Oil production cost function and oil recovery implementation- Evidence from an Iranian oil field

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Abstract

In the process of natural depletion of an oil reservoir, the reservoir pressure declines, as does the production rate. To prevent this decline, some oil recovery methods have been proposed. These methods, despite having impacts on the natural depletion production profile, have an impact on the cost function. In this study, we investigated how the cost function (that represents the natural depletion situation of an oil field lifecycle) changes with secondary oil recovery. Gaining more knowledge on this issue is of great importance in future decision making and capacity expansion in the oil industry. Empirical evidence is presented from an oil field in south west of Iran where immiscible gas injection has been applied. For this purpose we have estimated two production cost functions; one corresponds to the current situation of the oil field (with secondary oil recovery), and the other is a simulated situation that represents a natural depletion of the oil field so far. The results showed that the oil production cost function in a situation with secondary recovery has a lower stock effect parameter than compared to that of the natural depletion situation. This implies that the marginal production cost dependency on cumulative production decreases after secondary recovery implementation.

Keywords: Secondary oil recovery, Natural depletion, Stock effect, Oil production cost function

1. INTRODUCTION

During the lifecycle of an oil field, producers are attempting to obtain maximum recovery of the initial oil in place (IOIP) during the three processes of oil production: primary, secondary and tertiary recovery. In the "primary recovery" or "natural depletion" process, oil is extracted by reservoir natural pressure and this pressure is high enough to force crude oil to the surface. However, over time reservoir pressure declines and as a result, so does oil recovery. The ultimate recovery factor (an approximation of the quantity of oil that is technically recoverable) in the primary process is generally less than 30 percent, therefore a substantial portion of oil cannot be recovered during the natural depletion process (Kokal and AL-Kaabi, 2010). Consequently, producers are attempting to increase reservoir pressure, thus extending the productive life of the reservoir after the natural depletion process.

The process of increasing oil recovery and enhancing the ultimate recovery factor from an existing oil field after natural depletion is commonly known as "secondary recovery". This type of recovery is accomplished by the injection of gas or water into the reservoir to maintain or increase the reservoir pressure. These methods can increase the recovery factor by up to 50 percent (Kokal and AL-Kaabi, 2010). During secondary recovery, a large part of the crude oil still cannot be recovered so, producers must utilize artificial means under appropriate conditions to augment the ultimate recovery factor after secondary recovery. This process is known as "tertiary recovery" and includes thermal, chemical and miscible injection methods.

Two issues arise with the implementation of these oil recovery methods (secondary and tertiary). The first is the engineering issue regarding how production behavior has been affected by the implementation of oil recovery methods. Production behavior is known as a production profile and engineers have usually been able to address this issue by oil reservoir simulation that considers the specific performance of a reservoir. In the process of oil production, producers attempt to understand how the production profile that represents the natural depletion of the oil field lifecycle, would be affected by secondary recovery implementation and how this new production profile would again be affected by the implementation of tertiary recovery.

The second issue is an economic one and concerns how cost behavior will be affected as a result of the oil recovery implementation. Cost behavior is the general term for describing how cost changes when the level of output changes (Heitger *et al.*, 2008). The level of output in the oil production process has been changed with the implementation of secondary and tertiary oil recovery methods. Oil cost behavior is explained in this study through the marginal cost function.

As with the first issue, in the process of the oil production life cycle, producers and investors are trying to acquire knowledge about how the cost function that represents the natural depletion situation of the oil field lifecycle, will be affected by the implementation of secondary oil recovery methods and how this cost function will again be affected by tertiary oil recovery methods. This knowledge is crucial for future decision making and capacity expansion in the oil industry. This issue is more important for Middle East countries which hold around 53 percent of world oil reserves (Organization of the Petroleum Exporting Countries (OPEC), 2014).

One of the most notable properties of the oil cost function is the dependency of marginal cost on the cumulative production or stock of remaining reserves. This is known as the "Stock effect" and indicates that production cost increases with depletion of resource (Ghandi and Lin, 2012; Levhari and Liviatan, 1977; Lin, 2009; Lin and Wagner, 2007). In other words, the stock effect indicates how sensitive the production costs are to cumulative production. In the present study we address this economic issue to identify how the oil cost function that corresponds to the simulated natural depletion situation so far will be affected by the secondary recovery method.

