Comparative Analysis of Ministry of Oil and Kurdistan fiscal terms as applied to the Kurdistan Region
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EXECUTIVE SUMMARY

This report is written for Clifford Chance LLP, London, UK at the request of the Kurdistan Regional Government. It is a follow up to the report entitled "Government Take and Petroleum Fiscal Regimes (May 25, 2008)".

This report compares two alternative upstream petroleum arrangements for the development of the Kurdistan Region:

- **A risk service contract for exploration, development and production ("EDP-RSC") developed by the Ministry of Oil of Iraq ("MOO"), and**
- **A production sharing contract for exploration, development and production developed by the Kurdistan Regional Government ("KRG-PSC").**

The report provides an analysis of the structure of the fiscal terms of both models and the anticipated value of government revenues that can be estimated to be derived from these terms.

The EDP-RSC terms are based on a model contract provided to me, while the KRG-PSC terms are based on a typical average of the terms concluded so far in the Kurdistan Region. It should be noted that the EDP-RSC is only a MOO proposed model at this time and has not been formally approved by the Government of Iraq.

It is fundamentally important to structure fiscal terms in such a manner that the profitability to the investor is aligned with the goals of the government. If the profitability and goals are aligned, investors will automatically take decisions in such a manner that the value of the government revenues is maximized because in this way also their profits will be maximized.

If profitability to the investors is not aligned with the goals of the government, very significant losses can occur to the value of government revenues.

Under the EDP-RSC the contractor and the host government are seriously misaligned on most issues. These include:

- **There is no incentive for investors to explore for large low cost fields, the main driver would be to find high cost small fields;**
- **There is no incentive for investors to have low cost operations, in fact there is a strong incentive to have high cost operations based on poor development plans;**
- **There is no incentive to achieve a maximum recovery of the oil and gas and in fact a lower recovery could be more profitable to the IOCs; and**
- **The IOCs have an interest in low oil prices.**

On the other hand, under the KRG-PSC, the investor and the host government are fully aligned on all economic issues. These include:

- **There is a strong incentive for investors to find large low cost fields;**
- **There is an adequate incentive for investors to have low cost operations;**
- **There is a strong incentive to achieve a maximum recovery of the oil and gas from the reservoirs that is consistent with sound conservation practices; and**
- **The IOCs have an interest in high oil prices.**

It can therefore be expected that the performance of international oil companies under the KRG-PSC will be far superior than under the EDP-RSC. This will result in significant volumes of additional oil and gas production under the KRG-PSC's during the next three decades in the Kurdistan Region. It will also result in earlier production and lower cost production.

The EDP-RSC would not be considered in the national interests by most host governments because:

- **It does not achieve an optimal level of production with a maximum value of government revenues;**
- **It seriously exposes government to absurdly low government takes if low oil prices would occur after development plans and remuneration rates have been approved;, and**
- **It provides for overly generous conditions for the investors in the initial phases of the contract.**

On the other hand, the KRG-PSC would be considered in the national interests by many host governments because it does provide the framework for an optimal level of production and recovery of oil and gas from the reservoirs while creating a high value of government revenues. Nevertheless, from a fiscal design perspective, the KRG-PSC may not necessarily be optimal. The model contract could have been somewhat improved structurally through:

- **Creating a larger variation in government take between small and large fields;**
- **Creating a larger variation in government take between low and high oil prices;, and**
- **Providing stronger incentives to IOCs to be efficient.**

However, it should be noted that under current oil price conditions many PSCs in the world are sub-optimal and do not provide an adequate range in government take between low and high oil prices.

Under the hypothetical assumption that if an EDP-RSC and KRG-PSC would both start January 1, 2009, the losses under EDP-RSC relative to the KRG-PSC would be substantial for all field sizes as well as for a wide range oil prices.

At US $ 100 per barrel and for a 30 million barrel field, the losses would be close to half the value of the government revenues (on a 5% discounted basis): a present value loss of about $ 600 million. For a typical 100 million barrel field, the present value loss would be about 30% of the value or $ 1,200 million; and for a 300 million barrel field the value loss would be 20% of the value or $ 2,500 million.

If it is assumed that in total about 100 small fields will be discovered in the Kurdistan Region, in the field size range of 30 to 300 million barrels for a total potential of about 10 billion barrels, the total present value loss would be about $ 120 billion under the EDP-RSC regime.

The KRG-PSC's have already been concluded. However, had KRG waited until the EDP-RSCs would have to be concluded under a new petroleum law and based on the relatively slow bidding process of MOO, a two year delay could occur. This would increase the present value loss to $ 150 billion.

It can be noted that KRG assumes a total oil potential of around 30 billion barrels, in which case the present value loss would be 3 times larger ($450 billion) under the MOO proposed regime.

There is therefore no doubt that applying the EDP-RSC concept, instead of the KRG-PSCs, to the Kurdistan Region would be disastrous for Iraq, and it would be a real tragedy if the MOO proposed model would be applied in the rest of Iraq.

Although the terms for the KRG-PSC seem structurally acceptable, subject to the a above comments, no comparison was made with fiscal terms in other countries in order to determine whether the level of government take and government revenues is truly competitive.

Comparative analysis of Ministry of Oil and Kurdistan fiscal terms as applied to the Kurdistan Region

1. INTRODUCTION

This report is written for Clifford Chance LLP, London, UK at the request of the Kurdistan Regional Government.

Currently, the Kurdistan Regional Government has concluded a number of production sharing agreements for exploration, development and production of oil and gas in the Kurdistan Region.

At the same time the Ministry of Oil (MOO) of the Federal Government of Iraq has developed a number of alternative model contracts for:

- Exploration, development and production, as well as for
- Development and production only.

For both tasks MOO has developed two alternative contractual models:

- A risk service contract model, and
- A production sharing model.

Publicly, MOO has expressed the opinion that it would prefer the risk service contracts over production sharing contracts for political reasons.

This means that there are two alternative models for exploration, development and production of oil and gas in Iraq:

- The risk service contract for developed by MOO ("EDP-RSC"), and
- The production sharing contract of the Kurdistan Regional Government ("KRG-PSC").

In this context, it is important to examine which of these two models would be best suited for the development of the petroleum potential of the Kurdistan Region.

This report deals with this issue.

Potentially also the production sharing contract developed by MOO ("EDP PSC") would be available for these activities. However, the author does not have information on the actual figures for cost oil and profit oil shares and other fiscal features that MOO would use in this respect and therefore it is not possible to compare this contract with the KRG-PSC.

First, the risk service contract developed by MOO for exploration, development and production will be discussed (Section 2).

Subsequently, the production sharing contract developed by the Kurdistan Regional Government will be discussed (Section 3).

These two models will then be compared in Section 4.

It should be strongly emphasized that the models prepared by MOO are only models at this point in time. The models to be discussed will be the ones available to the author. MOO may have prepared other models as well with which the author is not familiar.

In accordance with the draft Federal Petroleum Law (February 15, 2007 version) these models would have to be reviewed by Federal Oil and Gas Council. This Council would have the power to implement different models or make significant changes to these models.

This Petroleum Law has not yet been passed and therefore this review has not yet taken place, so it is still possible that the MOO model may not be adopted by the Council.

Therefore, also the bid process has not yet taken place for any of the areas and as a result the actual terms and conditions that might be obtained under any of the MOO models are not known. The report is therefore based on the terms that MOO apparently intends to obtain based on the content of the proposed model contract.

2. MOO RISK SERVICE CONTRACT FOR EXPLORATION, DEVELOPMENT AND PRODUCTION

2.1. Description of the fiscal element of the model

The risk service contract developed by MOO for exploration, development and production of oil and gas ("EDP-RSC") has a number of unique features that make it different from other risk service contracts and production sharing contracts.

Following is a description of the main features of the EDP-RSC.

Term and Handover Date

Typically the contract would consist of the following time frame:

- A Phase-1 exploration period of 3 years
- A Phase-2 exploration period of 2 years
- A possible extension of the exploration period with another 2 years
- An appraisal period of 2 years
- A development period of 5 years, and
- A transfer period of 2 years.

