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

U.S. Department of the Interior
Minerals Management Service
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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.

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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 system measure associated with a field, and the only time that take, present value, or rate of return can be calculated with certainty is *after* the field has been abandoned and *all* the relevant revenue and cost data made public. Only in the case of "perfect" information, when all revenue, cost, royalty and tax data is known for the life of the field can profitability and the division of profits be reliably established.

Unfortunately, as most casual observers of the oil/gas industry are aware, it is rare indeed when the net cash flow from a real asset is available outside the firm, and rarer still if it is made public. Cash flow and cost information is proprietary. Operators on federal leases are required to report production data to the government on a well basis, and so the revenue and royalty stream on a structure, field, and/or property basis can be readily estimated, but the revenue stream is only half of the equation, and the all-important and ever-elusive cost data – including capital and operating expenditures, depreciation schedules, financing costs, interest on payments, decommissioning cost, etc. – need to be inferred. The reliability of the inference represents one of the primary limitations associated with the accurate computation of the economic and system measures associated with a field.

The computation of economic and system measures requires each of the revenue and expense items to be estimated and forecast over the life of the project. Imperfect information, incomplete knowledge, and private/market uncertainty dictate the terms of the correspondence. The manner in which these forecasts are performed, relying on both art and science, opinion and fact, rules-of-thumb and advanced quantitative modeling, 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 a case study, and in Chapter 1.10, conclusions complete the Chapter.

1.2. The Stages of an Oil and Gas Venture

A model oil and gas venture can be considered to consist of distinct stages separated in time as follows (Gerwich, 2000):

I. Leasing,
II. Exploration,
III. Appraisal,
IV. Development,
V. Production,
VI. Decommissioning.

In the United States, an oil company acquires mineral rights from the government or private landowner, while outside the U.S. a host government typically grants a license (lease, or block area) or enters into a contractual arrangement with an operator to develop a field without owning the mineral resources. The contractor or operator refers to an oil company, contractor group, or consortium. The host government is represented by a national oil company, an oil ministry, or both.

After acquiring leasing rights, the oil company will carry out geological and geophysical investigations such as seismic surveys and core borings. Seismic acquisition is usually performed by contractors who specialize in providing the service to industry. The company's geophysical staff process and interpret the data in-house or it may be contracted out to another contractor or the same contractor who acquired the data. If a play appears promising, exploratory drilling is carried out. A drill ship, semi-submersible, jack-up, or floating vessel will be used depending on the location of the field, rig supply conditions, and market rates. The purpose of exploration is to discover the presence of oil and gas.

If hydrocarbons are discovered, further delineation wells may be drilled to establish the amount of recoverable oil, production mechanism, and structure type. The number of wells required to develop the reserves depends on a tradeoff between risked capital and expected production. Generally speaking, the more wells a company is willing to drill (risked capital), the faster the rate of extraction and revenue generation. Development planning and feasibility studies are performed and the preliminary development plan will form the basis for cost estimation.

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.

At the end of the useful life of the field, which for most structures occurs when the production cost of the facility is equal to the production revenue (the so-called "economic limit"), a decision is made to decommission. Decommissioning represents a liability as opposed to an investment, and so the pressure for an operator to decommission a structure is not nearly as strongly driven as installation activities. In most instances, properties are divested and decommissioning liability is transferred to the new owner (although liability is never completely dissolved by this action). For a successful removal, operators generally begin planning one or two years prior to the planned date of decommissioning.

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 of taxation were added. Today there are numerous fiscal devices and sophisticated formulas to capture rent.

In the traditional concessionary system, the company pays a royalty based on the value of the recovered mineral resources, and one or more taxes based on taxable income. In its most basic form, a concessionary system has three components:

1. *Royalty,*
2. *Deduction,*
3. *Tax.*

The royalty is normally a percentage of the gross revenues of the sale of hydrocarbons and can be paid in cash or in kind. Royalty represents a cost of doing business and is thus tax-deductible. Other deductions typically include operating cost, depreciation of capitalized assets, and amortization. The revenue that remains after the fiscal cost has been deducted is called taxable income.

The definition of fiscal costs is described in the legislation of the country. Royalties and operating expenditures are normally expensed in the year they occur, and depreciation is calculated according to the tax legislation. The taxable income under a concessionary agreement is normally taxed at the country's basic corporate tax rate. Special royalty incentive programs and tax rates may also apply.

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[1] Changes may act in favor of operators (such as occurs with royalty relief and accelerated depreciation schedules) or act against operators (as would occur with an increase in the tax rate).

[2] The mines of Laurium were owned by the State but were leased to its citizens for one talent and a rent (or tribute) of one twenty-fourth of the output, in bullion.

The exact manner in which costs are capitalized or expensed depends on the tax regime of the country and the manner in which rules for integrated and independent producers vary. The successful-efforts and full-cost methods used in U.S. oil and gas accounting are discussed in detail in (Gallun et al., 2001). If costs are capitalized, they may be expensed as expiration takes place through abandonment, impairment, or depletion. If expensed, costs are treated as period expenses and charged against revenue in the current period. The primary difference between the two methods is the timing of the expense against revenue and the manner in which costs are accumulated and amortized.

1.4. Cash Flow Analysis of a Royalty/Tax Fiscal Regime

The terms and conditions of concessionary systems vary widely and may employ various sophisticated formulas to determine royalty and taxation levels, but underneath the diversity and complexity of terms, concessionary systems are fairly uniform in their treatment of royalty and tax obligation. The intent of the following discussion is to describe the elements common to most royalty/tax systems.

1.4.1. 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* is computed as

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - TAX_t ,$$

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,
TAX_t = Total taxes paid in year t.

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

$$NCF(f) = (NCF_1, NCF_2, ..., NCF_k) ,$$

and is assumed to begin in year one (t = 1) and run through field abandonment (or divestment) at $t = k$. The after-tax net cash flow vector serves as the basic element in the computation of take and the economic measures associated with the field.

1.4.2. Cash Flow Components: The gross revenues in year t due to the sale of hydrocarbons is defined as

$$GR_t = g_t^o \, P_t^o \, Q_t^o + g_t^g \, P_t^g \, Q_t^g$$

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:

$$\mathrm{GR}_t = g_t^o P_t^o Q_t^o + g_t^g P_t^g Q_t^g = \left(\frac{g_t^o P_t^o Q_t^o + g_t^g P_t^g Q_t^g}{Q_t^o + Q_t^g} \right) (Q_t^o + Q_t^g) = P_t^w (Q_t^o + Q_t^g)\,.$$

The gross revenues adjusted for the cost of basic gathering, compression, dehydration and sweetening form the base of the royalty:

$$ROY_t = R\,(GR_t - ALLOW_t).$$

The total allowance cost is denoted by $ALLOW_t$ and includes allowances set by regulation for the cost of gathering, compression, dehydration, and sweetening of the hydrocarbon stream. The royalty rate R, $0 \le R \le 1$, depends upon the location and time the tract was leased and the incentive schemes, if any, in effect. The "typical" federal royalty rate in the United States is R = 1/8th (12.5%) onshore and R = 1/6th (16.67%) offshore.

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[3] Barrels of oil equivalent is the amount of natural gas that has the same heat content of an average barrel of oil. One BOE is about 6 Mcf of gas.

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 function of company size, capital budget, and number of projects under consideration. Large firms tend to use a central review committee; formal written capital budgeting procedures; and a post audit on completed projects. Small firms tend not to 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 evaluate a contract's economic performance.

1.5.2. The Take Statistic: The division of profit between the contractor and government is referred to as "take." Take is a fiscal statistic as opposed to an economic measure, and so generally matters most to the host government. In fact, since take does not provide a direct indication of the economic performance of a field, the contractor holds only secondary interest in its value. Further, unlike the economic measures which are generally well-established, general confusion surrounds the application and interpretation of take. "Take" is commonly cited throughout the trade and academic press (Johnston, 2002a; Johnston, 2000; Johnston, 1994a; Johnston, 1993; Khin and Liang, 1993; Van Meurs and Seck, 1995; Van Meurs and Seck, 1997; Rapp et al., 1999; Smith, 1993; Smith, 1987; Wood, 1990a; Wood, 1990b;Wood, 1993) and various texts (Allen and Seba, 1993; Barrows, 1983; Barrows, 1994; Johnston, 1994b; Kemp, 1987; Van Meurs and Seck, 1995; Thompson and Wright, 1984; Van Meurs, 1971), and because of the commercial interest involved, strong opinions abound[4].

It is commonly accepted that the level of government take is inversely proportional to the overall quality of the investment opportunity. In a purely competitive world, countries

[4] The following quote is especially revealing: "I believe the government take statistic suffers from both under-use and over-use. When people are unaware of the weaknesses (and I believe few are intimate with all the weaknesses associated with the 'take' statistics), then over-use is extremely likely." (Johnston, 2002a).

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. A "tough" contract may be highly profitable, while a very "favorable" contract may not be. Good geologic projects do not always translate to profitable ventures.

Rutledge and Wright (1998) claim that a 50%-50% split between government and contractor was considered a fair value before the two oil shocks, but after the creation of OPEC, companies began to accept some erosion of their take. A study performed by Petroconsultants in 1995 showed that in more than 90% of 110 countries examined, government take ranged from 55%-75%. Other studies have shown similar results; e.g., (Johnston, 1994b; Kemp, 1987; Van Meurs and Seck, 1995; Van Meurs and Seck, 1997).

1.5.3. Annual Government and Contractor Take: The total cost in year *t*, TC_t, is defined as

$$TC_t = CAPEX_t + OPEX_t,$$

and the total profit is the difference between the gross revenues and total cost:

$$TP_t = GR_t - TC_t.$$

If the total profit in year *t* is written

$$TP_t = CT_t + GT_t,$$

then the contractor and government take is computed as,

$$CT_t = TP_t - ROY_t - TAX_t = \text{Contractor take in year } t,$$

$$GT_t = ROY_t + TAX_t = \text{Government take in year } t.$$

The contractor and government take in year *t*, expressed in percentage terms, is defined as

[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. A "tough" contract may be highly profitable, while a very "favorable" contract may not be. Good geologic projects do not always translate to profitable ventures.

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

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:

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

During the installation and development phase of a project, and before production begins, gross revenue is zero and total profit is negative. In this case, take is not defined, or by convention is set equal to $\tau_t^c = -1$. As production begins $GR_t > 0$, and if $GR_t > TC_t$, then $TP_t > 0$ and the division of profit can be computed; i.e., in this case, $0 \leq \tau_t^c \leq 1$. If $0 < GR_t < TC_t$, the government take is positive but $CT_t < 0$. In this case, $\tau_t^g > 1$ and $\tau_t^c < 0$ since $\tau_t^c + \tau_t^g = 1$.

<u>1.5.4. Cumulative Discounted Government and Contractor Take:</u> Cumulative discounted government and contractor take through year x, $x = 1,\ldots, k$, is computed as

$$PV_x\,(\tau^c) = \frac{PV_x(CT)}{PV_x(CT) + PV_x(GT)},$$
$$PV_x(\tau^g) = \frac{PV_x(GT)}{PV_x(CT) + PV_x(GT)},$$

where,

$PV_x(CT) = \sum_{t=1}^{x} \frac{CT_t}{(1+D^c)^{t-1}} =$ Present value of contractor take through year x, $x = 1,\ldots, k$,

$PV_x(GT) = \sum_{t=1}^{x} \frac{GT_t}{(1+D^g)^{t-1}} =$ Present value of government take through year x, $x = 1,\ldots, k$,

D^c = Discount factor for contractor,

D^g = Discount factor for government.

The choice of what discount factor to use is an important decision for companies evaluating projects since selecting D^c "too high" may result in "missing" good investment opportunities, while selecting D^c "too low" may expose the firm to unprofitable or risky investments; e.g., see (Allen and Seba, 1993; Deluca, 2003;

Ehrhardt, 1994). The government[6] does not (nor should not) value money in the same way as companies, and so generally speaking, $D^g \le D^c$. 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 D^c and D^g as decision parameters which range over specified design intervals. At the time of abandonment $x = k$, $PV_k(\tau^c) = \tau^c$ and $PV_k(\tau^g) = \tau^g$.

