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The Efficiency of Upstream Petroleum Contracts: Risk Service Contract in Focus

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ABSTRACT

Upstream contracts in petroleum sector may alter the behaviour of the contractor. This alteration may deviate the production path from the optimal one; this adverse effect is called distortionary effect of contracts. In this paper the distortionary effect of a risk service contract is evaluated using the data from an oil field in Middle East. The field is operated under a risk service contract signed in 2000 to increase the production by around 80,000 bbl/day. The contractual production profile (proposed by the contractor and stipulated within the contract) is compared against the estimated optimal production path over the contract life-cycle (2000-2024) and with the actual production. The optimal production path is calculated in both finite and infinite case using stochastic dynamic programming method. Results reveal that under different scenarios of discount rate, depletion rate and gas injection, the contractual production falls below the optimal production path which results in a loss of cumulative production of 5- 34% over the contract lifecycle. It is also shown that actual production is also below the optimal path and the path suggested by the contractor within the contract. It is discussed how contract time limitation affects adversely on the cumulative production of the field. Inflexibilities in contractual elements such as cap on total recoverable costs, stringent work program and upper/lower limit of production profile are discussed to be the main sources of distortion.

Keywords: Petroleum Upstream Contract, Distortionary Effect, Risk Service Contract, Buyback Contract, Stochastic Dynamic Programming
JEL Classifications: Q350, C61

1. INTRODUCTION

Several types of upstream contracts, such as production sharing contracts, are employed in the oil and gas industry. These are usually long-term agreements by which the relationship between the hosting country and the contractor is settled and the costs and benefits are shared accordingly. Different criteria are considered when it comes to evaluating and comparing these contracts. The main criteria is *efficiency* amongst the others such as *transparency* and *flexibility*.[1] It is discussed in the literature that the contract could distort the *level* or *timing* of the contractor's activities such as drilling, development or production (Kunce et al., 2003). Within this context, an efficient contract is the one that does not distort the behavior of the contractor.

Different methods such as static optimizations, contingent valuation, contract theory or dynamic optimization are used in the literature to quantify the distortionary effects of the contracts (Smith, 2014). However, the core idea remains the same; if the aggregate net present value (NPV) of the parties under the contract is less than that of in the neutral case[2], then there is a distortion and the contract is not economically efficient (Nakhle, 2008). Reviewing the literature reveals that, there is a relatively large body of the literature on evaluating the distortionary effects,

1 Daniel et al. (2010) for a detailed discussion about contract evaluation criteria.

2 This is the case in which owner develops the field without involving any other party.

however, the focus for decades has been on the tax royalty system which is widely used in the US and North Sea basin - (Deacon, 1993; Yücel, 1986l; Helmi-Oskoui et al., 1992; Leighty and Lin, 2012) and (Kunce et al., 2003; Blake, 2013; Smith, 2014; Berg et al., 2018; Hiorth and Osmundsen, 2020), Cerqueti and Ventura (2020), Hole and Ravnskog (2021) and Osmundsen and Wittemann (2024) - and more recently on production sharing and service contract - (Okoro et al. (2021), Aljomeh et al. (2021), Shirijian and Taherifard (2021), Osmundsen et al. (2024), Shaikhan et al. (2023)). Smith (2014) estimates the distortionary effect of different types of PSC alongside Tax Royalty system and shows which combination within each contract shows more efficiency. Ghandi and Lin (2017) also evaluate the distortion stems from Iraq Technical Service Contract and conduct a comparative analysis with PSC and show that TSC has the lowest efficiency. In Ghandi and Lin, the real data from Rumail field is utilized. Zhao et al., (2012) also focus on the PSC and estimate its efficiency. In particular, there are very few studies on the economic efficiency of the Iranian buy back contract. [3]To the best our knowledge, the only study on the distortionary effect of buy back is developed by Ghandi and Lin (2012) in which the buy back contract for a field in the Persian Gulf is analysed. Hendalianpour et al (2022) discuss the issue employing system dynamic approach.

Since in this research the behavior of the contractor in response to the tax changes is going to be modelled, hence, the behavioral changes of the field/reservoir in response to the contractor's behavior should also be taken into the modelling. This might be changes in the rate of drilling[4] or production, switching the production regime, considering Enhanced Oil Recovery or Improved Oil Recovery. From this angle, different researchers have taken different approaches[5]. In majority cases, the economists have tended to neglect the engineering characteristics of the problem. For example Yücel (1986), Pesaran (1990) Leighty and Lin (2012) do not discuss the physical features of the fields or basin they have analyzed. Some other researchers such as Ghandi and Lin (2012) and Ghandi and Lin (2017) consider a simplistic method to model the engineering features of the field. This is limited to a contractual production floor and ceiling which is embedded in the optimization problem as constraints.[6] There are few studies in which the engineering aspects of the field are carefully considered. As an example Helmi-Oskoui et al., (1992), Gao et al., (2009), Smith (2014), Farimani et al. (2017), Farimani (2018) and (Hiorth and Osmundsen, 2020) employ different approaches in this regard. Helmi-Oskoui et al., (1992) and Farimani (2018) use material balance equations to model the bahaivor of the field, while (Gao et al., 2009) and Smith (2014) rely on simulation and declining production function methods, respectively. However, none of the previously mentioned studies, other than (Farimani et al., 2017) model the EOR and the possibility of gas injection. Their model is solved analytically and no numerical solution is presented. (Hiorth and Osmundsen, 2020) also take into account the effect of tax in project design using real data of Norwegian Continental Shelf.

In terms of the oil price, no consistent methodology is tractable in the literature. Some researchers apply a flat oil price and argue that this is the method is used within the industry. For example see Kunce et al. (2003) and Leighty and Lin (2012) in which in the latter the flat price is one of the 4 price scenarios. Some authors take a more realistic approach and employ decreasing or increasing price scenarios. Deacon (1993) and Farimani (2018) fall within this group. In some other studies, the price forecast for the next 20-30 years from external sources such as Energy Information Administration is used; see Ghandi and Lin (2012) as an example. Nevertheless, reviewing the literature on the oil price volatilities, demonstrates that some research support the fact that oil price follows a stochastic process (Ghoshray, 2018). In contrast, some studies show that it is stationary around deterministic trends with structural breaks (Lee et al., 2006). Amongst the research which studies the distortionary effects of contracts, as far as we investigated, the price is not considered stochastic. To fill the gap, a stochastic price is taken into the model. To show to what extent stochastic prices affect the optimal path, in one of the scenarios, we compare the results of deterministic price with stochastic ones and discuss the differences.