Therefore, typically a contract would be for a term of 16 years. Upon the termination of the transfer period is the handover date. On this date the contractor hands over all operations to the national oil company and is no longer directly involved in the petroleum operations.

The term cannot be more than 20 years.

For gas there is a possibility for an additional holding period of 2 years in case of a significant gas discovery in order to develop a gas evaluation and marketing plan. Development period is 6 years.

Technical services agreement

The national oil company has the option to enter into a technical services agreement for 15 years on the handover date with the international oil company.

During this period of 15 years the contractor can also purchase under a long term agreement "Optional Oil" up to 20% of the volume of the production from the development area.

Cost Contributions

All costs associated with the petroleum operations are to be contributed by the contractor. This applies to all capital and operating costs.

Cost Recovery

In case the exploration results in the production of a commercial discovery, all petroleum costs can be recovered from 50% of the production until the date the field is handed over back to the national oil company. If in any year there are costs in excess of a value equal to 50% of the production, such costs can be carried forward into the next year for recovery.

However, the 50% cost limit is not absolute as would be the case in a production sharing contract. Any costs that remain to be recovered on the handover date will become due and payable on that date. Therefore all costs approved by MOO and the Joint Management Committee will be recovered. There is no risk to IOCs of not recovering costs due to the cost limit. All costs related to oil will be recovered as Repayment Oil at a location where oil is exported. In the case of gas, the cost will recovered as Repayment Gas at a delivery point where the gas is marketed.

Also contrary to a production sharing contract, there is no relationship between "cost oil" and "profit oil". For instance, if the petroleum costs are less than the 50% limit, there is no automatic increase in the amount of profit oil. The remuneration is separate and independent of the amount of cost oil.

It should be noted that the recovery of costs is calculated separately for each development area. In other words, if two or more commercial discoveries are made, three separate development plans will apply with three separate cost recoveries. The first plan will include all exploration costs incurred prior to the commercial declaration of the first field. The second plan will include only those exploration costs that are incurred between the first and second declaration of commercial discovery, etc.

Remuneration

The remuneration is determined on the basis of a remuneration index. This index is based on the development plan. As part of the development plan approval process, the contractor has to estimate the expected cumulative capital costs ("ECCC") until the hand over date.

Subsequently, the contractor has to make an estimate of the oil price (or gas price where applicable) and propose a remuneration index that results for each development area in no more than an IRR of 20%. The index is the ratio ("r") between the expected overall remuneration ("EOR") and the ECCC based on the IRR benchmark.

The remuneration is paid is direct proportion to the actual cumulative capital costs ("ACCC"), or in other words the remuneration paid at any point in time is r* ACCC.

However, the remuneration is limited by 10% of the production. If there is more remuneration due in any year than is available under the 10% limit, this remuneration will be carried forward. As with the cost limit, the remuneration limit is not absolute. Any outstanding amounts are due and will be paid on handover date on the basis of amortizations over two years after the handover date.

The remuneration is also paid as part of the Repayment Oil or Repayment Gas.

As with the recovery of the petroleum costs, the remuneration is separately made for each development area. In other words depending on the IRR assessment for each development area, , the remuneration indices would be different for each development area.

The remuneration cannot exceed the remuneration index multiplied by the ECCC.

There is a remuneration floor of 80% of the EOR in case the contractor manages to incur less costs than estimated.

Commercial discovery

A commercial discovery is a discovery which makes an IRR of 30% on a total project basis on a 25 year cash flow based on a price forecast accepted by MOO on the date the commercial discovery is approved.

Development Plans and Work Programs

The Development Plans and related Work Programs can be amended with the approval of MOO of Joint Management Committee (after a Commercial Discovery). All increases in Budget of more than 5% require prior approval.

Transport system

All transportation between the production measurement point in the contract area and the delivery point is done by the Transporter, which is an entity appointed by MOO. The contractor can present in his development plan the construction of a transport system. Such transport system is part of the Petroleum Costs, , and therefore is within the remuneration concept.

Taxation

Contractor is subject to all taxes, , but these taxes are paid on behalf of the contractor from the remuneration. Therefore, contractor is in principle not subject to any direct tax payments on Repayment Oil and Repayment Gas or his operations generally.

Economic and fiscal stability

If subsequent to the signing of the contract, changes in laws occur that materially impact on financial flows to the contractor, the parties will agree to restore the fiscal balance.

2.2. Overall comment on EDP-RSC

The overall contract is clearly a risk service contract. It requires a full investment by the contractor and the contractor will only receive his cost recovery and remuneration in case of a successful discovery.

The payment of the service contract fees in kind as Repayment Oil or Repayment Gas is an attractive feature of the contract for investors.

2.3. Basic economic analysis of the EDP-RSC

In order to do an economic analysis on the EFP RSC a typical exploration program will be analyzed.

Example

A typical exploration program is being evaluated on the basis of a set of cost assumptions. The typical exploration program is based on the phases of the EDP-RSC. It should be noted that in many cases the development of the discoveries can be implemented more quickly than assumed under the EDP-RSC contract. Rather than taking 9 years to have a commercial discovery, this could take place in 3 years or less. However, in order to properly assess the impact of the RSC the full term of the RSC is being used.

It is assumed that in Phase 1, the contractor will spend $ 8 million on geophysics and $ 12 million on an exploration well, in Phase 2 $ 12 million on an exploration well and in the extension of another 2 years of the exploration phase another $ 12 million for an exploration well. The total exploration program would be $ 44 million over 7 years.

It is estimated that there is a 60% probability of failure of this seven year exploration program. In case of success, it is estimated that there is a 20% probability for a 30 million barrel field, a 15% probability for a 100 million barrel field and a 5% probability for a 300 million barrel field.

In case of a discovery there would be a two year appraisal program of two wells of $ 12 million each in year 8 and 9 of the contract.

It is assumed that the total development and operating costs of the 30 million barrel field are $ 15 per barrel, with $ 270 million for capital costs and $ 6.00 per barrel for operating costs. The 100 million barrel field would cost $ 11 per barrel, with $ 660 million for capital costs and $ 4.40 for operating costs. The 300 million field would require $ 6 per barrel and would need $ 1,080 million in capital costs and $ 2.40 in operating costs.

It is assumed that the handover date would be at the end of year 16. Following is the production split before and after the handover date between the IOC and the NOC:

Production (million barrels)	Contractor production	NOC production
30 million barrel field	16.2	13.8
100 million barrel field	36.4	63.6
300 million barrel field	95.2	204.8

Upon a commercial discovery of the field the remuneration index would be determined in such a manner that the contractor would make 20% IRR. This would result in the following remuneration indices for the different outcomes:

Remuneration Index	Contractor production
30 million barrel field	1.66
100 million barrel field	1.20
300 million barrel field	0.69

Results

Table 1 provides the complete overview of the economics of the project.

What is clear is that the amount of repayment oil is not at all proportional to the field size. The 300 million barrel field results in an amount of repayment oil of 20.67 million barrels, while the 30 million barrel field results in 9.32 million barrels. This is due to the fact that the 30 million barrel field is higher costs and therefore also attracts a higher remuneration index in order to achieve 20% rate of return (“IRR”).

The profitability analysis indicates that the investor is indifferent among the outcomes of the exploration project between the various field sizes from an IRR perspective. The IRR is the same regardless of the outcome.

The 100 million barrel field is the most attractive from the perspective of the net present value discounted at 10% ("NPV10").

The 30 million barrel field is generally the most profitable to the investor. The profit to investment ratio discounted at 10% ("PIR10") is the highest for this field. Also the undiscounted net cash flow per barrel of oil equivalent ("NCF0/BOE") is the most attractive by a wide margin.

As an exploration project, the project would be attractive under the geological risk profile assumed in this example, assuming the investor seeks a risked hurdle rate of 10% IRR (real) as a minimum.

