# Iraq's Technical Service Contracts – A Good Deal For Iraq?

*By: Peter Wells*

*The following article was first published in Middle East Economic Survey (www.mees.com) on 23 November 2009. It is republished here courtesy of MEES and with the author's permission. **Dr Wells** is an international oil and gas expert with over 30 years technical and commercial experience, including at senior levels with major oil companies such as Shell and BP. He has been closely involved with several major oil and gas deals in the region, most notably in Azerbaijan and Iran. Dr Wells is currently an adviser to Toyota Motor Company on world oil and gas supply, and geopolitics of the Middle East and North Africa. He is also a founding director of geological consulting company Neftex Petroleum Consultants.*

**Introduction**

The idea for this article arose from the publication in September 2009 of full commercial terms and cash flow analysis for a Production Sharing Contract (PSC) signed by the Iraqi Kurdistan Regional Government (KRG) and Shamaran Petroleum Company. The Shamaran documents offer a rare glimpse of the detailed commercial terms of one of the KRG's PSCs. The model PSC published by the KRG lacks the precise commercial terms (in particular cost recovery limit and profit oil parameters) to permit third parties to analyze the contracts.

These terms and the published terms of the Technical Service Contracts (TSCs) signed by the Ministry of Oil in Baghdad provide enough information for a comparison of the two contract forms.

The West Qurna 1 license, awarded to ExxonMobil and Shell in November, was used as a suitable project for this analysis. This is a good project on good terms for Iraq. However, to do the analysis a more likely oil production profile was developed for the project than the winning bid, which offered a plateau rate of 2.325mn b/d.

**The KRG PSC With Shamaran Petroleum Corporation**

The key documents are: the KRG Oil and Gas Law, the KRG Model PSC and the September 2009 Notice of Meeting and Information Circular issued by Bayou Bend Petroleum Company for a shareholders meeting that was held in October 2009.

At this meeting, Bayou Bend changed its name to Shamaran Petroleum Company (member of the Lundin Group) and approved the PSC for Block 10 (Pulkhana field) with the KRG.

A diverting item in the published costs is the payment of some $7.5mn in "Third Party Arrangement fees". The nature of the services is not specified, but a "Tigris Energy Limited" is identified by the shareholders documents as being the recipient.

Shamaran analyzed reserves cases from 100mn to 250mn barrels at oil prices from $65/B to $100/B (Brent). Table 1 summarizes the key contractor economic parameters and outcome for the 250mn barrel reserves case for the Shamaran PSC.

**Table 1: Main Commercial Terms Of The Shamaran PSC For Pulkhama Oil Field**

| | | | |
|---|---|---|---|
| Duration: | | | |
| Exploration period | Initial term 5 years, extendable by 2 years. | | |
| Development period | Initial term 20 years, extendable by up to two 5 year periods. | | |
| Signature and capacity building bonuses | $45mn | | |
| Royalty rate | 10% | | |
| Cost recovery ceiling | 40% | | |
| Profit Oil parameters | R factor: (0 to 1) 26%; (1 to 2) sliding scale between 26 and 13%; (>2) 13%. | | |
| Exploration costs | $72mn | | |
| Capital costs | $508mn | | |
| Fixed operating costs | $20mn/year | | |
| Variable operating costs | $2/B | | |
| Reserves | 250mn barrels | | |
| | **$65/B Brent** | **$80/B Brent** | **$100/B Brent** |
| **Net Present Value at 10% discount rate (NPV10)** | $460mn | $624mn | $802mn |
| **Rate of Return (ROR)** | 34% | 44% | 56% |

Despite the discovery of oil in the structure on the block in 1959 (albeit with considerable uncertainty), the Rate of Return (ROR) to the contractor is 34-56% at likely oil prices, which is very high by contemporary standards. This is especially so, when compared with other OPEC countries, where rates of return on pure exploration contracts rarely exceed 20%. The KRG PSC gives away to the contractor both an excessive amount of rent and a significant oil price windfall – usually suppressed in most modern PSCs.

**The West Qurna 1 Project, Iraq, OPEC And Global Oil Supply-Demand**

ExxonMobil's winning offer for the West Qurna 1 project (southern half of the West Qurna field) combined a Remuneration Fee per Barrel (RFB) of $1.90/B with a seven-year plateau production rate of 2.325mn b/d to be reached by 2017. Capital and operating costs were set at $25bn each over the life of the TSC (20 years extendable to 25 years).