The oil recovery method in this study is immiscible gas injection that has been implemented as a secondary recovery method in one of the southwest oil fields in Iran. Gas injection has been recommended as a sustainable production scenario for increasing the ultimate recovery factor in Iranian oil fields (Derakhshan, 2002; Rostami *et al.*, 2013; Saidi, 1996). Gas injection is utilized to increase reservoir energy, displace the oil and drive it toward the wellhead and finally to improve the recovery factor from the present resource base. Gas injection may be either miscible or immiscible. "Miscible" means that the gas that is injected mixes with the oil and "immiscible" means that the gas that is injected into the reservoir gas cap does not mix or go into solution (Torabzadeh *et al.*, 1989).

For investigating how a cost function in the natural depletion process would be affected by immiscible gas injection, we define two scenarios. In the first scenario the current situation of an oil field is indicated, whereby sour gas (as an immiscible process) has been injected regularly in this oil field. The second scenario is a simulated scenario that demonstrates the natural depletion situation of this oil field so far. In this hypothetical scenario we assume that the producer did not implement gas injection and hence this scenario demonstrates the oil production situation without gas injection. In the simulated situation, we first simulated the cost and production trends during natural depletion and finally estimated the cost function.

To the best of our knowledge, this is the first study investigating the effect of secondary oil recovery on the production cost function. Previous literature in this area is limited to a few empirical oil cost function estimates. Our model contributes to the literature by helping in understanding of how cost behavior in the natural depletion process would change with secondary oil recovery implementation in practice. For this purpose, we have used data from one of the southwest onshore oil fields in Iran with 60 billion barrels IOIP, where the reservoir fluid is light oil and has an API of 34 with 0.4% sulfur. Oil production from this oil field began in 1957 with 44 thousand barrels per day and gas has been injected as an immiscible process, since 1988, at about 25 million cubic meters average per day.

Our results indicate that in the current scenario where gas has been injected into the reservoir, the cost of production is less dependent on cumulative production than in the simulated scenario (natural depletion). This positive result is due to the significant effect of secondary recovery on cumulative production and marginal cost. The study found that the magnitude of the recovery method's effect on the natural depletion cost function depends on the combination of cumulative production and marginal production cost changes after the implementation of recovery methods. The remainder of the article is organized as follows: oil production costs are explained in section two; gas injection costs are described in section three; section four considers the cost function in the current situation; section five provides an estimate of the cost function in a natural depletion situation; and the results are presented in section six, followed by the conclusion.

2. OIL PRODUCTION COSTS

The cost basket of the oil production process consists of two main parts: capital costs and operation costs. One of the difficulties in this type of research lies in obtaining precise costs data. In order to address this issue the followings were carried out in the course of study: valid approximation of costs based on previous research; interviews with experts and experienced personnel who have been active in this oil field; and official documents from the national Iranian oil company (NIOC)[1].

Capital costs refer to the costs that are usually incurred during the exploration and development process and include material and construction costs for the building and installation of physical facilities such as access roads to the site, pipelines, drilling of the wells, and facilities for separating oil from gas, water etc.[2] Capital costs can be divided into two main categories: (1) drilling costs and (2) non-drilling costs.

Drilling costs, or subsurface costs, refer to the entire cost of drilling new oil wells and consists of engineering, procurement, drilling material and drilling services costs. In this particular oil field, an average of ten wells have been drilled per year and there are 400 production wells so far. Advice from active personnel in this oil field indicates that the well cost is considered to be USD 15 million per well in real term. This covers all costs related to a new well. All costs in this paper are measured in constant USD (2012).

Non-drilling costs refer to surface facilities costs or infrastructure costs that consist of preparatory works such as roads and well pads. It also includes the cost component of project management. These costs have historically been equal to about 66% of the drilling cost (Adelman and Shahi, 1989). According to active personnel, non-drilling costs in this particular oil field are 43% of the well cost.