Table 1
Exploration Venture Results at $ 100 per barrel

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3000	10000	30000	3600
Total Capex	($ mln)	44	314	704	1124	251
Total Opex	($ mln)	0	180	440	720	138
Divisible Income	($ mln)	-44	2506	8856	28156	3211
Remuneration Index			1.66	1.2	0.69	
Repayment Oil	(mln bbls)	0	9.32	16.82	20.67	5.42
IRR	(%)	neg	20.0%	20.0%	20.0%	14.3%
NPV10	($ mln)	-32.5	90.8	139.6	134.5	26.3
PIR10	ratio	neg	0.64	0.48	0.30	0.23
NPV0/BOE	($/bbl)	0.00	17.37	8.30	2.50	6.67
GT0	(%)		79.2%	90.6%	97.3%	92.5%
GT5	(%)		80.0%	90.4%	97.1%	93.1%
GR0	($ mln)		1985	8026	27405	2971
GR5	($ mln)		901	3341	11134	1238

The undiscounted government take ("GT0") indicates a high government take ranging from 79.2% for the 30 million barrel field to 97.3% for the 300 million barrel field. The discounted government take would be about the same.

It should be noted that the "government take" as defined here covers the entire life of the oil field, not just the period of the 16 year contract. In other words the total government take is a mixture of a lower government take during the 16 year period and 100% government take after 16 years. The consequences of this will be evaluated below.

The undiscounted government revenues ("GT0") government revenues go up disproportionately with the field size, as can be expected. The government revenues include also the portion of the field life after 16 years. The 5% discounted government revenues ("GR5") follow the same pattern.

The economic analysis indicates that the optimal discovery for the investor would be a small expensive oil field. While, of course, the optimal discovery for the host government is a large low cost oil field.

In other words, rather than looking for low cost large fields as both the host government and the investor would normally want, under the EDP-RSC the investor is instead induced to explore for high cost small fields because they are more profitable to the investor.

The EDP-RSC seriously misaligns the investor and host government interests in terms of the definition of desirable exploration targets. This should be a very serious concern from a government perspective.

It should also be noted that there is a strong incentive under the EDP-RSC for the investor to "go slow" since the remuneration is based on the IRR, and therefore the NPV10 and PIR10 values increase with a slower program.

2.4. Sensitivity with respect to costs

An important issue is how the EDP-RSC would react to higher costs.

For instance, what would be the results of 25% higher costs than assumed in Table 1.

Table 2 illustrates the results for this analysis.

Table 2
Exploration Venture Results at $ 100 per barrel at 25% higher costs

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3000	10000	30000	3600
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	225	550	900	173
Divisible Income	($ mln)	-55	2383	8570	27695	3114
Remuneration Index			1.78	1.30	0.82	
Repayment Oil	(mln bbls)	0	12.12	21.89	27.60	7.09
IRR	(%)	neg	20.0%	20.0%	20.0%	14.5%
NPV10	($ mln)	-40.7	120.2	185.8	192.1	37.1
PIR10	ratio	neg	0.68	0.51	0.35	0.26
NPV0/BOE	($/bbl)	0.00	23.29	11.25	3.72	9.20
GT0	(%)		70.7%	86.9%	96.0%	89.4%
GT5	(%)		71.5%	86.6%	95.7%	90.0%
GR0	($ mln)		1684	7446	26580	2783
GR5	($ mln)		754	3060	10734	1146

What is obvious from Table 2 is that the higher costs require much higher remuneration indices in order to achieve a 20% IRR. The higher costs and higher remuneration indices result in a much larger volume of Repayment Oil.

The NPV10, PIR10 and NPV0/BOE are now all well over the levels of Table 1.

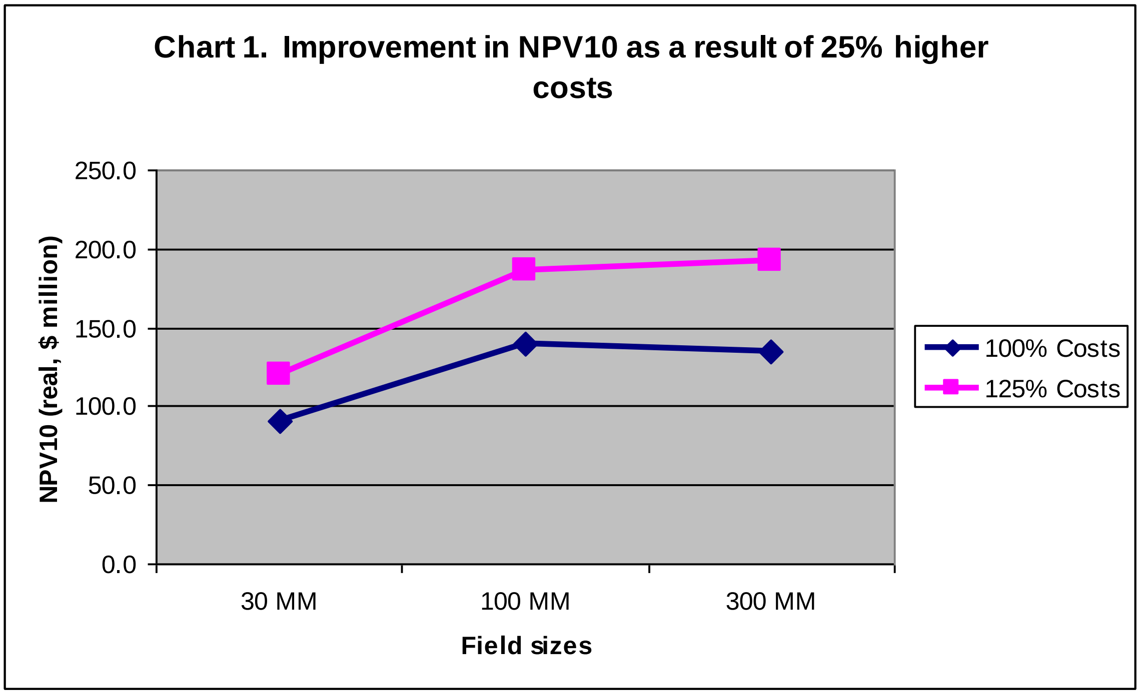


Chart 1 illustrates the dramatic improvement in NPV10 that can be achieved with 25% higher costs.

This means that the higher costs lead to a more profitable project. As a result, the government take and government revenues are now considerably lower.

The government clearly "over compensates" for the higher costs. For instance, comparing Table 1 and Table 2, for the 100 million barrel field, there is a loss of $ 286 million in divisible income. However, the loss in government revenues is $ 580 million, more than twice the cost increase. In other words, for every dollar increase in costs on the part of the investor, the government loses $ 2 in revenues. This makes it attractive for the investor to increase costs, regardless of the merit of the cost increase. This is called "gold plating" and reflects very poor fiscal design.

The fact that higher costs lead to much higher profits, will be a strong inducement on the part of the investors to submit sub-optimal development plans.

For instance, it can be assumed that a field can be developed in two ways:

- A large number of simple horizontal wells of low productivity, resulting in a very high capital costs, and
- A limited number of horizontal and multilateral wells of high productivity, resulting in low capital costs.

It is clear that the investor would propose the horizontal well concept, because the investor would make much higher profits on this basis.

In other words, a poor development plan and high costs result in a reward of high profits for the investor.

It is clear that the EDP-RSC system completely misaligns the interests of the investor and the host government in terms of cost efficiency.

It could be argued that MOO or the Joint Management Committee would prevent such a situation by rejecting the development plans that are not optimal as the EDP-RSC requires.

It should be noted that it would place a very heavy burden on MOO and the Joint Management Committee to have to "second guess" the development plans and work programs of the private investor on every twist or turn. International experience is that government officials that are typically underpaid compared to the private petroleum industry, and are usually less qualified, are typically not up to this task. The problems would be exacerbated if corruption problems would exist in the administration.

By fundamentally misaligning the interests of the investor and the host government and actually strongly encouraging investors to incur and declare higher costs, the EDP-RSC contract exposes Iraq to considerable risks of lower government revenues than otherwise would be obtainable.

2.5. Sensitivity with respect to oil prices

In case of lower prices, the cost limit is lower and therefore it takes longer to recover the capital, which in turn requires a stronger cash flow to achieve 20% IRR.

