Assessment of Iranian Petroleum Contracts Effectiveness: A Comparative Risk Analysis Approach Using Monte Carlo Simulation

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ABSTRACT

Background of petroleum contracts in Iran unveils different evolutions of arrangements, from Darcy to buy-backs and, more recently, new models called the Iranian Petroleum Contract (IPC). One of the prominent features of petroleum contracts is balancing risk and return between parties. We evaluate the effectiveness of IPC versus buy-back using a comparative risk simulation analysis approach. To this end, five key factors, including capital expenditures' volatility, operating expenditures' variations, deviation from the level of production specified in the contract, crude oil price changes, and alterations in finance cost, were identified as a risk and net present value (NPV) as reward variables. We simulate associations between variables under two buy-back and IPC contractual arrangements and apply the model to one of green oilfield development projects in Iran, as a case study. The distribution forms of project NPV reveal more flexible connectivity between risk-return under IPCs, from the contractor's viewpoint. Corresponding NPVs under IPC's fiscal regime are higher than buy-backs. We conclude that IPCs are more attractive to contractors and more effective in the development of upstream projects in the Iranian petroleum industry.

Keywords:

IPC, Buy-back, Risk Management, Upstream Project, Monte Carlo Simulation.

1. Introduction

Buy-back contracts have been used since the early 1970s to develop upstream petroleum projects in Iran. These are accounted as specific kinds of service contracts in which the contractor recovers operating expenditures (briefly Opex) and capital expenditures (briefly Capex) from the proceeds of the same oil or gas field. Also, the contractor usually undertakes the exploration and development phases and does engage in operation. These contracts provided the Ministry of Petroleum with an opportunity to develop some hydrocarbon fields in the early 1970s (especially the South Pars gas field) due to the low oil prices and the lack of internal resources of the National Iranian Oil Company (NIOC). However, the contracts had significant drawbacks, including high dependence of contractor's fee on Capex, low government supervision on contractor's activities, little flexibility and created many problems for the NIOC in the long run.

One of the key features of petroleum contracts financial regime is to balance risk-rewards of parties as well as align contractor and host government interest. There seems to have not been fully complied with in contracts; since even before the United Nations and the European Union sanctions (2005-2012), no buy-back has been concluded with International Oil Companies (IOC), and the total amount of capital invested in all Buy-back contracts has not exceeded $30 billion. However, according to Iran's Fourth Development Plan, the investment required by the petroleum industry was anticipated by about $60 billion (Derakhshan, 2006), and it has grown across the next five years to over $200 billion in Sixth Development Plan. A significant portion of which must be provided through foreign investments. Therefore, it was indispensable for the country to develop favorable contracts for the attraction of investments and exploiting maximum IOCs capital resources and technologies (Stevens, 2015). To this end, in early 2015, the Ministry of Petroleum (MOP) released a new generation of upstream contracts called IPC. The platform considered as a combination of Buy-back and Production Sharing Contracts (PSC); while maintaining the nature of Buy-backs, IOCs are entitled to take part in proceeds for a specified period. Increasing IOCs considerations using fee per barrel mechanism, extended duration of the contract, and engagement of IOCs into the operation phase are three distinctive features of IPCs. From MOP of viewpoint, a new model contributes to foreign investment attraction, technology & technical knowledge transfer, preserved production, Enhanced/Improved Oil Recovery (EOR, IOR) method, as well as penetrations in international markets through establishing Exploration and Production (E&P) companies.

Although the critical hindrance to IOCs investment in Iran's upstream sector has been the international sanctions, relief seems unlikely to be helpful; because the remaining Iranian oil fields are not very attractive. In the other hand, recent events in the oil market (sharp drop in oil prices, rising risks, tightening of bank lending regulations following the 2008 financial crisis, environmental policies against climate change, etc.) have led to a significant petroleum divestment (Mitchell et al.,2015). In such an environment (assuming revocation of sanctions), investment of IOCs in the Iran petroleum sector will highly depend on inherent risks in new contracts and the contractual terms and conditions of other petroleum competing countries (Stevens, 2015). There are risks, uncertainties, rights, and obligations in petroleum contracts that directly affect the economic interests of investors (contractor) and governments as well as the effectiveness of contracts. This study examines risk-reward connections in Buy-back and IPCs to assess the efficacy of IPCs using a risk management approach. We investigate the effects of financial arrangements on objectives of IPCs considering its risk-reward sharing framework and examine whether IPCs are well-balanced in terms of risk-sharing or not? Given the increased capital costs of major IOCs in recent years and the subsequent decline in stock values, their investment capacity will be limited (Stevens, 2015). The decline in global crude oil prices, which began in mid-2014, has also accelerated the unwillingness of IOCs to conclude service contracts rather than PSCs. Besides, other petroleum countries such as Mexico are expanding the presence of IOCs in upstream oil and gas activities and offering more attractive terms and conditions.

Therefore, Iran should compete to attract upstream capital and technical knowledge of major IOCs. A large volume of the country's oil fields still requires investment. This necessitates a candid balance between risk and reward, which is essential in assessing the effectiveness of IPCs against buy-backs. The second and third parts of the study are devoted to theoretical and methodological foundations. The

Monte Carlo simulation results are presented in section four. The fifth section contains conclusions and suggestions.

Theoretical Development

Background of Iranian Petroleum Contracts

Iran, as one of the largest countries with vast oil and gas reserves, has experienced a variety of contracts in its more than 100-year history of oil (from concessions to buy-backs and IPCs). Release of Oil Law Reform Act (2011) and the Oil Ministry Duties and Authorities Act (2012), has made significant changes in this regard. After the Islamic revolution and during two subsequent decades, buy-backs were dominant. Hence, petroleum contracts literature has been devoted more to this type of contract, but after ratification and enactment of the OLR Act (2011) and OMDA Act (2012), IPC contracts have received much attention from experts and scholars. Background of Iran's oil and gas contracts reveals two key elements that have played a prominent role in the formulation and development of contractual arrangements; sovereignty and ownership. Table 1 shows the historical evolutions of petroleum contracts in Iran.

