Petroleum Business Review, Vol. 8, No. 4, pp. 17–33, October 2024

Petroleum Profitability through Comparing the Financial Structure of Oil Contracts and Determining the Appropriate Contract: IPC, PSC, and Buyback

Laleh Abooshahab[1], Mohsen Hamidian[2], S. Mahboubeh Jafari[3], and Ghodratollah Emamverdi[4*]

[1] Ph.D. Candidate, Department of Management and Accounting, South Tehran Branch, Islamic Azad University, Tehran, Iran

[2] Assistant Professor, Department of Economics, Tehran Central Branch, Islamic Azad University, Tehran, Iran

[3] Assistant Professor, Department of Management and Accounting, South Tehran Branch, Islamic Azad University, Tehran, Iran

[4] Assistant Professor, Department of Management and Accounting, South Tehran Branch, Islamic Azad University, Tehran, Iran

Highlights

- The effects of fiscal regimes on investment choices in the oil and gas sector were analyzed by focusing on comparing mutual buyback, Iran petroleum contract (IPC), and production sharing contract (PSC) in the Shadegan field.
- Mutual buyback arrangements responded minimally to oil price changes due to their inherent fixed costs and preset expenses before production.
- In scenarios of climbing oil prices, the profitability for contractors under the production sharing contract notably increased.
- Superior returns were noted under the Iran petroleum contract, with every dollar invested yielding $1.3, alongside the most rapid investment recovery compared to other contracts.
- The study suggests that newer contract models like the IPC should be more financially effective and responsive to market variations, providing stakeholders with critical insights for selecting advantageous contracts.

Received: May 23, 2024; *revised:* June 03, 2024; *accepted:* July 01, 2024

Abstract

The choice of financial regime in oil-rich countries depends on proven reserves, exploration and production costs, geological characteristics, political risks, and oil market conditions. This work introduces contractual components of three contracts Iran petroleum contract (IPC), buyback, and production sharing contract (PSC) using Visual Basic programming language and creates a model structure for a 42-season period scenario with oil prices. Further, modeling based on the parameters of the Shadegan oil field is another innovation of this work. The aim of this research is to investigate the effective indicators in the oil and gas industry contracts based on oil price scenarios. The results show that many of the constraints of the reservoir owner have been modified in the direction of protecting oil fields and effectively controlling contractor's fees in modified mutual agreement and production sharing contracts. The financial system of the new oil contracts is also more efficient in case of an oil price increase and in the final years of production compared to production sharing and buyback contracts. Comparing indicators such as net present value, payback period, profitability index, and the share of both parties in the contract based on real and simulated data shows that entering new oil contracts in Iran, especially IPC in the Shadegan oil field, can protect the oil field, prevent uncontrolled oil extraction, and control

* Corresponding author:

Email: gh.emamverdi@iau.ac.ir

contractor's revenues, leading to lower costs and higher revenues compared to buyback and production sharing contracts for the host country (Iran).

Keywords: Buyback contract, Fiscal regime, Modern petroleum contract, Production sharing contract, Iran petroleum contract

How to cite this article
Abooshahab, L., Hamidian, M., Jafari, S. M., and Emamverdi, Gh., Petroleum Profitability through Comparing the Financial Structure of Oil Contracts and Determining the Appropriate Contract: IPC, PSC, and Buyback , Petroleum Business Review, Vol. 8, No. 4, p. 17–33, 2024. DOI: 10.22050/pbr.2024.459019.1335

1. Introduction

One of the important issues in the recent century is the rules and regulations governing the exploitation of oil and gas resources, which have long been a focal point for governments and oil companies on an international level. Oil, consisting of crude oil, natural gas, and gas condensates, is a special and strategic commodity that cannot be placed in the same category as other goods. Oil is of great importance for all countries, whether producing or consuming. Oil-producing countries are increasingly dependent on oil production and the revenues generated from it, and any interruption or reduction in the injection of oil dollars severely damages their economy. On the other hand, the civilization and economic prosperity of industrial and consuming countries rely on energy supply. Around 70% of the world's energy needs are met through oil and gas, and currently there is no hope for reducing the share of oil and gas in the world's energy basket (Keshavarz et al., 2021). Oil-rich countries need capital, knowledge, and management from consuming countries to extract their oil and gas resources, and in return, consuming countries need to invest and participate in these countries to ensure a stable energy supply. Therefore, foreign investment in oil and gas not only aims to generate income but also considers other benefits.

According to many politicians and legal experts, the issue of selecting the framework for contracts in oil investments has always been controversial and contentious. The history of oil contracts in recent centuries shows that oil contracts have been a symbol of the conflicting interests between foreign oil companies and the national interests of the host countries (Bramki et al., 2020).

This financial system of contracts determines how the revenues and incomes resulting from the implementation of an oil contract are divided between the oil-rich government and international companies. Therefore, the financial system must be designed in a way that firstly achieves the economic goals of the host government and maximizes its interests. On the other hand, the financial system must control the profits of the oil company and be attractive enough to encourage investment (Tordo, 2007).

Iran holds the top position globally regarding its oil and natural gas reserves (Farimani et al., 2020). Different countries design fiscal regimes for petroleum contracts to generate revenue from this sector, considering both tax and non-tax elements. The designed fiscal regimes should balance extracting income from the oil sector and retaining oil companies in the business (Banda, 2023). However, achieving this goal is not easy. The structure of fiscal oil regimes heavily depends on the models used in the contract design process (Banda, 2023), and fiscal regimes are determined by how oilfield revenues are divided, costs are recovered, and profits and taxes are paid (Mian, 2011). Countries with different contracts and agreements may have different fiscal regimes (Pedra, 2020). In this case, the main efficiency differences in contracts arise from fiscal regimes; therefore, evaluating and comparing the budgetary environment of oil contracts is crucial. This topic is crucial for countries whose economies highly depend on oil and gas (Feng et al., 2024). Many factors contribute to the change of fiscal oil regimes over time, including the experiences of oil-producing and oil-consuming countries, changes in oil and gas markets, and changes in a region's beliefs and attitudes (Diouf and Laporte, 2017).