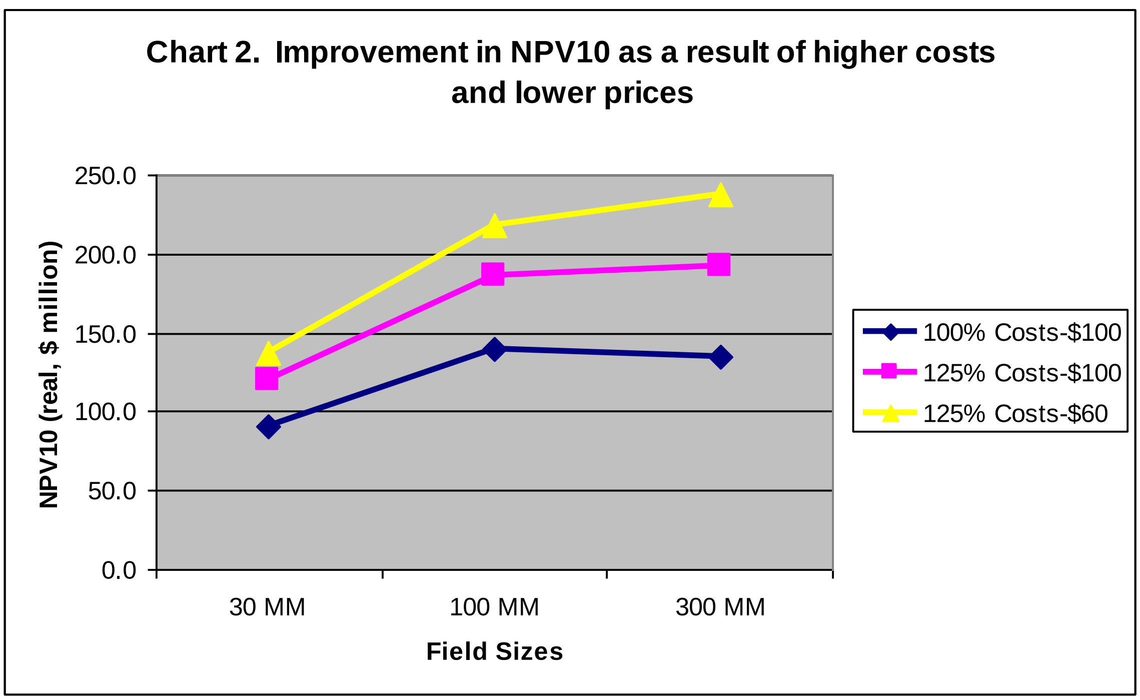
This is illustrated in Table 3, which analyzes the same project with 125% of the costs and a price level of US $ 60 per barrel.

The remuneration index needs to increase in order to create profits to the investor to achieve 20% IRR. This now results in a very strong increase in the Repayment Oil, since more profits have to be provided to the contractor with barrels that have a lower value. For the 30 million barrel fields the contractor now receives 22.37 million barrels or almost 75% of the total production. This is a "give away" by any international standard.

Table 3
Exploration Venture Results at $ 60 per barrel at 25% higher costs

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	1800	6000	18000	2160
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	225	550	900	173
Divisible Income	($ mln)	-55	1183	4570	15695	1674
Remuneration Index			2.11	1.59	1.07	
Repayment Oil	(mln bbls)	0	22.37	40.67	51.68	13.16
IRR	(%)	neg	20.0%	20.0%	20.0%	15.1%
NPV10	($ mln)	-40.7	136.9	218.7	237.7	47.7
PIR10	ratio	neg	0.78	0.60	0.43	0.34
NPV0/BOE	($/bbl)	0.00	27.61	13.75	4.85	11.44
GT0	(%)		30.0%	69.9%	90.7%	75.4%
GT5	(%)		28.2%	68.4%	90.2%	75.8%
GR0	($ mln)		354	3195	14240	1262
GR5	($ mln)		137	1233	5619	493

Chart 2 illustrates how the lower prices now result in a much higher NPV10. This chart illustrates how under the EDP-RSC the profits to the investor increase dramatically with higher costs and lower prices.



Because of the "guarantee" of a 20% IRR under the EDP-RSC, the government take now becomes very low under conditions of high costs and low prices. Table 3 illustrates how the discounted government take, the GT5, on the 30 million barrel field is now only 28.2%. Even on the 100 million barrel field the government take is now well below typical international average for such fields at US $ 60 per barrel with a GT5 of only 68.4%.

Government revenues suffer enormously as a result of the lower prices, because the government receives less for the oil, but needs to pay the contractor more.

In comparing Table 2 and 3 for the 100 million barrel field, it can be seen how a $ 4,000 million drop in divisible income results in a $ 4,251 million drop in government revenues. Therefore the government is clearly overcompensating for the drop in prices at the rate of $ 1.06 drop in undiscounted government revenues for every $ 1 drop in gross revenues as a result of lower prices. This is again a major design flaw of the system.

The interests of the investor and the government are completely misaligned. The "drivers" for the investor are exactly the opposite of what normal worldwide concepts would be. Normally, investors and governments seek to achieve both the highest possible prices and the lowest possible costs. Under the EDP-RSC, the investor is rewarded strongly for the highest possible costs under the lowest possible prices.

The EDP-RSC includes a special protection for the declaration of a commercial discovery. The commercial discovery has to meet certain standards, presumably in order to prevent the above conditions. However, this would mean that a viable field would not be developed because it is not in the interest of the host government to declare the field commercial.

However, the remuneration is fixed at the development plan approval stage. This means that the government is now significantly exposed to a significant price drop **– after the remuneration index has been approved on the basis of a higher price.**

Therefore, the host government is even more exposed, in case of a price drop after the discovery has been declared "commercial".

In fact, the remuneration to the contractor under very low prices could be so high for the 30 million barrel case that the amount of Repayment Oil is higher than the total cumulative amount produced by the field. This is an absurd result of this fiscal design. Iraq would actually lose oil rather than gain oil, and would be better off without the field or such a contract.

The EDP-RSC results in a complete "give away" of the national resource wealth under low price conditions and high costs, after a commercial discovery has been approved by MOO.

Most governments in the world protect themselves through fiscal systems that guarantee some resource income to government no matter how low the oil or gas prices are.

Therefore, the government take is always positive, usually at an attractive level. The fact that the EDP-RSC does not follow this international concept is a very serious deficiency of the fiscal design.

2.6. Sensitivity with respect to recovery of oil

An important drawback of a contract lasting only 16 years, with only 7 years production, is that the contractor will have no economic interest in the ultimate recovery of the oil.

The main focus of the contractor will be to build the initial facilities as expensively as possible. Whether this results in a suboptimal recovery of oil is of no concern to the investor.

Table 4 illustrates a case, whereby the contractor commits the same capital costs to installing the production capacity as under Table 2. However, the development plan and the design of the facilities and well drilling is inferior to that of Table 2 and therefore the national oil company subsequently only manages to recover 90% of the planned cumulative oil production.

Table 4
Exploration Venture Results at $ 100 per barrel, 25% higher costs and 90% of planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	2700	9000	27000	3240
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	203	495	810	155
Divisible Income	($ mln)	-55	2105	7625	24785	2771
Remuneration Index			1.78	1.30	0.82	
Repayment Oil	(mln bbls)	0	12.12	21.89	27.60	7.09
IRR	(%)	neg	20.0%	20.0%	20.0%	14.5%
NPV10	($ mln)	-40.7	120.2	185.8	192.1	37.1
PIR10	ratio	neg	0.68	0.51	0.35	0.26
NPV0/BOE	($/bbl)	0.00	25.88	12.49	4.13	10.22
GT0	(%)		66.8%	85.3%	95.5%	88.0%
GT5	(%)		68.2%	85.1%	95.3%	89.0%
GR0	($ mln)		1406	6501	23670	2440
GR5	($ mln)		644	2716	9789	1026

In this case, the contractor will receive exactly the same profits and cash flow (although on a per barrel basis the NCF0/BOE is higher because the amount of barrels is lower) despite the inferior design of the production facilities and well drilling. The Repayment Oil remains exactly the same.

The government take is now less because the same payments are made to the contractor on the basis of less total oil.

The losses in government revenues compared to Table 2 are very significant, whether discounted or undiscounted. The 5% discounted values of the government revenues (GR5) for the 300 million field are now $ 1 billion less as a result.

