Economic Efficiency and Optimal Contractual Design of Iraq's Oil Service Contracts[1]

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Abstract

Iraq's recent service contracts with international oil companies, known as technical service contracts (TSC), exemplify the increasing reliance of oil producing countries on service contracts. In this study, we examine the economic efficiency of Iraq's Rumaila producing field technical service contract via a dynamic optimization model of oil production and well drilling. A comparison of what our dynamic optimization model recommends as the optimal production profile with the most likely scenario to be realized suggests that the Rumaila producing field technical service contract could result in economically inefficient outcomes, with the loss in profit as high as $73 to $90 billion in 2008 dollars through the lifetime of the contract depending on the well productivity assumption. In order to assess the inefficiencies introduced by various aspects of a technical service contract and by other factors surrounding the implementation of the contract, we solve for the optimal production and well drilling under various constraints and find that economic inefficiency exists even after controlling for TSC specific elements, capital cost ceilings and other constraints. The existence of economically inefficient outcomes suggests that it may be desirable to address the potential sources of economic inefficiency through implementation of some policy reforms in Iraq's oil sector.

Keywords: Iraq technical service contract; oil production; dynamic optimization
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1. Introduction

Iraq's plans to expand its oil production through its recent technical service contracts (TSCs) with international oil companies (IOCs) exemplify the increasing reliance of oil producing countries on service contracts. Several other countries around the world have also adopted service contracts.[2] In the Middle East, in addition to Iraq, Iran and Kuwait have been using variations of oil service contracts since the 1990s (Ghandi & Lin, 2013).[3] Such reliance on the service contract framework has the potential to change the landscape of the geopolitics of energy around the world. On one hand, the service contract framework allows national oil companies to have more control over the oil supply. On the other hand, service contracts cover huge previously untapped resources that might otherwise have been unavailable in countries such as Iraq. This could lead to an unprecedented increase in the global supply of conventional oil in both the short and long term. For example, in the short term, Iraq's incremental oil production through the TSC framework has already helped alleviate the potential global negative effect of the Iranian oil export decline due to EU and US sanctions and embargos since July 2012. In fact, since the end of 2012, Iraq has replaced Iran as the second largest crude oil producer among OPEC members (Energy Information Administration (EIA), 2013). In the long run, the International Energy Agency (2012) estimates that Iraq oil production could reach an astonishing

[2] For a review of technical service contracts around the world, see Ghandi and Lin (2013).
[3] Considering the reserves in Iran, Iraq, Kuwait, and Venezuela, about 40% of the world's conventional oil reserves are being developed through variations of service contracts.

10.5 million barrels per day by 2035, which is higher than Saudi Arabia's 2012 crude oil production at 9.8 million barrels per day (Energy Information Administration (EIA), 2013).[4]

An oil or natural gas service contract is a financial and legal framework that host governments of some oil producing nations use to engage with the IOCs for long-term oil and natural gas development and exploration. Oil service contracts are different from the traditional production sharing framework in at least two ways. First, the reserves and the extracted resources are not handed over to the IOCs. Second, the IOCs' return including their profit has to be agreed upon during the signing of the contract (Ghandi & Lin, 2013). A service contract is also different from oilfield service contracts in which service companies receive a fixed return for their short term services.

In almost all the countries with service contracts, the primary motivation for pursuing the service contract framework is to garner the IOCs' cooperation for their development and exploration projects without having to transfer the control of the reserves and extracted resources to the IOCs. Therefore, host governments see this framework as a means of having IOCs in their countries in a more restricted environment compared with the traditional production sharing framework, thus addressing nationalist and pessimistic view points against the foreign companies' involvement.

However, despite widespread adoption of service contracts, it is unclear whether oil service contracts are economically efficient and whether these contracts provide the right

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[4] The International Energy Agency estimates that current Iraqi technical service contracts could bring the country's oil production to 5.3, 8.3 or 10.5 million barrels per day in the IEA Iraq Energy Outlook's delayed, high and central scenarios, respectively (International Energy Agency (IEA), 2012). The IEA's central scenario estimate of10.5
<Footnote continues next page.>

incentives for international oil companies to invest in these countries. An analysis of the economic efficiency of these contracts and the sources of economic inefficiency is important for the design of future economic and energy policy in these countries. In this paper we focus on oil technical service contracts in Iraq.

A TSC can be considered a hybrid between Iran's buy-back service contracts and production sharing contracts (Sankey, Clark, & Micheloto, 2010). Under a TSC, as with most other types of service contracts in other countries, including Iran's buy-back service contracts, but in contrast to production sharing contracts, the IOC does not benefit from oil price increases. However, a TSC is different from a buy-back contract in at least two major areas. First, in a TSC, the Iraqi government allows the IOC to recover the total capital expenditures including any cost overrun once the contract reaches an agreed upon minimum production level. That is in contrast with Iran's first- and second- generation buy-back contracts where the capital cost level is pre-determined and cost overrun is non-recoverable. Second, in Iran's buy-back service contract, the remuneration is determined in negotiations in association with the IOC's targeted rate of return. However, in the Iraqi TSCs, the remuneration is based upon per barrel production and is determined in a bidding process.

The Iraqi government has a range of possible contracts to choose from to use with international oil companies, including service contracts and production sharing contracts, as described in Article 9 of Iraq's post war constitution (Blanchard, 2008). However, probably due to sovereignty issues, the Iraqi government has been persistent in using technical service

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million barrels per day is lower than the cumulative contractual plateau production targets of all the technical service
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contracts. From a profit maximization point of view, a technical service contract might not be the most suitable option for Iraq. Moreover, since technical service contracts might not let international oil companies gain much from their investment, it is possible to make a strong argument for the Iraqi government to consider increasing the efficiency of their operation by either improving the contractual design of their technical service contracts or adopting other contractual frameworks. In this study, we examine the economic efficiency of Iraq's Rumaila producing field technical service contract via a model of dynamically optimal oil production and well drilling under five optimality scenarios.

A comparison of what our dynamic optimization model recommends under the general optimal scenario with the outcome of the most likely to be realized scenario suggests that the Rumaila producing field technical service contract could result in economically inefficient outcomes, with the loss in profits as high as $73 to $90 billion in 2008 dollars through the lifetime of the contract, depending on the well productivity assumption. In order to assess the inefficiencies introduced by various aspects of a technical service contract and by other factors surrounding the implementation of the contract, we solve for the optimal production and well drilling under various constraints and find that economic inefficiency exists even after controlling for TSC specific elements, capital cost ceilings and other constraints. The existence of economically inefficient outcomes suggests that it may be desirable to address the potential sources of economic inefficiency through implementation of some policy reforms in Iraq's oil sector.

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contracts, which is12 million barrels per day by 2020 (Sankey, Clark, & Micheloto, 2010).

The structure of the paper is as follows. First, we describe the status of the four rounds of auctioning in Iraq, which will be followed by an introduction to the cash flow mechanism of a producing field technical service contract, and then by a description of the Rumaila oil field. Subsequently, we discuss our methodology in modeling the optimal production of a field under technical service contract. Then we present the optimal results in comparison to the most likely scenario to be realized. Finally, we conclude with some discussion regarding the factors that could explain our results as well as some issues surrounding Iraq's technical service contracts that might affect these contracts and the country's future production plans.

2. Iraq's Technical Service Contracts

2.1. Background

The Iraqi government has held three rounds of licensing from June 2009, with 12 oil technical service contracts awarded in the first two rounds, and three non-associated natural gas technical service contracts[5] awarded in the third round as shown in Table 1. The fourth round, which consists of 12 exploration projects,[6] was held in May 2012. Of the 12 fields with awarded service contracts in the first two rounds, 6 fields are considered very large (brown) or large (green). The Iraqi government has awarded producing field technical service contracts (PFTSC)

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[5] The Korea Gas Corp.-led consortium won the bid on the Akkas natural gas field by offering a remuneration fee of U.S. $5.50 per barrel oil equivalent with an expected investment of U.S. $4.4 billion. Kuwait Energy and Turkish Petroleum International Co. together were awarded Siba and Mansouriya non-associated natural gas fields with remuneration fees of U.S. $7.50 and U.S. $7 per barrel oil equivalent for each field, respectively (Hafidh, 2010).

[6] The bidders have to bid on fees in return for their exploration activities (Hafidh, 2012).

for three[7] of the very large fields since they were already in production before the signing the contract, and the contracts' scope involve increasing the production levels. The remaining 9 service contracts use a framework known as a development and production technical service contract (DPTSC). In the next sub-section, we discuss the cash flow mechanisms of producing field technical service contracts in detail in order to define the components of our dynamic optimization model.

Table 1: Summary of Iraq's four licensing rounds

Round	# Pre-qualified bidders	Important Dates	Bid Projects' Scope	Outcome
1	35 [1]	June 30, 2009 results announced. [1]	To develop 6 oil and 2 non-associated natural gas fields [1]	One contract was awarded (Rumaila). Three other oil contracts were signed later. [1]
2	9 [1]	December 12, 2009 results announced. [1]	To develop 10 oil fields [1]	Seven contracts were awarded. Three contracts did not have any bidders. [1]
3	13 [4]	October 20, 2010 results announced. [4]	To develop 3 non-associated natural gas fields including two from the first round	Three fields were awarded to two international consortia [4]
4	46 [3]	Promotional Conference: August 2011 [2] Final Tender: November 2011 [2] Bidding Event: May 2012 [5]	To explore 12 oil and natural gas blocks [2]	Not yet determined
Sources				
[1]	Sankey, Clark, & Micheloto (2010)			
[2]	The Petroleum Services Group (PSG) at Deloitte (2011)			
[3]	Reuters (2012)			
[4]	Hassan Hafidh (2010)			
[5]	Hassan Hafidh (2012)			

2.2. Components of a Producing Field Technical Service Contract

The main cash flow components of a producing field technical service contract are either related to production or to fees/costs. The four production-related terms are the baseline

[7] These three fields include Rumaila, West Qurna 1 and Zubair.

production rate, the incremental production rate, the plateau production target and the improved production rate. The three important fee-related terms are supplementary fees, service fees, and remuneration, which is part of the service fees. Producing fields are those whose initial production began before the start of the new development that is taking place through a technical service contract. For these fields, the baseline production rate,[8] which declines annually at a 5% rate, is the fields' production rate before any development. The incremental production is any production above the baseline production.[9] The baseline and incremental production levels are used in the recovery of supplementary costs and petroleum costs via the supplementary fees and service fees parts of a cash flow of a producing field technical service contract, respectively. The term plateau production target (PPT) refers to the "net production rate that is to be achieved and sustained for the plateau production period." The plateau production period starts once the field's production reaches and stays for 30 consecutive days at the PPT level.[10] The plateau production target is bid on in the contract and is used for the remuneration calculation as part of the service fees of the cash flow. The next production-related term is the improved production target, which is defined as 10% higher than the initial production rate. Once production reaches and stays for 30 consecutive days at this level, the service fees eligibility date of the contract starts. After the

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[8] This term has been used in the technical service contracts for the three very large producing fields of Rumaila, West Qurna 1 and Zubair (Sankey, Clark, & Micheloto, 2010). In the official contract language, baseline production "constitutes the amount for any incremental production being derived from an assumed decline from the initial production rate at a compounded annual rate of 5%" (Republic of Iraq, Ministry of Oil, 2011).

[9] In the official contract language, incremental production means "the incremental volume of net production that is realized in excess of deemed net production volume at the baseline production rate," (Republic of Iraq, Ministry of Oil, 2011).

[10] The plateau production period may last 7 years.

service fees eligibility date, the IOC is eligible to recover the service fees of the contract (Republic of Iraq, Ministry of Oil, 2011).