Oil contracts are generally divided into two main categories. The first category consists of concession contracts, in which governments grant companies the right to exploit an oil reservoir in exchange for royalty and taxation. As the ownership of the oil reservoir is transferred to the contracting party in these contracts, some countries have legal obstacles to entering such agreements. The second category includes production sharing contracts (PSCs) (Jolai and Zamani, 2022). Service contracts constitute the third type of oil contracts; the contractor cannot become the reservoir owner or producer in these contracts. Instead, they can recover their expenses and remuneration from the proceeds of oil sales. Such contracts are prevalent in Iran, Venezuela, Mexico, Kuwait, and Angola (Feng et al., 2024). A buyback contract is a type of service contract that has been the main framework for developing Iran's oil and gas fields for over a decade. At least 25 contracts based on this method have been signed between the National Iranian Oil Company (NIOC) and Oil Industries' Commissioning and Operation Company (IOCs) for the development of Iran's oil and gas upstream projects (Marcel, 2006). It is, therefore, crucial to ensure that the fiscal regimes of contracts are designed and interacted with accurately. Although fiscal regimes may seem similar in structure, they can have varying impacts on oil projects and the distribution of profits between the government and the investors. It is important to note that economic calculations related to oilfields are highly uncertain and unstable, requiring careful consideration. When all revenue and cost data are disclosed, and the field is left, the computations conducted are considered trustworthy. It is crucial to have complete information regarding revenues, costs, taxes, and royalty payments throughout the field's lifespan to accurately measure profitability and profit-sharing. Moreover, revenue anticipation and project lifetime estimation are required for measuring economic and financial variables (Kaiser, 2007).

Recent studies have conducted a comparative analysis of oil contracts from legal and economic perspectives, yielding valuable insights. For example, Diouf and Laporte (2017) aimed to investigate the possibility of host governments revising their upstream fiscal regimes following a crisis and, if so, the immediate measures they might undertake. This research focused on 10 prominent oil-producing nations, encompassing Organization for Economic Co-operation and Development (OECD) countries and emerging markets, all seeking international investment. Despite encountering similar commercial and technical challenges, different countries exhibited varied fiscal reactions based on several factors. These factors encompassed the design of the fiscal regime, the industry's pre-crisis resilience, and the degree of economic dependency on oil revenues (Diouf and Laporte, 2017). Further, Kohan Hoosh Nejad et al. (2018) concluded that real value is one of the key criteria governments and contractors consider when comparing fiscal regimes in agreements. Furthermore, they demonstrated that using the net present value (NPV) for contractors in production sharing contracts instead of calculating the payback period (PP) in buyback contracts is a more efficient and cost-effective approach in the Azadegan oilfield. A study performed by Ramírez-Cendrero and Wirth (2024) examined the impact of financial incentives on Brazil's oil trade. The conflicting objectives of maximizing profits for oil companies (contractors) and the government's goal of ensuring long-term national interests and safeguarding the country's oil resources were examined. This was considered the primary reason for contract cancellations, revisions, and renegotiations. Currently, a study explored the optimal financial regime in oil contracts for Caribbean countries (McLean, 2023). It suggested that governments can protect their oil reserves and achieve desirable financial benefits by controlling and incorporating elements such as price trends or price stabilization, royalties, and taxes in the financial regime of upstream contracts.

Herein, considering all the embedded mechanisms in the financial regimes of three types of contracts available in Iran and simulating the financial aspects of all project phases, including the internal rate of return (IRR), the payback period, the profitability index (PI), we aimed to calculate the cash flow of the parties annually. Subsequently, it becomes possible to examine the effects and consequences of different scenarios on the contract parties by simulating the finances of all three contracts. To simulate the financial model of the contract, we utilized technical information related to the second phase of Shadegan field development as a case study using the Visual Basic programming language (VBA) for coding the contract data. One of the most notable features of VBA coding is transparency in calculations and the absence of any black box, which facilitates the verification of the results.

2. Literature review

This study used technical information related to the second phase of Shadegan field development as a case study. Shadegan field was discovered by drilling Well No. 1 in the Asmari reservoir in 1968. The field is located in the southwest of Ahvaz, Iran, and spans approximately 5.23 kilometers in length and 5.6 kilometers in width. It consists of two reservoirs: Asmari and Bangestan. The field production started in 1988, and it currently produces around 83,000 barrels of oil per day using 32 wells. Technical and economic information of the field is extracted by exploration and production companies that have comprehensive and in-depth studies in this area. Then, consulting companies simulate this data and information using reservoir simulation software to prepare master development plan (MDP) reports presented to the oil company.

The main assumptions of the model were the following: contract duration; the timing of exploration, development, and production phases; oil price growth in each period; production profile; natural decline rate; and payback period for capital expenses. These assumptions were considered inputs and adjusted within the model structure. The model was executed by evaluating the technical characteristics of the Shadegan field development phase.

In financial simulation, all phases of the project, including exploration, description, development, and production, are taken into account, and the cash flows of both parties are calculated seasonally considering all embedded mechanisms in the financial regime of the contract.

The common assumptions in the reference scenario regarding timing, costs, production, and prices are as follows. The values for pessimistic and optimistic oil prices scenarios are also provided in Figure 1.

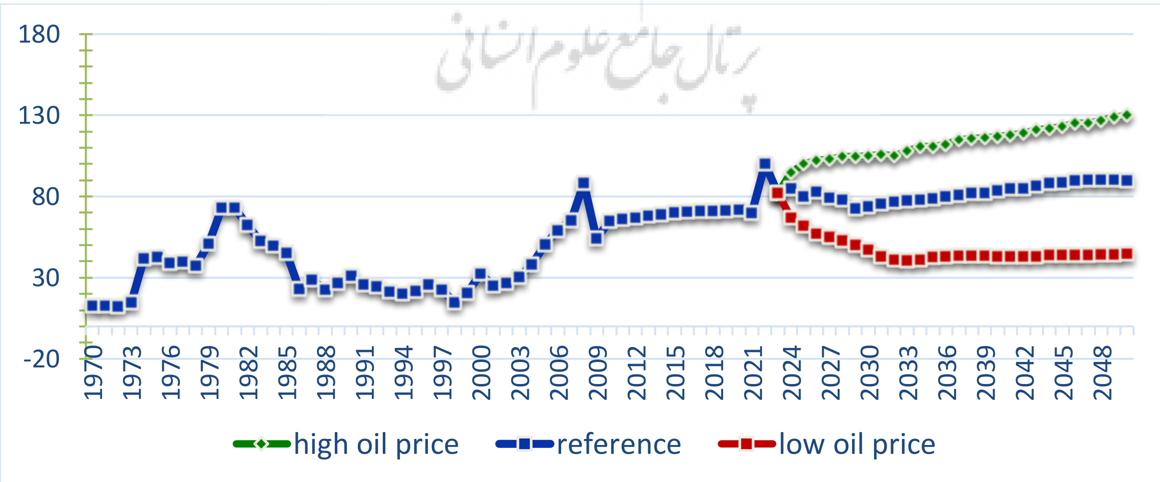

Figure 1

Oil price in three scenarios: the highest possible price, the lowest possible price, and the standard (medium) price

Table 1 shows that a minimum of a 12-year contract is required with a 10-year development period to reach a production of 140,000 barrels per day, which is one of the assumptions of this research for the development goals of the Shadegan field. Additionally, the amount of operational expenditure (OPEX) and capital expenditure (CAPEX) costs, the ramp-up production increase, and the plateau period are specified to achieve the stated goal (Table 1).

