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Investment Evaluation and Economic Analysis of Development Projects in the Rashadat and Doroud Oil Fields

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ABSTRACT

Oil and gas producing organizations across the globe compete over resources and reserves. The undeniable fact remains that the application of engineering principles-especially in exploration and production projects such as design, construction, and operation of efficient and economic plants and processes-is crucial. The lack of a viable global or national substitute for crude oil and the essential nature of this commodity in the economic portfolio has heightened the importance of oil and gas development projects. Drilling, well completion, and oil and gas production projects are considered highly complex businesses. The economic analysis of oil and gas operations requires the use of economic techniques and analyses in design and engineering. Economic evaluation of oil and gas investments is one of the core responsibilities in both domestic and foreign investments of oil and gas companies, among which risk assessment and profit evaluation are the most critical. Oil price is a key factor affecting internal company risk and industrial risk. Risk compensation reduces the overall profitability of oil and gas investments both domestically and abroad. The economic structure of the oil industry, due to the high risks and uncertainties associated with oil and gas projects and extremely volatile price levels, is significantly different from other industries. Additionally, the large number of uncertainties in the data used for investment decision-making in oil projects heavily influences decision-making processes. In this study, the Rashadat and Doroud oil fields were examined. Based on the results, investment in the Rashadat field-despite the higher risk of offshore operational conditions-is more justifiable than investment in the Doroud field, such that the profit from investment in the Rashadat field amounts to USD 896 million. Although the initial capital required for the Doroud field is lower than that of the Rashadat field, this is due to the high costs of offshore oil operations.

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1. Introduction

The oil and gas industries are considered the largest economic sectors globally [1]. Many economists believe that crude oil is the most important commodity in the world [2]. The oil and gas industry can be introduced as the most significant industry with a comparative investment advantage [3]. The energy portfolio in Iran and the world reflects the fact that, despite extensive efforts to diversify this portfolio, oil and gas still remain the most important energy sources globally [4]. Iran, as a developing country, is rich in vast energy resources and possesses large oil and gas reservoirs both onshore and offshore [5]. Oil companies generally base their decisions for a particular oil project on economic models [6]. Therefore, to improve decision-making processes and to effectively address modern challenges, developing a robust solution involving oil economics and risk assessment models is essential [7].

The oil and gas industry can be introduced as the most significant industry with a comparative investment advantage [8]. The government's high revenue from the oil sector, the comparative advantage of exploratory reserves, Iran's strategic geographic position in the energy corridor, and the goal of sustainable production are perhaps among the main reasons for the strong inclination toward investment in this economic sector [9]. The possibility-based approach, probabilistic approach, and Monte Carlo simulation are methods for risk assessment [10] and help identify potential problems in the execution and operation phases of a project to support project management in taking corrective actions in favor of the project [11]. The developed ECO PETRO model offers a deterministic model for evaluating the economic aspects of oil projects before project initiation and for reevaluating oil projects after successful exploration and prior to development or production phases [12]. Additionally, the ECO OIL model supports the development of strategies for optimizing risk management and the financial and investment policies of companies [13].

Each risk assessment approach has its advantages and disadvantages [14]. They complement each other in identifying potential future issues during project execution [15]. Further efforts have been made to improve the ECO PETRO model to develop an independent risk assessment tool [16].

Oil investment requirements are projected to reach USD 14 trillion by 2045. The total investment needs across the entire oil sector from 2022 to 2045 are estimated at USD 14 trillion (in 2023 dollars), averaging about USD 610 billion per year [11]. Of this amount, an estimated USD 11.1 trillion is expected to be required for the upstream sector, or an average of USD 480 billion per year [17]. The downstream and midstream sectors are estimated to require USD 1.7 and USD 1.2 trillion, respectively. The cumulative oil-related investment requirements by sector for the period 2023–2045 are presented in Fig. 2 [17].

