WORLD BANK WORKING PAPER NO. 179

Petroleum Exploration and Production Rights

Allocation Strategies and Design Issues

Silvana Tordo
with David Johnston
and Daniel Johnston

THE WORLD BANK

WORLD BANK WORKING PAPER NO. 179

Petroleum Exploration and Production Rights

Allocation Strategies and Design Issues

Silvana Tordo
with David Johnston
and Daniel Johnston

THE WORLD BANK
Washington, D.C.

Manufactured in the United States of America
First Printing: November 2009

Printed on recycled paper

1 2 3 4 5 12 11 10 09

World Bank Working Papers are published to communicate the results of the Bank's work to the development community with the least possible delay. The manuscript of this paper therefore has not been prepared in accordance with the procedures appropriate to formally-edited texts. Some sources cited in this paper may be informal documents that are not readily available.

The findings, interpretations, and conclusions expressed herein are those of the author(s) and do not necessarily reflect the views of the International Bank for Reconstruction and Development/The World Bank and its affiliated organizations, or those of the Executive Directors of The World Bank or the governments they represent.

The World Bank does not guarantee the accuracy of the data included in this work. The boundaries, colors, denominations, and other information shown on any map in this work do not imply any judgment on the part of The World Bank of the legal status of any territory or the endorsement or acceptance of such boundaries.

ISBN-13: 978-0-8213-8167-0
eISBN: 978-0-8213-8168-7
ISSN: 1726-5878 DOI: 10.1596/978-0-8213-8167-0

Library of Congress Cataloging-in-Publication Data has been requested.

Contents

Tables

Figure

Boxes

Acknowledgments

This paper presents the results of a study aimed to collect information on countries' experience with the allocation of petroleum exploration, development, and production rights. The paper was undertaken and written by Silvana Tordo (lead energy economist—Oil, Gas, and Mining Division, the World Bank). Input was provided by petroleum sector expert consultants David Johnston and Daniel Johnston. The comments of the following peer reviewers are gratefully acknowledged: Alan H. Gelb (director, Development Policy) and Robert W. Bacon (consultant, Oil, Gas, and Mining Division), both with the World Bank; Clive Armstrong (lead economist, Oil, Gas, Mining and Chemicals Department, International Financial Corporation); Charles P. McPherson (senior adviser, Fiscal Affairs Department, International Monetary Fund); Willy Olsen (consultant); and Kjell J. Sunnevåg (senior adviser, Norwegian Competition Authority). Comments were also provided by Robert M. Lesnick (adviser, Global Gas Flaring Reduction Initiative, Oil, Gas, and Mining Division, the World Bank). The author wishes to particularly thank Wayne W. Camard (senior economist, Africa Department, International Monetary Fund) for his helpful comments and suggestions during the preparation of this paper. Special thanks also go to Fayre Makeig and Stephen Spector for their editorial suggestions. Finally, the author owes a debt to Professor Paul Kemperer, Oxford University, whose theoretical and practical work on auctions provided inspiration for this paper.

Acronyms and Abbreviations

Technical terms:

CIT	Corporate income tax
E&P	Exploration, development, and production
EPC	Engineering, procurement, and construction
ERR	Effective royalty rate
FPWC	Financed public works contract
GoM	Gulf of Mexico
GTL	Gas-to-liquid
JVs	Joint ventures
LCV	Local content vehicle
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
MOU	Memorandum of understanding
NPV	Net present value
OCS	Outer Continental Shelf
PRRT	Petroleum resource rent tax
PSA	Petroleum-sharing agreement
PSC	Petroleum-sharing contract
RJBL	Restricted joint bidders list
R-factor	Ratio-factor
RoR	Rate of return
SA	Service agreement
SLD	Straight line decline
UKCS	U.K. Continental Shelf
USGoM	U.S. Gulf of Mexico

Government agencies and other entities:

AAPG	American Association of Petroleum Geologists
ABARE	Australian Bureau of Agricultural and Resource Economics
ANP	Agencia Nacional do Petróleo (Brazil)
API	American Petroleum Association
ARC	Aden Refinery Company (Yemen)
BERR	U.K. Department for Business, Enterprise & Regulatory Reform
CNPE	Conselho Nacional de Política Energética (Mexico)
CRE	Comisión Reguladora de Energía (Mexico)
compraNET	Government Procurement Electronic System (Mexico)
DECC	Department of Energy and Climate Change (United Kingdom)
DOI	Department of the Interior (United States)
EIA	Energy Information Administration (United States)

MMS	Minerals Management Service (United States)
MoM	Ministry of Oil and Minerals (Republic of Yemen)
MRC	Marib Refinery Company (Republic of Yemen)
PEMEX	Petróleos Mexicanos (Mexico)
PEPA	Petroleum Exploration and Production Agency (Republic of Yemen)
PETROBRAS	Petróleo Brasileiro (Brazil)
SEC	Security Exchange Commission (United States)
SECODAM	Secretaría de Contraloría y Desarollo Administrativo (Mexico)
SENER	Secretaría de Energía (Mexico)
SHCP	Secretaría de Hacienda y Crédito Público (Mexico)
SPE	Society of Petroleum Engineers
WPC	World Petroleum Congress
YC	Yemen Company
YGC	Yemen Gas Company
YOC	Yemen Oil Company
YOGC	Yemen Oil and Gas Company
YPC	Yemen Petroleum Company

Executive Summary

Petroleum has become an integral part of today's global economy and a key component of many national economies. Hence, the presence of petroleum in meaningful quantities can have important economic, developmental, and strategic consequences for a country. While a country's petroleum resource base is a gift of nature, translating this resource into saleable crude oil requires investment and effort. Whether governments choose to invest directly or allow private investors to do so, their primary concern should be to maximize the social benefits derived from the exploitation of the resource base. In practice, however, defining what constitutes maximum social welfare is essentially a political question, which helps explain the variety of objectives pursued by governments over time.

In order to exploit their natural resources efficiently, many governments rely on private oil companies. Governments have a challenging task in deciding which companies should be awarded the exclusive rights to explore, develop, and produce their resources, and on what conditions such rights should be awarded. There is little empirical documentation on the design and relative effectiveness of alternative systems for the allocation of petroleum exploration, development, and production (E&P) rights and their policy implications. This paper analyzes the available evidence on the advantages and disadvantages of various practices used by petroleum producing countries to allocate petroleum E&P rights, and draws conclusions about the optimal design of E&P allocation systems.