The Ministry of Oil has published an estimate of reserves for the project of 8.6bn barrels. With our estimate of oil-in-place of ~25bn barrels, this yields a recovery factor of ~35%. The main reservoirs in the field (Mishrif and Yamama) are carbonates with limited aquifer support, requiring water or gas injection to maintain pressure and production. Whilst water injection is the offered development scheme, the equivalent reservoirs in Iran have responded well to gas injection. The Iranians, due to lack of water, have made a virtue out of a necessity in using gas injection. They claim with some practical justification that recovery factors and field performance are comparable with or superior to gas injection. Given the potential shortage of water in southern Iraq, gas injection offers an attractive alternative development option to water.

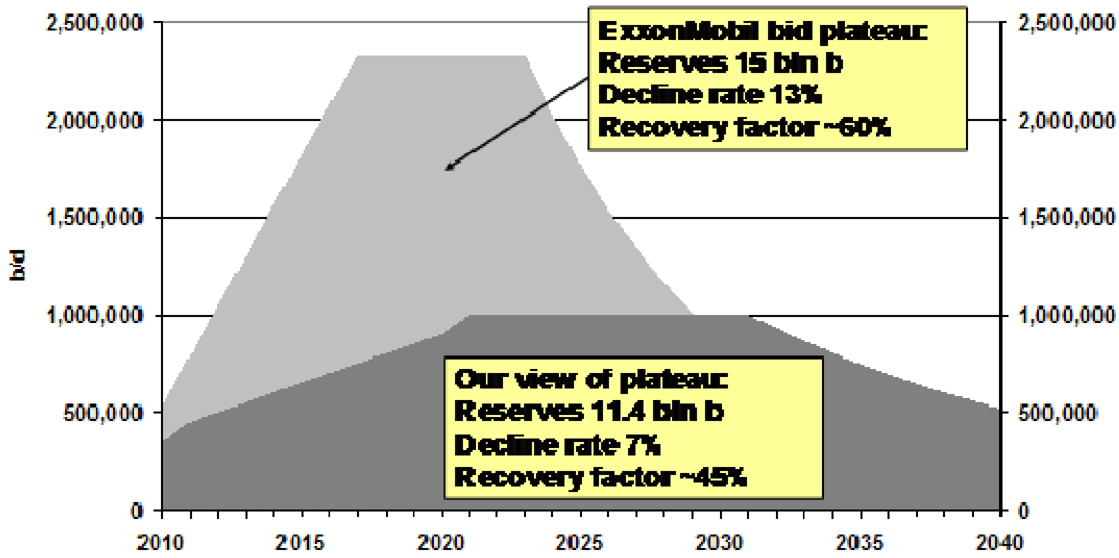
To build a cash flow for the West Qurna 1 project requires profiles for oil production and capital and operating costs. These are interconnected and merit critical analysis, starting with the mooted production profile with a plateau of 2.325mn b/d. We argue that this plateau rate is neither optimal, nor possible, nor necessary for Iraq. Of course, both the international oil companies involved and the Ministry of Oil are fully aware of these issues and constraints and their actual field development plans will reflect this.

**High Plateau Rate Not Optimal For Iraq**

With the published reserves of 8.6bn barrels, a 2.325mn b/d plateau could not be sustained for seven years. Indeed, with these reserves it could only be sustained for one year followed by an immediate and steep decline at over 15% per year. Typical decline rates for large Middle East OPEC fields are 5-7%. Only if the recovery factor is raised to 60% (reserves of 15bn barrels) can the plateau of 2.325mn b/d be sustained for seven years, and even then the decline rate is 13% per year. Deeper as yet undiscovered or incompletely appraised reservoirs could contribute additional reserves but these are highly unlikely to have an impact on the production profile for more than a decade. Furthermore, these additional reserves are not within the direct scope of the TSC for West Qurna 1.

Middle East OPEC oil fields have been developed with very conservative production profiles – typically with a plateau rate (b/d) to reserves (mn barrels) ratio of 50-80. This approach has advantages in providing stable long term revenues, a long production life of the field and a slow unfolding of reservoir problems. A plateau rate of 2.325mn b/d for West Qurna 1, even with reserves of 15bn barrels, represents a plateau/reserves ratio of more than 150 – comparable with many large non-OPEC oil fields such as Forties in the UK North Sea.

**Figure 1: Comparison Of Bid And Our Estimate Of Most Likely Production Profile For West Qurna 1**




**Plateau Rate Not Possible**

A 2.325mn b/d production plateau is also unlikely to be reached by 2016 due to logistical reasons and a shortage of either water or gas for injection. Water injection will be needed from the outset for most field development projects. The award of all Second Bid Round projects on top of Zubair, Nassiriya, West Qurna 1 and Rumaila will create a major water shortage in southern Iraq. It may be that water will have to be piped in from the Gulf – a major infrastructure project in its own right. Gas availability requires the installation of gas gathering systems/sweetening plants in Rumaila and other producing fields, pipeline systems to deliver the gas to the injection locations and compression facilities. Whilst the joint venture between Shell and the Ministry of Oil could offer increased gas availability in the future, contracts have yet to be signed and implementation will take some time.