This analysis indicates that there is no alignment between the contractor and the host government in the matter of the highest possible recovery of oil. The contractor may propose, and obtain approval for, development plans that achieve the highest possible net present value and cash flow per barrel to the contractor, but not the highest possible economic oil recovery. This could result in major losses in government revenues and oil production.

However, far more serious than possible losses in recovery would be the inability on the part of the state oil company in the subsequent years to benefit from possible new technology and achieve much higher recovery factors than originally contemplated. The vast majority of oil fields in the world achieve over time far higher recovery factors than originally anticipated as a result of ever improving technologies and information.

In the period after the 16 year service contract with the contractors, these contractors will continue to assist on the basis of a technical service agreement. It should be noted that IOCs will not sign such technical services agreements unless they are lucrative to the IOCs. Highly qualified human resources are now a scarce resource. IOCs will not dedicate a project team unless the profit margin per professional is attractive, for instance total yearly payments may have to be $ 2 million per IOC professional or more.

Table 5 shows the potential of much further recovery with a new phase of investment starting in year 17, resulting eventually in 30% higher recovery. This means the cumulative production of the fields would now be 39 million, 130 million and 390 million.

It is assumed that the IOCs signed a $ 10 million per year technical assistance contract in the case of a 30 million barrel discovery, a $ 25 million per year contract for a 100 million barrel discovery and a $ 50 million per year contract for a 300 million barrel discovery.

Table 5
Exploration Venture Results at $ 100 per barrel, 25% higher costs
130% of planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3900	13000	39000	4680
Total Capex	($ mln)	55	518	1218	1905	414
Total Opex	($ mln)	0	333	840	1470	266
Divisible Income	($ mln)	-55	3050	10943	35625	4000
Remuneration Index			1.78	1.30	0.82	
Repayment Oil	(mln bbls)	0	12.12	21.89	27.60	7.09
IRR	(%)	neg	20.3%	20.5%	20.9%	15.0%
NPV10	($ mln)	-40.7	126.6	204.2	232.9	43.2
PIR10	ratio	neg	0.72	0.56	0.42	0.30
NPV0/BOE	($/bbl)	0.00	18.94	9.61	3.63	7.97
GT0	(%)		75.8%	88.6%	96.0%	90.7%
GT5	(%)		75.7%	88.2%	95.8%	91.0%
GR0	($ mln)		2311	9693	34210	3627
GR5	($ mln)		985	3888	13324	1447

Table 5 shows how the IOCs would receive the same Repayment Oil, because there is no change in the contract in the first 16 years prior to the handover date.

However, now in addition the IOCs receive the profits from the Technical Services Agreements. Therefore the NPV10, IRR and PIR10 go up somewhat.

Table 5 shows how such further incremental recovery could result in potentially significant further increased government revenues.

Although this potential exist, international experience indicates that technical service agreements do not lead to significant production increases. This is due to two factors.

First, IOCs do not really have an incentive to give good advice. They receive the same consulting fees regardless of the results of the field production. In a world where human resources in the oil industry are severely stretched, they have no incentive to put their best professionals on the job.

Secondly, NOC's are often too inefficient to implement the advice given by the IOCs under technical services agreements, whatever the quality of this advice. This is due to many factors, such as the bureaucratic nature of decision making, delays in budget approvals, shortage of capital at critical moments, inability to provide for an integrated technical management of the oil field developments, inability to attract qualified personal in a world market that currently offers premium salaries for well qualified professionals, etc.

Kuwait has now had for more than a decade technical services agreements for the North Kuwait fields. Already in 1998 it was recognized that the North Kuwait fields could produce 900,000 bopd by about 2002. Today these fields are still at 600,000 bopd. It should be realized that under technical services agreements, the international oil companies are merely consultants. The implementation of the operations still has to be done through relatively inefficient state oil companies.

Technical service contracts (TSAs) with the international oil companies in the period after the handover date are unlikely to be successful in increasing recovery factors. Therefore, it is likely that the host government will end up with significant less oil production and government revenues than could have been the case under a more advanced petroleum arrangement, such as a well designed risk service contract or production sharing contract.

Table 6 shows what a relatively optimistic scenario would be under a technical service agreement.

Table 6
Exploration Venture Results at $ 100 per barrel, 25% higher costs
110% of planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	**($ mln)**	**0**	**3300**	**11000**	**33000**	**3960**
Total Capex	**($ mln)**	**55**	**518**	**1218**	**1905**	**414**
Total Opex	**($ mln)**	**0**	**288**	**730**	**1290**	**232**
Divisible Income	**($ mln)**	**-55**	**2495**	**9053**	**29805**	**3314**
Remuneration Index			**1.78**	**1.30**	**0.82**	
Repayment Oil	**(mln bbls)**	**0**	**12.12**	**21.89**	**27.60**	**7.09**
IRR	**(%)**	neg	**20.3%**	**20.5%**	**20.9%**	**15.0%**
NPV10	**($ mln)**	**-40.7**	**126.6**	**204.2**	**232.9**	**43.2**
PIR10	**ratio**	**neg**	**0.72**	**0.56**	**0.42**	**0.30**
NPV0/BOE	**($/bbl)**	**0.00**	**22.38**	**11.36**	**4.29**	**9.42**
GT0	**(%)**		**70.4%**	**86.2%**	**95.3%**	**88.7%**
GT5	**(%)**		**71.1%**	**86.1%**	**95.0%**	**89.4%**
GR0	**($ mln)**		**1756**	**7803**	**28390**	**2941**
GR5	**($ mln)**		**776**	**3227**	**11182**	**1198**

This table shows how the IOCs end up with exactly the same reward as under Table 5, but the host government receives considerably less revenues and discounted revenues than optimal levels, due to possible inadequate advice and ineffective implementation of the advice of the IOCs.

Kuwait is now trying to overcome these problems through so-called “enhanced technical service agreements”. Under these agreements even higher fees are provided to the IOCs through special bonuses if the advice and implementation happens to be successful.

Nevertheless, these agreements are still in the negotiation stage and it is therefore uncertain how these agreements will work.

2.7. Timing of government take

It should be noted that in order to achieve a 20% IRR in a very short period, the EDP-RSC has to be very generous to the contractor during the first 16 years.

Following table shows the government take during the first 16 years, the remaining years and the total government take for the case that was studied in Table 2.

Table 6. Timing of government take for scenarios of Table 2

	30 million barrels	100 million barrels	300 million barrels
GT0 first 16 years	**36.8%**	**56.3%**	**85.8%**
GT0 remainder	**100.0%**	**100.0%**	**100.0%**
GT0 total	**70.7%**	**86.9%**	**96.0%**

It is clear that the government take during the first 16 years is very generous to the contractors. In fact for the 30 million barrel field and the 100 million barrel field the levels of government take would be very much below competing countries with similar size fields. In other words, the EDP-RSC is really a combination of two components:

- A very generous contract to the private contractor for 16 years with a low government take, plus
- A state controlled remaining period with 100% government take.

It is highly questionable whether providing highly generous terms under service contracts to international oil companies over the next two decades or so, in order to ensure total state control in the long term for exploration acreage, is a good policy for Iraq.

It should be noted that the total state control that is achieved in this way may not be beneficial to Iraq. If the state companies would be relatively inefficient two decades from now, Iraq would give up very considerable government take in the short term in order to create inefficient operations in the long term.

The current status of the economy of Iraq is of a nature that massive government expenditure will be required to bring the Iraq population to a higher level of wealth. To reduce oil income during the next two decades in the new exploration areas in order to achieve the objective of total state control in the long term seems therefore a policy that is not in the national interest.

It is therefore clear that the timing of the government take under the EDP-RSC is highly unfavorable for the host government. Creating overly generous conditions for international oil companies on exploration acreage in the next two decades does

not seem a good policy to maximize the national benefit from the oil and gas resources in Iraq.