The three important fee-related terms are: supplementary fees, which cover supplementary costs;[11] service fees, which cover petroleum costs; and the remuneration fee. Supplementary fee payments are funded based on 10% of the revenue from the baseline production, and the payments start with the start of the contract or the effective date as defined in Article 19 of a producing field technical service sample contract.[12] Service fees and remuneration are due and payable to the IOC once the contract reaches the service fees eligibility date with priority given to petroleum cost repayments.[13] The total remuneration that the IOC receives in each quarter is based on the bid per barrel applicable remuneration fee and the incremental production as well as the performance factor. The bid per barrel applicable remuneration fee is determined in accordance to the stage of the IOC's cost recovery in the contract, which is based on an index called the R-Factor. The R-Factor, calculated annually, is a coefficient of the IOC's overall payback over the IOC's total expenditure. The R-Factor is used to gradually adjust the IOC's per barrel remuneration with the increase in the IOC's cost recovery as described in Table 2. In the early stages of the contract, the R-Factor is lower than 1, and therefore, the applicable remuneration is the same as the per barrel bid remuneration. However, later on with the increase

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[11] Supplementary costs are non-petroleum costs, which mostly include the signature bonus and de-mining costs (Republic of Iraq, Ministry of Oil, 2011).
[12] Article 19.3 specifies that the supplementary fees are paid in kind or in cash in U.S. Dollars. If paid in kind, the price of oil is determined based on provisions of the Valuation of Export Oil Article in the contract (Republic of Iraq, Ministry of Oil, 2011).
[13] It is also important to mention that the service fees payments to the IOC cannot exceed 50% of the deemed revenues of the incremental production. In other words, 50% of the revenue from the incremental production is the only source for the service fees payments (Republic of Iraq, Ministry of Oil, 2011).

of the R-Factor, the applicable remuneration declines. The remuneration fee is also adjusted with the performance factor during the plateau production period. The performance factor is defined as the ratio of the net production rate to the bid plateau production target and should never exceed 1.0 (Republic of Iraq, Ministry of Oil, 2011). In other words, the performance factor acts as a penalty for the IOC in case the net production rate stays below the plateau production target. At the same time, the performance factor could act as a constraint, since it does not allow the net production to exceed the plateau production target. In our dynamic optimization model, our general optimal scenario does not have any performance factor-related constraint. However, the other four optimality scenarios have performance factor-related constraints based on the contract or based on the estimates by Deutsche Bank that will be discussed in the Scenarios sub-section.

Table 2: Remuneration Fee and R-Factor in a Producing Field Technical Service Contract

R-Factor	Remuneration Fee per Barrel (USD)
Less than 1.0	100%
1.0. to less than 1.25	80%
1.25 to less than 1.5	60%
1.5 to less than 2.0	50%
2.0 and above	30%

Source: Republic of Iraq, Ministry of Oil, (2011)

2.3. The Rumaila Oil Field

We model the dynamically optimal oil production and well drilling for the Rumaila oil field, which is under development through a producing field technical service contract. The Rumaila contract was the first contract awarded in the first round of auctioning in Iraq in 2009.

The winner was a consortium of BP, CNPC and Iraqi State Oil Marketing Organization (SOMO) with 38%, 37% and 25% working interests, respectively.[14] The proposed plateau production target was 2.85 million barrels per day and the bid remuneration fee was $2 per barrel (Sankey, Clark, & Micheloto, 2010). Once reaching the plateau production target, Rumaila will be the second largest producing field in the world after Saudi Arabia's Ghawar oil field.

Rumaila was discovered in 1953 by the Iraq Petroleum Company in partnership with BP. Rumaila has three known formations that include the Main Pay reservoir, the Mishrif carbonate formation and the Yamama formation. In the beginning years, the production increase was to be based on the recovery of 275 existing wells, which are not producing. Main Pay is also the main reservoir for the initial production. However, the sustained peak production at the plateau production target is to be based on production from Mishrif formation (Daly, 2010).

3. Model

3.1. Iraqi Producing Field Dynamic Optimization Model

Our dynamic optimization model solves for the optimal oil production path and well drilling plan that yield maximum profit for the owner of the chosen field of the study through the lifetime of the contract, based on a choice of a discount rate. Therefore, the solution of our dynamic optimization problem yields the optimal trajectories for the control variables through time which maximize the present discounted value of the entire stream of per-period profit, subject to several constraints. Our dynamic optimization model yields the first-best benchmark

[14] We refer to BP and its partners as "IOC" or "IOCs" throughout the rest of the paper.

against which our other optimality scenarios and the most likely to be realized scenario are compared.

In designing our dynamic optimization model, we assume that the optimal decision is taking place in a cooperative manner between the IOC and the Iraqi government with the sole objective of maximizing the present discounted value of the entire stream of per-period net profits over the lifetime of the contract. In the case of the Iraqi producing field technical service contracts, even though the owner of the field is the Iraqi government, modeling optimal oil production requires an implicit assumption that the IOC and the Iraqi government are able to collude or cooperate on deciding about all aspects of development including production levels.[15] Later in this study and under our cash flow analysis we show that the cash flow mechanism of a producing field technical service contract does not allow the perfect cooperation of the Iraqi government and the IOCs. Thus, failure to cooperate is a potential source of economic inefficiency that can lead to lower profits. In order to assess the inefficiencies introduced by various aspects of a technical service contract and by other factors surrounding the implementation of the contract, we also consider other optimality scenarios as described in the Scenarios sub-section.

We use Bellman's (1957) set-up and mathematical representation in order to find numerical solutions for the following dynamic programming problem:[16]

$$v_t(N_t, CP_t) = max_{X_t, n_t}\{P_t * X_t - c(X_t, n_t, W_t, N_t) + \beta v_{t+1}(N_{t+1}, CP_{t+1})\}$$

[15] This is not an unrealistic assumption since the Iraqi constitution allows frameworks other than the technical service contract.
[16] The notation follows closely Gao, Hartley and Sickles (2009) since we use their functional forms and methodologies on cost, water injection and maximum production constraint.

subject to:

$$N_{t+1} = (1-\delta)N_t + n_t$$

$$CP_{t+1} = CP_t + 365X_t$$

$$W_t = \omega(X_t, N_t, n_t)$$

$$X_t \leq f(N_t^*, W_t, CP_t)$$

$$0 \leq X_t$$

$$0 \leq n_t$$

$$N_t^* = N_t + n_t,$$

where the control variables X_t and n_t represent respectively the extraction rate (in million barrels per day) and the number of new wells drilled during the time period t; the state variables N_t and CP_t are respectively the number of producing wells and the cumulative production at the start of time period t; $c(\cdot)$ is the cost function; W_t depicts the water injection rate (in million barrels per day) in time period t, which is determined by the function $\omega(\cdot)$ as will be discussed in the Constraints sub-section; N_t^* stands for total number of producing wells during time period t; P_t is the exogenous price estimates in time period t ; β is the discount factor; δ corresponds to the proportion of producing wells which are depleting in time period t; and finally $v_t(\cdot)$ is the value function (Gao, Hartley, & Sickles, 2009).

3.2. Cost

The cost function in this study represents the operation expenditures (opex) and capital expenditures (capex) during the contractual period. In designing our dynamic optimization model, we assume that the optimal decision is taking place in a cooperative manner between the IOC and the Iraqi government with the sole objective of maximizing the present discounted value of the entire stream of per-period net profits over the lifetime of the contract. Therefore, in contrast to Ghandi and Lin's (2012) cost function, which represents the operation and maintenance cost, here in this paper, our cost function reflects the capital expenditures, which also include development and reservoir engineering costs. Estimating the Rumaila specific cost function was out of the scope of this project since we did not have access to data and necessary tools for such estimation. In fact, the IOCs involved in this contract are spending huge resources to accomplish this extraordinary task.[17] On the other hand, as we discuss towards the end of this section, we believe we can justifiably approximate the cost function for Rumaila by using the approach and functional forms used by Gao, Hartley and Sickles (2009).

Gao, Hartley and Sickles' (2009) annual cost function has the following five main components which are described in detail in Table 3:[18]

$$C_t = \mu_t + V_t(365X_t) + \omega_t + M_t + \eta_t$$

where μ_t and η_t stand for total annual surface infrastructure maintenance cost and total cost of a new well respectively; M_t represents maintenance costs; V_t and ω_t are the variable operating costs and annual water injection cost, respectively. By replacing each component with its functional form, we obtain:

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[17] Personal communication with industry experts

[18] Gao, Hartley and Sickles' (2009) production cost function also includes exploration costs. They assume the exploration cost to be 20% of the development and operation cost combined. Even though the Ghawar oil field is a producing field, it still incurs exploration costs, which include "geological and geophysical surveys for discovery, and delineation of reservoirs and the drilling of exploration wells" (Gao, Hartley, & Sickles, 2009, p. 164). <Footnote continues next page.>

$$C_t = 365 * 0.44X_t + 0.7714(365X_t)^{-0.2423}(365X_t) + 365 * 0.20W_t + 0.2819N_t + 2.882n_t.$$

Water injection rate is a function of extraction rate and total number of producing wells including new drilled wells in time period *t* with the following functional form:

$$W_t = e^{0.7999}X_t^{0.9509}N_t^{*0.0306}.$$

Therefore, as listed below, the cost function depends only on the extraction rate at time *t*, total number of producing wells at the beginning of time *t* and the number of drilled wells during time *t*:

$$C_t = 160.6X_t + 67.411(X_t)^{0.7577} + 162.4482X_t^{0.9509}N_t^{*0.0306} + 0.2819N_t + 2.882n_t.$$

The above cost function is concave with respect to both the production and the total number of producing wells. The concavity of the variable operating cost implies the existence of an economy of scale in oil production. In other words, new per barrel incremental production will be less costly compared to existing production. As shown in Table 3, since the manpower is the primary component of Gao, Hartley and Sickles' (2009) variable operating cost, concavity implies an economy of scale with respect to labor. In order for this cost function to be applicable to Rumaila, it must therefore be the case that in Rumaila, there are economies of scale in the labor needed to operate new drilled wells. This is not an unrealistic assumption due to BP's plan for "real time management and remote monitoring of wells" through the company's in-house advanced technologies such as Field of the Future[19] (GDS Publishing, Inc., 2010). The concavity of the variable operating cost with respect to the oil production in the Rumaila oil field could

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However, for our dynamic optimization model of a producing field technical service contract, since there is no exploration involved, we just consider the development and operation cost.

also be explained by the fact that not all the new incremental production is coming from the new drilled wells. In fact, in the beginning of the contract in 2010, Rumaila had 550 producing and 150 injecting wells. Among the producing wells, half were in production and BP planned to bring the other half into production gradually, suggesting that it is reasonable to assume that the new incremental production is based on the new drilled wells as well as the old wells. Consequently, variable operating costs may be concave because resuming a flow of oil from existing wells might not be as costly as extracting oil through new drillings. Therefore, we could justify the economy of scale in the variable operating cost by considering the plans for rehabilitation of old wells. The fact that BP's plan includes resuming a flow of oil from existing wells could also justify using a concave water injection rate function with respect to the total number of producing wells. In other words, bringing back the existing producing wells into operation might not require the same proportionate increase in the water injection rate. On the other hand, considering just the new wells and as discussed, the concavity feature means that new producing wells will require more water, but in a decreasing manner, which suggests that the new wells are either productive enough that they need less additional water, or that the location pattern of the new wells are such that the water injection rate from a single water well could serve several production wells.

[19] As BP states, "through a programme called Field of the Future®, BP is installing a range of standardized digital, sensing and control technologies in its operations and integrating data to enhance real-time operating efficiency and recovery" (BP p.l.c, 2012).

Table 3: Components of Gao, Hartley and Sickles (2009) cost function

Main components	Break down of components		Explanation of functional form	Functional form
Development costs	Infrastructure and maintenance cost for surface installations[20]	Surface infrastructure costs	Included in the cost of drilling a new producing well	$\mu_t = 365 * 0.44X_t$
		Surface infrastructure maintenance costs	Total annual surface infrastructure maintenance cost (μ_t) as a function of extraction rate (X_t)	
	Oil well costs	Investment for new wells	Total cost of a new well (η_t)[21] with additional surface infrastructure as a function of the number of new drilled wells during time period t (n_t)	$\eta_t = 2.882n_t$
		Annual maintenance costs for old wells (millions of dollars)	Continuing investment is needed to maintain well productivity.[22] Maintenance costs (M_t) as the function[23] of number of wells (N_t) in time period t	$M_t = 0.2819N_t$
Production costs	Operating costs	Annual expenditures on manpower and other variable operating costs	Variable operating costs (V_t) as a function[24] of annual extraction rate ($365X_t$)	$V_t = 0.7714(365X_t)^{-0.2423}$
	Reservoir engineering costs	Annual water injection cost (millions of dollars)	In order to capture reservoir engineering costs, annual water injection cost (ω_t) are calculated as \$0.20 per daily barrel water injection rate (W_t) in time period t.	$\omega_t = 365 * 0.20W_t$

In general, there are at least three arguments which justify using Gao, Hartley and Sickles' (2009) cost function for our Rumaila dynamic optimization model. The first argument

[20] Gao, Hartley and Sickles, (2009) argue that a new producing well in Saudi Arabia may cost $482,000 in addition to the 0.44 dollars per barrel (1986 dollars) daily maintenance cost based on data from Center for Global Energy Studies (1993). They include a new producing well's $482,000 surface infrastructure cost in the cost of drilling a new well as part of oil well costs. For the surface infrastructure maintenance cost, and based on above mentioned daily maintenance cost, they use $\mu_t = 365 * 0.44X_t$ as their functional form.

