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Investigating the Effects of Contractual Factors and Arrangements on the Optimum Level of Production in Oil and Gas Projects: Evidence from the South Pars Phases 17 & 18

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Abstract

Development of oil and gas fields is facing many risks, which are mainly due to uncertainties about the existence of commercial reserves, natural and economic environment, political conditions of host countries, legal and infrastructure issues and a market for petroleum products. In such an environment, investors are often engaged as contractors to develop and operate petroleum projects, constantly seeking to recover their capital and operating expenditures quickly, through increasing production levels. But some geological and geophysical factors, hydrocarbon structure, technological and scientific constraints, as well as some of the contractual arrangements, such as cost recovery ceiling, virtually prevent the investor from gaining access to high economic benefits and quick recovery. The purpose of this study is to investigate the effects of contractual factors and arrangements on the optimal production levels of petroleum projects. To this end, information on the South Pars phases 17 and 18 projects were collected as a case and the optimal level of rich-gas production in this project was simulated in form of a nonlinear dynamic optimization model under the Iranian Petroleum Contract and Engineering, Procurement, Construction arrangements. The production levels and scenario analysis indicated that contractual factors and arrangements could affect the optimum level of petroleum production, significantly. Given that the production paths obtained for this project are different from that drawn by the Management and Consolidated Planning department in National Iranian Oil Company, the current production profile for the Phases 17 and 18 is not optimal, in which the executive suggestions are presented. These findings would be applicable to the formulation of Master Development Plans.

Keywords: Optimal Production, Petroleum Projects, Petroleum Contracts, IPC, EPC, South Pars Gas Field.

JEL Classification: C61, Q35, K32.

1. Introduction

Given the heterogeneous distribution methods of oil and gas resources

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around the world and the differences in economic developments, a supply of and demand for oil and gas have always been a matter of controversy. In such a situation, several countries are operating competitively in oil and gas projects, and they are increasingly being added to the competition. The development of oil and gas fields is facing a lot of risks, which are knitted to the uncertainties about commercial reserves, natural environment, political conditions of the resource-rich countries, economic environment, legal issues, infrastructure matters and the market for petroleum products (Economides, 2013). In such an environment, investors are often engaged as contractors to develop and operate petroleum projects, constantly seeking to recover their capital and operating expenditures quickly, through increasing production levels (Gustavson, 2000). However, some geological and geophysical factors such as hydrocarbon structure, technological and scientific constraints, as well as some of the contractual arrangements, such as cost recovery ceiling, virtually prevent the investor from gaining access to high economic benefits and quick recovery (Xiaoguang et al., 2003). Among the contractual elements, there are rights and obligations that directly affect the economic interests of the investor (contractor) and employer (government). One of the most important of these is the financial clauses and the contractual arrangements for recovery of cost and fees.

Determining the optimal level of oil and gas production is one of the main challenges in the preparation of Master Development Plans (MDP) in international projects. The production of oil and gas will be optimal when earn the most economic benefits to the parties, taking into account geological, geophysical, technological and contractual constraints (Zhao and Xia, 2012). However, the National Iranian Oil Company (NIOC) Management and Consolidated Planning (MCP) department consider only the technical and geological factors to determine production path from the fields in MDPs, regardless of the contractual factors and arrangements. This research takes a critical approach to the current procedures of NIOC for drawing production profiles and seeks to evaluate the effects of contractual factors and arrangements including capex, capex time scheduling, opex, recovery ceiling, agreed interest rates and contractor's fee on plotting the optimal production profile of oil and gas fields. To achieve this, the optimum gas production levels from the South Pars Phases 17 &18 were modeled under the contractual arrangements of Iranian Petroleum Contract (IPC) and Engineering, Procurement, Construction (EPC) using Non-linear Dynamic Optimization Model (NDOM) and then sensitivity of the optimum gas production levels with respect to contractual arrangements has been analyzed using scenarios. Finally, the level of production obtained has been compared with the production level determined by the NIOC.

It is expected that the results of this study can reflect the effect of contractual elements on the optimal level of oil and gas production. Research findings can be used to determine the optimum levels of oil and gas production in the formulation of MDPs. Also, the results of this study are important for companies active in the oil and gas industry and will help them to use more flexible elements and clauses when negotiating contracts, develop tailored exploiting strategies and design more effective and beneficial development plans. The contracting and investing companies in the oil and gas industry, MCP department and the energy and economic institutes of the country are the main target audience for this study.

2. Theoretical Foundations and Literature Review

The production level is the ratio of the annual production of oil or gas in terms of barrels and cubic meters to total geologically proven reserves, which is considered to reflect the speed of reserve extraction[1]. Economically, the optimal level of production is the rate of production in which the Net Present Value (NPV) of the future proceeds of the project is maximized (Li et al., 2005). To maximize the profitability of international projects, petroleum companies calculate the optimum level of production based on mathematical engineering models (Rao, 2000). The optimum production level in each oil and gas field is affected by three major factors. These conditions include the inherent geological conditions of reserves, technological factors and host country contracts (Li et al., 2005). The geological factors of reserves include the structural characteristics of the reserves, distribution of reserves, physical properties, type of oil and gas reservoirs, etc. have an

1. PRC, (2005), terms of oil/gas reservoir engineering. Oil and Gas Industry; Standard of PRC, SY/T 6174e2005.

impact on the optimal production level (Donkgun Luo & Zhao xu, 2013; Derakhshan, 2013; Ghorbani et al., 2013). Technological factors such as development program and facilities, well spacing, drilling, and production technology, water injection methods also play an important role in optimizing the inputs and outputs of petroleum projects (Donkgun Luo & Zhao xu, 2013; Derakhshan, 2013).

Among technological factors, the density of wells is very important and significantly affects production. If the density of production wells is high in a region, the greater flooding control would be greater and leads to a higher level of production. If the number of wells in an area is too large, the recoverable reserves of a single well reduced, the cost per barrel of oil or gas cubic meter increased, and consequently, the economic benefits (NPV) are reduced (Li Juan, 2006). The impact of petroleum contracts on the interests of the contractor will vary at different levels of production (Li et al., 2005). Since the financial elements of a contractor, such as ownership interest, tax, profit-sharing, etc., are determined in sliding scales in most countries, any change in the level of production will have significant effects on the way in which revenues and expenses are shared, and subsequently affect the NPV of the project (Luo and Yan, 2010). Therefore, it is possible to say that the economic benefits from the development of oil and gas projects do not depend solely on the one article of the contract; the combined effect of several factors (arrangements) affect the economic benefits of the project. Therefore, these combined effects of contractual arrangements should also be considered in determining optimal production (Zhao, Luo, and Xia, 2012).

Ohler (1979) studied the physical behavior of the reservoir in connection with the economic and engineering conditions. He found that the control of reservoir pressure had an unobtrusive effect on the optimal level of production. Nysta (1985) entered the limitations of the maximum proven reserves as a geological factor into a regression model and emphasizes the role of technology used in the development of oil and gas fields as one of the technical elements. He also added some macroeconomic variables such as interest rates and draws the optimal production level for one of the oil fields in the North Sea. The results confirmed the effect of input factors of production levels. Yu Qitai & Li Wenxing (1998) considered four elements that affect the extraction rates from oil fields. These elements were production level during the build-up phase, physical and geological characteristics of reserves, the discovery of new commercial proved reserves and using enhanced/improved recovery techniques. Using these data, they designed a multivariate regression model in which the optimum production rate during the plateau period served as an independent variable. Rao (2000) introduced a nonlinear planning model that aimed at minimizing the present value of future cash flows related to extraction and transfer of oil from the tank to the place of consumption, to achieve the optimal level of production. In his model, the optimal level of production as a function of the total amount of recoverable reserves, the production coefficient, and the pressure exerted on the reservoir. Qu (2001) also regressed the production level on well spacing and density. Li et al. (2005) estimated a multivariate regression model in which the oil recovery coefficient for hydrocarbon reservoirs was a dependent variable and some geological factors were independent. Gunnerud & Foss (2010) also present a new method for real-time optimization of process systems with a decentralized structure where the idea is to improve computational efficiency and transparency of a solution. The merits of the method are studied by applying it to a semi-realistic model of the Troll west oil rim, a petroleum asset with severe production optimization challenges due to rate-dependent gas-coning wells. This study indicates that both the Lagrange relaxation and in particular the Dantzig–Wolfe approach offers an interesting option for complex production systems. In all of the above studies, the influence of technical, geological and technological factors on production and extraction levels was confirmed. Some of the above studies have used regression models to determine the optimal oil field production. These models have two basic disadvantages. First, there are no limitations in these models and their effect on the optimal production level. Second, these models focus on geological, geophysical, engineering, and technological factors, and ignore the clauses and contractual arrangements.

Wang et al. (2005) presented an optimization model to show the optimal level of oil and gas production. In this model, the future value of the project's revenue based on analyzes of geological and technological factors was maximized using a target function. The results of this research showed that technical and geological factors such as reservoir pressure control could affect the optimal level of production, significantly. These results were confirmed by Yuting et al. (2013). Few studies have been conducted to assess the role of contractual obligations in oil and gas production.

Considering the production sharing contract in Indonesia, Yusgiantoro & Hsiao (1993) have provided a model for the optimal production of oil and gas. In this model, variables such as total reserves, crude oil prices, extraction rate, exploration costs, and development expenditures were considered, based on which the optimal production level was calculated under Indonesian PSCs. HelmiOskoui et al. (2012) extracted the time sequence for maximizing the profits of oil and gas operations and showed that the optimum level of production can be determined using the average level of oil and gas prices and costs per oil field. Ghandi & Lin (2012) considered the behavior of the NIOC in accordance with the contractual system in the two oilfields of Soroush and Nowruz and compared the optima; production levels under the terms of the contract. They modeled optimal level of production in their research based on the amount of inland reserves, inventories, withdrawal rates, fixed costs, and discount rates, and showed that the behavior of the NIOC was not optimal in terms of oil production in these two fields and not maximize the economic profits.