2.8. Summary and Conclusions on Exploration, Development and Production Risk Service Contract

Under the EDP-RSC the contractor and the host government are seriously misaligned on most issues. These include:

- **There is no incentive for investors to find large low cost fields, the main driver would be to find high cost small fields**
- **There is no incentive for investors to have low cost operations, in fact there is a strong incentive to have high cost relatively inefficient operations based on poor development plans**
- **There is no incentive to achieve a maximum recovery of the oil and gas and in fact a lower recoverycould be more profitable to the IOCs,**
- **The IOCs have an interest in low oil prices.**

The EDP-RSC would not be considered in the national interests by most host governments because:

- **It does not achieve an optimal level of production with a maximum value of government revenues,**
- **It seriously exposes government to absurdly low government takes if low oil prices would occur after development plans and remuneration rates have been approved, and**
- **It provides for overly generous conditions for the investors in the initial phases of the contract.**

3. KRG PRODUCTION SHARING CONTRACT FOR EXPLORATION, DEVELOPMENT AND PRODUCTION

3.1. Description of the fiscal element of the KRG-PSC

The Kurdistan Regional Government has concluded 30 production sharing contracts in the area under their control. All these contracts have been negotiated individually and are therefore slightly different. The following description is therefore applicable to a typical contract of average fiscal conditions.

Term and Handover Date

The exploration period is 7 years divided in a phase of 3 years, plus two 2 year renewals. The contractor is entitled to two one year further extensions of the exploration period in order to carry out appraisal work. There is also a possibility for a 2 year additional extension for gas marketing work.

In case of a commercial discovery there is a development and production period of 20 years with an automatic extension of 5 years under the same terms and conditions.

If a field is still producing at the end of the extended development and production period, the contract can be extended further for another 5 years. This means that for oil, the total maximum contract period is 39 years and for gas 41 years.

There is no handover date during the term of the contract.

Technical services agreement

There is no technical services agreement following the end of the term of the contract, since it is very unlikely that this will be required.

Cost Contributions

All costs associated with the petroleum operations are to be contributed by the contractor. This applies to all capital and operating costs.

Royalty and Surface Rentals

There are small surface rentals.

There is a royalty of 10% for oil and non-associated gas. The royalty for associated gas is zero.

Cost Recovery

Cost recovery is limited by the KRG Oil & Gas Law to a maximum of 45% of the Available Crude Oil of the contract area and 55% of the Available Non-Associated Natural Gas. Available Crude Oil and Available Non-Associated Natural Gas are the volumes net after deduction of the royalty. Therefore in effect the cost recovery limit is 40.5% of the total oil produced for cost recovery and 49.5% of the non-associated gas. Costs can be carried forward under the cost limits but not beyond the end of the contract.

Profit Oil and Profit Gas

Profit Crude Oil is defined as the Available Crude Oil less the Cost Oil. Profit Non-Associated Natural Gas is defined as Available Non-Associated Natural Gas less the Costs Gas. Profit Crude Oil and Profit Non-Associated Natural Gas automatically increase if costs are less than the cost limits.

The percentage Profit Crude Oil to government is determined on the basis of an R-factor. The R-factor is the ration of the gross revenues received by the contractor divided by the costs incurred by the contractor.

The government share of Profit Oil is 65% to 70% below an R-factor of 1.00, and 84% to 86% over an R-factor of 2.00. Between 1.00 and 2.00, the percentage increases linearly based on the R-factor.

For Profit Gas, the share is 55% below an R-factor of 1.00 for government and 82% for government over 3.00. Between 1.00 and 3.00 the percentage increases linearly with the R-factor.

Government Carried Interest

There is a 20% carried interest by a Kurdistan government company. The timing on when the 20% carry "clicks in" is different under various contracts as well as the duration of the carry. Typically the carried interest clicks in after a commercial discovery.

Third party interest

There could also be a third party interest that is not carried, but that needs to be made available.

Commercial discovery

A commercial discovery is a discovery that is commercial based on industry practice.

Development Plans and Work Programs

Development Plans and Work Programs have to be approved by the Management Committee. Costs can go 10% over budget.

Transport system

Pipelines beyond the contract area can be part of the Development Plan and recordable costs.

Taxation

The Profit Oil and Profit Gas include all taxes.

Economic and fiscal stability

The contract provides for economic and fiscal stability provisions.

Training, Environmental, Technology Transfer and Expat Funding

The contractor shall provide $ 150,000 per year for training during the exploration period, increasing to $300,000 per year for the duration of the contract, with similar payments for environmental assistance to the contract area. The expat placement and recruitment for the first five years is $250,000 and a one-off upfront payment for technology transfer (software, hardware and other similar needs) vary from $1 million to $3 million per contract.

Bonuses and Capacity Building Support

Each PSC includes a contract signature bonus from $1 million to $5 million, plus a capacity building funding for social and other similar projects in the contract area to be paid directly following the signature of the contract, ranging from $20 million for most contracts to much larger amounts in the case of lower risk acreages. Production bonuses to each contract are fixed at around $35 million payable at stages linked to cumulative production.,

3.2.Overall comment on KRG-PSC

In general the KRG-PSC is a traditional PSC, of a relatively modern conception, which establishes a higher benefit for government under more profitable conditions and encourages the development of non-associated natural gas.

3.3.Basic economic analysis of the KRG-PSC

Example

In order to do economic analysis on the KRG-PSC the same example will be analyzed that was used in Chapter 2 for the EDP-RSC. As indicated in Chapter, this example provides for a rather slow exploration phase.

Results

Table 7 provides the complete overview of the economics of the project.

The overall weighted IRR of the exploration venture is 14.7%. Therefore investors will invest in exploration if the have a hurdle rate of 10%.

The profitability for the investor goes up strongly with the field size. The IRR, NPV10, PIR10 are all strongly higher in case of a more attractive discovery. The NCF/BOE is slightly lower for the larger fields due to the effect of the R-factor.

Table 7
Exploration Venture Results at $ 100 per barrel

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3000	10000	30000	3600
Total Capex	($ mln)	44	314	704	1124	251
Total Opex	($ mln)	0	180	440	720	138
Divisible Income	($ mln)	-44	2506	8856	28156	3211
IRR	(%)	neg	14.7%	20.4%	30.6%	14.7%
NPV10	($ mln)	-47.5	46.1	202.8	699.4	46.1
PIR10	ratio	neg	0.38	0.83	1.90	0.38
NPV0/BOE	($/bbl)	0.00	13.56	13.34	13.05	12.27
GT0	(%)		83.8%	84.9%	86.1%	86.2%
GT5	(%)		86.2%	85.6%	85.9%	88.0%
GR0	($ mln)		2099	7522	24240	2769
GR5	($ mln)		972	3164	9849	1170

The undiscounted government take indicates ranges from 83.8% for the 30 million barrel field to 86.1% for the 300 million barrel field. The 5% discounted government take is higher for the small and medium sized fields, but slightly lower for the large field than the undiscounted values. This is due to the fact that the R-factor defers the higher percentages to later years. In general the government take is relatively “flat”. The progressive effect of the R-factor is absorbed by the regressive effect of the royalties and bonuses.

The difference between the GT0 for the large field and the small field could have been higher. The GT5 of the small field should have been lower than for the large field, rather than being slightly higher.

The undiscounted or discounted government revenues go up disproportionately with the field size, as can be expected, but the relative disproportionate increase for the large field is somewhat modest.

The KRG-PSC strongly aligns the interests of the investor and the government in terms of exploration objectives. The investor has a strong interest in finding large and low cost fields and so does the government. The investors will undertake every effort to find the largest and most profitable fields.

However, the government take is somewhat too "flat" with respect to variation in field size.

3.4.Sensitivity with respect to costs

An important issue is how the KRG-PSC would react to higher costs.

For instance, what would be the results of a larger exploration program in order to discover the first field and generally 125% higher costs per barrel than assumed in Table 7.

Table 8 illustrates the results for this analysis.

Table 8
Exploration Venture Results at $ 100 per barrel and 25% higher costs

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3000	10000	30000	3600
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	225	550	900	173
Divisible Income	($ mln)	-55	2383	8570	27695	3114
IRR	(%)	neg	12.9%	18.2%	28.1%	13.2%
NPV10	($ mln)	-55.7	32.6	182.7	682.8	34.7
PIR10	ratio	neg	0.21	0.60	1.49	0.28
NPV0/BOE	($/bbl)	0.00	13.89	13.64	13.21	12.34
GT0	(%)		82.5%	84.1%	85.7%	85.7%
GT5	(%)		86.1%	85.3%	85.6%	88.1%
GR0	($ mln)		1966	7206	23731	2670
GR5	($ mln)		908	3014	9600	1123

The IRR, NPV10 and PIR10 are now all well below the values of Table 7.