The first crucial set of decisions a government faces is whether or not to explore for petroleum, at what pace to explore, and who should undertake such exploration. There are several reasons why policy makers should promote oil and gas exploration:

- Exploration provides information on the existence, likely size, and distribution of petroleum reserves, which can be used to guide the definition of efficient inter-temporal depletion policies;
- Better knowledge of the size of petroleum reserves provides an input for the design of sustainable macroeconomic policies and for improving inter-generational equity through the choice of current consumption rates;
- Information about an area's geological potential affects the perception of geological risk and related market interest in—and competition for—E&P rights in the specific area; and
- Improved knowledge of the geological potential of an area allows the government to design appropriate strategies for the promotion and licensing of petroleum E&P rights, including delineation of blocks to be licensed, licensing procedures, and licensing terms that reflect the risk profile of the specific areas.

Clearly, exploration generates valuable information for policy makers, investors, and the public at large.

Who should undertake the risk of exploration, and in what measure, is another important policy decision. Companies hedge against risk by investing in a diverse portfolio of projects—often in several countries—and by involving partners. Countries rarely have the same ability to diversify their petroleum investments. Hence, often governments hedge against exploration risk by transferring part of it to private oil companies through contract and fiscal system design.

Indeed, the uncertainty and risk that characterize petroleum E&P activities pose special challenges to the design of efficient allocation policies. At the time of allocating exploration rights, neither the resource owner nor the investors know whether oil or gas will be found, in what quantities, at what cost it will be produced, and at what price it will be sold. Moreover, the resource is non-renewable, and a large portion of the total risk is project specific. For these reasons, even if a hypothetical social welfare function could be determined with precision, the uncertainty surrounding the existence and value of petroleum resources makes their management a complex endeavor.

Risk is not, however, the only challenge that governments and investors must face. Exploration and development activities require specialized, high-tech equipment and skills that are often not available in the host country, and are, in any case, limited in quantity. Capital investment is usually high and the largest investments occur several years before production. As a consequence, governments and investors are much more likely to observe higher levels of activity (and ultimately faster economic growth and higher profits) if they can spread their investment over several projects through partnering with other market participants. For governments, this strategy translates into the need to design efficient policies for the allocation of petroleum E&P rights to investors.

Countries allocate petroleum E&P rights in various ways; some use different forms of public tenders or licensing rounds, others use direct negotiation, and most use a combination of these systems. The conditions for award can vary substantially: some countries adopt rather rigid systems with very limited biddable parameters that affect the sharing of the rent between investors and owner of the resource; others award rights on the basis of work programs; in others, "everything is negotiable." Poorly conceived legal, regulatory, and fiscal frameworks may lead to inefficiency and loss of economic rent, which may not be mitigated through the allocation system. The most common allocation systems and biddable parameters include cash bonuses, work programs, royalties, and profit shares. Bundle bidding—that is, linking access to petroleum resources with downstream or infrastructure investments—is also used, particularly in developing countries.

In this paper, allocation systems are grouped into two categories: (i) open-door systems (E&P rights are allocated as a result of negotiation between the government and interested investors through solicited or unsolicited expression of interest); and (ii) licensing rounds. Two types of licensing rounds can be identified: (i) administrative procedures, in which E&P rights are allocated through an administrative adjudication process on the basis of a set of criteria defined by the government; and (ii) auctions, in which rights go to the highest bidder. In open-door systems, the criteria for award are often not pre-defined and known to market participants; the government retains considerable discretionary power and flexibility in awarding E&P rights. Open-door

systems are likely less competitive than licensing rounds and are generally considered less transparent and more vulnerable to corruption. Such systems can, however, be made more transparent through the definition of clear award criteria, the publication of negotiation results, and the use of external oversight bodies. Auctions are generally considered more efficient than administrative procedures or direct negotiations in allocating E&P rights, but their relative efficiency depends on the context and the design parameters.

The design of allocation systems requires the definition of the specific objectives that policy makers wish to achieve through the licensing of petroleum E&P rights. License allocation is, however, only one of the policy tools that can be used to achieve these objectives. Hence, it is important to ensure coordination and coherence with other policy tools, in particular the petroleum fiscal regime and market regulation. In addition, governments face a complex set of changing constraints and exogenous factors. The relative priorities among objectives and the interaction among the various constraints and exogenous factors influence the optimal design of allocation systems.

Effective allocation systems take into account: (i) the characteristics of the area to be licensed (such as geology, exploration risk, location, and distance to market); (ii) the structure of the market (such as level of competition, market segmentation, size and strength of the players, access to information, and domestic market); (iii) issues related to the ownership and access to the resource; and (iv) regulatory and institutional frameworks. Exogenous factors such as the expected level and trend of future oil and gas prices, and competition from other petroleum countries also affect a country's allocation strategy. Although general principles can guide the choice of allocation system, the design needs to be tailored to reflect the economic, social, and political objectives, constraints, and concerns that are unique to each country. Because social and political objectives are country specific, it is difficult to identify principles that apply to all countries. From an economic perspective, the government would want an allocation system that: (i) is consistent with the government's petroleum sector policy; (ii) favors the selection of the most efficient operator; (iii) involves low compliance and administration costs; (iv) minimizes distortionary effects; and (v) addresses market deficiencies.

In theory, the allocation system could be used as the primary mechanism for rent capture; for example, by choosing allocation criteria based on pure cash bonus payments. But unless the payment structure is designed to take into account information on the value of the resource that was not available at the time of award, there is a risk that the right to develop the resource in a specific area may be sold for a price that is well below, or well above, the true value of the resource extracted from that area. There may be some advantages to this approach in terms of early access to rent and of transparency. In practice, however, the most efficient allocation systems extract the rent by relying on some type of conditional payment—that is, payments linked to the true value of the resource—through the fiscal regime which defines the type and affects the timing and magnitude of these conditional payments. The uncertainty and risks that characterize petroleum E&P activities are critical in making this the more efficient approach, and explain why petroleum producing countries do not rely on cash bonuses as their sole or principal mechanism for rent extraction. The issue then becomes that of defining which parameter(s) of the fiscal regime, if any,

should be biddable or negotiable—and to what extent. In other words, the licensing of E&P rights requires that the government define both the minimum target price and how best to collect it.