Table 1

The shared presumption in the reference scenario

Criterion	Unit	Number	Criterion	Unit	Number
Contract length	Season	42	Investment cost (CAPX)	Million Dollar	938
Development period length	Season	20	Operating expenditure (OPEX)	$/barrel	5
Base production	1000 barrels per day	83	Indirect costs	% Of capital expenditures	20%
Production enhancement	1000 barrels per day	140	Interest rate (banking cost)	%	2%
Ramp-up	%	14%	Added bulk production	Million barrels	440.5
Plateau length	Season	24	Added bulk production	Million barrels	1353.5

We considered three scenarios for oil price trends based on the data derived from Bloomberg[*], BP reports[†], Platts[‡], and EIA[§] to analyze the economic evaluation for a wide range of oil prices. This analysis considered three different pricing scenarios: the standard (medium) price, the highest possible price, and the lowest possible price, as depicted in Figure 1.

2.1. The financial simulation model of the contract

In the IPC contract, the overall project returns for the government and the contractor are calculated as follows:

$$\sum Y_t^{HG} = \sum \{P_t Q_t - [(1-sp)(P_t.Q_t.RI_{t-1}.A) + \frac{DCC_t - DCC_{t-\tau}}{\tau} + IDC_t + COM_t \text{-} CF_t]\} \tag{1}$$

$$\sum Y_t^{FOC} = \sum \{(1-sp)\phi_t (P_t.Q_t.RI_{t-1}.A)\text{-}CF_t\} \tag{2}$$

Considering that the ceiling for the repayment of contractor claims in each period should not exceed a certain threshold (P_tQ_t), the total payment to the contractor in each period is calculated as follows:

$$TP_t = (1-sp)\phi_t(0) + (DCC_t - DCC_\tau)/\tau + IDC_t + COM_t)\text{-}CF_t \le \varphi P_t Q_t \tag{3}$$

A notable point in the IPC contract is that the contractor's return rate cannot exceed 17%. Therefore, the following relation must always be maintained in relation to the contractor's total cash flow:

[*] Bloomberg.com/energy//nwcouncil.org/sites/default/files/FUELMOD7_2__Rev_092309.xls
[†] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/xlsx/energy-economics/energy-outlook/bp-energy-outlook-2022-chart-data-pack.xlsx
[‡] Spglobal.com
[§] EIA.gov//forcasts/aeo/section_prices.cfm

$$Total\ Cash\ Flow_{FOC} = \sum_{t}^{N}(COM_t + Fee_t) \leq 17\% \quad (4)$$

The parameters used in IPC fiscal regime are reported in Table 2. According to this table, the contractor’s repayment in the IPC contract is 50% of the additional production. In case of a decrease in the price of oil from \$50, the number of wages paid to the contractor will be 81.5% of \$3.09, and in case of an increase in the price of oil to \$90, the wages will be adjusted upward and will increase for each barrel paid.

Table 2

The parameters of the IPC fiscal regime

Description		Value	
Base wage (fee per barrel)		\$3.09	
Cost recovery limit		50%	
Capital distribution period of the season		16	
Bank cost rate		2%	
Wage adjustment based on oil price		Price	Wage adjustment
	Interval 1	50>	81.5%
	Interval 2	70	100%
	Interval 3	>90	118.5%
Wage adjustment price based on IRR MAX		17%	

Production sharing contracts are divided into two categories: exploration and production sharing agreements (EPSA) and development and production sharing agreements (DPSA) (Kohan Houshmand et al., 2018). The income that an oil company can earn from this source, when $\sigma = 1 - \alpha - rp$, is given by:

$$TR = \sigma(1 - X)(1 - i)PQ \quad (5)$$

The net income received by the oil company in the production stage of production sharing contracts is calculated as follows:

$$Net\ Income = CR - Tax \quad (6)$$

where $CR = X(1 - i)$, PQ represents the income from cost recovery, considering the variables X, i, P, and Q. $Tax = t\sigma(1 - X)(1 - i) \times PQ$ denotes the amount of tax received by the government. Therefore, the net income received by the oil company in the production phase of the PSC contract equals:

$$GR_T = CR + TR - Tax - BC = (1 - i)[X + \sigma(1 - i)(1 - t)]P \quad (7)$$

The parameters related to the fiscal regime of the PSC based on the studied model are presented in Table 3.

Table 3

The parameters of the PSC fiscal regime

Description	Value
Royalty rate	15%
Cost recovery limit (after deducting royalty rate)	50%
Income tax	

Description	Value
Corporate income tax rate	25%
Capital depreciation period (year)	5
Government shares of oil profit (factor *R* in the first slide)	50%

The variables required to calculate the gross field income in a mutual buyback contract are presented in Table 4.

Table 4

The parameters of the buyback fiscal regime

Description	Value
Contractor fee	10%
Cost recovery limit	60%
Bank cost	7.7%
Capital depreciation period (year)	5

In the event of early production, the contractor initially recovers the operational and maintenance costs associated with early production. As a result, the gross field income is calculated by subtracting the operational expenses from the following formula:

$$GR_t = P_tQ_t - (O_C \,\&\, M_C)_t \tag{8}$$

The following equation is used to calculate the total investment of the contractor (I_t), which includes both capital expenditure and non-capital expenditure, from 0 to N':

$$\sum_{t=0}^{N'} I_t = \sum_{t=0}^{N'} C_t + \sum_{t=0}^{N'} XC_t \tag{9}$$

where C_t is the capital expenditure, and XC_t indicates the non-capital expenditure in period t.

Cost recovery included the recovery of capital costs (RC_t), the recovery of non-capital costs (RNC_t), and banking costs (BC_t). The RC_t was obtained by dividing the total capital costs incurred until the end of the development phase by the total repayment period. The RNC_t was calculated by dividing the total non-capital costs incurred until the end of the development phase by the total repayment period. The *BCt* was assessed every month, with the accrual date being the first day of the month, after which the contractor incurred the capital and non-capital costs.

