each concession. This factor is used to provide sufficient incentives for the contractors to explore un maturated frontier areas and deep-water concessions. Since the risk at the beginning of the project is high then gradually dimensions once a commercial discovery is declared and the field is developed. For this reason, assuming a high constant risk factor throughout the whole life of the field will not be fair to the government. To provide a reliable risk evaluation, the following assumptions are proposed:

1. Assuming the initial risk r_{fi}
2. The remaining risk r_{fr} (The remaining risk is assumed because the risk cannot be removed by 100%)
3. The risk decreases from r_{fi} to r_{fr} over an agreed period (nf) once production starts
4. The annual reduction in the risk factor will be $\frac{r_{fi} - r_{fr}}{nf}$
5. The assumed risk for any given period is the risk at the beginning of this period.

For example, assuming the initial risk (r_{fi}) is 20%, the remaining risk (r_{fr}) is 5%, and nf = 5 years once production starts. The annual reduction in the risk will be $\frac{20\% - 5\%}{5}$ =3%. The risk depreciation profile is shown in Table 1.

2.3. Modelling the Triggering Factors x_1 and x_2

Since the royalty has a direct impact on the economic life of the field, the triggering number x_2 at which the maximum royalty will be in effect should increase with time. In other words, the difference between x_2 and x_1 should increase as the production time passes. The proposed model for x_2 is given by Eq. (4).

$$x_2 = x_1 + \sum_i^n \left(\frac{Q_i}{\sum Qi} \right) \quad (4)$$

where: Q_i is the production for any accounting period (bbl).

Assuming 20% and 5% respectively as maximum and minimum royalty percentages, the impact of production time on the applicable royalty percentage is shown on Figure 1. As it is shown, for the same royalty index the applicable royalty percentage decreases with time. For example, if the royalty index is equal to 4 it will trigger the maximum royalty (*Roymax*) at t_1 while the royalty percentage will be 16% for t_2 and so one for the remaining production life of the field.

According to Eq. (2), as the risk factor approaches 100%, the royalty index (RI) approaches one. This value should be the minimum value of the royalty index (x_1) which triggers the minimum royalty percentage Roy_{min}. The slope (a_1) and the intercept (b_1) of Eq. (1) can be given by Eq. (5) and Eq. (6) respectively.

$$a_1 = \frac{R_{max} - R_{min}}{x_2 - x_1} \quad (5)$$

$$b_1 = (R_{max} - a_1 * x_2) \text{or} (R_{min} - a_1 * x_1) \quad (6)$$

3. MODEL SENSITIVITY ANALYSIS AND DISCUSSION

In this section, the impact of different boundary conditions of both the market and reservoir on the previously developed royalty model will be investigated under a deterministic and stochastic approach. These boundary conditions include crude price, production rate, and field development costs (CAPEX).

3.1. Methodology

To make the sensitivity analysis of the proposed royalty model as reliable as it is possible, the following methodology is adopted:

1. The input fiscal data of the proposed Royalty model is

Figure 2: The impact of crude oil prices on the applied royalty percentage

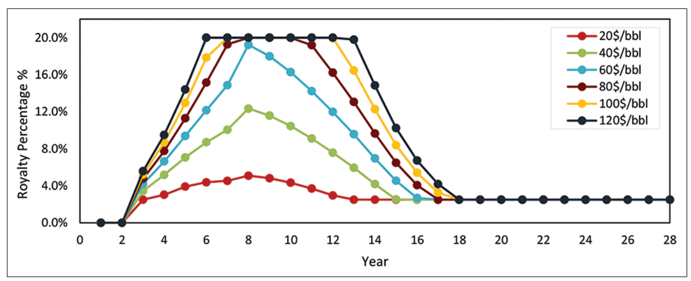


Figure 3: The impact of the production rate on the applied royalty percentage

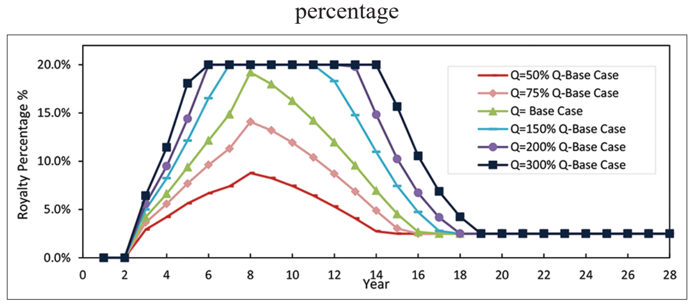


Table 3: QUE$TOR base case input data

Recoverable Reserves	100 MMBBL
GOR	500 SCF/bbl
Reservoir Depth	5000 ft
Reservoir Pressure	2500 psia
Reservoir Length	2.78 mile
Reservoir Width	1.39 mile
Terrain	Grassland
Elevation	164 ft
Plateau Rate	20 KBOPD
Years to Plateau	2 years
Plateau Duration	10 years
Field Life	25 years