Regarding optimization models, although these models take into account constraints; but they all face a complexity problem. Using any of the above-mentioned optimization models to determine the optimal level of production from oil and gas fields requires the collection and analysis of a large amount of technical and engineering data related to reserves, which follows on the complexity of the calculation and the understanding and implementation of the model. In many of these models, the second defect, namely, ignoring the constraints and provisions of the contract, remains in place in determining the optimal level of production and the economic benefits of investors. The most important contribution of this research is the incorporation of contractual financial variables in the optimization problem and applying the model to an actual project in order to achieve quantitative results. From a theoretical and applied point of view, this paper seeks to use contractual factors in determining the optimum level of petroleum production. From a methodological point of view, in order to overcome the inadequacies of regression models, in this research, dynamic nonlinear programming models of operation research courses are used. The geologic, technical and technological factors will be considered in an integrated fashion with the contractual factors in order to obtain an optimal level of petroleum production.

3. Methodology and Design

This research is applied and quantitative in terms of aims and methods. In the first analysis, in order to achieve the optimal levels of production under different contractual arrangements, quantitative data will be extracted and analyzed using scenario analysis. The strategy of this research is a kind of case study and its approach is inductive reasoning. The theoretical scope of this research can be reservoir management, operation management, contract management, and even financing and investment. The spatial scope is the Ministry of Petroleum (MOP), NIOC, Pars Oil and Gas Company (POGC). The time scope of this research can be considered now and near future. The study requires information relating to engineering, geology, cash inflows and outflows, and the terms of the contract for the development of Phases 17 and 18 of South Pars. This information was collected from MDPs for petroleum projects, phases 17&18 MDP, South Pars Gas Company (SPGC) financial and contracting department reports, international energy economic institutions such as International Energy Agency (IEA), US Energy Information Administration (EIA), Wood Mackenzie, etc.

Determining the optimum levels of production is an optimization process in which the combined effects of the geological, technical and contractual factors on the inputs and outputs along with profit maximization should be considered comprehensively over the lifespan of projects. In this research, NDOM is used to determine the optimum levels of gas production in which the maximization of the NPV of the project plays as the objective function and the technical factors and the combined effects of the contractual arrangements are considered as linear and nonlinear constraints. The NPV of gas projects consists of cash inflows and outflows from the National Oil, Gas and State Company, which is optimized with respect to the level of production as the main variable; therefore, in formulating and developing the NDOM, we must at first extract the relationship between the production level and the cash in-out flows, and then maximize the target function. Following Zhao, X., Luo, D. and Xia, L. (2012) we will estimate project output during build-up ($q_t = \frac{t}{t_1} * N * v_0$), plateau ($q_t$=N*$v_0$) and decline ($q_t = \mathrm{N} * V_0 * \frac{1}{2} * \sum_{k=1}^{12} \left(a * t^{b}_{(i-1)*12+k} * e^{-cV_0 t_{t_{(i-1)*12+k}}}\right)$) phases[1]. Then we draw revenue function, capital and operating cost functions. As well as Zhao, X., Luo, D. and Xia, L. (2012) the NDOM will set as following as presented in Equation 1 regarding some constraints:

$$Max\,\{NPV\ (V0)\} = \mathrm{MAX}\left\{\sum_{n=1}^{\infty} (CI(V_0)\_\mathrm{CO}(V_0))_t * (1+i_0)^{-t}\right\} \qquad (1)$$

c.t:

$$\frac{\partial NPV(V_0)}{\partial (V_0)}$$

$$s.t. N > 0$$

$$\sum_{t=1}^{3} q_t \leq N * efficient\ rate$$

$$0 < V_0 \leq \frac{q\ max * t_a}{N}$$

$$q_t \geq \frac{C_t}{p(1-r_g)} \qquad t_2 < t \leq t_3$$

$$0 \leq r_g < 1$$

where CI, CO, i and r_g stand for cash inflow, cash outflow, the discount rate at discounting time and participation of contracts, respectively and model constraints represent some mathematical, geological, economical and contractual limitations (will be discussed in the next section). That's what we are looking for is V_0. Given the dependence of oil-rich countries on oil revenues and the volatility of oil revenues due to the volatility of prices and their consequences, how governments

1. t1 year is the end of buildup phase, t2 is the end of plateau stage, N is the amount of proven geological reserves, and v0 is the average production rate at the Stabilization Stage expressed as a percentage. a, b and c are coefficients of estimated model.

decide on the extraction of oil and gas and turning that wealth into alternative assets is a fundamental issue. The issue of the scarcity of non-renewable sources of energy, such as oil and its rising price over time, and the efforts to replace the source of energy required, have led to the development of competing for oil resource technologies; therefore, there is a time span and price range that the cost of producing oil and gas will be more than energy cost replacement. At that time, there is an economic extraction point, although oil is present in physical reservoirs (Zhao, X., Luo, D. and Xia, L., 2012).

To solve the optimization equations, various methods such as Bellman numerology, Kan-Tucker method, Value Iteration function, repeated Bellman function, Guess and Verify, Howard's Improvement Algorithm, Repeat Policies (Policy Function Iteration) can be used. The optimization method used in this study is the Generalized Reduced Gradient or GRG method, which is capable of solving nonlinear planning problems in the framework of linear and even nonlinear constraints (Lee, 2004) and its logic-based analysis mechanism embedding the constraints in the optimized equations and turning them into an unconstrained problem. This is why these kinds of optimization methods are called gradients (Falloy, 2012). In order to set the matrix of the fundamental variables, the solver tool with the possibility of installing on Excel software was used. To solve the problem of optimization by the reduced gradient method Lingo software was used.

4. South Pars Phases 17&18 Development Characteristics:

South Pars gas field is the world's largest gas source located on the Iranian and Qatari borderline in the Persian Gulf and is named North Dome in Qatar. The area of this field is 9700 square kilometers, with Iran's share of 3700 SK. The Iranian storage area is about 14 trillion cubic meters of gas plus 18 billion barrels of gas condensate, which accounts for 5.7 percent of the world's total gas and nearly half of the country's gas reserves. One of the characteristics of this gas storage area in the 4th layer is the series and has the largest hydrocarbon reserves of the planet after the Saudi Alghavar field. Plans are now underway to develop 24 phases to produce 812 million cubic meters of gas and one million barrels of gas condensate per day. South Pars gas field development is in order to meet the growing demand for natural gas, injection into oilfields, LNG production, and supply of petrochemicals, gas exports and gas condensate. South Pars gas field development phases generally include marine facilities and equipment, gas pipelines, gas treatment plants and export facilities. This field was discovered in Qatar in 1979. The presence of gas in Iran was confirmed by the Exploration well No. 1 in 1991 and subsequently evaluated through the drilling of three appraisal wells by the Consortium TPL / Machinoexport / Saipem[1]. The reservoir blocks of the 17th and 18th phases, which are located on the western edge of the field, cover an area of 220SK. These phases contain about 16,000 billion standard cubic feet of gas and 1783 million barrels of condensate. A total of 44 wells, including 42 development wells and two appraisal-development wells in the four sea platforms have been drilled for phases 17 and 18. The contract for phases 17 and 18 was concluded as a single project through an EPC lump-sum priced between the NIOC and a consortium including the Iranian Offshore Engineering Company (IOEC), Oil Industries Engineering & Construction (OIEC) led by the Industrial Development and Renovation Organization (IDRO) in 2007.

Onshore facilities include receiving and disposing of gas and condensate units, stabilizing gas condensate, four lines of gas treatment each with a capacity of 500 million cubic feet per day, a compressor and gas compression unit, and a unit of sulfur recovery and recycling, developed by the OIEC. Two offshore platforms along with two 32-inch submarine pipelines each with a length of 105 kilometers for gas transportation, two marine pipelines of a total length of 105 kilometers each were constructed by IOEC to carry Glycol dilution. The National Drilling Company of Iran carried out drilling of 22 wells and Dana's drilling company, which also completed 22 other wells (a total of 44 wells). Sadra machine also launched two satellite platforms in a separate contract. At the maximum production level, the two phases 17 and 18 will jointly produce a total of about 2000 million cubic feet, equivalent to 56 million cubic meters of gas per day, along with significant amounts of gas condensate. The terms and conditions of payment to the contractors were such that the NIOC complied with the work and cost breakdown structures contained in the contract and with

1. SPGC contracting department, 2017.

regard to the physical progress of the work, based on the condition of the contractors. The adjusted total amount of capital expenditures was $ 6.236 billion as well as non-capital expenditures including insurance, taxes, customs duties equaling 15% of the capital expenditure of $ 935 million, for biennial spare parts and launching costs The equivalent of $ 187 million, for financing the project, is $ 765 million, as described in the Table1 below. Operational costs, repairs, and maintenance for the refinery are about $ 75 million and the offshore platforms cost about $ 25 million, a total of $ 100 million per year based on the annual cost of the SPGC and MDP.

Table1: Exploration and Development Costs for Phases 17&18

description	Actual costs ($ millions)	description	Actual costs ($ millions)
Onshore refinery	3105	Non-capex	935
Offshore pipelines	527	Launching phase costs	187
platforms	796	Bank and finance costs	765
drilling	1808	Total costs	8123
Total capex	6236		

Source: SPGC Contractual Department and Project MDP.

5. Production Profile and NPV under Neutral Scenario (Project MDP)

According to the information obtained from the MDP for phases 17 and 18, taking into account the production of 56.56 million cubic meters of gas per day (1.9 bcfd) and 95000 barrels of gas condensate at the plateau stage, the field production profile in neutral scenario is as Figure 1; where the pale blue lines represent the pathway for producing rich gas (1.9 bcfd) and dark blue lines indicating the amount of condensate production (95000 bpd) during plateau phase.