Given the increasing usage of service contracts in the oil and gas industry (Ghandi and Lin, 2017), in this paper the distortionary effects of buy back contract is investigated. We consider a development plan for an oil field which was amongst the first generation of buy-back contracts. The contract was concluded in 2000 between NIOC and a joint venture of international

3 In general, petroleum fiscal regimes are divided into two main groups: concession regimes (tax/royalty systems) and contractual regimes including production sharing contracts and service contracts. Service contracts are also divided in two main groups, risk service contracts and non-risk service contracts. A buyback contract falls within the risk service contract. Buy-back contract first was developed by the Iranian National Oil Company (NIOC) in 1995. It is classified as a risk service contracts upon which the contractor recovers its expenditures and receives the agreed remuneration fee out of the field proceeds. Since the first initiation of the contract, several major changes has been adopted and according to this, three generations of buy back contracts are identified. In the first generation the work scope was either exploration or development and the main feature was that the total capital expenditure must be agreed upon within the contract. In the second generation, exploration contractor was entitled to carryout field development directly and without any other contract if the field was commercial. In the third generation, the cap for the contract value was removed and it is exactly determined once the tenders are accomplished (Ghandi & Lin, 2014)

Buyback contract was introduced by the National Iranian Oil Company (NIOC) in 1993. The main logic behind was attracting foreign investments in the Iranian oil and gas industry after the war imposed by Iraq. Technically speaking, buyback falls within the risky service contracts, in which, all costs (both capital and operating) incurred by the investor and its remuneration must be recovered and paid using the field's proceeds. Buyback framework have been modified over time and 3 generations of it has been introduced to the industry. In the first generation, either exploration or production is assigned to the contractor and the total capital expenditure is capped. In the second generation if exploration is successful, the contractor will take over the development and still the total expenditure is capped. In the third generation, both exploration and production could be assigned, however, the expenditure is open and must be agreed upon amongst parties.

4 Since our model pertains to the production, we do not discuss further those research works which are relevant to exploration economics

5 Nystad (1985) and Farimani (2018) for a detailed discussion.

6 Farimani (2018) for a full discussion on how economists have modelled the engineering aspects of the fields.

E&P's[7]. The aim of this contract is to increase the production from 140,000 to 220,000 barrels/day.[8]

In this study, to show how a buy-back contract can affect optimal production path, we compare the proposed production path by the operator in its MDP with the optimized production path of the field. The optimized production path of the field is calculated in both finite and infinite horizon. The logic behind finding the optimal path in an infinite horizon is that, in the no-contract case, the owner is the same as operator and there is no time limitation. In fact, in this study, the effect of time limitation of a contracts is quantified as well. The actual production of the field (2000-2020) is also taken into consideration. Comparing the realized production with the optimal one shows the deadweight loss of the NIOC over the first 20 years of the contract.

The paper is formed of the following sections. In section 2 the theoretical basis of the model is presented. Section 3 devotes to parameter estimations. In section 4 solution method is discussed while section 5 sets out the results which is followed by the conclusion.

2. MODEL

As discussed earlier, the distortionary effect of Buyback contract is calculated by comparing the optimal production path in the neutral case with the path proposed by the contractor within the MDP. It is assumed that the under the neutral case the agent is a profit maximizing on an inter-temporal basis or over the lifetime of the contract. In other words, we face a dynamic optimization problem rather than a static one. At the same time, the agent decision making is bound with a technical constraints which appears as an optimization constraint. The law of motion in the optimization problem is also set based on the fact that the reserve is depleted as the production goes on and repleted as the gas is injected into the field[9]. The following general model for the field's optimal production is suggested[10]:

$$\pi = \max_{q_t} \sum \beta^t \left\{ P_t q_t - C(q_t, g_t, S_t) \right\} \quad (1)$$

$S.t$

$$S_{t+1} = S_t - q_t + \phi g_t \qquad (2)$$

$$\sum_{t=0}^{T} q_t \leq S \qquad (3)$$

$$q_t \leq q_{max} \qquad (4)$$

$$P_{t+1} = P_t + \varepsilon_{t+1} \; \varepsilon_t \sim (0, \sigma^2) \qquad (5)$$

$$S_t \geq 0,\ q_t \geq 0,\ g_t \geq 0,\ P_t = 0,\ S_0 = s,\ P_0 = P$$

$$\varepsilon_0 = \varepsilon$$

P_t is oil price (shock equation), q_t is nnual oil production, g_t is annual volume of gas injection (million barrel of oil equivalent), S_t is remaining reserve, ε is error term β is discount factor.

Equation no 1 shows inter temporal total profit of oil production. Equation no 2 shows changes in proven reserves.[11] Based on equation no 3 the field's oil production cannot exceed primary recovery plus secondary recovery. Equation no 4 also shows the maximum rate of extraction. Equation 5 represents the oil price distribution. In the following section, we explain how each equation is specified and estimated.

2.1. Cost Function

Leighty and Lin (2012) and Lin (2009) utilized the Exponential function to specify cost function:

$$C_t = \alpha q_t^{\alpha} S_t^{\gamma}$$

In this article, we employ the same form as it is a well-behaved function and is simple to add new variables into it.

Based on Saeedi (2001), gas injection in fields such as the one under study, can swipe the oil in a more efficient way than water. Hence, we add gas injunction costs into the model using the form developed by Ghandi and Lin (2012). The cost function then take the following form:

$$C_t = A q_t^{\alpha} S_t^{\gamma} g_t^{\theta} \qquad (6)$$

q_t is oil annual production, g_t stands for annual volume of gas injection[12] (million barrels of oil equivalent), S_t represents initial oil in place (million barrels) and A is the fixed coefficient for calibration purposes.