A detailed analysis of the allocation systems of six petroleum producing countries yields lessons of wider applicability. In particular:

- The relative maturity of a geological basin affects the level of competition and the size of the winning bid, whether the form of allocation is an administrative procedure or auction;
- The expected future oil and gas prices are a significant factor in explaining the variability over time in the number of bids and bid size for the same geological basin, particularly in frontier and immature areas;
- The number of bidding parameters should be limited and should clearly reflect the objectives that the government wishes to pursue through allocation;
- Transparent awards improve the efficiency of the allocation system and make it less vulnerable to political and lobbying pressure;
- Work program bidding is often used to directly affect the quality and level of exploration investment in an area;
- Cash bonus bidding is generally less efficient in frontier and underexplored areas, especially when the number of bidders is limited and the players are risk averse;
- Joint bidding does not imply anti-competitive behavior;
- The use of area-wide licensing or nomination affects bidders' strategies and outcomes as well as the pace of development of the resource base; and
- Market segmentation—that is, the extent to which different companies specialize in different types of exploration activities and tolerate different risks—is of great relevance to the design of efficient allocation systems.

Not all factors affecting the design of efficient allocation systems can be controlled or influenced by governments. A country's geological potential is a prime example of an independent factor. The geological potential determines countries' relative ability to attract investors and to extract the rent. Nonetheless, countries can try to affect the perception of prospectivity and reduce information asymmetries among market participants through the strategic use of geological, geophysical, and petrophysical data. Global market and economic conditions, including the expected level and trend of future oil and gas prices, also play an important role in shaping investors' strategies and attitude toward risk. Although governments have, at best, limited influence on these factors, they can adapt their allocation strategies to respond to changes in market and economic conditions.

In designing an allocation system, the form, biddable parameters, and bidding procedure play a large part in ensuring its efficiency. But equally important is the system's ability to (i) encourage bidders' participation, since the size of the winning bid is positively correlated with the number of bidders; (ii) deter collusion among bidders, since bidders may explicitly, or tacitly, conspire to keep bids low; and (iii) resist political and lobbying pressures, since this may distort allocation by favoring some bidders or consortia over others. The government's technical and administrative

capacity should also be taken into consideration when designing an allocation system, as it affects its efficiency.

Conclusions

There is no model allocation policy or system appropriate for all governments and all circumstances. Optimal design depends on a range of factors and requires the definition of the objectives that policy makers aim to achieve through the allocation of petroleum E&P rights. Some of these objectives may be more effectively achieved by combining allocation systems with other policy tools, in particular the fiscal system and market regulation. Country-specific objectives and constraints tend to change over time, as do exogenous factors. In addition, countries tend to license E&P rights in areas that have disparate characteristics. For these reasons, countries often adopt a range of allocation policies, including open-door systems and various forms of licensing rounds.

Despite the variety of factors influencing optimal design, most countries use similar solutions. In particular, when auctions or administrative procedures are used, most governments opt for simple simultaneous multi-object sealed-bid rounds. While this may appear to be paradoxical, there is a practical explanation. It is true that more complex bidding forms might increase rent capture at bidding. However, the potential marginal gain is often limited, owing to most E&P projects' high level of uncertainty and risk. The more risk-averse bidders are, the more likely it is that sealed bids will capture the rent more efficiently than other forms of auction. In fact, since bidders have only one chance to bid, fear of losing induces them to bid slightly higher than they might otherwise. First-price sealed-bid auctions are more likely to encourage entry, and are less exposed to the effect of information asymmetry and the risk of collusion among bidders than alternative forms of auction. In addition, while there is a positive correlation between the number of bidders and the size of the winning bids, the size of the winning bids is also strongly correlated with the quality of the blocks. Better quality blocks attract more bidders; more bidders increase the winning bid. When there is a large number of potential bidders for whom entry to the auction is easy, auction design may not matter as much.

Governments do not rely solely on allocation systems to maximize rent capture. Given the usually high level of uncertainty and risk associated with exploration activities, better results are often achieved by selecting a limited number of biddable parameters clearly targeted to the objectives of the government allocation policy, and by relying on the fiscal system to maximize rent capture (particularly if progressive fiscal systems are used). Progressive fiscal systems allow both governments and investors to reduce risk and correct inefficiencies due to imperfect information at the time of allocation. For this reason, they are more effective in capturing the economic rent than allocation systems. Moreover, market mechanisms such as joint bidding and secondary markets are widely used in the petroleum sector to correct inefficiency at the time of allocation.

Transparent selection criteria improve the bidding process. Transparency with respect to the evaluation criteria that will be applied by the government in selecting the winning bids will ultimately improve the efficiency of the bidding process. This is particularly true where multiple policy objectives are pursued by the government

through the licensing policy. Knowing the relative importance of these objectives will allow bidders to structure appropriate bids, reduce the administrative time used for reviewing proposals, and improve confidence in the fairness of the allocation system. However, a transparent allocation system is not a guarantee of efficiency; rather, efficiency depends on the system's parameters and how well they respond to the government's objectives, constraints, and exogenous factors. Bundle bids pose additional challenges in this respect.

CHAPTER 1

The Exploration, Development, and Production of Petroleum Resources

While a country's petroleum resource base is a gift of nature, translating this resource into saleable crude oil requires investment and effort. Whether governments choose to invest directly or allow private investors to do so, their primary concern should be to maximize the social benefits derived from the exploitation of the resource base. In other words, governments should seek to ensure that petroleum resources are produced and consumed for the benefit of the entire society. Criteria have been developed to guide the formulation of policy in cases that involve a certain level of value judgment.[1] In practice, however, defining what constitutes maximum social welfare is essentially a political question (Kalu, 1994), which helps explain the variety of objectives pursued by governments over time.

Maximizing the net present value (NPV) of the economic rent is often explicitly cited as a key government objective.[2] In addition, governments often pursue a variety of development and socioeconomic objectives, including job creation, technology transfer, environmental protection, and the development of local infrastructure. These objectives and their relative priorities, together with each country's unique constraints and concerns, determine the types of policies, strategies, and tactics available to policy makers in their role as custodians of a nation's mineral wealth.