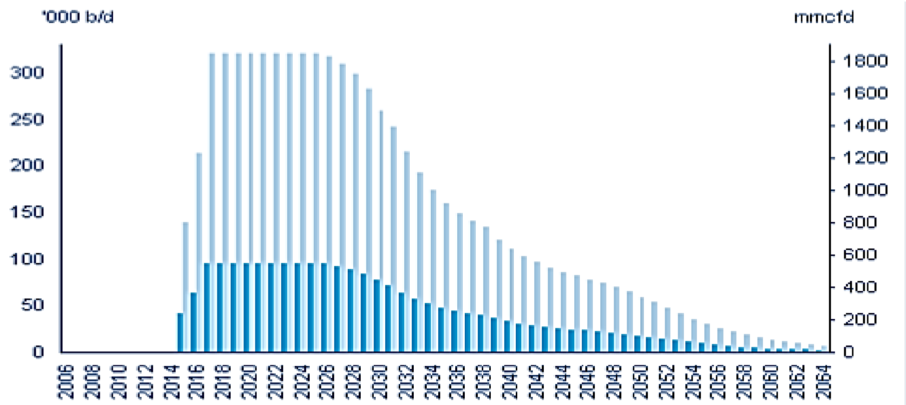

Figure 1: Production Profile for Phases 17&18 Based on MCP Department (1.9 bcfd = 56.6 mcmd)
Source: Project MDP.

Figure 1 shows the production path of the project in the normal state without affecting the type of contract, that is, the production path drawn up by the MCP department. We use this production path to calculate the NPV of the project revenues. We expect that considering the contractual elements, this path will fluctuate due to contract malfunctions,

In order to model and estimate the project's revenue, in addition to production information, the price information should also be available. In this part of the study, the Global Economic Model (GEM) & Upstream Data Tool (UDT) of wood Mackenzie estimates are used to estimate gas condensate prices, which are not significantly different from the predicted costs of the EIA. But it is a fundamental issue in estimating the price of wellhead gas; because the rich gas produced cannot be exported in the same way as oil, and there is no reliable price prediction in this regard. One of the ways to overcome this problem is to disassemble rich gas components and use the British Thermal Unit (BTU). Because of the fact that the gas composition is different in different phases of production (build-up, plateau, and decline), this methodology was not used. For the purpose of estimating the price of rich gas, time-series information on the price of wellhead prices in various parts of the United States was extracted from the EIA website, and the average price of well-headed gas sales between 1922 and 2012 (due to access to prices) was calculated in all parts of the United States. In the next step, using the econometric methods in R and R-studio software, first, the stationary of the gas price series was monitored and then estimated for 2012 to 2064. To predict the price of rich gas, must first draw a graph of this series as Figure 2:

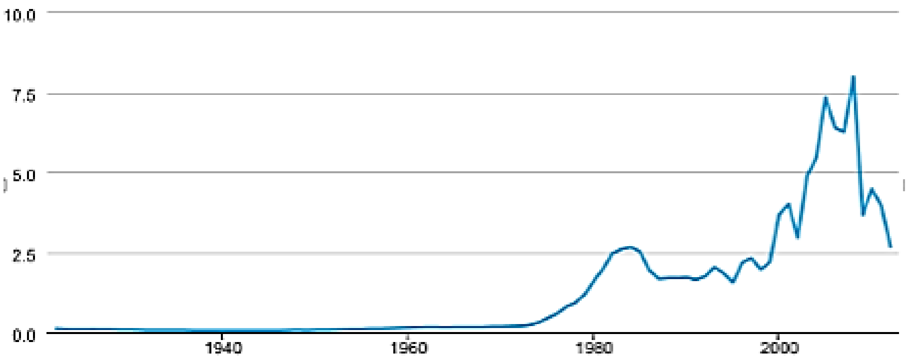

Figure 2: US Wellhead Gas Price Time Series 1922-2012 (Dollars per Thousand Cubic Feet)
Source: Research results

As you can see, there is an upward trend in this time series that started in 1975 approximately. Although this time series fluctuates over time, the overall trend is upward during the ascending period, and this suggests that we are probably dealing with a non-stationary time series that should be manipulated using econometric methods. This can be seen in Figures 3 and 4, respectively. For a time series, the Auto Regression (Moving Average) [AR (MA)] of the p-class (q-class), while the ACF (PACF)[1] chart succeeds to zero in succession, will be zero after the interruption of p(q). Therefore, the degree of autoregression (moving average) process can be determined from the ACF (PACF). In this way, in the first step- identification of the process- the wellhead gas price series is AR = 5 and MA =1. To test the stationarity of time series, it should be noted that in an ARMA process, the moving average part is always stationary for all of the time series. Therefore, being stationary for an ARMA process is only related to AR (Keshaverze Haddad, 2014). The ACF and PACF correlograms for this time series are presented in Figures 3 and 4, respectively. The lengths of bars for ACF and PACF are indicating the extent of partial autocorrelation for the corresponding lags; because they are lied out of

1. Auto Correlation Function (Partial Auto Correlation Function)

the confidence bands (blue color confidence bands) which would imply that we must reject the null hypothesis (H0: $\rho_4 = 0$) that there is no autocorrelation for time lags. Since there is significant autocorrelation for some lag(s), the US wellhead gas price time series is not stationarity.

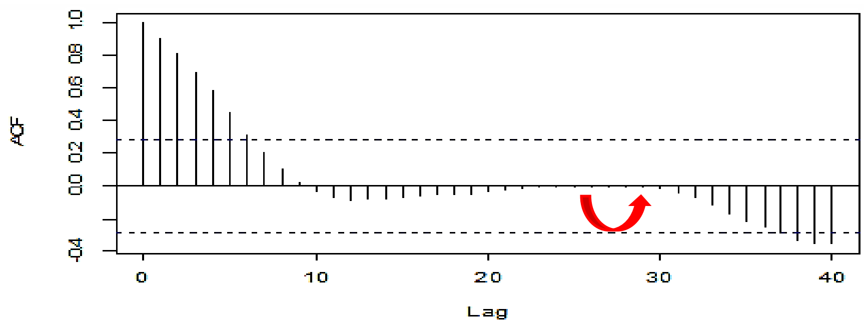

Figure 3: Auto-Correlation Function of US Wellhead Gas Price
Source: Research results

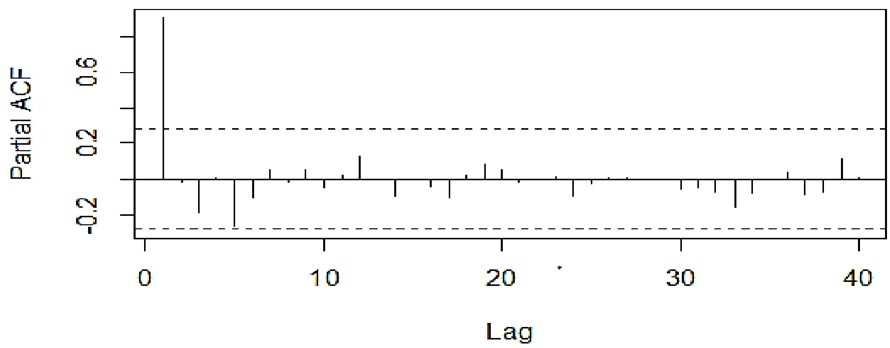

Figure 4: Partial Auto-Correlation Function of US Wellhead Gas Price
Source: Research results

As can be seen in the red highlight in Figure 3, the ACF graph is not dropping and mortal, this ensures that time series is not stationary. So as a possible treatment of the data in search of a better model to fit and to ensure being stationary, the first-order derivative (difference) of time series was used, and then the augmented dickey fuller test performed with the help of the unit root test. According to the augmented dickey fuller test, an arbitrary condition for an AR (p) is that the roots of the interpreter's equation lie outside the unit circle. Each time series has a second-order interpreter equation that may have three modes for the roots of this equation. The first mode is that the equation has two roots.

The second mode represents that the interpreter equation has a double root, and finally the third state is that the interpreter equation has no real root. If the Dickey-Fuller test show the roots of the interpreter equation in the unit circle, the interpreter equation has no real root, if it is outside the unit circle, then the interpreter equation has two real roots, and if it is exactly on the circle, then then we conclude that the interpreter equation has a double root. If a time series is stationary, then the interpreter equation roots must be real (out of the unit circle), so we hypothesize that the time series' interpreter equation has two real roots and run the unit-roots test. The results of the test are presented in Figure 5 below and show that the coefficient φ1 and φ2 interpreter's equation lie outside the circle and the stationarity/reliability of time series are confirmed.

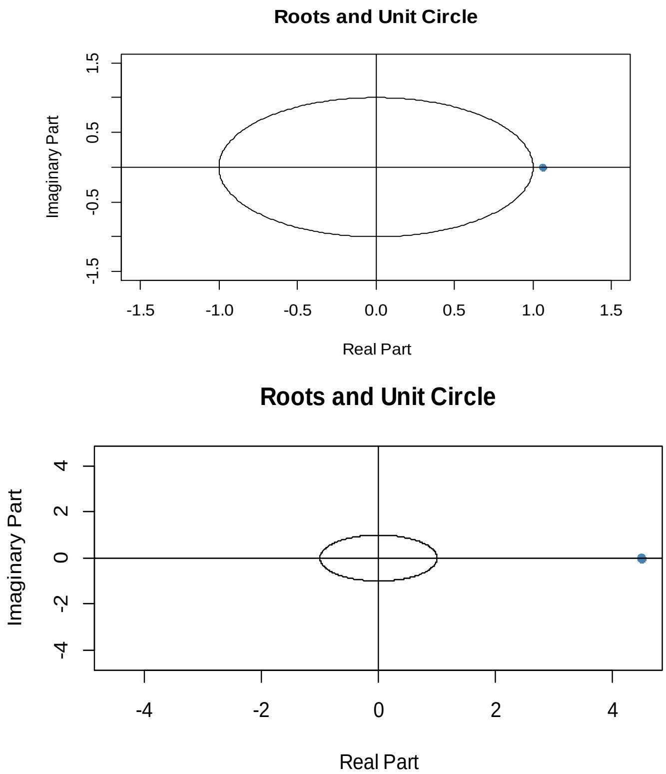

Figure 5: Unit Roots Test Results for φ1 and φ2

Source: Research results

After determining the order of the ARIMA[1] process and being

1. We refer to ARIMA instead of ARMA; because we used the first-order derivatives to test stationary of wellhead gas price.

stationary for the required time series, the adequacy of the estimated model must be evaluated to ensure that the estimated model is sufficiently feasible. The white noising of ACF and PACF of the waste is an acceptable criterion for assessing the adequacy of the estimated model. According to PACF and ACF in Figure 6, the residuals of the model are white noise with ARMA (0.0); therefore, the model is adequate to estimate wellhead gas price for ongoing years.