In addition to the oil production, remaining reserve and the gas injection- which form the indigenous cost items, there are few other variables which affect the production cost. Analysing the trend of oil prices and costs in the oil industry reveal a type of correlation which necessitate adjusting the cost function. In our model, the effect of oil price changes is included using a constant coefficient. In the following chart, the correlation between capex and opex variations with the oil price changes is depicted:

According to Figure 1 over the period of 1999 to 2018 (Q3) the correlation between the opex and capex with the oil price is estimated to be 94% and 92% respectively. In this period the oil price increased by 550% and the average of capex and opex soared to 160%. Since the primary cost function is calibrated for the year 1999 (when the contract is signed) therefore to adjust the cost function the following term is added:

7 Exploration and Development Companies

8 The contract value is capped at US$998 million, the construction period is 49 months and the repayment period is set at 60 months.

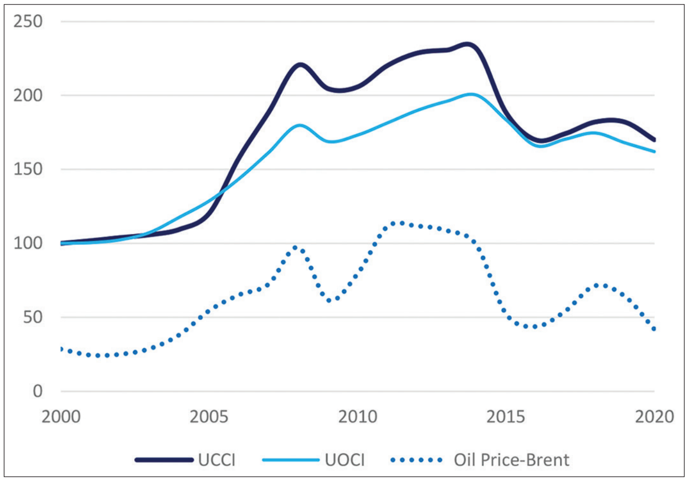
9 An Enhanced Oil Recovery process

10 The optimization problem presented here pertains to the finite case. The infinite case is has the same form, other than the time variable. This also represents the model in the case of stochastic price; in the deterministic case equation 5 is eliminated.

11 In dynamic optimization literature this equation is called Law of Motion.

12 The cost of gas injected is assumed to be zero since this gas can be recovered in the future and at the same time all gases produced in the country belongs to National Iranian Oil Company which is the main owner of the field under study.

Figure 1: Correlation of oil price with upstream operating cost index (UOCI) and upstream capital cost index (UCCI)



Source: HIS, 2020

$$h_t = \frac{160\%}{550\%} \cdot \frac{p_t - p_{1999}}{p_t} = \frac{160\%}{550\%} \cdot \frac{\Delta p_t}{p_t}$$

The following illustrates the final form of the cost function:

$$C_t = h_t A q_t^{\alpha} S_t^{\gamma} g_t^{\theta}$$

2.2. Remaining Reserve Equation

In most studies mentioned in the previous section, Most often the general form for a remaining reserve equation) is as follows: See Ghandi and Lin (2012) and Leighty and Lin (2012) as examples.

$$S_{t+1} - S_t = -q_t$$

As mentioned above, gas injection into the field is more suitable than water for increasing the field's recovery factor. In this article, we include gas injection into the remaining reserve equation:

$$S_{t+1} = S_t - q_t + \phi g_t \qquad (7)$$

2.3. Inequality of Maximum Efficient Production Rate

Maximum daily production is a function of remaining reserve, (Smith, 2014):

$$q_{max} = \frac{kS_t}{365}$$

In this equation, it is the maximum efficient rate which is determined as a proportion of remaining reserve. This rate (k) is estimated based on technical engineering relations and is different for every field. We run the model in two different scenarios based on different estimation conducted by two operating companies[13]. They estimated the MER for this field as at 0.053 and 0.073 respectively. (Iranian Technology Cooperation Office, 2006)

13 These data are collected from the proposed Master Development Plans (MDPs) by the tender participants.

3. MODEL ESTIMATION

3.1. Parameter α (cost function)

As oil production increases, production cost also soar. In a mathematical expression, this means that the first differential of cost function to oil production is positive. In most studies, even the second differential is shown to be also positive. As an example, the study by Leighty and Lin, (2012) showed a diminishing economy of scale.

In our model, a convex cost function is defined:

$$\frac{\partial^2 C}{\partial q^2} = \alpha(\alpha - 1)\frac{C}{q^2} \geq 0 \Rightarrow \alpha \geq 1$$

According to this model, the production parameter in cost function must be greater than one.

Most of first generation buy-back contracts were concluded for those type of fields which already passed their peak production. These fields were in their secondary recovery stage. The cost of increase in the production at this stage is greater than the cost of increase in production in the initial recovery period.

In other words, the cost of production of an additional barrel of oil in the secondary recovery phase is more than the average cost of oil production; so we would have:

$$\alpha = MC\frac{1}{AC} > 1$$

The USA Energy Information Administration estimated the cost of oil production in an offshore field in Abu Dhabi (similar to the field under study) to be US $3. (EIA, 1996) In addition to this, according to the Iranian Technology Cooperation Office (2006), production of any additional barrel of oil by gas injection costs additional US 42 cents. Hence, the average cost (AC) is US $3 per barrel and marginal cost (MC) is calculated at US $3 plus US 42 cents. Then α is estimated to be as follows:

$$\alpha = 3.42\frac{1}{3} = 1.14$$

3.2. Parameter θ (Cost Function)

This parameter indicates the relation between the volume of gas injection and the cost of production. In other words θ represents the elasticity of cost function to gas injection. The value of this parameter is expected to be positive, hence:

$$\frac{\partial C}{\partial g} = \theta\frac{C}{g} \Rightarrow \theta = MC_g\frac{g}{C}$$

In the above relation, MC_g represents the marginal cost of gas injection and g indicates the total volume of gas injection. According to this, the product of MC_g and g results in the proxy of total cost of injection. Above formula shows that θ is equal to the ratio between total cost of injection and total cost of production. These costs are estimated by Technology Cooperation

Office (2006) US Million Dollar 962 and 10,236. Therefore, the parameter of $\theta$is calculated as 0.094.