<u>1.5.5. The Characteristics of Take:</u> The computation of take depends critically on the ability to forecast the expected cash flow for the project. Unfortunately, estimating the cash flow of a prospective project is highly uncertain, and even under the best conditions, is based on incomplete and often unobservable information. In the GOM, the royalty and tax parameters of the fiscal regime are legislated, while in most concessionary agreements take is a negotiated quantity that depends on the economic conditions and prospectivity believed to exist at the time the contract is negotiated[8]. If economic, geologic, or political conditions change, the contract may be renegotiated. If the take statistic is used to characterize a field following development, the risk capital of the exploration program needs to be incorporated in the analysis.

Take can be characterized as:

- Take is a *site-specific* quantity that varies with numerous system parameters unique to the site, including but not limited to, the size and quality of discoveries, the time the field was developed, the life and profitability of the field, and the development plan of the operator.

- Take is an *uncertain* quantity since it is based on field parameters which are themselves uncertain, such as estimated reserves, development and operational plans, and cost structure; unknown parameters such as the cost of capital; exogenous parameters such as crude oil prices, inflation, currency exchange rates, local and global economic conditions, and regulatory changes; and user-defined

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[6] The Office of Management and Budget of the U.S. government suggests using a 5.8% discount factor in the evaluation of federal projects.

[7] One of the reasons why take statistics are usually quoted on an undiscounted basis is perhaps due to the misguided belief that the user does not have to select a value for D^c; in fact, the default condition is itself a selection (and not a very good one): $D^c = D^g = 0$. In general, due to the structure of most fiscal regimes the contractor share of undiscounted profits is greater than the contractor share of discounted projects; i.e.,

$$\tau^c(D^c = 0,\ D^g = 0) > \tau^c(D^c > 0,\ D^g > 0),$$

and similarly,

$$\tau^g(D^c = 0,\ D^g = 0) < \tau^g(D^c > 0,\ D^g > 0).$$

Thus, if profits are undiscounted, the contractor will overestimate and the government will underestimate its take contribution. Fortunately, this is usually tolerable since the value of take as a stand-alone statistic matters more to governments than contractors, and from the government's perspective, using an undiscounted take provides a lower-bound (conservative) estimate on the expected value.

[8] This adds a complicating dimension to the interpretation of take, since take encompasses the perception of the risk associated with field development at the time the contract is negotiated.

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 $(X_1, X_2, ...) = (P^o, P^g, R, T, D^c, D^g, \ldots)$ within a design interval, $A_i < X_i < B_i$, where the values of A_i and B_i are user-defined and account for a reasonable range of the historic uncertainty associated with each parameter. The design space Ω is defined as

$$\Omega = \{(X_1, ..., X_k) \mid A_i \le X_i \le B_i, i = 1, \ldots, k\}.$$

Step 2. Sample the component parameters $(P^o, P^g, R, T, D^c, D^g)$ over the design space Ω and compute the economic and system measures

$$\tau^c(f, \mathrm{F}) = \tau^c(P^o, P^g, R, T, D^c, D^g),$$
$$PV(f, \mathrm{F}) = PV(P^o, P^g, R, T, D^c, D^g),$$

and

$$IRR(f, \mathrm{F}) = IRR(P^o, P^g, R, T, D^c, D^g),$$

for each parameter selection.

Step 3. Using the parameter vector $(P^o, P^g, R, T, D^c, D^g)$ and computed functional values, of $\tau^c(f, \mathrm{F})$, $PV(f, \mathrm{F})$, and $IRR(f, \mathrm{F})$ construct a regression model based on the system data:

$$\varphi(f, \mathrm{F}) = k + \alpha P^o + \beta P^g + \gamma R + \delta \mathrm{T} + \varepsilon \mathrm{D}^c + \theta \mathrm{D}^g,$$

for each functional $\varphi(f, \mathrm{F}) = \{\tau^c(f, \mathrm{F}), PV(f, \mathrm{F}), IRR(f, \mathrm{F})\}$.

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: The development scenario selected is for an oil field with reserves estimated at 40 MMbbl and a projected 11-year life. The costs, production, and production prices are assumed fixed and the capital and operating expenditures are estimated under the base case P_{50} reserves[10]. The cash flow shown in Appendix Table A.1 is extracted from Johnston (Johnston, 1994b).

Total capital costs are \$101M distributed as (20%, 13%, 43%, 25%) over the first 4 years of the project's cash flow. Capital expenditures are assumed to comprise 18% intangibles (services) and 82% tangibles (facilities, equipment, etc.). The tangible capital costs are depreciated straight line over 5 years. Estimated operating costs during the life of the project are \$117M, which represents on average about \$3/bbl full cycle cost. OPEX is

[9] Extrapolating the functional relations outside the design space may be warranted in specific situations, but if the design volume changes dramatically, it is necessary to repeat the analysis for the new specification.
[10] The P_{50} reserves number represents an estimate that has a 50% chance of being larger (or smaller) than the value provided.

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, $0 \le R \le 1$, of gross revenues, and the income tax is calculated as a percentage T, $0 \le T \le 1$, 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, $0 \le D^c, D^g \le 1$, is assumed constant throughout the life of the field. The conversion factor g_t^o is assumed to be unity, and the allowance term $ALLOW_t$ is set equal to zero.

1.7.2. Regression Model Results: Regression models are constructed for $\tau^c(f, \mathrm{F})$, $PV(f, \mathrm{F})$, and $IRR(f, \mathrm{F})$ for 100, 500, 1000, and 5000 values sampled uniformly over the design space Ω defined as

$$\Omega = \{(P^o, R, T, D^c, D^g) \mid 10 \le P^o \le 30, 0.10 \le R \le 0.30, 0.25 \le T \le 0.45, \\ 0.15 \le D^c \le 0.40, 0.10 \le D^g \le 0.20\}.$$

The design space constrains the variation of the parameter set, and can be interpreted geometrically as a 5-dimensional "hyper" parallelpiped in Euclidean space E^5; the "volume" of Ω, $V(\Omega)$, correlates with the magnitude of the system variability.

The model results are shown in Appendix Table A.2. For the most part, the regression coefficients quickly stabilize with increased sampling. The 500 data point simulation is considered representative:

$$\tau^c(f,F) = 36.1 + 2.8P^o - 84.5R - 71.7T - 163.4D^c + 43.1D^g, \; R^2 = 0.75,$$
$$PV(f,F) = 74.3 + 5.2P^o - 129.2R - 99.1T - 318.1D^c + 21.0D^g, \; R^2 = 0.93,$$
$$IRR(f,F) = 16.9 + 1.7P^o - 44.1R - 30.7T - 85.3D^c + 2.3D^g, \; R^2 = 0.98.$$

All the coefficients have the expected signs and are statistically significant except the government discount factor. Contractor take, present value, and the internal rate of return all increase with an increase in commodity price, and decline as royalty and tax rates increase. This behavior is not unexpected, since an increase in the commodity price (holding all other factors such as cost and production fixed) will increase the profitability of the field. If the royalty and/or tax rate increases, the government will acquire a greater percentage of revenue, which will decrease the profitability of the field, and subsequently, contractor take.

As the contractor's discount factor is increased, the economics of field development become progressively worse, and eventually, uneconomic. If the royalties and taxes collected by the government are discounted at a higher rate, the contractor take and economic measures of the field will increase.

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

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

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 $\mathrm{F}(R,T)$ and $\mathrm{F}(\overline{R},\overline{T})$ are fiscally equivalent and the contractor will exhibit no preference between the fiscal regimes. ■

Example. For P = \$20/bbl, D^c = 15%, and D^g = 10%, the present value of field f under the fiscal regime defined by $(\overline{R},\overline{T}) = (0.125, 0.35)$ yields the present value

$$PV(f, \mathrm{F}(0.125, 0.35)) = \$81.9\text{M}.$$

The contractor will prefer the fiscal regime defined by R = 16.67% and T = 20% and should be "willing to pay" up to the market value \$9.4M to maintain (or negotiate) this arrangement. ■

1.7.4. Sensitivity Analysis: From the regression models shown in Appendix Table A.2, a 1% increase in the royalty rate impacts take, present value, and the rate of return slightly more than a 1% increase in the tax rate. Royalty comes "off the top" and is based on production and not profits, while tax receipts are profit-based. One reason why the impact of royalty is not *more* significant is due to the design space restriction: royalty is limited to a range bounded above by the tax rate, and thus, the royalty rate parameters selected from their design interval will on average have a smaller absolute value than the tax rate, and subsequently, a smaller relative impact. The impact of the contractor discount factor is also interesting, since on a relative basis we observe that a 1% increase in the discount factor has about three times the impact of a royalty or tax rate change.

1.8. Elements of Fiscal Design

There are many applications of regression modeling to the design of efficient and flexible royalty/tax systems. In this chapter the main elements of fiscal design are briefly highlighted.

1.8.1. Equivalent Fiscal Regimes: There are many ways to extract economic rent, but none of the arrangements is inherently more profitable than any other, and all petroleum arrangements can be made fiscally equivalent. For field *f* and fiscal regime $\mathrm{F}(R,T)$, the notion of equivalency is defined in terms of the system functional $\varphi(f)$.

Definition. The fiscal regime $\mathrm{F}_{\varphi(f)}(R,T)$ is said to be $\varphi(f)$-equivalent to the fiscal regime $\mathrm{F}_{\varphi(f)}(R^*,T^*)$, $\mathrm{F}_{\varphi(f)}(R,T) \sim \mathrm{F}_{\varphi(f)}(R^*,T^*)$, if $\varphi(R,T) = \varphi(R^*,T^*)$. ■

Example. Consider the parameter specification defined by P^o = \$20/bbl, D^c = 15%, and D^g = 10%. Contractor take is described by

$$\tau^c(R,T) = 71.9 - 84.5R - 71.7T\,,$$

and so for the fiscal regime defined by R = 10% and T = 30%, $\tau^c(0.10, 0.30)$ = 41.9%. For the fiscal system F defined by R^* and T^* = 20%, to maintain "take" equivalence R^* must satisfy the relation

$$\tau^c(R^*,T^*) = 57.6 - 84.5R^* = 41.9 = \tau^c(R,T)\,;$$

i.e., R^* = 18.6%, and $\mathrm{F}_{\tau^c}(0.10, 0.30) \sim \mathrm{F}_{\tau^c}(0.186, 0.20)$. Similarly, for the fiscal system defined by R^*= 12.5% and T^*, to maintain take equivalence,

$$\tau^c(R^*,T^*) = 61.3 - 71.7T^* = 41.9 = \tau^c(R,T)\,;$$

i.e., T^* = 27.1%, and $\mathrm{F}_{\tau^c}(0.10, 0.30) \sim \mathrm{F}_{\tau^c}(0.125, 0.271)$. ■

The exact manner in which equivalency is maintained is determined by the functional relationship established for the field and the fiscal regime under consideration.
Example. Consider the parameter specification (P^o, D^c, D^g) = (20, 0.15, 0.10). The rate of return measure is described by

$$IRR(R,T) = 38.3 - 44.1R - 30.7T\,,$$

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:

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

i.e., R^* = 17.0%, and $\mathrm{F}_{IRR}(0.10,\ 0.30) \sim \mathrm{F}_{IRR}(0.17,\ 0.20)$. Similarly, for F defined by R^*= 12.5% and T^*,

$$IRR(R^*,T^*) = 32.8 - 30.7T^* = 24.7 = IRR(R,T)\,;$$

i.e., T^* = 26.3%, and $\mathrm{F}_{IRR}(0.10,\ 0.30) \sim \mathrm{F}_{IRR}(0.125,\ 0.263)$. ■

The fiscal regime $\mathrm{F}(R,T)$ forms a class of $\varphi(f)$-equivalent systems, $\{\mathrm{F}(R,T)\}_{\varphi}$, defined by (R,T) through the linear functional $\varphi(f)$ as follows:

$$\{\mathrm{F}\}_{\varphi} = \{(R,T) \mid \varphi(R,T) = \varphi(R^*,T^*)\}.$$

For a properly specified system, three of the four system variables, R, T, R^*, T^*, must be known. If a fiscal regime is defined such that $R^* > R$ ($R^* < R$), then to maintain $\varphi(f)$-equivalency it is clear that $T^* < T$ ($T^* > T$).

<u>1.8.2. Feasibility Constraints:</u> For an operator to consider an investment opportunity feasible, certain minimum economic criteria must be satisfied. For example, if the fiscal regime of government is so constraining as to make development projects uneconomic, or if the fiscal marksmanship of a country is unrealistic and leaves production unprofitable, or if a contractor's expectation of return is unrealistically high, then the fiscal regime in the "eye" of the contractor would be considered infeasible since viable projects will either be abandoned prematurely or not developed.