[21] Drilling each new Arabian Light producing field costs $2.4 million besides the above mentioned $482,000 surface infrastructure cost, which brings total drilling cost to $2.882 million per well including the cost of water injection wells (Gao, Hartley, & Sickles, 2009)

[22] This does not include the surface infrastructure maintenance cost, since that is included in the development costs.

[23] This coefficient is based on two main assumptions. First, producing wells phase out gradually at a 5% rate during the wells' 20-year simulated assigned life. Second, the present value, at 10% discount rate, of the needed investment to keep the wells productivity during the 20-year period is the same as the initial well infrastructure investment (Gao, Hartley, & Sickles, 2009).

[24] This functional form, estimated by the Energy Information Administration (EIA), is based on the EIA's Estimator database. The Estimator includes discovered and/or undiscovered fields and production specifications of 8 geological plays with different field sizes, based on different recovery estimations, and with similar geology, geography and temporal specifications (Gao, Hartley, & Sickles, 2009).

for using Gao, Hartley and Sickles' (2009) cost function is that their cost function is for a field similar to Saudi Arabia's Ghawar oil field that has an important water injection component. Since the production plans in Rumaila are also based on water injection,[25] by using their cost functional form, we are able to capture water injection related costs in our model to some extent. However, geological differences between Rumaila and Ghawar may cause these two fields to have different cost functions. We address this caveat by conducting a cost sensitivity analysis where we analyze the effect of changing some components of the cost function on the results.

A second argument for using Gao, Hartley and Sickles' (2009) cost function relies on the fact that Gao, Hartley and Sickles (2009) have made several generalizations in order to estimate their cost function, generalizations which can also apply to the Rumaila oil field. First, the water injection rate, which is one of the five main cost terms, is based on a generalized simulation approach for a field similar to the Ghawar oil field. Second, since Ghawar is an Arabian light field, Gao, Hartley and Sickles (2009) use a "weighted annual average infrastructure cost per million barrels per day production capacity"[26] of Arabian light and medium fields to estimate its $482,000 (1986 dollars) surface infrastructure cost as well as its 0.44 dollars per barrel (1986 dollars) surface infrastructure daily maintenance cost. Third, Gao, Hartley and Sickles (2009) assume $2.4 million as the cost of drilling of a new producing well for an Arabian light crude, which in addition to the $482,000 surface infrastructure cost, account for the total cost of a new

[25] Water injection method is used in the secondary oil recovery operations on aged fields with depleted natural pressure. The injected water, through specific water injection wells, is to increase the reservoir pressure and to facilitate oil transition in the reservoir towards the producing wells. Each producing field may have several water injection wells located in different patterns depends on the characteristics of the reservoir. It is also possible that a single water injection well used for several producing wells (Rigzone, 2012).

[26] Gao, Hartley and Sickles' (2009, p. 164)

well (η_t). Gao, Hartley and Sickles (2009) therefore make some simplifying assumptions in terms of geology and crude characteristics in order to construct their cost function. In order to generalize their cost to Rumaila, we similarly make the implicit simplifying assumption that the Rumaila oil field and crude are similar to the field and crude in Gao, Hartley and Sickles' (2009) study. In order to account for possible errors due this generalization, we also do sensitivity analysis for the cost components that require such geology and characteristics assumptions. These cost components are annual surface infrastructure maintenance cost (μ_t) and the total cost of a new well (η_t), which together account for about 48% of total cost in 2010, as shown in Table 4.

A third argument for using Gao, Hartley and Sickles' (2009) cost function is that it gives us cost estimates close to BP's actual 2010 announced budget for Rumaila. We consider the year 2010 as the first year of the contract in our model, similar to the actual Rumaila producing field technical service contract. For this year, BP's $1.7 billion annual work plan includes drilling new producing wells and maintaining the production over the 275 producing wells that already were in operation in order to add an incremental production up to 200,000 barrels per day. The 2010 total production target including the incremental production from the new wells as well as production from existing wells is 1.2 million barrel per day (GDS Publishing, Inc., 2010). We estimate the annual cost of such production and wells plans for 2010 as $1.47 billion in 2010 real dollars[27] using the cost function and parameters from Gao, Hartley and Sickles (2009) that we calibrate based on Rumaila's specifications. Our 2010 cost estimate is therefore fairly close to

[27] $434.23 million dollars in 1986 dollars

the company's announced 2010 annual budget, which improves our confidence in using this cost function in our dynamic optimal oil production model for Rumaila.

Table 4: Our Cost Estimates Based on BP's 2010 Work Plan

Cost Item	Cost in Current 1986 Million Dollars	Cost in Real 2010 Million Dollars	Percentage with Respect to Total Cost (%)
Total Annual Surface Infrastructure Maintenance Costs (μ_t)	192.72	383.51	26%
Variable Operating Costs (V_t)	77.40	154.02	10%
Annual Water Injection Costs (ω_t)	230.74	459.16	31%
Annual Maintenance Costs for Old Wells (M_t)	77.52	154.27	10%
Total Cost of a New Well (η_t)	161.39	321.16	22%
Total Cost	739.77	1472.11	100%

3.3. Constraints

Our dynamic optimization model of a producing field technical service contract yields the optimal production path and the optimal number of new drilled producing wells each year. Based on a choice of a discount rate, our model chooses the production path and the number of new drilled producing wells each year to maximize the present discounted value of the entire stream of per-period net profit subject to several geological, technical and contractual constraints. The geological and technical constraints are essential since without them, the model might result in unfeasibly high or low production levels as well as infeasible drilling well plans in some periods. In addition, we use the contractually imposed constraints in defining scenarios besides our general optimal scenario, as illustrated in Table 5, in order to provide optimal solutions under the various constraints imposed by the contract and in order to assess the inefficiencies introduced by various aspects of a technical service contract. The production related constraints include a maximum production cap; a feasibility constraint between the production level of two consecutive periods (Ghandi & Lin, 2012); a minimum production limit; and a cumulative production cap based on the Rumaila 2010 recoverable reserve.

3.3.1. Maximum Production Constraint

For the maximum production cap, we follow Gao, Hartley and Sickles' (2009) methodology and estimated functional forms that address geological and technological limitations of extraction from an onshore oil field in Saudi Arabia. We discuss their approach in setting the maximum production constraint in detail below. There is also another maximum production cap based on the contract performance factor in coordination with the plateau production target (PPT) levels that we apply in four of our optimality scenarios (TSC optimal, TSC optimal considering cost, TSC actual optimal not considering the cost and TSC actual optimal), as discussed in detail in the Scenarios sub-section. For our general optimal scenario, however, we avoid using a fixed production level at the plateau production target (PPT) since in setting the PPT, the IOC and the Iraqi government might have taken into account some other economic and non-economic factors besides the geology/technology constraints. Therefore, since the maximum production constraint should reflect the physical limitations of the field, we do not have the additional PPT-based maximum production constraint in our general optimal scenario.

Gao, Hartley and Sickles' (2009) dynamic optimization model for Saudi Arabia's giant Ghawar oil field benefits from engineering-economic simulations based on Workbench Black

Oil software. Workbench Black Oil software simulates the fluid movements[28] in the reservoirs. The simulations happen through using partial differential equations describing the movement of the fluids[29] that take into account the reservoirs' geological and technological constraints. Gao, Hartley and Sickles (2009) use Workbench Black Oil software to generate data on the required water injection rates and number of producing wells in accordance to the simulation assigned production target on a field with similar physical characteristics to their field of study. They use the simulated data for two purposes. First, they econometrically estimate water injection as the following function of the extraction rate (X_t) and total number of producing wells (N_t^*) including new drilled wells in time period *t*:[30]

$$W_t = \omega(X_t, N_t, n_t) = e^{0.7999} X_t^{0.9509} N_t^{*0.0306}.$$

Gao, Hartley and Sickles (2009) also estimate the maximum production capacity in the vicinity of an average oil well based on the water injection rate W_t and the field's cumulative production CP_t using a semi-log functional form that best matches the simulated data. This functional form captures the geological constraint in the reservoir since it takes into account the effect of reservoir engineering on the production capacity. By extending the maximum production capacity function to the field as a whole, they arrive to the following functional form as the production constraint:

$$X_t \leq f(N_t^*, W_t, CP_t) = \{0.0451 + 0.0362 \log(W_t) - 0.0038 \log(W_t) \log(CP_t) - 0.0044 \log(CP_t)\} * N_t^*$$

[28] These include water injection to the reservoir, fluid transition in the reservoir and oil extraction from the reservoir's producing wells.
[29] Partial differential equations represent the science of fluid movements in the reservoir before and after the start of the production (Gao, Hartley, & Sickles, 2009).
[30] This captures the technological limitation of their field of study as mentioned in the above.

where N_t^* is the total number of producing wells including new drilled wells in time period t. The above functional form and estimated coefficients are also based on the assumption that the average oil well of their study has an annual cumulative production equal to 5% of the reservoir reserve. Based on their results, we assume that 5% of the Saudi Arabia's Ghawar reserve is at least 5 million barrels per day. Therefore, in order to use Gao, Hartley and Sickles' (2009) production capacity function as our production cap for Rumaila, which had one million barrels per day production in the beginning of 2010, amounting to about one fifth of the production in Saudi Arabia's Ghawar reserve, we divide the whole production capacity function by 5 in our model.

3.3.2. Minimum Production Constraint

We use the field's baseline production as the minimum production constraint for two reasons. First, in a producing field technical service contract, it is the responsibility of the joint company[31] to keep the production at the baseline level. Through this company, the IOC is responsible for seeking approval from the Iraqi government on the annual work program and the budget including the next year's IOC capital expenditures on the field. It is possible that the optimal production may be lower than the baseline. However, in a producing technical service contract, the IOC cost recovery is related to the baseline production level. Therefore, even

[31] Rumaila Operating Organization (ROO) is the joint company in this contract. In the Rumaila producing field technical service contract, Iraq State Oil Marketing Organization is BP's partner with 25% interest. However, the field's rehabilitation and expansion is managed by Rumaila Operating Organization, which was established by a BP-led consortium in November 2009, based on the terms of the contract. ROO is staffed from Iraq's national South Oil Company (Lando & Dourian, 2010).

though we are not modeling optimal production under technical service contract limitations in our general optimal scenario, we still keep the minimum production constraint at the baseline level, since in other contractual frameworks including production sharing, the IOC has to recover the cost based on some portion of production. In other words, we assume that in these producing fields, the IOC or any other entity in charge of the field would still be expected to keep the production at least at the baseline in any other contractual framework including frameworks that may be more economically efficient.

The second reason why we use the field's baseline production as the minimum production constraint is that the IOCs' low cost exposure due to rapid cost recovery is considered to be an important incentive in the producing field technical service contract.[32] The cost recovery starts[33] once the field reaches the improved production target.[34] The rapid cost recovery has been made possible due to the fact that the fields are in production before the start of the contracts. Therefore, the IOC has the incentive as well as the responsibility to keep the production at least at the baseline. As a result, we consider the baseline production rate as the minimum production constraint in our optimal production model based on 2009 production level before the start of the contract.

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[32] Personal communications with industry experts
[33] Service Fee Eligibility Date
[34] 10% higher than the initial production rate

3.3.3. Feasible Production

We also consider a feasible production constraint, which sets a cap on the largest possible absolute difference between the production level of two consecutive periods following Ghandi and Lin's (2012) approach. Ghandi and Lin's (2012) feasible production level is 10,000 barrels per day for two fields with about 190,000 combined per day production. For Rumaila, with a baseline and target plateau production of one and 2.85 million barrels per day, respectively, it is reasonable to set the feasible production level in a range between 50,000 to 150,000 barrels per day. However, Rumaila's proposed work plans also include installing additional incremental production capacity at 200,000 barrels per day in some years. Therefore, we set the Rumaila feasible production constraint at 200,000 barrels per day.