After calculating the cost recovery, the remuneration (*Remt*) was calculated and added to *PCRt* to determine the total claim.

$$TR_t = PCR_t + Rem_t = (R_C)_t + (R_{NC})_t + (BC)_t + Rem_t \; (N' < t < N'') \tag{10}$$

It is worth noting that the contractor’s claim ceiling in each period was 60% of the revenues generated from the field in that period. In other words, the total payment to the contractor in each period should be less than 60% of the total field income in that period (Ghandi and Lin, 2012).

$$TR_t = \theta GR_t \qquad \theta < 60\% \tag{11}$$

As a result, the government's minimum share in each period was 40% of the income in that period. Therefore, based on the mentioned equations, the government's receipts over the lifetime of the mutual buyback contract were calculated using the following formula:

$$\begin{aligned}\sum_{t=EP}^{t=EC} HGR_t &= \sum_{t=EP}^{t=EC} (GR_t - TR_t) \\ &= \sum_{t=EP}^{t=EC} (P_t Q_t - (OPEX_t + (RC)_t + (B.C)_t + Rem_t))\end{aligned} \tag{12}$$

where early production (*EP*) represents the host government's receipts (HGRs), *HGR* indicates the early production period, and end of contract (*EC*) denotes the end of the contract.

2.2. Indicators used in the model: government share

An essential aspect of evaluating a financial regime is its government share (*GT*). Government share is a part of the project's economic profit, which is an essential indicator for evaluating the fiscal regime of petroleum contracts. According to the definition presented by Humphreys et al. (2007), *GT* is defined by:

$$GT(\%) = \frac{total\ government\ revenue\ and}{total\ economic\ profit\ of\ the\ project} \tag{13}$$

Moreover, this index in modern petroleum contracts was measured as follows:

$$GT = \frac{\sum_{t=FDP}^{t=ELF} P_t Q_t - \sum_{t=FDP}^{t=EC} TR_t - \sum_{t=EC}^{t=ELF} (O\&M)_t - A}{\sum_{t=FDP}^{t=ELF} P_t Q_t - \sum_{t=FDP}^{t=ELF} (O\&M)_t - \sum_{t=0}^{t=EC} DCC_t - \sum_{t=0}^{t=EC} IDC_t} \tag{14}$$

In the new oil contracts, the government receives the government share of the cumulative revenue from the project economic profits until the end of the economic life of the field. The deduction amount represents the total amount received by the government during the economic life of the field, which is obtained in each period from the difference between the gross income of the field and the payment to the contractor in the new oil contract formula explained in Equation (3). The denominator of the equation is the economic profit of the project over the economic life of the field with project cumulative costs, including exploration and evaluation costs, direct capital and non-capital costs, and operational costs until the end of the economic life of the field. Here, the final time in calculating the host government's share is the economic life of the field. In cases where the contract is extended for full settlement with the contractor upon completion, *A* in the formula is greater than zero, and its value is adjusted by the amount outstanding at the end of the contract plus the cost of money transferred to the subsequent periods after the end of the contract. If at the end of the contract all expenses and contractor fees have been fully reimbursed, *A* equals zero.

3. Methodology

3.1. Sharing revenue and cost between parties

Figure 2 displays the production profile and development results of Shadegan field. As mentioned, the current production of the field is 80,000 barrels per day, and the development goal is to reach a production of 140,000 barrels per day. The red line represents the FOB production base for the contractor calculations. The blue line represents the duplication base, indicating that if this plan is not implemented, well production will decline. The green line represents the ramp up and plateau period, showing that production will be consistent for 24 seasons. In some IPC contracts, if the contractor can accelerate reaching the plateau period, they can use the difference between the blue and green lines as a basis for payment. However, typically, the basis for payment to the contractor in IPC contracts is 50% of the additional production added to the field, which is the 50% produced between the red and green lines in Figure 2.

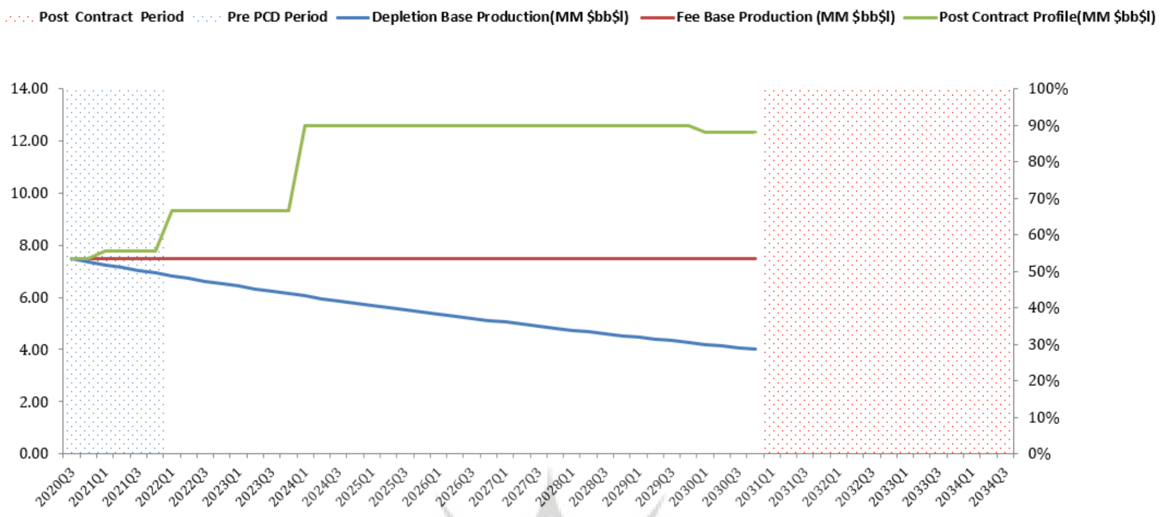

Figure 2

Fee base production: the distance between the red and green diagrams as the fee calculation base

It should be noted that repayments do not start from the beginning of the contract and increase with production in IPC contracts. Instead, once production reaches a certain level called first target production (FTP), payments to the contractor begin. This period is determined in the pre PCD-period. The post contract period is the period after the contractor's contract, during which some of the repayments remain to be made to the contractor, and the host country is obligated to repay all contractor debts, which include all the financial receipts and payments of this project. The bars above the input line represent the contractor's receipts, and the bars below the output line represent the contractor's cash outflows. It is evident that with an increase in production, which is assumed to be $5 per barrel, costs are increasing. In terms of timing cost recovery expenses, it is after an initial period that the contractor incurs costs and reaches the FTP point. Payments to the contractor begin at this point, as shown in Figure 4a by a tall blue bar representing the first payment. This is the same season where FTP happens (see Figure 4a). Figure 4b depicts the share of both parties in the field income, where the blue area represents the government's share as the owner of the reservoir in the field income.