The relationship of a fiscal system to operator constraints determines various "feasible" regions. A feasibility constraint is defined for a specific field and fiscal regime, and is determined by the functional $\varphi(f)$ and the selection of a user-defined parameter $\varepsilon > 0$.
Definition. The ($\varphi(f)$, ε)-constraint $\Pi_{(\varphi(f),\varepsilon)}(R,T) = \{(R,T) \mid \varphi(f) > \varepsilon\}$ for field f defines the set of fiscal parameters (R,T) that satisfy the design constraint $\varphi(f) > \varepsilon$. ■

Example. For (P^o, D^c, D^g) = (20, 0.15, 0.10), the rate of return functional is defined by

$$IRR(R,T) = 38.3 - 44.1R - 30.7T.$$

If the operator considers an acceptable rate of return for the investment to be 10%, then the operator's rate of return feasibility constraint is defined by

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

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

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

$$PV(R,T) = 132.7 - 129.2R - 99.1T.$$

If the operator considers a present value of \$50M the minimum acceptable return relative to the risk of the project, the initial capital required, and other investment opportunities available, then the present value feasibility constraint would be defined by the half-space:

$$\Pi_{(PV,50)}(R,T) = \{(R, T) | \; 129.2R + 99.1T < 82.7\}. \quad ■$$

1.8.3. Feasible Domain: The collection of feasibility constraints and the logic operator "AND" defines the operator's "feasible" domain, the region that will simultaneously satisfy all the economic requirements of the operator.

Definition. The feasible domain of the operator, $\Sigma^O(R,T)$, is defined as the intersection of the set of all feasibility constraints, $\Pi_{(\varphi(f),\varepsilon)}$:

$$\Sigma^O(R,T) = \bigcap_{(\varphi(f),\varepsilon)} \Pi_{(\varphi(f),\varepsilon)}. \quad ■$$

Since the intersection of all collection of convex sets is itself convex, it is not difficult to show the following theorem.

Theorem. $\Sigma^O(R,T)$ is a convex domain.

Example. For the parameter specification $(P^o, D^c, D^g) = (20, 0.15, 0.10)$ and feasibility constraints defined by (IRR,10) and (PV,50), the operator's feasible domain $\Sigma^O(R,T)$ is defined as

$$\Sigma^O(R,T) = \{(R,T) \,|\, 44.1R + 30.7T \le 28.3; 129.2R + 99.1T \le 82.7; R, T \ge 0\}. \quad ■$$

Analogous to the operator's feasible domain, the host government also maintains a feasible domain with respect to its own expectations on take, rate of return, present value and other socioeconomic objectives. In this case, if the economic and system functionals are denoted $\psi(f)$ and $\delta > 0$ represent the level curve parameters, then the host government's feasible domain is defined as follows.

Definition. The feasible domain of the host government, $\Sigma^{HG}(R,T)$, is defined as

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

where $\Pi_{(\psi(f),\delta)} = \{(R,T) \mid \psi(f) > \delta\}$ for field f, system functional $\psi(f)$, 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 $\Sigma^{O}(R,T) \cap \Sigma^{HG}(R,T) = \{\}$, then no deal is possible. If $\Sigma^{O}(R,T) \cap \Sigma^{HG}(R,T) \neq \{\}$, then a deal may be achieved.

<u>1.8.4. Progressive Fiscal Regimes:</u> The notion of "progressive" and "regressive" fiscal regimes are widely discussed in the trade press. Fiscal regimes that tax profitable projects heavily and marginal projects lightly are referred to as progressive, while fiscal regimes that taxes marginal fields heavily relative to profitable projects are called regressive. A progressive regime is usually defined by the absence of royalties, bonuses, and other types of payment based on gross production, while emphasizing profit-based mechanisms such as taxation and sliding-scale terms. A progressive fiscal regime usually encourages the development of marginal prospects since the government take is at its lowest when oil company profitability is low; and as the profitability of a field increases, the government will extract more take.

Two definitions of a progressive fiscal regime are provided. The first definition refers to the time history of one field, while the second definition refers to a collection of fields $\{f\}$ evaluated at a point in time. The relationship between government take and rate of return is used to define the fiscal regime.

Definition. A fiscal regime $\mathrm{F}(R,T)$ is said to be progressive (regressive) with respect to the field f if $\tau^{g}(f,\ \mathrm{F})$ and $IRR(f,\ \mathrm{F})$ are positively (negatively) correlated. ■

Definition. A fiscal regime $\mathrm{F}(R,T)$ is said to be progressive (regressive) with respect to the collection of fields $\{f\}$ if $\tau^{g}(f,\mathrm{F})$ is an increasing (decreasing) function of $IRR(f,\ \mathrm{F})$; i.e.,

$$\tau^{g}(f,\mathrm{F}) = \alpha + \beta\, IRR(f,\ \mathrm{F}),$$

where $\beta > 0$ ($\beta < 0$). ■

Example. Consider fields $\{f_1, f_2,\ldots, f_k\}$ evaluated under the parameter specification (P, D^{c}, D^{g}) and defined by the empirical relations:

$$\tau^{g}(f_i,\mathrm{F}) = A_i + B_i R + C_i T,\ i = 1, \ldots, k,$$
$$IRR(f_i,\ \mathrm{F}) = D_i + E_i R + F_i T,\ i = 1, \ldots, k,$$

where the values $A_i,...,F_i$ are specific to field f_i, i = 1, …, k. For a given value of (R,T), evaluate $\tau^g(f_i,\mathrm{F})$ and $IRR(f_i, \mathrm{F})$, i = 1, …, k, and estimate the relation

$$\tau^g(f,\mathrm{F}) = \alpha(R,T) + \beta(R,T)\ IRR(f, \mathrm{F}).$$

If $\beta(R,T) > 0$ the value (R,T) is said to determine a progressive fiscal regime. ■

Definition. The progressive fiscal domain $\Pi^p{}_{\{f\}}(R,T) = \{(R,T) \mid \beta(R,T) > 0\}$ defines the fiscal parameters that lead to a positive correlation between government take and contractor rate of return. ■

1.9. Deepwater Gulf of Mexico Case Study: Na Kika

1.9.1. Na Kika Deepwater Development: The Na Kika deepwater development is located approximately 140 miles southeast of New Orleans in water depths ranging from 1,800m (5,800 ft) to 2,100m (7,000 ft). See Appendix Figure A.1. The project is a subsea development of five independent fields – Kepler, Ariel, Fourier, Herschel, and East Anstey – tied back to a centrally located, permanently-moored floating development and production host facility situated on Mississippi Canyon Block 474 (Gallun et al., 2001). A sixth field, Coulomb, is in water depth of approximately 2,300m (7,600 ft) and will be tied back to the host facility as production capacity becomes available.

Shell and BP each hold a 50% interest in the host facility and the Kepler, Ariel, Fourier, and Herschel fields. In East Anstey, Shell has a 37.5% interest with BP holding the remaining 62.5%, and in the Coulomb field, Shell has a 100% interest.

The host is a semisubmersible-shaped hull with topside facilities for fluid processing and pipelines for oil and gas export to shore. See Appendix Figure A.2. The fields will flow production from 12 satellite subsea wells equipped to handle 425 MMcf/day of gas, 110,000 bbl/day of oil, and 7,000 bbl/day of water. The Kepler, Ariel, and Herschel fields are primarily oil, while the Fourier and East Anstey fields are primarily gas. The API gravity of the fields range from 25º (Herschel) to 29º (Fourier). The first phase of production from 10 wells in Kepler, Ariel, Fourier, East Anstey, and Herschel is due onstream during 4Q 2003. Coulomb is slated to begin in 2004 from two subsea wells.

1.9.2. Development Scenario: The development scenario for Na Kika is based on an estimated gross ultimate recovery of roughly 300 MMBOE. Proved reserves are currently estimated at 189 MMbbl of oil and 728 Bcf of gas. The cash flow projection is shown in Appendix Table A.3.

Total project cost is approximately $1.26B, excluding leasing costs of $20M (www.countonshell.com). Approximately 50% of the costs are associated with the fabrication and installation of the host facility and pipeline, 25% of the costs are associated with the fabrication and installation of the subsea components, and 25% are associated with the drilling and completion of the wells. The life cycle capital expenditures are estimated as \$3.73/bbl with operating cost estimated at \$1.20/bbl. OPEX is forecast to increase steadily from less than \$1/bbl early in the production cycle to over \$8/bbl near the end of the life of the field.

1.9.3. Deepwater Royalty Relief: For leases acquired between November 28, 1995 and November 28, 2000, the OCS Deepwater Royalty Relief Act (DWRRA; 43 U.S.C. §1337) provided economic incentives for operators to develop fields in water depths greater than 200 m (656 ft). The incentives provide for the automatic suspension of royalty payments on the initial 17.5 MMBOE produced from a field in 200-400 m (656-1,312 ft) of water, 52.5 MMBOE for a field in 400-800 m (1,312-2,624 ft) of water, and 87.5 MMBOE for a field in greater than 800 m (2,624 ft) of water (Baud et al., 2002). The impact of royalty relief is to make marginal fields economic, enhance the return/profitability of intermediate fields, and reduce the risk associated with some projects. The DWRRA expired on November 28, 2000, but leases acquired during the time royalty relief was active retain the incentives until their expiration. Reduction of royalty payments is also available through an application process for deepwater fields leased prior to the DWRRA but which had not yet gone on production. Provisions effective in 2001 are specified for each lease sale, are granted to individual leases (not fields as in the DWRRA), and are subject to change with each lease sale as economic conditions warrant.

If Q_t denotes the annual hydrocarbon production from field f in year t, $d(f)$ the (average) water depth of the field, and $Q(f)$ the volume of production for which royalty is suspended, then deepwater royalty rates are determined as follows:

$$\text{R(DWRR)} = \begin{cases} 0, \ \text{if} \sum_t Q_t \le Q(f) \\ 16.67\%, \ \text{if} \sum_t Q_t > Q(f). \end{cases}$$

If the lease on which the field is located was acquired between November 28, 1995 and November 28, 2000, then

$$Q(f) = \begin{cases} 17.5\,\text{MMBOE}, \ \text{if } 200\,\text{m} \le d(f) \le 399\,\text{m} \\ 52.5\,\text{MMBOE}, \ \text{if } 400\,\text{m} \le d(f) \le 799\,\text{m} \\ 87.5\,\text{MMBOE}, \ \text{if } d(f) \ge 800\,\text{m}. \end{cases}$$

For lease sales held after November 28, 2000, the water depth categories and value of $Q(f)$ is specific to the lease sale.

1.9.4. Regression Model Results: The design space for the four models under consideration is shown in Appendix Table A.4. In Model I the system parameters are selected uniformly from each design interval, and in Model II, the design intervals are more narrowly defined and the hydrocarbon prices assumed Lognormally distributed.

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., $P_t^o \sim$ LN(25, 5), $P_t^g \sim$ 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., $T_t \sim$ 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

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

$$PV(f) = 10{,}460.7 + 38.2P^o + 131.5P^g - 1{,}259.8R + 1.1Q - 1{,}856.1T - 3{,}699.4\,D^c + 79.8\,D^g,$$

$$IRR(f) = 63.4 + 2.6\,P^o + 8.6\,P^g - 58.9R + 0.1Q - 126.2T - 131.5\,D^c + 2.2\,D^g.$$

A quick glance at the regression coefficients of the functionals indicates some of the characteristics of royalty relief specific to the Na Kika development. First, the absolute magnitude of the tax coefficients exceeds the royalty rate. This is not entirely unexpected since a royalty suspension has been granted on the first $Q(f)$ MMBOE production thereby dampening its impact. Under royalty relief, the government foregoes royalty for a period of time, but its tax collection will increase (since the operators revenue will increase with suspended royalties).

The contractor and government discount factors are approximately equal in the take computation, but a significant difference exists in the present value and rate of return measures. If D^c and D^g are required to satisfy $D^c = D^g = D$, the new model coefficients for D is nearly the same as D^c and the rest of the model coefficients do not change appreciably.

In Model II, the hydrocarbon prices are assumed Lognormally distributed and the design intervals are more narrowly defined. The impact of these changes to the regression models is shown in Appendix Table A.5. The mean, P_5, and P_{95} estimates[11] of the computed measures are shown in Appendix Table A.6. These values bound the expected range of each measure for the design space and model specification. Observe that as the design specification becomes more narrowly defined, the range defined by $P_{95} - P_5$ generally shrinks, while the variability introduced through P_t^o and P_t^g do not noticeably affect the range.