3.3. Parameter γ (Cost Function)

This parameter indicates the relation between remaining reserve and production cost. Theoretically, when remaining reserve decreases, the cost of production increases, so we expect γ to have a negative value. Unfortunately, there is no data available in Iran to estimate this parameter so we consulted the study by Leighty and Lin (2012). Using the data from seven different fields in Alaska, they estimated the parameter to be −0.54.

3.4. Coefficient A

Coefficient A shows other factors which affect production cost. We use the calibration method to calculate this coefficient as follows:

$$A = \frac{C}{\overline{g}^{0.094}\overline{S}^{-0.54}\overline{q}^{1.14}}$$

In order to estimate parameter A, we must first find the value for C, g, S and q.

For a 25 years period, the average annual production is assumed to be 58.4 MMBL/year.[14]

If we divide the added oil reserve resulted from gas injection by the oil equivalent of gas, we find 2.7.[15] We find the gas injection volume as at 15 MMBOE.

Remaining reserve is also calculated to be 1548 MMBBL. This is calculated based on the average of initial oil in place-3096 MMBL- and the remaining reserve in the final stage of depletion which is zero.

To find C, the average cost of production- which is - is multiplied by the production volume to get MMUSD 196.5.

This gives us the value of A as 1.46. Below represents the final form of the cost function:

$$C_t = d(t)1.46 g_t^{0.094} S_t^{-.054} q_t^{1.14}$$

3.5. Parameter ϕ

ϕ represents to what extent gas injection improves remaining reserve. Taking derivative of equation 7 in respect to g_t results in:

$$\frac{\partial S_{t+1}}{\partial g_t} = \varphi \cong \frac{\Delta S}{\Delta g}$$

If we divide the volume of added reserve by total gas injected (in MMBOE) we find gas injection efficiency ratio which is estimated at 2.7 for this field.

14 The MDP developed by the contractor, propose a peak production of 220,000 bbl/day and a minimum of around 100,000 bbl/day in the last year of the MDP. The average rate of production over the 25 years will be 160,000 bbl/day. This results in around 58 MMB per year.

15 This parameter is calculated by Iranian Technology Cooperation Office (2006). They showed in their study that injecting 811 MM BOE of gas injection results in around 2,200 MMB of added reserve. This gives us the ratio of 2.7.

$$S_{t+1} = S_t - q_t + 2.7 g_t$$

4. SOLUTION

To solve the model, dynamic programming method is employed. To do that, Bellman's equation is defined as follow:

$$V(S_t, P_t) = \max_{q_t} \left\{ \begin{matrix} P_t q_t - d(t)1.46 g_t^{0.094} S_t^{-.054} q_t^{1.14} + \\ E\beta V(S_{t+1}, P_{t+1}) \end{matrix} \right\}^{16}$$

$S.t$

$$S_{t+1} = S_t - q_t + 2.7 g_t$$

$$P_{t+1} = P_t + \varepsilon_{t+1}\ \varepsilon_t \sim (0, \sigma^2)^{17}$$

$$\sum_{t=0}^{T} q_t \le S,\ q_t \le q_{max},\ S_t \ge 0,\ q_t \ge 0,\ g_t \ge 0,\ P_t \ge 0,\ S_0 = s,\ P_0 = P,\ \varepsilon_0 = \varepsilon$$

Since most dynamic optimisation models do not have exact solutions, or their solutions are both complex and time consuming, approximate solutions are used. There are two approximate numerical solutions to solve a dynamic optimization models: multivariable equation approximation and discretization (Judd, 1998). In our model, discretization for solving Bellmen's equation is employed. The method has the following stages:

4.1. Discretization of the State Variable

A bounded set of state variable is formed in which the members are distributed on an equidistance basis. The number of values for the state variable are called nodes. Discretization of S_t state variable is as follows:

$$X_t = \{s_1\ s_2 \cdots s_n\}$$

Here S_t variable has 1,000 nodes. In other words, the lower bound of remaining reserve is zero and upper bound is 1,545 and the distance between lower and upper bounds is divided into 1,000 sections.

4.2. Discretization of the Shock Variable (Crude Oil Price)

The crude price is considered to be a continuous stochastic variable. Now the underlying question is that if one can convert a continuous stochastic variable to a discrete stochastic variable? Based on (Tauchen and Hussey, 1991) the answer in general is positive. As for remaining reserve, one must define the lower and upper bound for the shock variable. In addition to the upper and lower bands, the occurrence probability of each value should also be determined. For instance, for P oil price's variable, the set is shown as follows:

16 The deterministic form of the Bellman equation takes the following form:

17 Both Augmented Dickey Fuller and Phillip-Prawn test was conducted and in both cases the hypothesis of oil price stationarity was rejected.

$$V(S_t, P_t) = \max_{q_t} \left\{ P_t q_t - d(t)1.46 g_t^{0.094} S_t^{-.054} q_t^{1.14} + \beta V(S_{t+1}, P_{t+1}) \right\}$$

$$P = \{P_1, P_2, \ldots, P_n\}$$

4.3. Oil Price Probability Distribution; the Test of Markov Chain for Oil Price

We first test if the oil price follows the Markov process[18] or not. In order to do that, (Bartlett, 1951) and (Hoel, 1954) test is employed. Within this method, the oil price is classified in specified ranges. In this current work, the oil price is classified into 13 sections[19] from 1987 to 2013. Subsequently, the number of transfers from one price range to the other is put in a 13*13 table (see appendix). The following term must be calculated for each part of the table:

$$\frac{\left(n_j - \frac{n_i n_j}{N}\right)^2}{\frac{n_i n_j}{N}}$$

$$N = n_i + n_j$$

The value of χ^2 statistics is defined as follows:

$$\sum_{i=1}^{n}\sum_{j=1}^{n}\frac{\left(n_j - \frac{n_i n_j}{N}\right)^2}{\frac{n_i n_j}{N}}$$

The degree of freedom is defined as follows:

$$df = (T-1)\,(k-1)^2$$

Where T stands for transfer period and k indicates the number of periods. In our model, df is calculated as 144 and the value of Bartlet and Hoel's statistics for the oil price is 291/4.

Since 291.4 > χ^2 (0.05,144), the null hypothesis is rejected. The null hypothesis was that the oil price is independent of last period's price. Therefore, the oil price fluctuations follow the Markov chain.