Operation costs refers to specific activity costs during the oil field lifecycle which are related to its operation including: equipment maintenance, product transport, overheads and workover costs. In the absence of detail regarding operational costs, it is common to assume that the OPEX is composed of the following elements: (1) related production costs and (2) non-related production costs.

Related production costs are also known as variable operation costs and refer to that part of the operation costs that is directly related to production. Energy Information Administration (EIA) (1996) provided the following functional relationship between production rate and variable operation costs for Persian Gulf countries:

$$\mathrm{var}\,OPEX = 0.7714Q^{-0.2423} \tag{1}$$

Where Q is production (million barrels/year), VarOPEX is variable operation costs (USD/barrel).

Non-related production costs refers to that part of operation costs which does not alter with production. For non-related production costs, usually known as fixed

[1]We exclude finance costs and rate of return for contractors in our analysis and our cost function represents the cost of operation, rather than the finance costs as in (Ghandi and Lin, 2012).

[2]Exploration and Appraisal (E and A) costs were not considered in our study. Since the studied oil field was discovered in 1950, E and A activities were done on it about 60 years ago, and so all its financial costs have been amortized so far.

operation costs, it is common to allocate a fixed percentage of total capital costs, which for Middle East countries has usually been 5% (Energy Information Administration(EIA), 1996; Mian, 2011).

3. GAS INJECTION COSTS

Gas injection costs usually refer to capital costs that are divided into three categories: (1) pipeline costs; (2) compressor costs; and (3) injection well costs. In constructing these costs we have used the same three data sources mentioned in Section 2.

Pipeline costs depend on the distance between the sources of gas and the oil field. Historically, the average of the injection volume in this oil field has been 25 million cubic meters per day. This volume has primarily been met through associated gas from nearby oil fields (around 75%), while the remainder came from the associated gas of this oil field, through a local gas pipeline system. All of the injected gas is sour gas and has been injected into the gas cap of this oil field as an immiscible process. For gathering sour gas from this and nearby oil fields, a local injection gathering pipeline system was built with the following piping (diameter in inches): 53 km of 26-inch, 6 km of 24-inch, 38 km of 20-inch; and 6 km of 16-inch. In building these pipelines, the producer incurs material and construction costs. According to experts, the materials and construction proportions of the total pipeline cost are 80 and 20 percent, respectively and according to khaleghi (2003) the material cost of the pipeline has been computed as:

$$MCP = 12.45\ DI^{1.3} \tag{2}$$

MCP is the material cost of the pipeline (USD 1000/km), and DI is the pipeline diameter (inches).

Compressor cost is approximated as a function of the horsepower required to inject gas into the reservoir. According to khaleghi (2003), the cost of each compressor is a function of its nominal power, which is also a function of the gas required to inject as below:

$$MCCC = 0.971\ \mathrm{HP} \tag{3}$$

Where MCCC is material and construction costs of the compressor station (USD 1000/hp) and HP is the horsepower (unit of compressor power). In this case study, we have 20 compressors with 4700 horsepower.

The injection well is fundamentally the same as the production well apart from the direction of flow. In this case, 18 injection wells were drilled in 1988 and due to lack of information about injection well costs we assume that the gas injection well costs are the same as the oil production well costs. Besides the aforementioned injection capital cost, operation costs of injection also exist; this cost is largely related to manpower and corrosion control. We consider the injection operation cost to be 10 percent of the injection capital costs. We exclude the gas price as a cost of secondary recovery in our analysis with regard to the point that natural gas remains underground and can be recycled at the end of the oil field lifecycle.