Uncertainty and Risk: Key Elements of Petroleum Exploration, Development, and Production

The exploration, development, and production of petroleum entail various activities, ranging from undertaking geological surveys and identifying hydrocarbon resources, to commercially exploiting them.[3] These activities involve different levels and types of risks and uncertainty,[4] which can be broadly categorized as:

- *Geological*—related to the likelihood that oil and/or gas are present in a particular location, and to the range of potential discoveries;
- *Financial*—related to project and economic variables; and
- *Political*—specific to each region or country.

In general terms, the geological risk begins to diminish after a discovery, while the political and financial risks intensify.[5] One reason for this is that the bargaining power and relative strength of the investor(s) and host government shift during the cycle of exploration and development. By the time production starts, capital investment is a sunk cost, and facilities installed in foreign countries represent a source of vulnerability to the investor (Tordo, 2007).

Initially, oil and gas lie in undiscovered reservoirs of various sizes situated at different depths in the earth's crust.[6] Although technological advances in recent years have helped substantially reduce the uncertainty of possible outcomes in both mature and frontier basins, the exploration of oil and gas remain a high-risk venture. Geological and geophysical data provide some indication of reservoirs' location and size, but, ultimately, the only way to determine whether oil and gas is present in commercial quantities is to drill a well. When an exploratory well is successful, additional wells are drilled to determine the extent of the discovery and the development options.[7] If the commercial viability of a discovery is established, more wells (that is, additional investments) are usually needed to develop the discovery. Once the production (and transportation) capacity is installed, oil and gas are produced over a number of years—usually at declining rates as resources are depleted. The level and length of production depend on a host of factors, both technical (such as size, reservoir characteristics, characteristics of crude oil and/or gas, and geography) and economic (oil and gas prices, project costs, fiscal regime, and so on). During the exploration phase, major uncertainties are related to volumes in place and project economics. As more information is acquired, these uncertainties are mitigated; meanwhile, uncertainties related to the recovery factor, reservoir performance, project cost, oil and gas price, and regulatory changes become more relevant.

Given these factors, it is difficult to determine, in advance, the existence and size of oil and gas resources, as well as their quality, potential production levels, finding and development costs, and future prices in the world market. Moreover, the resource is nonrenewable, and a large portion of the total risk is project specific. These facts bear important consequences for policy makers: even if a hypothetical social welfare function could be determined with precision, the uncertainty surrounding the existence and value of petroleum resources makes their management a complex endeavor. Policy makers are therefore motivated to devise and implement policies that reduce uncertainty. Promoting exploration activities helps to reduce uncertainty but, as this paper will show, requires numerous policy decisions.

The Decision to Explore for Petroleum Resources

The first crucial set of decisions a government faces is whether or not to explore for petroleum, at what pace to explore, and who should undertake such exploration.

Petroleum has played an important role over the past century, and its numerous uses have become an integral part of today's global economy. Hence, the presence of petroleum in meaningful quantities can have important economic, developmental, and strategic consequences for a country. On this basis only, we could conclude that information on the existence, likely size, and distribution of petroleum reserves is valuable to the society at large. This holds true even if exploration proves unsuccessful.

Because the cost of inefficient exploration (and production) translates into lower economic rent available to the public, the more efficient the exploration, the higher the social benefit. This basic economic concept has important implications for the design of policies for the award of E&P rights. These will be discussed further in this paper.

Exploration and Inter-Temporal Depletion Policies

Exploration can provide guidelines for the definition of efficient inter-temporal depletion policies (Julius and Mashayekhi, 1990; Sunnevåg, 1998). An efficient petroleum depletion policy would require production to occur in order of increasing costs, if the location and extraction costs were known with certainty (Gilbert, 1979). The sequence would depend on the distribution of exploration and extraction costs across different basins. Exploration can—through surveys and drilling—reduce uncertainty regarding the location and size of petroleum accumulations as well as their likely development costs. The accumulation of a stock of proved reserves[8] would—at least in theory—permit the more efficient scheduling of production of various deposits (Gilbert, 1979). This is particularly important if the depletion of some deposits leads to tight constraints induced by scarce capacity in production and transport, or if infrastructure needs to be in place for certain projects to be commercially viable. But generating a stock of proven oil and gas reserves ahead of time can be very expensive—especially when the time value of money is factored into the calculus. Furthermore, the government's ability to influence the sequencing and coordination of development and production activities is often limited by numerous technical, institutional, and contractual matters.

Exploration activities are usually carried out by oil companies at their own expense,[9] and development and production activities are planned with the objective of maximizing the project's return on investment. Delaying the development and production of proven reserves to match the optimum inter-temporal depletion policy of the country of operation would likely have a negative impact on the project's return on investment and on government revenue (through the fiscal system).[10] A further constraint on policy makers' ability to influence the timing of a project's development is linked to the availability of financing, equipment, and other specialized input, which may not coincide with the needs of the country's optimum inter-temporal depletion policy. In addition, although contractual agreements usually provide for government approval of development plans submitted by the operator, the instances when such approval can be denied or delayed are clearly defined.

It is difficult to assess the impact of market, regulatory, and political incentives on the optimal pace and pattern of exploration activity. In practice, policy makers often end up formulating their policy objectives in a more simplistic manner such as (i) ensuring a stable level of exploration and development; (ii) fostering the development of more remote regions; and (iii) promoting efficient development. Particularly in poor countries in need of development spending—or where political instability puts a premium on patronage expenditures—governments may simply aim to maximize revenue over the short term.

Exploration and Inter-Generational Equity

Three aspects related to the existence of petroleum revenue pose special problems for decision makers: (i) petroleum revenue may be quite large in relation to the rest of the

economy, but will not be permanent because the resource is exhaustible; (ii) the revenue size may be so large in relation to the economy itself that it would be difficult to identify productive uses for all of it, were it to be immediately spent; and (iii) the volatility of resource prices and the variability of production volumes can result in substantial changes in government resource revenue from year to year. Better knowledge of the size of petroleum reserves provides an input for the design of sustainable macroeconomic policies and for improving intergenerational equity through the choice of current consumption rates. Updating this knowledge may allow a country to devise fiscally sustainable consumption and savings policies, and adjust them over time. For example, countries with a high social discount rate at the outset may require very large oil revenue before that rate falls to a point that would favor deferring potential spending. In addition, "Dutch disease" and limits on absorption capacity produce deleterious macroeconomic effects that are well documented in the literature, and largely affect governments' policy options.[11]

Exploration and the Maximization of the Resource Rent

Information is an important aspect of any market and plays a crucial role in policy design. In the petroleum sector, availability of information about an area's geological potential affects the size of the resource rent that may be derived by the government from future exploitation activities.