Table 1: Background of Iran's petroleum contracts

Time horizons	Contracts type	Features
1901[1]-1955	Concessions	The exclusive right of exploration, development, and production of the country's oil and gas reserves was granted to the concessionaire for signature bonuses, equity interest, taxes, and so on. In some of these contracts, the concessionaire was also exempt from paying any customs and duties. Examples are Darcy (1901), Armitage-Smith (1919), 1933, and Amiranian (1937) contracts (Ebrahimi et al., 2014).
1955-1975	PSC	The structure of these contracts was not accompanied by the exercise of sovereignty, supervision, and control of the Iranian government, and is still prohibited by Iran's constitution law (Shiravi, 2017). Consortium Agreement (1955) between NIOC and Seven Sisters oil companies, SIRIP Agreement between NIOC and Italian oil company; A.J.I.P. Mineraria (1958), , and IPAC agreement between Iranian and Pan American (1959) are among the PSC contracts in Iran (Ebrahimi et al., 2014).
1975-1980	Risk service	Under these arrangements, the contractor would have to bear all the costs required for the exploration and development of the field until the project was entered into operation. Upon early production, all the above costs would recover from the proceeds of the operation site at a specified rate (usually 5% below market price as a risk premium (Shiravi, 2017).
1980[2]-1994	EPC	In the first decade of the Islamic revolution, Iran's policy was to use foreign resources to develop its oil and gas reserves in the form of turn-key projects, EPCs, and project financing methods (Ebrahimi et al., 2014). Most of all, EPC contracts were used, where a detailed description of the materials, goods, equipment, and services to be provided were fixed in the contracts.
1994-2015	Buy-back	These contracts were developed in three generations. As one of the most critical developments in the third generation, the contract authorized project cost ceiling determination after conducting comprehensive engineering studies and identifying a large proportion of bids from subcontractors and contractors through holding tenders with the approval government. In all three generations, following the completion of the development and entry into the production phase, if the production level was sustained within a specified period, the contractor shall hand over the operation to the government. It would only be present at the operation phase as the technical sponsor (with government approval).
2015-NOW	IPC	IPC is a combination of Buy-back and PSC, also referred to as advanced Buy-back. The contract, which is very similar to the contracts used by the Iraq central government, pays the contractor a fee on a per-barrel basis and allocates a maximum of 50% of revenue generated by an oilfield to the contractor each year (Cabinet Decree, 2015).

[1] . Iran's first oil field was discovered in the 1901 in Msjed Soleiman provenance.
[2] . Islamic revolution (1979).

IPC vs. Buy-back

Buy-back contracts have been used for many years, and are still very common in Iran. These contracts are suffering from significant drawbacks such as lack of technology and technical knowledge transfer, short life of the contract, high dependence of contractor's remuneration and fees on Capex, low supervision of the government, little flexibility, and local content. However, MOP introduced IPCs to bridge these gaps. In terms of the fiscal regime, IPC enables IOCs to obtain a reasonable reward that is prevailing under other contracts such as PSCs. The overall structure of the IPCs' financial model looks like a risk service contract. However, the period extends to 25 years, with a two-year renewal option for exploration and a five-year extension for the development and production phases, up to 32 years. These contracts cover all stages of research, appraisal, development, and production. It is cutting edge since the Islamic revolution that a contractor is engaged in an operation phase of Iranian petroleum projects. If the commercial field is discovered, the contractor enters into the development phase, and a joint development committee is formed. All costs and risks of the development phase are borne by the contractor, which guides and executes the operation. It will also joint with a national NIOC-qualified E&P company as a technical partner to transfer technical knowledge and comply with Iran's local content (Mohammadi Sam et al., 2015). What distinguishes such contracts from Buy-backs are contractor engagement into operation phase and extended contract period, which can provide sufficient incentives for the contractor to optimize production path. Another distinctive feature of IPC is the determination of contractors' Capex in an open ceiling manner, rather than fixed amounts. This mitigates the contractor's risk of Capex overrun caused by deviations of reservoir behavior over time or changing market conditions.

Unlike Buy-backs, where the contractor's fees and costs are reimbursed in equal installments over two to six years, in IPC, the contractor's fee will differ based on the production volume, oil price, and field risk structure. This provides sufficient flexibility and provides contractors with enough incentive to use advanced methods and technologies, maintaining production levels throughout the contract period. It also gains from the windfall bonus of higher oil prices to some extent. This motivates contractor investment in high-priced periods. Table 2 compares the pros and cons of the two most popular contracts (Taherifard et al., 2016).

Table 2: IPC vs. Buy-back

Elements	BB	IPC
Duration of contract	5-7 years	25 years
IOC engagement	Exploration and/or development phases	Exploration, development, production
Cost payment and recovery	Capital costs, along with bank costs and contractor fees, are fixed from the beginning and are repaid to the contractor over a maximum of 60% of the proceeds of the sale of oil during the 5 to 7-year installments. Operating costs are reimbursed to the contractor at the end of each year. Banking costs account for all the capital costs incurred. Taxes paid by the contractor shall be reimbursed as indirect costs. Recovery of the contractor's costs is solely from the underlying operation site (field) sources of revenues.	There is no ceiling for Capex at signing the date of the contract. Direct Capex is payable in 5 to 7-year installments plus indirect Capex and fees. The government pays a maximum of 50% of the proceeds annually to the contractor. The time of payment begins after the initial production has been reached. Bank costs are only accounted for the delay in the repayment of the contractor's claims. In case of an inadequate amount of production allocated to cover costs, the unpaid costs will be carried forward and would be paid plus accrued interests in the next period. The NIOC is authorized to reimburse the contractor for costs and fees from revenue generated by other operating fields if the natural gas field products are consumed domestically or cannot be exported.
Fee	The contractor's fee is determined based on a fixed rate of return at the time of the contract and paid to the contractor in equal installments over a period of 5 to 7 years. The fee rate was constant. If the contractual level of production is not met, only capital and bank costs will be paid to the contractor (excluding any fee). The criterion for contractor fee is the shelf-life of	The contractor's fee is determined based on daily production volumes and other factors such as oil price and risk structure of the field. The entitled fee is paid annually to the contractor along with reimbursement of Capex, finance charges, and Opex from 50% of the oilfield proceeds.

Elements	BB	IPC
	production at the plateau level over a consecutive 21-day period of 28 days.	