4. COST FUNCTION IN THE CURRENT SITUATION

In this section, we will address the first scenario in this study to find the current field specific cost function that indicates production rate with secondary recovery. Oil production costs increase with cumulative production or with the decrease in oil stock remaining in the ground. The reason for cumulative production being included in the cost function is that lower levels of reserves implies lower reservoir pressure which in turn implies higher costs of production (Ghandi and Lin, 2012; Halvorsen and Smith, 1991; Lin, 2009; Lin and Wagner, 2007; Livernois and Uhler, 1987; Mohaddes, 2013). The empirical production cost literature for exhaustible resources is also limited. Specific to oil and gas production, Livernois and Uhler (1987) with a linear form of the cost function, found empirically that extraction cost was inversely related to remaining reserves at the disaggregate level in the Canadian oil industry. Chermak and Patrick (1995) with a logarithmic linear form found decreasing marginal costs for natural gas production in the United States. Leighty and Lin (2012) proposed a composite cost function which is based on the logarithmic linear form and showed an increasing cost function for oil production in Alaska. Chakravorty *et al*. (1997) utilized world data on proven reserves and production costs compiled by the East-West Center Energy Program and found that the cost function that best fitted the data increased exponentially with cumulative production. It is as follows:

$$C_t = \alpha_0 e^{\alpha_1 S_t} \tag{4}$$

In this equation, Ct is oil production cost at time t (USD/barrel), St is cumulative production at time t (million barrel) and α_1 is known as the stock effect parameter. This parameter shows to what extent production cost is dependent on cumulative production; the greater ,means the more severe the dependence (Lin *et al*., 2009). In this study, we have used the cost function form proposed by Chakravorty *et al*. (1997). To construct a cost per barrel series in each year, we divided the total cost that has been computed based on section two and three by production amounts in each year. The cost function has been estimated for the period of 1986 to 2013 based on equation (4). The regression result in this scenario is indicated below. (All coefficients are statistically significant at the 1% level and we used AR (1) for correcting serial correlation in residuals):

$$C_t = 0.73e^{0.000204 S_t} \tag{5}$$

$$R^2 = 96.2\%,\ DW = 2.03$$

The result of the cost function in the current situation shows that the stock effect parameter is 0.000204 and as expected, marginal cost of production increases with cumulative production.

5. COST FUNCTION IN THE NATURAL DEPLETION SITUATIOIN

In this section, we address the second scenario of this study and estimate the oil production cost function that represents the natural depletion situation of the oil field lifecycle so far. The natural depletion situation refers to when oil comes to the surface without oil recovery methods. We have simulated the natural depletion situation by ascertaining the amount of oil that can be extracted, as well as the cost of production.

As gas injection commenced in this oil field in 1988, the oil production (without injection) trend must be simulated for the period of 1988-2013. For this purpose, in this study the result of a reservoir simulation has been used. Reservoir simulation is frequently performed to appraise oil reservoirs and production strategies and to provide valuable insights into the displacement mechanisms (Li, 2007). One of the production strategies which is often considered in the simulation is production without recovery methods. We have utilized the reservoir simulator result for this oil field for the period 1988-2000 (National Iranian oil company (NIOC), 2001). Due to a lack of up-to-date engineering simulation for the period 2001-2013 we have used the concept of "decline curve" for simulating the production for this timeframe.

Decline curve analysis is a widely used method for extrapolating a future trend in oil and gas production. There are three decline curve types: exponential, harmonic and hyperbolic decline. Of these, the exponential decline form is probably the most commonly used due to fewer parameters, ease of estimation and ability to capture common well dynamics (Luo and Zhao, 2012). In this study, we have also used the exponential form. Estimation of the decline curve was beyond the scope of this study. The production rate equation for exponential decline form is as follow: $q_t = q_i e^{-D_i t}$ and the exponential parameters (and) can be determined from regression between the logarithm of production rate and time (Towler and Bansal, 1993). The regression result based on the exponential form for the period of 1988-2000 is as follows:

$$q_t = 158e^{-0.038t} \tag{6}$$

$$R^2 = 97.1\%,\ DW = 1.61$$

That q_t is production (million barrels/year) and t is time variable. (Coefficients are statistically significant at the 1% level and we used AR (1) and MA (1) for correcting serial correlation in residuals). With the exponential form, and estimated coefficient, production has been predicted for 2001-2013. Finally, production in the natural depletion situation based on the reservoir simulator (1988-2000) and the decline curve (2001-2013) has been simulated (Fig. 1). As can be seen, in the natural depletion situation, the production rate is predicted to decline by around 50 percent compared to production with secondary recovery for the period of 1988 to 2013.

