Evaluation of the Economic Performance of International Exploration & Production Contracts

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[Re-edited below in 2005 by David Wood the article still retains much relevance to international E&P contracts]

This economic appraisal of 20 global exploration and production contracts identifies and explores the key variables that affect returns to Governments and International Oil Companies (referred to here as the "contractor"). The contracts shows a large diversity in their structure and in the post-tax profits a company can expect to receive from production controlled by them.

A systematic method for evaluating and comparing contract performance enables the relative importance of the key variables responsible for profit levels under the terms of a specific contract to be clearly identified.

Factors that limit a company's profits in a contract, such as cost recovery allowance, a government's right to back-in for an extra share of production, or an additional tax, can be modelled for the purposes of contract negotiation or project evaluation using the techniques reviewed.

The results of the evaluation are presented graphically in order to provide a simple but comprehensive frame of reference against which the performance of other contracts may be compared. E&P contract terms, combined with a number of other factors, determine the profit-ability of a project.

The reserves, costs to develop, production rates, operating and transport costs, oil and gas prices, and risks (exploration and political) associated with a project are the main factors that govern its profitability under the terms of the E&P contract.
A poor contribution by any one of these component factors can make a project uneconomic regardless of the quality of the other factors.
This analysis should be specifically useful to companies in the process of expanding internationally but without access to the detailed contract terms of many countries or computer models with which to evaluate them.

Contracts evaluated

Twenty contracts currently in operation or recently terminated have been used as the database for this study. Each has been assigned a letter from A to T. This database of contracts includes six from South America, five from Africa, four from the Middle East, four from the Far East, and one from Europe. [The contract countries were not specifically identified in the original article].

Contract symbols in the presented figures are:

A =UK (pre-1993)	B = Ras al Khaimah (UAE)
C = India	D = Somalia
E = Argentina	F = Papua New Guinea
G = Chile (1)	H = Chile (2)
I = Ethiopia	J = Benin
K = Colombia (1)	L = Colombia (2)
M = Oman	N = Libya
O = Vietnam	P = Cameroon
Q = North Yemen	R = South Yemen
S = Bolivia	T = Malaysia

Based on their fiscal structures these contracts can be subdivided into two main types, taxation driven and production driven, and seven sub-types as follows:

1. Taxation driven
1a. Double taxation system with the liability to one tax controlled by the cumulative revenue to cumulative expenditure ratio, as in Contract A.

1b. Double taxation system with the liability to one tax controlled by the contractor's rate of return calculated annually over the life of the project, as in contracts F and D.

2. Production driven
2a. Production splits are fixed, or varied on a sliding scale according to daily flow rates, and the contractor pays no income tax, but in some cases a fixed royalty is taken from gross production. These terms apply in contracts J, M, 0, R, and S. The production split for Contract M is one fixed percentage regardless of production rates, etc.

2b. Production splits are fixed, or varied on a sliding scale according to daily flow rates, the contractor pays income tax on its profits, and in some cases a fixed royalty is taken from gross production. These terms apply in contracts B, E, G, H, I, K, Q, and T. The production splits for contracts E and K are one fixed percentage regardless of production rates, and so on, although in the case of Contract E this can vary from field to field.

2c. Production splits vary according to the contractor's cumulative revenue to cumulative expenditure ratio, with the contractor's share of production then being exempt from taxes, as in contracts N and P.

2d. Production splits vary according to the contractor's rate of return calculated annually over the life of the project, with the contractor's profits additionally being subject to income tax, as in Contract C.

2e. Production splits vary according to the cumulative volume of reserves produced, with the contractor's profits additionally being subject to income tax, as in Contract L.

There are two other specific characteristics of the contracts that are relevant to the results of this evaluation and can also be used to group and compare some of the contracts.

3. Those contracts in which the respective government or state oil company has the obligation to pay a share of development and operating costs. In some cases this is an option rather than an obligation.

3a. Government pays more than 30% of capital and operating costs, as in contracts C, E (in certain cases) H, K, L, N, and P. In the case of Contract C this is optional as part of a back-in.

3b. Government pays less than 30% of capital and operating costs, as in contracts E (in certain cases), F, G, I, S, and T. In contracts F, I, and S this is optional.

For this evaluation, in those contracts where the state oil company has the option to back-in to part of the contractor's share of production by paying a proportionate share of the costs, it is assumed that this option is exercised.

4. Those contracts in which the maximum allowance of production from which development costs incurred by the contractor can be recovered is limited to 50% or less in any year, as in contracts N, 0, P, Q, R, S, and T.

It should be understood that although the fiscal structures of the 20 contracts studied are representative of the international contracts being signed by the oil industry, other contracts exist and will undoubtedly be developed in the future that do not fall into any of the sub-groups outlined above.

Thus the above sub-division is designed for the contracts considered in this study and not as a comprehensive classification scheme for international exploration and production contracts.

Evaluation methods

The type of evaluation procedure required depends to some extent on the overall objectives of the study required.

The ***most common objectives*** for such studies are:

A. To compare a new venture contract with those in an existing portfolio.

B. To establish the terms to be sought for an E&P contract being negotiated with a state authority.

C. To value and / or rank a portfolio of E&P contracts and prospects in order to select a drilling order.

D. Evaluate farm-in or farm-out projects.

For objective A the main steps of the evaluation procedure required are as follows:

1) ***Construct a computer model*** to combine petroleum production profiles, expenditure profiles, and the fiscal structure of each E&P contract in order to generate a post-tax cash flow for the contractor.
The cash flow calculated needs to be post-tax as the income tax rates and allowances vary significantly from contract to contract.

2) ***Analyze the cash flows*** produced in 1) by calculating a suite of relevant economic indicators discounted at various percentages where applicable.

In practice steps 1 and 2 would be calculated within the same computer model.
One method of doing this is to use commercially available spreadsheet software. It is possible with only limited experience to produce in a matter of hours a spreadsheet model for some of the most complex contracts.

Because of the diversity in the structures of E&P contracts it is the author's preference to develop a separate spreadsheet for each E&P contract rather than use complex coded programs that attempt to cope with all the different possible contract structures in a single package. However, some all-embracing programs are commercially available, widely used, and also capable of producing the similar analysis.

3) Use the computer model to ***evaluate a set of hypothetical model "oil fields"*** each with selected reserves, production profiles, and cost profiles that evaluate specific attributes of the E&P contracts.

In this study three field sizes are used, with recoverable reserves of 15 million, 50 million, and 350 million bbl of oil. The details of these fields are listed (Table 1).

In practice there are advantages to considering some additional model oil field sizes between 50 million and 350 million bbl, especially when evaluating contracts in which production splits are dependent upon thresholds of production rate or reserves produced.
It is for brevity that they are excluded here. The two smaller "fields" were selected to test the lower end of the production split scales (where applicable) with peak production rates of 6,600 b/d and 20,000 b/d.

These fields have been assigned high capital and operating expenditures in order that they test the cost recovery mechanisms of the E&P contracts.
The large field has been assigned a peak flow rate of nearly 120,000 b/d to test the complete production split scale in most contracts.

As a simplification only oil fields are considered in this comparison.

Table 1

Model Oil Field Specifications

Base Case Assumptions	15MMB	50MMB	350MMB
Flow rate bopd/well	350	1000	2500
Well decline %/yr	20%	20%	20%
Peak Production bopd	6600	20000	117500
Number of Wells	20	20	47
Year of Peak Oil	6	6	8
Production Startup	3	3	4
Years of Production	13	14	18
Total Capex $mm ($Yr1)	69	181	462
Total Capex $/bbl ($Yr1)	4.6	3.62	1.32
Total Opex $mm ($Yr1)	54	176	787
Total Opex $/bbl ($Yr1)	3.6	3.52	2.25
Total Opex $mm (mod)	83	278	1436
Total Opex $/bbl (mod)	5.53	5.56	4.10
Inflation Rate Costs (%/yr)	5%	5%	5%
Oil Price in Year 1 ($/bbl)	18	18	18
Oil Price Capped ($/bbl)	30	30	30
Oil Price escalation (%/yr)	5%	5%	5%

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Base case costs, production rates, and product prices for each model field size are applied consistently to each set of fiscal terms. Operating costs are split into a fixed annual component (~5% of total Capex) and a variable component of $1/barrel.
[***author note 2005***: The 1990 cost assumptions are comparable with 2003 assumptions except for high base case inflation and escalation rates – 2.5% would be a better assumption in 2005. The long run price of oil between US$18 and US$30 / barrel in nominal terms is in line with assumptions used by many major companies]

4) *Carry out a sensitivity analysis* for each field size and each E&P contract using the computer program and vary the key input parameters of the base case field models by specific percent-ages.

