

Economic Evaluation of Fiscal Regime of Buy-Back Contracts in Comparison with Production Sharing Contracts (Case Study: Azadegan Oil Field)

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Abstract

Fiscal regime is one of the main differences between petroleum contracts. Fiscal regimes in oil contracts are divided to two main categories namely Concessionary and Contractual Systems. In contractual systems, the main difference between service and production sharing contracts is the way of compensation of contractor services which could be in cash or in kind. In production sharing contracts the contractor receives a portion of produced oil. One of the main criteria to compare fiscal regimes is government and contractor takes in real values. Comparing the net present value of contractor take shows that it could have been more desirable and cost effective to use production sharing contract in Iranian Azadegan oil field instead of Buy-Back.

Keywords: Fiscal Regime, Buy-Back, Production Sharing, Take, Iran.

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1. Introduction

Fiscal regime is one of the main and most important differences between petroleum contracts. Some believe that more than 80 percent of the content of upstream contracts is the same and what makes distinction between these contracts is fiscal regime.⁴ The fiscal regime

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4. See Duval et al., 2009.

or fiscal system includes all legislative, taxation, contractual, and fiscal elements (Mian, 2011).

Surveying the literature about upstream oil and gas contracts shows that the fiscal regime has been studied through two perspectives: legal and economic/financial. The economic approach which we have adopted in this paper is to use the concepts of economics, mathematical tools, comparing the contracts via simulation. For example Kaiser and Pulsipher have developed an analytic framework that couples a cash flow simulation model with regression analysis to construct numerical functional associated with the fiscal regime. A meta-modeling approach has been used to derive relationships that specify how the present value, rate of return, and take statistic vary as a function of the system parameters. In Tordo (2007) simplified economic model of four hypothetical petroleum projects has been developed to illustrate the difficulties that a country would typically face in designing a suitable fiscal framework for the development of its hydrocarbon resources. In particular, simulations were conducted to show the effect on project economics of alternative fiscal terms and their relative responsiveness to changes in economic conditions.

However, perfect design of different elements of a fiscal regime and creating interaction between them is very important. In practice three important points should be noted. First, what matters is what governments want to achieve. A country may have low tax take for a number of reasons, namely, to attract more investment, to compensate for perceptions of high fiscal risk, high costs, small volumes, high geological risk, and basin maturity, or simply because of the belief in a low tax environment for business in general. Although Russia's PSCs signed between 1994 and 1995 are used sometimes to illustrate the defects of PSCs, it is important to consider the aims of the Russian government and country conditions at that period. The main objective was to stimulate foreign investment in geographically isolated and technologically complex hydrocarbon projects as well as to boost oil and gas production, all in a low oil price environment. In fact, the 1990s witnessed the lowest levels of oil price in recent decades, reaching \$10/bbl. back in 1998. As the investment climate improved – namely more political stability and more favorable economic conditions (especially higher oil prices) – the Russian government

leaned more towards securing higher share of revenues. This led the state to intervene and recast the PSC terms to ensure a better balance of reward between investors and the tax-levying authority. Most significantly, the state became a direct equity participant in the project (Nakhle, 2010).

Second, the conditions of the oil and gas region must be kept in perspective. A high level of government take may not be justified in cases of high-risk exploration and high-cost development (Nakhle, 2010).

Finally, the precise design and interaction of various taxes and other elements play an important role. Some regimes may have similar apparent structures and tax rates, but their impacts on oil projects' and companies' profitability and government take can be quite different. Several factors, such as tax reliefs and the process of calculating the tax base – or simply the way the fiscal model has been designed – can lead to significant differences among fiscal packages, while different structures and regimes can produce the same results in terms of revenue and tax take. Judgment about the effectiveness or strengths of a fiscal regime cannot be made simply by looking at the tax rate. The main indicator used to compare a fiscal regime in overall terms is the project government takes defined as the net present value of total government revenues as a proportion of pre-tax revenues. Government revenues in this context include all taxes, royalties, profit oil and bonuses paid to the government (Nakhle, 2010).

