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Fiscal System Analysis: Concessionary and Contractual Systems Used in Offshore Petroleum Arrangements

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ABSTRACT

The manner in which the fiscal terms and parameters of a contract impact system measures are complicated and not well understood, and so the purpose of this report is to quantify the influence of private and market uncertainty on concessionary and contractual fiscal systems. An analytic framework is developed that couples a cash flow simulation model with regression analysis to construct numerical functionals associated with the fiscal regime. A meta-modeling approach is used to derive relationships that specify how the present value, rate of return, and take statistic vary as a function of the system parameters. The critical assumptions involved in estimation, the uncertainty associated with interpretation, and the limitations of the statistics are also examined.

The report is divided into two parts. In Chapter 1, the concessionary system is examined and the deepwater Gulf of Mexico Na Kika field development is considered as a case study. In Chapter 2, the contractual fiscal system is considered with the deepwater Angola Girassol field development as a case study.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

Page

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1: CONCESSIONARY SYSTEMS

1.1. Introduction

The economics of the upstream petroleum business is complex and dynamic. Each year anywhere between 25-50 countries in the world offer license rounds; 20-30 countries introduce new model contracts or fiscal regimes; and nearly all countries revise their tax laws during their annual budgetary process. There are more fiscal systems in the world than there are countries because

- Numerous vintages of contracts may be in force at any one time,
- Countries typically use more than one arrangement, and
- Contract terms are often negotiated and renegotiated as political and economic conditions change, or as better information becomes available.

The focus of fiscal system analysis depends upon your perspective. From the host government's point of view, focus is usually maintained on the division of profit (take) between the contractor and government. From the operator's perspective, economic measures such as the present value and rate of return describing the expected profitability of the project are of primary interest.

There is a wide degree of uncertainty inherent in the computation of *any* economic or depends critically on the assumptions of the user. Most of the relevant economic conditions of a fiscal regime, regardless of its complexity, can be modeled, and thus the sophistication of the contract terms themselves usually do not represent an impediment to the analysis. The uncertainty is elsewhere.

Several sources of uncertainty exist:

- Geologic uncertainty,
- Production uncertainty,
- Price uncertainty,
- Cost uncertainty,
- Investment uncertainty,
- Technological uncertainty,
- Strategic uncertainty.

A detailed and realistic field description is the first and most important estimate that must be made. The size, shape, productive zones, fault blocks, drive mechanisms, etc. of the reservoir must be estimated with as much accuracy as possible since they determine the capacity of the structure and the required number and location of wells. Estimates of production rates can be based on geologic conditions at the reservoir level, decline curve analysis or similar techniques. Forecast production is only used as a guideline, however, since investment activity can dramatically alter the form of the production curve as well as recoverable reserves. Hydrocarbon price, development cost, technological improvements, and demand-supply relations impact the revenue of a lease and investment planning. Strategic objectives of a corporation are generally unobservable, nonquantifiable, and can vary dramatically over time.

The types of estimates that can be performed depend on the stage of development of the project and the design and planning information available. Initial cost and production estimates typically fall between “order-of-magnitude” estimates (on the order of 25%-50% accuracy) and “conceptual development plan” estimates (on the order of 15%-25% accuracy). The uncertainty associated with the value of the system measures will almost always fall within a broad range, and in the worst case, the range itself may be unknown.

The purpose of this Chapter is to develop an analytic framework to quantify the influence of private and market uncertainty on the economic and system measures associated with a field. A “meta-modeling” approach is employed to construct regression models of the system measures in terms of various exogeneous, fiscal, and user-defined parameters. In meta-modeling, a model of the system is first constructed, and then meta data is generated for variables simulated within a specified design space. Linear models are then constructed from the meta data. Meta-modeling is not a new construct, but as applied to fiscal system analysis is new, useful, and novel, being an especially good way to understand the structure and sensitivity of fiscal systems to various design parameters.

The outline of the Chapter is as follows. In Chapter 1.2 and Chapter 1.3, background material on the basic stages of an oil and gas venture and the two primary fiscal systems of the world's petroleum licensing arrangements are briefly outlined. In Chapter 1.4, the general framework of cash flow analysis governed by a royalty/tax fiscal regime is developed. The take measure is defined and critically examined in Chapter 1.5, and in Chapter 1.6, the meta-modeling approach is outlined. The basic elements of fiscal system design are presented in Chapter 1.7 for a hypothetical oil field, and in Chapter 1.8, formal definitions of equivalent and progressive fiscal regimes are provided. The notion of a feasible domain is also introduced. In Chapter 1.9, the Gulf of Mexico deepwater field development Na Kika is presented as

If the appraisal is favorable, and a decision is made to proceed, then financial arrangements will need to be made and the next stage of development planning commences using site-specific geotechnical and environmental data. Studies are carried out using one or more engineering contractor-construction firms, in-house teams, and consultants. Once the design plan has been selected and approved, the design base is said to be "frozen," and venders and contractors are invited to bid for tender. Environmental impact statements are prepared and submitted to the appropriate government agencies.

The operator lets contracts for the development according to the following segments:

Design of the substructure,
Design of the deck,
Design of the pipeline,
Fabrication of the substructure,
Fabrication of the deck,
Procurement of pipe,
Procurement of process equipment,
Installation of platform,
Installation of equipment,
Installation of pipeline,
Hookup,
Production drilling.

Several of these activities may be combined and awarded to one contractor depending upon the type and location of activity, the requirements of the contract, contractor specialization, and the supply and demand conditions in the region at the time.

Following the installation, hookup, and certification of the platform, development drilling is carried out and production started after a few wells are completed. Subsea completions may be used to produce from appraisal wells before field development. Early production is important to generate cash flow to relieve some of the financial burden of the investment. Workovers must be carried out periodically to ensure the continued productivity of the wells, and water/gas injection may be used to enhance productivity at a later time.

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1.3. Fiscal System Classification

1.3.1. Concessionary Systems: Governments decide whether resources are privately owned or whether they are state property. Under a concessionary system (also called a royalty/tax system), the government or land owner will transfer title of the minerals to the oil company which is then subject to the payment of royalties and taxes. The royalty and tax rates are normally specified in the country or state's legislation (and are thus transparent) and are the same for all companies (no negotiations involved). The fiscal terms of royalty/tax systems are not necessarily "fixed," however, because governments frequently change[1] their petroleum laws and taxation levels, and in some instance, terms of a royalty/tax system may be subject to negotiation. Sliding scale features and various levels of taxation may exist peculiar to one country or another; e.g., see (Barrows, 1983; Barrows, 1994; Johnston, 1994b), but most royalty/tax systems are fairly straightforward to understand.

1.3.2. Fiscal Components of Concessionary Systems: The concession was the first system used in world petroleum arrangements and can be traced to silver mining operations in Greece[2] in 480 B.C. (Anderson, 1998). The earliest petroleum concessionary agreements consisted only of a royalty. As governments gained experience and bargaining power, contracts were renegotiated, royalties increased, and various levels

The exact manner in which costs are capitali where,

g_t^o, g_t^g = Conversion factor of oil (o), gas (g) in year t,
P_t^o, P_t^g = Average oil, gas benchmark price in year t,
Q_t^o, Q_t^g = Total oil, gas production in year t.

The conversion factor depends primarily on the API gravity and the sulfur content of the hydrocarbon, and is both time and field dependent. The hydrocarbon price is based on a reference benchmark expressed as an average over the time horizon under consideration. The total amount of production in year t is expressed in terms of barrels (bbl) of oil, cubic feet (cf) of gas, or barrels of oil equivalent[3] (BOE).