Table 4: QUE$TOR 100 MMbbl base case output data for sensitivity analysis

Year	Crude Price	Production	Drilling Costs	Facility Costs	Fixed OPEX	Variable OPEX	Abandonment Costs
	$/bbl	KBOPD	MM$	MM$	MM$	MM$	MM$
1	60	0	0	34.7	0	0	0
2	60	0	35.89	48.59	0	0	0
3	60	5.56	28.76	6.95	12.34	3.65	0
4	60	12.22	0	0	15.03	7.29	0
5	60	18.88	0	0	15.29	10.79	0
6	60	20	0	0	15.42	12.22	0
7	60	20	0	0	15.58	12.61	0
8	60	20	0	0	15.46	12.44	0
9	60	20	0	0	15.37	11.81	0
10	60	20	0	0	15.45	12.54	0
11	60	20	0	0	15.49	12.93	0
12	60	20	0	0	15.62	12.49	0
13	60	20	0	0	15.38	11.54	0
14	60	20	0	0	15.42	12.22	0
15	60	17.29	0	0	15.37	11.25	0
16	60	12.44	0	0	15.24	8.92	0
17	60	8.63	0	0	15.18	6.18	0
18	60	5.97	0	0	15.06	5.53	0
19	60	4.14	0	0	14.99	4.73	0
20	60	2.85	0	0	14.93	3.86	0
21	60	1.97	0	0	14.82	2.53	0
22	60	1.37	0	0	15.04	2.91	0
23	60	0.96	0	0	14.96	3.35	0
24	60	0.66	0	0	14.9	3.09	0
25	60	0.47	0	0	14.81	2.08	0
26	60	0.33	0	0	14.84	2.44	0
27	60	0.22	0	0	14.87	2.72	0
28	60	0.03	0	0	2.48	0.46	0
29		0	0	0		0	15.76
30		0	0	0		0	12.61

Table 5: The probability distributions of the independent variables for sensitivity analysis.

Independent Variable	Distribution	Inputs	Inputs Values
Oil Price $/bbl	Beta PERT	Minimum	40
		Likeliest	60
		Maximum	100
Production Rate (Q*)	Beta PERT	Minimum	80%
		Likeliest	100%
		Maximum	120%
Development Costs (CAPEX*)	Beta PERT	Minimum	80%
		Likeliest	100%
		Maximum	120%

*Percent of the base case

Figure 4: The impact of the CAPEX on the applied royalty percentage

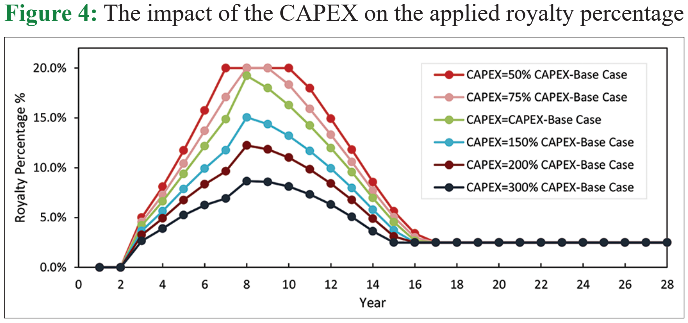


Figure 5: The impact of initial risk (rfi) on the applied royalty percentage

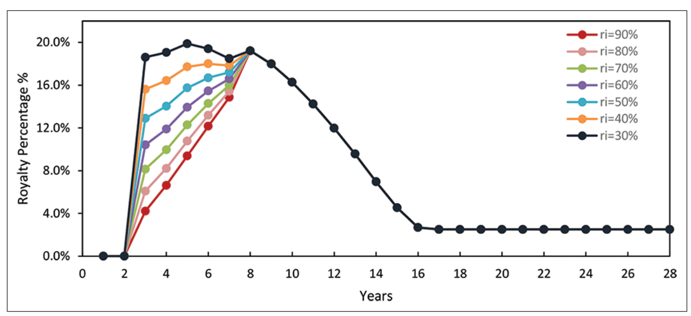
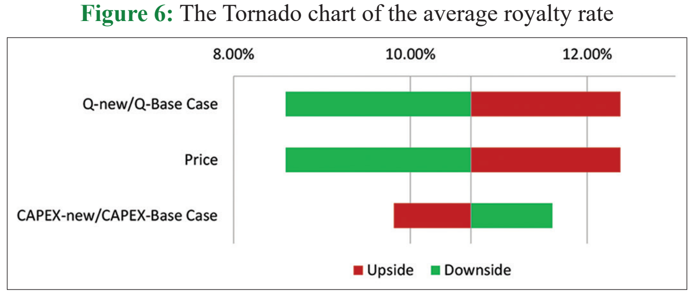


Figure 6: The Tornado chart of the average royalty rate



summarized in Table 2

2. A hypothetical base case of 100 MMbbl oil in place is developed using QUE$TOR 2015 software developed by HIS Markit Energy. The input and output data to QUE$TOR are summarized in Tables 3 and 4 respectively
3. In the deterministic sensitivity analysis, different values

Figure 7: The probability distribution of the proposed average royalty rate

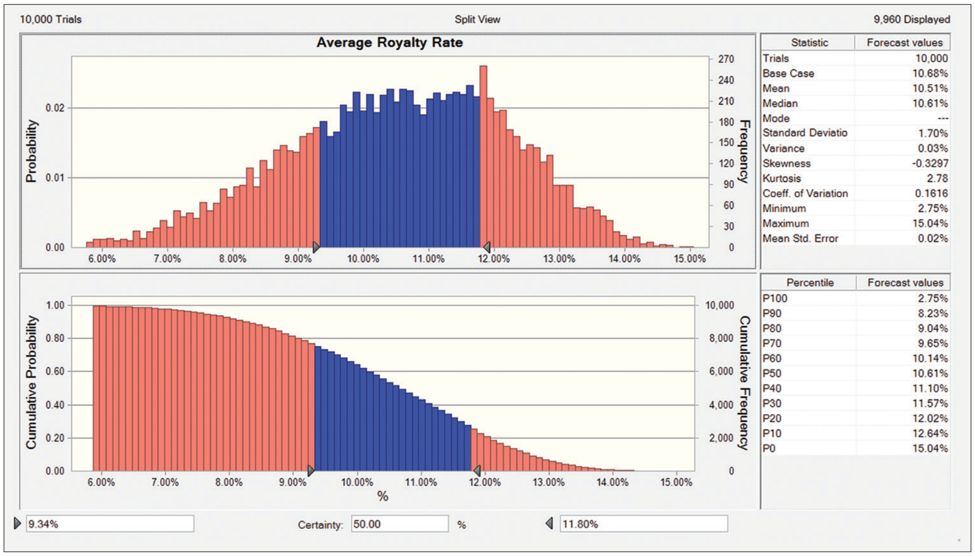


Figure 8: The impact of crude oil price on the government take under the fixed and proposed royalty model