However, there is a wide degree of uncertainty inherent in the computation of any economic or system measure associated with a field, and the only time that take, present value, or rate of return can be calculated with certainty is after the field has been abandoned and all the relevant revenue and cost data made public. Only in the case of “perfect” information, when all revenue, cost, royalty and tax data is known for the life of the field can profitability and the division of profits be reliably established (Kaiser & Pulsipher, 2004: 1). Most of the relevant economic conditions of a fiscal regime, regardless of its complexity, can be modeled, and thus the sophistication of the contract terms themselves usually does not represent an impediment to the analysis. The uncertainty is elsewhere. Several sources of uncertainty exist: Geologic uncertainty, Production uncertainty, and Price uncertainty, Cost uncertainty,

Investment uncertainty, Technological uncertainty, Strategic uncertainty (Kaiser & Pulsipher, 2004).

Therefore, considering the available information, this study has calculated the real value (time value) for the buy-back contracts of Iranian Azadegan oil field compared to production sharing contracts, using the simulation technique.

This study has organized such that after literature review, first the fiscal regime governing the buy-back contracts and production sharing contracts has introduced. Then, the economic information about Azadegan oil field is provided. Next, the theoretical foundation and research method are outlined, and the calculations are provided. Finally, the results and findings are presented.

2. Literature Review

Despite the fact that oil contracts have been present in Iran for more than a century, there has been few studies examining the economic and legal aspects of these contracts, and only a handful of studies have carried out an economic analysis or investigated the fiscal regimes. Of course, there have been relatively strong comparative studies on oil contracts in recent years.

Using the Analytical Hierarchy Process (AHP), Momeni Vesali et al. (2011) compares Buy-back and Production Sharing Contracts (PSC) together to find the optimum contractual method in finance and project implementation in oil-upstream section for both independent and Iranian joint fields. The most important decision-making criteria for making contracts in upstream section of oil and gas industry are classified to "Before" and "After" contract approval. The criteria were selected by Delphi method. To do this research, two questioners were filled out by professionals in oil industry in two stages and the data was analyzed by EC software. The analysis of data indicates that the PSCs are preferable than Buy-back contracts in both independent fields (76.56) and joint fields (73.46).

Kazemi Najafabadi et al. (2015) believe that in most cases, the adequacy of contracts in terms of economic benefits has raised questions and ambiguities for Iran. To investigate this topic, the gas buyback contracts are evaluated from an economic point of view. In order to assess the results more carefully, these contracts are

compared with the Production Sharing Contracts. Phases 2 and 3, and also 4 and 5 of South Pars Gas Field have been selected for this paper. Since these projects have been awarded in the form of buy-back contract, in addition of defining different scenarios, the Production Sharing Contract for the project has been simulated. After finding the best scenario in terms of the production sharing contracts for both projects, it has been found that for phases 2 and 3 of the South Pars, the Production Sharing Contract and for phases 4 and 5, the buyback contract, is proved to be more favorable for Iran.

Ghandi and Lin (2012) model the dynamically optimal oil production on Iran's offshore Soroosh and Nowrooz fields, which have been developed by Shell Exploration through a buy-back service contract. In particular, they examine the National Iranian Oil Company's (NIOC) actual and contractual oil production behavior and compare it to the production profile that would have been optimal under the conditions of the contract. They find that the contract's production profile is different from optimal production profile for most discount rates, and that the NIOC's actual behavior is inefficient—its production rates have not maximized profits. Because the NIOC's objective is purported to be maximizing cumulative production instead of the present discounted value of the entire stream of profits, they also compare the NIOC's behavior to the production profile that would maximize cumulative production. They find that even though what the contract dictates comes close to maximizing cumulative production, the NIOC has not been achieving its own objective of maximizing cumulative production.

3. Fiscal Regimes of Production Sharing Contracts and Buy-Back

Petroleum fiscal systems whereby the owner of mineral resources receives levies from the extraction company can be classified into two main categories. These are concessionary systems and contractual systems. Contractual systems are in most cases either production sharing agreements or service contracts. The difference between service contracts and production sharing contracts depends on whether the contractor receives compensation in cash or in crude. Under a production sharing agreement, the contractor receives a share of production and hence takes title to this crude (Mazeel, 2010).