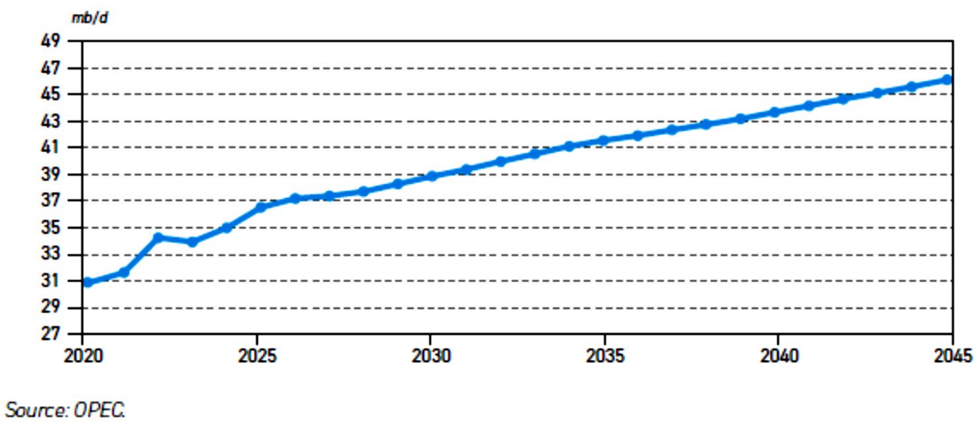

Fig. 1. Investment requirements for the entire oil sector, 2022–2045

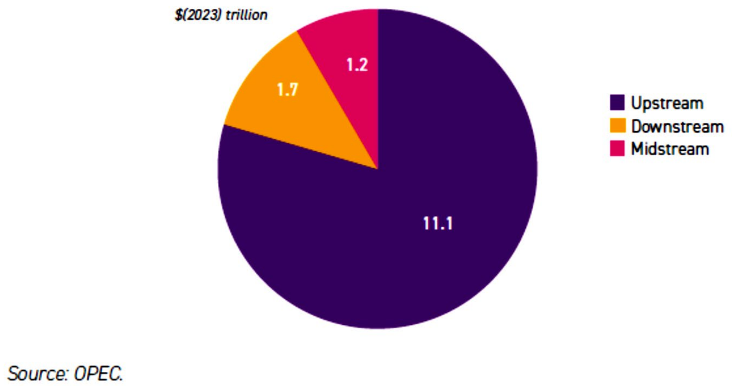

Fig. 2. Cumulative oil-related investment requirements by sector, 2023–2045

2. Risk analysis

2.1. Risk analysis of foreign investment in the oil and gas sector

To effectively integrate risk assessment with profit evaluation and facilitate investment decision-making, it is first necessary to analyze the risk factors involved in foreign oil and gas investments and categorize their types. Subsequently, the pathways through which these risks affect the benefits of development must be quantified and incorporated into the profit evaluation process in the form of risk compensation.

2.2. Identification and classification of risk factors for foreign and domestic investment in the oil and gas sector

After generalization and summarization, the risks associated with foreign oil and gas investments can be divided into four categories: internal corporate risks, macroeconomic and policy-related risks, risks related to investment target resources, and potential technical risks following the investment. The types and descriptions of these risks are presented in Table 1. The trends of high and low risk are illustrated in Fig. 3 [18].

Table 1: Types of risk

Risk type	Risk factor	Brief description and considerations
Resource-related	Resource quality	Crude oil quality, porosity, permeability, gas saturation, etc.
	Resource characteristics	Depth, area, oil/gas content, reservoir pressure, etc.
	Resource location	Climate type, geographic location, infrastructure, etc.
Technical	Exploration technology	Seismic technologies, evaluation skills, etc.
	Drilling and well completion tech	Drilling design, equipment operations, drilling safety, etc.
	Fracturing technology	Hydraulic fracturing design and operation, raw materials, equipment risks, etc.
	Surface construction technology	Design modifications, material and structural risks, construction conditions, etc.
	Gathering and transportation tech	Pipeline network design risks, construction, corrosion, leakage, emissions, etc.
	Production scheme	Water flooding and recovery technologies, recovery systems, alternative plans, etc.
Economic	Market environment	Market competition, demand, scale, prices, etc.
	Economic policy	Policies related to taxation, subsidiaries, mining rights, environmental protection, etc.
	Financing environment	Interest rate, exchange rate, inflation, etc.
Organizational	Corporate organizational capacity	Management systems, decision-making mechanisms, emergency response mechanisms, etc.
	Human resource management capacity	Workforce downsizing, labor shortages, etc.