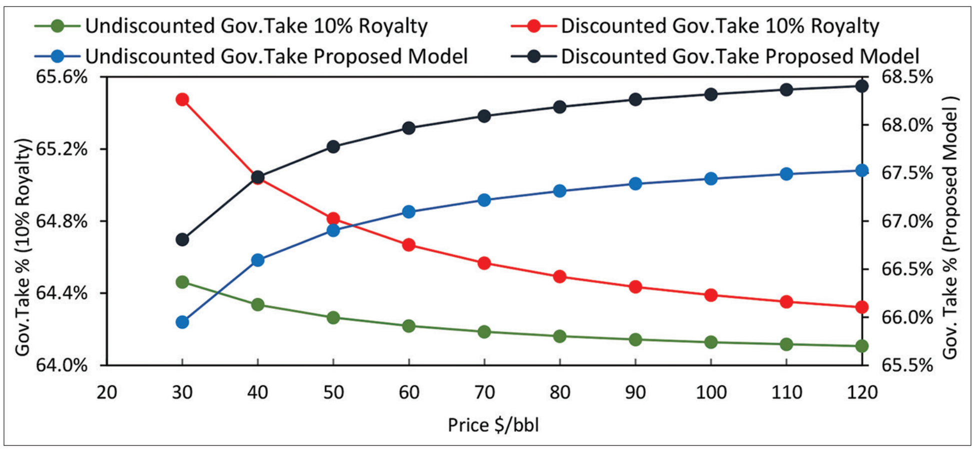
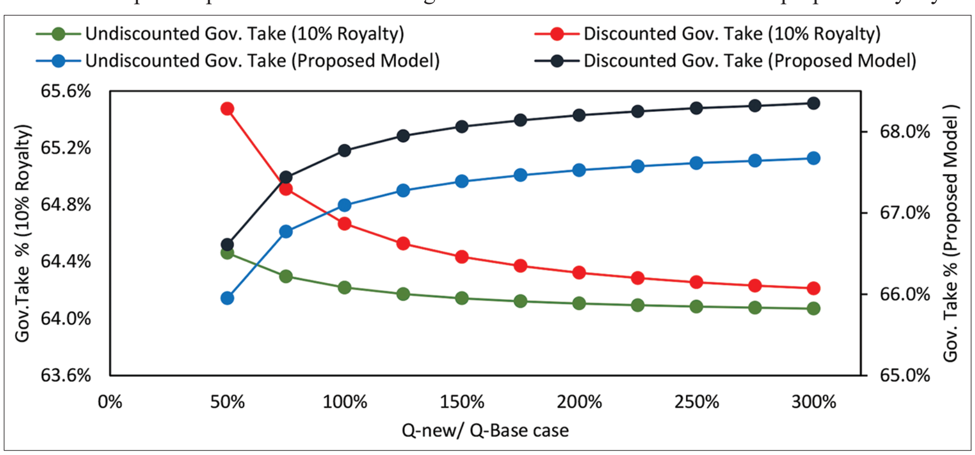


Figure 9: The impact of production rate on the government take under the fixed and proposed royalty model



of crude price, CAPEX, and the production rate will be assumed. Each variable will be investigated independently or by assuming other parameters are held constant during the analysis

4. The sensitivity of the development costs (CAPEX) and the production rate (Q) are checked relative to the base case. For example, if (Q= 200% Q-base case) or (CAPEX= 200% CAPEX-base case) this means the new rate or the new CAPEX is twice the base case rate or the base case CAPEX and so on.

To perform stochastic analysis, Crystal Ball software developed by ORACLE is used. The independent variables and their assumed

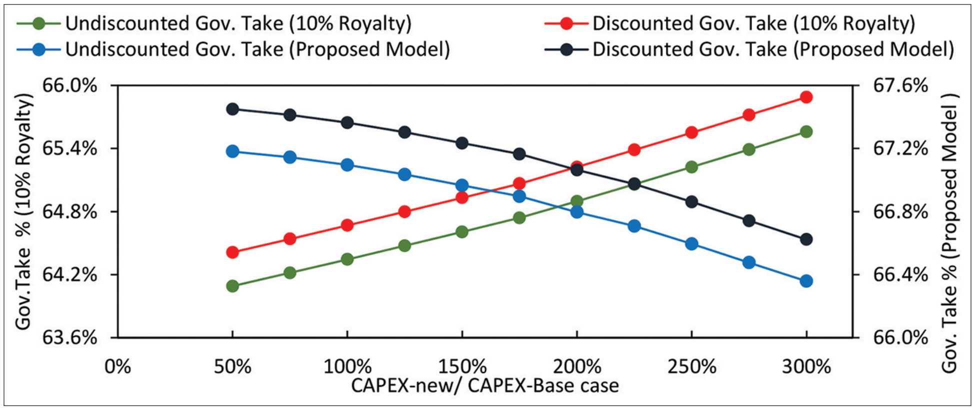


Figure 10: The impact of CAPEX on the government take under the fixed and proposed royalty model