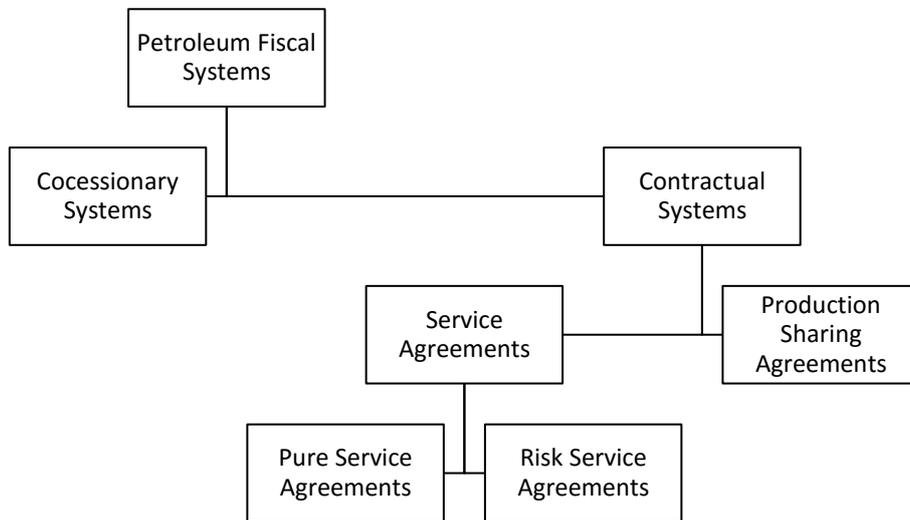


Figure 1: Classification of Petroleum Fiscal Systems

Source: Johnston, 1994

2.1 Fiscal Regime of Buy-Back

A buy-back contract is a kind of service contract with unique features, and therefore it is sometimes regarded as a separate kind of agreement. Buy-back contracts might be concerned only with development of discovered oil fields or with both their exploration and development. Considering that the overwhelming majority of buy-back contracts signed and executed up until now are concerned with field development, this study examines the financial and tax model of field development buy-back contracts.

Since the signing of the first petroleum buy-back contract in 1995, no specific contractual framework has been adopted by the National Iranian Oil Company (NIOC) or other authorities. However, NIOC has always provided the contractors with its desired framework, and the negotiations are conducted within that framework. Considering that the details of each contract are finalized through negotiation, the provisions of buy-back contracts can be diverse, and are almost never identical. The ambiguities of previous contracts have been resolved in the new ones, and the contracts have gradually become more comprehensive (Shiravi, 2014).

The most important change in the provisions of buy-back contracts appeared in 2007, with the enactment of "General Framework of Buy-

back Contracts" by NIOC board of directors, where the determination of the capital costs ceiling is postponed until after subcontracts tenders, rather than at the time of contract signature. In other words, instead of determining the capital costs ceiling at the time of contract signature, the parties foresee a method for doing so during the execution of the project. The financial and tax model introduced here is based on this new method.

In buy-back contracts the "Petroleum Costs" are classified into four categories, the reimbursement of any of which follows a specific system.

Table 1: Petroleum Costs in Buy-Back, 2008 Model

Cost Titles	Definition	Characteristics
Capital Costs	All field development costs that are incurred according to the contract provisions and are applied to the project account according to auditing principles, provided that they are not recognized under other expenses.	<p>There is a ceiling on these cost:</p> <ul style="list-style-type: none"> •First, the incurred costs must be audited, and if confirmed, they are reimbursable. •Second, if completion of the project and achieving its goals required less costs than the aforementioned ceiling, only the actual incurred costs will be reimbursable¹. •Third, if completion of the project and achieving its goals required more costs, the contractors should carry them out on their own, and cannot ask the NIOC for reimbursement, unless these extra costs were related to <i>additional work</i> and/or <i>change in scope</i> of work². •Of course, determination of the ceiling takes place after FEED (front-end engineering design) studies and subcontract tenders.

1. By reducing the work, the capital costs ceiling will decrease in proportion to the work omitted from the master development plan (MDP), and consequently the contractor fee will be reduced.

2. It is worth noting, the criterion for realization of additional work and reducing work is respectively increasing and decreasing the development operation objectives set forth in the MDP. Change in scope of services too oversees the changes in the MDP, which seems necessary for achievement of development operation objectives of the MDP.