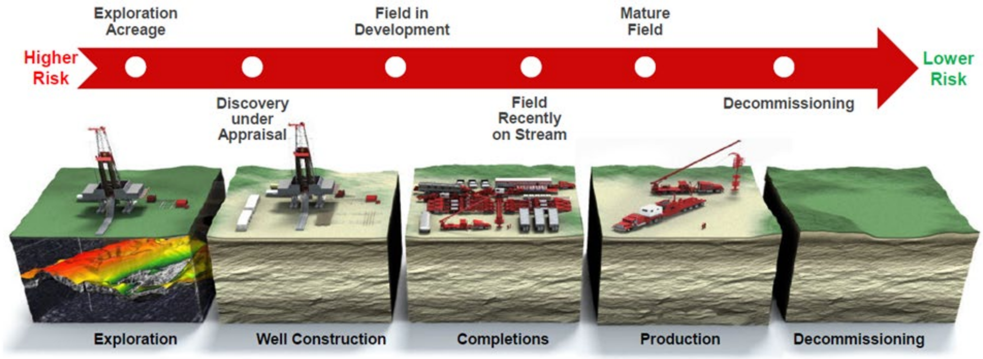

Fig. 3. An oil field life cycle stages

2.3. Pathways of risk factors impacting development benefits

Risk factors affect the future returns of oil and gas investment in the country. The timing and manner of these impacts differ depending on the type of risk involved. Fig. 3 shows risk evolution over an oil field life cycle. Apparently, oil price risk exists throughout the entire investment and development life cycle, whereas exploration risk is only present during the exploration phase. Recovery cost depends on the depth of oil and gas resources, while resource quality is associated with the selling price. In this regard, it is necessary to identify the path through which each risk factor affects development returns, and based on the transmission path of such impacts, a risk compensation mechanism should be designed. The pathways through which risk factors impact development benefits vary and are realized through effects on future investment cash inflows or outflows abroad.

2.4. Designing compensation methods for risk factors

Resource-related risk factors such as hydrocarbon quality, oil/gas-bearing area, and burial depth generally remain unchanged. The production capacity phase for oil and gas development takes 2 to 5 years, during which no significant changes in development technologies are expected. However, the production and sales phase of oil and gas resource development can last 10 to 20 years, during which factors such as global oil prices, investment and financing interest rates, and production technologies continuously evolve over time. Therefore, compensation methods for static and dynamic risk factors must be designed separately.

2.5. Designing compensation for technical risks

In terms of technical risks, except for production technology, all other technologies related to exploration, drilling, fracturing, and other aspects are considered static risks, since the duration of exploration and production capacity building is relatively short. Different investors may possess varying technical capacities and face different levels of risk. It is believed that technical risks lead to variations in investment.

2.6. Designing compensation for dynamic risk factors

Static risks related to resources and technology maintain stable levels of risk in the short term, for which the risk compensation method is designed based on recoverable reserves and related investments. However, production-technology, economic, and internal risks have long-term impacts, during which the levels of risk change over time and cannot be compensated through specific reserves or investments.

2.7. Risk compensation-based assessment method for dynamic risks

As mentioned above, identification and classification of risk factors are conducted, compensation modes are designed respectively for static and dynamic risk factors, correction coefficients are determined for static risks, and compensation coefficients are determined for dynamic risks. The foreign oil and gas investment evaluation model can be developed using the discounted cash flow method under risk compensation, thereby effectively integrating risk assessment and profit evaluation.

2.8. Discounted cash flow method

The discounted cash flow (DCF) method, also known as the net present value (NPV) method, examines the profitability of a project throughout its entire life cycle. This method can effectively reflect the development benefits of a project and highlight the characteristics of companies in achieving maximum economic profit. It is considered the most effective and practical method for evaluating oil and gas investments.

2.9. Profit evaluation model related to risk compensation

In risk compensation design, resource-related risk factors should be compensated through recoverable reserves, technical risks should be compensated through various investments, and economic and internal corporate risks should be compensated using a dynamic discount rate.