Petroleum Contracts Risk Factors

With more than two decades of use of buy-backs in the Iranian oil and gas industry, the risks involved in these contracts are increasingly apparent. IPC contracts have only been used for the last three years, and the weaknesses and uncertainties have not yet been identified in practice. Buy-back contractors generally face Capex overrun risk, fail to reach the level of production specified in the contract (early production level), risk of falling oil and gas prices, and some technical risks (Mohammadi et al., 2015). Governments also face risks such as increased Opex, a decline of production after delivery, and lack of preserved production, which generally there is not a mechanism for mitigating such risks in buy-backs (Shiravi, 2017). The risk of rising costs (third-generation) is also inherent for the host government (Taherifard & Salimifar, 2013). In third-generation Buy-backs, the cost ceiling is determined after holding tenders, purchase of equipment, and the issuance of purchase orders (Taherifard and Salimifar, 2013). This mechanism covers almost the risk of Capex overrun, but the technical risks and non-capital costs overrun are in place. Also, oil prices drop risk is the case for both contractor and government (Taherifard & Salimifar, 2013).

Given that fee in Buy-backs is payable after meeting the production level specified in the contract, delay in the accomplishment of this clause postpones payment of the contractor's fee (Ghandi & Lawell, 2017). The first production level is determined at the beginning of the contract based on available information. So, after undergoing a period of development operations and tracing of reservoir behavior (depending on the specification of the field or cost ceiling clauses), the contractor may conclude it is not possible to meet the level of early production. In such a case, due to the mechanism defined in contracts, the development bonus will not be awarded to the contractor (Li et al., 2017). It may agree upon lower production levels to hedge against the risk of falling production. The cost of money (finance cost) in oil and gas contracts is usually determined by the LIBOR plus a certain percentage. If the Weighted Average Cost of Capital (WACC) of the contractor exceeds the rate assumed in the contract, the contractor will be at risk. Since the base rate in calculating the cost of money in Buy-backs and IPCs is LIBOR, any change in this rate can have a significant impact on parties' NPVs (Ghandi & Lawell, 2017). If variation in the scheduling of the contractor's capital expenditures is accompanied by a delay in completing the project, it also endangers the interests of the host government. Ghandi & Lawell (2017) considered changes in Opex, Capex overrun, changes in oil prices, changes in LIBOR, deviations from contractual production levels, and changes in contractor's fee (remuneration) as significant risk factors in Iran's petroleum contracts that have a substantial impact on the returns of upstream projects in Iran's' oil and gas environment.

Methodology

This study consists of two stages, including the extracting risk factors and the comparative analysis of the Buy-back and IPC in terms of identified risks. In the identification phase, risk and uncertainty factors were identified in petroleum contracts through deskwork and archival methods. Fieldworks were also used to obtain the desired results in the form of interviews and to recognize better the environmental risks associated with Iran's oil and gas contract contingencies. Given the limitations in extracting the kind of risk variable distribution functions, five key risk variables, including oil price change, LIBOR fluctuations, deviation from the level of production specified in the contract, increase in Opex, as well as Capex overrun are captured to run simulations. The second stage is risk assessment and analysis using the Monte Carlo method. This phase investigates the effectiveness of IPCs versus Buy-backs using NPV and risk variables. To visualize the simulation of government and contractor cash flows under IPC and Buy-Back, the North Yaran oil field project has been applied as a case. Information about projects obtained from the Master Development Plan, NIOC documents, experts' opinions, and approximations used in parallel investigations. North Yaran oil field is one of the significant Iranian oilfields located 130 kilometers west of Ahvaz at the zero border point with Iraq.

The in-place oil in the field is estimated to be more than two billion barrels. The development of this field started in 2011 with the signing of the agreement between Persia Oil and Gas Development Company and NIOC. This is the first successful experience of Buy-back concluded with an Iranian contractor with the least deviation from the schedule. The contract period is assumed to be 25 years from 2019 to 2044, and the exploration and development period is considered five years, the project expected to commence early production in 2024. The spending/recovery periods for Capex is also considered to be five years. The plateaued period has also been considered for 17 years. According to the MDP, total Capex and Opex (annul basis) required are estimated to be $805 million and $ 21 million in terms of nominal amounts in 2010, respectively. Field production started at 5,000 barrels per day (build-up), and after crossing 15,000, it reached 30,000 barrels per day during the plateau phase. During the decline phase, the level of production is assumed to be 15,000 barrels per day. Oil prices are based on the Energy Information Administration's (EIA) forecasts (underlying scenario). Optimistic and pessimistic scenarios have also been analyzed separately.

Cumulative extraction from the field based on technical assumptions of MDP is estimated to be 957.9 million barrels during the contract period. The cost oil rate is assumed to be 50% and 60% of revenues in IPC and BB, respectively. The LIBOR plus 1% risk premium (determined in the contract) is used to calculate the cost of financing. The 10% discount rate (common among oil companies) is used to discount future cash flows of the field. The base fee rate is set at $12 per barrel in IPC (given the low risk of the field). If the price of oil is between $ 40- $60, the base fee will increase by 20% ($14.4), and at prices above $60 a barrel, it will increase by 40% ($16.8) per barrel. Capex incurred prior to the commencement of early production shall be paid within a maximum of five to seven years from the date of spending, but the recovery would initiate after getting the project into the early production phase. Capex incurred from the time of initial production is also recovered within 5-7 years from the expense date. This holds constant even for indirect Capex. Money or bank charges are also calculated following the formula specified in the contract and, on the basis of direct Capex, from the spending date to the year of recovery and amortized during the recovery period. To simulate, using data from the oil and gas industry, the characteristics of the risk variables distribution function were identified. Table 3 illustrates the risk factors attributes (Thang et al., 2017; Blade & Wolf, 2009; Rodriguez et al., 2005; Orman & Dagan, 1999; Ross, 1987):

Given the unavailability of the probability distribution function for the delay as well as the contractor's fee risk variables, these are not considered in simulation steps. Due to the internationalization of the oil and gas industry, most risk variables (regardless of operation sites) follow a similar distribution pattern. Since the cost of money is considered as a function of the LIBOR in Iran's petroleum contracts, this variable was plotted using historical data from 1987 to 2018 period to capture distribution function characteristics. Because we did not access information on production levels specified in the contracts, its distribution function cannot be obtained. However, oil production has a normal distribution form, and we also used a normal distribution form for the production deviation risk variable, which can be a good approximation.