Table 1: Petroleum Costs in Buy-Back, 2008 Model

Cost Titles	Definition	Characteristics
Non-Capital Costs	All taxes, tariffs, and other costs paid by the contractor to authorized bodies, such as State Taxation Affairs Organization, customs, municipalities, or Social Security Organization.	They account for approximately 10 to 15 percent of capital costs, have no ceiling, and are fully reimbursable.
Operating Costs	Costs that are promised and paid by the contractor, after approval by NIOC, directly, essentially, and exclusively for <i>operating activities</i> , supply of spare parts, and acquiring post-project-delivery insurance coverage	There is no ceiling for operating costs and no cap on cost recovery.
Cost of Money	Costs of financial resources	<ul style="list-style-type: none"> • All capital and non-capital costs earn interest from the first day of the next month when they are incurred. • The interest rate is agreed upon in the contract, which is usually a number larger than the LIBOR interest rate; for example, 75% plus LIBOR rate. • The operating costs will not earn interest if they are reimbursed in the season following the one in which they are incurred, unless there is a delay in their reimbursement. • If NIOC fails to pay the contractor's fee in due time, the unreimbursed items will earn banking fees.

Source: Shiravi, 2014; Hatami and Karimian, 2014

It is natural to have unrecoverable costs alongside those that can be recovered. In the accounting procedures of the exploration-development model in buy-back contracts, the unrecoverable costs are classified into 18 sections in details; some of the most important ones are the costs of establishing offices abroad, costs related to

contractor's violation of the general standards of the oil industry in the execution of development operations, and costs of legal duties and deductions incurred abroad (Hatami and Karimian, 2014).

2.2 Fiscal Regime of PSC

Production sharing contracts or agreements (PSCs or PSAs) gives an international oil company (IOC) or consortium exploration and production rights for a fixed period in a defined Contract Area or Block. The IOC bears all exploration risks and costs in exchange for a share of the oil or gas produced. Production is split between the parties according to formulae in the PSC that may be fixed by statute, negotiated, or secured through competitive bidding. If the IOC does not find a commercial discovery, there is no reimbursement of costs by the government (Mazeel, 2010).

The agreement could be for exploration, development and production (abbreviated as EPSA), or it could be for the development of a certain field (no exploration), which is known as a development and production sharing agreement (DPSA). The combination is also referred to as EPSA/DPSA. If the host government is also a joint venture partner with the contractor, then both partners will pay their proportionate share of the costs and receive a proportionate share of the revenue. In addition, the contractor will also share a percent of its share with the host government (Mian, 2011).

In a PSC, the difference between net revenue and cost oil determines the profit oil that will be shared between the contractor and the government, depending on the split rate. As such, the contractor's share can be expressed as in the following (Nakhle, 2010):

Contractor profit oil = Net revenue – Cost recovery – Government share

Finally, the contractor's profit oil can be subject to income tax. In this case, the contractor's profit oil plus cost oil minus allowable deductions can be considered as the taxable income under a concessionary system. In general, investment credits and uplifts are cost recoverable but not deductible for calculation of income tax (their cost recovery may form part of taxable income). The opposite is true for bonuses, which are not cost recoverable but are tax deductible (Nakhle, 2010).

2.3 Development Plans of Selected Iranian oil Fields

2.3.1 Azadegan Oil Field

Azadegan oil field is located 85 km southwest of Ahvaz, south of Hour-al-Azim region (Hawizeh Marshes), and 10 km from the border with Iraq. Its underlying geological formation consists of four layers, namely Sarvak, Kazhdomi, Godvan, and Fahilan. More than 90% of its oil in place (OIP) is found in the Sarvak formation, with an estimated OIP of 20 billion barrels, which was later estimated at 30 billion barrels (Center for Innovation and Technology Cooperation of I.R. of Iran Presidency (CITC, 2006). The oil field's development contract was signed in February 2004 as a buy-back contract between the National Iranian Oil Company and INPEX Corporation¹ with a share of 75% and participation of Naftiran Intertrade Company (NICO) with a share of 25%. However, after a few years of delay and under the pretext of insecurity of the region, the Japanese company did not conduct any specific operations, and after the sharp rise in crude oil prices, and consequently the spike in capital costs, withdrew from the contract and was replaced by Petroiran Development Company². Examination of the measures taken by Petroiran Development Company shows that the project was defined by excessive confusion, disorganization, and lack of decision-making power; and that the oil field began its initial production after a substantial delay (Dehghani, 2014).

According to the ultimate development plan of Azadegan oil field, beginning experimentally, after four years the production rate was to be 50 thousand barrels by 2007, which would increase to 150 thousand barrels by mid-2008 (CITC, 2006).