Since our problem is solved using Value Function Iteration, considering discretization of the state variable:

$$s_l \in S, P_m \in P$$

We rewrite Bellmen's equation:

$$V_{i+1}\left(s_l, P_m\right) = \max_{q_t, g_t}\left\{\begin{array}{l} u\left(q\left(s_l, P_m\right), g\left(s_l, P_m\right), s_l, P_m\right) \\ +\beta\sum_{j=1}^{M}\pi_{mj}V_i\left(\tilde{s}, \tilde{P}_j\right)\end{array}\right\}$$

The Value function Iteration is continued up until:

$$\left|V_{i+1} - V_i\right| \le \varepsilon$$

In this study the value of ε is set at 10^-6.

Finally, the optimal path of the control variable will be extracted:

$$q^* = q(sl, P_m)$$

5. RESULTS

In this section, we compare the optimal production path – defined in the previous section- with that of suggested by the contractor in MDP[20] within different scenarios of discount rate, gas injection and depletion rate. In addition, an infinite version of the model is also calculated. As discussed earlier, the infinite problem, reveals the optimal path of the owner of the field in no- contract scenario. We also solve the model in a deterministic case and compare the results with stochastic one to see how taking the price as a stochastic element affects the analysis.

5.1. Finite Scenarios

Under finite case, four different scenarios are developed. Depletion rate, Discount rate and gas injection rate are the varying factors by which four scenarios are formed.

5.1.1. Reference scenario

We adopt the following assumptions in this scenario:

$$S_0 = 1545,\ a = 0.053,\ P_0 = 12,\ \beta = 0.95,\ g = 0.4q$$

The field depletion rate is 0.053, the primary oil price is 12 USD/bbl[21], the discount factor 0.95 and the daily injection rate is 0.4 of production.

5.1.1.1. Daily production

Based on Figure 2 and comparing the optimal production path with the suggested production by the contractor indicates that over the 24 years life of the contract, optimal production is above the path suggested by the contractor. The maximum difference is observed in the year 18th of the contract where the difference reaches at 21,000 barrels/day or 17% difference.

5.1.1.2. Cumulative Production

The cumulative production under the optimal production path is 1,332 million barrels while in the contractual case remains at 1,200 million barrels, 8% decrease.

5.1.2. Second scenario; the effect of depletion rate

In this scenario, the field's depletion rate increases from 0.053 to 0.073. The other parameters remains unchanged.

$$S_0 = 1545,\ a = 0.073,\ P_0 = 12,\ \beta = 0.95,\ g = 0.4q$$

18 Some Stochastic process follows Markov chain in which the state of the variable in the future solely depends on the current situation and is independent of the past history; sometimes called memoryless process.

19 It is notable that Batlet test is insensitive to the number of sections. Higher sections result in having more cells with zero value. In contract, reducing the number of sections results in missing some of the data.

20 Master Development Plan

21 This is the price, initially was applied by the Iranian Petroleum Ministry in evaluating the first generation of buy-back contracts.

5.1.2.1. Daily production path

As it shown in the Figure 3, having implemented a higher MER, allows the model to start the production from higher rates. In this scenario, the production starts from around 300,000 bbl/day, way beyond the starting production in the reference scenario. Also, comparing two production paths under this scenario reveals that optimal production is higher than contractual production over the whole period of the contract. Relaxing the MER constraint, allows the model to increase the production; this depletion is replaced with the EOR process of gas injection. Due to this enhanced oil recovery process, production does not see any reduction over this period.

5.1.2.2. Cumulative production

As regard to cumulative production and as was expected, the optimal path results in higher value. Under the optimal path and over the 24 years of production, cumulative production will amount 1,609 million barrels while under the contractual path this reduces to 1,200 million barrels. The difference is 25% or around 400 million barrel, much higher than the difference observed in the reference scenario.

5.1.3. Third scenario; the effect of higher gas injection

In this scenario, daily gas injection increases from 0.4 of daily production equivalent to 0.6 of daily production equivalent.

Figure 2: Comparing the optimal production path with the path suggested by contractor (reference scenario: $S_0 = 1545$, $a = 0.053$, $P_0 = 12$, $\beta = 0.95$, $g = 0.4q$)

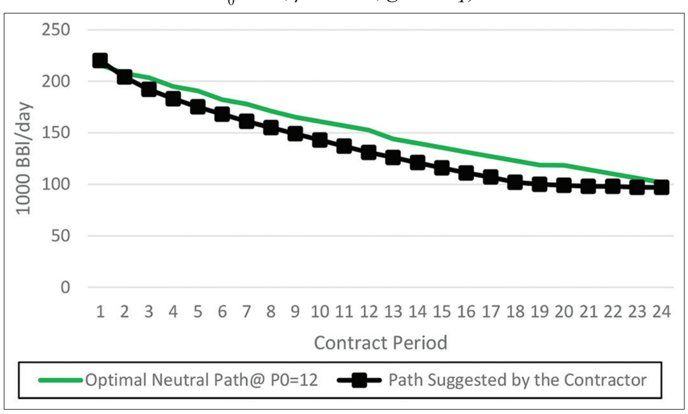
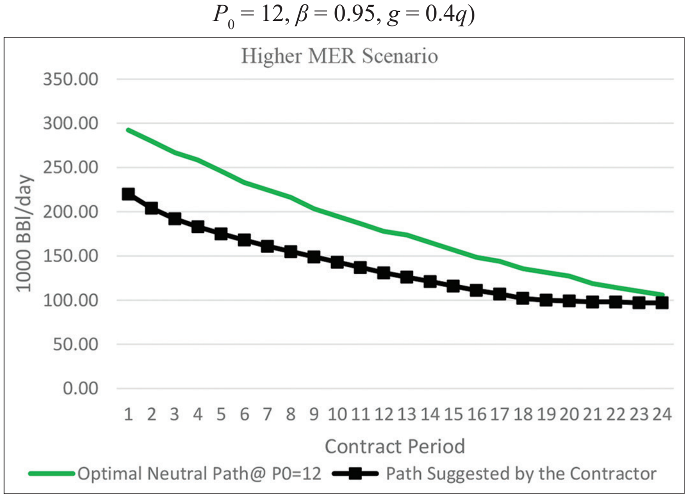


Figure 3: Comparing the optimal production path with the path suggested by contractor (reference scenario: $S_0 = 1545$, $a = 0.073$, $P_0 = 12$, $\beta = 0.95$, $g = 0.4q$)



$$S_0 = 1545,\ a = 0.073,\ P_0 = 12,\ \beta = 0.95,\ g = 0.60q$$

5.1.3.1. Daily production

The optimal production path is higher than the contractual production over the entire life of the contract (Figure 4). In fact, under higher rate of gas injection, the field is able to keep producing at high levels. In the 18th year of the contract, the difference between optimal production and contractual production peaks at 50,000 barrels/day. Comparing the path with the first (reference) and second scenario demonstrates that injecting higher volumes of gas, boosts the production over the whole life of the contract and the minimum production in this scenario which happens in the last year of contract (131,000 bbl/day) is around 30% above the same value in previous scenarios.