Similarly, Figures 4d and 4e illustrate the cash flow of the input and output for the buyback and PSC contracts, and Figures 4c and 4f show the division of field revenue between the contractor and the host country.

One of the key characteristics of oil contracts is the flexibility or "scalability" of the contract, indicating that with an increase in revenue, the project's profitability should increase for both parties, not just one (Lirong et al., 2022). This is particularly important in high-risk industries such as the oil and gas sector. While in other industries, companies receive a fixed amount from the government after selling their goods or services, in the oil and gas industry, international oil companies typically receive their rewards through participating in a portion of the revenues, profit sharing, or a combination of these factors (Al Jabri et al., 2022). The main reason for this fundamental and significant difference is the high risks involved in oil activities (Algozhina, 2022).

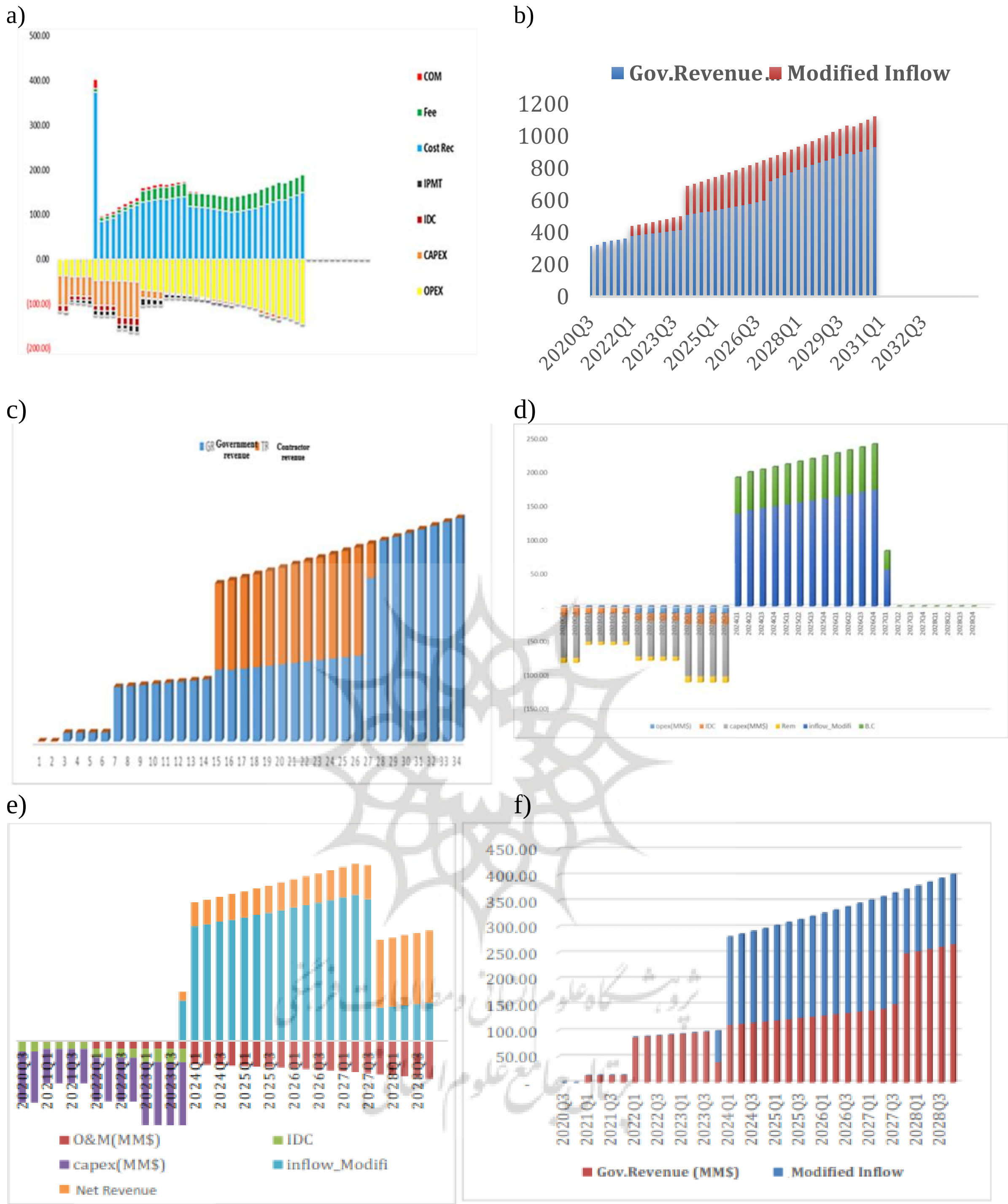

Figure 4

a) The cashflow of the project under IPC, b) the sharing of the IPC contract revenue, c) the cashflow of the project under buyback contracts, d) the sharing of buyback contract revenue, e) the cashflow of the project under PSC, and f) the sharing of the PSC contract revenue

Since expenditures and fees are predetermined at a constant rate before the onset of repayments under the buyback contract, the effect of oil price is manifested as follows. If the oil price decreases due to any reason, exceeding the allowed contract ceiling, the contractor's repayment is transferred to subsequent periods, and the contractor's profit decreases. Conversely, when oil prices rise, the contractor's sole positive outcome is the timely recovery of expenditures and receiving a fixed price. In addition, the cash flows for the IPC and PSC fiscal systems show that an increase in oil prices results in a rise in the contractor's profitability under the PSC system. However, this profitability remains within a specific threshold under the IPC system, even with a rise in oil prices. In terms of the cash flow and different oil price scenarios, modern oil contracts are more desirable for reservoir owners than PSCs and buybacks.

The comparison between the financial regimes of all three contracts in Figure 4 shows that in terms of income realization timing for the government compared to the project cash flow, the government income is higher in the initial years and lower in the middle years in the IPC contract. Toward the end of the contract, the government income is approximately the same in all three regimes. Therefore, it can be stated that the recovery of the contractor expenses occurs in the PSC and buyback regimes, which may reduce the attractiveness of the IPC contract for the contractor.

3.2. Financial and economic indicators in IPC contracts

This study assessed contract fiscal performance using NPV, IRR, and PP. The NPV of the IPC contract at the base price is 288.13; in contrast, buyback and PSC contracts feature shorter intervals, pegged to fees and oil profits, respectively. Profitability index indicates a $1 IPC investment yields $1.30 profit. Financial calculations show a 24-month PP comparison in Figure 5a. Additionally, the contractor's cash flow shifts from negative to positive after 25 months.