1. Japan's Indonesia Petroleum Exploration

2. Referring to the sharp rise in prices and costs, the contractor withdrew from the project after receiving 120 million dollars

Table 2: Financial information of Azadegan Buy-Back contract (\$million)

Capex	1026
Non-Capex	205
Bank-Charges	330
Remuneration	699
Cost of Money	Libor + 0.75

Source: Dehghani, 2014

4. Research Method

A closer evaluation of various fiscal regimes round the world shows that concessionary regimes and PSCs can be designed in a way to generate similar economic outcomes. What matters is the ambition of the host government and the way the fiscal regime is structured to deliver these objectives. Very onerous fiscal terms can be found under concessionary regimes, such as Norway where government take reaches 78 per cent. Back in the 1980s, the UK government take reached nearly 90 per cent for a brief period (Nakhle, 2010)

This study intends to calculate the value of the current takes of the foreign contractors in the buy-back contracts of Azadegan oil field, and compare it to production sharing contracts, using the simulation technique.

4.1 Calculating the Present Value of Variables in Buy-Back Contracts

Here, the capital costs of the buy-back contracts are calculated using the future value of an annuity relation. The equation below (Mian, 2011) is used to calculate the future value equivalent to a set of similar payments (a set of equal cash flows taking place at the end of consecutive periods)¹:

$$F_v = A_v \left[\frac{(1+i_e)^t - 1}{i_e} \right] \quad (1)$$

To calculate the Opex in Buy-Back contracts, we use future value of a single sum received/invested (at a compound interest) at present (Mian, 2011):

1. In fact, it is assumed that the capital costs have been invested in equal proportions in each year, from the effective date until the delivery of the project to the employer.

$$F_v = \sum_{t=1}^{n-1} (P_v)_t (1 + i_e)^t \quad (2)$$

To calculate the Remuneration Cost of Money ($\text{LIBOR}^1 + 0.75\%$)², we use present value of an annuity (Mian, 2011):

$$P_v = A_v \left[\frac{(1+i_e)^t - 1}{i_e(1+i_e)^t} \right] \quad (3)$$

In all i_e relations, the LIBOR rate³ is applied from the effective date of the contract until project delivery date.

It is worth noting that the taxation system governing the buy-back contracts is considerably different from other service contracts, and the income tax payable by the contractor is considered as a non-capital cost in the project account; which will be reimbursed to the contractor in the amortization period, according to the conditions set forth in the contract and the appendix related to product sales. There are no clear explanations for justification of this duality. It can be said that in buy-back contracts, the contractor is exempt from paying a large portion of the income tax. In other words, tax plays a fictitious role in these contracts and does not affect the contractor's income; because the levied taxes are paid by the contractors and again reimbursed to them as a non-capital cost. Hence, when allocating oil to the contractor, the sums are adjusted such that the net payment to the contractor is tax-free (Hatami and Karimian, 2014). Indeed, according to the contract signed between NIOC and the contractor, the income taxes are ultimately paid from the project proceeds, rather than by the contractor. In a way, this defeats the purpose of the legislator who was aiming to earn revenue for the government through taxation (Rokni-Hosseini, 2014). Hence, no taxes are assigned to the contractor in buy-back contracts.

1. The interest rate is agreed upon in the contract, which is usually a sum larger than the LIBOR interest rate. In the contracts investigated here, 75% had been added to the LIBOR rate.

2. Here, it is assumed that these sums are paid to the oil company in equal installments and over a certain period.

3. The average Dollar LIBOR rate for 12 months is available at www.fedprimerate.com.

4.2 PSC Simulation

Based on the information provided about buy-back contract of the Azadegan oil field, this section aims to answer the question what happens to the rate of the contractor take¹, assuming the agreement was signed as a production sharing contract. Considering that the production sharing contracts are prepared for long-term use and cover a significant portion of a field's lifespan, it was assumed that the contract continue until 2016². During the contract period, the oil fields' production rate³ is assumed to be fixed⁴.

4.2.1 Costs

In production sharing contracts, the international oil company is responsible for two major payments. One of them includes the direct and indirect operation costs, which are here assumed equivalent to capital and non-capital costs incurred by the contractors of the phases under study in buy-back contract. The extraction costs are also added to these, because unlike buy-back contracts, in production sharing contracts the production phase is connected to the development phase (Iranpour, 2014).

The extraction cost per barrel is assumed to be 12 dollars for Iran⁵.