3. Investment

Decision-making for investment in oil exploration and production projects is always a highly complex endeavor. These projects are influenced by numerous high-risk factors associated with the oil industry, such as relatively high initial capital requirements, long-term investment horizons (projects may last up to 20 years or more), and negative cash flow during the initial years and sometimes during the final years of the project's life cycle. These factors, along with highly volatile price levels, significantly increase the number of uncertainties in the data used for investment decision-making in oil projects, thus severely affecting the mindset of decision-makers. Investment in the oil industry is carried out under significant risk due to the nature of the exploration and production process. Oil price fluctuations also add a high level of risk to oil investments.

These risk factors are the primary reason economic data used to evaluate projects often lacks precision. Most oil companies make investment decisions for specific oil projects based on economic models developed in Excel spreadsheets by in-house economists or external specialists using available data from various sources (such as petroleum engineers, geologists, etc.). As a result, each oil company develops its own economic model. These models are characterized by vague definitions of input variables and how they relate to output parameters. Therefore, to improve the decision-making process in oil projects and effectively face modern challenges, developing a robust solution for oil economics modeling and associated risks is essential. Key business and investment indicators of oil projects provide the tools used to enhance the decision-making process. The most common indicators used to evaluate oil projects include: Net Cash Flow (NCF); Discounted Cash Flow (DCF); Net Present Value (NPV); Internal Rate of Return (IRR); and Payback Period.

3.1. Net cash flow

The net cash flow of a project is defined as the remaining cash after covering all costs over a year or a period. To express the annual net cash flow associated with an oil project, cash payments must be subtracted from cash receipts for the specified period.

Cash Inflows (Revenue) – Cash Outflows (Costs) = Net Cash Flow (1)

A negative cash flow for a year is not necessarily bad for the entire investment; it may indicate that the company is making a large investment during this period that will yield high returns later. For example, the initial years of an oil project, during which large sums are spent on exploration and development, but no returns are yet realized. After gathering all the required information, net cash flow calculation begins, and the total project cash is classified into revenue and expenses.

3.1.1. Revenues

Revenue is derived from the sale of petroleum products (oil, gas, or condensates), in addition to other activities such as proceeds from asset sales or interest from reserves (release, depreciation, etc.). To calculate the revenue from oil sales, prices must be forecasted. For each project, the price forecast should be chosen based on the economist’s expertise. Some opt for a fixed real price forecast, while others select spot price forecasts with fixed rates, etc.

3.1.2. Costs

To produce oil, there are two main cost types: financial costs (including bonuses, royalties, taxes, etc.) and field costs, which can be classified into four elements: Exploration costs, development costs, operating costs, and abandonment costs.

Exploration and development costs together are called CAPEX, while operating costs are called OPEX. Abandonment cost is considered a special category because it is related to environmental safety and provides no future benefit to the company. It is also a significant cost component and may equal or exceed development costs. The allocation of field costs (CAPEX, OPEX) varies from company to company due to the variable nature of oil projects (e.g., different types of reservoirs) and the fiscal regime applied to the project (e.g., some host governments define which costs are capitalized and which are expensed).

3.1.3. Capital costs

Exploration costs include the expenses of geological and geophysical studies conducted by the company or purchased from third parties such as service companies. In addition, exploration wells are drilled, and their costs are considered exploration costs. If the exploration attempt fails, the cost is termed a sunk cost. Typically, sunk costs do not directly appear in the evaluation of a project's future cash flow, but they impact the actual financial state of the project.

3.1.4. Development costs

Development costs comprise three main components: the cost of drilling development wells, the cost of production installation and commissioning, and the cost of facilities required for transporting oil. Development methods and techniques vary from project to project depending on several factors such as onshore/offshore location, available technologies, rock types, field size (oil or gas), etc.

3.1.5. Operating costs

Operating cost (OPEX) represents the operational and maintenance cost of the oil project. Operating costs may be classified based on different criteria. OPEX classification based on time. Operating cost based on time is classified into historical operating cost (which is determined after its occurrence) and predetermined operating cost (which is calculated before its occurrence). Predetermined operating cost is either forecasted operating cost or standard operating cost. OPEX classification based on the nature of the incurred element. Operating cost based on the nature of the incurred element is classified into six categories:

- Labor

Labor costs represent wages and wage benefits for all personnel involved in oil production at the field. The required number of personnel and hourly rate for each are clearly defined. Wage benefits generally include all compensations provided to employees, excluding time-work wages.