The mobilization of oil field equipment (particularly drilling rigs), material and support services into southern Iraq just to service the projects awarded so far (Rumaila, West Qurna 1 and Zubair) will be a major effort and likely to be much slower than the published aggressive development plans require. These will require several hundred drilling rigs to be operating by 2011. Apart from this challenge, the required supply chain to service this scale of development hardly exists and will be unlikely to meet the demand for tubulars, cement, drilling fluids, staff, support services, line-pipe, valves, processing plant, well-heads, etc, etc…

Finally, major new export infrastructure will be required in the south to evacuate incremental oil production significantly above 2.5mn b/d. Designing, tendering and construction of these facilities will take time and the process has barely started.

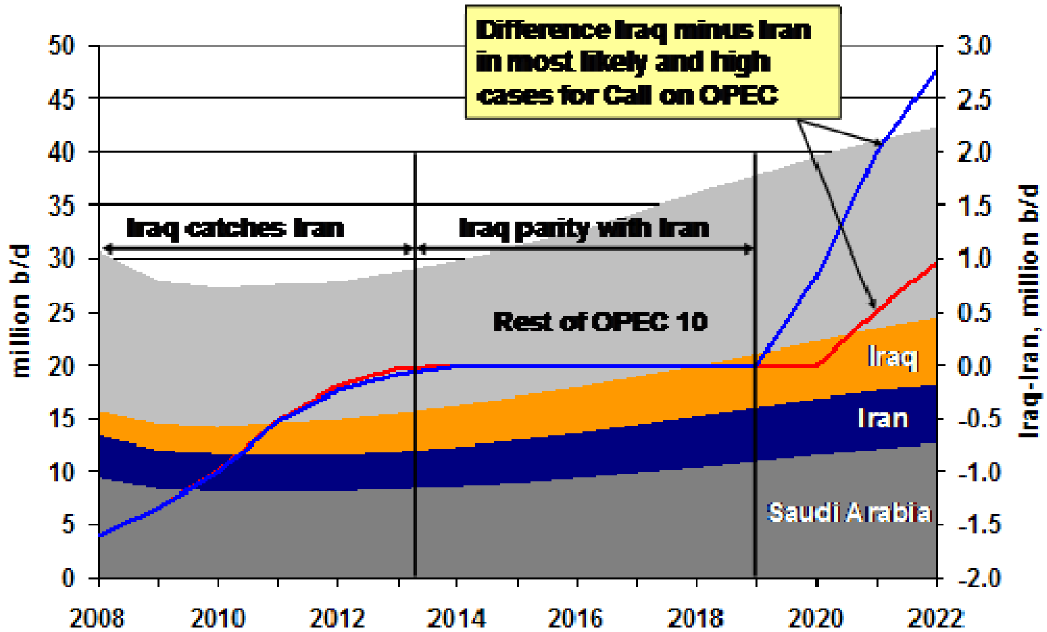
However, whilst these matters are very important, they are not the major issue, which is that the call on Iraq's crude oil is likely to require much more modest production than the mooted development plans.

**Plateau Rate Not Needed – Yet**

High production plateaus for Iraqi oil fields are not needed until after 2017 due to a subdued call on OPEC. Our World Oil Supply Model, developed in 2005 for Toyota Motor Company, integrates all global liquids supplies, forecasts for exploration success and demand scenarios. The model works at the scale of individual oil fields for crude oil and has, to date, successfully forecast global production, demand, spare capacity and oil price trends.

Figure 2 summarizes our view of the call on OPEC and the likely pathway for Iraq's oil production. In our most likely case, the call on OPEC only rises above 2007 levels after 2014 and reaches some 42mn b/d in 2022. In our high case for call on OPEC, due to a more rapid rise in global oil demand and weaker non-OPEC supply, the call on OPEC rises to some 45mn b/d by 2022. For much of the period to 2017, OPEC's spare capacity is likely to exceed 5mn b/d and OPEC will be under pressure to support the oil price.