1. Here, we calculated the present value of the sums received by the foreign company through the buy-back contract and compared them with those of a production sharing contract. The scenario in which this sum is smaller is beneficial for the host company, because it has been able to reduce the contractor take.

2. Thus, the duration of contract for Azadegan is 10 years.

3. Here, the production rate is assumed to be equivalent to the highest daily production rate of each field in buy-back contracts.

4. This assumption is not far-fetched, because the production estimation profile of the oil field under study bears out the sustained maximum production of the fields (refer to CITC, 2006, and Dehghani, 2014). In addition, the long term presence of the contractors in production sharing contracts propel them to maximize their profit within the duration of the contract, therefore the chance of maintaining the rate of production is higher compared to buy-back contracts. In other words, the buy-back contractors are not concerned with the production process in the long-term, because buy-back contracts are short in nature, and thus, foreign contractors are not interested in observing the standards of protective production in the long-term (CITC, 2006).

5. According to IEA's 2008 World Energy Outlook, the oil production cost in Middle East and North Africa (MENA) was 6 to 26 dollar per barrel, and in conventional oil fields around the world it was 6 to 39 dollars (www.worldenergyoutlook.org). Moreover, Rystad Energy studied the oil

The relation (1) is used to calculate the future value of costs incurred by the oil company.

4.2.2 Royalty

As it was mentioned, in production sharing contracts, there are payments made to the host company as royalty and various kinds of remuneration; here, only the royalty was taken into account. The royalty is deducted from the gross income (proceeds made from the well) immediately, and therefore it is paid at the beginning of the contract. Different conditions and percentages can be assigned for royalty in different contracts, however, it usually stands between 8 and 15 percent of the gross income, which will be paid to the government out of the oil or gas sales, regardless of the profitability (or lack thereof) of the operation. This number was 12.5% in the pre-revolution production sharing contracts in Iran, which was increased to 20% after the signing of the contract addendum with the Oil Consortium (Amir-Moeini, 2006). Examining the experiences of other countries shows that the highest royalty interest belongs to Venezuela standing out at 30 percent. Now considering that the profitability of Iranian oil wells and fields is above the global average, this rate can be increased from 15 to 30 percent of the total net production (Amir-Moeini, 2006). Here, the royalty rate is assumed to be 15%, which is, as explained, a minimum rate. The relation (2) is used to calculate the time value of the royalty.

As it was mentioned, the contractor is allowed to recover its expenses out of the net income (Cost Oil). Of course, there is no cap on this recovery in most production sharing contracts; and usually

production process in 20 countries and investigated the average cost price per barrel in each country. Its 2016 report, which made use of information collected from more than 15 thousand oil fields from 20 major oil producing countries, presents the investment costs and production operation costs separately for each country. In this report, production of one barrel of oil in Iran is estimated at 12 dollars (<http://www.rystadenergy.com/Database>). Although the extraction cost is part of the production cost, we included the production cost based on the 2016 study in the financial model, so as to cover the possibility of increase in costs over time and take into account the effort made to maintain the production rate. Of course even this is a worth case scenario, because the higher is the costs, the higher is the contractor's income in the financial model.

reimbursement faces two limitations, or idiomatically, two pay ceilings. One limitation is defined based on a specific percentage of the produced oil rate within specific time intervals. That is the oil company cannot claim the whole produced oil to cover its expenses. The second condition and limitation is the duration of contract, and indeed the duration of the operation and production stage. Reimbursement of expenses is possible only when the oil field is commercialized, i.e. when the operation stage begins, which can continue as long as the contract is valid, for instance 10 years (Kazemi-Najafabadi, 2014). In the simulation carried out here, the annual percentage of cost amortization is assumed such that the rate of annual payments remains the same.

4.2.3 Cost Oil

As we know, the sums those remain after the deduction of the royalty and recoverable costs is called Profit Oil. These sums are divided between the host government and the oil company following the provisions stipulated in the contract. The method and formula for sharing the petroleum products, especially the profit oil, between the government and the contractor is one of the major topics in production sharing contracts. The profit oil can be divided between the parties based on fixed share or sliding scale methods. In the fixed share method, the host government and the contractor agree at the beginning that the profit oil should be divided between the parties based on a fixed percentage without change (for instance: 40% for the contractor and 60% for the government). This method is rarely employed for sharing the profit oil, and more flexible methods that can be adapted to the conditions and features of the project are used instead (Hatami and Karimian, 2014).