Using a modern computer it is possible to run thousands of sensitivity cases for each variable. However, if the sensitivity cases are carefully selected, it is possible to obtain almost the same results using some 20 cases for most contract structures.

The key input parameters that have been varied in this study are: capital expenditure, operating expenditure, inflation rate for capital and operating expenditures, oil price through production period, flow rate of the wells, and time of production start-up.
In this study for each E&P contract and field size a base case and 18 sensitivity cases were run (Table 2). For 20 contracts and three field sizes this amounts to 1,140 cases.
The values of five key economic indicators were recorded for each case, and if a range of discount factors had been used this number could easily have doubled. Thus, even the modest sensitivity analyses presented require the generation and synthesis of more than 5,000 numbers.

Table 2

Economic Cases Evaluated for Sensitivity Analysis of Fiscal Terms					
Metric	**Very Low**	**Low**	**Base Case**	**High**	**Very High**
Rate of Inflation	I-100%	I-50%	I	I+50%	I+100%
Operating Costs	O-50%	O-25%	O	O+25%	O+50%
Capital Costs	C-50%	C-25%	C	C+25%	C+50%
Oil Price		$18/bbl flat (no escalation)	$18/bbl + 5% /year escalation to ceiling of $30/bbl	$20/bbl + 5% /year escalation	
Rate of Production		P-25%	P	P+25%	
Start of Production		S-1 year	S	S+1year	

Such sensitivity analysis enables means, ranges and other performance statistics of selected economic yardsticks to be calculated and analyzed for each set of contract terms.

5) ***Establish the values of key input parameters that are required to generate specific values of key economic indicators*** for each E&P contract and field size using the computer model.

As with the sensitivity analysis of the input parameters there is an infinite number of cases that can be run. In this study the author has one as an example, i.e., the ***oil price in dollars per barrel required to provide investor's rate of return of 15% for each field size and E&P contract***.

6) ***Analyze the results*** calculated for the key economic indicators statistically and graphically to relate trends in these indicators to specific aspects of the fiscal structures of the E&P contracts studied.

7) ***Select the graphical illustrations*** of the economic indicators most suited for the contract and-or prospect evaluation objective being performed.
For objective B the evaluation procedure is almost the same as for A except that an additional sensitivity analysis would be performed on the negotiable fiscal terms. For objectives C and D the hypothetical fields of step three of the procedure for objective A are replaced by real prospects or fields, and a new step 4 would be introduced consisting of risk analysis.

Also the sensitivity analysis of input parameters could either be replaced or supplemented with a Monte Carlo simulation, as the range of uncertainties associated with the input parameters of each prospect should be established well enough to express as probability distributions. Some additional risk weighted economic indicators (including certain cash flow to investment ratios) become of value for objectives C and D.

For objective D a final step of sensitivity analysis is required to establish what acquired or farmed out interest in a project optimizes the appropriate economic indicators.

The evaluation presented here concentrates initially on objective A, but touches on aspects of objectives B, C, and D in order to clarify the relative importance of contract terms to the economic analysis with those objectives. In establishing the relative performance of E&P contracts using the above methodology it is accepted that some of the assumptions are somewhat artificial and designed for the ideal world. For example, in all cases it is assumed that the contractor has no sunk costs or other past expenditures in a concession or country that can be used to reduce his tax liabilities under an E&P contract. Moreover, it is assumed that there is a similar tax treaty in effect between the country of each contract and the country in which the parent company of the contractor is registered and liable for taxes.

In the real world this is not the case and, regardless of the relative performance of the contracts, for a particular contractor such additional factors could make contracts in one area more favorable than another despite them having a poorer economic performance in terms of fiscal structure.

Also it is clear that model fields do not reflect the real world, except by chance, for most contract areas. For example, an oil field of a particular reserve size would have very different capital, operating, and transportation cost profiles depending on the geographic location of both field and contract area, the depth and flow rates from the reservoir, and the distance from existing infrastructure and markets.

Thus, evaluating the economic results generated for a set of contracts with model field sizes can only be the first step in establishing the true performance of each contract.

The next step is to evaluate each contract with a field size and cost, production and tax profiles appropriate for the contract area and the contractor. This will provide a better idea of the real value of the contract terms and lead on to the analysis of real prospects and-or fields in the contract area. Notwithstanding the above, evaluating contracts with model fields is the only way to obtain an objective comparison of the economic performances of a set of contracts.

Economic comparison results

Here are results of such an analysis on the set of 20 international contracts referred to in the first part of this article.

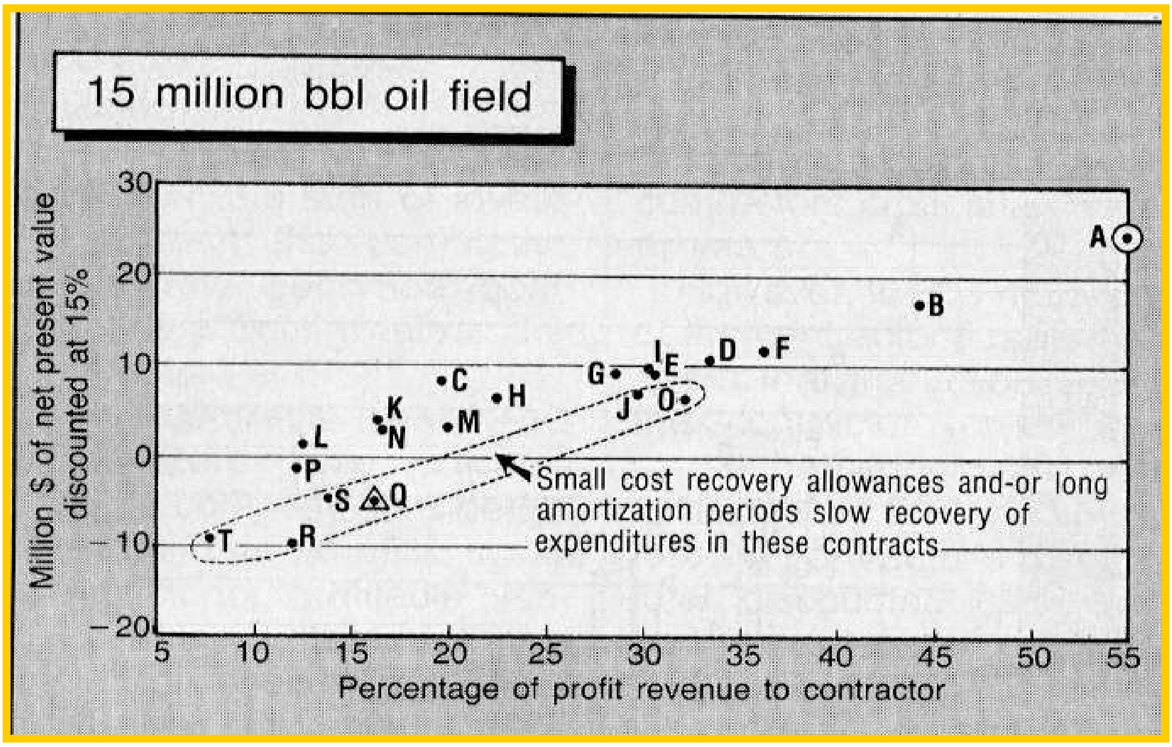
Key Indicator cross-plots

The net present value discounted at 15% (NPV-15%) is plotted against the percentage of post-tax profit revenue to the contractor using the base case field parameters (Table 1) for each contract.

[**Author note:** 15% discount rate used in 1990 is significantly higher than that used by most oil companies in 2003 – a 10% rate would be more appropriate in 2005]

The 15 million bbl oil field (Fig. 1a) shows good positive correlation between these two economic indicators.

Fig. 1a



The variation among the contracts is remarkably high; the percentage profit revenue to the contractor varies from about 7.5% to 55%. There is also extensive variation recorded by all other commonly used economic indicators.

Those contracts with poor cost recovery mechanisms have been circled to show that they plot below the main trend. This demonstrates that for a given percentage of profit to the contractor such contracts provide the contractor with a lower NPV-15% than contracts with better cost recovery provisions.