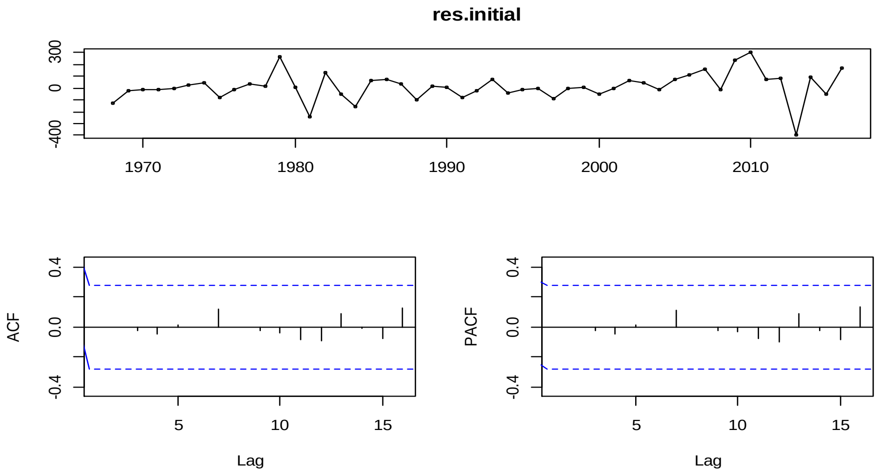

Figure 6: ACF and PACF of Residuals for Wellhead Gas Price Estimation Model
Source: Author's Estimation.

Given the above-mentioned issues and the fact that we estimate the adequacy of the estimated model to a large extent, we can predict the modeling time series. The output of these predictions is presented in Figure 7. In this Figure, the blue line represents the basic scenario; the most popular scenario that must occur for the future of rich gas prices (with high confidence levels), which is only used in this study. The most probable path that can be perceived according to the past behavior of the time series and applied to its future is presented in this baseline scenario. In addition, there are four prediction ranges in the graph, which distance from normal. The bright gray areas on the top of the blue line represent too optimistic scenarios (the lowest popularity) for the rich gas price that means the maximum potential price level. Reversely, the bright gray areas below the blue line represent too pessimistic scenarios (the lowest popularity) for the rich gas price that means the minimum potential price level. The mid-purple areas also have a moderate chance of burning (moderate likelihood).

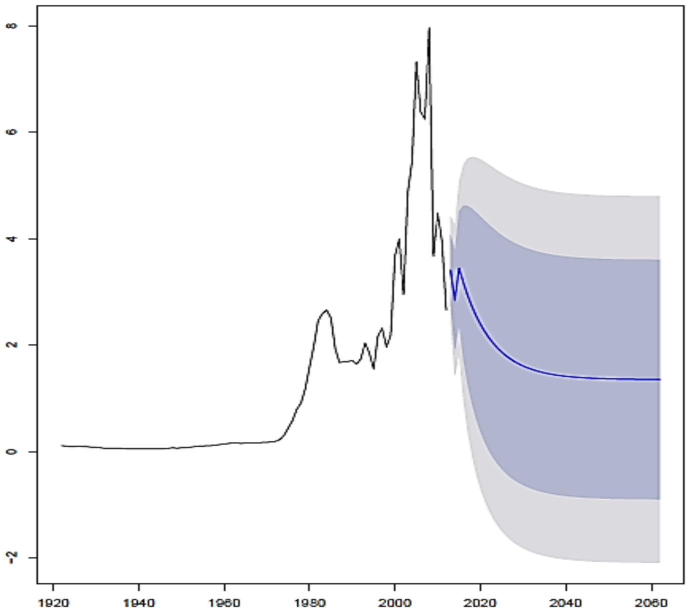

Figure 7: Wellhead Gas Price Estimation to 2064 (End of Project)
Source: Author's Simulations.

After predicting the average price of gas at the wellhead in different parts of the United States, to estimate the price of gas produced from Phases 17 and 18 (with the aim of calculating NPV of project) and its customization in order to differentiate the composition and quality of the produced gas, according to GEM and UDT provided by the Wood Mackenzie, gas prices for the South Pars Phases 17 and 18 were considered at 13.3 percent discount with respect to the US average prices.

In order to model the optimum production profile, capital and non-capital expenditures, including operating, non-operating, direct and indirect costs and money and banking charges before 2018, in actual (and not estimated) amounts, collected from the contracting, finance and accounting departments of SPGC, NIOC and documents recorded at the NIGC. All necessary information regarding the cash outflows of the project for the years after 2018 extracted from the MDP of phases 17 and 18, and in some cases also from the economic reports provided by the Wood Mackenzie. To calculate the NPV of future incomes, the discount rate is equal to the Weighted Average Cost of Capital; but these rates are associated with constraints such as ongoing changes in the structure and composition of project capital (due to continuous repayment of debts). According to Adelman (1993), a 10 percent discount rate is standard for countries producing oil and gas, such as the United States". Following Adelman (1993) and wood Mackenzie GEM, we used a 10% discount rate in NDOM to calculate NPV. This rate also describes the WACC of the project[1] and used in IPC and EPC scenarios. Rosenberg.et.al (2000), believes that acceptable discount rates for oil and gas project lie between 9% and 12%. Considering the above assumptions and information, in the neutral scenario, the total PV of future cash flows (gross) from the South Pars phases 17 and 18, as of January 1, 2018, is approximately $ 54030 million Regardless of the payment of any taxes; that is divided between operating expenses (direct and indirect), operating costs (variable and fixed) and net cash flows (NPVs) as Figure 8:

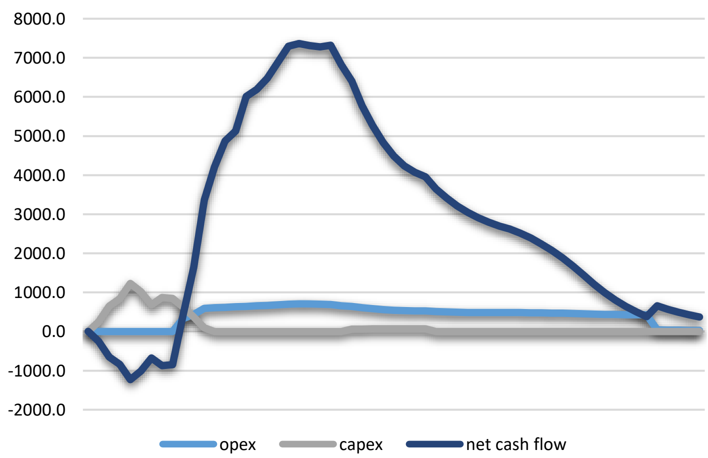

Figure 8: PV Division (Opex, Capex and Net Cash Flow)
Source: Research results

Therefore, net of any tax, and without considering any disruptions derived from contractual arrangements, the NPV of the cash flows from the project is approximately $ 37760 million, based on nominal figures for January 2018 at the production level of 1.9 bcf [56.56 mcm] per day

1. According to the financing structure of project, the average cost of capital is 9.8%, with a slight margin of error, does not have a significant difference with 10% in the significance level of α=5%.

in plateau stage.

6. Parameters and Assumptions of the Optimization Model

In this study, the model proposed by Zhao & Luo and Xia (2012) is used to determine the optimum gas production level from phases 17 and 18 of the South Pars gas field. In the following, at first, the expression of the subjective form and the estimation of revenue, cost, and dynamic production functions are discussed. After estimating the functions, the optimization problem is plotted and the optimal production path is modeled under EPC and IPC. According to information from the MCP and the technical and engineering reports, the total in-place gas reserves in the phases 17 and 18 of is assumed to be equals to 15.99 trillion feet Cube. In the calculation of the optimum gas production level, the production of gas condensate has been neglected; therefore, the fee function (contractor's fee) in an IPC contract is estimated only on the basis of rich gas production (excluding condensate). Gas condensate is computed only in the calculation of the NPV of the project's cash flows. The contractor's fee is estimated in the IPC contract with consideration of the phases 17 & 18 projects as offshore and low-risk projects. Since the models presented in this study have an unlimited time horizon and full-field depletion is considered economically, salvage value is considered zero. Other assumptions are summarized in Table 2 below:

Table 2: Optimization Model Assumptions

Current production rate (annual)	4.54%
Production profile	2015-2064
Build-up stage	2015-2017
Plateau stage	2017-2034
Decline stage (IOR,EOR, closure)	2034-2064
Discount rate and date	**10%, January 2018**

Source: Project MDP, MCP Department

Generally, the gross annual revenue (from 2015 to 2064) is calculated with the following formula, Equation 2:

$$\mathrm{TR}_t = (p_t * q_t) \quad (2)$$

here $\mathbf{p_t}$ is the wellhead gas price in year t, $\mathbf{q_t}$, the annual production of gas in year t (previously discussed) and $\mathbf{TR_t}$ is also the total gross revenue from gas sales. The production function at the three stages will be as Equations 3, 4 and 5, respectively:

2015 - 2017: $q_t = \frac{t}{3} * 15990\ bcf * v_0$, t = 1, 2 , 3. (3)

2017 - 2034: $q_t = 15990\ bcf * v_0$, $2017 \leq t \leq 2034$ (4)

2034 - 2064: $$q_t = 15990\ bcf * V_0 * \frac{1}{12} * \sum_{k=1}^{12} \left(0.975 * t_{(i-1)*12+k}^{-0.08} * e^{-0.37 V_0 t_{t_{(i-1)*12+k}}}\right)$$

$2064 \geq t \geq 2034$ (5)

Fangjin Wang et al. (2007) gathered information on the production profile of 61 oil and gas fields located in different geographically developed areas of the world and showed that the coefficients obtained to predict production in the decline phase are highly correlated. Using the econometric model, they calculated the required coefficients. Following this research, the resulting coefficients have become a standard, and later researchers such as Zhao et al. (2012) have used this model. Coefficients of a, b, c have been used to follow the model developed by Fangjin Wang et al. (2007) and Zhao et al. (2012). In all of the above revenue functions, the v_0 is the target variable or optimal production rate that we are trying to calculate. To determine the gas price, the pricing information used in modeling the cash flows which was calculated and predicted previously with the help of R and R-studio econometric software, was used. Now the project cash inflow is estimated using Equation 6, in which rg stands for contract participation.