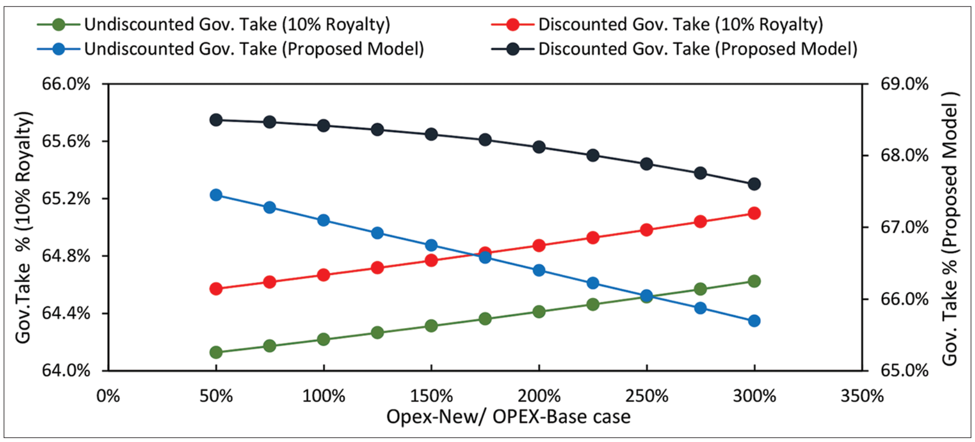


Figure 11: The impact of OPEX on the government take under the fixed and proposed royalty model

Figure 12: The tornado diagram of the undiscounted government take under the fixed royalty model

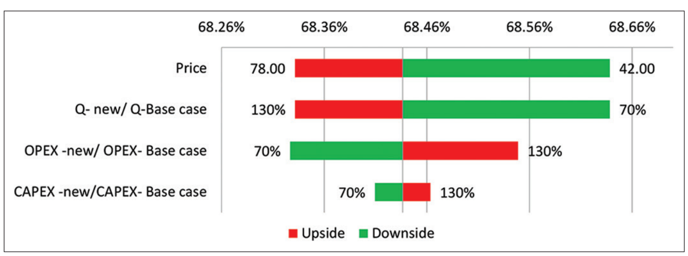


Figure 13: The tornado diagram of the discounted government take under the fixed royalty model

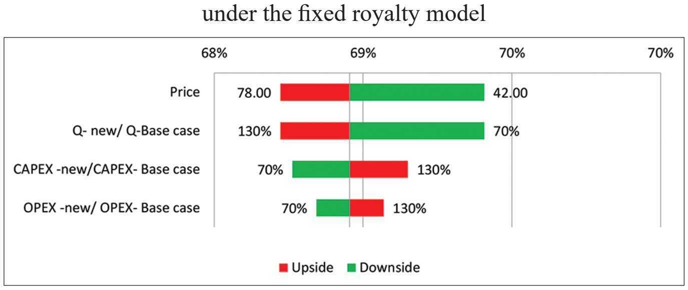


Figure 14: The tornado diagram of the undiscounted government take under the proposed royalty model

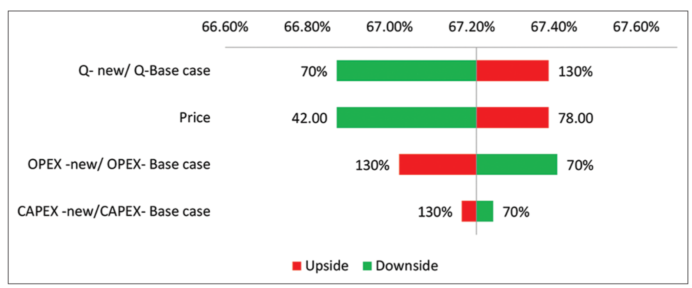
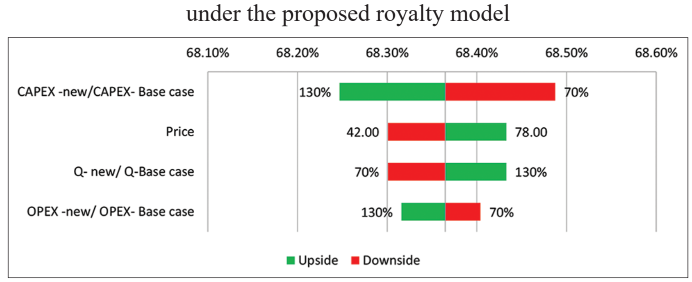


Figure 15: The tornado diagram of the discounted government take under the proposed royalty model



probability distributions are defined in Table 5. A Monte Carlo Simulation with 10,000 trials is then run with the percentile computed as probability above a value. For stochastic analysis, the impact of the input variables on the average royalty throughout the whole life of the field will be analyzed.

3.2. Model Sensitivity Analysis Discussion

The impact of both crude oil prices, production rates (Q), and the development costs (CAPEX) on the proposed royalty model is shown on Figures 2-4 respectively. As it is clearly