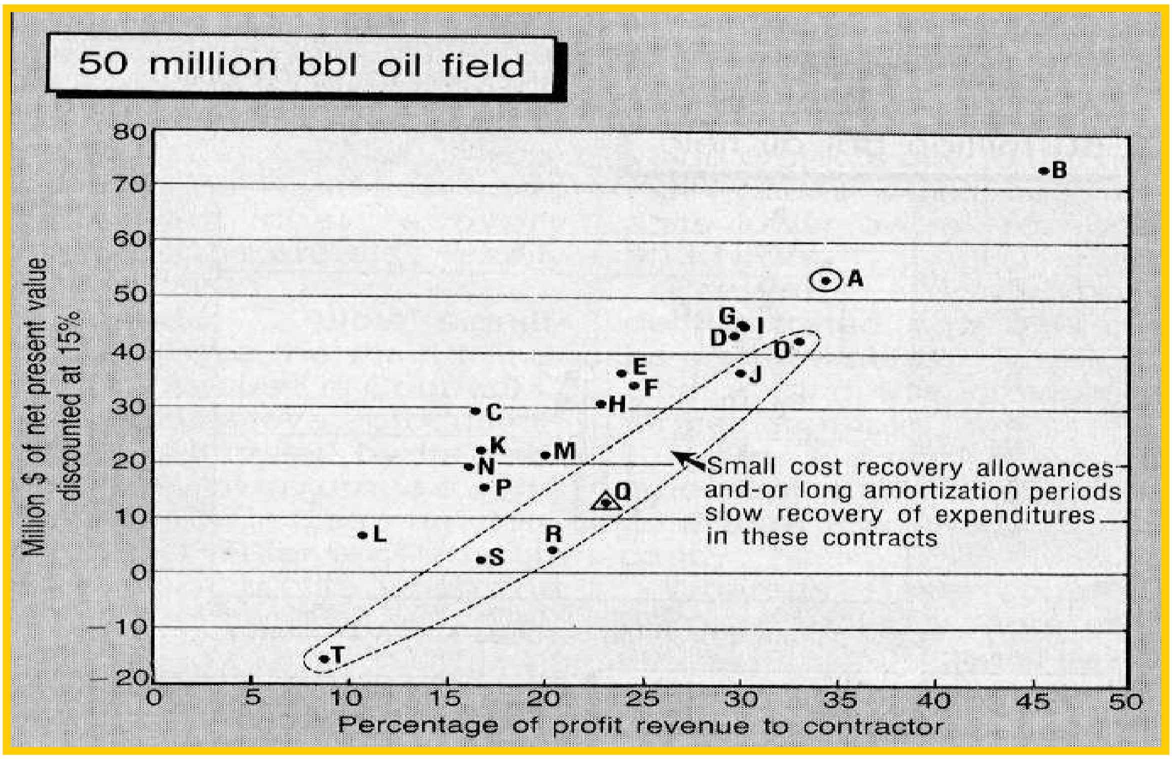
Although the contractor gets a certain percentage of profits, he gets it later with the poor cost recovery contracts. Hence when the time-value of the profits is considered, by economic indicators such as NPV, investor's rate of return (IRR) etc., this relatively late payout is distinguished.

The payout time in years - time from the start of investment until the cumulative cash flow becomes positive—also discriminates such contracts.

Five contracts have NPVs below zero. This indicates that if a company considers a discount rate of 15% as its yardstick for profitable ventures, this 15 million bbl field would be uneconomic under those five contracts.

Fig. 1b for the 50 million bbl field shows a similar trend, but only one contract distinguishes the field as uneconomic. The same contracts with poor cost recovery mechanisms are also readily distinguished.

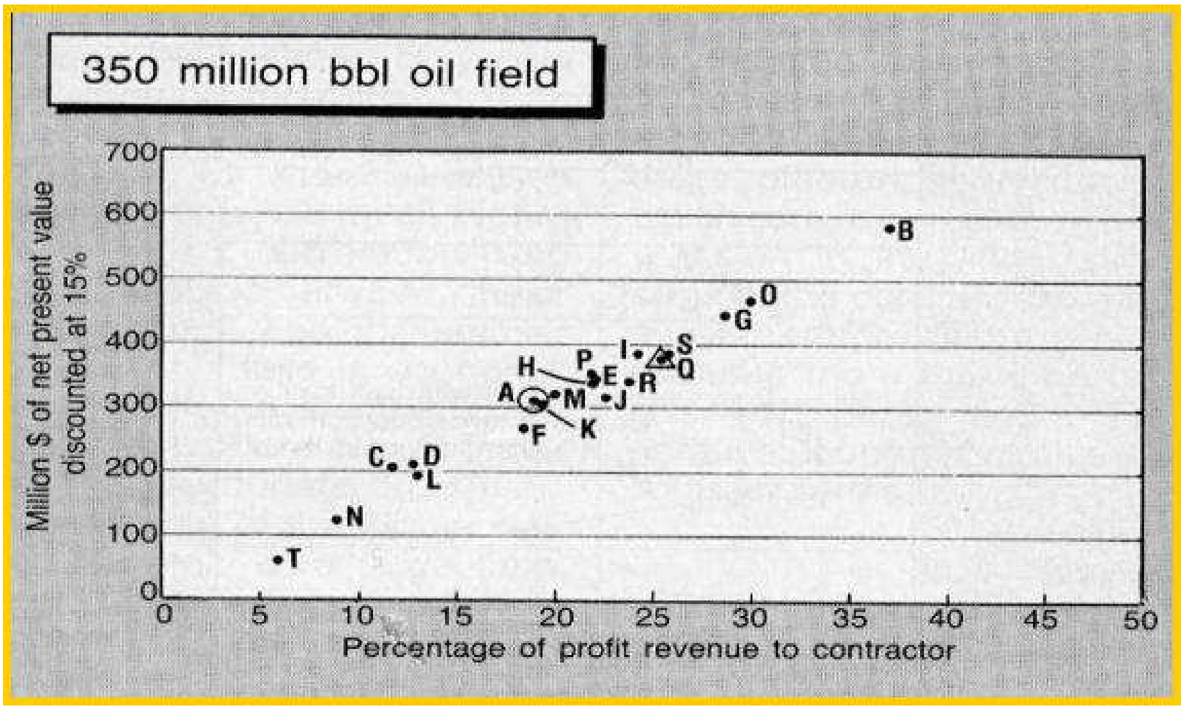
Fig. 1b



Contract C plots significantly above the main trend. This is because in Contract C the contractor's production split is controlled by its periodic rate of return; i.e., the contract optimizes the contractor's IRR for a given percentage of profits when the IRA of the project is less than30%. This also has the effect of providing the contractor with a higher NPV relative to its percentage share of profits than other contracts in such cases.

Fig. 1c for the 350 million bbl field shows a much higher degree of correlation and less scatter between these parameters than the smaller fields. This field is economic under all the contracts assuming a 15% discount factor is the appropriate threshold.

Fig. 1c



Because of the higher revenue levels of a large field, costs can be recovered in an adequate time frame, even using those contracts with poor cost recovery provisions. Consequently the poor cost recovery contracts are not distinguished from the main trend on this graph. This demonstrates that the cost recovery allowance is most important for fields with a low revenue-high cost ratio.

Contract C is also not distinguished from the main trend. It is distinguished on a plot of IRR vs. percent profit revenue (not shown here), because the contract provides the contractor with its greatest profit share early in the production history but then dramatically reduces the contractors profit share in later years.

However, for the major part of the contractor's production share the production split to the contractor is low, because the periodic rate of return is above 30%, and therefore the contractor's revenue, total discounted cash flow, and percentage of profit revenue are reduced.

Contract C is a good example of where using IRR as the only economic indicator a company might tend to overvalue projects due to the high IRR values calculated, despite lower overall revenues and NPVs. Previous studies have demonstrated how IRR can be an unreliable economic indicator, and this provides a further example.

In Fig. 1 a to 1c, it is of interest to note that the order of the contracts changes significantly. Whereas some contracts become relatively more profitable for the larger fields, such as G and Q, others become relatively less profitable, such as A, F, and D— the taxation driven contracts. Contracts Q and A are highlighted to emphasize these different relationships, which are due to the large variation in the fiscal structures of the contracts studied. It is therefore important to evaluate more than one field size when performing a comparative economic analysis of contract terms.

Data reduction

For interpretation it is necessary to reduce the quantity of numbers involved in the sensitivity analysis of the input variables in a statistically meaningful way.
Hence an arithmetic mean and a standard deviation for each economic indicator have been calculated for the 19 cases (1 base case plus 18 sensitivity cases) run for each field size and contract evaluated.

Due to the symmetrical design of the sensitivity analysis performed—the input parameters are varied by about the same positive and negative percentages from a base case—the calculated means are very close to the respective base case values.
However, the spread of data about the means, given by the standard deviations is a good indication of how sensitive the respective contracts are to the input variables used.