$CI = R_t * (1 - r_g)$ (6)

In the IPCs, all direct and indirect capital expenditures plus monetary costs (interest), as well as other operating expenses and, will be recovered at most 50% of the field revenues within 5 to 7 years. Therefore, to sum up, the revenue function from gas sales in the South Pars phases 17 and 18 projects for the EPC contract is CI = Rt, which has three forms in three stages. This function is also estimated in the IPC contracts with a coefficient of participation of 50%, which after the recovery of costs, the revenue function of the IPC contract will be identical to the revenue function of the EPC contract.

Given that the phase of exploration and development of phases 17 and 18 have already been completed and operations have begun, instead of estimating exploration and development costs in pre-operational periods, historical data have been used (nominal amounts of 2018). Information about the costs of exploration and development before exploitation for phases 17 and 18 of the South Pars has also been confirmed by the property management department of NIOC, which has been reflected in the category of "capitalized assets" ledger accounts. Given that IPC contracts provide for an exploration and development period of roughly 7 years, it is assumed that all costs of exploration and development of South Pars phases 17 and 18 (approximately $ 8.8 billion) are equally pended in 7 installments from 2007 to 2014 and have been fully recovered in the upcoming periods from 50% of the field revenues. In general, capital expenditures at the development stage can be divided into two parts of the initial investment in wells and land engineering and re-investment into additional production wells (Zhao et al., 2012; Ghandi & Lin, 2012). Considering 56.56 mcm of gas production per day from 44 production wells, an average of 45 million cubic feet of daily production per well is produced in phases 17 and 18 of South Pars. In this case, the number of production wells in future periods is estimated using Equation 7:

$$n_c = \frac{15990\ bcf * V0}{365 * 45\ mmcfd} \tag{7}$$

Considering the above function, the number of wells required for gas and water injection in the future can also be estimated by having a ratio of injection to production and the number of wells produced as a function of the production level. According to Amiri and Ghaseminejad (2011), the ratio of injection to gas production for phases 17 and 18 is considered to be 1800 to 6500 cubic feet; in this case, the total number of injection wells in phases 17 and 18 South Pars in decline stage is estimated using the Equation 8:

$$n_k = \frac{\left(1+\frac{1800}{6500}\right)*15990\ bcf*V0}{365*45\ mmcfd} \tag{8}$$

According to data from the US EIA, as well as GEM of Wood Mackenzie, the development costs for each well in Phase 17 and 18 were roughly equal to $ 170 million. In this case, the future developmental cost function is estimated as a function of the optimal production level as Equation 9 as follows:

$$I_k = \frac{\left(1+\frac{1800}{6500}\right)*15990\ bcf*V0}{365*45\ mmcfd}*170\ \text{US\$M} \tag{9}$$

Infrastructure costs and maintenance of wellhead facilities as well as oil wells related costs, major components of development expenditures. Infrastructure and maintenance costs of surface facilities are divided into fixed and variable parts relative to oil and gas production levels. Expenditure such as collection and transmission of produced gas, secondary recovery costs (EORs), water and electricity costs, etc. are part of variable infrastructure costs and expenses such as road construction costs, camps and facilities are among fixed expenditures. Information regarding these costs is available on the EIA website for different geological structures and can be used for Iran. As phases 17 & 18 are in offshore and low-risk low-risk, variable cost per 6000 cubic feet is about 2.34$, approximately. According to GEM and UDT, fixed cost for infrastructure developments of phases 17&18 is estimated to be 12.17 million $ per annum. Converting 6000cf to mcf, another development cost function is defined as in Equation10:

$$I_d = (390\$ * 15990000\ \text{mmcf}* V0) + 12.170\ \$\text{m} \tag{10}$$

Considering above functions, total development cost function is modeled as Equation11:

$$I = \left(\frac{170\ \$M*(1+\frac{1800}{6500})}{365*45\ \text{mmcfd}} + 390\$\right)*15990\ \text{bcf}*V0 + 12.17\ \$m \qquad (11)$$

After modeling capital expenditures now it is time to draw operating cost functions. Wang et al. (2005) and Zhao et al. (2012) estimated operating cost as a function of optimum production level. These authors estimated operating costs at the plateau stage using Equation 12:

$$C_t = c_{nt} * n_k + c_{qt} * q_t \qquad (12)$$

where c_{nt} operating expense per production well and c_{qt} represents the operating expense per unit of production (for example cubic foot). Opex per well can be estimated by dividing total opex during the project by the number of production wells. Regarding total opex and 44 productions well for phases 17& 18, the opex per well is around 380 million$. Also according to GEM and UDT, operating expenses per 6000 cubic feet are estimated to be 4.46 $ which is not significantly different from EIA figures[1]. Replacing these figures in the opex equation will result in Equation 13:

$$C_t = \left(380\ \$m * \frac{\left(1+\frac{1800}{6500}\right)*15990000\ \text{mmcf}*V0}{365*45\ \text{mmcfd}}\right) + (785\$ * 15990000\ \text{mmcf} *\ V0) \ (13)$$

Now we can run the optimization model for EPC and IPC contracts.

7. Optimum Production under EPC Contractual Arrangements

The general framework of the dynamic optimization model in the form of an EPC contract and in the plateau stabilization stage from 2017 to 2034 will be as Equation14:

1. 4.5$ per 6000 cubic feet.

$$\boldsymbol{Max}\,\{\boldsymbol{NPV}\,(\boldsymbol{V0})\} = \mathbf{MAX}\left\{\sum_{t=1}^{17}\left((\mathbf{15990}\boldsymbol{bcf} * \mathbf{p}\ * \boldsymbol{v}_{\mathbf{0}})_{-}\left(\left(\frac{\mathbf{170\$M}*\left(\mathbf{1}+\frac{\mathbf{1800}}{\mathbf{6500}}\right)}{\mathbf{365}*\mathbf{45}\boldsymbol{mmcfd}} + \mathbf{390\$}\right) * \mathbf{15990}\ \boldsymbol{bcf} * \boldsymbol{V}\mathbf{0} + \mathbf{12.17\$}\boldsymbol{m}\right) - \left(\left(\mathbf{380\$}\boldsymbol{m} * \frac{\left(\mathbf{1}+\frac{\mathbf{1800}}{\mathbf{6500}}\right)*\mathbf{15990000}\ \boldsymbol{mmcf}*\boldsymbol{V}\mathbf{0}}{\mathbf{365}*\mathbf{45}\boldsymbol{mmcfd}}\right) + (\mathbf{785\$} * \mathbf{15990000}\boldsymbol{mmcf} *\ \boldsymbol{V}\mathbf{0})\right)\right)_{\boldsymbol{t}} * (\mathbf{1}+\mathbf{10}\%)^{-\boldsymbol{t}}\right\} \tag{14}$$

Regarding the following constraints:

$$s.t.N > 0$$
$$\sum_{t=1}^{3} q_t \leq N * efficient\ rate$$
$$0 < V_0 \leq \frac{q\ max * t_a}{N}$$
$$q_t \geq \frac{C_t}{p(1-r_g)} \qquad t_2 < t \leq\ t_3$$
$$0 \leq r_g <\ 1$$

The first constraint states (mathematical) that the NPV function must have a maximum point in order to claim that the corresponding V0 is optimal. The second limitation as a technical-geological constraint point to the fact that all primary or proven gas or crude oil reserves should be positive. The third indicates the maximum production ceiling or production ceiling of the project, which indicates that cumulative production from the project site should not exceed the product of the proven in-field reserves at the Maximum Efficient Rate, briefly MER (5%). The fourth condition, which indicates that the optimum production level cannot be more than neutral in production, implies a contractual limitation and ensures that the optimal level for producing rich gas under the l EPC and IPC formats are necessarily less than 56.6 million cubic meters per day (1.99 bcfd). The fifth function of the maximization function is the trajectory of the rich gas production. Under this economic constraint, if the continued production is economically justifiable and cost-effective, the operating proceeds (after deducting the coefficient of participation of the second-party contract) outweigh the costs and expenses of that operation during that period. Given that t_3 happens for all oil and gas projects (that is, the termination of the project or decommissioning), it cannot be construed as a constraint; but would be a limitation in cases before reaching the end Project life (t_3). Finally, the sixth limitation of this function as a contractual limitation states that the coefficient of participation of domestic or foreign contractors in the implementation of oil and gas projects cannot be 100% without the participation of the NIOC, while this coefficient is zero in EPC contracts.

Based on the results, the optimal production level of gas from the phases 17 and 18 of at the plateau phase and under the contractual arrangements of the EPC is estimated about 1.845bcfd which, given the constant consideration of proven geological reserves, the annual extraction rate will be 0.0421 (approximately 4.2%). Therefore, the optimal production level achieved by the EPC contract is significantly different from the production profile drawn by the MCP department. Subsequently, net of any taxes, considering the EPC's contractual arrangements and the resulting constraints, the NPV of this project (from the government point of view) is estimated to be $ 36,163 million approximately, based on nominal figures of January 2018. The main reason for this decline is a change in the scheduling of capital expenditures relative to the pre-determined MDP (due to the delay in the implementation of the project). The gas production profile of the South Pars phases 17 and 18 under the contractual arrangements of EPC will be as Figure 10.