This means that the higher cost lead to a project that is considerably less profitable, as it should be.

Nevertheless, the government revenues are still considerably lower. In fact the $ 286 million loss in divisible income now results in a loss of $ 316 million in loss of government revenues. This means for every dollar cost increase the government looses $ 1.10 in government revenues. This is slight "gold plating". This means that the R-factor is somewhat too sensitive and therefore this aspect of the fiscal terms could have been better from a structural fiscal point of view.

Nevertheless, the slight gold plating is not so strong that it will result in sub-optimal development plans. Investors are strongly induced to seek the highest possible production for the lowest possible costs.

The KRG-PSC system aligns the interests of the investor and the host government in terms of cost efficiency. Both parties have an interest in achieving the lowest possible costs. Nevertheless, the incentive for investors to be efficient could have been somewhat stronger.

3.5.Sensitivity with respect to oil prices

The sensitivity to oil prices is illustrated in Table 9.

Table 9
Exploration Venture Results at $ 60 per barrel and 25% higher costs

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	1800	6000	18000	2160
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	225	550	900	173
Divisible Income	($ mln)	-55	1183	4570	15695	1674
IRR	(%)	neg	7.3%	12.2%	20.8%	8.4%
NPV10	($ mln)	-55.7	-28.0	45.1	343.3	-15.1
PIR10	ratio	neg	-0.18	0.15	0.75	-0.12
NPV0/BOE	($/bbl)	0.00	7.30	8.59	8.05	6.98
GT0	(%)		81.5%	81.2%	84.6%	85.0%
GT5	(%)		92.0%	85.3%	85.2%	91.3%
GR0	($ mln)		963	3711	13281	1422
GR5	($ mln)		448	1538	5308	595

The drop in oil prices results in a considerable decline of the profitability of the venture for the investor. All profitability indicators are now significantly lower. In fact on a fully risked basis this project would be unattractive as an exploration project.

It is obvious that both the investor and government are strongly aligned in the matter of price. Both parties strongly favor a higher price.

However, the loss in government revenues as a result of a one dollar price drop is $ 0.87. This means that the project becomes rapidly less profitable under lower prices. In this case the government take could have declined somewhat more.

The government take is also somewhat too "flat" as a result of price variation. This means a large variation in price creates only a minor variation in undiscounted government take. This results in a situation whereby under low prices, the government take is well protected, but the projects could become unattractive. Under very high prices, the government take becomes low and the government leaves too much on the table.

It should be noted that most PSC's today do not protect the host governments very well under high prices over $ 60 per barrel. So this is certainly not a unique feature for the KRG-PSC.

3.6. Sensitivity with respect to recovery of oil

Under the KRG-PSC the contractor has a contract over the entire life of the possible oil field.

Therefore the investor has a strong interest in achieving the maximum possible recovery of the oil.

Table 10 illustrates the case of the poor development plan that was also evaluated in Table 4. The NPV10, PIR10 and IRR all decline if the contractor has a poor development plan and recovers less oil.

Table 10
Exploration Venture Results at $ 100 per barrel, 25% higher costs and 90% of the planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	2700	9000	27000	3240
Total Capex	($ mln)	55	393	880	1405	314
Total Opex	($ mln)	0	203	495	810	173
Divisible Income	($ mln)	-55	2105	7625	24785	1674
IRR	(%)	neg	12.4%	17.8%	27.9%	12.7%
NPV10	($ mln)	-55.7	26.0	165.6	644.0	28.8
PIR10	ratio	neg	0.17	0.54	1.40	0.23
NPV0/BOE	($/bbl)	0.00	13.98	13.87	13.44	12.41
GT0	(%)		82.1%	83.6%	85.4%	85.5%
GT5	(%)		86.2%	85.0%	85.3%	88.2%
GR0	($ mln)		1727	6377	21155	2369
GR5	($ mln)		814	2713	8764	1017

The government revenue losses are also considerable. However, for every dollar loss in terms of divisible income, the government looses $ 0.88 and the contractor $ 0.12. Therefore, both parties have an interest in achieving the highest optimal recovery that is consistent with good conservation practices.

Table 11 provides the overview of the case where 130% of the original planned recovery is achieved.

Table 11
Exploration Venture Results at $ 100 per barrel, 25% higher costs 130% of planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3900	13000	39000	4680
Total Capex	($ mln)	55	518	1218	1905	414
Total Opex	($ mln)	0	293	715	1170	224
Divisible Income	($ mln)	-55	3090	11068	35925	4041
IRR	(%)	neg	13.9%	19.5%	28.9%	14.3%
NPV10	($ mln)	-55.7	49.3	237.6	800.9	52.1
PIR10	ratio	neg	0.29	0.66	1.48	0.37
NPV0/BOE	($/bbl)	0.00	13.57	13.27	12.57	12.13
GT0	(%)		82.9%	84.4%	86.4%	86.0%
GT5	(%)		85.7%	85.3%	86.2%	87.8%
GR0	($ mln)		2561	9342	31023	3474
GR5	($ mln)		1128	3799	12084	1409

The NPV10, PIR10 and IRR are all higher than in Table 8. This means that the investor will have a strong interest to fully pursue the highest possible recovery and apply the best possible technology in order to achieve these objectives.

The government is the mean beneficiary of this higher level of recovery through significantly higher government revenues.

As discussed above, the investor also has an incentive to achieve the lowest possible costs. Therefore, rather than having 25% higher costs the investor would try to achieve the planned costs or even lower costs. Table 12 provides the overview if the investor achieves the higher recovery on the basis of the planned costs.

Table 12
Exploration Venture Results at $ 100 per barrel and 130% of planned recovery
130% of planned recovery

		Dry Hole	30 MM	100 MM	300 MM	Project
Gross Revenues	($ mln)	0	3900	13000	39000	4680
Total Capex	($ mln)	55	414	974	1524	332
Total Opex	($ mln)	0	234	572	936	179
Divisible Income	($ mln)	-55	3252	11454	36540	4169
IRR	(%)	neg	15.6%	21.5%	31.4%	15.7%
NPV10	($ mln)	-55.7	61.4	248.8	821.0	62.1
PIR10	ratio	neg	0.45	0.87	1.90	0.56
NPV0/BOE	($/bbl)	0.00	13.02	12.63	12.50	11.88
GT0	(%)		84.4%	85.7%	86.7%	86.7%
GT5	(%)		86.2%	86.1%	86.4%	88.0%
GR0	($ mln)		2744	9813	31666	3613
GR5	($ mln)		1213	4012	12388	1473

Again the NPV10, PIR10 and IRR are considerably higher than in Table 11 and therefore the investor has not only an interest in the highest possible recovery, but also to achieve this at the lowest possible costs.

The investor and the host government are fully aligned to create the best possible development plan and achieve the highest possible oil recovery, that is consistent with good conservation practices, at the lowest possible costs.

3.7. Timing of government take

The KRG-PSC provides for an encouragement of a somewhat lower government take in the first 16 years of the cash flow due to the R-factor, which in the early years provides for a lower percentage profit oil.

However, Table 13 shows that the early incentive is modest. KRG does not loose very significant revenues in the early years.

Table 13. Timing of government take for scenarios of Table 8			
	30 million barrels	**100 million barrels**	**300 million barrels**
GT0 first 16 years	**80.3%**	**78.0%**	**78.6%**
GT0 remainder	**84.4%**	**86.7%**	**88.5%**
GT0 total	**82.5%**	**84.1%**	**85.7%**

This means that Iraq would benefit immediately and fully from the revenues generated by the fields discovered in the Kurdistan Region.

The timing of the government take under the KRG-PSC is reasonable and creates immediate benefits for Iraq as soon as production starts.