Particularly in frontier areas, uncertainty about the geological potential often represents the lion's share of the risk associated with petroleum projects.[12] Risk has a big impact on determining exploration threshold field size. Exploration threshold analysis helps to decide whether or not to attempt exploration efforts. The threshold is estimated by making assumptions about the probability of success and the value of the reserves that may result from successful efforts. Expected price and costs, reservoir characteristics, and the country's fiscal system all affect the determination of threshold field size. Due to the different level of risk, exploration thresholds are several orders of magnitude larger than development field size thresholds. Reducing the geological risk—or rather the perception of risk—will reduce the exploration and development thresholds, and the risk premium required by investors.[13] In other words, reducing the geological risk will increase market interest in—and competition for—E&P rights in the specific area, and increase the potential for and size of future resource rents. It is worth noting that negative exploration results would not necessarily reduce exploration interest in an area. This is because the interpretation of exploration results entails a certain level of subjectivity and can vary substantially across companies, depending on factors such as previous experience in working in similar geological settings, new data or new theories, and the ability of the interpreters.[14]

Improved knowledge of the geological potential of an area allows the government to design appropriate strategies for the promotion and licensing of petroleum E&P rights, including delineation of blocks to be licensed, licensing procedures, and licensing terms that reflect the risk profile of the specific areas.

The acquisition of geophysical data[15] ahead of licensing E&P rights has been used by many governments to reduce geological risk and increase competition among potential investors.[16] Exploration drilling, which is carried out after E&P rights have been awarded, provides more refined information on the size and distribution of

petroleum accumulations than geophysical data alone. This type of information has important externalities for neighboring areas as well as for the overall perception of geological risk. Given the high expense of obtaining technical data and its value to potential competitors, access to it is normally restricted to the license holders and the government. But press announcements by the government and the license holders, with respect to drilling results, often provide useful indicators and are closely monitored by market participants. Studies of competitive bidding rounds in the U.S. Gulf of Mexico (USGoM) show the importance of "information asymmetry" among bidders—holders of leases in areas neighboring tracts on offer were able to secure rights in the better value tracts. According to Mead (1994), "The asymmetrical information condition reflects the fact that bidders for wildcat leases buy two products: the right to produce any oil and gas from the tract, and the potential information advantage in bidding for an adjacent tract. Bidders overpay for wildcat tracts for the first product only."

Who Carries the Risk of Exploration?

Clearly, exploration generates valuable information for policy makers, investors, and the public at large. Although the chance of exploration drilling success has been steadily rising over the last 50 years—mainly driven by advances in seismic imaging technology—exploration remains a risky business. The average exploration success rate worldwide is approximately one in three wells (33 percent). In the 1960s the average was one in six (17 percent). There is ample variation among countries and across basins within the same country. For example, in the U.K. Continental Shelf (UKCS), the average exploration drilling success rate in the Southern Basin is about 28 percent, while in the remaining areas it is around 10 percent.[17]

Who should take the risk of exploration—and in what measure—is an important policy decision. Governments have basically four alternatives; they can: (i) develop the resource themselves; (ii) pay an oil company to develop the resource for a fee; (iii) sell the right to develop the resource to an oil company; or (iv) implement a combination of the three previous options. If a government chooses to develop the resource directly or to hire oil companies to develop the resource on its behalf, it will have to bear the risk of exploration and development entirely. Risk management is an important feature of the oil industry. Companies hedge against risk by investing in a diverse portfolio of projects, often in several countries, and by involving partners. Countries rarely have the same ability to diversify their petroleum investments. It is therefore not surprising that governments, even when they participate in commercial activities through a national oil company, seldom choose to bear the risks of direct exploration. Usually, governments hedge against exploration risk by transferring part of it to the investors through contract and fiscal system design.

Usually, the investors bear the costs and risks of exploration. If a discovery is made, the government, often through its national oil company, has the option to participate in a petroleum project for, or up to, a set percentage participating interest.[18] Normally, the government participating interest is a working interest carried through exploration (rarely through development); that is, investors bear the risk and cost of exploration (and development as the case may be) and the government/national oil company's share of cost is paid out of production according to a procedure specified in

the petroleum contract.[19] In some countries, however, the government "backs in" without repaying the investor for its share of the expenses borne and/or the risk taken during the exploration phase.[20] Investors' expenses are carried forward until full recovery (or until such time specified in the petroleum contract). In any case, if no commercial discovery occurs, the cost of exploration is borne solely by the investors.

Risk is not, however, the only challenge that governments and investors must face. Exploration and development activities require specialized, high-tech equipment and skills that are often not available in the host country, and are, in any case, limited in quantity. Capital investment is usually high and the largest investments occur several years before production. As a consequence, governments and investors are much more likely to observe higher levels of activity (and ultimately faster economic growth and higher profits) if they can spread their investment over several projects through partnering with other market participants. For governments, this strategy translates into the need to design efficient policies for the allocation of petroleum exploration, development, and production rights to investors.[21]

Notes

[1] For a detailed discussion of these criteria, see Pareto (1927), Kaldor (1939), Hicks (1939), Bergson (1938), Hayek (1945), Samuelson (1947), and Webb (1976).

[2] In this paper, *economic rent* or *resource rent* is defined as the surplus value after all costs (including normal returns) have been accounted for; that is, the difference between the price at which the resource can be sold and its respective extraction and production costs, including normal return (basic return equivalent to the rate of interest on risk-free long-term borrowing plus a margin necessary to compensate for the technical, commercial, and political risks associated with the investment).

[3] Appendix I outlines the phases of a typical petroleum project.

[4] Exploration, development, and production (E&P) can be seen as a series of investment decisions made under decreasing uncertainty, where every exploration decision involves considerations of both risk and uncertainty (Rose, 1992). Risk considerations involve the size of investment with regard to budget, potential gain or loss, and probability of outcome. Uncertainty refers to the range of probabilities that some conditions may exist or occur (Suslick and Schiozer, 2004).

[5] A detailed discussion of the risk and uncertainty associated with oil and gas E&P activities is beyond the scope of this paper. Ample literature exists on risk analysis applied to petroleum exploration, development, and production. See for example, Grayson (1960); Rose (1987); Harris (1990); Rose (1992); Ballin, Aziz, and Journel (1993); Davidson and Davies (1995); Lerche and MacKay (1999); Back (2001); and Demirmen (2001). A synopsis of advances in risk analysis for petroleum exploration can be found in Suslick and Schiozer (2004).