5.1.3.2. Cumulative production

In this scenario, cumulative production of the field will be 1,502 million barrels as compared to contractor's suggested production path, i.e. 1,200 million barrels, this shows a deadweight loss of 302 million barrels of oil caused by the contract.

5.1.4. Fourth scenario; the effect of zero gas injection

In this scenario, daily gas injection decreases from 0.4 of daily production equivalent to zero. Other parameters remain unaffected.

$$S_0 = 1545,\ a = 0.073,\ P_0 = 12,\ \beta = 0.95,\ g = 0$$

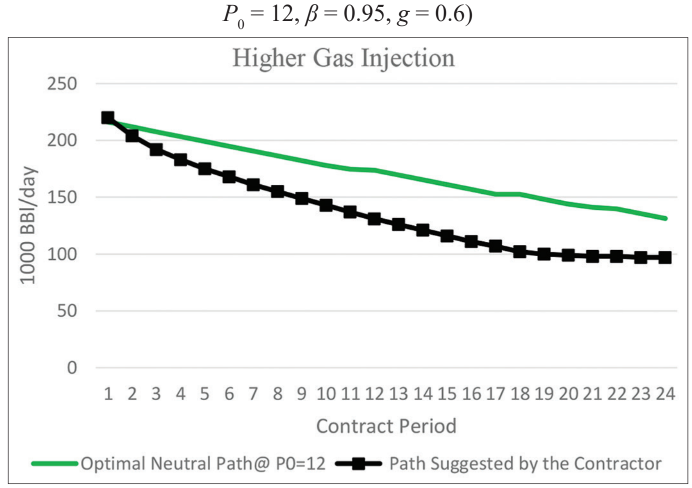
5.1.4.1. Daily production

Stopping the gas injection process, reduces the production significantly and the optimal path falls below the one suggested by the contractor (Figure 5). The production reduces up to 50,000 bbl/day, which records the lowest level of production amongst all scenarios.

5.1.4.2. Cumulative production

The cumulative production reduces to 1,059 million bbl as compared to 1200 million bbl in the reference scenario. This indicate approximately 20% decrease in the cumulative production.

Figure 4: Comparing the optimal production path with the path suggested by contractor (reference scenario: $S_0 = 1545$, $a = 0.053$, $P_0 = 12$, $\beta = 0.95$, $g = 0.6$)



5.1.5. Fifth scenario, the effect of discount rate

In this scenario, the discount rate has increased from 5% to 10% whie the other elements remain the same.

$$S_0 = 1545, a = 0.053, P_0 = 12, g = 0.4q, \beta = 0.91$$

5.1.5.1. Daily production

Comparing 2 production path reveals that having a higher discount rate, results in higher level of production over the whole life of the contract (Figure 6). In other words, production accelerates under a higher discount rate. In graph above, the optimal path in the reference scenario, in which discount rate is 5%, is also represented. As it shown, changing the discount rate from 10% to 5% does not alter significantly the optimal path in the first 20 years of the production period. However, in the latest periods of the contract, the production under 10% discount rate stands above that of 5%.

5.1.5.2. Cumulative production

Analyzing the results shows that increasing the discount rate results in a higher cumulative production. While under the contractual scenario the cumulative production amounts 1200 million barrel, the cumulative production under 10% discount rate is 1331 million barrel which shows a distortionary effect of 131 million barrels. It is notable that the distortion under 5% discount rate (reference scenario) is only 107 million barrels.

Figure 5: Comparing the optimal production path with the path suggested by contractor (reference scenario: $S_0 = 1545$, $a = 0.053$, $P_0 = 12$, $\beta = 0.95$, $g = 0$)

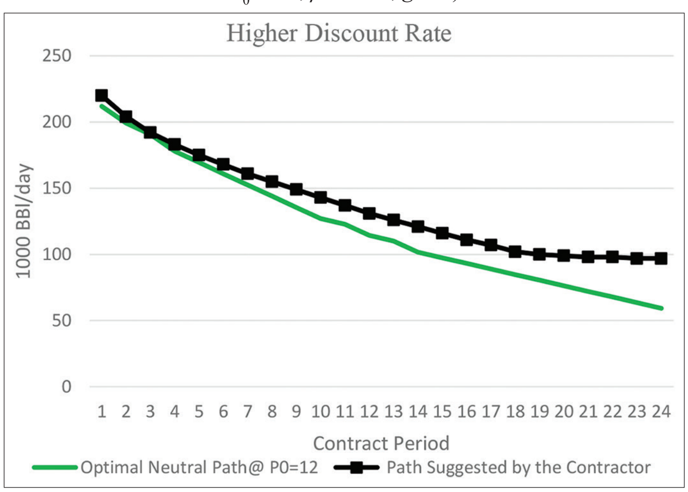


Figure 6: Comparing the optimal production path with the path suggested by contractor (reference scenario: $S_0 = 1545$, $a = 0.053$, $P_0 = 12$, $g = 0.4q$, $\beta = 0.91$, $g = 0.4q$)

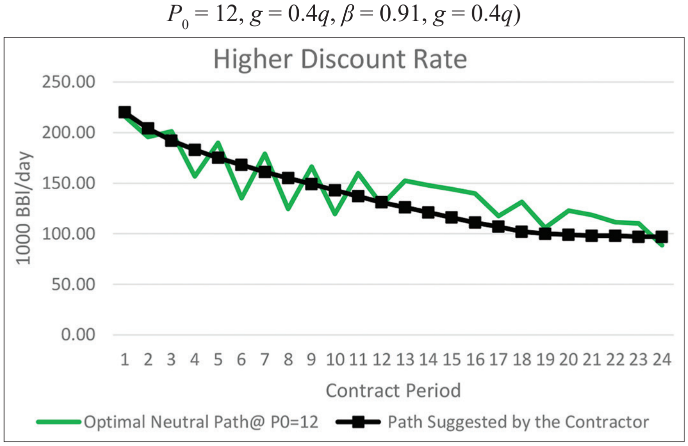


Figure 7 put together the cumulative production under different scenarios. The highest production occurs where MER increases. The important issue is the fact that, the contractor path results in the same cumulative production as zero gas injection does. One can deduct that the contractor has no plan for gas injection.