Table 3: risk factors characteristics

Risks	Unit	Distribution form	Mean	Std. deviation	Min	Mode	Max
Oil price changes	$/barrel	Normal	114.9	62.12	--	--	--
Deviation from specified production	barrel	Normal	3793	3.288	--	--	--
Capex variations	$m	Triangular	--	--	145.6	161.6	177.8
Opex variations	$m	Triangular	--	--	19.5	21.7	23.9
LIBOR changes	%	Triangular	--	--	0.2	5.7	9.3

Simulation Analysis

In the first step, the NPV of the oil field was calculated through cash flow modeling. Table 4 shows how it is divided under IPC and Buy-back. As is evident, in the IPC, the contractor's share of the project NPV is $136.69 million, while the contractor has suffered losses in the Buy-back. The government's take was almost the same as for buy-back and decreased from 4949$ to 4831$ in IPC arrangement.

Figure 1 and Figure 2 also show the division of project NPV across key players; investor and government. As it can be seen, the investor's share of total proceeds has been sharply appreciated under IPC and the losses has converted to a gain.

The main reason behind the increase in NPV of the project under IPC is the engagement of contractors in the operation phase. According to IPC, the contractor is obligated to implement EOR and IOR methods using up-to-date techniques and knowledge until decommissioning. Also, the feed mechanism in IPC increases the contractor's revenue significantly. However, to judge the risk distribution structure of two contracts, it is necessary to analyze the sensitivity of NPVs concerning predetermined risk factors. The probability distribution functions of NPV for the whole project, contractor, and Iran's government (NIOC) are separately simulated under IPC and buy-back arrangements using a random walk generation process with 5000 runs. Results for each of the six possible modes are presented in Table 5 (all figures in millions of dollars).

Table 4: NPV of the project in the base case

Contractual arrangements	Project NPV ($m)	Contractor share ($m)	Government share($m)
IPC	4967.91	136.69	4831.22
Buy-back	4890.86	-58.37	4949.23

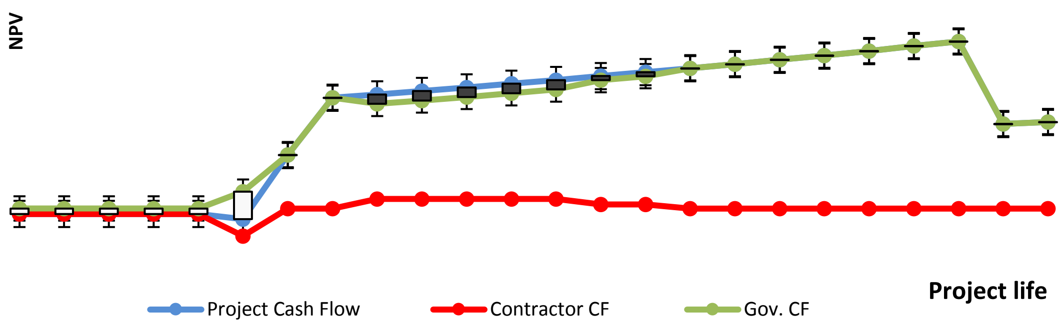

Figure 1: project NPV under buy-back

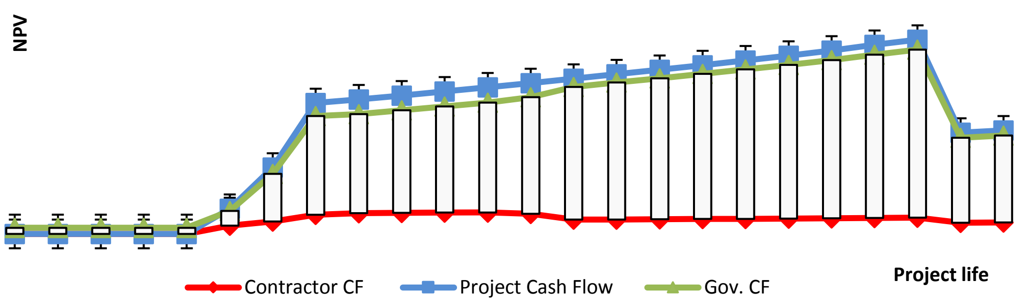

Figure 2: project NPV under IPC

Table 5: summary of simulation results

NPVs	Buy-back				IPC			
	Min	Mean	Max	Bin length	Min	Mean	Max	Bin length
Whole project	-1417.41	4872.84	55608.47	2000	-861.46	5364.46	41108.20	1400
Contractor	-1025.79	-626.26	-479.26	100	-862.41	30.69	2437.54	200
Government	-395.41	5626.05	44548.41	1500	-460.91	5339.85	42096.74	1500
Number of runs	5000				5000			

Figures 3 and 4 show NPV distribution functions of the future cash flows from the North Yaran oilfield for the entire project under IPC and Buy-back arrangements.

In general, the probability distribution functions for NPV of the North Yaran oilfield project have been identical. The average NPV of the entire project under IPC is $ 5364 million, while in buy-back is estimated to be $4872 million. The minimum NPVs in distribution functions under IPC and buy-back are $ 861 million and $ 1417.41 million, respectively. The corresponding maximum values are $ 41,108 for IPC and $ 55608 million for buy-back. According to NPV simulation findings, IPC contract accounts for more than 90% of the NPV distribution frequency between $ 500 and $ 13100 million, while more than 90% of the NPV distribution frequency in the buy-back model has lied between $500 and $14500 million. This means more disperse of NPV probability distribution for the whole project in buy-back than IPC, implying the risky nature of the buy-backs. . In the new generation of Iranian oil contracts, in addition to recovering operating costs and capital expenditures and interest costs of currency in other oil and gas contracts (Buy-backs), the contractor is also entitled to receive a production bonus, which is determined based on the fee per barrel and causes the contractor's take shifts upwards and gains from the loss.