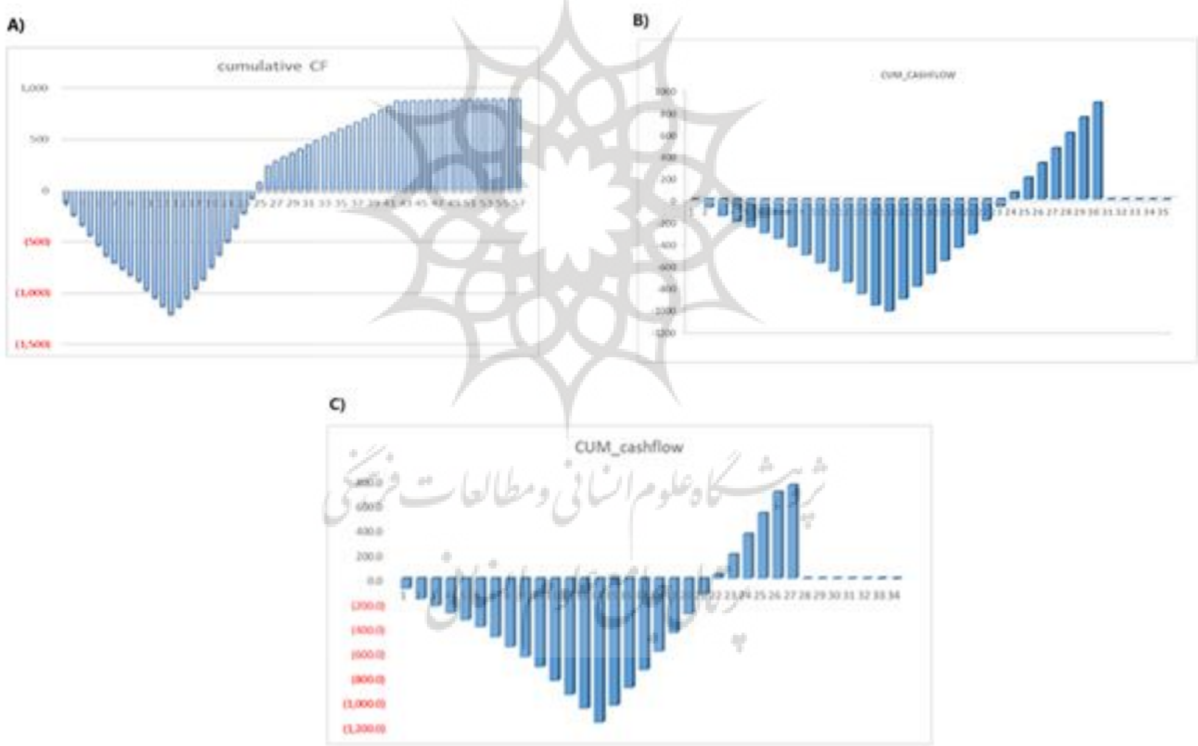

Figure 5

The payback period index in IPC (a), PSC (b), and buyback contract (c); the change in the direction of the blue rod indicates a month in which the contractor's cash flow changes from negative to positive.

3.3. Financial and economic indicators in buyback contract

The NPV of the buyback contract reached 209 based on its evaluated performance. As previously stated, buyback and PSC contracts consider shorter classification, which serves as the fee base in buyback contracts and oil profit in PSC. Additionally, neither of these contracts considered any measures to safeguard oilfields or implement methods for enhanced recovery. In a buyback contract, the profitability index equals 1.28 per $1 investment. In Figure 5c, the PP index in the buyback contract shows a decrease in the contractor's share of boosted oil production from 28% to 14% in correlation with an increase in oil prices.

3.4. Financial and economic indicators in PSC contract

As a result of the oil price rise, the government's revenue in the PSC increases from 54% to 67%, while contractor's revenue decreases to 33%. The NPV of the PSC reaches $200 million, and the PP index for the PSC contract is $1.24 per $1 invested. Figure 5b shows that the PP index within the PSC is equivalent to 24 seasons, with cumulative cash flow signals beginning in the 18^{th} month when there is a rise in oil.

Table 5 lists the summary of the results from the fiscal modeling of the three contracts.

Table 5

The base price scenario

Oil contract	government share (GT)	IRR (%) monthly	NPV (MM$)	PP	PI
IPC	Employer's share of enhanced oil recovery (MM$): 51%	4.00%	288.13	25 seasons	$1.30 profit per $1 investment
PSC	Employer's share of enhanced oil recovery (MM$): 54%	4.00%	200	24 seasons	$1.24 profit per $1 investment
Buyback	Employer's share of enhanced oil recovery (MM$): 71.9%	4.00%	209	22 seasons	$1.23 profit per $1 investment

Additionally, capital expenses in mutual benefit contracts are capped, which creates a competition between foreign oil companies to increase costs while the National Iranian Oil Company monitors and controls these expenses. IPC, on the other hand, is a long-term contract encompassing all production stages and can maximize production over the field's life and achieve sustainable production. However, the IPC contract still suffers from a flawed tax system. Furthermore, comparing the share of foreign contractors based on the current net value received in the Shadegan field project shows that signing IPC contracts could be more desirable and cost-effective for the host country (Iran) compared to buybacks and PSCs. The IPC resembles buyback in its service-oriented approach, where the contractor's fixed fee is unrelated to oil prices. In contrast, the production sharing contract links the contractor's income directly to oil prices, affording new oil contracts and greater host country's revenue.

Future scenario modeling indicates the superior efficiency of new oil contracts compared to production sharing contracts and buybacks. In buybacks, fixed costs are impacted by oil prices only when falling beyond limits set in the contract, delaying the contractor reimbursements and reducing profits. Cash flow trends reveal PSC contractor profit increasing with rising oil prices. Profitability index favors IPC at $1.3, production sharing contract at $1.24, and buyback contracts at $1.23 per dollar invested. Payback periods vary, turning positive after 25 months in IPC, 24 months in PSC, and 22 months in buyback. Net present values also favor IPC over production sharing contracts and buybacks at base oil prices. For new oil contracts, enhanced oil recovery operations could lead to negative cash flows due to incurred expenses.

4. Results

In oil contracts, precise design and interaction among different elements play an important role in the financial regime. Some financial regimes may have seemingly similar structures, but their impact on oil projects and the profit sharing between the government and the investor can be completely different.