Table 1 compares the cumulative production, maximum rate of production, starting point of production and final rate of production within the above five scenarios. It shows that having no gas injection, push the model to start from a low level of production. In fact, without gas injection, the pressure of the field drops which will result in a low cumulative production and consequently net present value. Hence, the model starts with a conservative rate of production. It is also notable that the maximum rate of production is almost equal in all scenarios other than the scenario under which the MER goes higher. It reflects the fact that, the optimization problem dictate the maximum possible production from the field. This is because of the fact that marginal cost of production is very low as compared to oil price. Comparing the final rate of production also shows two important notions: first, gas injection can keep the production rate high even in the last periods of the contract; conversely, having no gas injection leaves the field with a low level of production in the final stages of production.

5.2. Infinite Scenario

Within the infinite scenario, no time restriction applies into the model. The model is solved in an infinite time horizon and production may last for hundred years and the volume of production are of low values. Although, the owners might not be patient enough to produce at such a low levels, however, it gives a bright picture of how time constraint distort the optimal path. The following graph (Figure 8), puts together all scenarios and shows how the optimal path varies in different scenarios.

Comparing the cumulative production in different scenarios shows that extending the optimization period improves significantly the cumulative production. In contrast to what is expected, the cumulative production does not increase as MER increases. Having

Figure 7: Cumulative production under different scenarios

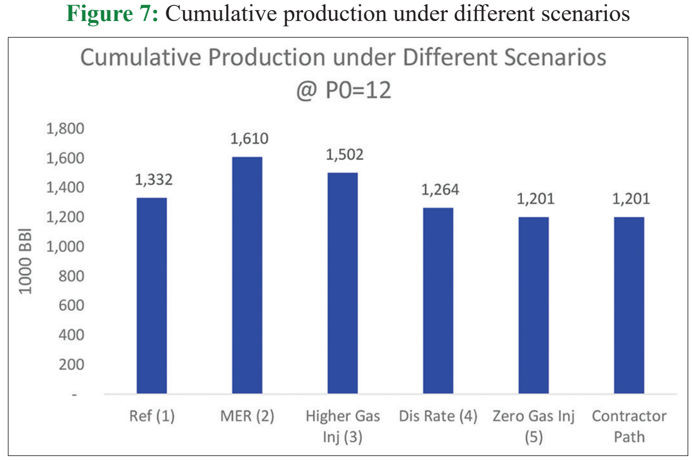


Table 1: Cumulative production and production path feature in different scenarios

Scenario	Cumulative production (Million bbl)	Starting point of production (bbl/day)	Maximum production (bbl/day)	Final point of production (bbl/day)
Reference	1200	216,000	216,000	101,000
Higher MER	1609	292,000	292,000	105,000
Higher Gas Injection	1502	216,000	216,000	131,000
Zero Gas Injection	1059	211,000	211,000	59,000
Higher discount rate	1200	216,000	216,000	89,000

Table 2: Cumulative production under infinite optimization in different scenarios

Scenario	Reference	Higher MER	Higher gas injection	Higher discount rate	Zero gas injection
Cumulative production (MMBBL)	2,447	2,429	3,711	2,544	1,436

Figure 8: Infinite scenarios

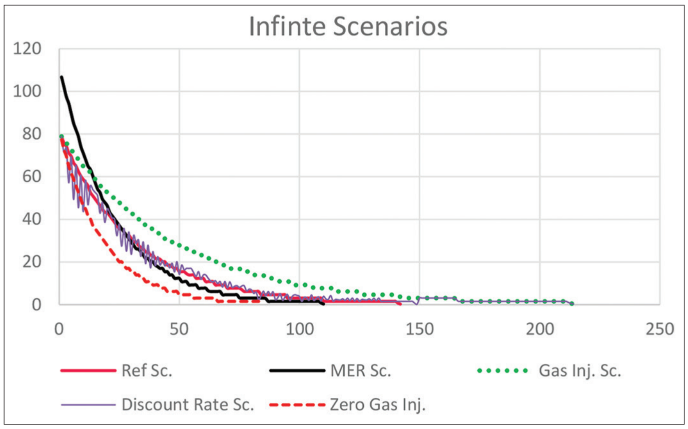
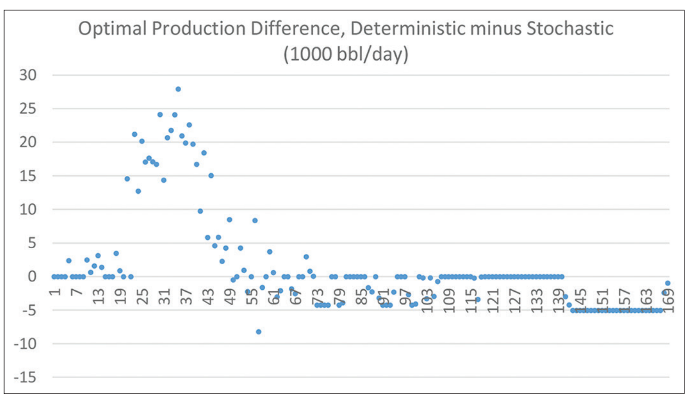