**Figure 2: Our Forecast Call On OPEC Crude Oil, Production From Iran, Iraq and Saudi Arabia And The Difference Between Iraq And Iran For Most Likely And High Cases For Call On OPEC.**

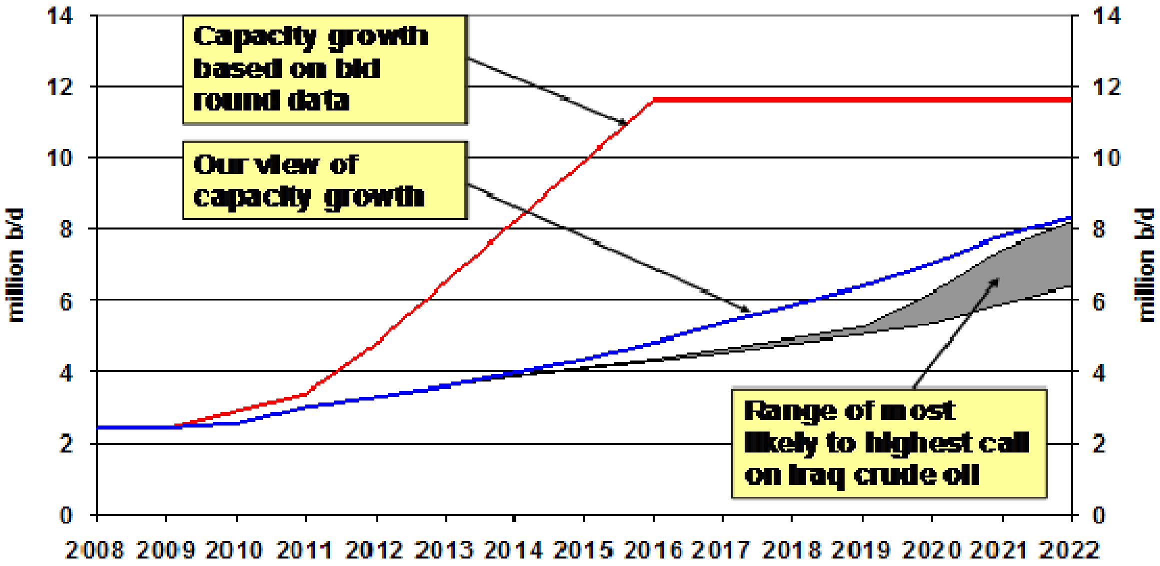



In these circumstances, we do not see Saudi Arabia or Iran making much room for Iraq's oil production to significantly exceed that of Iran. Iran and Iraq had production quota parity within OPEC in the late 1980s, the last time a meaningful comparison was possible. We consider that Iran will be able to maintain production capacity of 4-5mn b/d to 2018, and Iraq is expected to reach production parity with Iran around 2014. After that OPEC constraints are likely to peg Iraq's production to that of Iran until 2019 or 2018 in the most likely or high cases for 'call-on-OPEC' respectively. Therefore the call on Iraq's crude oil production is forecast to be limited to 4-5mn b/d between 2014 and 2018.

It would seem that around 2013-14 we can expect some heated and interesting quota debates within OPEC regarding the accommodation for Iraq. In our view, Iran will not yield parity and Saudi Arabia will be reluctant to unilaterally absorb Iraq's production ambitions. We also consider that, despite these strains, Iraq will remain in OPEC for geopolitical reasons and out of self interest.

Figure 3 compares the estimated maximum production capacity profile from the bid and published plateau data, with our more modest capacity and production forecasts based on the not optimal, not possible and not needed arguments. However, we note that Iraq's production capacity will be urgently needed after 2020.

**Figure 3: Comparison Of Maximum Production Capacity Forecast From Iraq's Bid Round Data With Our Most Likely Forecast For Production Capacity And Production For Both Most Likely And High Cases For 'Call On OPEC'**




Finally, where does this leave Iraqi Kurdistan? The planned development of Iraq's southern oil fields and the cap on production imposed by OPEC membership will severely impair the ability of Iraqi Kurdistan to develop export capacity for its newly discovered oil. Essentially Kurdish oil will not be needed until much later, and will cost the state more per barrel – partly because of the requirement to build new infrastructure and partly because of the "give away" terms of the KRG's oil deals (see comments above on the Shamaran contract and below). This will likely increase the pressure from the Kurds for control of the Kirkuk oil field.

**Comparison Of KRG's PSC And The Ministry Of Oil's TSC For West Qurna 1**

Based on the arguments above and a preferred production profile with a plateau rate of 1mn b/d (plateau production capacity of 1.3mn b/d) as a base case, we do not expect the performance penalty to be applied to the contractor in the TSC as we anticipate the government will order a reduced production rate to comply with its OPEC quota.

The other key elements of the base case are:

- Oil price $60/B (Brent flat nominal).
- Contractor's real rate of return (RROR) 15%.
- Capital and operating costs corresponding to the 2.325mn b/d plateau.

In the TSC, cost recovery and remuneration are allowed from only 50% of the incremental production – which makes the contractor's RROR and NPV10 (Net Present Value at 10% discount rate) highly sensitive to the early years of the capital cost profile. Therefore, we expect the contractor to carefully plan development spending, ramping it up slowly to match the increase in incremental production so as not to accumulate too much unrecovered costs. We have used this sensitivity to tune the capital expenditure profile to deliver a RROR of 15% from the TSC.