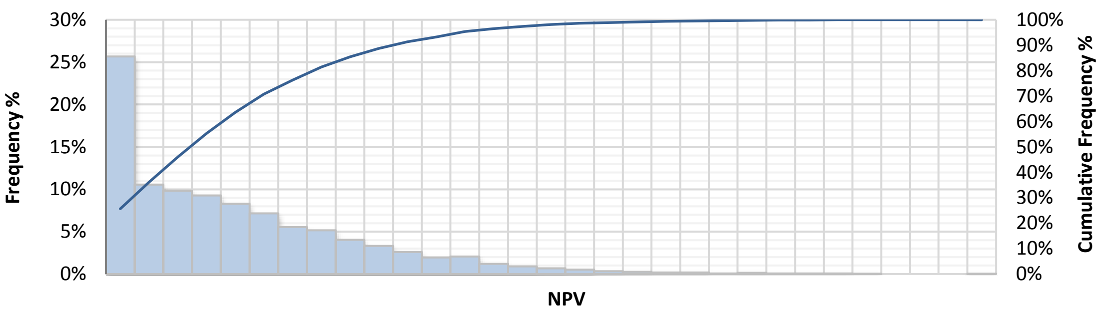

Figure 3: NPV distribution for the whole project under IPC arrangement

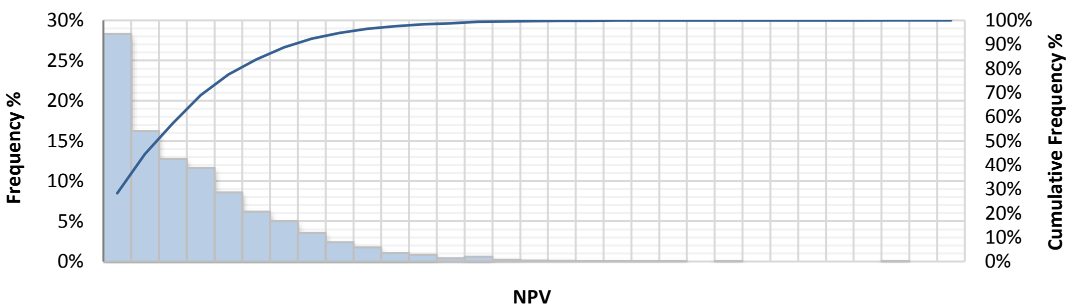

Figure 4: NPV distribution for the whole project under the Buy-back arrangement

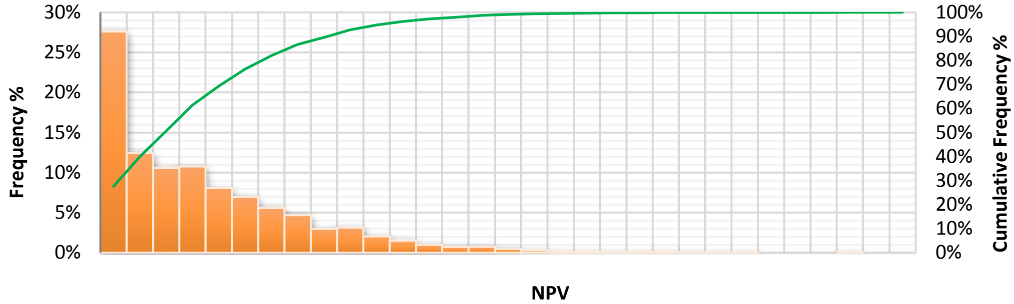

Figure 5: NPV distribution for the government under IPC arrangement

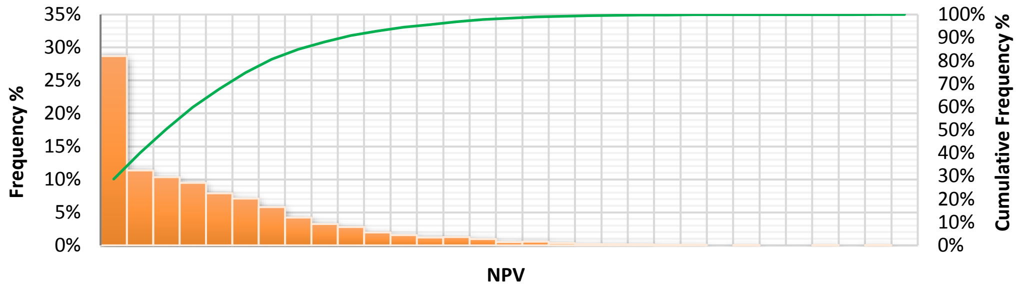

Figure 6: NPV distribution for the government under Buy-back arrangement

Figures 5 and 6 reflect the NPV distribution functions of the future cash flows from the North Yaran oilfield contributed to NIOC as representative of the Iran government under IPC and buy-back arrangements. The probability distribution function form under two contractual models is approximately the same. However, the average government NPV under Buy-back arrangements ($5626 million) is higher than IPC ($5339 million). One of the most important reasons for the difference is the significant portion of the field's production paid to the contractor in terms of the fee. In Buy-back, the contractor fee is predetermined and fixed, so the contractor would not be engaged in the operation phase. According to the distribution functions for government, the minimum government NPVs under IPC and Buy-back arrangements are $-460.91 and $-395.41 million, respectively. The corresponding maximum values are $ 42096 and $ 44548 million. However, as stated for the whole project, the deviation range of the government NPV in the buy-back contract is greater than IPC. Also, 90% of the NPV distribution frequencies are lied between $ 1000 to $ 14100 million in IPC, while this range was extended for buy-back ($ 1100 to $ 16100 million). This also indicates that government NPVs under buy-back arrangements are more dispersed. In the new Iranian oil contract called IPC, the contractor will benefit from receiving a fee to encourage the preserved production behavior of the reservoir and to participate in the production stages and implementation of EOR & IOR methods, etc. In other words, the government is willing to give up part of its current interests in exchange for more years of exploiting the oil and gas field. This reduces the government's receipts and makes the distribution function of NPV to the government more compact.