Oil and gas streams can be valued individually or combined into one product stream. For Q_t^o and Q_t^g expressed in BOE, define

$$\alpha_t = \frac{Q_t^o}{Q_t^o + Q_t^g} \text{ = Proportion of hydrocarbon production in year } t \text{ that is oil,}$$

$$1 - \alpha_t = \frac{Q_t^g}{Q_t^o + Q_t^g} \text{ = Proportion of hydrocarbon production in year } t \text{ that is gas.}$$

A weighted average hydrocarbon price for a combined oil and gas production stream is computed as

$$P_t^w = \alpha_t g_t^o P_t^o + (1 - \alpha_t) g_t^g P_t^g \text{ = Weighted average hydrocarbon price in year } t.$$

The equivalence between the individual and combined product streams is clear from the following relation:

$$GR_t = g_t^o P_t^o Q_t^o + g_t^g P_t^g Q_t^g = \left(\frac{g^o P^o Q_t^o + g^g P^g Q_t^g}{Q_t^o + Q_t^g} \right) (Q_t^o + Q_t^g) = P_t^w (Q_t^o + Q_t^g).$$

Capital expenditures (*CAPEX*) are the expenditures incurred early in the life of a project, often several years before any revenue is generated, to develop and produce hydrocarbons. *CAPEX* typically consist of geological and geophysical costs; drilling costs; and facility costs. Capital costs may also occur over the life of a project, such as when recompleting wells into another formation, upgrading existing facilities, etc. These cost are usually of a considerably smaller magnitude and duration than the initial capital expenditures.

Operating expenditures (*OPEX*) represent the money required to operate and maintain the facilities; to lift the oil and gas to the surface; and to gather, treat, and transport the hydrocarbons. In many fiscal systems, no distinction is made between operating costs and intangible capital costs, and both are expensed.

Taxable income (*TAX)* is determined as the difference between net revenue and operating cost; depreciation, depletion, and amortization; intangible drilling costs; investment credits (if allowed), interest in financing (if allowed), and tax loss carry forward (if applicable). Depletion is seldom allowed although some countries allow capital costs and bonuses to be expensed. In the United States, state and federal taxes are determined as a percentage of taxable income, usually ranging between 35%-50%, and here denoted by the value T, $0 \le T \le 1$:

$$TAX_t = T(NR_t - CAPEX/I_t - OPEX_t - DEP_t - CF_t),$$

where,

$NR_t = GR_t - ROY_t =$ Net revenue in year t,

$CAPEX/I_t =$ Intangible capital expenditures in year t,

$DEP_t =$ Depreciation, depletion, and amortization in year t,

$CF_t =$ Tax loss carry forward in year t.

The tax and depreciation schedule is normally legislated and will vary significantly from country to country. In the United States, all or most of the intangible drilling and development cost may be expensed as incurred, whereas equipment cost must be capitalized and depreciated. Tax losses in the U.S. may be carried forward for at least three years.

1.5. Economic and System Measures

<u>1.5.1 Economic Indicators:</u> The purpose of economic evaluation is to assess if the revenues generated by the project cover the capital investment and expenditures and the return on capital is consistent with the risk associated with the project and the strategic objectives of the corporation. Economic analysis requires a commitment of both time and monetary resources, and the degree to which procedures for capital expenditures are formalized is a fun;endt15 mformformy 275 Tw[(The purpose of ecD0 Tc0 cfhe d001080 Tc-4.3932 0 T institutionalize such procedures (Boudreaux et al., 1991; Pohlman et al., 1987). The primary analytic techniques utilize a time value of money approach; e.g., see (Dougherty, 1985; Mian, 2002; Seba, 1987).

For field *f* and fiscal regime denoted by F, the present value *(PV*(*f*, F)) and internal rate of return (*IRR*(*f*, F)) of the cash flow vector *NCF*(*f*) is computed as

$$PV(f,\mathrm{F}) = \sum_{t=1}^{k} \frac{NCF_t}{(1+D)^{t-1}},$$
$$IRR(f,\mathrm{F}) = \{D \mid PV(f,\ \mathrm{F}) = 0\},$$

where D is the (discount) rate that equates the present value to zero. A profitability index, or investment efficiency ratio, normalizes the value of the project relative to the total investment and is calculated as

$$PI(f,\mathrm{F}) = \frac{\mathrm{PV(f,F)}}{\mathrm{PV(TC)}}.$$

The present value provides an evaluation of the project's net worth to the contractor in absolute terms, while the rate of return and profitability index are relative measures used to rank projects for capital budgeting. Economic values are not intended to be interpreted on a stand-alone basis, but should be used in conjunction with other system measures and decision parameters. A combination of indicators is usually necessary to adequately with favorable geologic potential, high wellhead prices, low development costs, and low political risk will tend to offer tougher fiscal terms than areas with less favorable geology, low wellhead prices, high development cost, and high political risk. The economic strength and political stability of the country, oil supply balance, regional market demands, global economic conditions, and financial health of the oil sector also influence fiscal terms and the value of take[5]. It is important to remember, however, that countries with harsh fiscal regimes or the greatest success probability provide no guarantees in the profitability of the play.

$$\tau_t^{\,c} = \frac{CT_t}{TP_t}\,,$$

$$\tau_t^{\,g} = \frac{GT_t}{TP_t}\,.$$

Take varies as a function of time over the life history of a field. Three cases arise depending on the value of gross revenue and total profits:

- $GR_t = 0$: $\tau_t^{\,c} = -1$;
- $GR_t > 0$, $TP_t < 0$: $\tau_t^{\,c} < 0$;
- $GR_t > 0$, $TP_t > 0$: $0 \leq {}_t^{\,c}$

Ehrhardt, 1994). The government[6] does not (nor should not) value money in the same way as companies, and so generally speaking, $D^g \leq D^c$. Undiscounted take[7] is computed by setting $D^c = D^g = 0$. Discounted take is computed by assuming $D^c = D^g \neq 0$, or by considering ^{c}

preferences. The terms that determine take are identical, or nearly identical, to the economic measures of the system, and the variability associated with the computation of take is considered to have the same order-of-magnitude as the present value and rate of return measures.

- Take is an *unobservable* quantity since field data is normally considered confidential and the cost history of fields is usually not maintained by operators or shared outside the firm. The only time that take or *any* economic indicator associated with a field can be calculated with certainty is *after* the field has been abandoned and *all* the relevant revenue and cost data made public. The fiscal terms of a contract and the inability to model contractual terms such as training commitments, domestic market obligations, carries and other factors that impact the cash flow (investment in working capital, working capital recovery, interest payment, repayment of principle) contribute to the uncertain and unobservable nature of the measure.

- Take is a *biased*, *unverifiable*, and *nontransparent* quantity since it is based upon incomplete, uncertain, and unobservable information. Under most circumstances there is no way to "check" or "validate" the computed measure, and since the calculation is typically performed without reference to the model assumptions involved, the measure is usually not transparent. Only in the case of "perfect" information, when all revenue, cost, royalty and tax data is known for the life of the field can the division of profits between the contractor and government be reliably established. Only in the case of perfect information can take be calculated in a statistically meaningful manner.

- Take is a *fiscal* statistic as opposed to an economic statistic, and so generally matters more to the host government than the contractor. Take is of secondary interest from the contractor's perspective since it does not provide a direct indication of the economic performance of the field.

- Take is often a *negotiated* quantity that depends upon the strength, knowledge, experience, and bargaining position of the oil company and host government, the perception of the risk associated with the field development at the time the contract was written, and the availability of opportunities worldwide. For contractual fiscal systems, "model" contracts are used as a starting point for negotiation, and the final negotiated fiscal terms are not normally disclosed or released to the public.

- Take is *inconsistent* relative to standard economic measures since it is frequently computed/reported on an undiscounted basis. There can be a significant difference in the computation of take depending on the manner in which the cash flow elements are discounted.