Most contracts use R-factor for triggering sliding scale factors such as cost recovery, profit oil split, royalty, taxes, etc. The R-factor is the ratio of the cumulative contractor's revenue after taxes and royalty, and the cumulative contractor's cost from the day the contract is signed. The $R = 1$ implies a breakeven point for the contractor. The R-factor is calculated each year or quarterly and is used as the basis for adjusting the royalty fraction, cost recovery, profit oil splits, and taxes in accordance with a predetermined schedule. Thus, as the contractor

makes more profit, a larger portion of the gross revenue is paid to the host government in the form of royalty, taxes, profit oil, etc. (Mian, 2011). The table below was used for calculation of the profit oil. There are different tables used in production sharing contracts of different countries, but the same logic governs them. Here, the table below has been selected. The relation (3) is used to calculate the time value of profit oil.

Table 5: Suggested R-Factor

Contractor Take (%)	Host Government Take (%)	R-factor
50	50	1.25-1.5
45	55	1.5-1.75
40	60	1.75-2
30	70	2-2.25
20	80	2.25-2.5
10	90	More than 2.5

Source: Kasriel & Wood, 2013

R-factor mechanisms in many PSCs use an inverse relationship, whereby the contractor gets a higher percentage share of total profit oil when the R-factor is low and a lower share when the R-factor is high. For example – again, simplistically – the PSC might use a scale whereby the contractor gets (Kasriel & Wood, 2013).

Indeed, by connecting government/contractor take to R-factor which is depend to oil price, the take will be sensitive to oil price as well.

4.2.4 Tax

The last issue is tax. It was mentioned that in production sharing contracts tax is a major source of cash flow for the governments. Some studies show that the average tax rate for contracts subject to income tax was 45 percent. The income tax on companies in pre-revolution Iranian production sharing contracts was levied at 50-55 percent, which increased to 85 percent when OPEC approved collection of additional taxes (Amir-Moeini, 2006).

According to Article 107 of amendment (enacted in August 2015) to Direct Taxes Act of 1988 of Iran, the taxable profit of foreign

natural or legal persons residing abroad for the income made in or from Iran is assessed as follows: For preparation of design for buildings and installations, topography, drawing, supervision and technical calculations, provision of training and technical assistance, transfer of technology and other services, granting of royalties and other rights and transfer of cinematograph films, whether the profit is derived as the price or the fee for the screening of films, or under any other titles, except the incomes that in accordance with the provisions of this law are subject to another method for determination of the taxable income or the tax, the taxable profit shall consist of ten percent (10%) to forty percent (40%) of all payments derived by them during a tax year, depending on the nature of the activity and its profitability. According to the executive by-law of the Article 107 of the Direct Tax Act (enacted July 2016 by Council of Ministers) on the subject of determining the coefficients of taxable income earned by foreign legal persons and enterprises residing abroad, the coefficients of taxable income earned by foreign legal persons and enterprises residing abroad for the income earned in Iran through all cases of contracting and technical services, exploration, development, and operation in the fields related to upstream hydrocarbon is 15 percent. This 15% is for cases of contracting and technical services, exploration, development, and operation, however, the profit made from goods and equipment supply has not been regarded as income, and it seems they are practically tax-free. Thus, it can be contended that this is a minimum rate. For instance, in the sample Iraqi technical service contract (model of 2009), the tax is equivalent to 35% of the contractor's fee (Wells, 2009). The relation (3) is used to calculate the time value of tax.

4.3 Findings and Conclusion

The net present value received by the international oil company (IOC) in development plan Azadegan oil field, both as buy-back and production sharing contracts, is presented in the table below.

Table 2: NPV Received by the International Oil Company (IOC), (\$million)

oil field	BB	PSC
Azadegan	1004	245

According to the results, through a buy-back contract, the IOC profits 1004 from the development plan of Azadegan. Whereas, if the plans are in the format of a production sharing contract, the sums would be 245. This means buy-back contracts in this oil field have imposed a heavier cost on the country, and a production sharing contract would be more desirable. Of course it should be noted that in this study, all financial variables related to the host government, such as the loyalty and tax, were at a minimum level.

In conclusion, the adoption of production sharing contracts instead of buy-back contracts in the said oil field would have been more beneficial and cheaper for the host country (Iran).

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