Table 6: QUE$TOR 500 MMbbl base case output data for comparative analysis

Year	Exploration Costs MM$	Appraisal Costs MM$	Production Rate KBOPD	Development Wells MM$	Facility Costs MM$	Fixed OPEX MM$	Variable OPEX MM$	Abandonment Costs MM$
1	3.262	0	0	0	0	0	0	0
2	3.262	3.262	0	0	0	0	0	0
3	3.262	3.262	0	0	0	0	0	0
4	0	0	0	0	52.5	0	0	0
5	0	0	0	2.89	90.24	0	0	0
6	0	0	0	46.83	87.85	0	0	0
7	0	0	20	2.76	0	18.68	11.73	0
8	0	0	40	0	0	19.24	21.34	0
9	0	0	60	0	0	19.8	30.95	0
10	0	0	80	0	0	20.44	41.33	0
11	0	0	80	0	0	20.74	41.33	0
12	0	0	80	0	0	20.44	41.33	0
13	0	0	80	0	0	20.45	41.49	0
14	0	0	80	0	0	20.47	41.65	0
15	0	0	80	0	0	20.45	41.49	0
16	0	0	80	0	0	23.77	41.49	0
17	0	0	80	0	0	20.44	41.33	0
18	0	0	80	0	0	20.44	41.33	0
19	0	0	80	0	0	20.44	41.33	0
20	0	0	74.38356	0	0	20.35	38.93	0
21	0	0	64.16438	0	0	20.47	34.44	0
22	0	0	55.36986	0	0	19.99	30.27	0
23	0	0	47.78082	0	0	19.85	26.81	0
24	0	0	41.20548	0	0	19.71	23.66	0
25	0	0	35.56164	0	0	19.61	21.08	0
26	0	0	30.68493	0	0	22.83	18.87	0
27	0	0	26.46575	0	0	19.45	17.1	0
28	0	0	22.84932	0	0	19.4	15.61	0
29	0	0	19.69863	0	0	19.33	14.02	0
30	0	0	17.0137	0	0	19.28	12.8	0
31	0	0	14.68493	0	0	19.22	11.57	0
32	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	42.37
34	0	0	0	0	0	0	0	21.18

Table 7: The input fiscal data for the two hypothetical concessionary systems

1	First System (Fixed Royalty Model)	
	Fixed Royalty Rate	10%
2	Second System (Proposed Royalty Model)	
	Maximum Royalty	20%
	Minimum Royalty	5%
	Estimated Risk Factor	20%
	Remaining Risk	10%
	Risk Relief Period	5 years
3	Common Fiscal Features	
	Tax Rate	60%
	Depreciation	5 -years straight line
	Discount Rate	10%

shown, during favorable boundary conditions i.e., high oil prices, high production rate, or low CAPEX, the royalty percentage is high and lenient to the government and the opposite is true during the periods of unfavorable boundary conditions.

The impact of the negotiated initial risk (r_{fi}) for a 5-year relief period is shown on Figure 5. As it is indicated, as the initial risk increases, the royalty percentage decreases to provide a sufficient incentive for the investors to explore and develop un maturated concessions or concessions with high exportation and development risks. Another important note also can be concluded from Figure 5 that all the curves converge toward the eighth year beyond which the royalty is independent of the initial risk factor. This is because the risk relief period is assumed to be 5 years and the production starts in the 3rd year.

The tornado diagram with 20% change from the base case and the probability distribution with corresponding statistical and percentiles values of the average proposed royalty model are shown on Figures 6 and 7 respectively. As it is shown on Figure 6, the tornado chart confirms the previously concluded remarks of Figures 2-4 that the proposed royalty increases with both the price and the production rate while decreasing with the CAPEX. According to the probability distribution curve shown on Figure 7, with 50–50% confidence, the average royalty rate lies between 9.34% and 11.8% with a mean value of 10.51%. From statistical analysis, the minimum and maximum royalty rates are 2.75% and 15.04% respectively. In addition, with 50 percent confidence (P50), the average royalty of this field will be equal to or more than 10.61%.

Table 8: Calculation of government and contractor's NCF for concessionary system

Royalty Calculations

Annual Revenue=Average Daily Production (KBOPD) *Days Per Year *Average Oil Price ($/BBL)
Annual Royalty Payments=Annual Royalty Percentage *Annual Revenue
Annual Revenue Net Royalty=Annual Revenue - Annual Royalty Payments
Company Income Tax
Annual Claimable Tax Deductions=OPEX+Intangible CAPEX+Depreciated Tangible CAPEX+Loss Carry Forward+Other
Annual Taxable Income=Annual Revenue Net Royalty - Annual Claimable Tax Deductions
If Taxable Income is Positive
Annual Tax Payments=Tax Rate % *Taxable Income

Government Net Cash Flow (NCF_{gov})

Government (NCF_{gov}) = Annual Royalty Payments+Annual Tax Payments

Contractor Net Cash Flow (NCF_{con})

Contractor NCF (NCF_{con}) = Annual Revenue - Annual Royalty Payments -CAPEX - OPEX - Annual Tax Payments

Net Present Value (NPV)

$$NPV = \sum_{i}^{n} \frac{(NCF)_i}{(1+dr)^i}$$ where, *dr* is the discount rate or the cost of capital which is company-specific

Internal Rate of Return (IRR)

$$\sum^{n} \frac{(NCF)_i}{(1+IRR)^i} = 0$$, where, IRR is the discount rate which makes NPV equals to zero

Undiscounted Take %

$$Undiscounted\ Contractor\ Take = \frac{NCF_{con}}{NCF_{con} + NCF_{gov}}$$

$$Undiscounted\ Government\ Take = \frac{NCF_{gov}}{NCF_{con} + NCF_{gov}}$$

Discounted Take %

$$Discounted\ Contractor\ Take = \frac{NPV_{con}}{NPV_{con} + NPV_{gov}}$$

$$Discounted\ Government\ Take = \frac{NPV_{gov}}{NPV_{con} + NPV_{gov}}$$

KBOPD refers to thousand barrels per day

4. COMPARATIVE ANALYSIS AND ECONOMIC DISCUSSION

In this section, the impact of the proposed royalty model on the behavior of the fiscal system, the government, and the contractor take are investigated using deterministic and stochastic analysis. This impact will be analyzed under different crude oil prices, production rates, development costs (CAPEX), and operating costs (OPEX). For comparative analysis, the following methodology is adopted:

1. A hypothetical onshore base case field with 500 MM bbl is developed using QUE$TOR software. The estimated production rate and the associated exploration and extraction costs are summarized in Table 6
2. Two hypothetical concessionary fiscal systems are assumed. The first system is modeled with a fixed royalty percentage while the second one is equipped with the proposed royalty model. The fiscal assumptions for the two systems are summarized in Table 7
3. The government and the contractor's net cash flow under the hypothetical concessionary system is coded in an Excel spreadsheet as summarized in Table 8
4. To account for the uncertainties inherent in the economic data assumptions, stochastic analysis using Crystal Ball software is utilized. The independent variables and their assumed probability distributions are defined in Table 9. Monte Carlo Simulation with 10,000 trials is then run with the percentile computed as probability equal or above a value
5. The impact of the selected stochastic variables on government Cumulative NCF, NPV, undiscounted and discounted take, the contractor IRR, is reported. The reported values are the base case, mean, maximum, P90, P50, and P10. The calculations of selected profitability indicators are summarized in Table 7.

Table 9: The probability distributions of the independent variables for comparative analysis

Independent Variable	Distribution	Inputs	Inputs Values
Fixed Royalty Percentage	Beta PERT	Minimum	5%
		Likeliest	10%
		Maximum	20%
Oil Price ($/bbl)	Beta PERT	Minimum	30
		Likeliest	60
		Maximum	120
Production Rate (Q*)	Beta PERT	Minimum	50%
		Likeliest	100%
		Maximum	300%
Development Costs (CAPEX*)	Beta PERT	Minimum	50%
		Likeliest	100%
		Maximum	300%
Operating Costs (OPEX *)	Beta PERT	Minimum	50%
		Likeliest	100%
		Maximum	300%
Tax Rate	Beta PERT	Minimum	30%
		Likeliest	60%
		Maximum	80%

Figure 16: Government and contractor cumulative NCF under the fixed and proposed royalty model

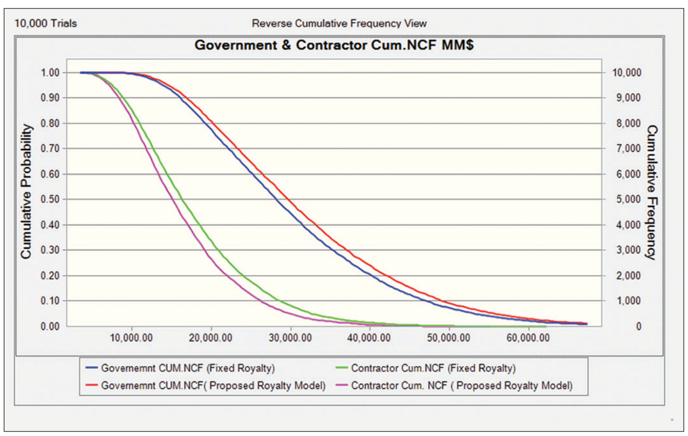
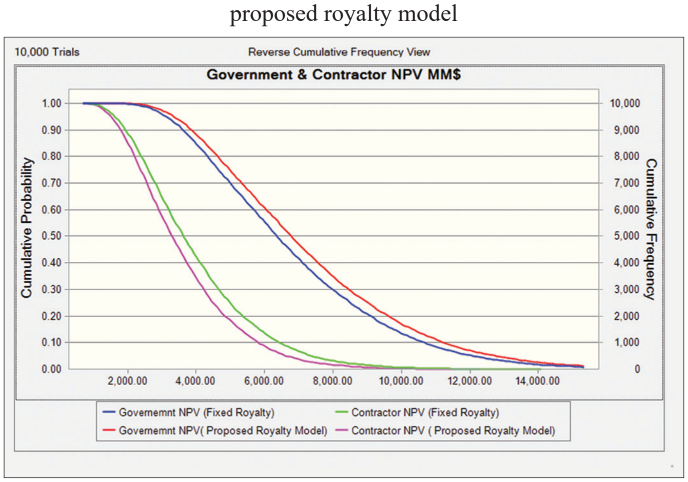


Figure 17: Government and contractor NPV under the fixed and proposed royalty model



4.1. Comparative Analysis Results and Discussion

The impact of crude oil prices, production rate (Q), development costs (CAPEX), and the operating costs (OPEX) are shown on

Figure 18: Government and contractor undiscounted take under the fixed and proposed royalty model

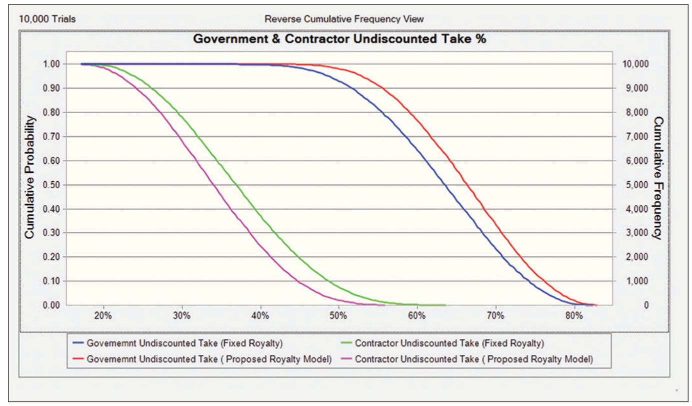


Figure 19: Government and contractor discounted take under the fixed and proposed royalty model