1.6. Meta-Modeling Methodology

The impact of changes in system parameters is usually presented as a series of graphs or tables that depict the measure under consideration (present value, rate of return, take, etc.) as a function of one or more variables under a "high" and "low" case scenario; e.g., (Smith, 1993; Wood, 1990a; Wood, 1990b; Wood, 1993). While useful, this approach is generally piecemeal and the results are anchored to the initial conditions employed. The amount of work involved to generate and present the analysis is also nontrivial, and the restrictions associated with geometric and tabular presentations of multidimensional data are significant; e.g., on a planar graph at most three or four variables can be examined simultaneously. A more general and concise approach to fiscal system analysis, which is also believed to be new, is now presented.

The value of take, present value, and internal rate of return varies with the selection of the price of oil (P^o), the price of gas (P^g), the royalty rate (R), the tax rate (T), the contractor discount factor (D^c), and the government discount factor (D^g), in a complicated manner, but it is possible to understand the interactions of the variables and their relative influence using a constructive modeling approach. The methodology is presented in three steps.

Step 1. Bound the range of each variable of interest

This procedure is sometimes referred to as a "meta" evaluation since a model of the system is first constructed, and then meta data is simulated from the model in accord with the design space specifications. The cash flow meta data are then analyzed and linear models describing the system constructed of linear models do not suffice to adequately represent the meta data, then non-linear terms can be incorporated into the analysis.

The design base, cost structure, and production profile is assumed fixed, and so the relationships derived relate to the manner in which the system variables interact under a given development plan and fiscal regime. A good rule of thumb is to sample until the regression coefficients "stabilize." If the regression coefficients do not stabilize, or if the model fits deteriorate with increased sampling, then the variables are probably spurious and linearity suspect. After the regression model is constructed and the coefficients $(k, \alpha, \beta, \gamma, \delta, \varepsilon, \theta)$ determined, if the model fit is reasonable and the coefficients statistically relevant, the value of the system measures $\varphi(f, \mathrm{F})$ can be estimated for any value of (P^o, P^g, R, T, D^c, D^g) within[9] the design space Ω .

1.7. A Functional Analytic Approach to System Measures

In the case of perfect information, the computation of the economic and system measures associated with a field will not depend on the individual performing the calculation. In reality, however, the computation of present value, rate of return, and take is strongly dependent on the level of system information available and the assumption set of the user. Examples provided in the literature typically represent *hypothetical* developments under "reasonable" assumptions, and continuing in this tradition, we illustrate the general approach on a specific field development.

To investigate the impact of a royalty/tax fiscal system for a specific field, it is necessary to calculate the after-tax cash flow under the fiscal system and to examine the factors that influence the economic performance of the field.

1.7.1. Development Scenario:

initially stable at around $2.5/bbl and is forecast to increase significantly near the end of the life of the field.

The royalty regime is calculated as a percentage R, $0 \leq R \leq 1$, of gross revenues, and the income tax is calculated as a percentage T, $0 \leq T \leq 1$, of taxable income. Tax losses are carried forward from a previous year if negative. The fiscal terms are assumed to be described completely by the values of R and T; i.e., there are no royalty/tax holidays, domestic market obligations, government participation, or negotiated terms. The inflation rate per cash flow stream is assumed to be zero. The oil price and the contractor and government discount factors, D^c and D^g, $0 \leq D^c$, ^{g}

1.7.3. Valuation Strategy: To determine the impact of fiscal terms on project economics an operator will typically compare several economic measures under different development scenarios. For illustration, however, only the present value functional is used to evaluate a prospect's net worth.

Definition. The value to an operator of field *f* under the fiscal regime $\mathrm{F}(R,T)$ is defined as

$$V(\mathrm{F}(R,T)) = PV(f, \mathrm{F}). \quad \blacksquare$$

Example. For P = \$20/bbl, D^c = 15%, and D^g = 10%, the present value of field *f* under the development scenario previously outlined is computed as

$$PV(f, \mathrm{F}(R,T)) = 132.7 - 129.2R - 99.1T.$$

The fiscal regime defined by (R,T) = (0.1667, 0.20) yields the present value

$$PV\,(f, \mathrm{F}(0.1667, 0.20)) = \$91.3\mathrm{M}. \quad \blacksquare$$

To compare a field under two fiscal regimes, the contractor will compare the present value functionals.

Definition. For field *f*, the fiscal regime $\mathrm{F}(R,T)$ is preferred to the fiscal regime $\mathrm{F}(\overline{R},\overline{T})$ if

$$V(\mathrm{F}(R,T),\ \mathrm{F}(\overline{R},\overline{T})) = PV(f, \mathrm{F}(R,T)) - PV(f,\ \mathrm{F}(\overline{R},\overline{T})) > 0.$$

If $V(\mathrm{F}(R,T),\ \mathrm{F}(\overline{R},\overline{T})) < 0$, the contractor will prefer $\mathrm{F}(\overline{R},\overline{T})$ to $\mathrm{F}(R,T)$, and if $V(\mathrm{F}(R,T),\ \mathrm{F}(\overline{R},\overline{T})) = 0$, then $\mathrm{F}(R,T)$

selected from their design interval will on aver and analogous to τ^c-equivalency, the *IRR*-functional computed for (R,T) = (0.10, 0.30) yields *IRR*(0.10, 0.30)= 24.7%. For the fiscal system F defined by *R** and *T** = 20%, *IRR*-equivalence is maintained through the following relation:

$$IRR(R^*,T^*) = 32.2 - 44.1R^* = 24.7 = IRR(R,T)\,;$$

$$\Pi_{(IRR,10)}\,(R,T) = \{(R, T) |\ 44.1R + 30.7T < 28.3\};$$

e.g., $(R, T) = (0.2, 0.2)$ satisfies the operator criteria while $(R, T) = (0.4, 0.4)$ does not. ■

$$\Sigma^{HG}(R,T) = \bigcap_{(\varphi(f),\delta)} \Pi_{(\varphi(f),\delta)} \,,$$

where $\Pi_{(\psi(f),\delta)} = \{(R,T) \,|\, \psi(f) > \delta\}$ for field *f*, system functional *ψ*(*f*), and constraint parameter δ. ■

The definition of the operator and host governments feasible domains allows a simple (geometric) characterization of a "deal." Agreement can be reached between the operator and host government on the terms of the contract for a specific field if the intersection of the respective feasible domains is non-empty. More formally,

Theorem. If $\Sigma^{O}(R,T) \cap \Sigma^{HG}(R,T) =$

Model III employs the same parameter intervals as in Model II but the oil and gas price is assumed to vary over each year of the production cycle; i.e., P_t^o ~ LN(25, 5), P_t^g ~ LN(3.5, 1.5) for t = 1,…, 12. In Model IV, the Model III parameters are applied with an annual tax rate selected from a triangular distribution; i.e., T_t ~ TR(0.38, 0.44, 0.50) for t = 1,…, 12.

The results of the regression models for $\tau^c(f, Q)$, *PV*(*f*, *Q*) and *IRR*(*f*, *Q*) are shown in Appendix Table A.5. The model coefficients all have the expected signs, the fits are robust, and all the coefficients – except the government discount factor – are highly significant. For any value of (P^o, P^g, R, Q, T, D^c, D^g) within the design space, the regression model can be used to evaluate and compare parameter selections. For Model I, the results of the meta-model yield

$$\tau^c(f) = 80.0 + 0.2\,P^o + 0.5\,P^g - 53.0R + 0.04Q - 79.1T - 84.3\,D^c + 86.2\,D^g,$$

PV(*f*)=10,460.7+38.2*P(*

The inclusion of structural variability in Model III and Model IV, where the hydrocarbon

$$V_{\tau^c}(f,Q) = \frac{\tau^c(f,Q) - \tau^c(f,0)}{\tau^c(f,0)} = \frac{0.04Q}{38.0} = 0.00105Q\,;$$

so that for Q = 17.5 MMBOE, $V_{\tau^c}(f,Q)$ = 0.018%; Q = 52.5 MMBOE, $V_{\tau^c}(f,Q)$ = 0.055%; and Q = 87.5 MMBOE, $V_{\tau^c}(f,Q)$ =

CHAPTER 2: CONTRACTUAL SYSTEMS

2.1. Introduction

Most governments in the world want oil and gas companies to explore for and develop the hydrocarbon resources of their country since development and production activities provide foreign direct investment, new jobs and infrastructure creation, revenue for the government, and improved conditions for its citizenry. The extent to which revenues accruing from natural resources generate wealth for an economy is a lively and much debated subject. For a recent review of the literature in this area, see (Stevens, 2003). Governments encourage exploration and development activity through their license rounds and fiscal terms.