[11] The P_5 and P_{95} measures indicate that 5% of the time the estimated value is expected to be less than P_5 or greater than P_{95}.

The inclusion of structural variability in Model III and Model IV, where the hydrocarbon prices and tax rates are now assumed to vary annually, negatively impacts the robustness of the model fits, but the impact on the regression coefficients is relatively minor in most instances.

The ratio δ/γ for each regression model provides an estimate of the correspondence between royalty relief volume suspensions and the royalty rate. For the present value functional, for instance, a 1 MMBOE change in royalty suspension is equivalent to 0.087% ≈ 0.1% change in the royalty rate. Or in other words, a 10 MMBOE increase in the value of $Q(f)$ is roughly equivalent to a 1% decrease in the royalty rate with respect to its impact on the present value of the field. Similar observations follow for the take and rate of return measure.

1.9.5. The Impact of Royalty Relief: The design parameters of royalty relief include the royalty rate R, $0 \le R \le 1$, and level of the suspension volume, $Q(f)$. Intuitively, it is clear that decreasing the value of R and/or increasing $Q(f)$ will act in favor of the contractor, but the exact manner of the impact can only be determined through empirical modeling.

If P^o = \$25/bbl, P^g = \$3.5/Mcf, R = 16.67%, T = 40%, and D^c = 20%, D^g = 10%, then based on the functional constructed for Model I,

$$\tau^c(f) = 38.0 + 0.04Q,$$
$$PV(f) = 1{,}192 + 1.1Q,$$
$$IRR(f) = 71.9 + 0.1Q.$$

For $Q = 0$ (no royalty relief), the take, present value, and rate of return of the investment is estimated at 38%, \$1.192B, and 71.9%, while with Q = 87.5 MMBOE (royalty relief), $\tau^c(f)$ = 41.5%, $PV(f)$ = \$1.288B, and $IRR(f)$ = 80.7%. As $Q(f)$ increases, royalty is suspended on the initial $Q(f)$ MMBOE production, and both the contractor take and economic measures of the field increase.

The value of royalty relief to the operator as a percentage of the present value is estimated as

$$V_{PV}(f, Q) = \frac{PV(f,Q) - PV(f,0)}{PV(f,0)} = \frac{1.1Q}{1192} = 0.092Q;$$

so that for Q = 17.5 MMBOE, $V(f, Q)$ = 1.6%; Q = 52.5 MMBOE, $V(f, Q)$ = 4.8%; and Q = 87.5 MMBOE, $V(f, Q)$ = 8.1%.

In terms of the contractor take, the percentage variation of $\tau^c(f)$ as a function of Q relative to the baseline case of no relief is also readily computed:

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

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, $V_{\tau^c}(f,Q)$ = 0.092%.

1.10. Conclusions

The weaknesses and uncertainty associated with the application of take have not been properly addressed in the literature, and so the first task of the paper was to delineate the shortcomings of this statistic and to offer a fresh perspective on interpretation.

To understand the economic and system measures associated with a royalty/tax fiscal regime a meta-model was developed. In the meta-evaluation procedure, a cash flow model specific to a given fiscal regime is used to generate meta data that describes 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. Modeling take and economic measures in this manner is especially useful for contract negotiation strategies and plays a central role in understanding the intricate mechanics of fiscal system analysis**.**

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 deepwater Na Kika development was considered. The impact of royalty relief on the field economics of Na Kika was also examined.

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 2.3, the basic features of concessionary and contractual systems are outlined. In Chapter 2.4, the cash flow analysis of a generic PSA is developed, and in Chapter 2.5, the economic and system measures associated with a field are defined. In Chapter 2.6, the 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. For example, in Saudi Arabia's first bidding round for onshore natural gas exploration, one Saudi official commented: "The key factors in successful bidding would be neither signature bonuses nor the amount of government take. Our objective is not the cash. The minimum work program will primarily be the main bidding parameter." (Husari, 2003)

Stage 1. The host government (HG) divides prospective exploration areas into concession areas or blocks B $= \{B_1,...,B_k\}$. Data packages are prepared for each block B_i, $i = 1,\dots, k$, 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 a data package is purchased by the foreign oil company (FOC). FOCs submit details of proposed consortia and comment on the (draft) model contract and fiscal terms. Companies may need to be "pre-qualified" to form consortia.

Stage 3. The HG may meet with pre-qualified operators for clarification of the process, the bidding parameters, the fiscal systems, the model contract, etc. The HG may also emphasize the main bidding parameters, volume of production desired, expected time frame for development, etc.

Stage 4. The FOC evaluates exploration and development scenarios for individual blocks based on public and proprietary information. Technical and commercial bids are prepared consistent with the geologic prospectivity, strategic objectives, and capital budget of the firm.

a. Technical bids provide a work commitment schedule W describing the seismic work (in kilometers) and the number of wells to be drilled (by type – exploratory, delineation, etc. and total footage) to be performed on each block B_i.
b. Commercial bids specify the fiscal terms F and biddable parameters which will govern the block if exploratory activities find commercial quantities of resource.

Stage 5. The HG receives the bids for each block B_i and evaluates the work commitment and fiscal terms offered. Work commitment is a certain[13] event, while the proposed fiscal terms only hold if commercial quantities of oil/gas are discovered.

a. Technical bids are evaluated[14] on the work commitment proposed; the technical standing, experience, capabilities, past business practices, and financial position (credit worthiness/financial strength) of the FOC; and previous experience and success in exploration in the area or similar areas. The present value of the work commitment, *PV*(W), represents the expected cost of the work program to drill X wells and shoot Y miles of seismic. The

[13] Unless optionality agreements are written into the contract. Penalty terms for noncompliance are usually specified.

[14] Technical bids are typically evaluated by engineers, geologists, and management personnel within the exploration department of the National Oil Company or Oil Ministry. Commercial bids are evaluated by economist, financial personnel, and lawyers in the legal/financial division.

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

[15] The Royal Dutch/Shell statement of general business principles is standard:

"*Profitability ... is essential for the proper allocation of corporate resources and necessary to support the continuing investment required to develop and produce future energy supplies... The criteria for investment decisions are essentially economic, but also take into account social and environmental considerations and an appraisal of the security of the investment.*"

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:

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

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:

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

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.

[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 oil company normally has to pay income tax on its share of profit oil, although in some instances the National Oil Company may pay a portion of the amount.

2.4. Cash Flow Analysis of a Production Sharing Agreement

The terms and conditions of PSAs vary widely and change frequently, and are often subject to negotiations (and renegotiations) which are unobservable and uncertain. Production sharing agreements are known for their diversity and complexity of terms, and so it should come as no surprise that PSAs need to be analyzed and treated on an 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

$$NCF(f) = (NCF_1, NCF_2, ..., NCF_k),$$

and is assumed to begin in year one (t = 1) and run through field abandonment (or divestment) at $t = k$. The after-tax net cash flow vector serves as the basic element in the computation of all system measures associated with the field.

2.4.2. Cash Flow Components: The gross revenues in year *t* due to the sale of hydrocarbons is defined as

$$GR_t = g_t^o\, P_t^o\, Q_t^o + g_t^g\, P_t^g\, Q_t^g,$$

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 wellhead 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 oil, and the amount of impurities, condensate, and hydrogen sulfide of natural gas (Hyne, 1995). Conversion factors are both time and field dependent. The hydrocarbon price is based on a reference benchmark expressed as a time average over a given horizon.

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, $CAPEX_t$ and $OPEX_t$, are estimated relative to the expected reserves and development plan. 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. 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.

Various types of bonus payments may be required in a PSA. Signature bonuses are sometimes paid upon finalization of negotiations and contract signing, while discovery bonuses are paid in cash or equipment upon discovery of oil/gas. Signature and discovery bonuses are normally one-time fees, while production bonuses are paid when production reaches one or more specified levels. Bonus payments are not normally considered for cost recovery.

The profit oil is the portion of production or revenue that the government shares with the contractor after royalties and cost oil (CO_t) is recovered from the gross revenue:

$$PO_t = GR_t - ROY_t - CO_t.$$

The profit oil is split between the contractor and government:

$$PO_t = PO/C_t + PO/G_t,$$

where,

$PO/C_t = PO(\boldsymbol{\psi})PO_t =$ Contractor profit oil in year t,

$PO/G_t = (1 - PO(\boldsymbol{\psi}))PO_t =$ Government profit oil in year t,

$PO(\boldsymbol{\psi})$ = Profit oil split, $0 \leq PO(\boldsymbol{\psi}) \leq 1$.

The cost recovery scheme determines how the cost oil is computed. Many variations of cost recovery exist, and in its most basic form is computed as

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

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,

$DECOM_t =$ Decommissioning cost recovery fund apportionment in year t.

Unrecovered costs carried over from previous years may include tax loss carry forward, unrecovered depreciation balance, unrecovered amortization balance, and cost recovery carry forward. Some contracts allow capital expenditures to be expensed in the year incurred and recovered from the cost recovery, while in other cases, these costs have to be amortized and only the amortized amount is allowed for recovery. Depreciation schedules are normally legislated, and in nearly half of PSAs worldwide, are not permitted for cost recovery. Investment credits and uplifts are incentives that allow the contractor to recover an additional percentage of capital costs through cost recovery. The anticipated cost of abandonment may be accumulated through a sinking fund that matures at the time of abandonment.

The amount of revenues the contractor can claim for cost recovery is normally bound from above by the so-called "cost recovery ceiling," and in some cases, a time limitation for full cost recovery may also be imposed. Cost oil is constrained in value through a functional relation such as

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

where the value of $CR(\psi)$, $0 \leq CR(\psi) \leq 1$, may be constant or based on a sliding scale[18]. It is generally agreed that operators must be allowed to recover their costs for a venture to be profitable, but the manner in which the costs are recovered and the impact of cost ceilings on the economic measures of the field are not well understood.

Taxable income is determined as a percentage of the contractor profit oil and tax loss carry forward, if applicable. Tax rates are denoted by the value $T(\psi)$, $0 \leq T(\psi) \leq 1$, and may be fixed or based on a sliding scale:

[18] Note that when $GR_t = 0$, $CO_t = 0$; or in words, the operator can only begin to recover cost after production begins.

$$TAX_t = \begin{cases} T(\psi)(PO/C_t - CF_t), & PO/C_t - BONUS_t - CF_t > 0 \\ 0, & PO/C_t - BONUS_t - CF_t \leq 0, \end{cases}$$

where CF_t represents the tax loss carry forward in year t.

A number of elements commonly employed in PSAs, such as commerciality requirements, government participation, domestic market obligations, ringfencing, and reinvestment obligations impact the net cash flow position of the contractor. These terms are referred to and denoted as $OTHER_t$ in the cash flow equation. In some instances, the impact of these conditions may be quantifiable; at other times, it may not be possible to incorporate the terms in the analysis. In all cases the terms are field, contract, and operator specific. The reader is referred to (Allen and Seba, 1993; Johnston, 1994b; Thompson and Wright, 1984) for further description of these elements.

2.4.3. Sliding Scales: Sliding scales are one of the most common and distinctive features of PSAs. The idea of a sliding scale is to create a fiscal arrangement that adjusts to the private and market uncertainties that occur over the life cycle of a project and impact the contractor or host government. Sliding scales represent a mechanism intended to control (or dampen) volatility and bound uncertainty. The principal is to adjust the terms of a contract to the profitability of the field, so that as production rates and/or oil prices increase, or reach a given threshold level, the contractor should be willing to accept a smaller amount of cost recovery, to take a smaller share of profit oil, to pay a larger tax rate, etc. Similarly, as production rates and/or oil prices decrease, the government should be willing to reduce tax levels, to accept a smaller share of profit oil, etc. The idea is to try to achieve balance within a dynamic and volatile market environment.

Production bonuses, royalty rates, cost recovery, profit oil splits, and tax rates are typically based on sliding scales that are a function of one or more variables. The variables that are typically used include the average daily production, cumulative production, crude oil price, or "R-Factor[19]"; parameters such as the age or depth of reservoirs, field location, crude oil quality, water depth, and rate of return factors may also be employed. The variables are frequently negotiable.