With the same profiles for production, capital and operating costs we have adjusted the profit share parameters in the cash flow model of the KRG PSC so as to deliver the same RROR of 15%, at the same oil price. This makes the two contract forms directly comparable. Appendix

1 summarizes the parameters and Figures 4 and 5 the cash flows for the two contracts applied to West Qurna 1 in the base case.

**Figure 4: Cash Flow For The TSC For West Qurna 1.**

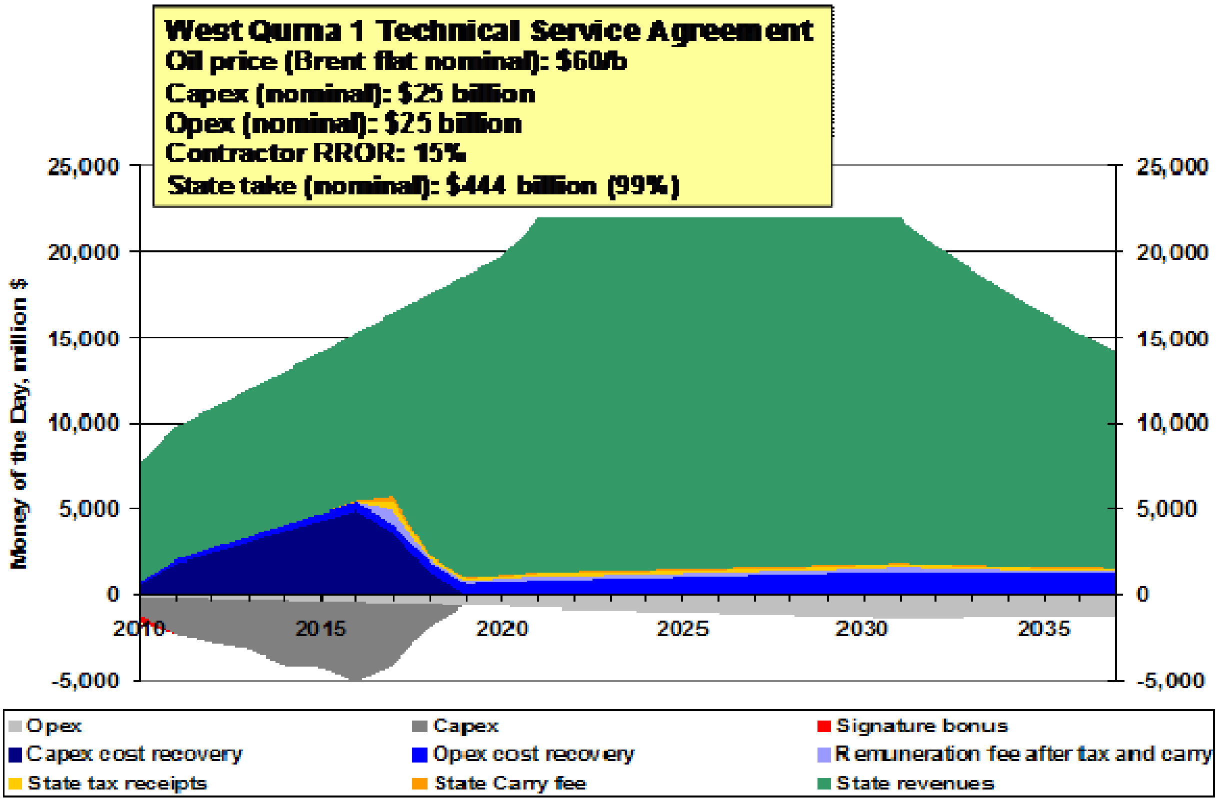
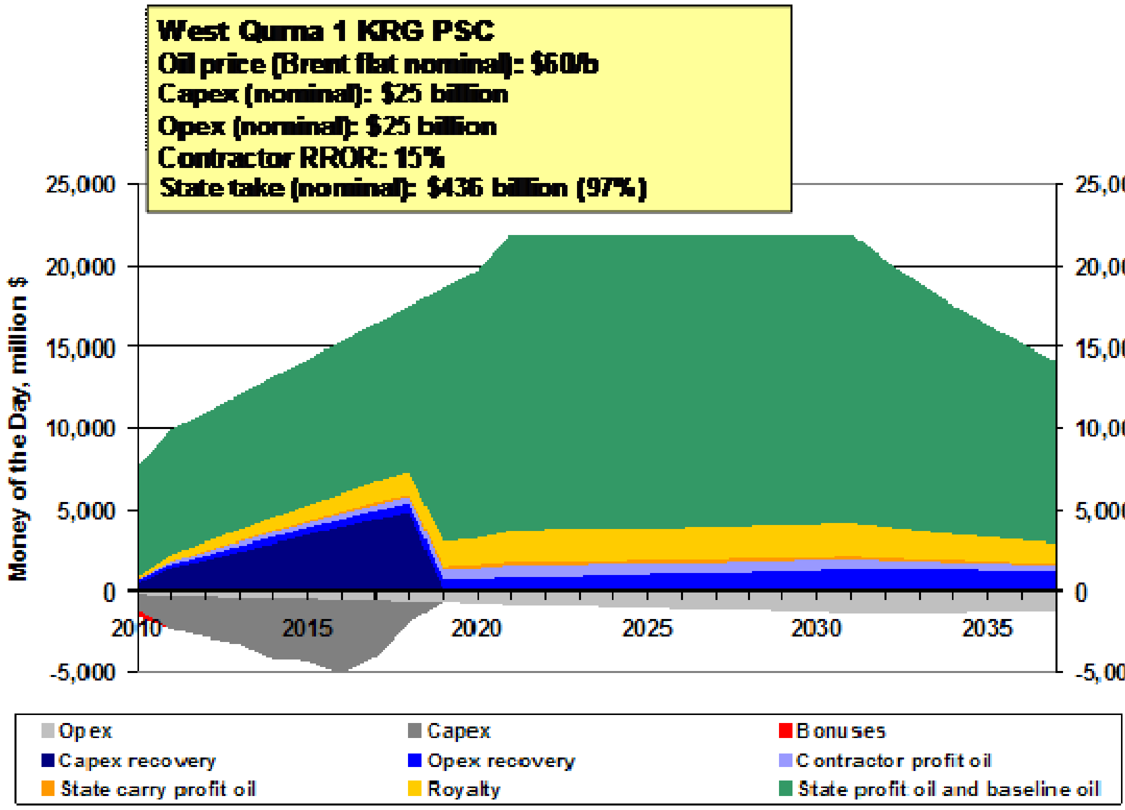