Exploration and development is a high risk capital intensive business. Finding oil and natural gas throughout most of the world is difficult, costly, and uncertain. The cost of obtaining leases and conducting exploratory work requires a significant investment before reserves are found and economic viability ensured. Investment, in its most basic form, is paying now for the promise of a reward later, and particularly in oil and gas ventures, there are risks of various kinds that need to be considered. Does oil exist in the region? If reserves are found are they smaller than expected or decline faster than geologic conditions suggest? Can the project be brought on line on time and under budget? Will oil prices remain strong or nose-dive? How will inflation rates behave? Will the government try to renegotiate the terms of the contract at a later date?

The first objective of an exploration project is to satisfy the economic criteria established by the company. The project must achieve the goals from which the corporation can profit in the form of monetary gain, enhanced knowledge, or strategic opportunity. The government's perspective is more broadly defined since its desire is to provide a fair return to the state while maximizing the wealth from its natural resources. If balance between these two competing interests can be reached, then a deal can be struck.

The purpose of this Chapter is to develop an analytic framework to quantify the influence of private and market uncertainty on the economic and system measures associated with a field under a Production Sharing Agreement (PSA). The impact of changes in system parameters is usually presented as a series of graphs or tables that depict the present value, rate of return, or take (or whatever measure is under consideration) as a function of one or more variables under a "high" and "low" case scenario; e.g., (Smith, 1993; Wood, 1993). While useful, this approach is generally piecemeal and the results are anchored to the initial conditions employed. A more general and concise approach to fiscal system analysis, previously applied to a royalty/tax system, is developed in this paper.

The outline of the Chapter is as follows. In Chapter 2.2, the licensing and negotiation process involved in exploration and development activities is formalized, and in Chapter meta-modeling approach is presented in terms of a generalized fiscal system analysis. A hypothetical oil field is used to illustrate the analytic approach in Chapter 2.7, and in Chapter 2.8, the Angolan deepwater field development Girassol is presented as a case study. In Chapter 2.9, conclusions complete the Chapter.

2.2. The Licensing and Negotiation Process

Parties to a potential contract must be able to agree to the terms of the contract if a "deal" is to be made. The "deal" in oil and gas industry lore is the stuff of legend, and the wheeling, dealing, rough, and romantic industry of black gold does not necessarily lend itself to a sequence of precise and explicitly-enumerated stages, but categorizing, decomposing, and specifying the licensing and negotiation process is nonetheless a useful exercise even if it is ultimately flawed.

Signing a "bad deal" is the basic fear for both the contractor and host government, although the meaning of a "bad deal" varies with each party. Signing an unprofitable deal is the basic fear of the contractor, and contractors hedge against this outcome by involving multiple partners, maintaining a diverse portfolio of projects, and by paying particularly close attention to the risk-reward indicators estimated for each project. The economic measures – present value, rate of return, and profitability index – serve as a primary gauge for a contractor's negotiating strategies.

The objective of a host government is to acquire and maximize the wealth from its natural resources by encouraging appropriate levels of exploration and development activity. Since oil is a non-renewable resource, the benefits producers receive should be as owners of the oil, and not a rent. Oil is a commodity that is dispensed. The host government wants oil and gas companies interested in exploration to create healthy competition and market efficiency, and in the high pressure environment in which government representatives work, negotiations occur on a stage that is scrutinized and politicized by many government agencies, officials, and the press. The host government is primarily interested in the division of profits with the contractor[12], as well as various economic and socioeconomic indicators.

The basic stages of licensing and negotiation are presented in the following stylized framework. For a more comprehensive review of each stage, see (Bunter, 2002; Dur,1993). Refer to Appendix Figure B.1 for a schematic of the basic process. The timetable associated with each stage depends upon many factors, such as the economic conditions and political uncertainty that exist at the time of the licensing and/or negotiation, the level of interest of foreign participants, the experience of the host government and level of bureaucracy, the commitment and interest of the personnel involved, the frequency and timing of competitive prospects, etc. The basic stages follow.

[12] This is not always the case and depends upon conditions specific to the country

Stage 1. The host government (HG) divides prospective exploration areas into concession areas or blocks $\mathrm{B} = \{B_1,\ldots,B_k\}$. Data packages are prepared for each block B_i, $i = 1,\ldots, k$, and the form (or a draft) of the model contract Γ and fiscal terms F to be used as the basis for bid preparation is specified. The license round is advertised, and government officials may make a promotional tour to increase the awareness and interest in the sale.

Stage 2. For each block B_i

value of the total work requirement is important in determining the winning bid but is not necessarily an overriding factor.

b. Commercial bids are evaluated to test the fiscal terms proposed by each contactor. The evaluation of fiscal terms are more complicated and time consuming than the evaluation of the work commitment since it is based on a number of conditions that are uncertain (such as discovery, commerciality, reserve size, and field characteristics). Take and economic indicators associated with the development plan are the primary measures computed by the HG.

Stage 6. The HG compares the bids received to determine which terms are the "most favorable." The FOC(s) with the most favorable terms are short listed for further negotiation. In some cases, after the selection of the short list contractor(s), only "fine-tuning" of the contract is required. In other cases, additional more difficult negotiations will be required to "hammer out" an agreement.

Stage 7. The HG and FOC negotiate the final terms of the contract such that the economic, development, and socioeconomic objectives of each party are satisfied.

a. (FOC Perspective) The FOC concentrates primarily, but not exclusively, on profitability measures associated with the contract[15]. The common economic measures include

   $PV(B_i, \mathrm{F})$ = Present value of block B_i under fiscal system F,
   $IRR(B_i, \mathrm{F})$ = Internal rate of return of block B_i under fiscal system F.

b. (HG Perspective) The HG focus is more broadly defined since it wants to provide a fair return to the state, create healthy competition and market efficiency, and maximize the wealth from its natural resources. The HG considers the division of profits defined by the take statistic,

   $\tau^c(B_i, \mathrm{F})$ = Contractor take for block B_i under fiscal system F,

   the economic measures $PV(B_i, \mathrm{F})$ and $IRR(B_i, \mathrm{F})$, and socioeconomic measures,

   $U(B_i)$ = Socioeconomic measures for block B_i.

Stage 8. Terms of the fiscal regime F which are negotiable are suggested by the contractor to enhance their objective functions. These terms are then evaluated by the host government. The process is continued until either a mutually agreeable set of terms is determined, in which case a deal is made, or agreement cannot be reached and the deal is dead or negotiation resumes[16] at a later date. The negotiation process is specified as follows:

a. (FOC Perspective) The fiscal terms are negotiated to maintain company criteria on the expected economic and system measures for the risk capital invested:

$$\mathrm{E}[PV(B_i, \mathrm{F})] \geq A_i,$$
$$\mathrm{E}[IRR(B_i, \mathrm{F})] \geq B_i,$$

where the values A_i and B_i are usually "known," at least approximately, for the block under consideration.

b. (HG Perspective) The fiscal terms are negotiated to maintain government criteria on providing a fair return to the state, attracting foreign investment, and maximizing the wealth from its natural resources:

$$\mathrm{E}[PV(B_i, \mathrm{F})] \leq D_i,$$
$$\mathrm{E}[IRR(B_i, \mathrm{F})] \leq E_i,$$
$$\mathrm{E}[\tau^c(B_i, \mathrm{F})] \leq F_i,$$

where the values of D_i, E_i, and F_i are again known[17] approximately. The HG also has development and socioeconomic objectives that are specified in generalized functional form $U(B_i)$,

$$U(B_i) \geq G_i.$$

Stage 9. The outcome of negotiation either results in a deal or no-deal.

a. (Deal) If the fiscal terms F can be negotiated such that the functional values satisfy the FOC and HG constraints,

$$A_i \leq PV(B_i, \mathrm{F}) \leq D_i,$$
$$B_i \leq IRR(B_i, \mathrm{F}) \leq E_i,$$
$$\tau^c(B_i, \mathrm{F}) \leq F_i,$$
$$U(B_i) \geq G_i,$$

then an agreement can be reached and terms of the contract can be signed.

b. (No Deal) If fiscal terms cannot be agreed upon, the deal is dead.