[6] For an overview of petroleum geology, exploration, drilling, and production-related issues, see Hyne (2001).

[7] The discovery is appraised to determine whether it is commercially viable.

[8] Reserves whose existence and size have been proven by drilling. For a classification of reserves, see the industry standards 2000 prepared by the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC), and the American Association of Petroleum Geologists (AAPG); see also the Security Exchange Commission (SEC) guidelines.

[9] Usually the risk and cost of unsuccessful exploration are carried by the investor. The cost is shared between the investor and the government through the fiscal system once production starts.

[10] Unless, of course, the delayed production is large enough to affect the supply-demand balance, in which case the increase in oil and/or gas prices may offset the difference in the net present value (NPV) of the delayed rent.
[11] Dutch disease refers to an exchange rate appreciation that can decrease the competitiveness of non-resource sectors.
[12] Frontier areas are those that are unexplored or lightly explored (for example, Western Australia and the Barents Sea). Classifications vary widely across regions and are usually based on the availability of geological and geophysical data, the number of wells drilled, and the probability of success.
[13] For an analysis of the impact of risk on the resource rent, see Garnaut and Ross (1975) and Johnston (2003).
[14] For a discussion of interpretation of petroleum exploration data, see, for example, Chaves and Lewis (1994); Hyne (2001); Razak and Dundar (2001); Rose (2001); Abel, Lima Silva, Campbell, and De Ros (2005); and Smalley and others (2008).
[15] To find accumulations of petroleum, geologists must rely on subsurface information and data obtained by geophysical surveying. These data, once interpreted, are used to construct maps, cross-sections, and models that allow analysts to infer or to actually depict subsurface configurations that might contain petroleum. Such depictions are prospects for drilling.
[16] Various arrangements are used to allow governments to contract service companies to acquire and often interpret geological and geophysical data ahead of licensing rounds at no cost to the host government. This type of arrangement is known as a multi-client survey and is further discussed in Chapter 2, endnote 29.
[17] The statistics are taken from Wood Mackenzie and IHS Energy. It is worth noting that exploration success is much higher in mature than in frontier areas. Wood Mackenzie's statistics reflect a portfolio of different maturities.
[18] A participating interest is an undivided percentage interest that each investor owns at any particular time in the rights and obligations of a petroleum contract.
[19] A working interest owner bears the cost of exploration, development, and production of an oil and gas field and, in return, is entitled to a share of production from that field. A carried interest is an agreement under which one party agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest, and subject to contractual terms for recovering its costs.
[20] When a government "backs in," it directly participates in the costs and benefits of a petroleum contract (that is, the working interest option). Approximately 50 percent of the countries that exercise their right to "back in" do not reimburse the exploration expenditure incurred by the initial working interest parties.
[21] Guidelines for the design of efficient licensing policies are provided in Chapter 3.

CHAPTER 2

Alternative Approaches to the Granting of Petroleum Exploration, Development, and Production Rights

States have sovereign jurisdiction over their natural resources and are responsible for maintaining a legal regime for regulating petroleum operations. The legal basis for hydrocarbon exploration, development, and production is normally set in a country's constitution.[1] Normally, the hydrocarbon law, formulated at the parliamentary level, sets out the principles of law, while those provisions that do not affect these principles or that may need periodic adjustment (that is, technical requirements, administrative procedures, administrative fees, and so on) are set in regulations.[2]

The conditions under which governments grant rights to explore, develop, and produce petroleum resources are very important for the design of allocation policies and the choice of allocation system. In addition, poorly conceived legal, regulatory, and fiscal frameworks may lead to inefficiency and loss of economic rent, which may not be mitigated through the allocation system. For this reason, this chapter opens with a brief overview of the most common legal and fiscal frameworks for petroleum exploration, development, and production (E&P) activities, prior to discussing allocation systems.

Legal Regimes for Petroleum E&P

Various legal regimes have been developed to address the rights and obligations of host governments and private investors. These are usually classified into two main categories:

- Concessions (also called licenses or tax/royalty systems); and
- Contracts:
  - Production sharing contracts (PSCs) (also called production sharing agreements); and
  - Service agreements (SAs).

Although these arrangements are conceptually different from each other—particularly in terms of levels of control exercised by the government, ownership rights, and compensation arrangements—they can be used to accomplish the same purpose. There is often substantial variation between concessions or contracts within a given category. Some regimes have characteristics of more than one category and are considered "hybrids." For example, many PSCs (such as those in Indonesia, Nigeria, Malaysia, India, China, and Russia) also have royalties and/or taxes included in their standard agreements.

Concessions

A concession grants an exclusive license to a qualified investor.[3] Historically, mineral rights were granted by concession. The original concession (i) granted rights to petroleum development over a vast area; (ii) had a relatively long duration; (iii) granted extensive control over the schedule and manner in which petroleum reserves were developed to the investor; and (iv) reserved few rights for the sovereign, except the right to receive a payment based on production. The provisions of modern concession agreements are much different from the original model. In addition to reducing the area coverage and the duration of the agreement, modern concessions also contain relinquishment clauses and express obligations to enter into a work program.

One of the main characteristics of concessions is that the state retains considerable liberty to modify, at any time, those terms and conditions that are not negotiated but fixed by legislation.[4] In practice, because a stable investment environment is important to encourage or maintain investments by private companies, states are motivated not to abuse this prerogative.

A concession grants an oil company (or a consortium) the exclusive right to explore for and produce hydrocarbons within a specific area (called the license area, block, or tract, depending on local laws) for a given time. The company assumes all risks and costs associated with the exploration, development, and production of petroleum in the area covered by concession. Often a license fee or bonus is paid to the government. The government's compensation for the use of the resource by the investor will typically include royalty and tax payments if hydrocarbons are produced. Nearly half of the countries worldwide use a concession-type regime.[5] Across this group of countries, there is considerable diversity of fiscal arrangements (for example, the rate and structure of the royalty, the use of corporate taxes and/or special taxes, incentives such as investment allowances and credits, and so on).