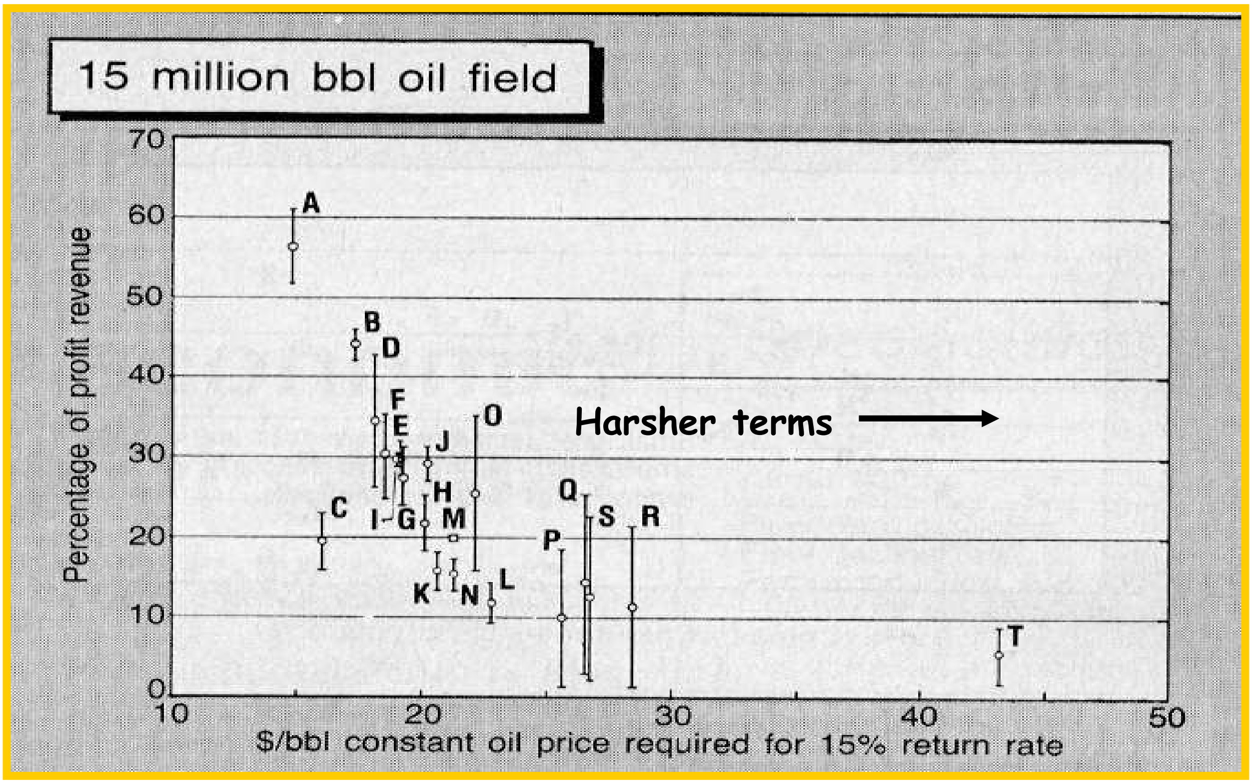
Fig. 2a to 2c illustrate for the 15 million, 50 million, and 350 million bbl fields, respectively, the arithmetic mean (dot) plus and minus one standard deviation (bar) for the percentage of post-tax profit revenue to the contractor. The x axis in these graphs is the constant oil price value (US$/barrel) required to provide the contractor with an IRR of 15% for the base case field input parameters (Table 1). This provides a synthesis of the results of the sensitivity analysis performed on both input parameters and economic indicators.

These graphs are particularly instructive about the relative economic viability of the contracts for specific field sizes. They also indicate those contracts in which the greatest uncertainties exist in the level of contractor profits to be expected.
A reasonable negative exponential correlation exists between these parameters for the 15 million bbl field.

Contract C falls below the main trend for reasons explained above.

This field is only economic, assuming a 15% IRR threshold, with eight contracts for a constant oil price of $20 /bbl. The field becomes economic with 15 contracts for a constant oil price of $23/bbl.

Fig. 2a

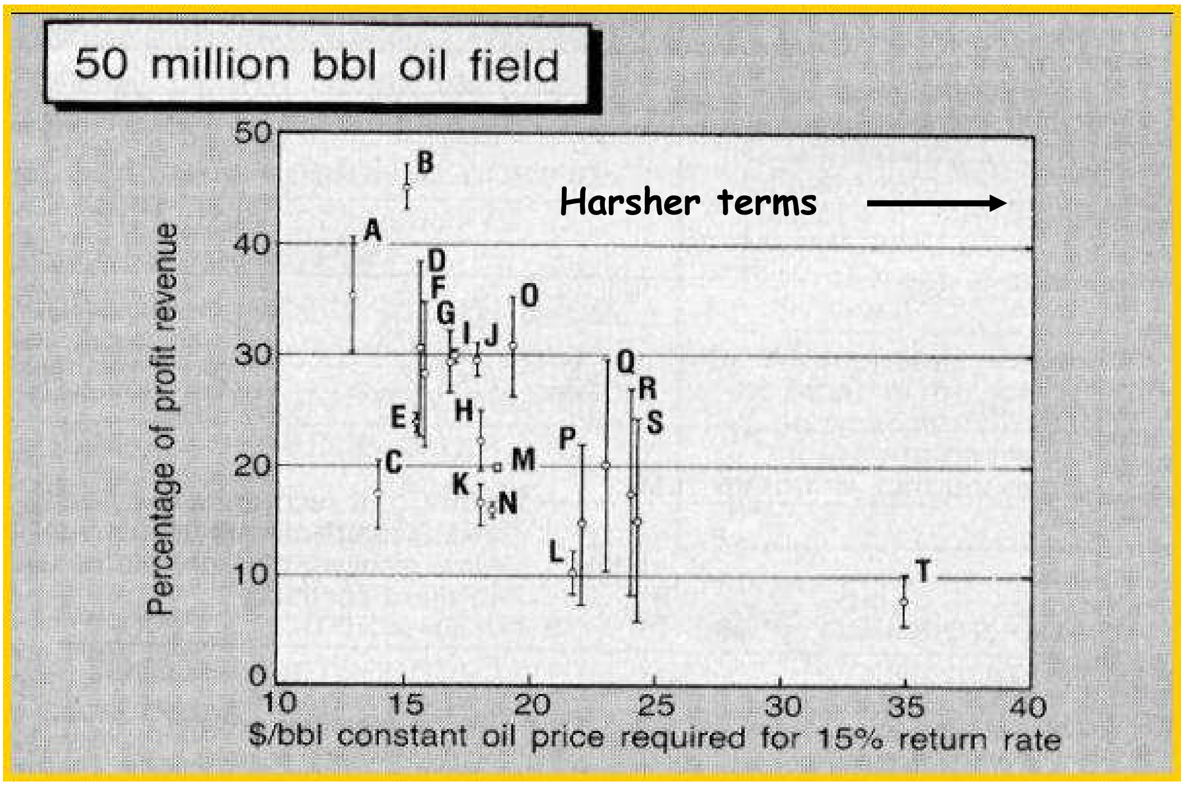


The contracts with the poorest cost recovery mechanisms—O, P, Q, R, and S— have large standard deviations. This is because the profit revenue to the contractor, and other economic indicators, drop significantly for the high cost sensitivity cases as these costs have to be recovered from the contractor's "profit oil" split (i.e. indicative of regressive fiscal terms). The standard deviations for the taxation driven contracts are also quite high in Fig. 2a for the 15 million bbl field, particularly for Contract D. This is because the secondary taxes in these contracts become payable, or the rates increase dramatically, at certain economic thresholds. They are designed this way to help small fields to be economic for the contractor even in a low oil price environment (i.e. the contracts have progressive fiscal mechanisms). The high and low sensitivity cases straddle these thresholds, thereby resulting in a wide range of profitability for the contractor under the terms of Contract D.

For the 50 million bbl field the relationship of these parameters is similar to that shown for the 15 million bbl field but with a greater scatter.

This field is economic (assuming a 15% IRR threshold) with 14 of the contracts for a constant oil price of $20/bbl. The field becomes economic with 19 contracts for a constant oil price of $25/bbl.