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[16] These are very real concerns as the failed $25B Saudi Gas Initiative illustrates. From the beginning of talks with Saudi Aramco, ExxonMobil steadfastly demanded a 15%-18% rate of return on its investment, while the Saudis offered only 8%-10%. It is not surprising that the deal, after several years of talks, died.

[17] The degree to which the threshold limits are known for each functional depend in large measure on the host government's experience in licensing, the perceived geologic prospectivity and political risk in the region, the financial strength of the host government and desire for foreign capital, and the economic conditions that exist at the time.

Stage 10. The FOC submits final negotiated terms to the HG and then proceeds with activity as specified in the work commitment schedule.

2.3. Background Information

2.3.1. Contractual Systems: In most countries of the world, the government owns all the mineral resources, but will offer to foreign oil companies blocks to explore and develop. Contractual systems derive from the Napoleonic era and are based on the French legal concept that mineral resources should be owned by the state for the benefit of all citizens (Allen and Seba, 1993; Johnston, 1994b). The host government gives the oil company the right to receive a share of the production (or revenue) in accord with a PSA or Service Contract. The basic terms of a contractual system is usually determined through legislation, but many aspects may be negotiated. The terms of model contracts are frequently put forward by the host government as a basis for bidding and represent the *start* of negotiation between the contractor and government. The terms of model contracts are also frequently subject to renegotiation as political and economic conditions change, or as additional information becomes available.

2.3.2. Fiscal Components of Contractual Systems: In a production sharing agreement, exploration is performed by the operating company at its own risk. The risk is similar to the risk associated with exploration under a contractual system, but significant differences arise in how the expenditures are recovered if commercial reserves are found and the manner reserves are split between the host country and the company.

In its most basic form, a PSA has four components:

1. *Royalty*,
2. *Cost Recovery*,
3. *Profit Oil*, and
4. *Tax*.

The royalty is computed as a percentage of the gross revenues of the sale of hydrocarbons, and like many elements in a PSA, may be determined on a sliding scale the terms of which may be negotiable or biddable. The oil company pays royalty to the government and is then entitled to a pre-specified share of production for cost recovery. The remainder of the production is split between the government and the oil company at a stipulated (often negotiated) rate. The o individual basis. The intent of the following discussion is to provide a general analytic framework to describe the fiscal terms common to most PSAs.

2.4.1. After-Tax Net Cash Flow Vector: The net cash flow vector of an investment is the cash received less the cash spent during a given period, usually taken as one year, over the life of the project. The after tax net cash flow associated with field *f* in year *t* generally takes the form

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - PO/G_t - TAX_t - OTHER_t,$$

where,

NCF_t = After-tax net cash flow in year *t*,
GR_t = Gross revenues in year *t*,
ROY_t = Total royalties paid in year *t*,
$CAPEX_t$ = Total capital expenditures in year *t*,
$OPEX_t$ = Total operating expenditures in year *t*,
$BONUS_t$ = Bonus paid in year *t*,
PO/G_t = Government profit oil in year *t*,
TAX_t = Total taxes paid in year *t*,
$OTHER_t$ = Other costs paid in year *t*.

The after tax net cash flow vector associated with field *f* is denoted as

$$(\quad)\quad(\quad_{1},\quad_{2},\ldots,\quad_{k})$$

The gross revenues adjusted for the cost of transportation and basic processing form the base of the royalty payment,

$$ROY_t = R(\boldsymbol{\psi})(GR_t - ALLOW_t),$$

where the total allowance cost is denoted by $ALLOW_t$ and the royalty rate $R(\boldsymbol{\psi})$ depends upon the location and time the tract was leased and the incentive schemes, if any, in effect. The royalty rate $R(\boldsymbol{\psi})$, $0 \leq R(\boldsymbol{\psi}) \leq 1$, may be fixed or a sliding scale may be employed. The terms of the royalty rate, like many other PSA factors, may be negotiable or biddable.

The capital and operating expenditures, $CAPEX_t$

$$CR_t = U_t + CAPEX/I_t + OPEX_t + DEP_t + INT_t + INV_t + DECOM_t,$$

where,

$CR_t =$ Cost recovery in year t,

$U_t =$ Unrecovered cost carried over from year $t-1$,

$CAPEX/I_t =$ Intangible capital expenditures in year t,

$DEP_t =$ Depreciation in year t,

$INT_t =$ Interest on financing in year t,

$INV_t =$ Investment credits and uplift in year t,

$=$

return on capital is consistent with the risk associated with the project and the strategic objectives of the corporation. The primary analytic techniques utilize a time value of money approach (Brealey and Myers, 1991), and several popular measures such as the present value, internal rate of return, and

$$\tau_t^{\,c} = \frac{CT_t}{TP_t},$$

$$\tau_t^{\,g} = \frac{GT_t}{TP_t}.$$

2.5.3. Government and Contractor Discounted Take: Take varies as a function of time over the life history of a field and is best computed on a discounted cumulative basis to account for the distribution of the cash flow and the distinct manner in which the contractor and government value money. The contractor and government take computed

- Duration (exploration, production),
- Relinquishment,
- Exploration obligations,
- Bonuses (signature, discovery, production),
- Royalty rate,
- Cost recovery schedule,
- Depreciation,
- Profit oil split,
- Taxation,
- Ringfencing,
- Domestic market obligations,
- Investment uplift, and
- State participation.

Tax rates, depreciation schedules, government participation, investment credits, domestic obligation, and ringfencing are normally legislated and thus provide no opportunity for negotiation, while relinquishment requirements, bonus payments, cost recovery, and profit sharing can be subject to negotiation. Generally speaking, the more aspects of a contract that are subject to negotiation the better, since flexibility is often required to offset differences between basins, regions, and license areas within a country (Johnston, 1994b).

<u>2.6.2. System Functionals:</u> A contract is written for the block B_i, and if exploratory efforts on the block are successful, one or more fields will be discovered. The terms of the contract that were negotiated *before* exploratory activities were undertaken now hold for the commercial activity on the block. If the field discoveries are "significantly different" than the assumptions used in the negotiation process (either on the upside or downside), or if economic or political conditions change dramatically, then renegotiation of the terms of the contract may be initiated by the contractor or host government.

A field is described by its expected reserves X(f), development plan D(f), cost structure C(f), and production profile Q(f):

$$f \leftrightarrow \{ X(f), \; C(f), D(f), Q(f)\}.$$

Contract Γ is a function of the fiscal terms negotiated for the block, and it is impossible, except under the very simplest contracts, to quantify *all* aspects of the PSA[21]. Fortunately, the[5 terms)Tj(f gble, contract most0 relevant 15 from an(economic perspective can TD8.8(s(), Q()Tj/T

3. Infer results of the change in factor ψ_i through the difference $\Delta\varphi(\boldsymbol{\psi}, \boldsymbol{\psi}')= \Delta\varphi(\mathrm{F}(\boldsymbol{\psi}), \mathrm{F}(\boldsymbol{\psi}'))= \varphi(f, \mathrm{F}(\boldsymbol{\psi}'))- \varphi(f, \mathrm{F}(\boldsymbol{\psi}))$.