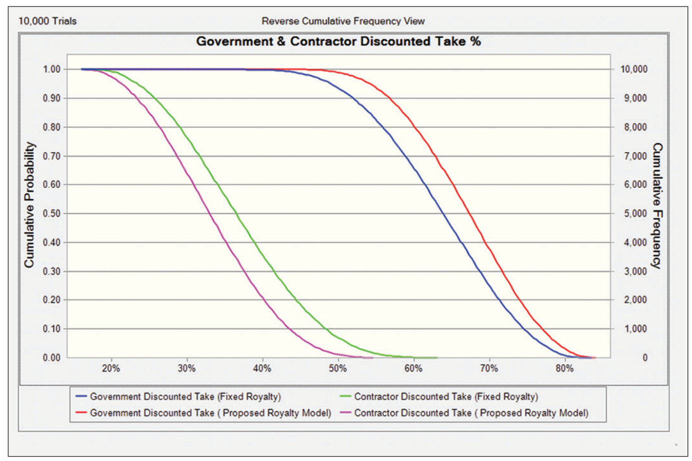
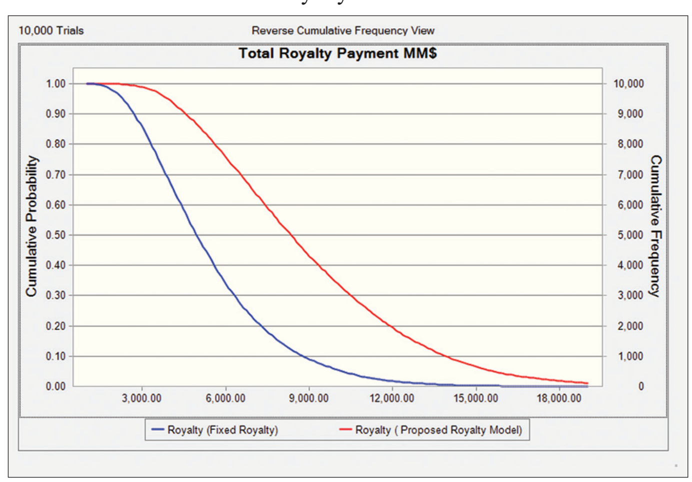


Figure 20: Total Royalty payments under the fixed and proposed royalty model



Figures 8-11 respectively. As shown on Figures 8 and 9 that the government's take under the fixed royalty model decreases as the price or the production rate increases while its take under the proposed model increases as the price, or the production rate increases. On the other hand, the government take under the fixed royalty model increases as the CAPEX or the OPEX increases while its take decreases with the CAPEX or the OPEX under

Table 10: Government and Contractor Cumulative NCF and NPV under the fixed and proposed royalty model

Indicator	Fixed Royalty Model				Proposed Royalty Model			
	Cumulative NCF MM$		NPV MM$		Cumulative NCF MM$		NPV MM$	
	Government	Contractor	Government	Contractor	Government	Contractor	Government	Contractor
Base Case	19174.64	9354.23	4377.83	2025.8	19482.47	8985.52	4389.56	1976.28
Mean	30301.54	17700.59	6840.08	3938.85	31794.65	16283.82	7256.27	3570.04
Min	7243.8	3058.06	1620.66	590.06	7602	3123.35	1755.92	609.58
Max	97514.84	59900.3	22131.47	13496.69	103419.57	53287.1	23533.71	11903.7
P90	16037.87	8713.29	3602.22	1901.56	16783.56	8160.12	3846.36	1745.69
P50	28393.3	16191.99	6406.02	3593.77	29885.56	14970.49	6826.86	3271.29
P10	47241.16	28586.56	10697.16	6410.47	49409.9	26194.66	11277.29	5794.01

Table 11: Government and Contractor undiscounted and discounted take under the fixed and proposed royalty model

Indicator	Fixed Royalty Percentage				Proposed Royalty Model			
	Undiscounted Take %		Discounted Take %		Undiscounted Take %		Discounted Take %	
	Government	Contractor	Government	Contractor	Government	Contractor	Government	Contractor
Base Case	67	33	68	32	68	32	69	31
Mean	63	37	64	36	66	34	67	33
Min	39	18	39	17	41	17	44	16
Max	82	61	83	61	83	59	84	56
P90	52	26	52	25	56	24	57	23
P50	64	36	64	36	66	34	67	33
P10	74	48%	75	48	76	44	77	43

Table 12: Total royalty and tax payments under the fixed and proposed royalty model

Indicator	Fixed Royalty Percentage		Proposed Royalty Model		Amount of royalty increase MM$	Amount of tax reduction MM$	Net Increase MM$
	Total Royalty MM$	Total Tax MM$	Total Royalty MM$	Total Tax MM$			
Base Case	5143.3	14031.34	6004.19	13478.28	860.89	553.06	307.83
Mean	5406.68	24894.86	8892.7	22901.95	3486.02	1992.91	1493.11
Min	1031.18	6570.82	1150.08	6511.37	118.9	59.45	59.45
Max	23523.83	79895.74	27480.6	78869.72	3956.77	1026.02	2930.75
P90	2709.11	13328.76	4566.18	12217.38	1857.07	1111.38	745.69
P50	4954.33	23438.97	8425.09	21460.47	3470.76	1978.5	1492.26
P10	8727.15	38514.01	13947.52	35462.38	5220.37	3051.63	2168.74