3.3.4. Well Productivity Constraint

Our well productivity constraint, which we include in all of our optimality scenarios, accounts for the fact that there are production limitations in terms of barrels per day that an average new well can handle. We base our well productivity constraint on the Deutsche Bank forecast of the number of new drilled wells that we also use in order to define the Rumaila most likely scenario to be realized. In particular, for each year we divide the Deutsche Bank total production forecast for that year by the Deutsche Bank forecast of the total number of producing wells in that year. This calculation results in what we call "well productivity", which varies by the year of the contract based on the production and new wells drilling plan with a minimum of 1,740 barrels per day and a maximum of 3,240 barrels per day as shown in Figure 1.

As seen in Figure 1, under the Deutsche Bank forecast, well productivity first declines until around 2020, after which it rises. Rumaila's incremental production was to be initially based on the production from the Main Pay, where the wells have high productivity.[35] In later years, the production from the Mishrif formation was to be used to keep the production at the plateau production target. The Mishrif formation's wells have lower productivity.[36] The transfer of production from the highly productive Main Pay to the less productive Mishrif formation is a likely explanation for the declining productivity from 2010 to 2020. After 2020, with additional production estimates and no new wells as estimated by Deutsche Bank, the productivity will reverse course as shown in Figure 1.

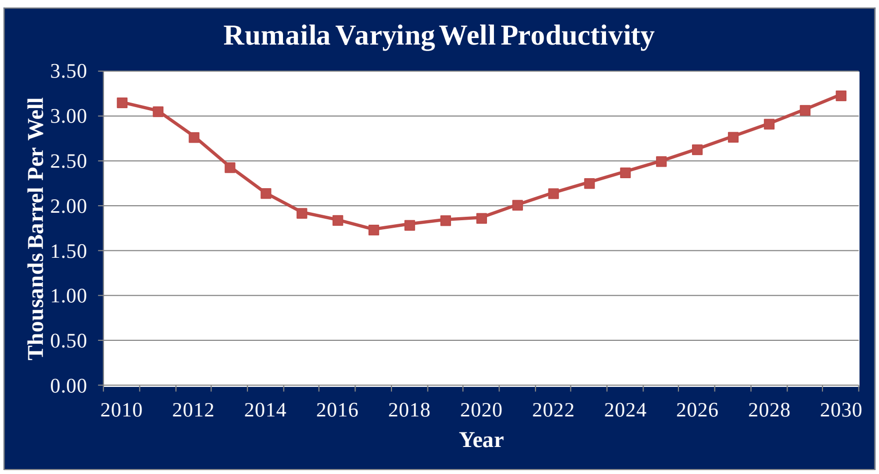

Figure 1: Rumaila average well productivity based on Deutsche Bank production and number of new of wells drilling for the varying well productivity case

Well productivity is imposed as a separate constraint in all optimality scenarios. In order to account for the sensitivity analysis on the well productivity assumption, we report optimal results

[35] Personal communication with industry experts
[36] Personal communication with industry experts

for 2 cases of well productivity. In the first case, we fix well productivity at its maximum level of 3,240 barrels per day. In the second case, we allow well productivity to vary each year according to the annual well productivity plotted in Figure 1.

3.4. Scenarios

In order to account for factors that could affect the overall economic efficiency of the Rumaila contract, we define five optimality scenarios that are different in one or more incorporated constraints as listed in Table 5. The overall goal is to show the potential sources of economic efficiency in the contract or outside the contract by comparing our optimal results with the outcome from the most likely to be realized scenario.

The most likely scenario to be realized values for production and new wells drilled are based on Deutsche Bank forecasts. To calculate the cost, revenue and the present discounted value of the entire stream of per-period profit for the most likely scenario to be realized, we evaluate our cost, revenue and value functions at these Deutsche Bank values for production and new wells drilled.

Our five optimality scenarios are: general optimal, technical service contract (TSC) optimal, TSC optimal considering capital cost ceiling, TSC actual optimal not considering capital cost ceiling, and TSC actual optimal. The general optimal scenario is the dynamic optimization model described above, and yields the first-best benchmark against which our other optimality scenarios and the most likely to be realized scenario are compared. The remaining optimality scenarios allow us to account for the realities that the IOC and the Iraqi government face in implementing the contract.

The general optimal scenario results are what our model recommends as the optimal production path and the optimal trajectory for drilling new wells when only considering geology-based constraints as well as some general well-related constraints in order to avoid unreasonably high number of wells or unreasonably high well productivity for some years. Besides the well productivity constraint that was discussed in the previous sub-section, the other well-related constraint is the maximum number of feasible new wells in each year, which we incorporate into the model based on Deutsche Bank's realistic estimate of well drilling plans in coming years.[37]

In our TSC optimal scenario, we impose additional constraints in order to control for the TSC imposed conditions including an additional maximum production cap based on the performance factor and plateau production target as specified in the contract. In Table 5 we refer to this as the "max production cap based on performance factor at 2.85 million barrels per day" in order to distinguish between the general optimal and TSC optimal since the 2.85 million barrels per day is the targeted plateau production, and the IOC has the obligation to reach that level. Otherwise, IOC's remuneration is adjusted through the enforcement of the performance factor. Our TSC optimal considering capital cost ceiling scenario applies an additional constraint

[37] The maximum number of wells constraint is also to account for possible shortage of drilling rigs in Iraq due to the need for such rigs from other development projects. In general, a drilling rig can drill 12 wells per year on average (personal communication with industry experts). Considering BP's announced plan for having 20-25 rigs at the maximum (Daly, 2010), it is reasonable to expect 240 to 300 wells as feasible number of wells to be drilled in each year. Therefore, we set the maximum feasible number of new drilled wells in each period at 285, which is in the upper range of the feasible number of wells. The maximum number of wells at 285 is slightly higher than the maximum number estimated by Deutsche Bank at 220 and the 275 wells that BP plans to bring online in the first
<Footnote continues next page.>

on capital expenditures to the TSC optimal scenario. This is to account for the possibility that the Iraqi government may change its mind about the capital cost level a few years after the start of the contract. The cost constraint is in fact the cost associated with the production and well drilling estimates of our most likely to be realized scenario using our cost function. Therefore, the constraint is partially based on the Deutsche Bank production and well drilling estimates and partially based on the functional form of our cost function.

We also have two scenarios that could represent optimal solutions considering additional limitations that the IOC and the Iraqi government may face in implementing the contract, including Iraq's export capacity constraint and Iraq's new quota in OPEC.[38] These two optimality scenarios are the TSC actual optimal not considering capital cost ceiling scenario and the TSC actual optimal scenario. These two scenarios have a lower maximum production cap of 2.35 million barrels per day that is based on Deutsche Bank's lower than contractual level plateau production target estimate, and therefore account for the factors that lead to Deutsche Bank's lower than contractual level plateau production target estimate. In addition, in the TSC actual optimal not considering capital cost ceiling scenario, we avoid enforcing a capital cost ceiling. However, we incorporate the capital ceiling in the TSC actual optimal scenario for the reasons discussed in the above.

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three years of the development starting 2010, (GDS Publishing, Inc., 2010), since it may be possible that the optimal number of wells is higher than BP's well rehabilitation plan in 2010.

[38] These important limitations are discussed in detail in the conclusion section.

Table 5: Scenarios

	Scenarios				
List of Constraints	**General Optimal**	**TSC Optimal**	**TSC Optimal Considering Capital Cost Ceiling**	**TSC Actual Optimal Not Considering Capital Cost Ceiling**	**TSC Actual Optimal**
Production Constraints					
Min production based on 2009 baseline production (2010-2030)	X	X	X	X	X
Max production (2010-2030)	X	X	X	X	X
Production feasibility cap (2011-2030)	X	X	X	X	X
Cumulative production cap based on 2010 recoverable reserve	X	X	X	X	X
Max Production cap based on performance factor at 2.85 million barrels/day[39] (2022-2030)		X	X		
Max Production cap based on performance factor 2.65 million barrels/day[40] (2010-2021)		X	X		
Max Production cap based on performance factor 2.35 million barrels/day (2022-2030)				X	X
Max Production cap based on performance factor 2.15 million barrels/day (2010-2021)				X	X
Wells Constraints					
Non-negativity of the Number of New Wells Drilled (2010-2030)	X	X	X	X	X
Well productivity constraint (2010-2030)	X	X	X	X	X
Max feasible number of new wells drilled in each period (2010-2030)	X	X	X	X	X
No new wells after 2020	X	X	X	X	X
Cost Constraint			X		X

3.5. Model Time Horizon

The Rumaila technical service contract is a 20-year contract with the possibility of extension up to 5 years (Sankey, Clark, & Micheloto, 2010). Since the contract effective date was December 2009, and since in reality BP and its partners took over the field from the beginning of 2010, it is reasonable to consider 2010 as the start of our optimization model. Having 2010 as the first period in our optimal model matches well with Deutsche Bank's

[39] This is the contractual production plateau target.
[40] Due to the performance factor in the contract, the operator cannot reach the plateau production target before the start of the plateau production period as specified in the contract. Therefore, we set this constraint in accordance to the production feasibility constraint.

Rumaila production estimates for 2010, which include baseline and incremental production.[41] Thus, we allow the model to choose optimal baseline and incremental production levels starting the year 2010 and ending 20 years later at the end of the 20-year contract, in 2030.

3.6. Control and State Variables

As discussed, our optimization model generates the optimal production and number of new drilled wells under five scenarios. We compare the optimal production paths and number of new drilled wells with production and wells drilling as forecasted by Deutsche Bank as shown under the most likely scenario to be realized in the result section. We also assume that Rumaila cumulative production level and recoverable reserve estimates in the beginning of 2010 are 13.08 and 16.08 billion barrels respectively.[42] The cumulative production is our state variable, and the recoverable reserve estimates is used in the model as a constraint to limit the overall cumulative production. We assume that in the beginning of 2010, Rumaila had 275 producing wells (Daly, 2010).

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[41] Personal communication with Deutsche Bank Securities Inc, September 2011

[42] These estimates are based on International Energy Agency [IEA] (2012) Iraq Energy Outlook and personal communication with Deutsche Bank Securities Inc, September 2011.

3.7. *Discount Rate*

Following Gao, Hartley and Sickles (2009), who report their optimal results based on discount rates of 10% and 30%, we run our model using discount rates of 10% and 20%,[43] which are two reasonable choices for a range of possible discount rates, in order to account for uncertainties and in order to not choose an arbitrary discount rate. We choose the 10% discount rate as the lower end of the range for two reasons. First, IOCs treat their internal discount rate as propriety information, and in order to avoid revealing that, they use a 10% discount rate in their joint cash flows with their partners. In the same way, the IOCs negotiate deals with their partners and host governments over net present value of cash flow with 10% discount rate (NPV10).[44] Second, in contrast to the oil sector in Iraq, other parts of Iraq's economy are not growing fast enough to absorb today's oil revenues. Therefore, for the government of Iraq, future gain might be more valuable. This perception towards future gain implies low discount rates. And it seems that a discount rate as low as 10% is reasonable.

We treat the 20% discount rate as the higher end in the scenario analysis for two reasons. First, the 20% discount rate or higher, as Adelman (1993) argues, is the suitable discount rate for countries with oil revenue as the largest portion of governments' revenue, which should also include Iraq. In other words, since oil revenue is these governments' main sources of income, they prefer present to future production. Such preference also implies that these countries should have a low discount factor or high discount rate. This is also the basis for Gao, Hartley and

[43] We use the model outcomes based on the 20% discount rate as part of our sensitivity analysis.

Sickles' (2009) 30% choice of discount rate. However, similarly to what Ghandi and Lin (2012) suggest for the case of Iran's buy-back service contracts, in Iraq's technical service contracts, the presence of international oil companies may imply lower than 20% discount rates. Second, we are looking for a discount rate that represents the IOC and the Iraqi government as if they are colluding or cooperating in deciding the optimal production level. This is in contrast to Gao, Hartley and Sickles (2009), since their choice of discount rate represents the Saudi Aramco or the Saudi government.