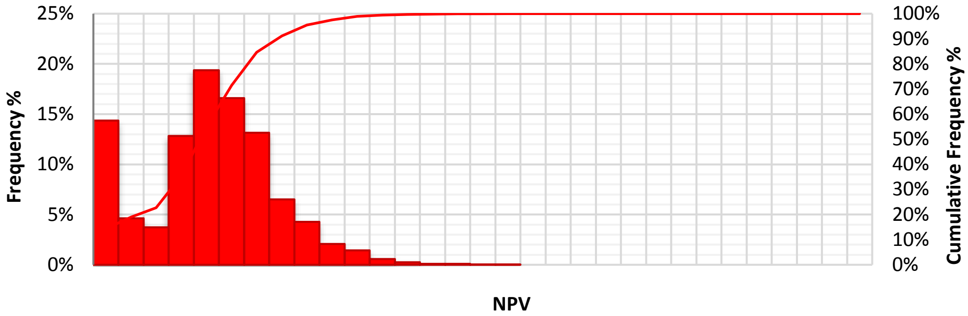

Figure 7: NPV distribution for the contractor under IPC arrangement

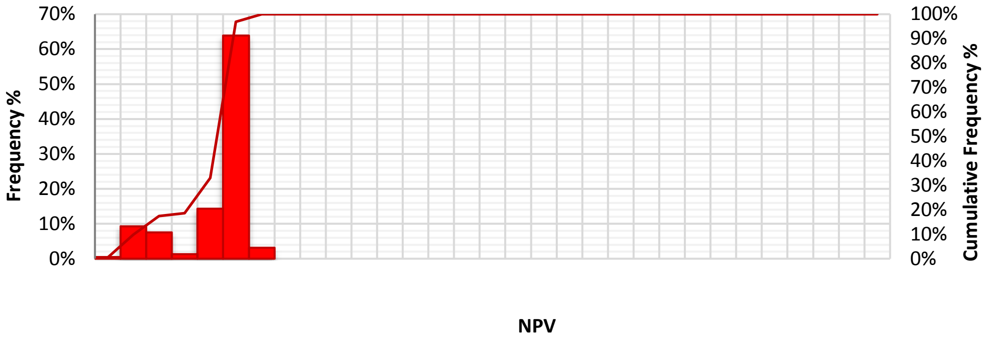

Figure 8: NPV distribution for the contractor under Buy-back arrangement

The most crucial point to consider is the significant difference in contractor (investor) cash flows under IPC and buy-back arrangements. Figures 7 and 8 show the contractor's NPV distribution functions under the IPC and buy-back arrangements. The average contractor NPV is negative under buy-back. This means not only buy-back has not provided a return on investment, but also caused money losses. This has also led us to the unpopularity of buy-backs in recent years. Under the buy-back, NPV of investor is estimated, on average, $ -626 million, whereas if using the IPC, the investor NPV upgrades significantly ($ 30 million). More than 90% of the NPV probability distribution of investor NPV is lied between $-700 to $700 million, while this is for buy-back between $-1000 to $-400 million. This indicates that the NPV variable probability distribution for the contractor is contrary under buy-back arrangements and less attractive. As we mentioned, the contractors' take is upgraded in IPC; because receiving a fee per barrel of oil and engagement in the operation phase till EOR and IOR methods. This mechanism backhanders contractor losses and provides enthusiasm for more preserved production. So it is rational and persuasive for contractor's NPV distribution function to be wider and flat normal looking like under IPC.

What has been said so far about the return function for the government and the contractor was assuming that the oil price follows the baseline scenario. Now we need to check the model robustness and analyze effects of crude oil price changes on NPV probability distributions for the project, contractor, and government. To this ends, two price scenarios developed by the EIA (optimistic & pessimistic) were separately incorporated into the model. The sensitivity of NPV distribution functions was investigated across contradictory situations. Table 6 and 7 indicate simulation results assuming an optimistic and pessimistic scenarios for oil prices, respectively. The contractor's fee in Iran's new oil and gas contracts is highly dependent on oil and gas prices. In other words, the contractor's fee mechanism is defined and embedded in such a way that if the oil price rises above a certain level, the contractor's fee will be adjusted. Of course, this fee also depends on other factors such as the level of risk in the field and the drilling site, which is omitted because it is the same in all scenarios. Only the economic factor, the price of crude oil, is addressed. The simulation results under two scenarios are presented, accordingly.

Table 6: NPV simulation results- an optimistic scenario for oil prices ($m)

Contracts	Stakeholder	Min	Mean	Max
IPC	Project	(845)	20546	52804
	Government	0.00	19437	54536
	Contractor	(858)	1020	3462
Buy-back	Project	(1395)	19933	54187
	Government	(391)	20467	58456
	Contractor	(990)	(563)	(476)

Table 7: NPV simulation results- a pessimistic scenario for oil prices ($m)

Contracts	Stakeholder	Min	Mean	Max
IPC	Project	(867)	252	2579
	Government	(856)	621	2500
	Contractor	0.00	(353)	18
Buy-back	Project	(1400)	(234)	2132
	Government	(395)	(619)	3061
	Contractor	(1030)	375	(477)

Figures 9, 10, and 11 compare NPV of project, government, and contractor under the optimistic scenario.

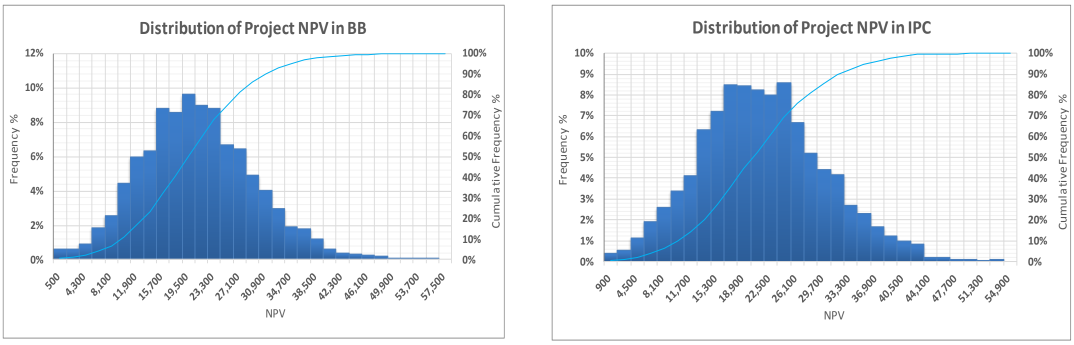

Figure 9: NPV distribution for the whole project under optimistic oil price scenario