Under a concession, the ownership of petroleum in situ remains with the state, until and unless petroleum is produced and reaches the wellhead, at which point it passes to the investor. The investor is not exposed to changes in its reserves and production entitlements when the oil price changes. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for the E&P of hydrocarbons generally passes to the state at the expiry or termination of the concession (whichever is earlier), and the investor is typically responsible for abandonment and site restoration.

Production Sharing Contracts

A contract-based regime envisages an agreement concluded between one or more (usually foreign) oil companies (contractors) and a state party. The state party may be the state itself—represented by its government—or a state authority (such as a government ministry or a special department or agency) or the national oil company. The national oil company may be granted general authority to engage in petroleum operations or the sole right to receive an exclusive license, and the authority to engage the assistance of oil companies.

Like a concession, a PSC grants an oil company or consortium (the "contractor") the right to explore for and produce hydrocarbons within a specified area and for a limited time period. The contractor assumes all exploration risks and costs in exchange for a share of petroleum produced from the contract area. Production is shared among the parties according to formulas defined in the relevant PSC and applicable legislation.

Unlike a concession, a PSC provides the investor with the ownership of its share of production only at the delivery point or export point (as defined in the contract). Changes in the oil and gas price result in adjustments to the investor's share of reserves and production entitlement. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration—and production of hydrocarbons—generally passes to the state, usually upon commissioning.[6] Furthermore, unless specific provisions have been included in the contract (or in the relevant legislation), the government (or the national oil company) is typically legally responsible for abandonment.

Service Agreements

Under an SA, the state hires the contractor to perform exploration and/or production services within a specified area, for a specific time period. Contractor services are compensated by a fixed or variable fee. The state maintains ownership of petroleum at all times, whether in situ or produced. The contractor does not acquire any ownership rights to petroleum, except where the contract stipulates the right of the contractor to be paid its fee "in kind" (with oil and/or gas) or grants a preferential right to the contractor to purchase part of the production from the government. Pure SAs are rare, but some do exist (such as the Iranian buy-backs), and are similar to engineering, procurement, and construction (EPC) contracts. Most industry SAs contain elements of risk for the contractor.

Fiscal Regimes for Petroleum E&P

Both governments and investors have a common objective: to maximize the value from the exploitation of petroleum resources (the "size of the pie"). When it comes to dividing that value ("sharing the pie"), governments and investors often have divergent views. Table 2.1 summarizes the objectives of fiscal systems from the viewpoint of governments and investors. These objectives can be largely accommodated through appropriate fiscal system design.

Table 2.1. Objectives of Fiscal Systems

Government	Investor
• Supports macroeconomic stability by providing predictable and stable tax revenue flows • Captures a greater share of the revenue during periods of high profits • Maximizes the present value of revenue receipts by providing for appropriations during the early years of production • Is neutral [a] and encourages economic efficiency	• Has a minimum number of front-end-loaded nonprofit-based taxes • Permits to repatriate profits to shareholders in their home countries • Is transparent, predictable, stable, and based on recognized industry standards

Source: Author.
Notes: a. The neutrality of a tax can be assessed by its impact on the resource allocation. With respect to the investing company, a tax is neutral when it leaves the pre-tax ranking of possible investment outcomes equal to the post-tax ranking. With respect to a particular industry, a tax is neutral when it does not divert investments to or from that industry.

Taxation Instruments and Methods

Petroleum activities around the world are subject to a great variety of taxation instruments. These include taxes that apply to all other sectors of the economy as well as taxes that are specific to the oil industry. In addition, nontax forms of rent collection (such as surface fees, bonuses, and production sharing) are common.

Special provisions, or "incentives," are often included in petroleum fiscal regimes to modify the timing or magnitude of revenue appropriations. These provisions are normally intended as incentives designed to: (i) attract investors; (ii) accommodate unique attributes of a petroleum asset; or (iii) sway investors' choices toward specific public policy goals. Accelerated capital cost allowances, depletion allowances, interest deduction rules, loss carry-forwards, investment credits, and royalty or tax holidays are among the most commonly used special provisions.

A variety of conditions and obligations are also imposed on companies that affect the cost of operation. Some are fairly common, while others reflect a country's specific condition. These include inter-company services, valuation of oil and gas, foreign exchange regulations, domestic market obligations, government equity participation, performance bonds, landowner compensations, local content obligations, and requirements intended to ensure good environmental practices and adequate site reclamation funding. Evaluating the impact of these costs on different investors can be a complex exercise.

A fiscal system can be assessed in terms of its impact on investment decisions[7] in either the short run (capital allocation within an existing portfolio of assets) or the long run (the decision to reject or invest in a project); in other words, by its neutrality. This can be expressed in terms of the net present value (NPV) of the expected project cash flows. Intuitively:

- All taxes reduce the NPV of a project and make it less attractive. Therefore, the higher the level of taxation, the lower the number of possible investments under prevailing market conditions.

- The timing of revenue collection is a major determinant of the NPV of a project. Fiscal systems that reduce or defer revenue collection (that is, are back-end loaded) are preferred by companies because they increase the NPV and accelerate the investment's payback.
- The NPV is significantly influenced by the risk profile of the investment. Therefore, fiscal systems that reduce the perceived political or economic risks are preferred.

An overview of the main tax and non-tax instruments commonly used in the oil industry and an evaluation of their effects on government revenues and investment decisions are given in Appendix II and Appendix III.

Theoretically, it is possible to replicate a particular fiscal regime using different combinations of fiscal instruments; for example, a PSC can be replicated by a combination of royalties and taxes.[8] In practice, different tax instruments have different amounts of risk associated with them, and respond to changes in project variables in a different manner.[9] Therefore, in designing their fiscal systems, governments have to make a trade-off between the revenue that they could generate with a given system, and the uncertainty associated with the receipt of that revenue.[10]

Comparison of Key Fiscal Elements of Concessions, PSCs, and SAs

The main fiscal elements of the three categories of petroleum regimes are summarized in Table 2.2 (next page).

The Allocation of Petroleum E&P Rights

While countries use diverse systems to allocate petroleum E&P rights, these systems can be grouped under two main categories:

- Open-door systems: licenses are awarded as a result of negotiations between the government and interested investors through solicited or unsolicited expressions of interest.
- Licensing rounds:
  - Administrative procedures—licenses are allocated through an administrative adjudication process on the basis of a set of criteria defined by the government; and
  - Auctions—licenses are allocated to the highest bidder.