3.8. Price Estimates

Our optimal production model provides the optimal production profile in the time horizon of the model, based on the choice of a discount rate. We assume such optimization takes place in 2010, before the start of the contract. This assumption is necessary since as Ghandi and Lin (2012) argue, at different point of time, the price estimates are different, and since we want to compare the outcome of model under the general optimal scenario with the outcomes under the other optimality scenarios and under the most likely scenario to be realized, we have to make sure other factors, such as price estimates, do not play significant roles. Our calibrated Rumaila specific price estimates in the model is based on the EIA's 2010 Reference price forecast[45] from 2010 to 2030, the end of the contract.[46]

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[44] Personal communications with industry experts

[45] EIA's 2010 Reference case price forecast time horizon is 2035.

[46] By relying on the EIA's price estimates, we can relax the consideration of the price effects of new sources of energy including solar on the world oil market as pursued by Gao, Hartley and Sickles (2009).

In order to use the EIA 2010 Reference estimates, we implicitly follow the EIA's Reference case assumption that OPEC's share of world oil production will stay at the current 40% level by 2035. However, Iraq's ambitious production plans have the potential to suppress the world oil prices in the mid-term. The EIA 2010 Low Oil Price accounts for the Iraqi production ramp up by assuming a sharp increase in OPEC's share of world oil production to 50% by 2035 (Energy Information Administration (EIA), 2010). Therefore, in order to make sure that we capture such possibility and its potential price effect on our model outcome, we also report our results based on the EIA 2010 Low Oil Price scenario as part of our price related sensitivity analysis.

In addition, since price volatility through time could affect our optimization results, as another part of the price related sensitivity analysis, we report optimal results based on the EIA 2012 Reference case price projection.

The EIA 2010 world oil price projection is a price forecast of a "light, low-sulfur (or "sweet") crude oil delivered at Cushing, Oklahoma" (Energy Information Administration (EIA), 2010, p. 36). In a more detailed description, EIA's 2012 forecast "is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, which is similar to the price for light, sweet crude oil, West Texas Intermediate (WTI), traded on the New York Mercantile Exchange" (Energy Information Administration (EIA), 2012, p. 23). In addition, the EIA's 2012 Reference case projection relies on assumption that WTI and Brent price differences will disappear once the Cushing, Oklahoma and Gulf of Mexico pipeline completed (Energy Information Administration (EIA), 2012). Since we use a price formula based on the Brent price, as we discuss below, we extend EIA's 2012 Reference case assumption to EIA's 2010 Reference and Low Oil Price scenarios, and we assume that the EIA's 2010 Reference and Low price forecasts could be used as appropriate forecasts for the Brent price until 2030. We need to make this assumption in order to calculate Rumaila crude price estimates until 2030 based on the average 2010-2012 price discounts discussed below.

Rumaila, as a giant field, produces at least three blends including Basra Light, Basra Medium and Basra Heavy with 34˚, 30˚, 22˚-24˚ API and 2.1%, 2.6%, 3.4% sulphur respectively (Jassim & Goff, 2006). However, we treat all Rumaila production as Basra Light that are exported as a simplistic assumption and in order to estimate the Rumaila production price forecast. Iraq's State Oil Marketing Organization (SOMO) announces next month Basra Light Official Selling Price (OSP), as discounts to three international market price indices, based on Basra Light U.S., Europe and Asia export. As the other simplistic assumption, we assume that all Rumaila production is exported to Europe and its price follows Basra Light Official Selling Price (OSP) price. Table 6 shows Basra Light monthly OSP for U.S. and Europe destinations from November 2010 to August 2012 with a two-year average price at $3.96 below the North Sea Spot BFOE[47] (Brent) and $1.65 per barrel below Argus Sour Crude Index.

Table 6: Basra Light Discount Price 2010-2012

Month	For U.S. Delivery Discounted against Argus Sour Crude Index ($/Barrel)	For Europe Delivery Discounted against North Sea Spot BFOE (($/Barrel)
Nov 2010	1.1	2.3
Dec 2010	1.15	2.55
Jan 2011	1.15	1.9

[47] BFOE stands for Brent-Forties- Oseberg-Ekofisk as a "family of North Sea crude oils, each of which has a separate delivery point. Many of the crude oils traded as a basis to Brent actually are traded as a basis to Dated Brent, a cargo loading within the next 10-21 days (23 days on a Friday)." (ICE Crude Oil, 2012)

Feb 2011	1.35	3.4
Mar 2011	1.35	4.6
Apr 2011	1.65	4.6
May 2011	1.95	6.5
Jun 2011	2.1	7.05
Jul 2011	2	5.25
Aug 2011	1.75	4.55
Sep 2011	1.85	4.05
Oct 2011	1.7	3
Nov 2011	1.6	4.1
Dec 2011	1.6	3.15
Jan 2012	1.5	2.5
Feb 2012	1.7	4.35
Mar 2012	2	2.55
Apr 2012	2	2.55
May 2012	1.9	6.1
Jun 2012	1.8	4.5
Jul 2012	1.65	4.4
Aug 2012	1.5	3.2
Average 2010-2012	1.65	3.96

Source: Dow Jones Newswires. Dow Jones Energy Service (2010-2012)

Table 7 shows the three Rumaila calibrated price estimates that we use in our model based on the EIA 2010 and 2012 Reference and Low Oil Price cases considering the $3.96 per barrel premium.

Table 7: Rumaila Calibrated 2010-2012 Price Estimates

Year	Based on EIA 2010 Reference Case (2008 $/Barrel)	Based on EIA 2010 Low Oil Price Case (2008 $/Barrel)	Based on EIA 2012 Reference Case (2010 $/Barrel)
2010	66.34	66.34	75.43[48]
2011	69.10	53.88	88.90
2012	75.45	50.92	90.77
2013	81.78	49.90	99.74
2014	86.95	48.83	106.93
2015	90.56	47.63	112.95
2016	94.27	47.77	115.95
2017	97.27	47.82	118.93
2018	100.45	47.86	120.04
2019	102.51	47.95	121.26
2020	104.32	47.90	122.71
2021	105.56	47.87	124.03
2022	106.96	47.86	125.46
2023	108.36	47.84	126.52
2024	109.67	47.80	127.57
2025	111.13	47.77	128.60
2026	112.65	47.75	129.51
2027	114.36	47.75	130.38
2028	116.17	47.70	131.42
2029	118.08	47.66	133.07
2030	119.54	47.67	134.53

[48] This represents actual Basra Light average price in 2010.

4. Results

4.1. Dynamic Optimization Model Results

We present the results from our dynamic optimization model for the above-mentioned five optimality scenarios in two well productivity cases and in comparison with the most likely scenario to be realized for extraction rate (Figure 2 and Figure 3); number of new drilled wells (Figure 4 and Figure 5); cost (Figure 6 and Figure 7); per-period revenue (Figure 8 and Figure 9); and present discounted value of entire stream of profit (Figure 10 and Figure 11). These results are based on a 10% discount rate and a calibrated price estimate based on the EIA 2010 Reference case.

Figure 2 and Figure 3 show extraction rates for five optimality scenarios in comparison with the production path of the most likely scenario to be realized through 2030 for the fixed high well productivity and varying well productivity cases, respectively. In both cases, our model suggests that it would be optimal to have a higher production level than is likely to be realized until 2024-2025 for the general optimal and TSC optimal scenarios. This is an indication that the implementation of the contract might yield economically inefficient outcomes. The lower production path of the TSC optimal scenario compared to the general optimal production path is due to the TSC optimal scenario's maximum production cap based on the performance factor and the plateau production target at 2.85 million barrels per day. Therefore, the performance factor component of a technical service contract could contribute to the overall inefficiency of the contract. In addition, since the production path of the TSC optimal in both well productivity cases are higher than is likely to be realized (comparing orange and black scenarios), it seems that other factors besides the terms of the contract, factors that we study through our other optimal scenarios, could play important roles in decreasing the efficiency in a technical service contractual framework.

The TSC actual optimal not considering capital cost scenario has a lower maximum production cap at 2.35 million barrels per day compared to the TSC optimal scenarios' at 2.85 million barrels per day. However, in the beginning years, this scenario yields a similar production profile to the general optimal and TSC optimal scenarios in both well productivity cases, as shown in blue color in Figure 2 and Figure 3, with a higher production level than is likely to be realized until 2017. The higher production levels of the TSC actual optimal not considering capital cost ceiling than what is likely to be realized in the beginning years could be interpreted as existence of additional economic inefficiency even after accounting for the inefficiencies introduced by the performance factor and the actual plateau production target at 2.35 million barrels per day as estimated by Deutsche Bank. The incorporated lower maximum production cap at 2.35 million barrels per day is also the reason for the TSC actual optimal not considering capital cost scenario's lower production path than the general optimal and TSC optimal (comparing red and orange scenarios with blue) in the years after 2017.

The two scenarios that show different outcomes under each of the two well productivity cases are the TSC optimal considering capital cost ceiling and TSC actual optimal (green and purple). Under the high well productivity assumption (Figure 2), the cost constraint does not play a binding role as both scenarios follow the production paths of their counterparts without the cost constraint. However, for the varying well productivity case, these two optimal scenarios that have the additional cost constraint follow the production path of the most likely scenario to be realized. This could be explained by the fact that cost is more important determinant factor under varying well productivity case since wells have lower productivity in almost all the years of the contract than the fixed high well productivity case. With lower productivity, the per barrel cost of the same production level is higher, and as a result, it makes sense to see lower production profiles than other optimal scenarios. In addition, since the cost constraint is indirectly based on the most likely to be realized production and well drilling plans, it is reasonable to see production profiles and well drilling plans (Figure 5) that closely follow the most likely scenario to be realized.

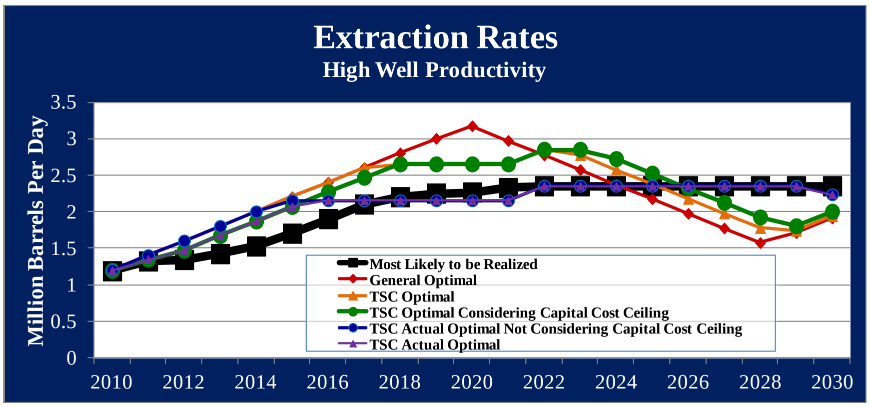

Figure 2: Rumaila optimal extraction rate of the five optimal and the most likely to be realized scenarios through 2030 assuming high well productivity.

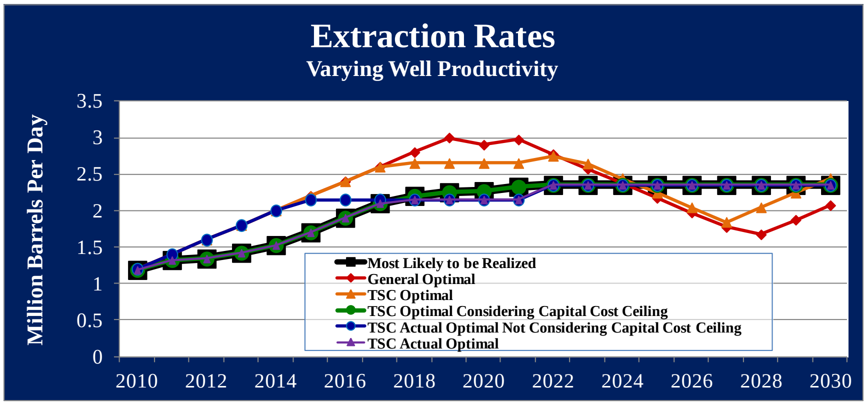

Figure 3: Rumaila optimal extraction rate of the five optimal and the most likely to be realized scenarios through 2030 assuming varying well productivity.