Fig. 2b

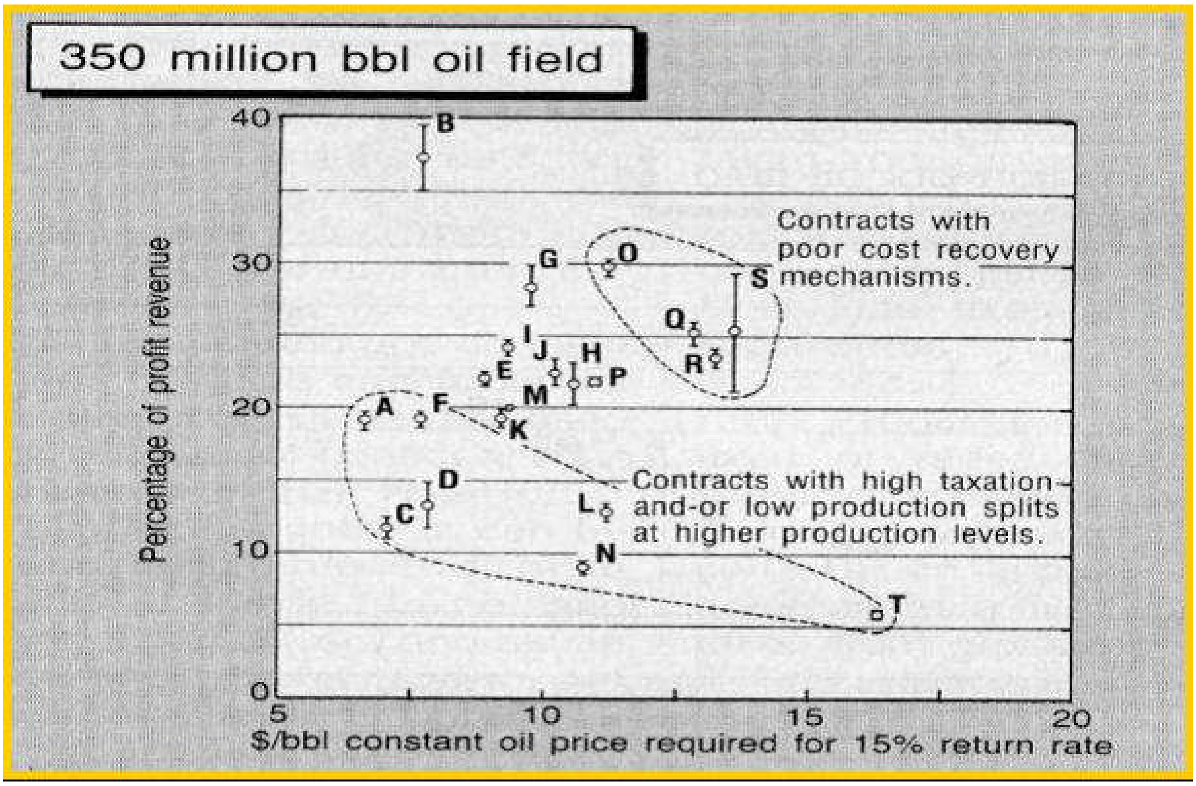


Those contracts in which the state oil company contributes significantly to the development and operating expenditures (C, H, K, L, N, and P) of the field plot distinctly on the lower side of the trend. This indicates that by paying less the contractor recovers a smaller share of the profits.

The negative correlation between these parameters is very poor for the 350 million bbl field size.

The standard deviations of the contractor profit revenue for all contracts, except Contract S (zero cost recovery), are small. This indicates that the level of contractor profit is much less sensitive to uncertainties in cost, prices, and production rates than for the smaller fields. This field is economic (assuming a 15% IRR threshold) with 10 of the contracts for a constant oil price of $10/bbl. The field becomes economic with 19 contracts for a constant oil price of $15/bbl.

Fig. 2c



The scatter in Fig. 2 is caused by three groups of contracts:
A) The tax driven contracts tend to plot towards the bottom left corner on this graph. This reflects taxes limiting contractor profits at high revenue levels. However, these contracts remain economic at very low oil price thresholds, due to lower taxation rates or allowances against taxes when projects become less profitable.

B) The production driven contracts with relatively low average production splits, and-or with high associated income tax rates, also plot towards the bottom left corner on this graph. This is due to these contracts limiting the contractors profits for the larger fields or, more correctly, for fields with high daily production rates.

C) The contracts with poor cost recovery mechanisms plot towards the upper right corner on this graph. This signifies that providing revenues are sufficient for contractor costs to be adequately recovered from the cost oil allowance these contracts are capable of being highly profitable. However, the economic threshold of these contracts remains at a relatively high oil price. As the oil price falls it becomes increasingly difficult for the contractor to recover costs and maintain profits with these contracts.

The relationships between the mean and standard deviations of NPV, IRR, and payout time when plotted against the constant oil price required to provide the contractor with an IRR of

15% show similar trends to those illustrated for percentage of profit revenue in each element of Fig. 2.

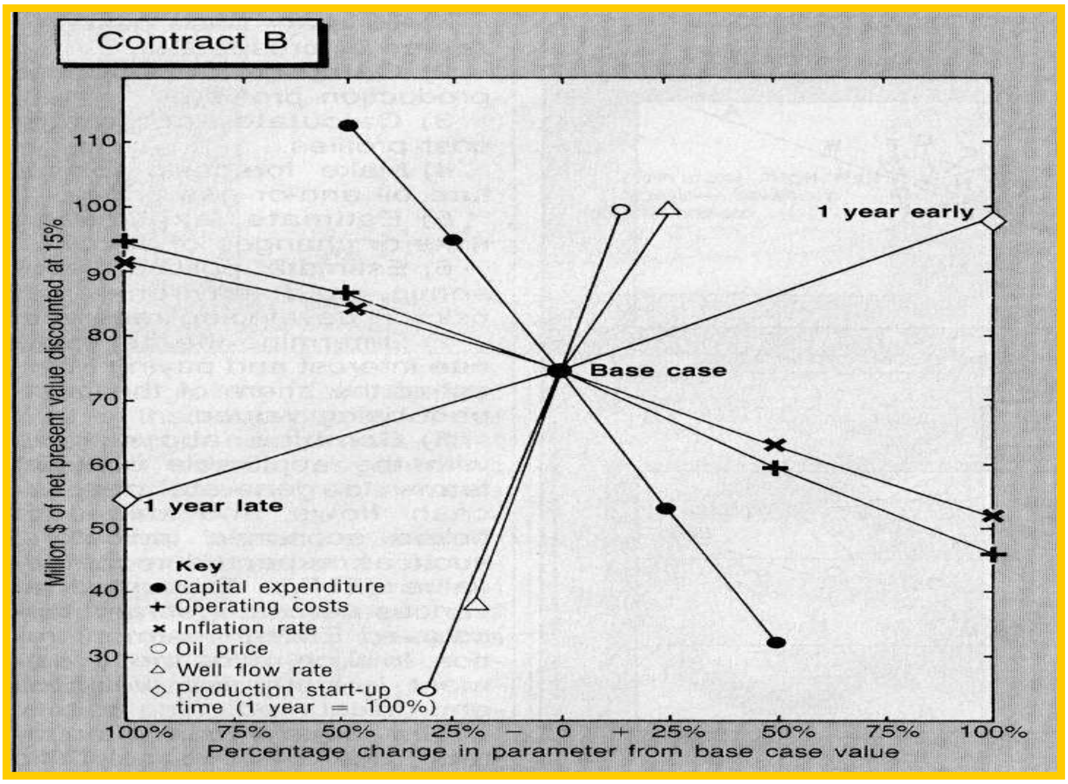
Spider diagrams to display sensitivity analysis

An informative way to illustrate the complete sensitivity analysis of the input variables for a particular field size and contract is to plot the value of a key economic indicator for each sensitivity case run versus the percentage variation of the input parameter varied from its base case value. The resulting diagram is referred to as a spider diagram for obvious reasons. The patterns shown on these spider diagrams vary perceptibly from contract to contract giving them a finger print" like value.

Such diagrams can be used to establish variations of which input variables a contract is particularly sensitive and to understand the detailed mechanism of those contracts with the most complex fiscal structures.
Fig. 3 shows spider diagrams for NPV-15% displaying the sensitivity analysis of input variables.

The spider diagram for Contract B is typical of NPV spider diagrams for the production driven contract mechanisms.