- Operating services

Service costs refer to expenses arising from subcontracting between the contractor and service companies, such as maintenance contracts, pumping contracts, cleaning contracts, transportation of personnel, etc.

- Materials and parts

Material costs include all small tools used in oil production. These tools are consumables and cannot be treated as assets, such as batteries, treatment chemicals, and spare parts for any maintenance of production facilities.

- Utilities

Utilities include fuel, gas, water, etc., used to operate production equipment.

- Overhead costs

Annual overhead is defined as business operating expenses not directly tied to a specific project or operation. These costs include wages and administrative expenses, public relations, finance, budget and management control, legal issues, and insurance management. The share of overhead allocated to a specific oil project is usually defined by the contract between the contractor and the host government.

- Transportation

Transportation costs are incurred in moving produced oil from the field to a refinery, processing facility, export terminal, or any point of sale, using pipelines, tankers, or both.

3.1.6. OPEX classification based on traceability

Operating costs are classified based on traceability into direct costs and indirect costs. Direct costs can be directly attributed to oil production, such as wages of wellsite workers. Indirect costs cannot be directly associated with oil production, for example, administrative overhead costs.

3.1.7. OPEX classification based on volume changes

Some elements of operating costs do not change with variations in production volume and are referred to as fixed costs, such as overhead expenses. Other elements of operating costs vary with production volume and are therefore called variable costs, such as fuel and other utilities used in oil production.

4. Standard oil economy model (EcoPetro_Model)

The standard oil economy model (EcoPetro_Model) provides a comprehensive deterministic model that integrates all necessary variables for the economic evaluation of oil exploration and production projects, serving as a baseline model to assist decision-making processes under risk and imprecise data.

Every economic model includes simplifications of reality. These simplifications are acceptable as long as they do not distort the essence of the model. In the EcoPetro model, it is assumed that the production of an oil project can include oil, gas, or both; associated gas condensates are included with the main product in the oil production volume. Furthermore, the contractor represents a single entity and holds 100% operational share. In reality, the government may have an operational share, and the contractor may consist of more than one company.

Additionally, the net cash flow shown in the EcoPetro model refers to the project's operational cash flow. Depreciation is calculated parallel to the production start year. It is also assumed that the variable values of costs, prices, and production are estimated by petroleum engineers and geologists, and the model represents linear correlations between these values.

The structural equation system of the EcoPetro model includes seven main groups of equations: revenues, costs, fiscal regimes, depreciation (capital cost discount), key business indicators, government and contractor share indices, and expected monetary values. The EcoPetro model variables are divided into three groups:

a) Exogenous variables include only variables that are independent of other variables and their values are determined by external and uncontrollable conditions. Therefore, they are input values in the model, such as oil price, discount rate, production specifications, etc.
b) Endogenous variables appear as dependent variables in at least one equation in the structural equation model and therefore their values are determined by other variables. This endogenous group is used to calculate other variables in the model; for example, revenue is an endogenous variable and is used in the cash flow calculation.
c) Decision variables are also dependent variables and are used in decision-making processes like discounted cash flow. These variables may or may not be used in subsequent calculations. The variables used in the structural equation system are collected in data repositories tables. The structural equation is constructed not only for the total project aggregation but also on an annual basis.

5. Case study investment analysis in Rashadat oil field and Doroud oil field

For implementing the oil economy model, the development of Rashadat oil field and Doroud oil field is examined. Rashadat field is one of Iran's oil fields located 108 km southwest of Lavan Island and amid the waters of the Persian Gulf. Production from this field began in 1968 (1347 in the Iranian calendar). Previously, this field was known as the Rostam oil field. The field includes 33 wells on the platforms R4, R3, and R7. In this study, the investment value comparison is made between the production satellite platforms R4, named W4 and W0, using the oil economy model. Offshore projects represent complex and high-risk investments.