8. Optimum Production under IPC Contractual Arrangements

Optimizing the production path within the framework of IPC contracts due to the addition of various and sometimes complex financial parameters is much more difficult than optimizing the optimal production path for the EPC contract. In IPC contracts, the division of proceeds from project implementation between the host government or its legal representative and foreign company is represented by Equations 15 and 16:

$$GT = p_t * q_t - [(1-g) * \phi t * (p_t * q_t * R_t) + \frac{DCC}{\beta} * s + IDC_t + COM_t + OPEX_t - CF_t] \quad (15)$$

$$FOCT = (1-g) * \phi t * (p_t * q_t * R_t) - CF_t] \quad (16)$$

where GT represents the government take (here the MOP), FOCT represents the revenue of the foreign company, φt is the contractor's fee or contract remuneration in year t, which is a function of price, production, R factor, and field type, Rt is the same factor as R Which is equal to the total contractor's cumulative revenue from the beginning to the end of the previous period with respect to the total costs recovered in the same period, β represents the duration of the period for the repayment of direct capital costs (between 5 and 7 years), and CF is the amount of employer liabilities that is carried forward because of the rape of the repayment ceiling considered to period. Accordingly, if $t < \beta$, the value of s is equal to 1 and otherwise equal to zero. In IPC contracts, all costs of the oil operations, including Direct Capital Costs, Indirect Capital Costs and operating costs will be recovered in the form of petroleum costs. It is worth noting that the amount of petroleum cost in each period will not exceed 50% of the revenue or field output and will be at most equal to 50% of the revenue or production of the field. The cost of capital that has been incurred since the initial production date is also settled within 5 to 7 years after that date. The costs of money are calculated in terms of the formula specified in the contract, and on the payment of direct costs, from the date spent to the year of recovery. Also, indirect costs will be spent before the start of primary production within 5 to 7 years, starting with the date of initial production. Indirect costs after the initial production have been settled within 5 to 7 years from the date that are spent (Hosseini, 2014).

In addition to the costs incurred by the contractor, he also receives a certain fee, which is paid from the field income along with the costs. In IPC contracts, the contractor's fee is calculated based on the amount of production realized from the field. Since phases 17 and 18 are classified as low-risk, independent and offshore projects, following the research by Bahadori (2015) at the NIOC, the base rate of fee for every 1,000 cubic feet of gas will consider $0.12 ($120 per million cubic feet of gas), which is adjusted annually on the basis of R factor. This factor is used in contracts of countries like Venezuela, Colombia, Qatar, Iraq, and Malaysia. In IPC contracts, the decreases in fee rate with increasing contractor revenues over costs incurred during the project period. This is in order to prevent the windfall income to the contractor and, as noted, is used in many of the world's oil contracts. The R-factor equation is measurable by Equation17:

$$R_{t+1} = \frac{\phi_t + CR_t + R_t * AC_t}{TC_t + AC_t} \tag{17}$$

where φ_t represents the fee, CRt, the recovery rate in year t, Rt is the factor R, and ACt is the total of expenditures from the beginning to year t. TCt also represents the expenditures incurred in year t. Since ACt the total sum of all costs from period 1 to the previous period (t-1) must be considered in the R state equation as a separate state variable since, in each state equation, the state value in the next period is required only to be relevant to the values of the current period for variables (and not past periods). This variable is defined by Equation18:

$$\mathrm{AC_{t+1}} = \mathrm{AC_t} + \mathrm{TC_t} \tag{18}$$

So:

$$\mathrm{AC_t} = \sum_{\mathrm{k=1}}^{\mathrm{t-1}} \mathrm{TC_k}$$

Another variable whose value in each period is related to the values of the previous period and the choices of the control variable depends on it, is the cumulative unrecovered cost of the contractor, which is represented by $ACFt$. The value of this variable, especially in the last year of the contract, is very important; because if the amount exceeds 50% of the value of the production, the contract will not be refunded to the contractor. This variable is defined then by Equation 19:

$$ACF_{t+1} = ACF_t + CF_t * (1 + CoM) \tag{19}$$

In the IPC contract, in each period, up to 50% of the field income can be assigned to reimburse the contractor's costs and fees, and if the contractor's claims exceed the specified ceiling during the period, the reimbursement of the surplus will be due to the subsequent period; therefore, these limitations can be specified as Equation 20:

$$AP_t = TP_t - CF_t \leq \%50 * p_t * q_t \tag{20}$$

By considering the components of the contractor's repayable claims (TPt), the above function can be re-expressed by Equation 21:

$$APt = ((1-g) + (S*DCCt/\beta + COMt + OPXt) - CFt \leq 50\% * pt*qt \tag{21}$$

So the recoverable cost for a contractor in each period is calculated as Equation 22:

$$CFt = \max(TPt - \mu PtQt, -ACFt) \tag{22}$$

This relationship states that the contractor's deferrals in each period are obtained from the maximum difference between the contractor's claims (TPt) and the repayment ceiling ($\mu PtQt$), and the negative accumulated deferrals. If the above-mentioned difference (TPt-$\mu PtQt$) is positive, it means the contractor's claims exceed the repayment limit, the deferred amount in this period will be positive and equal to the difference. However, if the above-mentioned difference (TPt-$\mu PtQt$) is negative (that is, the contractor's claims are less than the repayment limit), the deferred amount in this period (in the absence of accumulated cumulative write-offs) will be negative (which means partial /complete repayment of all cumulative deferrals of the contractor), But its amount will be at least equal to the cumulative deferrals.

Capital and operational expenditure functions are estimated in the previous section. The Cost of Money (COM) function is also estimated ~~as~~ by Equation 23:

$$\mathrm{COM_t} = (1 + \mathrm{LIBOR} + \mathrm{prm}) * \mathrm{CF_{t-1}} \tag{23}$$

where the rate of Libor has been extracted annually from www.global-rates.com and Premium's interest rate is 1% according to IPC contracts. Now the general framework of the dynamic optimization model in the form of an IPC contract and in the plateau stabilization stage from 2017 to 2034 will be as Equation 24:

$$\text{Max}\,\{\text{NPV (V0)}\} = \sum_{t=1}^{17} \text{pt} * 15990\text{bcf} * v_0 - \{(1\text{-g}) * \phi t * (\text{pt} * 15990\text{bcf} * v_0 * \text{Rt}) + \frac{\text{DCC}}{7} * s + \text{IDC}_t + (1 + \text{LIBOR} + 1\%) * \text{CF}_{t-1})_t + \text{OPEX}_t - \text{CF}_t\} * (1+10\%)\text{-t} \quad (24)$$

where g is equal to 50% before the contractor's recovery (first 7 years) and then equal to zero. The constraints governing this model are the same as the constraints governing the target function in the EPC contract.

Based on the results, the optimal production level of gas from the phases 17 and 18 of at the plateau phase and under the contractual arrangements of the IPC is estimated about 1.77 bcfd which, given the constant consideration of proven geological reserves, the annual extraction rate will be 0.0405 (approximately 4%). Therefore, the optimal production level achieved by the IPC contract is significantly different from the production profile drawn by the MCP department. Subsequently, net of any taxes, considering the IPC's contractual arrangements and the resulting constraints, the NPV of this project (from the government point of view) is estimated to be $ 31,402 million approximately, based on nominal figures of January 2018. The main reasons for this decline are changes in the IPC's arrangements for recovery of capital, non-capital and operating costs, costs of money most importantly, contractor's fee. The gas production profile of the South Pars phases 17 and 18 under the contractual arrangements of IPC will be as shown in Figure 9.

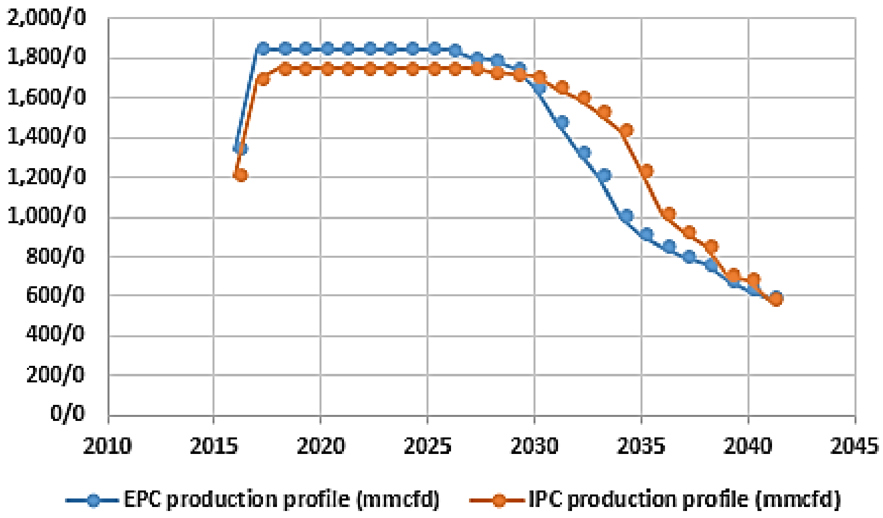

Figure 9: IPC vs EPC Production Profile (mmcfd) for Phases 17&18
Source: Simulation Results.

As can be seen, the production of gas from the Phases 17 &18 project under the IPC and EPC contractual arrangements has the same overall trend, which is expected to slow down starting in 2030 and continue until 2042. The major difference between the optimal production paths based on the two contracts is that, in IPC contracts, the contractor's interests continue to be profitable in the long run even after the recovery of capital and non-capital expenditures (fee per thousand cubic meters' rich gas) and although in the stabilization stage, the optimal level of production is lower than the EPC contract, but instead, the project will enter into a decline reduction period of about 2 to 3 years later. In addition, because of the application of enhanced or improved recovery methods and the recovery factor by the contractor, the decline phase in the IPC contracts has a more moderate slope relative to the EPCs, and this trend continues until the termination of the IPC contract. After termination of the IPC contract, the behavior of the optimum level of production in both cases will be the same and consistent.