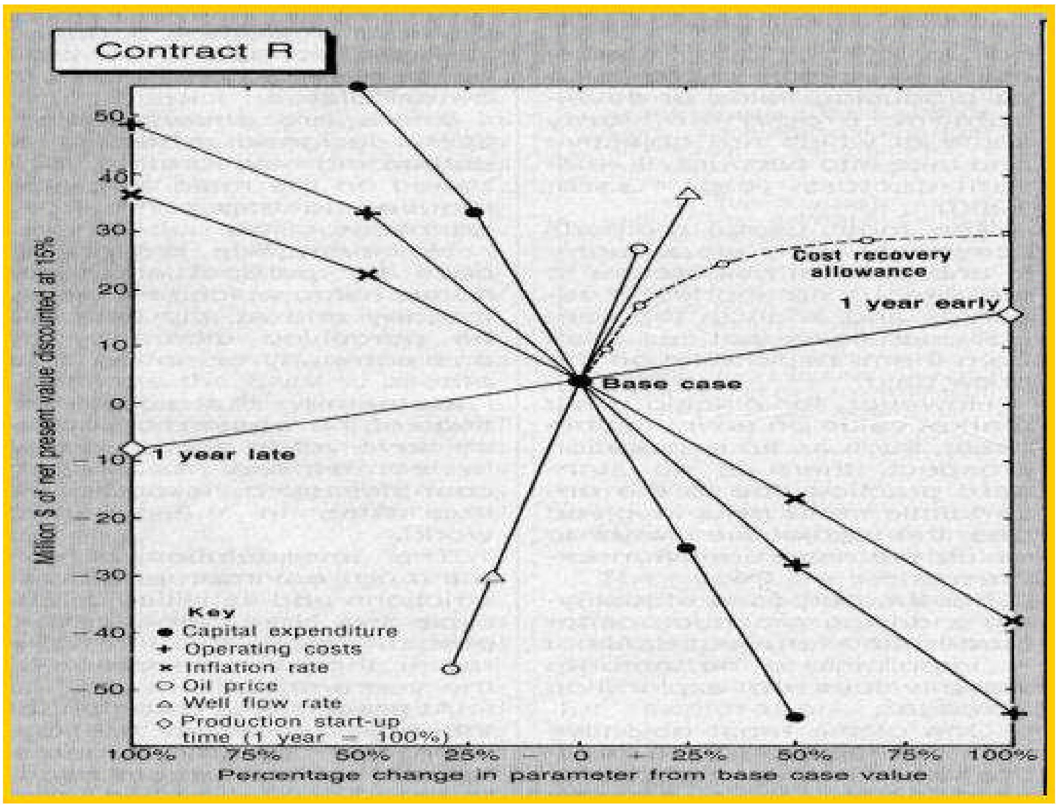
Fig. 3a



The trends are approximately symmetrical and relatively predictable. The contractor's NPV is more sensitive to oil price and production rates than costs.
Also the contract is less sensitive to operating costs, inflation rates (applied to operating and capital costs), and time of production start-up than to capital costs.

The spider diagram for Contract R in Fig. 3b is a typical NPV spider diagram for a production driven contract with a low cost recovery allowance from gross production. This type of contract is very sensitive to variations in costs as well as oil prices and production rates. Relatively small changes in costs, inflation rate, production rate, or oil price for this particular field can change the base case into a reasonably economic project or an economic disaster under the terms of this contract.

Fig. 3b



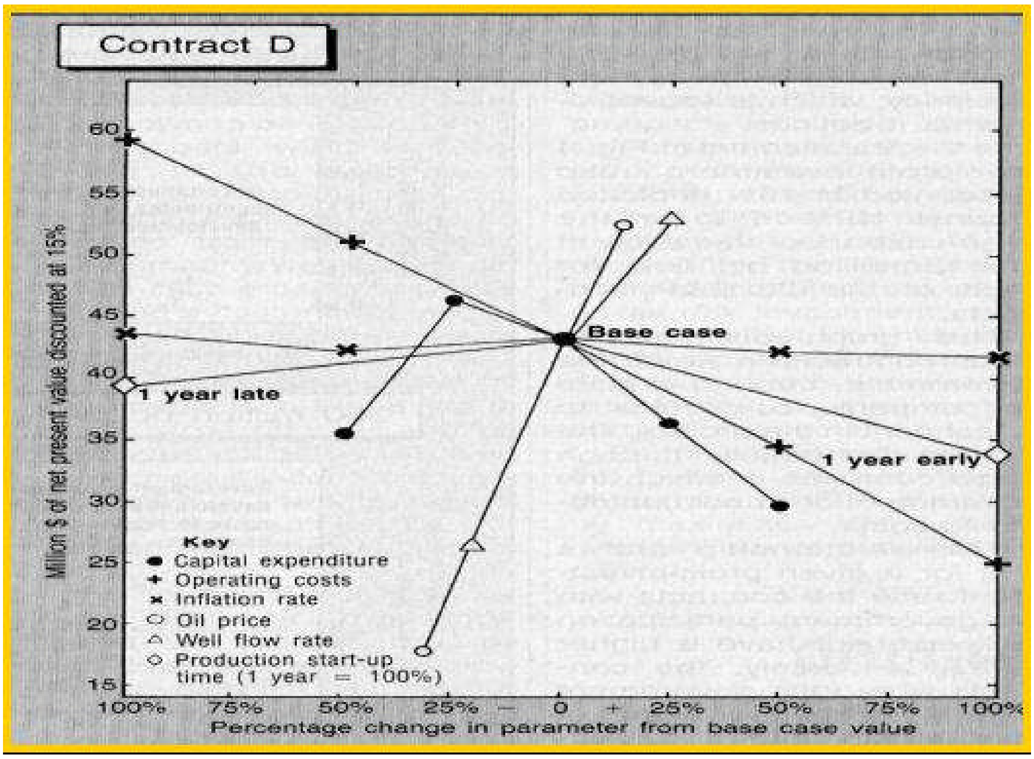
The Contract R diagram illustrates why careful plan-fling of the expenditure levels and annual profiles versus production profiles is essential to optimize the contractor's profits under the terms of such contracts.

The Contract R diagram also illustrates how such spider diagrams can be of use during the contract negotiation phase. The dotted line shows the effect on NPV for this 50 million bbl field under Contract R but for a range of higher cost recovery allowances. It is concluded from this analysis that obtaining even a small increase in the cost recovery allowance is worthwhile, but anything more than a 30% increase from the base case percentage allowance has little impact on the NPV for this particular field.

Clearly analysis of the effects of other negotiable contract terms can be performed in a similar way using spider diagrams.

The Contract D spider diagram in Fig. 3c is typical for a taxation driven contract with one tax controlled by a periodic rate of return to the contractor.
This spider diagram is quite asymmetrical and the trends unpredictable, typical of contracts in which a rate of return is involved in the fiscal structure. There is much less overall variation involved in the sensitivity analysis of NPV for this particular field size (i.e., low standard deviation).

Fig. 3c



Plotting the NPV of each case divided by the mean or base case values for the three contracts in Fig. 3a to 3c would illustrate this point more clearly. However, spider diagrams are at their most useful when the absolute value of the economic indicator is plotted rather than a derivative.

A higher sensitivity to oil price and production rate is also apparent in the Contract D diagram. For this field case the contract is virtually insensitive to inflation rate and the time of production start-up. Curiously both the earlier and the later production start-up times evaluated result in lower profitability for the contractor than the base case.

This indicates that a carefully planned field start-up time is required to optimize the field's profitability to the contractor. Unlike the typical production driven contracts the earliest possible production start-up does not necessarily result in optimum profits with such contracts.

The reason for the asymmetry in the capital cost variations in the Contract D diagram in Fig. 3c is that the lower costs through the project result in higher periodic rates of return to the contractor, to which the contract responds with higher tax rates (or in the case of other contracts introduces a supplementary tax). Somewhere between 25% and 50% lower capital costs than the base case causes the contract to pass this tax threshold.

The unpredictability of the effect in variations of the input variables on contractor profits with contracts controlled in part by periodic rates of return justifies calculating a much larger number of sensitivity cases. Once a quick look sensitivity analysis, such as the one illustrated here, is completed certain variables can be targeted for more detailed analysis. This could help to define more precisely the critical values at which significant tax breaks occur.

An iterative computer model is clearly of value for such detailed analysis. When planning a field development under one of these contracts detailed sensitivity analysis is a very useful aid. After detailed analysis a spider diagram can appropriately look more like a can of worms!

Other contracts that can result in significantly asymmetrical spider diagrams, of the type shown in Fig. 3c, are those where the production split to the contractor varies according to the contractor's periodic cumulative revenue to cumulative investment ratio (for example, contracts N, P). However, the asymmetry is generally more predictable and less extreme than for those contracts with a rate of return control.

Only examples of spider diagrams for NPV and the 50 million bbl yield are included here. However, two points worth noting for NPV spider diagrams for the 350 million bbl field are:
1) All contracts are significantly more sensitive to oil prices and production rates than costs;
2) The changes in NPV caused by varying capital costs, operating costs, and inflation rate are much more similar than for the small field sizes.

For the 15 million bbl field the spider diagrams show that NPV is almost as sensitive to changes in capital costs as to oil price. Unlike the other contracts the rate of return controlled contracts (i.e., contracts C, D, and F) are not so sensitive to significant decreases in capital costs. This is because as soon as the contractor's periodic rate of return increases in such circumstances, the contract compensates by cutting the share of profit oil to the contractor. The poor cost recovery contracts are very sensitive to changes in both costs and prices as they are for the 50 million bbl field (Contract R, Fig. 3b).