In the remainder, we simulate the trend of production costs. Our investigation showed that there are three differences between total production costs in this scenario and in the current scenario. The first difference is that in the natural depletion scenario we only have production costs (section two) and we do not have injection costs (section three). The second difference is that due to a lower production rate during natural depletion, a lower variable operation costs is expected than that implied by

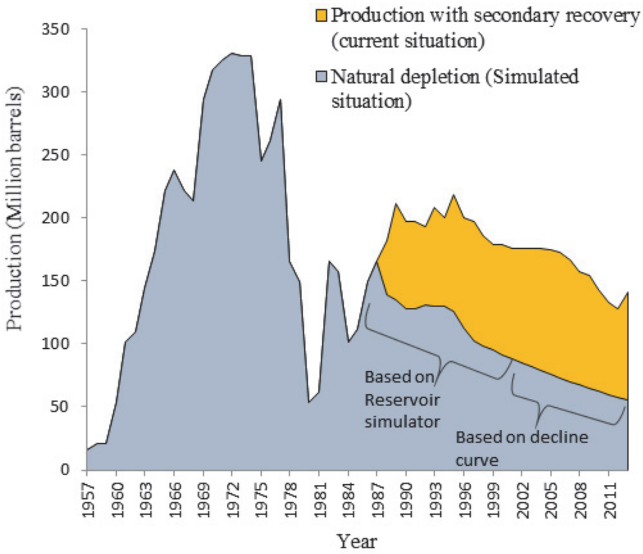

Figure 1. Production profile in two scenarios.

equation (1). The third difference is that in the current scenario (production with secondary recovery), oil production wells which are close to the injection wells usually have a higher gas to oil ratio (GOR[3]) and in order to reduce this high GOR, an extra oil production well is usually drilled. We therefore exclude this extra oil production well in the natural depletion scenario. Our examination showed that about one extra oil production well has been drilled per year due to higher GOR, hence, we exclude one oil production well in each year in natural depletion scenario.

After constructing cost data and cumulative production in the natural depletion scenario, the cost function has been estimated for the period of 1986-2013 and the result is presented below: (All coefficients are statistically significant at the 1% level and we used AR (1) and MA (1) for correcting serial correlation in residuals):

$$C_t = 0.88e^{0.000606S_t} \tag{7}$$

$$R^2 = 99\%,\ DW = 1.92$$

Results of the cost function in the natural depletion scenario indicated that the stock effect parameter is 0.000606 and that production costs also increased with cumulative production as in the current scenario with secondary recovery.

[3]The ratio of the volume of gas that comes out of a solution, to the volume of oil at standard conditions.

6. RESULTS

In this study, we have investigated the effect of immiscible gas injection as one type of secondary recovery method on the oil production cost function in the natural depletion process of the oilfield lifecycle so far. For this purpose two oil production cost functions have been estimated. The results indicate a lower stock effect parameter after implementing secondary recovery. The stock effect parameter in the current scenario with secondary recovery was 0.000204 and in the natural depletion scenario was 0.000606. This indicates that in the current production policy with secondary recovery, the cost of production is less dependent on cumulative production. This positive result is due to the significant effect of secondary recovery on cumulative production and marginal cost. The significant increase in cumulative production is the result of high secondary recovery efficiency. (In this case study the recovery factor increases from 27 to 33 percent after gas injection. Due to a high amount of IOIP, a significant increase in cumulative production has been observed). The lower marginal production cost after secondary recovery, compared to natural depletion, is due to a substantial surge in the periodic production rate (average of 93 percent per year) and a minor increase in the periodic production cost after gas injection implementation (average of 19 percent per year).