3.8. Summary and Conclusions on Production Sharing Contract of the Kurdistan Regional Government.

Under the KRG-PSC the contractor and the host government are fully aligned on all economic issues. These include:

- **There is a strong incentive for investors to find large low cost fields,**
- **There is an adequate incentive for investors to have low cost operations**
- **There is a strong incentive to achieve a maximum recovery of the oil and gas from the reservoirs that is consistent with sound conservation practices, and**
- **The IOCs have an interest in high oil prices.**

The KRG-PSC would be considered in the national interests by many host governments because it does provides the framework for an optimal level of production and recovery of oil and gas from the reservoirs while creating a high value of government revenues.

Nevertheless, from a fiscal design perspective, the KRG-PSC is not optimal. The contract could have been somewhat improved structurally through:

- **Creating a larger variation in government take between small and large fields,**
- **Creating a larger variation in government take between low and high oil prices, and**
- **Providing stronger incentives to IOCs to be efficient.**

It should be noted that under current oil price conditions many PSC's in the world are sub-optimal and do not provide an adequate range in government take between low and high oil prices.

4. COMPARISON BETWEEN THE MOO AND KRG CONCEPT FOR EXPLORATION, DEVELOPMENT AND PRODUCTION IN THE KURDISTAN REGION

The most important test of the comparative fiscal design is which system will result in the highest value of government revenues. In this report the value is assessed using a 5% discount rate in real terms ("GR5").

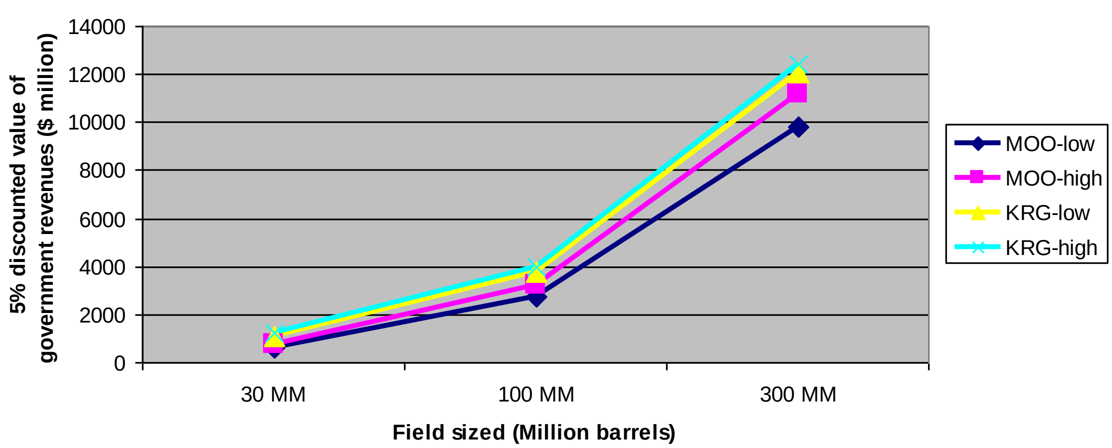
Under the EDP-RSC, the investors have a very strong incentive to incur the highest possible costs. Therefore, it is certain that under this regime IOCs will propose development plans that are more costly than the alternatives. It is therefore that we need to use the data based on a 25% higher cost for analysis.

Under the EDP-RSC, the ultimate government revenues are entirely dependent on the level of oil and gas recovery that the NOC obtains after the hand over date as a result of the state controlled operations. In this respect it can be estimated that the NOC may achieve between 90% and 110% of the originally planned recovery under the initial development plan. The GR5 results of Table 4 and 6 therefore reasonably reflect the discounted revenues that Iraq can expect under this concept.

Under the KRG-PSC, the IOCs have a strong incentive to propose the best development plans resulting in the highest overall recovery at the lowest possible costs. Therefore, the GR5 values of Table 11 and 12 reflect reasonable values that Iraq can expect based on this production sharing contract.

Chart 3 provides a comparison of the two regimes assuming that the MOO contract options and the KRG contract options would both start January 1, 2009.

Chart 3. Value to Iraq of government revenues under MOO and KRG concepts assuming all contracts would start Jan 1, 2009



It is abundantly clear that for the entire range of field sizes considered in this report, the GR5 values based on the MOO concept are far inferior compared to the KRG concept.

Relative to the KRG concept the MOO concept could result in staggering losses for Iraq. For fields of about 30 million barrels, about half the value of the government revenues would be lost, or close to $ 600 million per field. For fields of about 100 million barrels about 30% of the value would be lost or about $ 1,200 million per field. For fields of 300 million barrels about 20% of the value would be lost or about $ 2,500 million per field. This is based on $ 100 per barrel. The losses would be higher under higher prices.

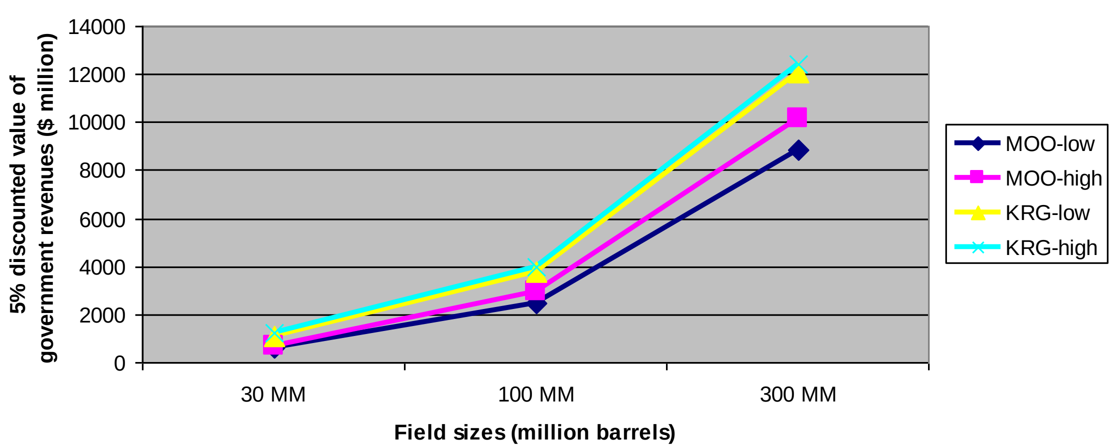
It is not known what the success of the exploration in the KRG will be, but if about 100 fields would be discovered in field size ranges from 30 to 300 million barrels, the total losses in the value of government revenues of the MOO concept to Iraq could exceed $ 120 billion in present value (to January 1, 2009) based on a price of $ 100 per barrel at the field delivery points.

Of course, by relying on the rights defined under the Iraq constitution, and the regional oil and gas law, KRG has already moved forward. There would be considerable delays if the same area would be developed under the MOO concept.

Even if the new petroleum law would be approved during 2009 and MOO would start a bid process in 2009, it is likely that there would be at least a two year delay in the granting of the contracts due to the relatively slow bid process preferred by MOO.

Chart 4 shows the results if the delay is included in the calculations.

Chart 4. Value to Iraq of government revenues under MOO and KRG concepts assuming a two year delay in MOO contracts



For the small 30 million barrel fields the losses are now well over half. For the 100 million barrel field the losses are almost 40% or $ 1,500 million per field and for the 300 million barrel field the losses are almost 30% of $ 3,500 million per field.

On a total 100 field discovery basis (assuming a potential of 10 billion barrels of oil) the total present value loss for Iraq of the MOO concept would be about $ 150 billion.

It is worth noting that KRG assume a total oil potential of around 30 billion, in which case the present value loss would be 3 time larger ($450 billion) under the MOO proposed regime.

It should be noted that this assessment is very conservative, since it is based on the relatively slow exploration program provided as an example. Under the MOO concept companies are induced to have a slow program. However, under the KRG concept IOCs have a strong interest in moving as fast as possible. Therefore, the effect of faster possible exploration results and faster developments under the KRG concepts is not captures in the above assessment and these matters would greatly increase the losses to Iraq.

There is therefore no doubt that applying the EDP-RSC concept to the Kurdistan Region would be disastrous for Iraq from the point of view of the maximization of the value of government revenues from oil and gas, compared to the current ongoing implementation of the KRG-PSC's.

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