Clearly spider diagrams have many uses in detailed prospect and development project analysis as well as in. comparing and understanding the fiscal mechanisms of contracts themselves. The patterns on spider diagrams drawn for payout time and percentage of profits are different from those shown here for NPV and can be useful in certain circumstances.

Discounted profit-Investment ratios

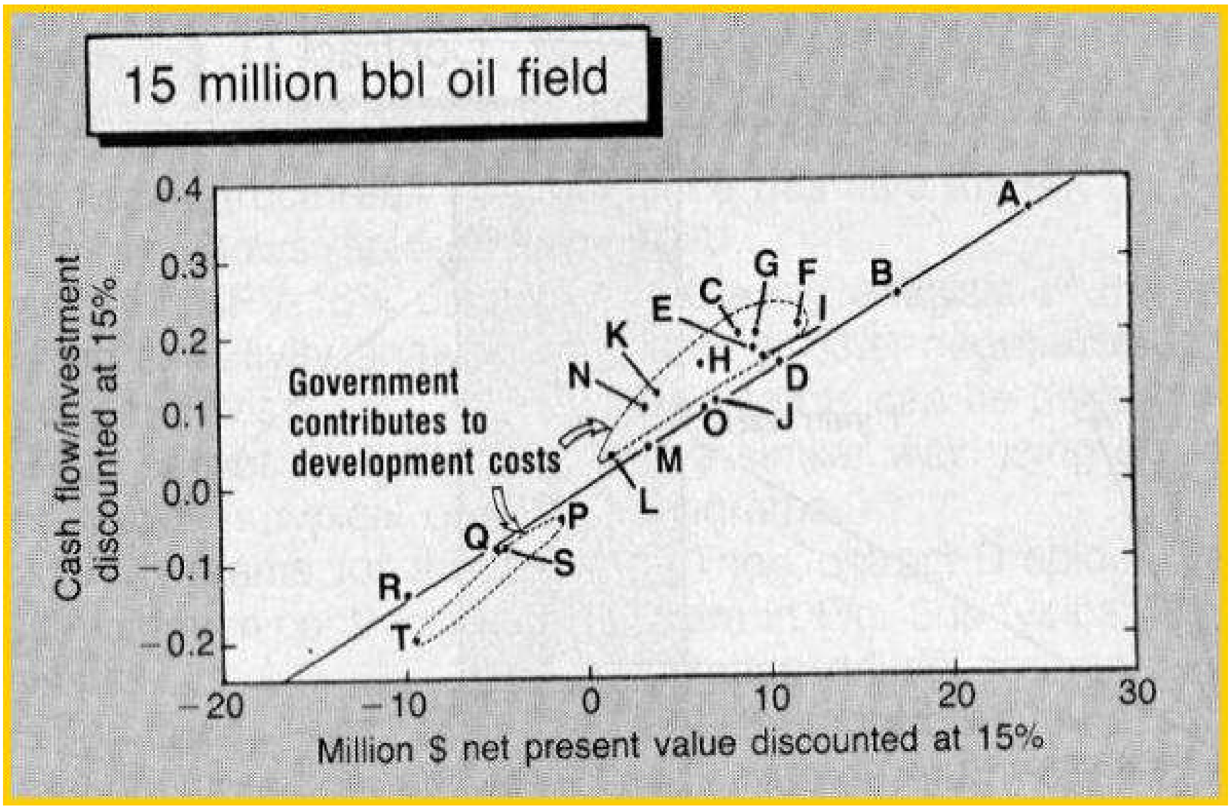
Profit-investment ratios can be of value in the economic comparison of E&P contracts. There are several ways to define profit and investment, so it is important to clarify the definitions applied here:

"Profit" is the sum of the post-tax cash flow.
"Investment" is the sum of all expenditures made by the contractor in the project, including exploration costs, capital investment, and operating costs.

To calculate a discounted profit-investment ratio both profit and investment are discounted at the appropriate discount rate.

It should be remembered that investments are involved in the numerator and denominator of this ratio as defined here. This ratio can also be referred to as NPV / investment or as the investment efficiency, which is essentially what it defines.
In Fig. 4a the profit-investment ratio discounted at 15% is plotted against NPV-15% for the base case input variables of the 15 million bbl field for each of the 20 E&P contracts.

Fig. 4a

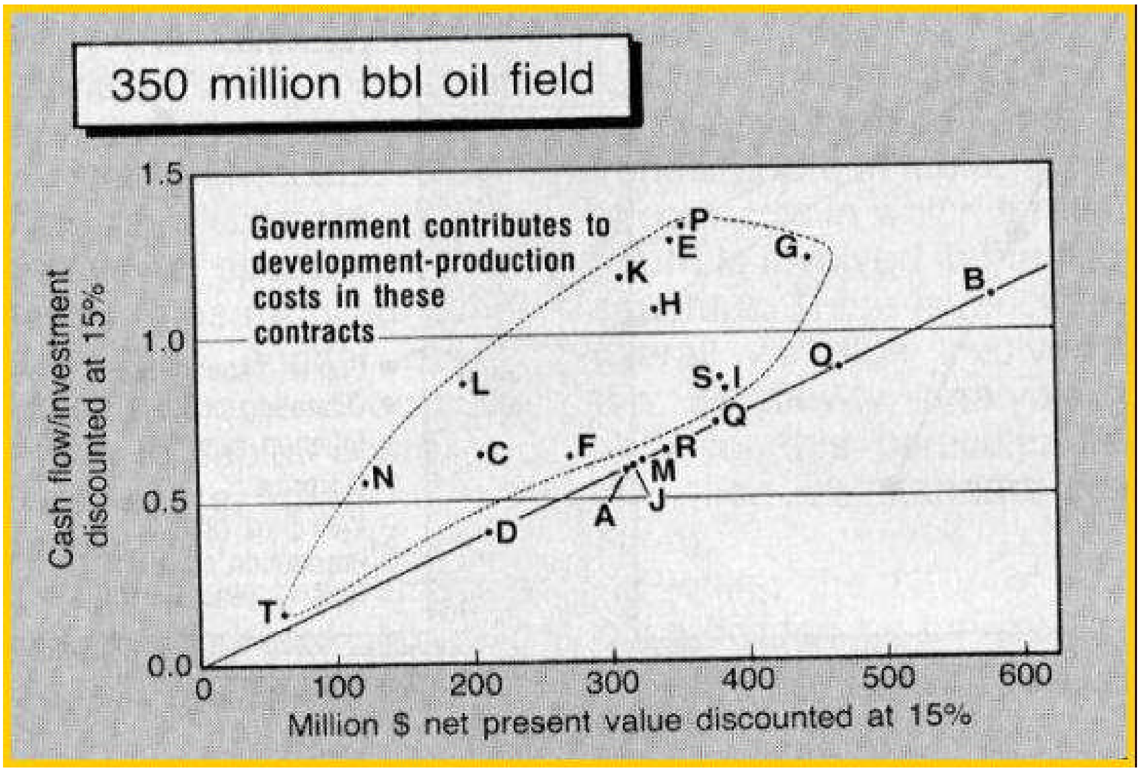


This graph distinguishes those contracts in which the government, through a state oil company, contributes to investment in the project. The drawn line passes through those contracts in which the government does not contribute to costs.
This relationship shows that for a given profit-investment ratio the contracts with no government participation in investment have a higher contractor NPV (except when that NPV is negative when the contractor NPV is less negative for a given profit-investment ratio).

Conversely, the contracts where the government pays a substantial share of investments require less investment on the part of the contractor to yield the same profit-investment ratio than contracts where the government does not contribute to investment. A graph of profit-investment ratio vs. investment would show this. In cases where a company has limited funds it then becomes important to maximize the profit-investment ratio.

Fig. 4b shows the same relationship for the 350 million bbl field. The NPV for the same profit-investment ratio is substantially lower for those fields in which the government contributes to investment (i.e., in return for a greater share of the profits, which is larger for the larger fields).

Fig. 4b



For approximately the same profit-investment ratio this field provides the contractor with less than half the NPV under Contract L than under Contract O for less than half the investment.

The effect of optional government back-ins once a field has been discovered can be evaluated using plots similar to those shown in Fig. 4. Such analyses are sometimes of use during the phase of contract negotiation or bidding with a government, i.e., for a potential contractor to establish how different levels of government back-in effect contractor profits and break-even points. For the contracts analyzed in this study it has been assumed that where the government has an option to back-in to production that option has been exercised.