4. Employ the graphical relations $\Delta\varphi(\mathrm{F}(\boldsymbol{\psi}), \mathrm{F}(\boldsymbol{\psi}'))$ in fiscal system analysis.

Although useful and commonly employed in fiscal system analysis, there are also

2.7. A Functional Analytic Approach to System Evaluation

2.7.1. Development Scenario: The development scenario outlined is for a hypothetical 40 MMbbl field with a projected 11-year life depicted in Appendix Table B.1. The projected production, capital expenditures, and operating expenditures are extracted from Johnston (Johnston, 1994b) under a base case development scenario specified for P_{50} reserves.

Total capital costs are estimated at $69r

For a given component specification, such as (P, CR, T, D^c) = (20, 0.6, 0.35, 0.10), it is easy to express take in terms of the present value or rate of return measure through regression:

$$PV(f, \mathrm{F}) = 52 + 2.9\ \tau^c(f, \mathrm{F}).$$

More generally, the correlation between τ^c and PV is $\rho(\tau^c, PV) = 0.76$, and $\rho(\tau^c, IRR) = 0.46$, $\rho(PV, IRR) = 0.61$.

The expected value and standard deviation of the system measures are shown in the last and with the exception of *PO*-1 and *Q*(*f*), all the coefficients are highly significant. The present value of the project increases with the price, cost oil and profit oil, and decreases with the tax rate and corporate discount factor. The model coefficients for *PO*-1 and *PO*-2 suggest that the value of *PO*-2 is considerably more significant to the profitability of the field than *PO*-1. Insights derived from the regression modeling are a quick and convenient way to evaluate and direct negotiation strategies.

2.8. Deepwater Angola Case Study: Girassol

2.8.1. The Angola Play: The West Africa play runs along the Nigeria-Angola axis and includes the countries Nigeria, Cameroon, Equatorial Guinea, Sao Tome and Principe, Gabon, and Angola. Refer to Appendix Figure B.2. When the continents were spreading millions of years ago, a large volcanic ridge extended across the South Atlantic which closed off and restricted the northern oceanic waters, which eventually evaporated into salt basins along the north of the ridge (Shirley, 2000). The result is that the West Africa region has extremely rich source rocks in salt basins characterized by faulting – adding up to large structures with good migration paths. South of Angola (and the ridge), the geology changes dramatically and so do the pros

The development plan was scheduled in two phases. In phase I, approximately 75% of the $2.7B budget was used to construct a

Cost oil is defined in terms of the cost recovery scheme as follows:

$$CO_t = \min(CR_t,\ CR(\psi)GR_t),$$

where $CR(\psi)$ is determined through a Uniform distribution, $CR(\psi) \sim U(0.25, 0.75)$, and unrecovered cost in year $t - 1$ is carried forward and recovered in a subsequent period. If $CR(\psi)GR_t > CR_t$, then CR_t will be selected through the minimization operator "min" in the cost oil, and there will not be any unrecovered cost. On the other hand, if $CR(\psi)GR_t < CR_t$, then the selection of $CR(\psi)GR_t$ will prevent full cost recovery, and the difference between these two quantities, or

$$U_t = CR_t - CR(\psi)GR_t,$$

determines the unrecovered cost which is passed through to the next year.

Uplift is a fiscal incentive which allows the contractor to recover an additional percentage of the development costs associated with placing a discovery into production[24]. Uplift follows the Uniform distribution, $UP \sim U(0.30, 0.50)$, and acts as a multiplier on all tangible and intangible capital expenditures as follows:

$$(1+ UP)CAPEX/T_t\ ,$$
$$(1+ UP)CAPEX/I_t\ .$$

The contractor and government discount factors are assumed to range as follows:

$$D^c \sim U(0.05, 0.20),$$
$$D^g \sim U(0.00, 0.10).$$

Domestic market obligations and government participation are not considered, and since the range of the oil price is assumed to fall below $30/bbl, the price cap fee does not play a role in the analysis.

In Model II and Model III the depreciation schedule and profit oil split are considered design variables. Depreciation schedules are an accounting convention designed to emulate the cost associated with a reduction in the value of a tangible asset. Although different assets normally have different depreciation horizons, most PSAs in the world use a 5-year straight line depreciation schedule, and Angola is no exception with most contracts written since 1984 using a 3-5 year straight line schedule. D_d denotes a d-year straight line depreciation schedule, and the value of d is assumed to be integer-valued, $d = 3$, $d= 5$, or $d = 7$. In Model III the profit oil split schedule is generalized in terms of a variable tranche Y_i and percentage value Z_j as shown in Appendix Table B.8. The values

[24] For example, if a contractor spent $100M on development costs (drilling, production facilities, transportation costs) and the government allowed a 40% uplift, then the contractor is allowed to recover $100(1+0.4)M = $140M.

of Y_i, i = 1,…, 4 and Z_j, j = 1,…, 4 are selected from the distributions shown in Appendix Table B.6.

2.8.6. Regression Model Results: The results of the regression models for $\tau^c(f, \mathrm{F})$, $PV(f, \mathrm{F})$, and $IRR(f, \mathrm{F})$ for Models I-III are shown in Appendix Tables B.9-B.11.

In Model I, the coefficients α_i of the linear model

$$\varphi(f, \mathrm{F}) = \sum_{i=1}^{7} \alpha_i X_i$$

for parameter vector $(X_1,...,X_7) = (P, R, CR, UP, T, D^c, D^g)$ and $\varphi(f, \mathrm{F}) = \{PV(f, \mathrm{F}), \tau^c(f, \mathrm{F}), IRR(f, \mathrm{F})\}$ are estimated using standard least squares regression. For the most part, the model coefficients maintain the expected signs, the fits are generally very robust, and the coefficients are statistically significant. Coefficients that do not exhibit the expected signs are usually not statistically significant.

The present value functional of the field development is estimated as

$PV(f, \mathrm{F}) = -724.8 + 54.5P - 28.7R + 731.4CR + 278.0UP - 514.7T - 4639.1\, D^c - 120.7 D^g$,
so that at $(P, R, CR, UP, T, D^c, D^g) = (25, 0, 0.5, 0.4, 0, 0.15, 0.05)$,

$$PV(f, \mathrm{F}) = \$412.7\mathrm{M}.$$

The regression coefficients for take and rate of return are shown in Appendix Table B.9, and when evaluated at the above parameter specification yields

$$\tau^c(f, \mathrm{F}) = 6.8\%,$$
$$IRR(f, \mathrm{F}) = 7.1\%.$$

In Model II, separate regression models are constructed for the depreciation schedules D_d, d = 3 and d = 7:

$$\varphi(f, \mathrm{F}) = \sum_{i=1}^{7} \alpha_{ij} X_i,\ j = 3, 7.$$

To model the impact of a change in depreciation schedule, it is necessary to dynamically link the requirements of depreciation with the uplift parameter and the unrecovered cost. The uplift parameter is a Uniform random variable which impacts the amount of tangible capital expenditures that can be depreciated, subsequently impacting the cost recovery schedule and the amount of unrecovered cost. The results of Model II are shown[25] in Appendix Table B.10.

[25] The results of the regression models could also be combined into one relation,

In Model IIa, a 3-year depreciation schedule is applied, while in Model IIc, a 7-year depreciation schedule is used (Model IIb = Model I, a 5-year depreciation schedule). For comparison we evaluate each model at $(P, R, CR, UP, T, D^c, D^g) =$ (25, 0, 0.5, 0.4, 0, 0.15, 0.05). The results in this case,

$$PV(f, D_3) = \$387.9\text{M},$$
$$PV(f, D_5) = \$412.7\text{M},$$
$$PV(f, D_7) = \$382.5\text{M},$$

are inclusive since the expected relation $PV(f, D_3) > PV(f, D_5) > PV(f, D_7)$ does not hold across the three depreciation schedules.