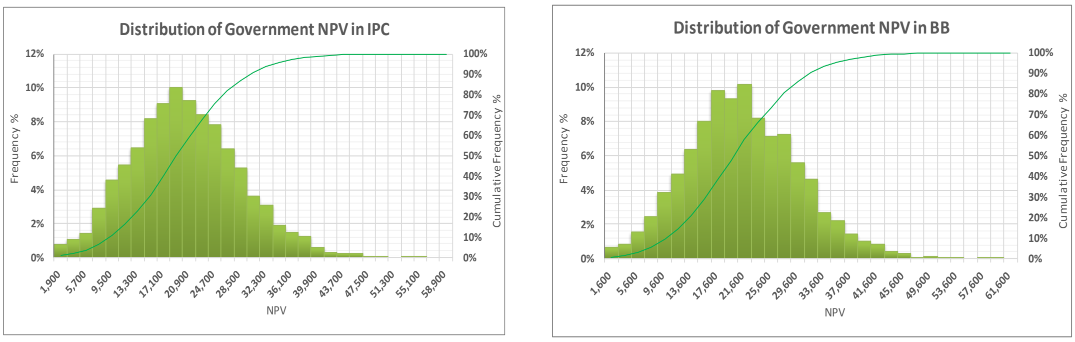

Figure 10: NPV distribution for the government under optimistic oil price scenario

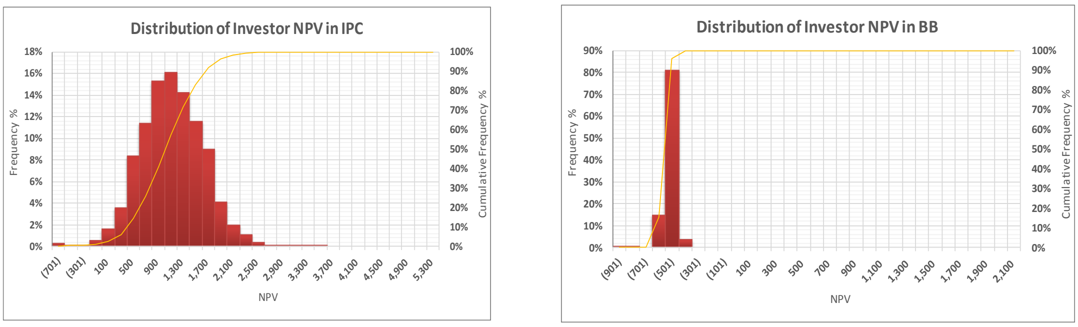

Figure 11: NPV distribution for contactor under optimistic oil price scenario

Figure 9 implies if the crude oil price rises (the optimistic scenario occurs), NPV probability distribution of field under IPC and buy-back arrangements would be almost the same. However, the average NPV in the IPC would be $20456 million and higher than the average NPV in buy-back ($19933 million). Given the deviation range of NPV, buy-backs are more sensitive to the dispersion of crude oil prices and bear a higher risk. The current statement holds constant across other NPV distribution functions forms (Figures 10 and 11). In the event of a rise in crude oil prices (optimistic scenario), the NPV probability distribution of the employer is almost the same as the whole field under IPC and buy-back arrangements. However, the average NPV of the employer in the IPC contract will be $ 19.437 million and lower than the average NPV in the buy-back contract ($ 20.467 million). Also, considering the range of changes obtained for the employer NPV, it can be said that in NPV of buy-back contracts, the government is more sensitive to increased crude oil changes and has a higher risky structure.

It can be observed that in case of increase in crude oil price (optimistic scenario occurs), the probability distribution of the project contractor NPV in the IPC contract is completely different from the buy-back contract. Overall, the investor's average NPV is $ 1,020 million in the IPC contract, while the project contractor's average in the buy-back contract indicates the contractor is unprofitable. Unlike government NPVs, the range of changes obtained for investor NPVs in buy-back contracts is less than for contractor NPVs in IPC contracts. In general, due to the existence of a reward payment mechanism to the contractor and also the possibility of adjusting the fee per barrel of crude oil, based on the increase-decrease in crude oil prices, the NPV probability distribution of the investor in the IPC contract is positive and higher in average; with respect to buy-back. This is also the case for pessimistic scenarios. NPV distribution function forms under two scenarios for oil prices are in line with normal oil prices case in previous sections, and the results didn't change significantly. The only difference between the distribution functions of NPV is the function curve shifting to the right-hand side (affirmative).

Figures 12, 13 and 14 also represent NPV of project, government, and contractor under the pessimistic scenario.

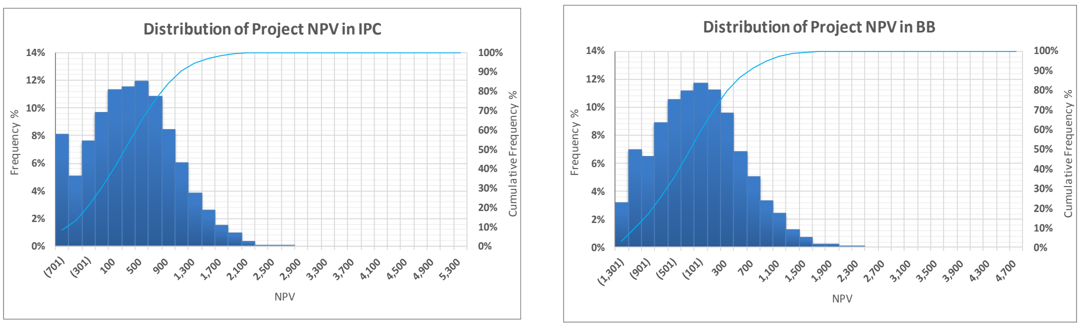

Figure 12: NPV distribution for the whole project under pessimistic oil price scenario