On the other hand, different structures and financial regimes can achieve similar results in terms of revenue and profit sharing. However, despite this diversity, there are a few economic principles that can guide us when evaluating or designing a financial regime. Of course, the experience of countries in this regard is very important. The main indicator for providing a general comparison of financial regimes is the profit sharing between the parties of the project, defined as their share of the total net present value of revenues as a share of pre-tax revenues (Nakhla, 2010). Therefore, this study intends to calculate the current value of the profit sharing percentage of the foreign contractor in the Shadegan oil field buyback and PSC and compare it using simulation techniques with an IPC. A significant question to consider was whether global petroleum corporations exhibited a preference for a particular oil contract type based on fluctuating price trends and future price forecasts. Additionally, it was worth pondering whether their predictions regarding the future direction of global prices influenced their contract selection or emphasis on a specific contract type.

In buyback contracts, capital repayment converted to oil varied with market prices. Contractors received more oil when prices were low, and less when high. In PSCs, contractors obtained a fixed oil percentage, risking losses if prices fell compared to the contract, which could lead to less profit than buyback contracts. Unlike buyback, PSCs offered higher profit potential with increased oil price, avoiding market fluctuations (Li et al., 2017).

In the case of PSCs, there was a relationship that some experts did not view as favorable. They argued that petroleum companies tended to favor PSCs since they could receive revenue as a barrel of oil. This meant that an increase in oil prices would result in higher revenue for them. However, others argued that since these companies took on the risk of oil price declines in PSCs, they should also benefit from any increase in revenue resulting from oil price increases (Ghandi and Lin, 2012). Petroleum companies often do not see a significant increase in profits when oil prices rise. Their share is limited, reducing significantly with an increase in oil prices. Collaborating with other petroleum companies to benefit from oil price increases can vary depending on the situation. However, according to the Ghandi et al. (2012), there is no logical reason for petroleum companies to receive even a 1% share of the profit from a rise in oil prices. Despite IPC's benefits, declining oil prices could decrease the contractor's IRR, revealing the limited financial flexibility of IPC compared to PSCs. IPC addressed PSC weaknesses, especially in high oil price periods. In PSCs, revenue stayed fixed after a threshold, while the revenue of the IPC gradually fell with rising oil prices. PSCs constrained the contractor's profit with oil price hikes and had lower and decreasing PP levels compared to the IPC at various oil prices. In the IPC, oil price thresholds led to reduced PP, impacting appeal. The government share in IPC was lower due to oilfield safeguarding, raising price from 71% to 85%. This highlighted the potential inefficiency of IPC compared to buyback contracts, representing significant value for employers.

Feng et al. (2024) developed a model comparing investment and production in two oil contract types. Their findings showed that PSCs encouraged higher investment than buyback contracts, and investment rose with IOCs' involvement in buyback contracts. Optimal oil production depended on IOCs' PSC share and government's buyback operating costs. Low IOCs' share or costs favored buyback, while PSCs excelled in other cases. The study also explored optimal revenue distribution by host governments, highlighting ratios for maximizing oil revenue. Discount factors and oil prices positively influenced investment and production across both contract types (Feng et al., 2024). Sahebhonar et al. (2017) conducted a study to evaluate the impact of financial contract components on variables such as the internal rate of return, payments received, price, and investment volume. They also considered the fixed factors in their analysis.

In contrast, our focus was assessing the financial effectiveness of three common oil contracts in a specific oil field across Iran and other oil-rich countries using financial modeling. We analyzed indicators such as the payback period, the net present value, the profitability index, and the internal rate of return for contractors, along with the employer's share as the reservoir owner. We also conducted sensitivity analysis on oil prices. Our findings echoed Soleimani's study, indicating IPCs become less attractive for contractors as oil prices rise, limiting their internal rate of return beyond a threshold (Jolai and Zamani, 2022). Unlike buyback contracts, where income adjusts to market prices, oil contractors in buyback receive fewer installments as prices rise and more when they fall, posing risks due to oil price fluctuations. Hence, production sharing contracts could be more advantageous and cost-effective for reservoir-owning countries compared to buyback contracts. Talebian Moghaddam et al. (2023) showcased disparities between profit accumulation and incremental production in varying contract regimes, revealing a government–contractor mismatch. Examining the economic aspects of the IPC and PSCs, such as the wages, the repayment period, cost recovery ceiling, the interest rate, ownership, and government share in oil profits, we found that reducing IPC cost recovery ceiling did not increase incremental production. Moreover, raising the government's share and cost recovery ceiling negatively impacted total production in PSCs.

5. Conclusions

The financial regime of a country is the product of balancing the interests of the host government and international companies. Oil-producing countries have used financial regimes with various characteristics and proportional to economic, political, and social conditions and expectations of oil prices. They can use a range of options in selecting and designing a financial regime within the chosen financial and contractual framework that is suitable for their country's conditions and goals. In this work, we compared the financial regimes of buybacks and PSCs with the IPC. The evaluation and comparison of the mutual benefit contract with the IPC from the perspective of economic efficiency of the financial regime, i.e., maximizing production from the field, maximizing the government's share of oil, the tax system, risk-to-reward balance, and cost reduction, show that mutual buybacks still have intrinsic flaws despite passing three generations. The short-term nature of these contracts causes contractors to bring maximum production during the depletion period to recover their oil costs and fees. Therefore, the reservoir is at serious risk. In such contracts, operation management, development rests with the contractor, and operation production is in charge of the National Iranian Oil Company. Due to the absence of necessary infrastructure and access to modern technology, optimal production from wells is jeopardized. In the mutual benefit tax system, relevant taxes are paid by the contractor and repaid as non-capital expenses.

Summarizing the results obtained herein concludes that although it is possible to adjust the parameters of all three contracts in such a way that the same results are obtained in static conditions, changes in economic conditions can have different effects on each of these three financial regimes due to some restrictions specified in Iran's petroleum contracts such as the installment of capital costs and the lack of direct connection between contractor's wages and field income. Regarding the lack of direct connection between contractor's wages and oil prices, increasing the base reward rate can compensate for this decrease in attractiveness. Nevertheless, this does not seem very desirable because foreign companies only benefit significantly higher profitability in case of a sharp increase in prices in the production sharing financial regime. Therefore, if the National Iranian Oil Company representing the government wants to maintain the attractiveness of the contract in case of an increase in oil price, the base wage rate must be set high from the beginning. Then, in this case, the risk of no increase in price is borne by the government, and the contractor will still receive a profit rate higher than the usual during the contract period even if the price does not increase. This work only compared the financial consequences of the three contract financial regimes, and economic indicators such as the net present value, the profitability index, the payback period, and other related factors were calculated and compared. As stated, the ultimate conclusion is that the attractiveness of production sharing contracts in terms of financial and economic indicators is higher, and in the absence of fundamental legal issues and contract type constraints, using such contracts can lead to attracting more capital. Therefore, it can be mentioned that PSCs are more attractive for attracting capital and foreign contractors compared to IPC and buyback contracts. On the other hand, buyback contracts will generate more income for the host country. Because both objectives must be considered in the context of contracts, we can conclude that IPC can create a balance for the host country to attract investment and achieve the desired income from the field.