Figure 9: Stochastic versus deterministic assumption for price

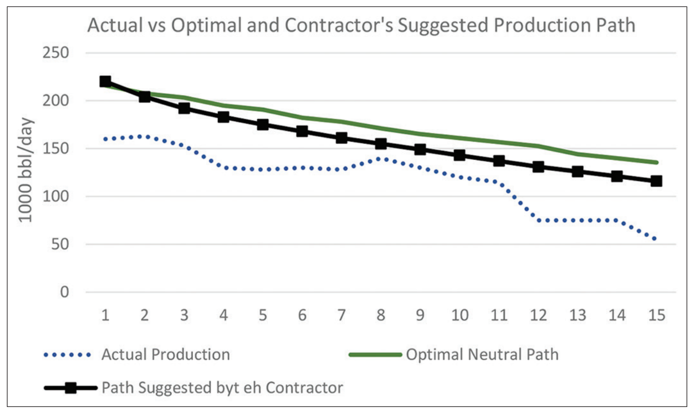


a higher rate of MER in the infinite horizon model, results in an aggressive rate of production in the early periods and a sharp reduction in the later periods. The highest effect remains for higher gas injection in which recovery factor of the field goes to 100%. Table 2 summarizes the outcome of the optimization problem in different scenarios:

5.3. Deterministic versus Stochastic

As is discussed earlier, different studies deal with oil price factor in different ways. We first run the model in the deterministic infinite form and then solve it using stochastic price assumption. We compare the results in just one scenario to see how stochastic price assumption affects the results. As it shown, in early years of production, the deterministic case results in higher level of production as compared to stochastic case. However, in later years, they either match or are very similar. The reason lies in the fact that under stochastic case, the agent expects higher level of price in the future and shifts the production to later years Figure 9.

Figure 10: Actual production versus optimal and contractor's suggested path



5.4. Actual versus Planned and Optimal Production

In Figure 10 below, the actual production[22] of the field is being compared to the optimal path of production and the path was suggested by the contractor in its master development plan. As it is revealed, the actual production is well below the optimal and the suggested path which shows a significant amount of value and volume loss over the period of contract. It appears that the actual production declines faster than the two other paths, meaning that perhaps the contractor has not accomplished the gas injection or other measure of improved or enhanced recovery based on best practice in the industry. Obviously, the cumulative production does also show a significant amount of loss over the period of the contract.

6. CONCLUSION AND DISCUSSION

Comparing the optimal production path of the field under study with the path suggested by the contractor within a buy-back framework indicates that in all scenarios, paths do not match. Cumulative production under the contractual regime has always

22 The data of production for the field under study was not open access and fully accessible

been less than the optimal path. The difference varies between 63-409 million barrels depending on the scenario. This means that the buy-back contract of the onshore field distorts the optimal production path.

In addition, since all first generation buy-back contracts are very similar, it will not be surprising if we extend the distortionary effect of the contract we study to all other first generation buy back contracts.

The main question arises is the underlying reason for such a distortion. Although answering this question in full details is out-with the scope of this paper, however a brief explanation followed by some recommendations to rectify the distortions are discussed.

6.1. Inflexibility of Buyback Contracts

The issue of inflexibilities in the buy-back contract is also discussed from a different angle by Ghandi and Lin, (2012), where they analyze the effect of contractual limitations on the share of contractor in high oil prices. However, our focus is on a different part. All first generation buy-back contracts, including the one we investigate, apply a ceiling on the contractor costs. This feature violates the principle of contract flexibility in two ways: First, information about the oil and gas reserve at the outset of the production is relatively limited and is bound with high uncertainty. As the development phase and production go on, the contractor may change the development and production program, such as increasing the number or the depth of the wells. In this case, the total capital expenditure will have to increase while the contract is not sufficiently flexible to accommodate these changes. Consequently, the contractor does not have the incentive to invest in enhanced or improved oil recovery plans. This will reduce the ultimate recovery factor and cumulative production. This argument is supported by Ghandiand Lin (2017) where they show how stringent cap on the capital cost in Iraq Technical Service Contract results in inefficiency.

Second, similar to oil price, the capital costs and operating costs vary significantly over time. As shown earlier in this study, over the period of 1999 to 2012 (Q3) the correlation between the opex and capex with the oil price was estimated to be 94% and 92% respectively. If contractor faces an inflated capital and operating costs over the period of contract, there is no room for manure as per the contract and all risks must be taken by the contractor. In practice, this disincentive the contractor to employ best industry practice which in fact results in lower cumulative production and ultimate recovery factor.

To rectify this deficiency, three types of modifications are suggested. First, due to gold plating issue, most often the hosting countries tend to set a ceiling for the capex, however, an alternative could be setting up a joint management committee within which annual working programs and costs breakdown are agreed upon by both parties. This allows both parties to make more efficient decisions based on the new information they acquire from the field as the development or production progresses.

Applying sliding scale schemes in remitting the rewards or fees can also ameliorate the inflexibility. A sliding scale regime such as R-factor smooth down high fluctuations in the market.[23] As an example, if contractor's cost increases, such a sliding scale regime, protect the contractor against sharp fall in the fee or rewards payments.

The other solution could be making the hosting government more involved in the project through methods such as state participation. Having the hosting country as one of the participants in project management will mitigate some of the risks result from cost changes.

From the risk management point of view, in the first generation of buyback contracts, investment risks are not distributed appropriately amongst the parties. Contractor bears the risk of cost fluctuations and work program changes. Applying either R-factor, setting up a joint management committee or allowing for state participation will mitigate the contractor's risk.

6.2. Underestimated Contractual Production Path

As per the first generation of buy back contracts, if the contractor does not meet the contractual production (i.e. the production path which is agreed upon in the contract), the hosting country will merely recover the costs, and no fees or rewards will be remitted. This feature, make the contractors to suggest an underestimated targeted production to be included in the contract. In other words, the contractor faces the risk of low production and mitigate it through suggesting a lower level of target production. Once the contractual production or target production is set at a low level, the contractor will not have any incentive to produce at higher levels. This will result in lower cumulative production. As it shown in Figure 10, even in this case, the actual production is much below the optimal path. The alternative method is setting annual production target. Within this context, similar to annual working program and costs breakdown, the annual production profile is also agreed upon within the joint management committee. This way, the contractor will have the opportunity to achieve higher rates of production while the required costs are discussed within the committees.

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