Figure 4 and Figure 5 display what our optimality scenarios recommend as the optimal drilling of new wells through time compared to the most likely scenario to be realized for the fixed high well productivity and the varying well productivity cases, respectively.[49] For the fixed high well productivity case, while our model recommends stable plans for drilling new wells for the optimal scenarios in most years, in the most likely to be realized scenario, the number of new drilled wells is much higher especially in the years 2013 to 2017. In order to explore the exact reasons of such differences in the new well drilling plans and as part of the sensitivity analysis, we also run the model for the varying well productivity case.

Under the varying well productivity case, the drilling plans of the general optimal and the TSC optimal scenarios are higher than that of the most likely scenario to be realized, but follow its general trend. The new well drilling plans of the two capital cost constrained optimality scenarios (the TSC optimal considering capital cost and the TSC actual optimal) match closely

[49] We don't consider any new well drilling after 2020 in our dynamic optimal model following Sankey, Clark, and Micheloto (2010).

with that of the most likely scenario to be realized. This is likely because we calculate the capital cost and the varying well productivity constraints based on Deutsche Bank production and new well drilling plans. As a result, it is reasonable to see these two optimal scenarios' new well drilling plans at or below the most likely scenario to be realized. However, for our TSC actual optimal not considering the capital cost ceiling scenario, the optimal drilling new wells starts at a higher level in the beginning years and continues to a lower level starting 2015 compared to the most likely scenario to be realized. The higher number of wells in this scenario also matches with the higher production level of the TSC actual optimal not considering the capital cost ceiling compared to the most likely scenario to be realized as shown in Figure 3 in the beginning years.

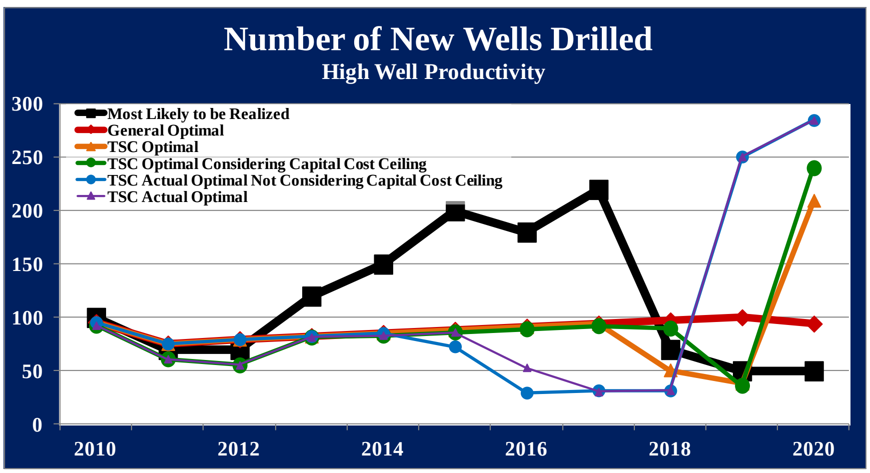

Figure 4: Rumaila Drilling New Well Plans of the four optimal and the most likely to be realized scenarios through 2020 assuming high well productivity.

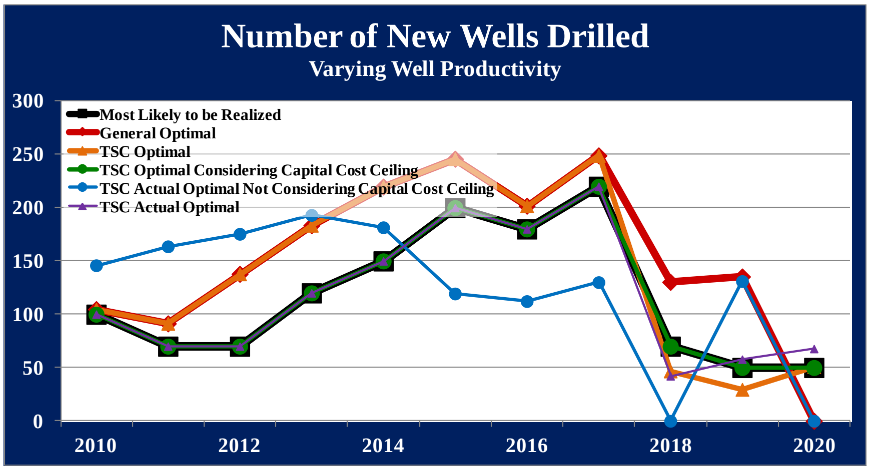

Figure 5: Rumaila Drilling New Well Plans of the four optimal and the most likely to be realized scenarios through 2020 assuming varying well productivity.

Figure 6 and Figure 7 present the cost associated with each of the five optimality scenarios through 2030 for the fixed high well productivity and the varying well productivity cases, respectively. For the fixed high well productivity case (Figure 6), the yearly cost of the most likely scenario to be realized is always greater than or equal to the yearly cost of all optimality scenarios. This is an interesting result since as shown in Figure 2, the production profile of the most likely scenario be realized is the same or smaller than all the optimality scenarios under the high well productivity case. However, while our model recommends stable plans for drilling new wells for the optimal scenarios in most years, in the most likely to be realized scenario, the number of new drilled wells is much higher especially in the years 2013 to 2017. Thus, the higher cost of the most likely to be realized scenario is likely due in part to an inefficiently high number of new wells being drilled.

As shown in Figure 7, for the varying well productivity case, the cost constraint is binding for the two cost constrained optimality scenarios. In these two scenarios (the TSC optimal considering capital cost ceiling and TSC actual optimal), the production and well drilling plans follow the most likely scenario be realized, as shown in Figure 3 and Figure 5. Therefore, it is reasonable to see similar trends for per-period cost as well. The per-period associated cost of other three optimality scenarios are higher in all the years (until 2018 for the TSC actual optimal not considering capital cost ceiling). The higher production profiles and new wells drilling plans for the general optimal and TSC optimal scenarios could explain their higher associated cost compared to the most likely scenario to be realized. However, the production profile of the TSC actual optimal not considering capital cost is higher than the most likely scenario to be realized in the beginning years, and it is the same starting 2017. In the absence of a cost constraint, it is optimal in this scenario to choose a higher number of new wells in the beginning years until 2014 (blue line in Figure 5) with higher production (blue line in Figure 3) to be offset by a lower number of new wells with the same production profile later on as in the most likely scenario to be realized.

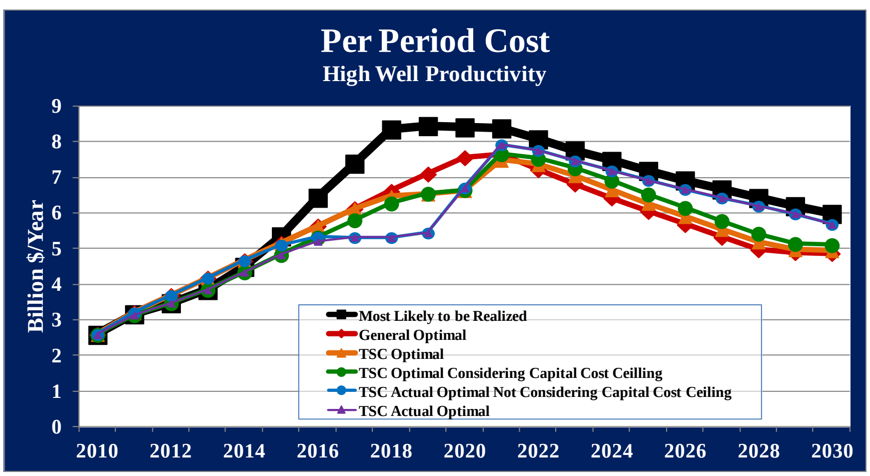

Figure 6: Rumaila associated cost of extraction and development of the five optimal and the most likely to be realized scenarios through 2030 assuming high well productivity.

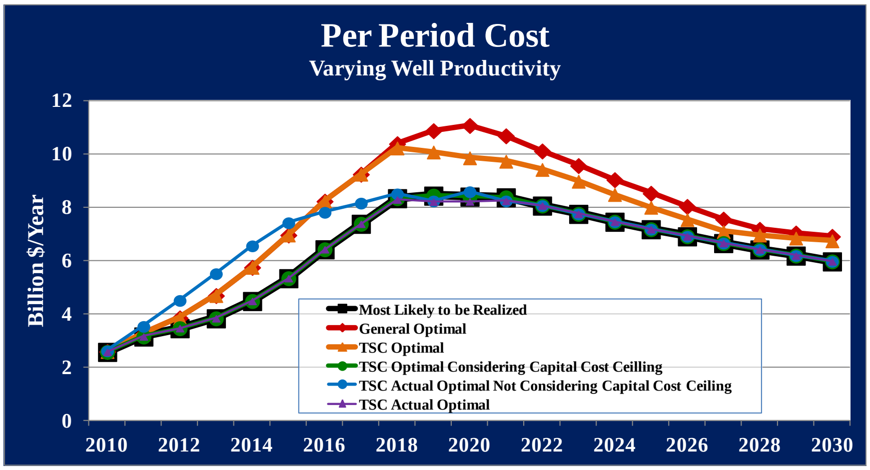

Figure 7: Rumaila associated cost of extraction and development of the five optimal and the most likely to be realized scenarios through 2030 assuming varying well productivity.

Figure 8 and Figure 9 summarize per-period revenue associated with each of the five optimality scenarios compared to the most likely scenario to be realized through 2030 for the fixed high well productivity and the varying well productivity cases, respectively. Under the fixed high well productivity assumption, per-period revenue of the optimal paths are higher or about the same in the beginning years due to the most likely scenario to be realized lower production (Figure 2) in most years compared to the optimal scenarios. We see similar per-period revenue trends for most optimality scenarios, under the varying well productivity assumption, as shown in Figure 9, except for the TSC optimal considering capital cost ceiling (green scenario). The TSC optimal considering capital cost ceiling yields the same per-period revenue as in the most likely scenario to be realized due to the similarity of production and new wells drilling plans in these two scenarios.

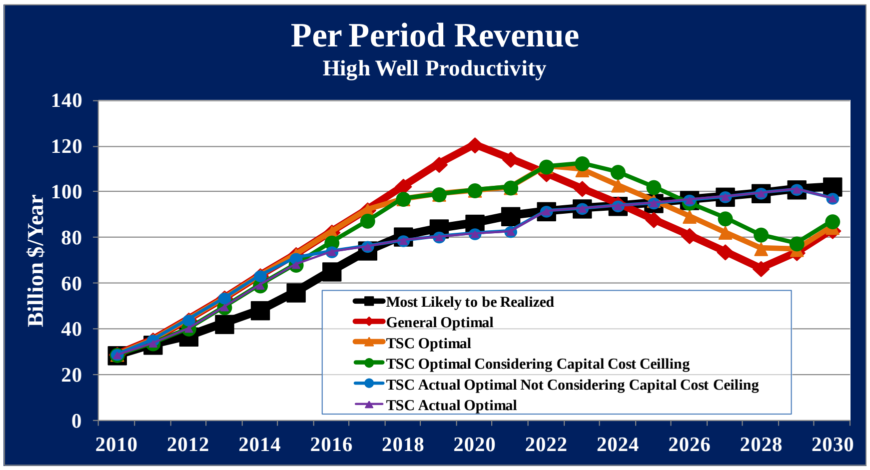

Figure 8: Rumaila per-period revenue of the five optimal and the most likely to be realized scenarios through 2030 assuming high well productivity.

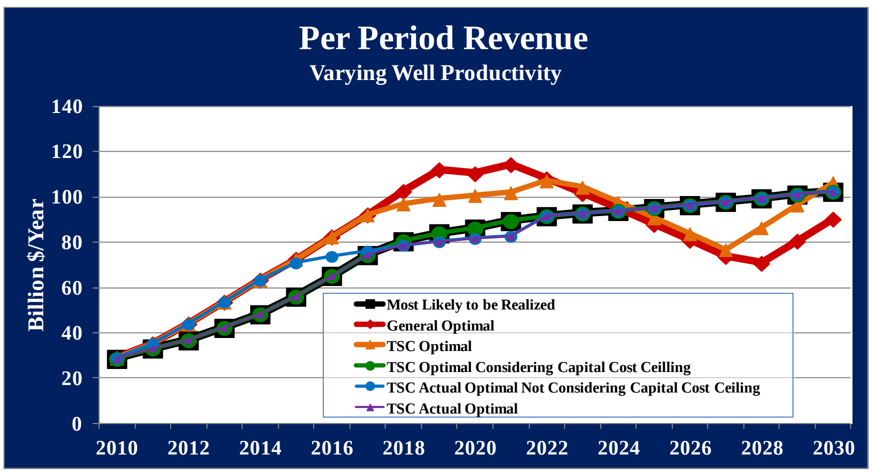

Figure 9: Rumaila per-period revenue of the five optimal and the most likely to be realized scenarios through 2030 assuming varying well productivity.