In Model III, the profit oil split schedule depicted in Appendix Table B.7 is considered the "design" variable. As a casual examination of Appendix Table B.7 reveals, the variable selected to drive the model (q), the number of tranches (4), the tranche thresholds (25, 50, 100), and the value of the profit oil split percentages (55, 30, 20, 10) specify the Angolan profit oil split. In total, ignoring the selection of the driver variable and number of tranches, 3 threshold levels denoted Y_i, i = 1,2,3, and 4 profit oil split percentage values Z

to delineate the system parameters (X_i) from the design parameters (Y_j, Z_k). Since the

2.9. Conclusions

To understand the economic and system measures associated with a contractual fiscal regime a meta-model was developed. In the meta-evaluation procedure, a cash flow model specific to a given fiscal regime is coupled with a simulation strategy to investigate the influence of various system variables. Meta-modeling is not a new idea, but as applied to fiscal system analysis and contract valuation, is new, novel, and useful.

A constructive approach to fiscal system analysis was developed to isolate variable interaction and determine the manner in which private and market uncertainty impact take and the economic measures associated with a field. Functional relations were developed by computing the component measures for parameter vectors selected within a given design space. The relative impact of the parameters and the manner in which the variables are correlated was also established in a general manner. The methodology was illustrated on a hypothetical oil field and a case study for the Angolan deepwater Girassol development was considered. The impact of fiscal design on the field economics of Girassol was also examined.

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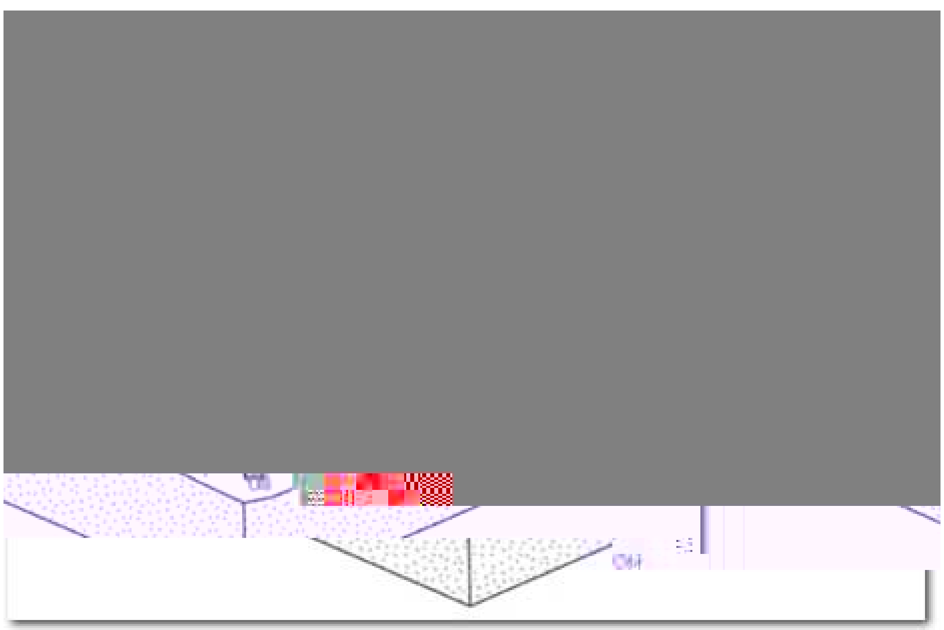
APPENDIX A

CONCESSIONARY SYSTEMS FIGURES AND TABLES

Source:Shell (www.shell.com)

Figure A.1: The Na Kika Field Development.



Source: Shell (www.shell.com)

Figure A.2: The Na Kika Host Platform and Subsea Well Configuration.

Table A.3

Projected Production, Capital Expenditures, and Operating Expenditures for the Na Kika Field Development

Year	Oil Production (bbl/day)	Gas Production (MMcf/day)	CAPEX/T ($M)	CAPEX/I ($M)	OPEX

Table A.4

The Design Space of the Na Kika System Parameters

Parameter (unit)	Model I [a]	Model II[b]	Model III	Model IV
P^o($/bbl)	U(20, 30)	LN(25, 5)	LN(25, 5)[c]	LN(25, 5)[c]
P^g ($/Mcf)	U(2, 5)	LN(3.5, 1.5)	LN(3.5, 1.5)[c]	LN(3.5, 1.5)[c]
R (%)	U(0.10, 0.20)	U(0.15, 0.18)	U(0.15, 0.18)	U(0.15, 0.18)
Q (MMBOE)	U(0, 100)	U(0, 100)	U(0, 100)	U(0, 100)
T (%)	U(0.35, 0.50)	U(0.40, 0.50)	U(0.40, 0.50)	TR(0.38, 0.44, 0.50)[d]
D^c (%)	U(0.15, 0.40)	U(0.05, 0.15)	U(0.05, 0.15)	U(0.05, 0.15)
D^g (%)	U(0.05, 0.15)	U(0.00, 0.05)	U(0.00, 0.05)	U(0.00, 0.05)

Footnote: (a) U(a, b) denotes a Uniform probability distribution with endpoints (a, b).

(b) LN(c, d) represents a Lognormal probability distribution with mean c and standard deviation d.

(c) P^o and P^g are assumed to vary on an annual basis; i.e., $P^o = P_t^o \sim$ LN(25, 5) and $P^g = P_t^g \sim$ LN(3.5, 1.5) for t= 1, …, 12.

(d) TR(e, f, g) represents a Triangular probability distribution with minimum e, most likely f, and maximum g. T is assumed to vary on an annual basis; i.e., $T = T_t \sim$ TR(0.38, 0.44, 0.50) for t= 1, …, 12.

Table A.5

The Impact of Royalty Relief on Contractor Take, Present Value, and Internal Rate of Return for the Na Kika Field Development

$\varphi(f)$		$\varphi(f) = k + \alpha P^o + \beta P^g + \gamma R + \delta Q + \varepsilon T + \theta D^c + \lambda D^g$								R^2
	Model	k	α	β	γ	δ	ε	θ	λ	
τ^c (f)	I	80.0(161)	0.2(18)	0.5(13)	-53.0(-50)	0.04(42)	-79.1(-112)	-84.3(-198)	86.2(78)	0.99
	II	86.7(369)	0.2(26)	0.1(21)	-54.1(-51)	0.04(121)	-77.4(-243)	-108.6(-337)	107.9(164)	0.99
	III	86.8(123)	0.1(4)	0.1(2)	-53.3(-21)	0.03(50)	-78.6(-99)	-107.9(-145)	107.0(70)	0.98
	IV	86.7(30)	0.1(1)	0.1(*)	-54.6(-12)	0.04(30)	-76.0(12)	-108.9(-81)	106.8(40)	0.95
$PV(f)$	I	1460.7(33)	38.2(40)	131.5(42)	-1259.8(79)	1.1(12)	-1856.1(-30)	-3699.4(-99)	79.8(1)	0.97
	II	2113.6(29)	56.9(98)	232.0(119)	-2200.6(-7)	1.8(17)	-3404.8(-35)	-8294.5(-83)	27.6(*)	0.98
	III	2252.5(12)	52.6(12)	226.5(14)	-1957.1(-3)	1.2(6)	-3414.2(-17)	-8086.6(-42)		

Table A.6

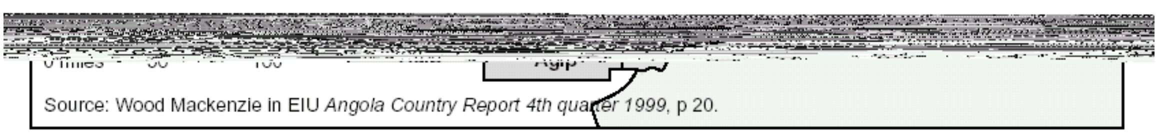
Statistical Data for the Na Kika Regression Models

Functional (unit)	Model	P_5	Mean	P_{95}
τ^c (*f*) (%)	I	15.1	31.6	53.4
	II	31.8	38.6	45.7
	III	31.4	38.4	46.2
	IV	33.3	39.4	45.9
PV(*f*) ($M)	I	483	939	1,540
	II	1,178	1,809	2,745
	III	1,321	1,756	2,324
	IV	1,339	1,818	2,331
IRR(*f*) (%)	I	42.1	62.7	95.2
	II	64.8	89.7	125.6
	III	69.9	87.7	112.7
	IV	70.9	90.8	120.7

APPENDIX B

CONTRACTUAL SYSTEMS FIGURES AND TABLES

Figure B.1: Typical Bid Evaluation and Negotiation Process in Licensing Agreements.