Doroud oil field, with an approximate area of 5km² within a 25km² domain in the Kharg island region and northwest of the Persian Gulf, is considered one of Iran's largest oil fields. Production from this field began in 1964 (1343 in the Iranian calendar). The field contains 24 wells. In this study, the investment value in Doroud oil field is compared using the oil economy model. Although offshore investments are complex and high-risk, due to the island nature and proximity to the shore, investment risk in this field is lower for investors. In this study, the project is considered as a concession and contractor investment. The structural equation system of the EcoPetro_Oil model is derived from the structural equation system of the standard oil economy model (EcoPetro_Model), which is used in this study.

Proven and recoverable oil reserves in the EcoPetro_Oil model for wells on satellite platforms W0 and W4 are estimated at 7 billion barrels of oil, with a probability of success (POS) for the exploration phase of 16% and for the development phase 60%, considering residual risks after a successful exploration phase, such as technical, financial, and political risks. The exploration phase will start in 2025 and last seven years, with total exploration costs of 87 million USD. The development phase is planned from 2032 to 2045, and the total development cost is estimated at 1,400 million USD

First production will start in 2032, initially extracting from 5 wells, reaching 12 producing wells by 2036. The plateau phase is estimated to last 4 years, after which production will decline at a rate of 10% from 2043 until 2048 (end of production). All wells will be abandoned in the final year. An annual amount of 21 million USD is allocated as abandonment costs over 10 years from 2032 to 2048. The real oil price is fixed at 83 USD per barrel, with an estimated inflation rate of 20%. Net cash flow in the EcoPetro_Oil model is discounted at a rate of 15%, and OPEX is estimated at a real value of 12.5 USD per barrel.

To better understand the correlation between NPV and other variables for the base case of the EcoPetro_Oil model where the contractor receives a share of oil, profit, and oil costs instead of sales revenue besides field costs (CAPEX, OPEX, and abandonment), the contractor also pays financial costs (royalties, bonuses, and taxes). It is notable that tax is one of the largest costs for the contractor, and abandonment costs in the base case of EcoPetro_Oil are considered negligible compared to other field cost variables. The same applies to bonus costs compared to other financial cost variables.

Sensitivity analysis based on deterministic data is a common approach in the oil industry to evaluate exploration and production projects. In the EcoPetro_Oil model, it is assumed that oil production, oil price, and field costs (CAPEX, OPEX, and abandonment) are the key business indicators. Two types of deterministic sensitivity analyses are performed: changing one variable at a time and changing multiple variables simultaneously (multivariate changes). When changing one variable at a time, the increase rate (maximum value) and decrease rate (minimum value) for each key variable, as shown in Table 2, are defined relative to actual values.

Table 2. Input scenarios for deterministic sensitivity analysis: one-variable-at-a-time change

Decreased value	Decrease rate	Increased value	Increase rate	Input value	Unit	Key variables
8.49	40%	116.2	40%	83	USD/barrel	Oil price
18,400	20%	27,600	20%	23,000	barrels/day	Oil production rate
4,560	20%	6,840	20%	5,700	million USD	OPEX
4,089.6	20%	6,134.4	20%	5,112	million USD	CAPEX
16.8	20%	25.2	20%	21	million USD	Well abandonment

6. EcoPetro_Oil model for the Rashadat field

Oil production, oil price, and field costs represent the most critical uncertainty variables in the EcoPetro_Oil model. To implement a probabilistic sensitivity analysis, a degree of uncertainty (margin of error) is identified for each uncertain input variable. While the uncertainty of variables varies depending on the phase of the oil project, The proven and recoverable oil reserves in the EcoPetro_Oil model for the Doroud oil field are estimated at 6.9 billion barrels, with an estimated probability of success for the exploration phase of 20% and for the development phase of

70%. The exploration phase will begin in 2025 with an estimated cost of 93 million USD and will last for five years. The first production is expected to begin in 2030, with oil and gas extraction carried out from 8 wells. The ramp-up period will last 2 years, with development costs estimated at 1,387 million USD. This will be followed by a 3-year plateau phase. Production will then begin to decline in 2036 at a rate of 10% per year until 2046 (the final year of production). In the following year, all wells will be abandoned.