Figure 10 and Figure 11 indicate the present discounted value of entire stream of profit of the five optimality scenarios compared to the most likely scenario to be realized through 2030 for the fixed high well productivity and varying well productivity cases, respectively. Under the high well productivity case as shown in Figure 10, a comparison of our general optimal and the most likely scenario to be realized suggests that Rumaila producing field technical service contract could result in economic inefficient outcomes, with the loss in profits as high as $90 billion in 2008 dollars. The present discounted value profits associated to our other four optimality scenarios also suggest that economic inefficiency exists even after controlling for TSC specific imposed constraints as well as capital cost ceiling constraint and any other constraints reflected in our TSC actual optimal based on Deutsche Bank lower plateau production target estimate compared to the contractual plateau production target.

Under the varying well productivity case, as shown in Figure 11, a profit loss, and therefore economic inefficiency, still exists at a lower level of $73 billion in 2008 dollars. In addition, we see the same incremental decline in the entire stream of per-period profit due to the additional constraints, as in the high well productivity case. Under the varying well productivity assumption, all our optimality scenarios yield a higher entire stream of per-period profit compared to the most likely scenario to be realized except for the cost constrained scenarios. Even with our cost constrained optimal scenarios under the varying well productivity case, however, our model yields close to or the same entire stream of profit compared to the most likely scenario to be realized. Since the outcome of the most likely scenario to be realized was generated in the absence of a capital cost restriction, it is still possible that the actual outcome of the contract would have a present discounted value of profit even lower than our two capital cost constrained optimal scenarios if in reality the government of Iraq enforces the capital cost ceiling restriction.

Overall, in our modeling simulations, we have been able to clearly show the effects of various factors on the entire stream of per-period profit. However, the difference in the present discounted value of the entire stream of per-period profit between the TSC actual optimal and the most likely scenario to be realized, under the high well productivity assumption, might suggest that there are other factors that might explain the remaining difference. However, we do not see such a profit difference under the varying well productivity case.

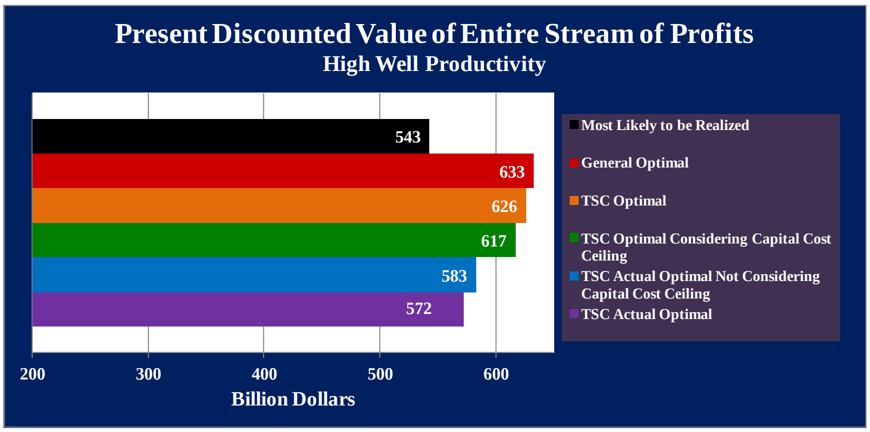

Figure 10: Rumaila dynamic optimal model's present discounted value of entire stream of profit of the four optimal and the most likely to be realized scenarios through 2030 assuming high well productivity.

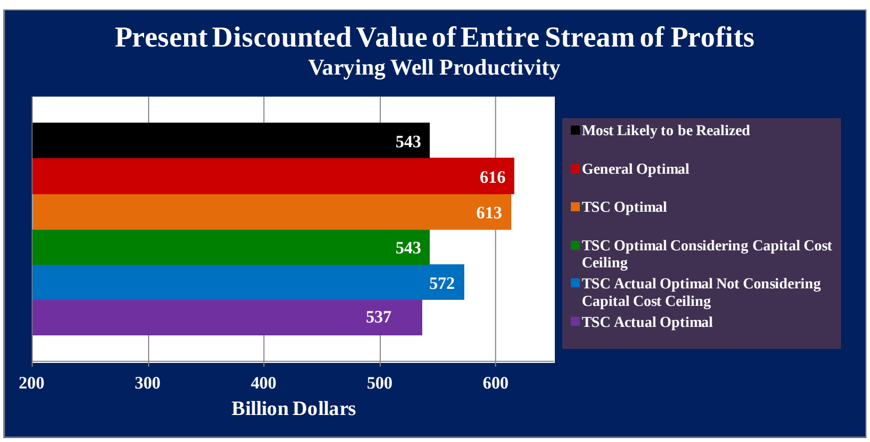

Figure 11: Rumaila dynamic optimal model's present discounted value of entire stream of profit of the four optimal and the most likely to be realized scenarios through 2030 assuming varying well productivity.

4.2. *Sensitivity Analysis*

For robustness, we also perform sensitivity analysis for the discount rate, price and components of our cost function for the general optimal, TSC actual optimal and TSC actual optimal not considering capital cost scenarios, and we compare the outcomes with the most likely scenario to be realized under new assumptions. As mentioned above, the base case dynamic optimization results we report are based on a discount rate of 10% and calibrated price estimates based on the EIA 2010 Reference case. For robustness, we try discount rates of 5% and 20% and price estimates based on the EIA 2010 Low Oil Price case and the EIA 2012 Reference Price case estimates.[50] Our sensitivity analysis shows that qualitative results for the relative trajectories for the extraction rate, cost and revenue for the three scenarios (general optimal, TSC actual optimal not considering capital cost ceiling, TSC actual optimal) are robust to these individual changes. The present discounted value of entire stream of profit for all three scenarios are much lower under the 20% discount rate and the EIA 2010 Low Oil Price case than what we report as our main results based on a 10% discount rate and EIA 2010 Reference case.

As discussed earlier in the paper, we perform sensitivity analysis with respect to two components of the cost function as well. As for the first component, since the 0.44 dollars per barrel surface infrastructure daily maintenance cost is in 1986 dollars, we also try the per barrel surface infrastructure daily maintenance cost in 2008 real dollars, which could be as high as 0.86 dollars. However, after incorporating the 0.86 dollars per barrel surface infrastructure daily maintenance cost, we did not find any significant difference in the outcomes of the three scenarios relative to each other. We also do cost sensitivity analysis based on the total cost of new wells for only our general optimal scenario.[51] A comparison of these results with the outcomes of the most likely scenario to be realized confirms the robustness of results.

4.3. Cash Flow Analysis Results

As shown in Figure 10 and Figure 11, the current implementation of the Rumaila producing field technical service contract could result in economically inefficient outcomes and a loss of profit as high as $73 to $90 billion depending on the well productivity assumption. In order to explore ways of incentivizing the contract for the IOCs to follow an optimal policy, we also model Rumiala producing field technical service contract cash flow from the IOC perspective under the high well productivity as well as varying well productivity cases. If the optimal policy not only leads to higher overall profit but also to both a higher net present value and a higher rate of return to the IOC, then both the Iraqi government and the IOC would do better under the optimal policy, and there may be a way to better structure incentives for the IOC to follow the optimal policy.

As shown in Figure 12 and Figure 13 for both well productivity cases, our cash flow analysis suggests that at a 10% discount rate BP and its partners could benefit from a net present

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[50] As listed in Table 7.

[51] We do not conduct the sensitivity analysis based on the total cost of new wells for the TSC actual optimal scenario. That is because the TSC actual optimal scenario would result in optimal solutions even with the higher cost of drilling new wells, but due to the cost cap, the overall profit is lower than the most likely scenario. Therefore, a fair comparison between the outcomes of the scenarios is not possible.

value around $1.9 billion as opposed to the $1.3 billion[52] from the most likely scenario to be realized if they follow our general optimal scenario production path and new wells drilling plan.[53] In other words, IOC's net present value could be increased up to $600 million or 31% following our general optimal policy. Similarly for the rate of return, our results show that following our study optimal scenarios could improve the IOC rate of return from 22% of the most likely scenario to be realized to at least 25% only considering the contractual imposed conditions on the optimality through TSC optimal, or 26% considering our general optimal. However, if the contract turns out the way it is predicted by Deutsche Bank with lower than expected plateau production target, then the optimality does not lead to significant increase in the IOCs' gain in terms of net present value and rate of return as reflected under our TSC actual optimal in Figure 12 and Figure 13. In addition, under our TSC actual optimal not considering cost scenario, as shown in Figure 10 and Figure 11, even though there could be profit gain in the project following this scenario compared to the most likely scenario to be realized, since the additional cost will be a burden on the IOC, the current cash flow framework makes no room for additional gain by the IOC to offset the extra cost's effects in order to decrease the cost exposure (higher NPV) and also to increase the IOC return (higher ROR). This is an important finding

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[52] Our findings that BP and its partners' net present value and the rate of return are $ 1.31 Billion (2008 dollars) and 22% respectively, as shown in Figure 12, are comparable with Rumaila NPV and IRR estimates by Sankey, Clark, and Micheloto (2010), with the difference that their calculation is net for BP. But here we consider BP and its partners as a single IOC. This was a simplifying assumption in order to avoid complication with regards to the capital expenditures share of each partner since in our cost function that we use in the cash flow we do not have such distinction.

[53] Our general optimal scenario was defined as a representative general case without any contract specific constraints. However, we have modelled Rumaila cash flow based on the cash flow mechanism of a technical service contract. Therefore, it is reasonable to consider the NPV and ROR under the general optimal scenario as the least the IOC in this contract could expect to get. It is the least since under other frameworks, including a production sharing, IOCs could gain more in general under similar situations.

since while we show that it is possible to operate for higher economic efficiency, if the actual implementation lays out the way as predicted by Deutsche Bank, it might be hard to provide incentives to the IOCs in this contract to follow an optimal policy such as the policy prescribed by our TSC actual optimal not considering capital cost ceiling scenario.

The NPV and the ROR of the TSC optimal considering capital cost ceiling show different results under the two well productivity cases. While we find that under the high well productivity assumption there are additional benefits for the IOC to follow the optimal policy considering the contractual constraints and in case the contract faces the capital cost restrictions, we do not see such gains under our varying well productivity case. That is because the production and well drilling plans of this scenario is very similar to the most likely scenario to be realized.