2.5. Economic and System Measures

2.5.1. Economic Indicators: The purpose of economic evaluation is to assess if the revenues generated by the project cover the expenditures and capital investment, and the

[19] The R-Factor (RF) can be defined in various ways, but in its most basic form, is computed as the ratio of the contractor's cumulative revenue after taxes and royalty to the contractor's cumulative cost:

$$RF_x = \frac{\sum_{t=1}^{x}(GR_t - ROY_t - TAX_t)}{\sum_{t=1}^{x} TC_t},$$

where $TC_t = EXP_t + CAPEX_t + OPEX_t + OTHER_t$. The terms may be inflation adjusted.

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 investment efficiency ratio are frequently employed in analysis.

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

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

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 that are used to establish which projects should be selected to optimize the use of capital funds. A combination of indicators is usually necessary to adequately evaluate a contract's economic performance.

2.5.2. Government and Contractor Annual Take: The division of profit between contractor and government determines take. The total profit in year *t* is determined as,

$$TP_t = GR_t - TC_t,$$

where,

$TP_t =$ Total profit in year *t*,

$TC_t = CAPEX_t + OPEX_t =$ Total cost in year *t*.

The contractor and government take is computed as,

$CT_t = TP_t - BONUS_t - ROY_t - PO/G_t - TAX_t =$ Contractor take in year *t*,

$GT_t = BONUS_t + ROY_t + PO/G_t + TAX_t =$ Government take in year *t*.

The contractor and government take in year *t*, expressed in percentage terms, is defined as

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

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 on a cumulative discounted basis in year x, $x = 1,\ldots, k$, is written

$$PV_x(\tau^c) = \frac{PV_x(CT)}{PV_x(CT) + PV_x(GT)},$$
$$PV_x(\tau^g) = \frac{PV_x(GT)}{PV_x(CT) + PV_x(GT)},$$

where,

$PV_x(CT) = \sum_{t=1}^{x} \frac{CT_t}{(1+D^c)^{t-1}} =$ Present value of contractor take through year x, $x = 1,\ldots, k$,

$PV_x(GT) = \sum_{t=1}^{x} \frac{GT_t}{(1+D^g)^{t-1}} =$ Present value of government take through year x, $x = 1,\ldots, k$,

D^c = Discount factor for contractor,

D^g = Discount factor for government.

It is common practice to report take *without* discounting[20], and this case is easy to handle by setting $D^c = D^g = 0$ in the above relation. Discounted take is computed by assuming $D^c = D^g \neq 0$, or by considering D^c and D^g as decision parameters which range over specified design intervals.

2.6. Generalized Fiscal System Analysis

2.6.1. Terms of a Contract: The basic terms of a contract Γ are set forth by the legislative and regulatory requirements of the host government. The primary terms of a PSA include

[20] Undiscounted take is considered somewhat perverse, however, and failure to discount will significantly bias the statistic. One reason why take is frequently not discounted may be due to the requirement that the user select the "appropriate" value of D^c and D^g, but the default condition is itself a selection (and not a very good one): $D^c = D^g = 0$. See also footnote 7.

- 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).

2.6.2. System Functionals: 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 terms of a contract most relevant from an economic perspective can usually be quantified without regard to the complexity and sophistication of the fiscal conditions, and if a condition can be specified its "impact" can usually be assessed.

[21] For instance, how does one quantify the impact of dispute resolution agreements, procurement guidelines, government involvement, sovereign immunity waivers, management commitments, relinquishment requirements, or license duration on the economic and system measurements?

The fiscal terms of a contract are written in terms of functionals described through the parameters of the fiscal regime:

$$\mathrm{F}\ (\psi) = (\mathrm{F}_1(\psi), \ldots, \ \mathrm{F}_m(\psi)),$$

where $\mathrm{F}_i(\psi)$ are functions of the variable set ψ. A partial representation of ψ includes elements such as $q_t = Q_t/365$, CQ_t, P_t, RF_t,... The primary fiscal terms of a contract include

$B(\boldsymbol{\psi})$ = Bonus payment,
$R(\boldsymbol{\psi})$ = Royalty rate,
$CR(\boldsymbol{\psi})$ = Cost recovery schedule,
$PO(\boldsymbol{\psi})$ = Profit oil split, and
$T(\boldsymbol{\psi})$ = Taxation structure.

The functionals can be constant; i.e., $\mathrm{F}_i(\psi) = \alpha$, $\alpha \geq 0$, but more often than not, the functions are based on one or more sliding scales, the terms of which are often negotiable.

The economic and system measures of a field are written in general as $\varphi_i(f, \mathrm{F})$, and denoted in vector form as

$$\Phi(f, \Gamma) = (\varphi_1(f, \mathrm{F}), \ldots, \varphi_l(f, \mathrm{F})).$$

A variety of system measures are employed, and as previously defined, include

$\tau^c(f, \mathrm{F})$ = Contractor take,
$\tau^g(f, \mathrm{F})$ = Government take,
$PV(f, \mathrm{F})$ = Present value,
$IRR\ (f, \mathrm{F})$ = Internal rate of return, and
$PI(f, \mathrm{F})$ = Profitability index.

2.6.3. Meta-Modeling Methodology: The manner in which the system functionals $PV(f, \mathrm{F})$, $\tau^c(f, \mathrm{F})$, and $IRR(f,\mathrm{F})$ depend upon the fiscal terms $\mathrm{F}(\psi)$ is of considerable significance since contract negotiation determines in large part the profitability of the project and the revenues received by the host government. There are many ways to analyze a fiscal system, and the standard approach is a variation on one basic theme. For field f and fiscal regime F,

1. Specify a baseline case through the variable set $\boldsymbol{\psi}$ and compute $\varphi(f, \mathrm{F}\ (\boldsymbol{\psi}))$.

2. Change the variable set $\boldsymbol{\psi}$ one (or more) factors at a time $\psi_i \rightarrow \psi_i'$, $\boldsymbol{\psi}' = (\psi_1, \ldots, \psi_i', \ldots, \psi_n)$, and compute $\varphi(f, \mathrm{F}(\boldsymbol{\psi}'))$.

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 significant limitations associated with this approach. The methodology is piecemeal and the results are only valid relative to the initial conditions specified. The analysis does not readily describe how the variables interact or the relative significance of the parameters. The amount of work involved to generate and present the model results is nontrivial, and the restrictions associated with geometric and tabular presentations of multidimensional data is significant; e.g., on a planar graph at most three or four variables can be examined simultaneously. Fiscal system analysis is more often confusing rather than illuminating because of the limitations associated with the solution approach.

A more general and concise approach to fiscal system analysis, previously applied to a royalty/tax fiscal regime, is now described. A meta-modeling approach is developed to construct functional relations that describe how the system variables interact and impact the system measures. A cash flow model of the system is first constructed, and then parameters of the system are defined and bound through specified design intervals. The parameters of the system are sampled from the design space and evaluated in the cash flow model. The results of the model and system parameters are then analyzed and linear models constructed from the generated data. The general approach is as follows.

1. Specify the variable set $\boldsymbol{\psi}$ and determine the design interval $l_i \le \psi_i \le u_i, i = 1,...,n,$ for each parameter of interest. Denote the design space as Ω:

$$\Omega = \{\psi = (\psi_1,...,\psi_n) \mid l_i \le \psi_i \le u_i, i = 1...,n\}.$$

2. Form $\boldsymbol{\psi}^* = (\psi_1^*,...,\psi_n^*)$, where ψ_i^* is sampled uniformly from the design interval, $U[l_i, u_i]$, $i = 1,...,n,$ and compute $\varphi(f, \mathrm{F}(\boldsymbol{\psi}^*))$.

3. Based on the data sets $\{\boldsymbol{\psi}^*\}$ and $\{\varphi(f, \mathrm{F}(\boldsymbol{\psi}^*))\}$, estimate for each measure φ the functional relation

$$\varphi(f, \mathrm{F}(\boldsymbol{\psi})) = \sum_{i=1}^{n} \alpha_i(\varphi)\psi_i,$$

where the coefficients $\alpha_i(\varphi)$ are determined through regression modeling.

4. Employ the functional relations $\varphi(f, \mathrm{F}(\boldsymbol{\psi}))$ in fiscal system analysis and design.

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 \$60M and distributed as 28% intangibles (services) and 72% tangibles (facilities, equipment, etc.). The tangible capital costs are depreciated using a 5-year straight line schedule. Estimated operating costs during the life of the project is \$117M representing on average a \$3/bbl full cycle cost. OPEX is initially stable at \$2.5/bbl but increases significantly near the end of the life of the field.

The royalty rate is calculated as a percentage $R(\psi)$, $0 \le R(\psi) \le 1$, of gross revenues, and the income tax is calculated as a percentage $T(\psi)$, $0 \le T(\psi) \le 1$, of taxable income. Tax losses are carried forward from a previous year if negative. The cost oil CO_t is computed as:

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

for $0 \le CR(\psi) \le 1$, and the profit oil split $PO(\psi)$ is assumed constant throughout the life of the field.

Cash flows are presented in nominal terms, and the oil price $\mathrm{P_t}$ and the contractor and government discount factors, $0 \le D^c, D^g \le 1$, are assumed constant. The conversion factor g_t is assumed to be unity and the allowance term $ALLOW_t$ is set equal to zero. There is no government participation or domestic market obligations associated with the contract.

2.7.2. Regression Modeling Results: The design space for the two models considered are specified in Appendix Table B.2. In Model I, the PSA is developed with no sliding scale parameters, and in Model II, a sliding scale profit oil schedule is examined.

Regression models are constructed for $\tau^c(f, \mathrm{F})$, $PV(f, \mathrm{F})$, and $IRR(f, \mathrm{F})$ for 500 points selected uniformly from the design space interval. The regression coefficients quickly stabilize with the sample rate and the 500 data point simulation is considered representative. The regression results for Model I are shown in Appendix Table B.3:

$$\begin{aligned}
&\tau^c(f) = 14.1 + 0.1P - 18.4R + 40.8PO - 27.3T - 54.7D^c + 61.6D^g,\ R^2 = 0.95,\\
&PV(f) = -25.3 + 3.7P + 24.0CR + 118.2PO - 80.8T - 204.1D^c,\ R^2 = 0.87,\\
&IRR(f) = 1.0P - 12.2R + 9.1CR + 36.4PO - 21.2T - 42.0D^c,\ R^2 = 0.31.
\end{aligned}$$

All the coefficients have the expected signs and the model fits are fairly robust. For any value of (P, R, CR, PO, T, D^c, D^g) within the design space shown in Appendix Table

B.2, the regression models can be used to evaluate and compare the impact of user-specified parameters.

Contractor take increases with an increase in commodity price and profit oil and falls with the royalty and tax rate. As the contractors discount factor is increased, or the government discount factor is decreased, take declines. For (P, R, T, D^c, D^g) = (20, 0.15, 0.35, 0.20, 0.10),

$$\tau^c(f, \mathrm{F}) = 4.5 + 40.8PO,$$

indicating that for PO = 10%, a 1% increase in PO will increase $\tau^c(f, \mathrm{F})$ by 0.5%, while if PO = 60%, a 1% increase in PO will increase $\tau^c(f, \mathrm{F})$ by 2.8%. It is clear that as the component vector varies within the design space, so too will the functional relation between take and profit oil. For instance, for (P, R, T, D^c, D^g) = (25, 0.125, 0.50, 0.15, 0.10),

$$\tau^c(f, \mathrm{F}) = -1.4 + 40.8PO,$$

and in this case, a 1% increase in the profit oil will increase take 1.5% (at PO = 10%) and 1.1% (at PO = 60%).

The present value functional increases with price, cost oil and profit oil, and decreases with the tax rate and corporate discount factor. An increase in commodity price will increase the value of the venture, and as cost oil is increased, the contractor can recover a greater percentage of its cost earlier in the life of the field. Similarly, as profit oil is increased, a greater share of the profit is received by the contractor sooner, further increasing the value of the project. The present value functional evaluated at P = \$20/bbl, T = 35%, and D^c = 10% yields

$$PV(f, \mathrm{F}) = 50.6 + 24.0CR + 118.2PO.$$

Under very tough fiscal terms; e.g., CO = PO = 10%, the field remains profitable, but whether the field satisfies the rate of return criteria of the operator is another matter. For (P, R, T, D^c) = (20, 0.15, 0.35, 0.10),

$$IRR\,(f, \mathrm{F}) = 6.6 + 9.1CR + 36.4PO,$$

and at CR = PO = 10%, $IRR(f, \mathrm{F})$ = 11%.