**Figure 5: Cash Flow For The KRG PSC For West Qurna 1.**




From Iraq's point of view the following economic issues are of interest in the relative performance of the contracts:

- Maximizing Iraq's revenues in the short (five years), medium (10 years) and longer term (25 years) relative to the contractor.
- Capture of most, if not all, of the windfall revenues from oil price rises.
- Alignment of Iraq's and contactor's interests with regard to long term care of the oil field.
- Incentivising the contractor not to overspend capital or operating costs.

**Table 2: Summary Of Relative Performance Of The KRG PSC And The TSC**

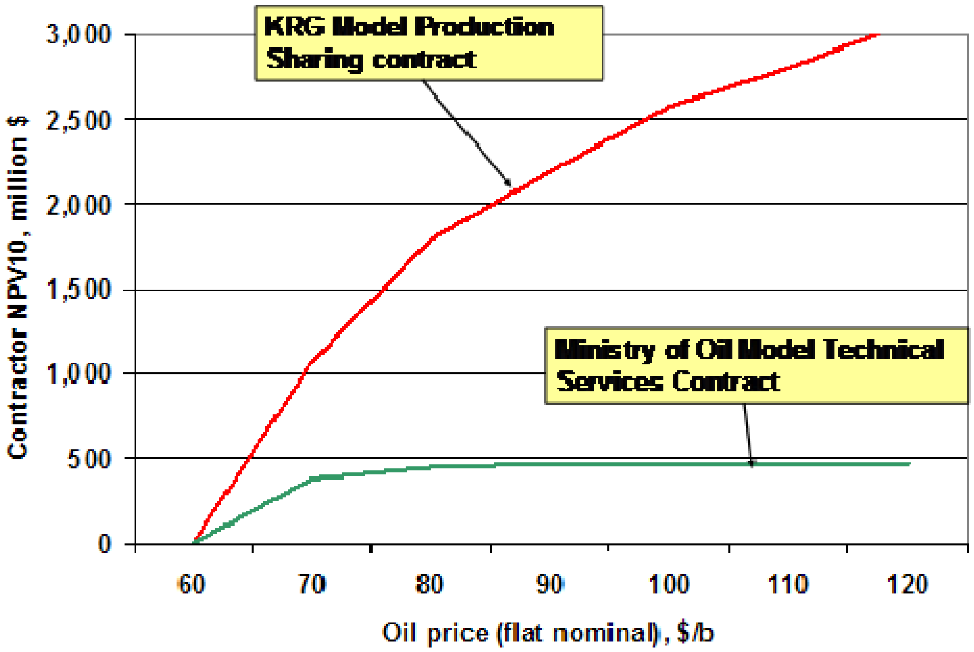
| | KRG PSC | TSC | Comments |
|---|---|---|---|
| **Maximizing Iraq's revenues ($75/B)** | | | Over the initial 5 years of the project, the contracts behave similarly with early cash flow to Iraq aided by royalty and the lower cost recovery ceiling in the KRG PSC. After 7 years, the TSC yields a consistently higher revenue and NPV10 to Iraq than the KRG PSC. In revenue terms the difference widens from ~$1bn after 10 years to more than $8bn after 25 years. |
| **5 year term** | | | |
| Iraq's revenues (money of the day) | $52.8bn | $52.8bn | |
| Iraq's NPV10 | $38.6bn | $38.4bn | |
| **10 year term** | | | |
| Iraq's revenues (money of the day) | $136.2bn | $138.5bn | |
| Iraq's NPV10 | $70.6bn | $71.4bn | |
| **25 year term** | | | |
| Iraq's revenues (money of the day) | $557.6bn | $568.4bn | |
| Iraq's NPV10 | $120.9bn | $122.8bn | |
| **Capture of windfall profit from oil price** | | | The KRG PSC profit sharing mechanism delivers a windfall profit to the contractor. The revenue difference widens from $8bn at $60/B to $14bn at $100/B. The TSC yields almost all of any windfall profit from oil price rises above $60/B to Iraq and not to the contractor. |
| **$60/B** | | | |
| Iraq's revenues (money of the day) | $435.3bn | $443.6bn | |
| Iraq's NPV10 | $94.0bn | $94.7bn | |
| **$80/b** | | | |
| Iraq's revenues (money of the day) | $598.5bn | $610.0bn | |
| Iraq's NPV10 | $130.1bn | $132.3bn | |
| **$100/b** | | | |
| Iraq's revenues (money of the day) | $762.1bn | $776.4bn | |
| Iraq's NPV10 | $167.2bn | $170.3bn | |
| **Alignment of long term interests** | Both contracts encourage additional field investment through either profit oil or remuneration fee mechanisms. | | |
| **Incentives for contractor to reduce or contain capital and operating expenses** | Both contracts have strong incentives not to raise capital or operating expenses. The TSC is especially strong on containing early capital spending and in making sure the most b/d of production are obtained for each $ invested. | | |