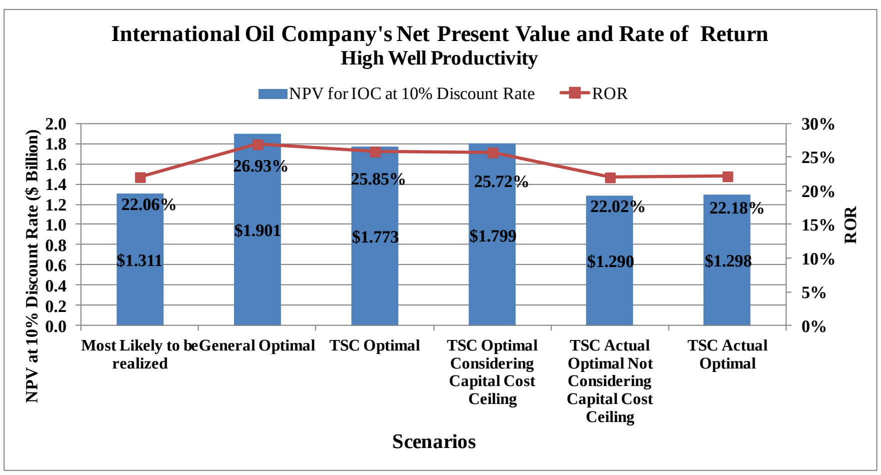

Figure 12: Rumaila NPV and ROR to the IOC for high well productivity case

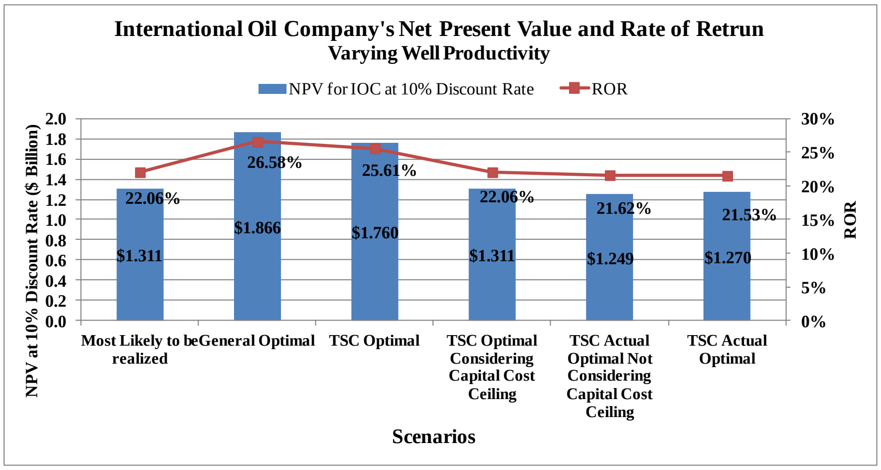

Figure 13: Rumaila NPV and ROR to the IOC for varying well productivity case

5. Conclusion and Discussion

As shown in Figure 10, the present discounted value of entire stream of profit of all of our five optimality scenarios are higher than the most likely scenario to be realized under the fixed high well productivity case. Therefore, we conclude that the Rumaila producing field technical service contract and its implementation could result in economically inefficient outcomes. This conclusion holds even under the varying well productivity case, as portrayed in Figure 11, except for the optimality scenarios with the binding capital cost ceiling constraint. However, since the most likely scenario to be realized outcome was generated in the absence of a capital cost restriction, there is still the possibility that the actual outcome of the contract would have a present discounted value of profit even lower than our two capital cost constrained optimal scenarios if in reality the government of Iraq enforces the capital cost ceiling restriction.

We define our four optimality scenarios in addition to the general optimal with the consideration that each new scenario has additional constraints based on the imposed conditions of the contract or on factors surrounding the implementation of the contract. As a result, while the outcome of each of the four optimality scenarios of TSC optimal, TSC optimal considering capital cost ceiling, TSC actual optimal and TSC actual optimal not considering capital cost ceiling all represent optimal solutions similar to our general optimal scenario, their lower present discounted value of entire stream of profit compared to the general optimal, as shown in Figure 10 and Figure 11, could be interpreted as the result of economic inefficiencies. Therefore, the imposed constraints in these four scenarios are all potential sources of economic inefficiencies.

Potential sources of economic inefficiencies that could help explain our results include: the terms of a technical service contract and its structure and process (through TSC optimal and TSC optimal considering capital cost ceiling scenarios); factors that lead to Deutsche Bank's lower than contractual level plateau production target estimate (through TSC actual optimal and TSC actual optimal not considering capital cost scenarios); incentives faced by IOCs to pursue an optimal policy in Rumaila; and the Iraqi government's objectives in static settings. In what follows, we discuss each of these factors and the way they relate to the constraints imposed in our four optimality scenarios.

Compared to the general optimal scenario, the TSC optimal scenario has a performance factor constraint, which is an additional contract specific restriction that the IOCs face. As shown in Figure 10 and Figure 11, incorporating the performance factor constraint in the TSC optimal scenario results in about $3 to $7 billion loss of profit compared to the general optimal and depending on the well productivity assumption. Therefore, we conclude that performance factor related terms of a technical service contract could contribute to the overall economic inefficiency of the contract. In order to comply with the performance factor, the IOC could keep the production at a sub-optimal level, or it might prevent the production to reach the field's geologically highest possible level in time, and that could result in economic inefficiency. In addition to the terms of the contract, the overall TSC structure and process in relating the IOC's profit (per barrel remuneration) to PPT could cause the IOC to bid production paths that might not result in economically efficient outcomes. For example, the bidding process requires the IOCs to bid the lowest per barrel remuneration, and that could be a reason for the operator (IOC) to not follow an optimal production path as long as the IOC economic goals, in terms of the ROR and NPV, are met.[54]

The implementation of the Rumaila producing field technical service contract might be affected by some other factors outside the contract. For example, Iraq's future OPEC quota[55] has the potential of limiting Iraq's production if the country decides to join the quota's system and to comply the system, unless the new quota accommodates Iraq's production expansions. The OPEC quota's effect will likely be higher on Iraq's bigger fields especially Rumaila. This suggests that there is a possibility that the Iraqi government might later change its mind about the plateau production target in some fields.[56] In addition, for the next few years, Iraq's export

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[54] We did not investigate such a possibility in our study.
[55] Iraq has not had an OPEC quota since 1990 after Iraqi invasion of Kuwait. However, the country is determined to return to the OPEC's quota system by seeking a potentially conflicting quota higher than Iran's at 3.34 million barrels per day. However, unless OPEC accommodates Iraq's production expansion plans in the cartel's quota system, a lower quota may affect Iraq's production plans assuming the country decides to comply with OPEC's quota system (Ajrash & DiPaola, 2011).
[56] As of May 2013, the Iraqi government has started the process of negotiating down the plateau production targets with the IOCs. And at least on Majnoon and West Qurna 2 fields, the government has reached new agreements with
<Footnote continues next page.>

terminals and pipelines also play significant role in limiting the production level of the developed fields, which might prevent reaching the plateau production target.[57] In fact, Deutsche Bank's plateau production target estimate at 2.35 million barrels per day, lower than contractual, is in anticipation of effectiveness of such factors on the outcome of the contract. In order to account for these factors, in our TSC actual optimal, we incorporate Deutsche Bank estimated plateau production target as an additional constraint in the optimization. Based on the TSC actual optimal result, as shown in Figure 10, we conclude that on one hand these factors have the potential to affect the economic efficiency of the contract due to the $61 billion loss of profit compared to our general optimal under the fixed high well productivity. Assuming well productivity changes yearly, then the loss of profit could be much higher as shown in Figure 11. On the other hand, there is still $29 billion gain in the profit compared to the most likely scenario to be realized if the TSC actual optimal policy were to be pursued for the high well productivity case.

By comparing the NPV and ROR of the most likely scenario to be realized with those of the other optimality scenarios, as shown in Figure 12 for the high well productivity case, we find that the IOCs in this contract could benefit from following an optimal policy as recommended in this study even under the imposed conditions of this contract in all except the two TSC actual

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Shell and Lukoil, respectively, on reduced PPT. Similar negotiation is underway on Rumaila with BP and its partners (Personal communication with the industry experts).

[57] In case of Rumaila, the produced crude could reach the export points through the Strategic Pipeline 1 (SP1) to the north or through the Southern Distribution Pipeline System to Fao terminal in the south on the Persian Gulf shore. However, the pipelines and the terminal are not in full capacity working conditions due to years of wars and poor maintenance. The Iraqi government oil infrastructure expansion plans could cost $50 billion dollars (Sankey, Clark, & Micheloto, 2010). The country's struggle in securing funds for these costly plans may suggest that the insufficient export facilities could restrict the production plans.

optimal scenarios. In fact, we find that there is no significant improvement in the IOCs net present value and rate of return under our two TSC actual optimal scenarios compared to the most likely scenario to be realized. This is an important finding since it implies that deviations from the contractual goals due to the above mentioned factors leave no incentives for the IOCs to pursue optimal policies such as what our model recommends under the two TSC actual optimal scenarios. The low NPV and ROR of our two TSC actual optimal scenarios also reinforces that the contractual terms and factors outside the contract might prevent the possibility of providing any incentives to the IOCs to follow an optimal policy in the framework of a technical service contract.

In addition, our cash flow analysis shows that both the general optimal and the TSC optimal would yield almost the same NPV and ROR to the IOCs in this contract under both well productivity cases. Thus, the IOCs in this contract do not receive any additional gain from following the general optimal instead of the TSC optimal. However, if the IOCs and the Iraqi government cooperated to maximize joint profits, they would jointly earn a higher present discounted value of the entire stream of per period profit under the general optimal scenario, as seen in Figure 10 and Figure 11. Since the NPV and the ROR calculation is based on the producing field technical service contract cash flow, the result that the IOCs earn the same NPV and ROR under the general optimal and the TSC optimal could suggest that the contract cash flow framework prevents the Iraqi government and the IOCs from fully cooperating. In other words, the IOCs' NPV and ROR are misaligned with the higher present discounted value of the entire stream of per period profit under the general optimal scenario. Therefore, we conclude that the lack of incentives for the IOCs or failure to cooperate perfectly could contribute to the overall economic inefficiency in this framework.[58]

Finally, the other important potential source of economic inefficiency is related to the Iraqi government and its entities' objectives. Instead of maximizing the present discounted value of its entire stream of profits, their objective may instead be to maximize current revenue while keeping development costs as low as possible.[59] In addition, there might be misaligned responsibilities among different Iraqi government entities involved in this contract. In particular, entities that are awarding the contracts, making cost decisions and receiving the revenue are different with different objectives. The Ministry of Oil and in particular, its Petroleum Contracts and Licensing Directorate (PCLD) follow a policy of maximizing revenue with emphasis on the higher plateau production target in the bidding process. However, the state-owned South Oil Company, which oversees the Rumaila operation, has to approve the IOCs' work plans and their capital expenditures. And their main concern at the South Oil Company is the cost. In addition, the flow of revenue from the fields goes through the Ministry of Oil's Treasury department. In other words, South Oil Company decides on the cost without seeing the revenue.[60] Thus, even though the contract awarded by the PCLD is agnostic about how much it would cost to reach the plateau production target, the South Oil Company is able to enforce a cost constraint on the IOCs after the contract is awarded. The different Iraqi government entities involved in the contract

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[58] We do not actually investigate such possibility directly in our study. In other words, we just show that the IOC in this contract might not have the necessary incentive to follow a different policy. But that does not mean that the lack of incentive is the reason for the profit loss as we see under the two well productivity cases as shown in Figure 10 and Figure 11.
[59] Personal communication with industry experts
[60] Personal communication with the industry experts

may therefore have different objectives which are not well-aligned with maximizing the present discounted value of the entire stream of profits.

While we do not investigate Iraqi government objectives and their effects on the overall efficiency directly, we do incorporate the capital cost restriction possibility into our TSC optimal considering cost scenario, and we find that the loss of profit, as shown in Figure 10, could reach $16 billion compared to our general optimal scenario under the fixed high well productivity case. The loss of profit could be much higher, as shown in Figure 11, if the well productivity varies year by year. In other words, the Iraqi government's entities interference on the capital cost level could indeed affect the production plans and overall economic efficiency of the contract with a high potential of a loss in profit. Indeed, the cost concern may be particularly important in Iraq's southern fields, including Rumaila, due to the fields' huge and costly water injection requirements. Water injection in the southern oil fields is costly mostly due to the insufficient water supplies, and due to the reliance of these fields on seawater transfer plans. The seawater transfer plans include delivering and processing seawater for hundreds miles from Persian Gulf, which could cost $10 billion dollars. Even though the cost should eventually be recovered through the oil production revenue from the developed fields through technical service contracts' cost recovery framework (Sankey, Clark, & Micheloto, 2010), the water issue could affect the production plans in these fields. The water issue has recently become even more complicated due to ExxonMobil's departure out of the Iraq's southern fields water supply project in February 2012 (Middle East Economic Survey, 2012).

The existence of economically inefficient outcomes suggests that it may be desirable to address the potential sources of economic inefficiency through implementation of some policy reforms in Iraq's oil sector. The presence of economic inefficiency even under our most realistic scenarios implies the importance and the necessity of reforms in the design of the technical service contract and of improvements in the implementation of these contracts. Besides improvement in the framework of the technical service contract, considering the adoption of other contractual frameworks at this stage, after about 4 years of starting the first technical service contact, is necessary and helpful since the Iraqi Constitution allows other contractual frameworks. In addition, it is important to understand that the implementation of other frameworks might not be possible unless it is accompanied with more general reforms in the Iraq oil sector's governing organizations, institutions and companies.

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