The value of the profit oil split is apparently a more significant parameter than the selection of cost recovery (about four-to-five times more significant), and so the contractor would be well served to focus attention on negotiating the best terms for this factor. For example, if CR = 40% and PO = 50%, then every one percentage point increase in the cost recovery (profit oil) will lead to a 0.2% (1.0%) increase in the present value of the project, or in absolute dollar terms, every one percentage point differential is worth \$240,000 (\$1.2M).

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 two rows of Appendix Table B.3. The expected value and standard deviation of the system measures, E[$\varphi(f$, F)] and $\sigma[\varphi(f$, F)], is a function of the design space Ω and the value of $\sigma[\varphi(f$, F)] is dependent on the "volume" of Ω, so that for instance if tighter bounds on the intervals are selected; e.g., $P \sim U(20, 25)$, $R \sim U(0.125, 0.167)$, $CR \sim U(0.40, 0.60)$, etc. a reduction in the value of $\sigma[\varphi(f$, F)] is expected.

2.7.3. Profit Oil Sliding Scale: After the base model is constructed, it is relatively easy to develop more sophisticated sliding scale mechanisms for one or more fiscal parameters of the PSA. Complexity can be added a layer at a time and the impact of the specification analyzed sequentially for each component term. In Model II, a two-tranche sliding scale profit oil schedule is illustrated.

A profit oil sliding scale is defined in terms of cumulative production as follows:

$$PO(\psi) = \begin{cases} PO\text{-}1, & \sum Q_t \leq Q(f), \\ PO\text{-}2, & \sum Q_t > Q(f), \end{cases}$$

where the variables PO-1 and PO-2 are bound in the design intervals:

$$PO\text{-}1 \sim \mathrm{U}(0.40, 0.60),$$
$$PO\text{-}2 \sim \mathrm{U}(0.30, 0.40),$$

and the factor $Q(f)$ serves to trigger the application of PO-2. The value of $Q(f)$ is described in terms of MMBOE and is selected uniformly from the interval 5 MMBOE ≤ $Q(f)$ ≤ 35 MMBOE:

$$Q(f) \sim \mathrm{U}(5, 35).$$

The results of the regression model are depicted in Table 4.

The present value functional is computed as,

$$PV(f) = -17.1 + 2.7P + 17.0CR - 58.1T - 176.8\,D^c + 5.5PO\text{-}1 + 106.4PO\text{-}2 + 0.1Q,$$

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 prospects. More than 30 deepwater fields in West Africa are planned to come on stream by 2007, with the majority of these located in Angola and Nigeria (Deluca, 2002). Within 10 years the West Africa region has the potential to mature to a scale that will rival the North Sea at its peak (Edwardes, 2000).

Oil production started in Angola in 1955, and since 1975, has been the principal export, contributing between 75% and 90% of all government revenue through signature bonuses, equity profit oil shares, additional contract deals, taxes, and duties. The petroleum industry accounts for about 50% of Angola's GDP (Clarke, 2000). In 2002, oil production averaged 920,000 BOPD and plans are to achieve 1.5 MMBOPD by 2006 (Angola, 2003). Current proved and probable reserves are estimated at 20 Bbbl of oil and 7-8 Tcf of gas (Angola, 2003). The USGS petroleum assessment for undiscovered resources is estimated at 15 Bbbl oil and 42 Tcf gas. To date, 34 offshore blocks have been delineated, and the major operators ChevronTexaco, ExxonMobil, TotalFinaElf, and BP have assembled enough field developments that the government now has a queue. Angola is expected to challenge Nigeria in the years ahead as Africa's leading crude oil producer.

2.8.2. Angolan Production Sharing Agreements: Angola adapted a PSA in 1979 for shallow waters, and later modified the contract with fiscal incentives applied to demarcated deepwater zones. The fiscal system in Angola has been characterized variously as "tough" and "very tough" over the years, and estimates of government take range between 81%-88% (see Bindemann, 1999; Johnston, 1994b; Van Meurs and Seck, 1997). Sonangol is the National Oil Company and the business arm of the government. Sonangol's main function is to oversee the petroleum operations of foreign companies, and under Angolan law, has exclusive rights to make concessions in the form of PSAs (www.mbendi.co.za).

Angolan PSAs typically have no royalty requirements and the 50% tax rate may be paid in lieu by Sonangol. Cost recovery is usually fixed at 50% but this can be increased under certain circumstances. A negotiable uplift on development cost (40% ceiling) and a (3-5)-year straightline depreciation schedule hold for most contracts written since 1984. Exploration cost is expensed and ringfencing is required for cost recovery around the license (for exploration) and around a field (for development).

The profit oil split in contracts written before 1990 tended to be on a volume-basis, but today, the value of $PO(\psi)$ is based on R-Factors that are negotiable. Before 1991, contract duration for exploration was typically 3 years plus two 1-year extensions. After 1991, exploration was defined as 3 years plus three 1-year extensions for shallow water, and 4 years plus one 2-year extension for deepwater. The terms of production currently extend for 20-25 years. The work requirements to be performed are specified in the exploration obligations, which is block specific and biddable; e.g., Conoco (1986) spent $60M on 4,000km seismic and 6 wells; Total (1989) spent $9M on seismic and 2 wells. Signature bonuses[22] vary with the block, operator, lease sale, and other factors; e.g., blocks 31-33 brought in $300M in signature bonus from BP, TotalFinaElf, and ExxonMobil in 1999; while block 21 ($40M, BHP), block 24 ($69M, ESSO) and block 25 ($85M, Agip) also held significant interest (Shirley, 2001a; Shirley, 2001b).

Prior to 1991, there were no domestic market obligations, but at the request of Sonangol there is now a prorate option with rights up to 40% of production and the contractor responsible for marketing local sales. A price cap fee of 100% is paid to Sonangol on all revenue generated by oil prices in excess of the price cap which is currently set above $30/bbl. A training contribution of $200,000 per year per block is set during the exploration phase, and $0.15/bbl once production starts. A number of other factors also impact the bottom line. Customs duties and fees include a stamp duty of 0.5% on customs clearance documents for imports and exports; a statistical tax of 0.1%, and fees for services rendered by state agencies. Foreign oil companies are subject to special foreign exchange terms to retain outside the country, and to dispose of, the proceeds derived from oil sales. Special legislation and regulatory measures protect foreign companies from the local currency's devaluation.

2.8.3. Block 17 Deepwater Development: The Girassol deepwater development in block 17 was one of the first commercial deepwater fields in Angola and is by far the most spectacular in Angola's deep water province (Cottrill, 2001). Girassol was discovered in 1996 approximately 150km off the Angolan coast in 1,350m water depth. Elf Exploration Angola, an affiliate of the French company TotalFinaElf, formed a project team for Girassol and took it to sanction in July 1998. TotalFinaElf serves as operator with a 40% interest along with its partners ExxonMobil (20%), BP (16.67%), Statoil (13.33%), and Norsk Hydro (10%). The initial development of Girassol experienced delays, and three and a half years after the decision to proceed with the development was taken, first oil flowed in December 2001. Girassol is estimated to have recoverable oil reserves between 725 MMBOE and 1 BBOE.

[22] In Angolan bidding rounds, companies bid for the operatorships as well as for the rights to non-operating equity, and at both times, a signature bonus is required.

The development plan was scheduled in two phases. In phase I, approximately 75% of the $2.7B budget was used to construct and install a Floating Production Storage Offloading (FPSO) vessel[23] and drill 24 wells. In phase II, 15 additional wells will be completed. The complete subsea system will have 23 producers out of a total of 39 wells feeding in pairs to daisychains of manifolds. Fourteen water injectors and 2 gas injectors are planned. The subsea installations consist of 70 km of infield pipelines linked to insulated flowline bundles and 3 riser towers carrying production to an FPSO to process 200,000 BOPD, treat 180,000 BPD and inject 390,000 BPD of water. See Appendix Figure B.3 and Appendix Figure B.4. By mid-2002, production from Girassol reached a plateau output of roughly 200,000 BOPD.

A number of additional discoveries have been made on block 17, and at the end of 2002, 15 oil discoveries now exist: Girassol, Dalia, Rosa, Lirio, Cravo, Orchidea, Camelia, Tuplia, Jasmim, Perpetua, Violletta, Anturio, Zinia, Acasia, and Hortensia. Jasmim is being developed as a satellite tied back to Girassol, and is due to start production in 3Q 2003. Project sanction for Rosa will take place in 2003 at the earliest, and a decision to develop Cravo and Lirio will be taken later. It is likely that Rosa, Cravo, and Lirio will be developed as satellites to Girassol. Calls for tender have been launched for Dalia's $3B development scheme scheduled to start in 2006 (Beckman, 2003).

2.8.4. Development Scenario: The development scenario for Girassol is based on an estimated gross ultimate recovery of 725 MMBOE. The projected production, capital expenditures, and operating expenditures are shown in Appendix Table B.5 based on publicly available sources of information. Total project cost is estimated at $2.7B. Approximately 40% of the costs are associated with the fabrication and installation of the FPSO; 20% to the underwater network of flowlines, risers, and umbilicals which form the links between wellhead and floater; 20% to the subsea system; and 20% to the drilling and completion of the wells. Life cycle capital expenditures are estimated at $1.94/bbl, with operating cost estimated at $2.25/bbl.

2.8.5. The Design Space: The design space for the three models under consideration is shown in Appendix Table B.6. The contract parameters for the "model" Angolan PSA are specified in Model I, while the basic elements of fiscal design are explored in Model II and Model III. In Model II, the impact of a change in the depreciation schedule is examined, and in Model III, the profit oil split is generalized so that we may determine what an incremental change in the profit oil split functional is worth.

The model PSA has no royalty requirements and tax is paid in lieu by Sonangol, and so the contract parameters are specified to reflect small variations in these parameters; i.e., $R \sim U(0.00, 0.10)$, $T \sim U(0.00, 0.20)$. Exploration costs are expensed and development costs are depreciated according to a 5-year straight line schedule. The profit oil split is specified in Appendix Table B.7, and since the production stream is specified under a fixed development scenario, it is clear that the profit oil percentage terms are determined by the value of $q_t = Q_t/365$ shown in Appendix Table B.5.

[23] The FPSO has a storage capacity of 2 MMbbl.

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

$PV(f, \mathrm{F}) = -724.8 + 54.5P - 28.7R + 731.4CR + 278.0UP - 514.7T - 4639.1\,D^c - 120.7D^g$, 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_i, i = 1,…,4, determine a 7-dimensional structure.

There are various system and preference constraints associated with the profit oil functional shown in Appendix Table B.8 that must be incorporated in the design structure, most notably, $Y_1 < Y_2 < Y_3$ (system constraint) and $Z_1 > Z_2 > Z_3 > Z_4$ (preference constraint). Thus, in the selection of the sample intervals, if $Y_i \sim \mathrm{U}(a_i, b_i)$, then $b_1 \le a_2$ and $b_2 \le a_3$ is required to prevent the occurrence of spurious relationships. The preference constraint is not as strictly defined and in principle it is possible (although not likely) that mixed relations such as $Z_1 < Z_2 > Z_3 < Z_4$ will be designed. In the selection of design intervals for Z_i some overlap in the sampling is therefore permitted.

The regression model for the profit oil structure is presented in generalized form as

$$\varphi(f, \mathrm{F}) = \sum_{i=0}^{7} \alpha_i X_i + \sum_{j=1}^{3} \beta_j Y + \sum_{k=1}^{4} \gamma_k Z_k$$

$$\varphi(f, \mathrm{F}) = \sum_{i=1}^{7} \alpha_i X_i + \sum_{j=1}^{3} \beta_{2j+1} D_{2j+1}, \qquad D_j = \begin{cases} 1, D_j \text{ depreciation schedule used} \\ 0, \text{otherwise.} \end{cases}$$

Under a standard royalty/tax fiscal regime we would expect $\beta_3 > \beta_5 > \beta_7$ since a quicker depreciation schedule means that the operator can recover their cost more quickly, but in a PSA regime with cost recovery schemes, the cost ceiling controls the degree to which depreciation schedules impact the cash flow. If cost recovery schemes are dominant, then the impact of advanced depreciation may not be detectable.

to delineate the system parameters (X_i) from the design parameters (Y_j, Z_k). Since the structure of the regression model has changed by the addition of 7 new variables, it is clear that the coefficients α_i will change relative to Model I, and to ensure the stability of the model results, additional iterations should be performed. The signs of the coefficients α_i, i =1, …,7 should be the same as Model I, while the signs for β_j, j =1, 2, 3 and γ_k, k =1, …,4 are expected to be positive since an increase in the tranche level or profit oil split percentage will increase the profitability of the field, and subsequently, the take, present value, and internal rate of return measures.