The trend of real marginal production cost is shown in Figure 2. As can be seen in this graph, the trend of the marginal oil production cost in the natural depletion process changed notably after secondary recovery implementation, implying a substantial positive effect of secondary recovery implementation in this oil field. Point A indicates the time of recovery implementation. In changing the secondary recovery implementation time, we expect Point A to move along the natural depletion cost

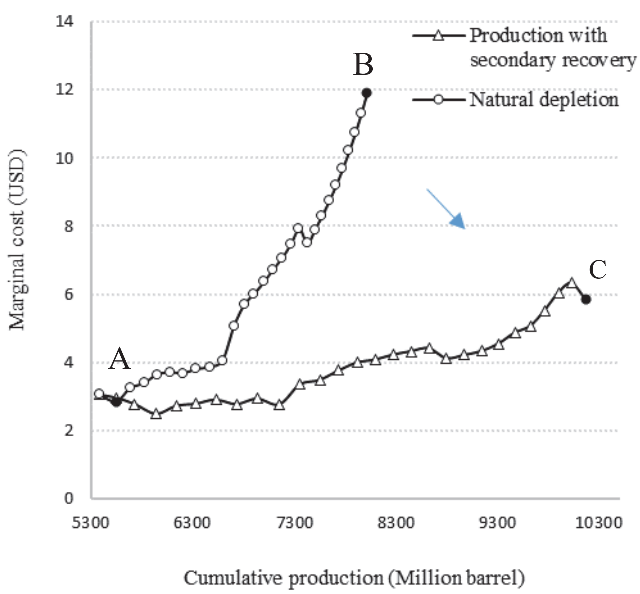

Figure 2. Oil production cost curves.

curve. As a consequence of later secondary recovery than in the present case, Point A would move upward along the natural depletion cost curve. After recovery implementation, a diagonal shift from AB to AC has been observed, which implies more production and less marginal cost in each year after secondary recovery. This diagonal shift is a result of a rightward and downward shift. The rightward shift is due to an increase in cumulative production and the downward shift is due to a decrease in the marginal production cost. The magnitude of this diagonal shift depends on the magnitude of the increase in cumulative production and the reduction in production costs after secondary recovery.

In this context, we can also explain the effect of tertiary recovery on the cost curve. If tertiary recovery has been taken into account, the AC cost curve will be affected and will shift. The size of this shift depends on the tertiary recovery efficiency and the tertiary recovery effect on marginal production cost. As with secondary recovery, the implementation time could be shown with a specific point on the AC cost curve and this Point would be close to Point A with early implementation and close to Point C with late tertiary recovery implementation. It is possible that the stock effect parameter would remain unchanged or increase in some cases of tertiary recovery where there is a low recovery efficiency and a high implementation cost.

7. CONCLUSIONS

Decision making process regarding selecting oil recovery methods depends on knowledge about the consequences of these activities. The two most important consequences regarding the recovery methods are variation of production and cost behavior after their implementation. Production behavior (usually known as the production profile) is predicted by oil reservoir simulators. Cost behavior is explained through the marginal cost function. One important property of oil cost behavior is the dependency of the production cost on cumulative production and the "Stock effect" indicating that production cost increases with depletion of reserves.

Based on empirical evidence from one of the southwest Iranian oil fields (where immiscible gas injection as a secondary recovery method has been considered), we find a stock effect parameter for the current production scenario of 0.000204. For the natural depletion scenario the stock effect parameter is 0.000606. This implies that the cost of production in the production scenario, when considering secondary recovery, is less dependent on cumulative production. Less dependency reveals that the cost of a lower level of oil reservoir is not as much as in natural depletion. Our graphical analysis demonstrates that the cost function shifts to the right and down when the secondary recovery method is taken into account. This is due to a significant increase in cumulative production and lower marginal production costs after secondary recovery. Generally, the effect of the recovery method on the cost function depends on a combination of how much cumulative production and marginal production costs per barrel change after recovery implementation.

Gas injection has been recommended as a sustainable production scenario for increasing the ultimate recovery factor in Iranian oil fields. Supporting the results i.e. the positive effect of gas injection on production profiles, our result reveals that gas injection could have a positive effect on the cost function in the natural depletion process and decrease the dependency of production costs on cumulative production. Therefore, natural gas is recommended as a crucial energy policy for injection in this oil field and others in Iran. As injected gas can also be recycled at the end of the oil field lifecycle, the injected gas could also be used for other purposes, such as export.

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