9. Scenario Analysis

Scenario 1: Reduction of Contractor's Fee to 60 $ per mmcfd

In this scenario, it is assumed that the base rate of contractor's fee per thousand cubic feet of gas compared to the base scenario ($ .12 per thousand cubic feet) will be reduced to $.60 per thousand cubic feet.

The optimal production path in this scenario based on the IPC contract is shown in Figure 10:

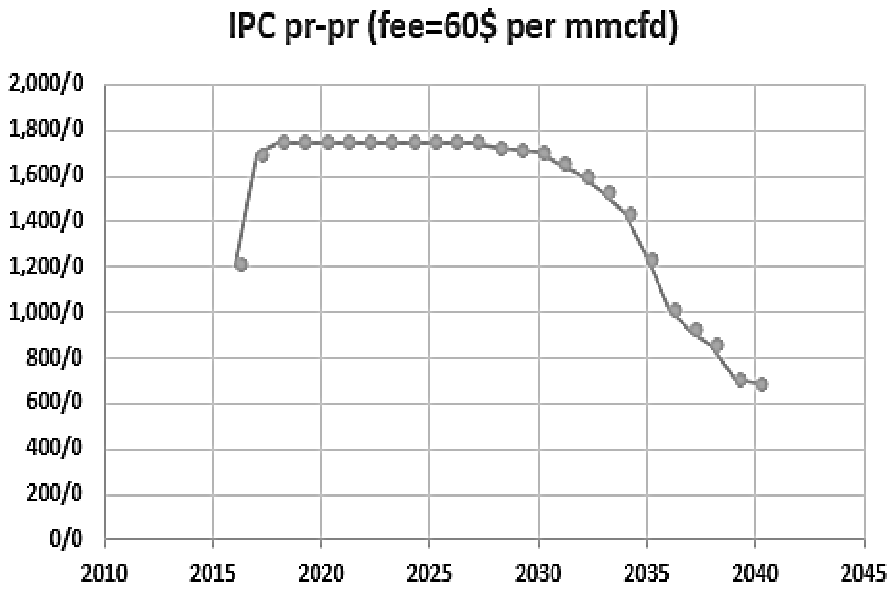

Figure 10: IPC Production Profile (mmcfd) under Scenario 1
Source: Simulation Results.

In this case, the optimal path of production in the IPC contract will be the same as the reference scenario (1.77 bcfd). This could be due to the fact that in this scenario, unlike the reference scenario, because of the low fee, repayment to the contractor will not be delayed at any time, and the carry forward amount will be zero. In other words, the lower contractor's fee causes the contractor's claims not to exceed the stipulated repayment limit (50%).

Scenario 2: Increasing the Contractor's Fee to 150 $ per mmcfd (Figure 11)
The optimal production path in this scenario based on the IPC contract is shown in Figure 11:

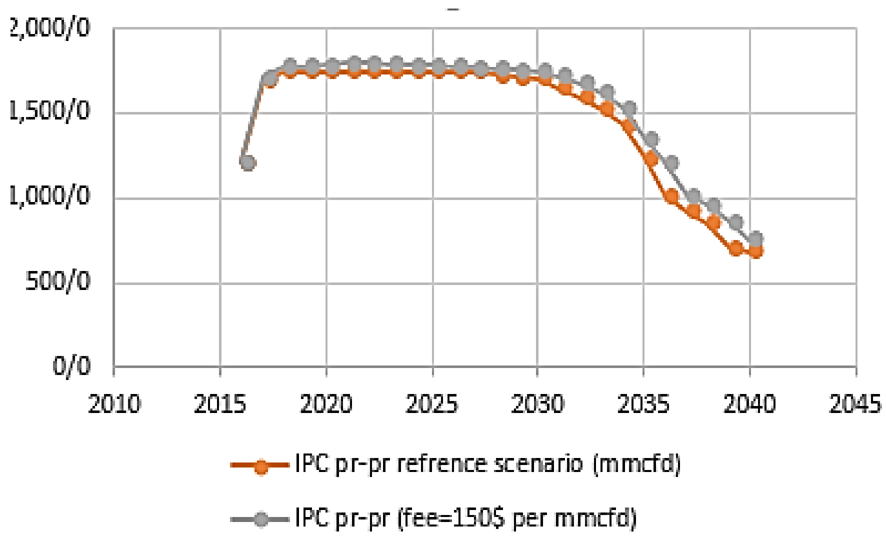

Figure 11: IPC Production Profile (mmcfd) under Scenario 2
Source: Simulation Results.

According to the Figure11, the optimal production path in Scenario 2 during the years of the contractor's presence is slightly different from the reference scenario and is at a higher level because, by increasing the contractor's fee as the most important component of profitability, the recoverable amounts by the contractor increased in each period and in the case of failure to reimburse the full amount in the next period will be subject to interest rates; therefore, in this scenario, a higher level of production must be realized in order to recover the costs of the contractor in the light of the time value of the money and the incentive of the contractor. In general, it can be concluded from scenario 1 and 2 that, under the conditions examined, optimal production under the IPC contract does not change much with changes in contractor fees. One of the main reasons for this is the severe limitations of production ceilings per period determined by technical and geological constraints. In fact, the constraint of maximum production in a dynamic planning problem is highly binding.

Scenario 3: Reduction in Recovery Period of Capital Costs

In this scenario, unlike the reference scenario (7-year subscription period), the payback period is considered to be 5 years. The optimum level of rich gas production in this scenario for the plateau period is roughly equal to 1.85 bcfd, which the optimal production path under the IPC contract is as shown in Figure 12:

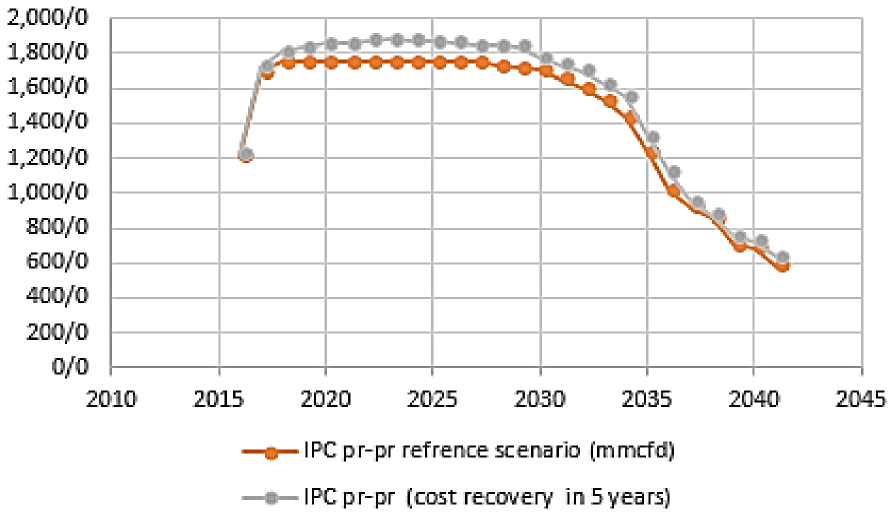

Figure 12: IPC Production Profile (mmcfd) under Scenario 3
Source: Simulation Results.

As seen in this scenario, the optimum level of production in the early years of stabilization of plateau is higher than the reference scenario. This is due to the fact that the production must be such as to allow to repay the contractor's expenses within five years from the date of the original withdrawal. Because there are technical and geological constraints such as maximum production ceilings or MER all contractor costs are not reimbursed within 5 years, and part of it, along with the COM will be transferred to the next periods. This leads to a slight difference in the optimal level of production in this scenario with the reference scenario for several years.

Scenario 4: Increasing the Recovery Period of Capital Costs
In this scenario, unlike the reference scenario (the 7-year subscription period), the payback period is considered to be 10 years. The optimum level of rich gas production in this scenario for the period of the plateau is about 1.69 bcfd, which is the optimal path of production under the IPC contract as Figure 13 follows:

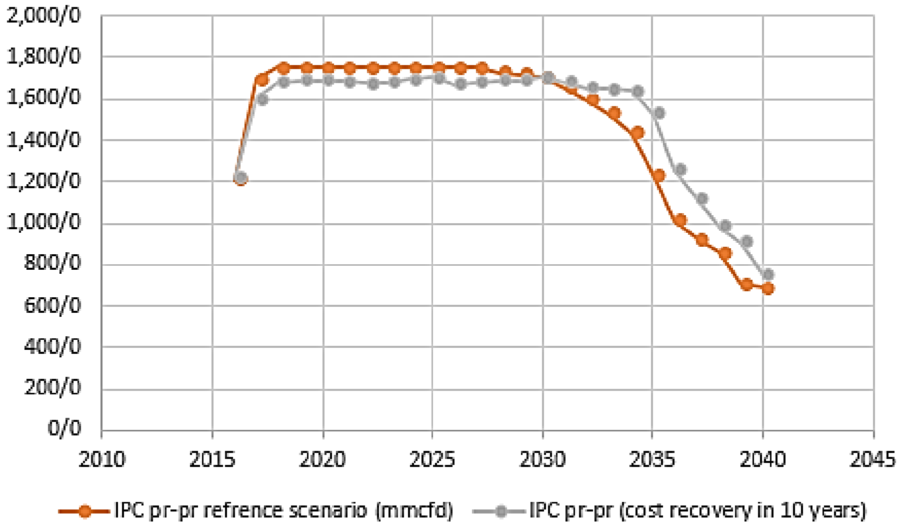

Figure 13: IPC Production Profile (mmcfd) Under Scenario 4
Source: Simulation Results.