For all the economic criteria that matter to Iraq, the TSC either equals or is considerably superior to the KRG PSC. At base case conditions, Iraq's revenues would be $8bn less over the life of the project with the KRG PSC compared with the TSC. This worsens considerably at higher oil prices: at $100/B (Brent flat nominal) Iraq's revenues would be $14bn worse off with the KRG PSC compared with the TSC. The KRG PSC is relatively simple and has only a very limited cap on windfall profits to the contractor from high oil prices. On the other hand, the commercial terms of the TSC have a very effective capping mechanism on contractor windfall profits arising from high oil prices. This is clearly shown in Figure 6.

It is worth noting that oil price windfall profits are not necessarily a feature of all PSCs. The PSC for the Kashagan oil field offshore Kazakhstan has excellent, sophisticated commercial terms that effectively cap the contractor's windfall profits through a combination of sliding scale taxation and a cascade of sliding scale profit sharing schemes.

We expect capital spending on West Qurna 1 to be less than that indicated for a plateau rate of 2.325mn b/d – partly because this rate of spending is probably not possible in the near term in Iraq and partly because this level of production capacity will not be needed. To compare the contracts in this case, we have reduced the capital by half (in line with a production capacity plateau of 1mn b/d) but kept all other parameters the same. In this case, the KRG PSA performs very poorly with contractor's NPV10 up considerably from zero to $1,366mn and the contractor's RROR up from 15% to 56%. The TSC performs much better with only modest increases in NPV10 (from 0 to $447mn) and RROR (from 15% to 33%). Effectively, by using the KRG PSC instead of the TSC, Iraq would be worse off by some $1bn in net present value and by more than $8bn in revenues over the life of the project.

**Figure 6: Relative Sensitivity Of The TSC And The KRG PSC To Oil Price**




## Conclusions

In our view, the bid plateau rates for West Qurna 1 (2.325mn b/d), Rumaila (2.8mn b/d) and Zubair (1.125mn b/d) are neither possible nor necessary until after 2017. Not possible because of the logistical requirements, particularly drilling, the shortage of water for injection and the need for new export infrastructure; and not necessary because a likely subdued call on OPEC will cap Iraq's production to 4-5mn b/d between 2014 and 2018. Thereafter, higher Iraqi production capacity will be needed, but the required investment pace can be more leisurely over the next decade. Of course, both the international oil companies involved and the Ministry of Oil are well aware of these issues and in reality the production plateaus of the fields are likely to be less than the bid levels.