Source: Wood Mackenzie in EIU *Angola Country Report 4th quarter 1999*, p 20.

Figure B.2: Angola Oil License Blocks.

Source: Stolt Offshore (www.stoltoffshore.com)

Figure B.3: The Girassol FPSO.

Source: Total (www.total.com)

Figure B.4: The Girassol Development Plan.

Table B.1

Projected Production, Capital Expenditures, and Operating Expenditures for a Hypothetical 40 MMbbl Field

Year	Oil Production (MMbbl)	CAPEX/I ($M)	CAPEX/T ($M)	OPEX ($M)
1994	0	0	10.0	0
1995	0	0	8.0	0
1996	0	0	15.0	0
1997	4.500	15.0	10.0	11.5
1998	7.000	2.0	0	14.0
1999	5.600	0	0	12.6
2000	4.760	0	0	11.8
2001	4.046	0	0	11.0
2002	3.439	0	0	10.4
2003	2.923	0	0	9.9
2004	2.485	0	0	9.5
2005	2.087	0	0	9.1
2006	1.732	0	0	8.7
2007	1.427	0	0	8.4
2008	0	0	0	0
Total	40.000	17.0	43.0	117.0

Source: Johnston, 1994b; Table 4-3.

Table B.2

Table B.3

Contractor Take, Present Value, and Internal Rate of Return for a Hypothetical 40 MMbbl Field – Model I Results

Model Coefficient	$\varphi(f, \mathrm{F}) = \alpha_0 + \alpha_1 P + \alpha_2 R + \alpha_3 CR + \alpha_4 PO + \alpha_5 T + \alpha_6 D^c + \alpha_7 D^g$		
	$\tau^c(f, \mathrm{F})$ (%)	$PV(f, \mathrm{F})$ ($M)	$IRR(f, \mathrm{F})$ (%)
α_0	14.1 (14)	-25.3 (-4)	2.5 (*)
α_1	0.1 (7)	3.7 (34)	1.0 (9)
α_2	-18.4 (-11)	0.7 (*)	-12.2 (-2)
α_3	-1.9 (-1)	24.0 (7)	9.1 (3)
α_4	40.8 (75)	118.2 (35)	36.4 (10)
α_5	-27.3 (-15)	-80.8 (-7)	-21.2 (-2)
α_6	-54.7 (-40)	-204.1(-24)	-204.1 (-24)
α_7	61.6 (18)	-23 (-1)	-23 (-1)
R^2	0.95	0.87	0.31
$E[\varphi(f, \mathrm{F})]$	15.5%	$24.7M	14.8%
$\sigma[\varphi(f, \mathrm{F})]$	9.2%	$36.4M	12.8%

Footnote: t-statistics are in parenthesis, (*): t-statistic < 1

Table B.4

Contractor Take, Present Value, and Internal Rate of Return for a Hypothetical 40 MMbbl Field – Model II Results

$\varphi(f, \mathrm{F})=$

Table B.5

Projected Production, Capital Expenditures, and Operating Expenditures for the Girassol Field Development

Year	Production (bbl/day)	CAPEX/T ($M)	CAPEX/I ($M)	OPEX ($M)
1999	0.0	32.31	0.00	0.00
2000	0.0	204.77	252.35	4.92
2001	0.0	337.12	316.02	5.91
2002	192,000.0	98.07	168.02	31.43

Table B.6

The Design Space for the Girassol Field Development

Parameter (unit)	Model I[a]	Model II	Model III
P^o ($/bbl)	U(10, 30)	U(10, 30)	U(10, 30)
R (%)	U(0.00, 0.10)	U(0.00, 0.10)	U(0.00, 0.10)
CR (ψ) (%)	U(0.25, 0.75)	U(0.25, 0.75)	U(0.25, 0.75)
UP (%)	U(0.30, 0.50)	U(0.30, 0.50)	U(0.30, 0.50)
T (%)	U(0.00, 0.20)	U(0.00, 0.20)	U(0.00, 0.20)
D^c (%)	U(0.05, 0.20)	U(0.05, 0.20)	U(0.05, 0.20)
D^g (%)	U(0.00, 0.10)	U(0.00, 0.10)	U(0.00, 0.10)
D_d (yr)	d= 5	d = 3, 7	d = 5
Y_1 (MBOPD)			U(0, 25)
Y_2 (MBOPD)			U(25, 50)
Y_3 (MBOPD)			U(50, 100)
Z_1 (%)			U(0.30, 0.75)
Z_2 (%)			U(0.20, 0.40)
Z_3 (%)			U(0.10, 0.30)
Z_4 (%)			U(0.00, 0.20)

Footnote: (a) $U(a, b)$ denotes a Uniform probability distribution with endpoints (a, b).

Table B.7

Angolan Profit Oil Split (1990)

q (MBOPD)	$PO(q)$ (%)
< 25	55
25-50	30
50-100	20
> 100	10

Table B.8

A Generalized Profit Oil Split Functional

q (MBOPD)	$PO\ (q)$ (%)
$< Y_1$	Z_1
$Y_1 – Y_2$	Z_2
$Y_2 – Y_3$	Z_3
$\geq Y_3$	Z_4

Table B.9

Girassol Regression Model I Results

Model Coefficient	$\varphi(f, \mathrm{F}) = \alpha_0 + \alpha_1 P + \alpha_2 R + \alpha_3 CR + \alpha_4 UP + \alpha_5 T + \alpha_6 D^c + \alpha_7 D^g$
	c

Table B.10

Girassol Regression Model II Results

Table B.11

Girassol Regression Model III Results

Model Coefficient	$\varphi(f, \mathrm{F}) = \sum_{i=0}^{7} \alpha_i X_i + \sum_{j=1}^{3} \beta_j Y_j + \sum_{k=1}^{4} \gamma_k Z_k$	
	$\tau^c(f, \mathrm{F})$ (%)	$PV(f, \mathrm{F})$ ($M)
α_0	1.2 (3)	-1666.1 (-15)
α_1	0.01 (4)	47.4 (48)
α_2	-4.8 (-6)	-214.2 (-1)
α_3	-0.5 (-3)	869.4 (22)
α_4	-0.4 (-1)	216.9 (2)
α_5	-4.5 (-11)	-408.2 (-4)
α_6	-30.5 (-57)	-3793.4 (-29)
α_7	28.3 (18)	9.9 (*)
β_1	0 (0)	0 (*)
β_2	0 (5)	0 (1)
β_3	0 (9)	0 (4)
γ_1	0.8 (2)	90.2 (1)
γ_2	3.8 (9)	403.9 (4)
γ_3	4.9 (6)	869.6 (4)
γ_4	40.0 (50)	3771.7 (20)
R^2	0.94	0.92
P_5	1.4	-533
Mean	4.0	180
P_{95}	7.7	738

Footnote: t-statistics are in parenthesis, (*): t-statistic < 1

(1) being
a dialogue with all potentially
with an emphasis on working to enhance the
MMS assistance and expertise to economic
protection.