According to Figure 13, with the increase in the period of partial repayment of contractor's capital expenditures in the early years, the optimal production level is lower than the reference scenario. In this scenario, the contractor and the employer prefer to postpone the proceeds of the project to the future, and also with regard to the remaining reserves, the transshipment period will be longer than the reference scenario and the cost of capital to implement the upgrading methods will be postponed to subsequent years, which will be in the interest of the contractor due to the time value of money. In scenarios 3 and 4, also the production ceiling and MER are generally applicable, and it prevents the significant impact of the contract on reimbursement of contractor costs on the optimum level of gas production from Phases 17 and 18.

Scenario 5: Reduction of Recovery Coefficient
In this scenario, unlike the reference scenario (50% rebate ceiling), it is assumed that the repayment ceiling for contractor costs in the contract is 30%. The optimum level of rich gas production in this scenario for the plateau period is approximately equal to 1.89 bcfd, which is the optimal path of production based on the IPC contract as Figure 14 follows:

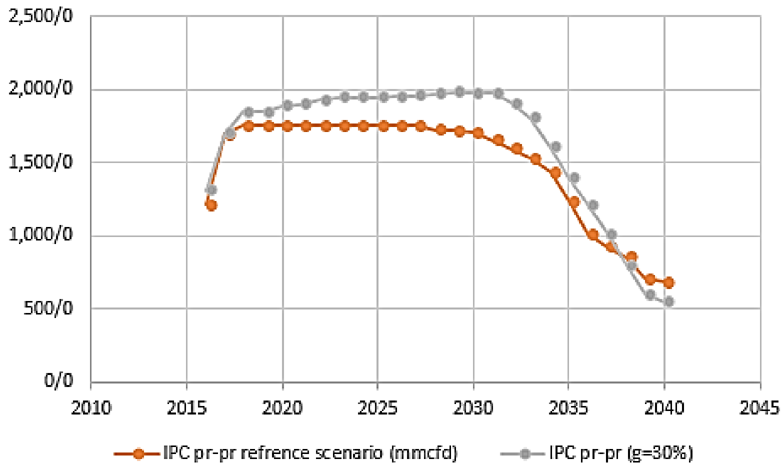

Figure 14: IPC Production Profile (mmcfd) under Scenario 5
Source: Simulation Results.

Given the fact that the contractor's cost recovery ratio is low and in contrast to the employer's participation rate, in the early years of plateau, the optimum level of rich gas production was higher than the reference scenario and in some years the maximum extraction rate (1.99bcfd of MDP), which takes into account the time value of money, this behavior towards the reservoir is in the interests of the contractor and employer, and also causes contractor cost will not be carried forward and the employer will spend less on future COM. Of course, in this regard, the maximum production limit is mandatory and does not allow unpreserved behavior to occur.

Scenario 6: Increasing of Recovery Coefficient

In this scenario, contrary to the reference scenario (50% rebate rate), it is assumed that the repayment ceiling for contractor costs in the contract is 80%. The optimal level of rich gas production in this scenario (approximately 1.73 bcfd) is very close to the optimal production level in the reference scenario, which is shown in Figure 15 below:

In this scenario, during the stabilization period of the reservoir, there is no significant difference between the optimal route in the neutral scenario and the increase in payment ceiling of up to 80% of revenue, and only 4 to 5 years after the stabilization, the optimal production level is lower than the reference scenario and can be recovering the contractor's expense in the very early years. Of course, given the importance of the time value of money for the employer and the contractor, this retreat from the optimal level of production in the reference scenario is immediately abandoned and compensated in the late years of the plateau period.

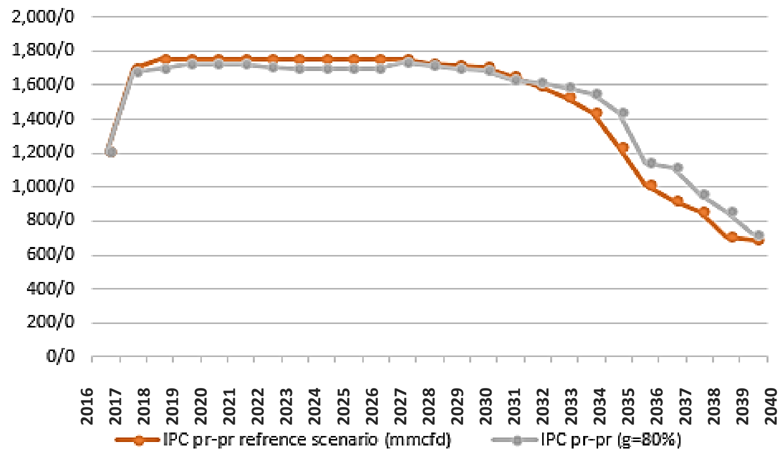

Figure 15: IPC Production Profile (mmcfd) under Scenario 6
Source: Simulation Results.

Now we can sum up scenarios as Figure 16:

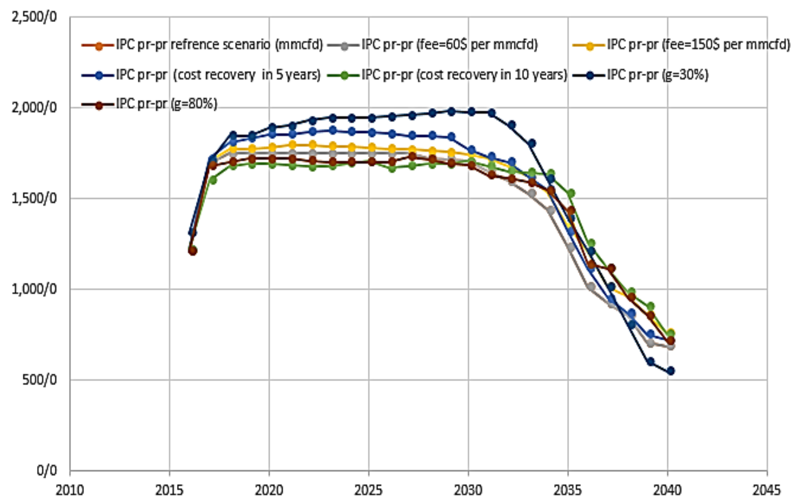

Figure 16: Summary of Scenario Analysis of Optimal Production Level under Different Contractual Arrangements
Source: Simulation Results.

According to the above, it can be concluded that contractual factors and arrangements can also affect the production profile of oil and gas projects and consequently the NPV of future cash flows as well as geological and technical factors.

10. Conclusions and Discussions

The level of oil and gas production from the upstream projects of the country is one of the most important factors in the MDPs and plays an unbreakable role in the return on investment and profitability of the parties to the contract, especially the contractor. In Iran's oil and gas contracts, the preparation of an MDP is one of the responsibilities of the MOP. So the production profile for oil and gas projects is estimated by the MCP department and presented in the form of the MDP to the contractor. Currently, plotting and profiling oil and gas production in MDP is based solely on technical and geological factors and plays an important role in designing and building the required capacity for subsurface and wellhead equipment (capital expenditures). The results of this study, as well as Nutao (2005); Zhao, Luo and Xia (2012); Helmi Oskoui et al. (2012); and Ghandi & Lin (2012) indicated that the determination of the optimal production level of oil and gas projects is strongly influenced by the provisions, arrangements, and mechanisms contained in the contract, as well as technical and geological factors. In other words, the level of production provided by the MCP department of NIOC is not optimal and will vary depending on the terms and conditions governing contracts, from the EPC to the IPC contract. Also, the results of this study showed that NDOMs are suited tools for estimating the optimum profile of oil and gas production; because they enable us to review the current production level with changes in economic, technical, technological and contractual conditions, and renew the optimal path. In this research, the optimal path in the neutral state (the production profile of the MCP department) was also presented. In this case, it was assumed there is no contractual disruption and the results are optimal in terms of government. The results showed that in all of the scenarios examined, the NPV of the project was lower in contract models than neutral, which indicates the effect of contractual factors.

For realistic modeling of the exploiter problem in the framework of oil contracts, one should design a suitable model for extraction and production that has different stages of exploitation and the physical rules governing extraction. On the other hand, the financial and economic components of the contract must be fully detailed in the objective function and the optimization constraints. Based on the results, it is suggested that the MCP department of NIOC and other planners in the preparation of oil and gas project's MDPs should pay attention to contract factors and arrangements to draw the production profile of oil and gas projects. Also, oil and gas companies, including foreign contractors and domestic exploration and production companies, as well as the MOP, will use dynamic optimization models to formulate strategies for the development and exploitation of oil and gas fields, and the requirements for preserved production. The determinant factor of the optimal production path in all scenarios is the production ceiling or the maximum effective rate that is calculated on the basis of technical engineering relationships. Therefore, focusing on incentive mechanisms to encourage the contractor to use advanced technologies such as hydraulic fracture technology, fishbone lifts, and directional drilling, implementation of the EOR and IOR methods, increase the MER and hence the recovery factor of reservoirs. Considering some limitations related to data gathering, the internalization of variables such as the contract duration, MER and the gas/water injection volume, in order to calculate the optimal amount of each to maximize the present value of the entire operating period cash flows and defining an intergenerational utility function as an alternative to objective function are among topics that are recommended for researchers interested in this field.

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Nomenclature

ACF	Auto Correlation Function
AR	Auto Regression
BTU	British Thermal Unit
COM	Cost Of Money
DCC	Direct Capital Cost
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPC	Engineering Procurement Construction
GEM	Global Economic Model
IDC	Indirect Capital Cost
IDRO	Iranian Development & Renovation Organization
IEA	International Energy Agency
IOEC	Iranian Offshore Engineering & Construction
IPC	Iranian Petroleum Contract
MA	Moving Average
MCP	Management & Consolidated Planning
MDP	Master Development Plan
MER	Maximum Efficient Rate
MOP	Ministry Of Petroleum
NDOM	Non-linear Dynamic Optimization Model
NIGC	National Iranian Gas Company
NIOC	National Iranian Oil Company
NPV	Net Present Value
OIEC	Oil Industries Engineering & Construction
PACF	Partial Auto Correlation Function
POGC	Pars Oil & Gas Company
SPGC	Sought Pars Gas Company
UDT	Upstream Data Tool