Even a slower paced expansion of production capacity in southern Iraq will leave little room for significant exports of new oil from the KRG area. This will create greater pressure from the Kurds to gain control of the Kirkuk oil field. The alternative option is for Iraqi Kurdistan to break away from Iraq and OPEC constraints. This would require the close cooperation and support of Turkey.

A direct comparison of the KRG PSC with the TSC applied by the Ministry of Oil in Baghdad reveals a number of serious shortcomings in the KRG PSC. In the first place, even for small exploration projects such as the Shamaran PSC the contractor's rate of return of more than 30% for oil prices greater than $65/B is internationally excessive. Secondly, the KRG PSC delivers too great a windfall profit to the contractor at higher oil prices.

In the case of the West Qurna 1 project, a contract based on the KRG PSC would be greatly inferior to the TSC used by the Ministry of Oil. Even in a base case of $60/B, the TSC delivers

$8bn more in revenue to the state than the KRG PSC. At oil prices of $100/B this revenue difference rises to $14bn. Unlike the KRG PSC, the TSC very effectively caps the contractor's revenue, rate of return and net present value at higher oil prices. Both contracts encourage savings in capital and operating expenditure, but the contractor's return in the TSC is especially sensitive to capital expenditure in the early years – encouraging prudent, timely and effective use of investment funds. The contractor is highly incentivised to obtain the highest incremental b/d rate per dollar invested. In every commercial respect, from the state's point of view the TSC is superior to the KRG PSC.

In addition, with the successful conclusion of the First Bid Round, the Ministry of Oil will have achieved the timely, open, clean and transparent award of several major oil field development projects to reputable and capable operating companies – ExxonMobil, ENI and BP – on very advantageous terms for Iraq. The three projects awarded to date alone represent capital investment of more than $50bn and incremental production capacity by 2017 of at least 2-2.5mn b/d. The state take on the revenues from these projects will be close to 99%.

The contrast with the KRG is considerable. The KRG's PSCs have been awarded by opaque, secret negotiations to companies with, in the main, very limited major international field operating experience. The profit sharing terms of the KRG PSC are simplistic by the standards of modern PSCs and yield lower revenues and value to the state than PSCs in comparable countries.

***To contact the author: peter.ra.wells@gmail.com***

**Appendix 1: Comparison Of Main Terms Of The KRG PSC And The TSC For Our Selected Base Case.**

| | Technical Service Contract | KRG Production Sharing Contract |
|---|---|---|
| **Duration** | 20 years extendable to 25 years. | 25 years extendable to 30 years. |
| **Bonuses** | Signature bonus of $400mn cost recoverable as Supplementary Fees from 10% of gross revenues from baseline production. | Signature bonus of $400mn and production bonuses not cost recoverable. |
| **Cost Recovery** | Remuneration Fee per Barrel (RFB) and cost recovery allowed from 50% of gross revenues with cost recovery taking preference. | Cost recovery from 45% of gross revenues from incremental production after deducting Royalty. |
| **Remuneration Fee/Profit Oil** | RFB $1.90 per incremental barrel.<br>RFB reduced by R factor sliding scale as costs are recovered.<br>R = cumulative contractor income/cumulative contractor costs.<br>0<R<1: 100% of fee.<br>1<R<1.25: 80% of fee.<br>1.25<R<1.5: 60% of fee.<br>1.5<R<2: 50% of fee.<br>2<R: 30% of fee.<br><br>There is a penalty for underperforming on the plateau rate: RFB is multiplied by the Performance Factor (net production/bid plateau rate). This is not applied if the government orders lower production or if production is limited by access to external infrastructure. | R factor applied to profit oil.<br>R = cumulative contractor income/cumulative contractor.<br>0<R<1: profit oil share 10%.<br>1<R<2: sliding scale between 10 and 8%.<br>R>2: profit oil share 8%. |
| **Carry** | Full carry of all costs and 25% of remuneration fee to Regional Operating Entity. | Full carry of costs and 25% of profit oil to state entity. |
| **Taxation** | 35% tax rate levied on net remuneration fee after deduction of 25% carry. | Tax paid from state profit oil. |
| | None | 10% on gross revenues. |
| **Baseline production** | 2009 production 280,000 b/d, 5% decline rate thereafter. | 2009 production 280,000 b/d, 5% decline rate thereafter. |
| **US $ inflation rate** | 3% | 3% |
| **Cost inflation rate** | 5% | 5% |
| **Capex (money of the day)** | $25bn | $25bn |
| **Opex (money of the day)** | $25bn | $25bn |
| **Base Case Parameters:** | | |
| **Oil price (Brent flat nominal)** | $60/B | $60/B |
| **Contractor NPV10** | 0 | 0 |
| **Contractor Real Rate of Return (RROR)** | 15% | 15% |
| **State take, money of the day** | $444bn | $436bn |
| **State take, %** | 99% | 97% |