The results of Model III are shown in Appendix Table B.11. The α_i coefficients change while the β_j coefficients are identically zero, indicating that the selection of threshold levels does not noticeably impact the present value of the field. This apparently anomalous relation is explained by closer examination of the field's production profile. From Appendix Table B.6, observe that Girassol flows in excess of 100 MBOPD for the first 9 years of production, and since $Y_3 \sim$ U(50, 100), it is clear that Z_4 will be the only percentage value used in the first 9 years of production. Further, since $Y_3 \sim$ U(50, 100), anywhere between 1-4 years of production may be added at the profit oil split percentage Z_4 depending on the sample value selected for Y_3. Thus, since the profile is fixed and the tranche levels are restricted through process constraints, variability in the Y_3-tranche levels cannot effectively be felt. The first 9-13 years of production will be maintained at profit oil split percentages determined by Z_4 and Z_3.

The coefficients γ_k are positive and statistically significant with magnitudes $\gamma_1 < \gamma_2 < \gamma_3 < \gamma_4$ as expected. Girassol is expected to flow in excess of Y_3 for nearly a decade, and so the value selected (negotiated) for Z_4 is the most significant term of the profit oil schedule. The regression model also allows us to infer the value of each of these terms. In brief, every percentage point increase negotiated in Z_i translates to a $0.01\gamma_i$ increase in the present value of the field; i.e., a percentage point increase in Z_4 is worth \$38M, \$9M for Z_3, \$4M for Z_2, and \$1M for Z_1. Observe also that the impact of the choice of Z_4 (as well as Z_3) dominates the choice of the cost recovery factor CR and uplift UP. The coefficients for take can be interpreted similarly. Every 1% point increase in Z_i translates to a $0.01Y_i$ increase in the contractor take; i.e., a 1% increase in Z_4 equates to a 0.4 percentage point addition in take.

For $(P, R, CR, UP, T, D^c, D^g) =$ (25, 0, 0.5, 0.4, 0, 0.15, 0.05),

$$PV(f,\ \text{F}) = -523.2 + 90.2Z_1 + 403.9Z_2 + 869.6Z_3 + 3771.7Z_4$$

$$\tau^c(f,\ \text{F}) = -1.3 + 0.8\,Z_1 + 3.8Z_2 + 4.9Z_3 + 40.0\,Z_4$$

and so at (Z_1, Z_2, Z_3, Z_4) =(0.50, 0.40, 0.25, 0.10),

$$PV(f,\ \text{F}) = \$278.0\text{M}$$

$$\tau^c(f,\ \text{F}) = 5.8\%.$$

A number of additional insights follow from a more detailed examination and comparison of the model functionals.

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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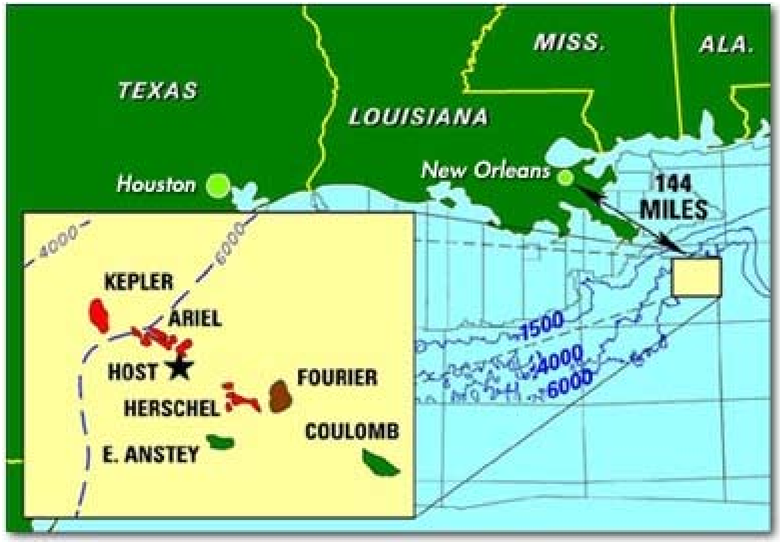
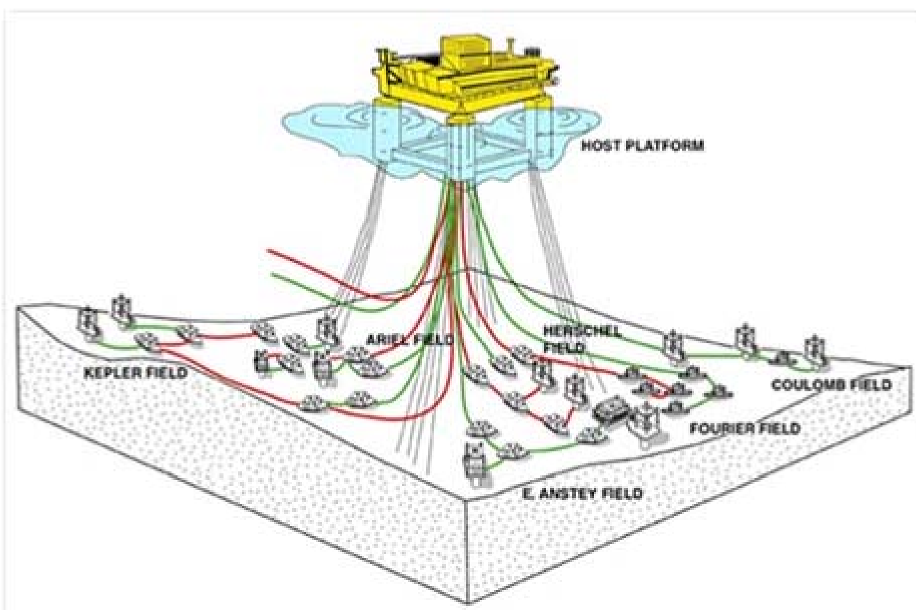
APPENDIX A
CONCESSIONARY SYSTEMS FIGURES AND TABLES



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.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	10	10	0
1995	0	5	8	0
1996	0	3	40	0
1997	4.500	0	25	11.5
1998	7.000	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	18	83	117.0

Source: Johnston, 1994b; Table 3-2.

Table A.2

Regression Models for Contractor Take, Present Value, and Internal Rate of Return for a Hypothetical 40 MMbbl Field

$\varphi(f)$	Iterations	$\varphi(f) = k + \alpha P + \beta R + \gamma T + \delta D^c + \varepsilon D^g$						R^2
		k	α	β	γ	δ	ε	
$\tau^c(f)$	100	44.5(2)	3.1(7)	-72.6(-2)	-89.1(-2)	-216.3(-6)	-6(*)	0.70
	500	36.1(7)	2.8(30)	-84.5(-10)	-71.7(-8)	-163.4(-21)	43.1(3)	0.75
	1,000	28.8(6)	2.9(34)	-77.1(-9)	-51.0(-6)	-174.1(-26)	21.7(1)	0.65
	5,000	29.1(10)	2.8(56)	-81.2(-17)	-56.6(-11)	-165.2(-41)	50.0(5)	0.73
$PV(f)$	100	76.7(4)	5.3(16)	-132.8(-5)	-111.7(-3)	-331.1(-13)	64.3(1)	0.93
	500	74.3(16)	5.2(61)	-129.2(-16)	-99.1(-12)	-318.1(-46)	21.0(1)	0.93
	1,000	76.2(21)	5.4(86)	-146.5(-22)	-98.5(-15)	-325.4(-65)	-0.3(*)	0.93
	5,000	74.6(47)	5.4(95)	-135.0(-49)	-101.1(-37)	-316.0(-145)	1.7(*)	0.93
$IRR(f)$	100	18.1(13)	1.8(73)	-40.7(-15)	-30.5(-14)	-89.1(-47)	2.3(1)	0.98
	500	16.9(26)	1.7(153)	-44.1(-40)	-30.7(-28)	-85.3(-90)	2.3(1)	0.98
	1,000	17.9(37)	1.8(218)	-43.7(-52)	-31.3(-38)	-87.4(-139)	-0.5(*)	0.99
	5,000	18.2(54)	1.8(311)	-44.3(-79)	-31.7(-55)	-86.2(-189)	-0.6(*)	0.99

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

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 ($M)
2001	0.0	0.0	52.83	0.00	0.00
2002	0.0	0.0	350.13	19.24	0.00
2003	100,000.0	325.0	475.33	263.98	5.66
2004	95,177.5	312.0	0.00	0.00	25.30
2005	95,177.5	312.0	0.00	0.00	30.09
2006	82,002.8	304.2	0.00	0.00	30.09
2007	55,538.0	235.5	0.00	0.00	30.09
2008	37,514.4	171.9	0.00	0.00	30.09
2009	25,279.5	125.2	0.00	0.00	37.28
2010	16,683.1	91.5	0.00	0.00	37.28
2011	11,694.0	66.8	0.00	0.00	37.28
2012	0.0	48.8	0.00	0.00	106.47
Total			878.29	283.22	369.65

Source: Data provided by Thierno Sow of the MMS.

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	
$\tau^c(f)$	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)	609.8(2)	0.84
	IV	2088.8(4)	74.2(14)	212.9(13)	-3285.9(-4)	2.2(9)	-3632.6(-3)	-8407.1(34)	-212.1(*)	0.75
$IRR(f)$	I	63.4(54)	2.6(145)	8.6(103)	-58.9(-24)	0.1(49)	-126.2(-76)	-131.5(-131)	2.2(1)	0.99
	II	72.9(40)	2.8(185)	5.6(196)	-68.4(-8)	0.2(50)	-150.0(-61)	-171.5(-65)	2.2(*)	0.99
	III	82.8(6)	2.9(9)	8.4(7)	-68.5(-1)	0.1(7)	-167.2(-10)	-160.0(-11)	1.6(*)	0.44
	IV	83.9(2)	3.4(8)	7.71(6)	-169.1 (-3)	0.2(9)	-152.1(-2)	-186.8(-9)	19.8(-2)	0.34

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

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

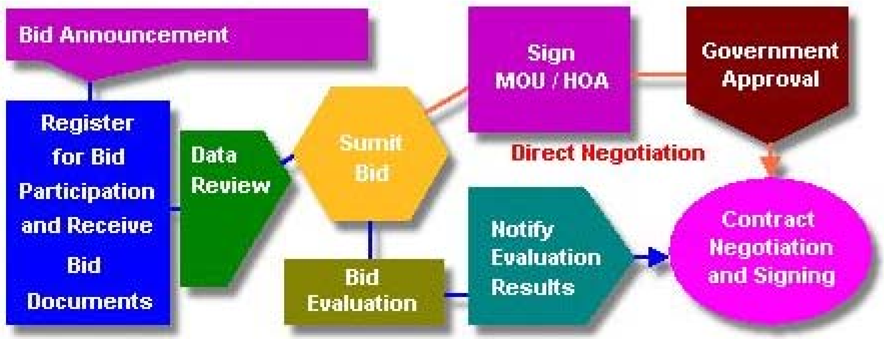


Figure B.1: Typical Bid Evaluation and Negotiation Process in Licensing Agreements.