6. Funding details

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

7. Declaration of interest

None.

Nomenclature

CAPEX	Capital expenditure
IPC	Iran Petroleum Contract
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating expenditure
PSC	Production sharing contract

References

Al Jabri, S., Raghavan, M., Vespignani, J. (2022). Oil prices and fiscal policy in an oil-exporter country: Empirical evidence from Oman. Energy Economics, 111(1), 106103–106114. DOI: 10.1016/j.eneco.2022.106103.

Algozhina, A. (2022). Monetary policy rule, exchange rate regime, and fiscal policy cyclicality in a developing oil economy. Journal Energy Economics, 112(1), 106126–106132. DOI: 10.1016/j.eneco.2022.106126.

Banda W. (2023). A system dynamics model for assessing the impact of fiscal regimes on mining projects. Resources Policy, 81(1), 103408. DOI: 10.1016/j.resourpol.2023.103408.

Bramki Yazdi, H, Manzour, D, and Shadkar, M. (2020). Optimization of upstream oil and gas contracts: Principal-agent model. Journal of Economic Research, 20(76), 187–222. doi: 10.22054/joer.2020.11904.

Diouf, A., Laporte, B. (2017). Oil contracts and government take: Issues for Senegal and developing countries. J. Energy and Dev, 43(1), 213–222. URL: https://heinonline.org/HOL/LandingPage?handle=hein.journals/jeldv43&div=14&id=&page=

Farimani, FM., Mu, X., Sahebhonar, H., Taherifard, A. (2020). An economic analysis of Iranian petroleum contract. Petroleum Science, 17(1), 1451–61. DOI: 10.1007/s12182-020-00486-2.

Feng Z, Zhang SB, Gao Y. (2014). On oil investment and production: A comparison of production sharing contracts and buyback contracts. Energy Economics, 42(1), 395–402. DOI: 10.1016/j.eneco.2014.01.010.

Ghandi, A., Lin, CY. (2012). Do Iran's buyback service contracts lead to optimal production? The case of Soroosh and Nowrooz. Energy Policy, 42(1), 181–190. DOI: 10.1016/j.enpol.2011.11.070.

Humphreys, M., Sachs, J., Stiglitz, JE., (2007). Editors. Escaping the resource curse. Columbia university press.

Jolai, F., Zamani, F. (2022). Dynamic Reservoir and Stochastic Oil Pricing Model of IPC Contracts: Optimizing and Sensitivity Analyzing. Journal Industrial Management, 14(1), 143–167. DOI: 10.22059/imj.2022.328510.1007857.

Kaiser, M. J. (2007). Fiscal system analysis—concessionary systems. Energy, 32(11), 2135–2147. DOI: 10.1016/j.energy.2007.04.013.

Keshavarz, M., Iranmanesh, H., Dehghan, R. (2021). Modelling the Iranian Petroleum Contract fiscal regime using bargaining game theory to guide contract negotiators. Petroleum Science, 18(6): 1887–98. DOI: 10.1016/j.petsci.2021.09.018.

Kohan Hoosh Nejad, R., Manzoor, D., Amani, M. (2018). Economic Evaluation of Fiscal Regime of Buyback Contracts in Comparison with Production Sharing Contracts (Case Study: Azadegan Oil Field). Journal Iranian Economic Review, 22(2), 579–598. DOI: 10.22059/IER.2018.66167.

Li, C., Jiang, M., Ge, H., Li, Z., Luo, D. (2017). An operational risk analysis of Iran Buyback contract and its policy implication. Energy Strategy Reviews, 16(1), 43–53. Doi: 10.1016/j.esr.2017.02.003.

Lirong, D. O., Kunye, X. I., Yebo, D. U., Li, W. A., Zhang, X., Cheng, D., Ying, H. (2022). Exploration discovery and hydrocarbon accumulation characteristics of the Doseo strike-slip and inverted basin, Chad. Petroleum Exploration and Development, 49(2), 247–256. DOI: 10.1016/S1876-3804(22)60021-1

Marcel, V. (2006). Oil titans: National oil companies in the Middle East. Brookings Institution Press. URL: https://www.jstor.org/stable/10.7864/j.ctt12879z9.

McLean, S. (2023). Exploring the elements of an optimal hydrocarbon fiscal regime. Repositorio. URL: https://repositorio.cepal.org/handle/11362/48720.

Mian, M.A. (2011). Project Economics and Decision Analysis, Vol. 1: Deterministic Models. 2nd Edition, PennWell Publishing Co., Tulsa. URL: https://www.scirp.org/reference/referencespapers?referenceid=1634022.

Nakhle, C. (2010). 4 Petroleum fiscal regimes: evolution and challenges. In The taxation of petroleum and minerals (pp. 105–137). Routledge.

Pedra PP. (2020). The Impact of Fiscal Incentives in the Pre-Salt Oil Business in Brazil. Doctoral dissertation, Universidade Federal do Rio de Janeiro.

Ramírez-Cendrero, JM., Wirth, E. (2024). Oil fiscal regime and national oil companies. The hydrocarbon sector in Argentina 2003–2022. The Extractive Industries and Society, 17(1): 101399–10412. DOI: 10.1016/j.exis.2023.101399.

Sahebhonar, H., Lotfalipour, M. R., Hooshmand, M., Feizi, M. (2017). Comparative Analysis of Fiscal Terms of Iran Petroleum Contract (IPC) and Production Sharing Contract (PSC): Case Study of South Azadegan Field. Quarterly Journal of Applied Theories of Economics, 4(1), 87–118. URL: https://ecoj.tabrizu.ac.ir/article_6108.html?lang=en.

Talebian Moghaddam, H., Shirkavand, S., Dehghan, R., Mohammadi, S. (2023). Evaluating the Impact of Economic Components of IPC and PSC Contracts on Cumulative Production of Oil Fields: A Case Study of Foroozan Oil Field. Quarterly Energy Economics Review, 19(76), 29–56. URL: http://iiesj.ir/article-1-1520-en.html.

Tordo, S. (2007), Fiscal Systems for Hydrocarbons: Design Issues, The World Bank: www. worldenergyoutlook.org, Pages 1–67.