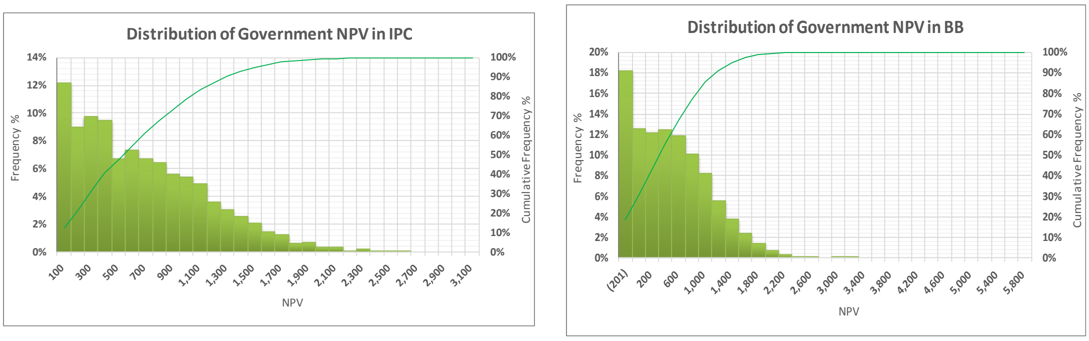

Figure 13: NPV distribution for the government under a pessimistic oil price scenario

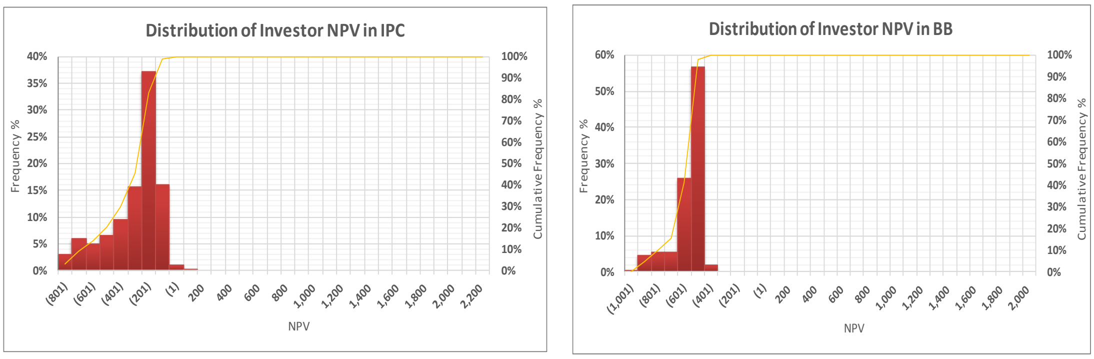

Figure 14: NPV distribution for contactor under pessimistic oil price scenario

Conversely, in the pessimistic scenario, the NPV probability function is skewed to the left (negative). Figure 12 shows that if crude oil prices fall (a pessimistic scenario occurs), the NPV probability distribution of the entire field under IPC and buy-back is different. The average NPV of the project in the IPC contract is $ 252 million; while this amount is equal to -234 million dollars in the buy-back contract for Yaran oilfield. Considering the range of changes obtained for the NPV of the whole project, it can be said that in NPV buy-back contracts, the field is more sensitive to crude oil reduction compared to IPC contract arrangements and has a higher risk.

Figure 13 shows that in the event of a fall in crude oil prices (a pessimistic scenario), the NPV probability distribution of the employer varies as well as the entire field under IPC and buy-back arrangements, and the average NPV of the project employer in the IPC contract is $ 621 million or less. The average NPV in the buy-back will be ($ 327 million). Also, considering the range of changes obtained for the government NPV, it can be said that in buy-back contracts, the government NPV is more sensitive to the reduction of crude oil prices (dispersion) and has a higher risk. In the event of a fall in crude oil prices (a pessimistic scenario occurs), the NPV probability distribution of the contractor in the IPC contract is quite different from the cross-selling contract. In general, if the price of crude oil falls; the investor's average NPV is $ 353 million in the IPC contract, while the project contractor's average NPV in the buy-back contract (if crude oil prices fall) is $ 619 million. This indicates that from the contractor's point of view, investing in buy-back contracts is more risky than IPC ones.

To sum up, NPV distributions' functions are not sensitive to oil prices; but they are highly dependent on the contractual arrangements (Buy-back and IPC). Furthermore, from contractor (investor) points of view, there is a more rational and reasonable connection between risk factors and rewards in IPC arrangement than buy-back. Fee per barrel determination/adjustment mechanism in IPC based on production volumes, oil prices, and risk category of green /brown oil and gas fields are considered as the most important driver in contractors' distribution functions. Also, the sum of payments to the contractor in the IPC contract is higher than the buy-back, and therefore the corresponding distributions are positive.

Conclusions and Recommendations

We sought to examine the effectiveness of IPCs versus buy-back contracts from financial risk-reward sharing views. The effect of financial arrangements on the objectives of the contract was examined, and the feasibility of achieving the purposes specified in the contract evaluated by considering its financial and economic framework from the risk window. Based on the above structure, the relevant financial model was simulated to plot the NPV probability distribution functions of the North Yaran oilfield and the necessary analyzes performed using the Monte Carlo stochastic process. Findings indicate that, in IPC contracts, due to the contractor's participation in the operation phase, as well as the flexible determination of contractors' fee per barrels of oil, the average contractor NPV is greater than buy-back. This thoroughly balances risk-reward allocations between parties.

Hence, IPC offers a more reasonable association between contractor risk and return parameters than buy-back, making it more attractive to foreign investors. The effectiveness of IPC over buy-back in upstream projects of Iran's oil and gas industry can be concluded. One of the main strengths of IPC is high flexibility and attractiveness for the foreign investor and balanced sharing of significant risks, especially the Capex overruns. Another contribution of IPC is linking of fee with production rather than costs (as in buy-back), which transfers the risk of production decline to the contractor and motivates to implement advanced EOR and IOR techniques; otherwise, production drop will result in fee cadence. However, the lack of savings index suffers IPCs; because the contractor tends to over invoice due to lack of cost ceilings. This is the case for almost all service contracts, and the essential way to deal with is the savings index. Policymakers and regulatory bodies are recommended to use the cost-saving index in IPCs to fortify the reasonable relationship between cost savings and contractor rewards. We conclude that the fiscal regime of IPC has been bolstered in different aspects compared to buy-back. Therefore, considering the better results of IPC contracts in terms of flexibility, attractiveness, and risk sharing, we recommend the use of IPC in small, joint, and Caspian oilfields. In the absence of fundamental legal and political problems, IPC can lead to more foreign investment in Iran's petroleum environment.

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