The real oil price input is assumed to be constant at 83 USD per barrel, and the inflation rate is estimated at 20%. The net cash flow in the EcoPetro_Oil model is discounted at a rate of 15%. Real OPEX is estimated as a fixed annual OPEX of 36 million USD plus a variable OPEX of 11 USD per barrel of oil equivalent. The deterministic sensitivity analysis, with one-variable-at-a-time changes, is presented in Table 3.

Table 3. Input scenarios for deterministic sensitivity analysis, one variable change at a time (EcoPetro_Oil Model) for Doroud field

Decrease value	Decrease rate	Increase value	Increase rate	Input value	Unit	Key variables
49.8	40%	116.2	40%	83	USD/barrel	Oil Price
16800	20%	25200	20%	21000	barrels/day	Oil Production Rate
3440	20%	5160	20%	4300	million USD	OPEX
3840	20%	5760	20%	4800	million USD	CAPEX
16	20%	24	20%	20	million USD	Well Abandonment

7. Conclusion

This study begins with the identification and classification of risks in oil and gas investments both domestically and internationally, and investment in this vast industry. Based on the concept of risk compensation, compensation methods have been developed for each identified risk, where resource-related risks are compensated by recoverable reserves, technical risks by exploration and development investments, internal company risks, and economic risks by a dynamic discount rate.

Risk assessment and profit evaluation have been effectively integrated, and a risk-compensation-based evaluation model for overseas oil and gas investments has been successfully developed. The evaluation of oil and gas investments abroad should not only consider the benefits of development but also examine risk factors in the investment and development process to avoid overestimation of benefits and decision-making errors.

It can be concluded that risk factors weaken comprehensive benefits and interfere with investment feasibility and priorities. During the model development process, it is revealed that internal enterprise risk and average industry risk for oil and gas investments are strongly linked to oil price fluctuations. Accordingly, investors should pay close attention to future oil price trends. The timing of occurrence of various risk factors differs, and their risk levels may continuously change over time. The dynamic discount rate can adequately compensate for the dynamic changes in risk factors.

The advantage of this method, as presented in this paper, lies in the separate compensation of risk factors during the benefit evaluation process. Based on the transmission paths of risk factors, a comprehensive evaluation index is developed to objectively combine risks and benefits using adjusted evaluation parameters and dynamic discount rates. Thus, the effects of multiple subjective factors and multi-objective decision-making problems in the evaluation process are eliminated. Additionally, repeated calculations of risk factors are avoided.

The EcoPetro model provides a clear definition of input variables and extensive flexibility in cost calculation and the selection of financial regimes. Key business indicators for evaluating a project using the EcoPetro model include NCF (Net Cash Flow), NPV (Net Present Value), IRR (Internal Rate of Return), payback period, and withdrawal indices (government take, contractor take), as well as Expected Monetary Value (EMV). All variable values can be entered into the EcoPetro model either in real or inflation-adjusted terms. The EcoPetro model is based on simplifications of reality and deterministic input values; therefore, its outputs require additional analyses to cover uncertainties in the input data.

To verify the efficiency of the EcoPetro model, various models (EcoPetro_Oil) were implemented, where the EcoPetro_Oil model represents a production sharing contract from the Rashadat and Doroud fields. The EcoPetro model is complex but well-defined. The cases and data used to test the oil models (EcoPetro_Oil) are well-selected and provide a clear picture of the profitability of oil projects.

Comparing the key business indicators of the EcoPetro_Oil models shows that the revenue of the Rashadat oil field, approximately 896 million dollars, is higher than that of the Doroud oil field, about 875 million dollars. However, the NCF for the Doroud field, around 12,142 million dollars, is less than that of Rashadat, about 15,800 million dollars, due to the higher capital costs of offshore projects.

The EcoPetro model is a deterministic model for economic evaluation of potential oil projects or re-evaluation of oil projects after a successful exploratory project before development or production stages. Additionally, it supports strategy preparation and decision analysis at various times before project initiation and later at any stage of the project lifecycle, helping optimize risk management and the company's financial and investment policies.

Further efforts to improve the EcoPetro model have been suggested to add features such as portfolio optimization with integrated EMV calculation, precise POS (Probability of Success) assessment, and project management, aiming to create an independent risk assessment tool covering all geological, commercial, and political risks of oil projects.

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