Ranking, valuing prospect portfolios

Notwithstanding the foregoing sections it is important for the economist to appreciate that establishing favorable terms for the E&P contract is only one of the factors in determining whether a project is attractive. There have to be prospects or fields with technical merit in the contract area, and the exploration and political risks have to be acceptable.

The oil industry has a number of well established methods for placing a fair market value on tangible assets such as producing fields or development properties, only some of which are objective and take into account all relevant factors (e.g., Garb, 1990). The most useful methods commonly apply economic and political risk factors to the various categories of reserves and analyze the various cash flows that can arise from them, depending on the price paid.

However, for placing a fair market value on an intangible asset, such as an exploration prospect, there is no standard practice due to the uncertainties and risks involved and the subjective ways in which the risks are often expressed.
For the purposes of justifying a drilling prospect, or for farm-in and farm-out deals, it is important to be able to place values on exploration acreage.

One of the most objective methods requires slight modifications to one method for establishing the fair market value of existing reserves, and involves the following steps:

1) Estimate base case reserves of prospect(s).
2) Calculate applicable production profile(s).
3) Calculate contractor cost profiles.
4) Make forecasts for future oil and-or gas prices.
5) Estimate exploration risks or changes of success.
6) Estimate political, economic, and environmental risks in developing reserves.
7) Determine the net revenue interest and paying interest of the share of the prospect being valued.
8) Combine above data with the applicable contract terms to generate post-tax cash flows and calculate risked economic indicators, such as expected monetary value (EMV) discounted at various percentages and discounted EMV-investment ratios. In such ratios the investment is both risk weighted and discounted.

The above method is more of an art than an objective scientific procedure. The uncertainties that exist in steps 4, 5, and 6 leave scope for a wide range of risked cash flows to be calculated.

There are several objectively designed schemes for estimating exploration risk based on the main elements required to trap commercial quantities of oil.

However, this is not the case for political and economic risks, which change by the day and at any time will be perceived differently by one company or nation than others.

Something that some factions of the western oil industry have yet to accept is that in some less developed countries such risks can be less than in the western world. The uncertainties of expanding environmental restrictions and liabilities in Europe and North America [and a habit there of periodically imposing windfall profits taxes] will probably make this the norm rather than the exception in the years ahead.

At present it is common for the high perceived political, economic, and environmental risks of a new venture country due to a lack of first hand knowledge of that country, rather than the quality of the prospects concerned — that prevent some companies entering exploration ventures in those countries.
As the industry's international exposure and experience grows, the perceived risks will become less, and more international projects will pass the required economic thresholds for participation using the above method of valuation.

The valuation method outlined above can be applied to value a portfolio of acreage and prospects each with their own reserves, costs, risks and contract terms. The only constants at any one time in such a valuation will be the discount rate used for the valuation. Oil and gas prices will vary slightly due to fluid compositions and geographic locations of the prospects. Contract terms become one of several variables in the overall valuation.

The discount factor used to calculate the EMV to be considered as a fair market value for the acreage or prospect should reflect a company's cost of capital and will usually be several points higher than the interest available from placing such funds on deposit at a financial institution.

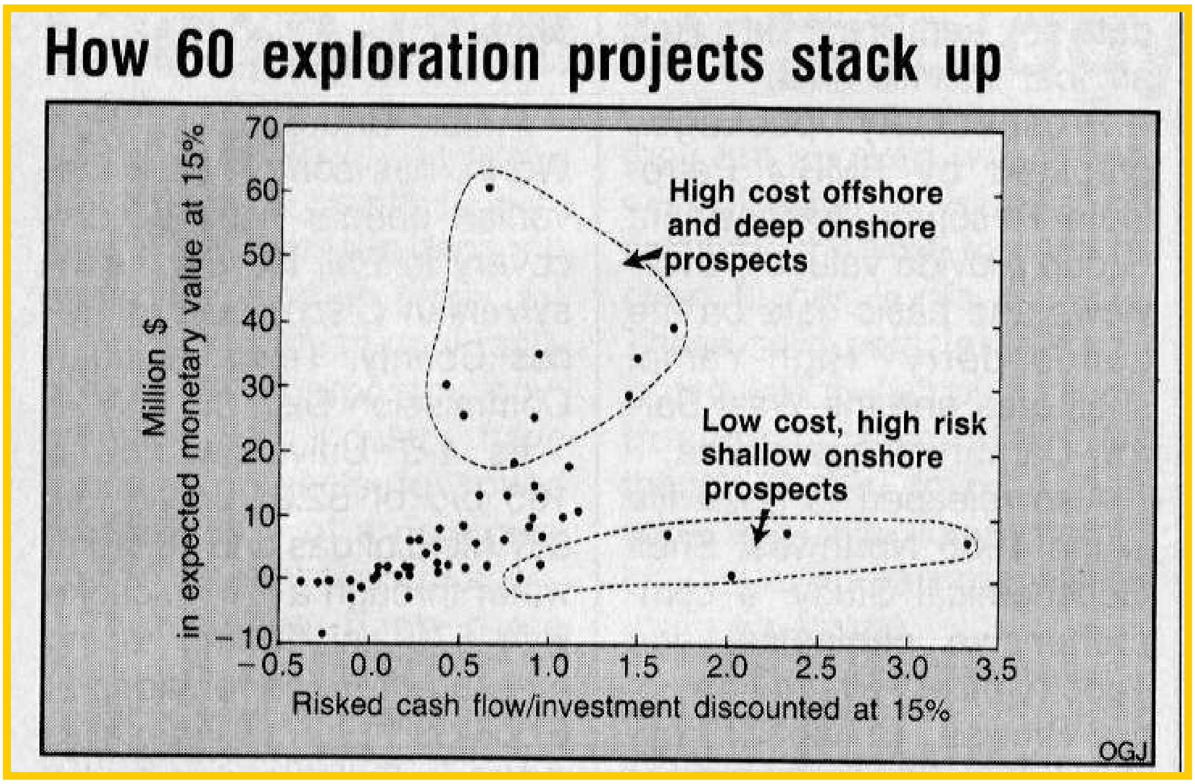
Discount rates of 15-25% were appropriate in 1990 [7.5% to 15% are more appropriate in 2003].

Fig. 5 illustrates the results of a valuation for a portfolio of 60 prospects.
The risk weighted economic indicator EMV, discounted at 15%, is plotted against the ratio of EMV to risked total investment similarly discounted. These parameters can be considered as a risked weighted versions of NPV and discounted profit-investment ratio, respectively.

They combine the rewards of success at the appropriate chance of success and the costs of failure at the appropriate chance of failure for specific prospects and projects. The chances of success for exploration prospects rarely exceed 30%, and for high risk prospects are less than 5%. The average chance of success for the portfolio presented is 12% and ranges from 1-28%. Several prospects in the portfolio studied have negative EMVs. This is not unusual as many prospects with attractive NPVs when risked are shown to be uneconomic.
Prospects with negative EMV's at the company's threshold discount rate for profitable ventures would be dropped (culled) from the portfolio. The company would elect not to drill such

prospects unless required by a contract obligation in a contract area where no better prospects existed.

Fig.5



The large scatter shown by the prospects in Fig. 5 is due to the large number and diversity of variables involved in the risked values calculated. However, two groups of prospects can be distinguished from the main cluster:

1) The high cost-high reward offshore prospects. These are characterized by high EMV but relatively low EM V-investment ratio indicating relatively poor investment efficiency.

2) The high risk-low cost shallow depth onshore prospects. Despite very low risk factors these prospects have small positive EMVs, but very high EMV-investment ratios due to the low costs indicating relatively high investment efficiency.

A well-balanced portfolio should clearly include both the above types of prospects, and a selection of other high and low risk prospects. A work program too heavily weighted to the high-risk end of the spectrum runs a significant chance of consuming its exploration budget on dry holes. A work program too heavily committed to high cost projects has a significant chance of consuming its exploration budget to test very few prospects (not necessarily a bad thing if some are discoveries) or of requiring large scale financing projects to develop its discoveries. In the latter case there is also the greater chance of making sub-economic discoveries, the most frustrating of all results.

The relationship shown in Fig. 5 can be used to rank a prospect portfolio and thereby prioritize the order in which prospects should be drilled. There are parameters that are particularly useful for highlighting the values of prospects for which, as a result of farmout deals, the net revenue interest being valued is either promoted or carried. One of these is the **EMV risk investment ratio**. In this ratio only the exploration costs (discounted) are included as risk investment. When a net revenue interest in a prospect is fully carried this ratio is infinite. The ratio is also high for partially carried prospects.

By drilling prospects with the highest values of this ratio for given EMV's, a company maximizes the potential returns from its available risk capital.

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