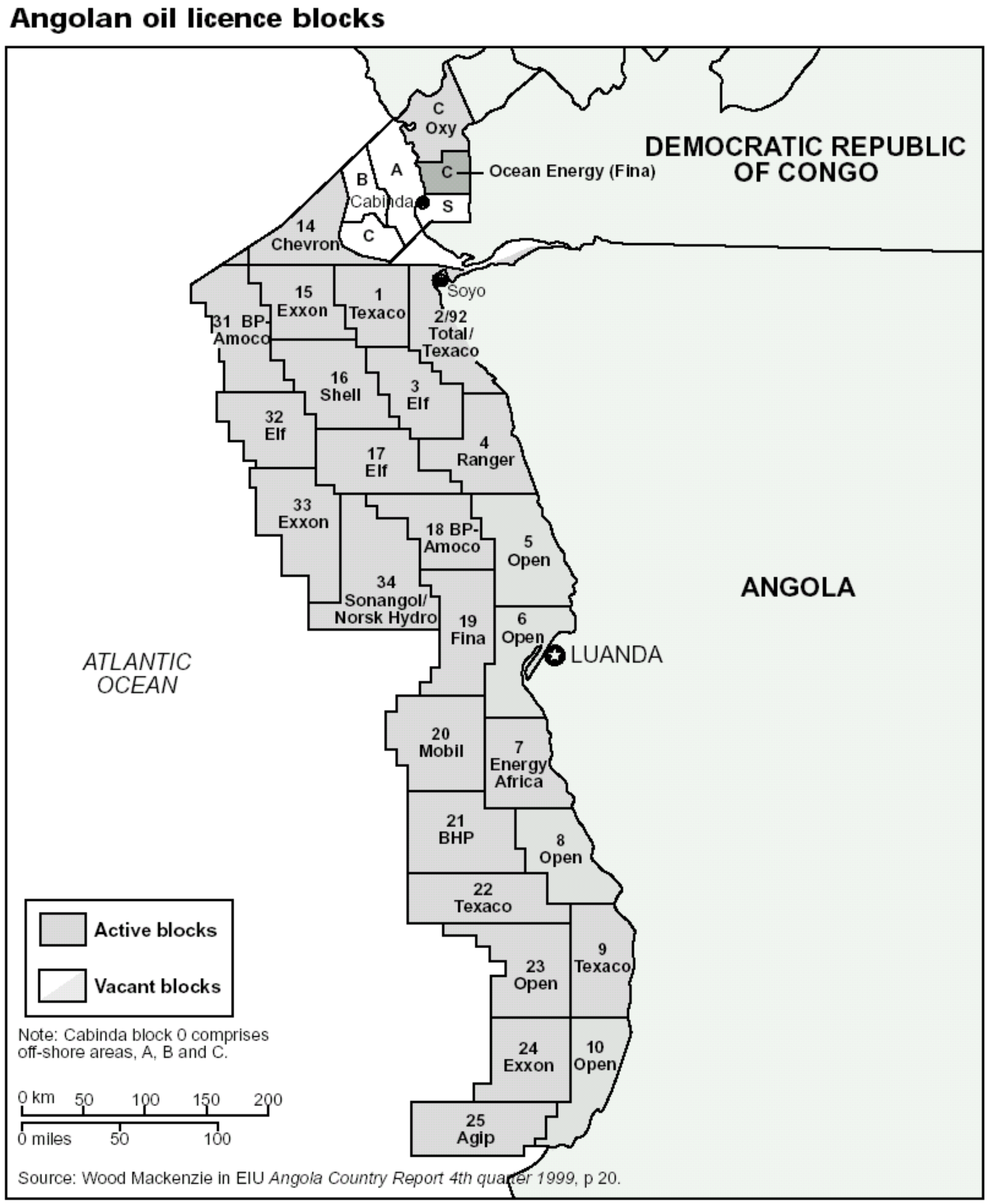
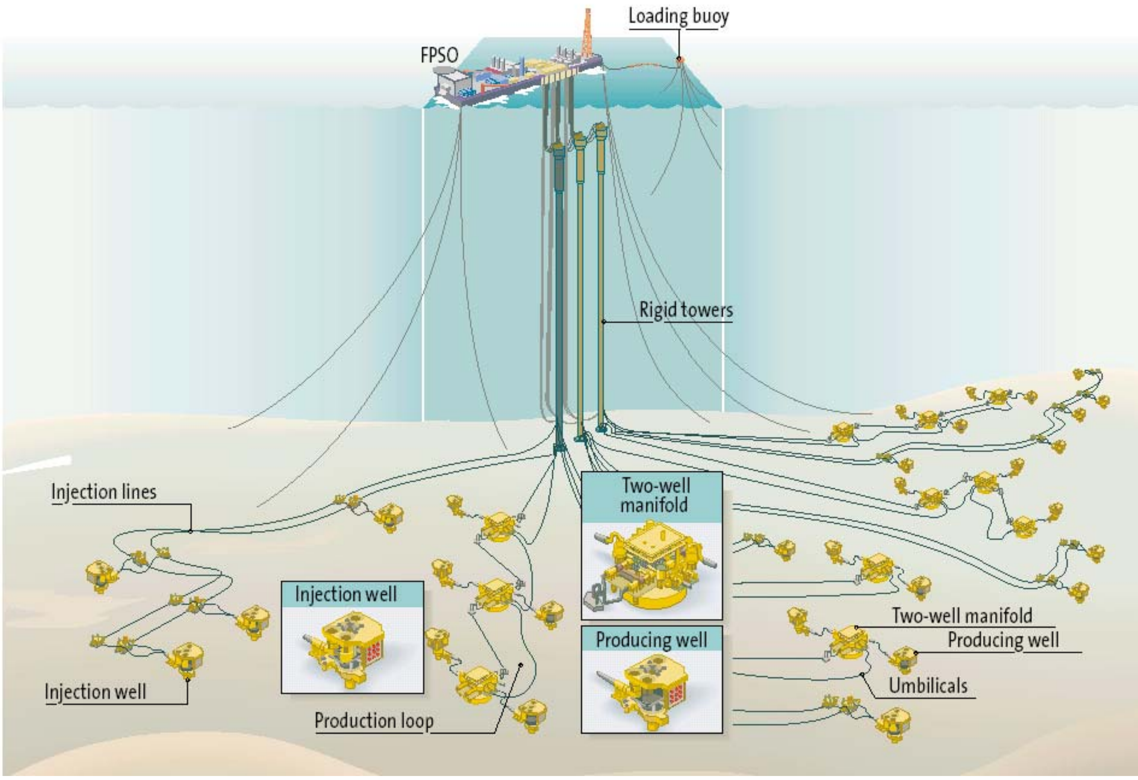


Figure B.2: Angola Oil License Blocks.

Source: Stolt Offshore (www.stoltoffshore.com)

Figure B.3: The Girassol FPSO.

Girassol development program (Angola)



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

The Design Space of the System Parameters

Parameter (unit)	Model I[a]	Model II
P^o ($/bbl)	U(10, 30)	U(10, 30)
R (%)	U(0.10, 0.30)	U(0.10, 0.30)
CR (%)	U(0.10, 0.75)	U(0.10, 0.75)
PO (%)	U(0.10, 0.75)	U(0.10, 0.75)
T (%)	U(0.20, 0.40)	U(0.20, 0.40)
D^c (%)	U(0.15, 0.40)	U(0.15, 0.40)
D^g (%)	U(0.10, 0.20)	U(0.10, 0.20)
Q (MMBOE)		U(5, 35)
PO-1(%)		U(0.40, 0.60)
PO-2 (%)		U(0.30, 0.40)

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

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

Model Coefficient	$\varphi(f, \mathrm{F}) = \alpha_0 + \alpha_1 P + \alpha_2 R + \alpha_3 CR + \alpha_4 T + \alpha_5 D^c + \alpha_6 D^g + \beta_1 PO\text{-}1 + \beta_2 PO\text{-}2 + \gamma Q$		
	$\tau^c(f, \mathrm{F})$ (%)	$PV(f, \mathrm{F})$ ($M)	$IRR(f, \mathrm{F})$ (%)
α_0	8.8(13)	-17.1(-3)	16.9(-9)
α_1	0.0(15)	2.7(53)	1.7(91)
α_2	-12.4 (-20)	-0.7 (*)	2.3 (1)
α_3	-0.8 (-4)	17.0 (-2)	12.2 (21)
α_4	19.5 (31)	-58.1(-12)	-32.1 (-18)
α_5	-46.0 (-95)	-176.8 (-45)	-88.6 (-63)
α_6	50.9 (42)	-4.3 (*)	-3.8 (-1)
β_1	1.4 (2)	5.5 (1)	2.6 (2)
β_2	40.2 (32)	106.4 (10)	58.6 (16)
γ	0.1(1)	0.1 (2)	0.2 (1)
R^2	0.97	0.91	0.96
$E[\varphi(f, \mathrm{F})]$	14.9%	$15.3M	10.2%
$\sigma[\varphi(f, \mathrm{F})]$	14.1%	$22.5M	11.7%

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

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
2003	192,000.0	0.00	0.00	64.33
2004	192,000.0	0.00	0.00	64.33
2005	192,000.0	0.00	0.00	64.33
2006	192,000.0	0.00	0.00	64.33
2007	184,856.0	0.00	0.00	95.60
2008	156,249.0	0.00	0.00	95.25
2009	130,373.8	0.00	0.00	94.94
2010	108,782.9	0.00	0.00	94.68
2011	83,553.0	0.00	0.00	137.69
2012	76,930.7	0.00	0.00	94.30
2013	64,190.5	0.00	0.00	94.14
2014	53,560.1	0.00	0.00	94.02
2015	44,690.1	0.00	0.00	93.91
2016	37,289.1	0.00	0.00	93.82
2017	31,113.8	0.00	0.00	93.75
2018	25,961.1	0.00	0.00	93.68
2019	21,661.8	0.00	0.00	93.63
2020	19,464.8	0.00	0.00	65.31
Total		672.28	736.38	1634.31

Source: Data provided by Thierno Sow of the MMS.

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	$\varphi(f, \mathrm{F}) = \alpha_0 + \alpha_1 P + \alpha_2 R + \alpha_3 CR + \alpha_4 UP + \alpha_5 T + \alpha_6 D^c + \alpha_7 D^g$		
	$\tau^c(f, \mathrm{F})$ (%)	$PV(f, \mathrm{F})$ (\$M)	$IRR(f, \mathrm{F})$ (%)
α_0	11.2 (75)	-724.8 (-25)	-18.9 (-37)
α_1	0.01 (3)	54.5 (103)	1.1 (115)
α_2	-7.5 (-14)	-28.7 (*)	-2.6 (-2)
α_3	-0.5 (-5)	731.4 (36)	17.4 (49)
α_4	-0.3 (-1)	278.0 (5)	7.9 (9)
α_5	-7.3 (-28)	-514.7 (-10)	-11.2 (-13)
α_6	-43.1 (-121)	-4639.1 (-67)	-86.7 (-14)
α_7	43.5 (81)	-120.7 (-1)	-2.4 (-1)
R^2	0.96	0.94	0.96
P_5	3.5	-364	-5.6
Mean	6.7	195	5.0
P_{95}	11.2	957	17.2

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

Table B.10

Girassol Regression Model II Results

Model IIa (d=3)	$\varphi(f, \mathrm{F}) = \alpha_0 + \alpha_1 P + \alpha_2 R + \alpha_3 CR + \alpha_4 UP + \alpha_5 T + \alpha_6 D^c + \alpha_7 D^g$ $\tau^c(f, \mathrm{F})$ (%)	 $PV(f, \mathrm{F})$ ($M)	 $IRR(f, \mathrm{F})$ (%)
α_0	11.2 (79)	-922.1 (-33)	-18.5 (-26)
α_1	0.01 (5)	56.5 (110)	1.1 (52)
α_2	-8.1 (-16)	-164.1 (-2)	-2.6 (-1)
α_3	0.4 (4)	881.9 (42)	15.6 (41)
α_4	-0.6 (-2)	270.7 (5)	7.4 (10)
α_5	-7.3 (-27)	-607.6 (-12)	-11.3 (-11)
α_6	-43.0 (-120)	-4368.0 (-62)	-86.6 (-25)
α_7	43.2 (82)	69.7 (*)	-2.5 (*)
R^2	0.96	0.95	0.94
P_5	3.5	-460	-6.2
Mean	6.6	160	5.6
P_{95}	11.1	915	18.9
Model IIc (d=7)			
α_0	11.0 (54)	-586.8 (-15)	-14.6 (-15)
α_1	0.01 (3)	50.3 (68)	1.0 (88)
α_2	-8.8 (-12)	-252 (-2)	-2.6 (-1)
α_3	0.3 (2)	672.6 (24)	14.9 (37)
α_4	-0.2 (*)	320.7 (4)	7.1 (7)
α_5	-7.2 (-19)	-531.1 (-7)	-11.8 (-12)
α_6	-42.4 (-88)	-4988.6 (-53)	-88.6 (-68)
α_7	43.5 (57)	-85.1 (*)	-2.5 (-1)
R^2	0.96	0.94	0.96
P_5	3.4	-374	-5.3
Mean	6.7	195	4.6
P_{95}	11.3	897	15.4

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

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

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.