Figure 21: Total Tax payments under the fixed and proposed royalty model

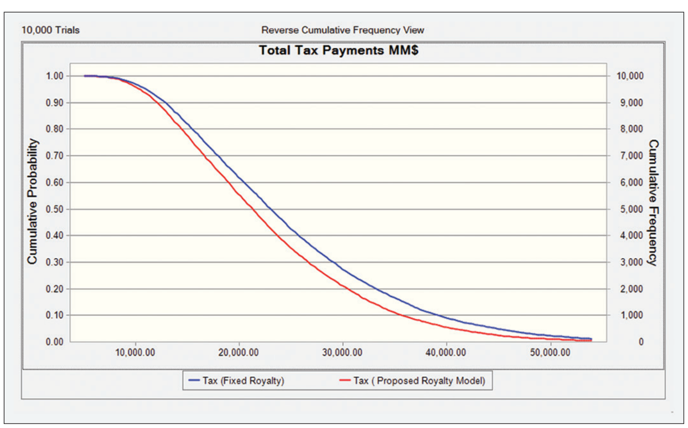
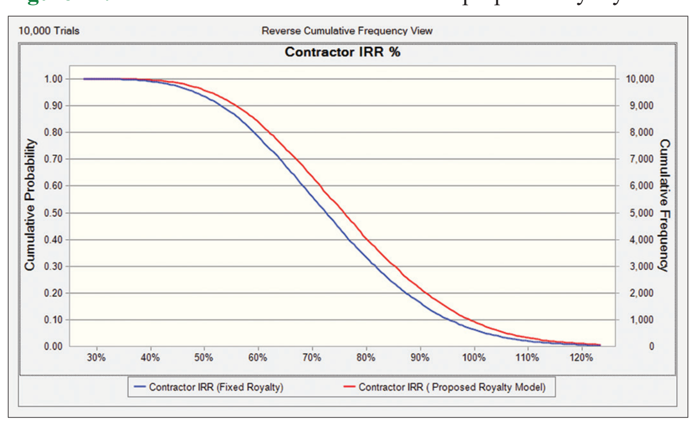


Figure 22: Contractor IRR under the fixed and proposed royalty model



the proposed model as shown on Figures 10 and 11 respectively. The negative correlation between the government take under the fixed royalty model with the crude price or the production rate and the positive correlation between its take and the CAPEX or the OPEX strongly prove that the fixed royalty model is a regressive system. Once the fixed royalty percentage is replaced with the new modified royalty model, the fiscal system becomes highly progressive. This progressive behavior is approved by the positive correlation between the government take and the crude prices or the production rate and the negative correlation between the government take and the CAPEX or the OPEX. The regressive behavior of the fixed royalty model and the progressive behavior of the proposed royalty model are clearly shown on the sensitivity tornado diagrams with a 30% change of the base case shown on Figures 12-15.

Table 13: Contractor IRR under fixed and proposed royalty model

Indicators	Contractor IRR %	
	Fixed Royalty Model	Proposed Royalty Model
Base Case	61	67
Mean	73	77
Min	28	32
Max	140	145
P90	53	55
P50	72	76
P10	95	99

According to the deterministic analysis, the key feature of the proposed royalty model is that it provides the investor with sufficient incentives to develop marginal or low profitability fields and deep offshore concessions with high development costs. This is because its take increases with the decrease in the price or the production rate or with the increase in the development costs (CAPEX).

The stochastic results of the Monte Carlo simulation of the government and contractor cumulative NCF and NPV are summarized in Table 10. As it is summarized in Table 10 that the proposed royalty model provides the government with high cumulative NCF and NPV in comparison with the fixed royalty model under all the statistical and percentiles metrics. The cumulative probability curves of both the government and contractor cumulative NCF and NPV are shown on Figures 16 and 17 respectively. The higher government cumulative NCF and NPV under the proposed model results in higher undiscounted and discounted take as summarized in Table 11 and shown on Figures 18 and 19 respectively.

Although the proposed royalty model provides the government with high royalty and lower tax payments in comparison with the fixed royalty model as shown on Figures 20 and 21 respectively, the increased amount due to the royalty payments is significantly higher than the amount of tax reduction under the proposed model resulting in higher government cumulative NCF as summarized in Table 12. For example, under P50, the royalty increased by 3470.76 MM$, and the tax payment is reduced by 1978.5 MM$ resulting in a net increase of the cumulative government NCF by 1492.26 MM$. This result is further confirmed by calculating the difference between the cumulative government NCF under the proposed and fixed royalty model for P50 in Table 10 i.e. (29885.56-2839.3= 1492.26 MM$).

Although the proposed royalty model channel the government with higher income, it is still highly lenient to the investor. This lenient behavior is approved by the higher contractor IRR under the proposed royalty model relative to the fixed model under all the statistical and percentiles matrices as shown on Figure 22 and summarized in Table 13.

5. CONCLUSION AND POLICY IMPLICATIONS

In this study, a novel royalty model for upstream fiscal systems is developed. The new model is designed as a function of the boundary conditions of both the market and the productive resources. These boundary conditions are the associated exploration and production risks, commodity prices, the extraction costs, besides the expected production and depletion rate. Based on the deterministic, stochastic, and subsequent comparative analysis, the policymakers should adopt the proposed model for the following reasons:

1. The new royalty model provides the investors with sufficient incentives to develop marginal and low profitability fields because of the contrast between the royalty payments and the crude oil prices and production rate
2. As the applied royalty percentage decreases with increasing the extraction costs i.e. (CAPEX and OPEX), the proposed model provides sufficient incentives to explore and develop deep offshore fields with high development and production costs
3. Since the proposed royalty model is negatively correlated with the estimated exploration and production risks, the proposed model encourages the investor to explore and develop unmatured and frontier regions
4. The intrusion of the proposed royalty model makes the fiscal system progressive. This progressive behavior makes the government take increases as the project profitability increases i.e. (higher prices, higher production rate, or lower costs), while the contractor take increases as the project profitability decreases
5. The proposed model is a win-win model for both the host government and the contractors. This is because the proposed royalty model allows the government to capture higher take, besides allowing the contractor to achieve a suitable rate of return.

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