Each category has advantages and disadvantages in terms of transparency and economic efficiency. Within each category, countries use various allocation mechanisms. Some countries use rather rigid mechanisms with limited biddable items that affect the division of profit between government and investors. Others award their acreage on the basis of the work program bidding, with all financial elements "fixed" by legislation. In other countries, everything is negotiable.

Table 2.2. Fiscal Elements of Petroleum Agreements

	Concession	Production sharing contract (PSC)	Service agreement (SA)
Basic elements	In its most basic form, a concessionary system has three components: royalty, deductions (such as operating costs, depreciation, depletion and amortization, and intangible drilling costs), and taxes.	Under a PSC, the contractor receives a share of production for services performed. In its most basic form, a PSC has two components: cost recovery and the division of profit oil. However, many PSCs have four components: royalty, cost recovery, profit oil, and taxes.	Under a SA, the contractor receives a fixed or variable fee for the services performed. Corporate income taxes may apply.
Royalty	The royalty is normally a percentage of the proceeds of the sale of the hydrocarbon.[a] It can be determined on a sliding scale, the terms of which may be negotiable or biddable or statutory, and paid in cash or in kind. The royalty is tax deductible.	Similar to concessionary systems. In addition, royalties are not normally cost recoverable but tax deductible.	Not applicable.
Fiscal costs	The definition of fiscal costs is described in the legislation of the country or in the particular concessionary agreement. Royalties and operating expenditures are normally expensed in the year in which they occur, and depreciation is calculated according to applicable legislation.[b] Some countries allow the deduction of investment credits, interest on financing, and bonuses.	Fiscal costs are defined and rules for amortization and depreciation are established in the legislation of the country or in the particular PSC. After payment of royalties, the contractor is allowed to recover costs in accordance with contractual provisions (a cost recovery limit may apply). The remainder of the production is split between the host government and the oil company at a stipulated (often negotiated) rate.	Fiscal costs are defined and rules for amortization and depreciation are established in the agreement.
Cost recovery	There are no cost recovery limits.	Usually, costs can be recovered up to a limit as defined in the PSC.	Cost recovery limits are sometimes imposed on the contractor.
Taxable income	The taxable income under a concessionary agreement may be taxed at the country's basic corporate tax rate. Special investment incentive programs and special resource taxes may also apply. Tax losses may be carried forward until full recovery or for a limited period of time.	Corporate taxes may apply or may be paid by the host government or its national oil company on behalf of the contractor. Income tax is calculated on taxable income (revenue net of royalties, allowable costs, and government share of profit oil). Tax losses may be carried forward until full recovery or for a limited period of time.	Corporate taxes may apply or may be paid by the host government or national oil company on behalf of the contractor. Income tax is calculated on the difference between the service fees and the allowable costs. Tax losses may be carried forward until full recovery or for a limited period of time.

Source: Adapted from Tordo, 2007.

a. In some cases, the royalty is calculated on net production. Some countries use fiscal prices for the purpose of royalty and corporate tax calculation. These prices are defined periodically and are normally linked to international market prices. The majority of the countries refer to arms'-length sales to third parties. Whether or not a country uses fiscal prices, deductions or additions are normally allowed to account for differences in quality between the reference crude (gas) and the particular crude (gas) as well as transport costs.

b. 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.

Open-Door Systems

In open-door systems (also known as negotiated procedures), the government may or may not invite investors to submit offers within a specified deadline. Rather, interested investors are allowed to submit expressions of interest—normally to the Ministry of Petroleum (or its equivalent) or the relevant regulatory agency—with respect to specific areas at any time. Negotiations may then start between the government and the applicant, if the government so chooses. Depending on the country's legal and regulatory requirements with respect to public procurement and award of petroleum E&P rights, the government may solicit the participation of other investors and start parallel direct negotiations. This practice aims to introduce some level of competition among market participants in order to strengthen the government's bargaining position. In fact, the process can be designed so as to approximate the effects of an auction. In other words, the open-door system could be incentive compatible; that is, structured so that each bidder finds it in its interest to honestly report its valuation (McAfee and McMillan, 1987).

In some countries, the law specifically provides for the possibility to resort to direct negotiations when licensing rounds result in single bids, in which case negotiations are conducted with the sole applicant.[11]

In open-door systems, the criteria for award are often not predefined and known to market participants. Therefore, the government retains considerable discretionary power in awarding E&P licenses or contracts. For this reason, direct negotiations are often criticized for their lack of transparency, insufficient competition, and potential for corruption.

Licensing Rounds

Licensing rounds can be more or less market-based depending on the degree of government discretion involved in the process.

Administrative procedures

Licenses are awarded to investors by way of administrative processes on the basis of criteria defined by the government. The government has ample latitude to define whatever criteria it deems appropriate. Thus, administrative processes can be very flexible and allow the government to pursue multiple policy objectives. But decision criteria are sometimes vague or not publicly stated. As such, it may be difficult for bidders to know the reasons for government selection, which may not respond to the logic of efficient allocation or rent maximization. The public is often unable to judge whether the award was done fairly. In general terms, in countries that lack a tradition of good governance, administrative processes may leave more room for corrupt or collusive practices.

An example of this type of arrangement can be found in the United Kingdom, where licenses are awarded on the basis of work programs (typically seismic and exploration drilling) proposed by the bidders. This allows the government to retain some control over the level of exploration investment in the industry, but it does require a certain level of technical capacity and resources to evaluate the proposals. Thus, it may not be suited to all circumstances—for example, when the government's

capacity is insufficient or constrained, or in some cases where there is no knowledge of the resource base.[12]

Auctions

Auctions can be designed as pure market-based systems where licenses and contracts are awarded to the highest bidder. Bidding parameters can be single or multiple. Usually these include bonus payments, and/or royalties, and/or various forms of profit sharing.[13] Pure market-based systems do not impede the government from pursuing policy objectives other than the maximization of the rent (such as, for example, promoting the interest of the national oil company or encouraging local participation) through the allocation mechanism, although this may complicate the design and efficiency of the auction.

There are four basic forms of auctions:

- *Ascending bid* (English auction). The price is raised until only one bidder remains. Prices may be announced by an auctioneer, or may be called by the bidders, or may be posted electronically. With this type of auction, each bidder knows the level of the current best bid at any point in time and can adjust its bidding strategy accordingly.
- *Descending bid* (Dutch auction). As opposed to the English auction, the price is lowered from an initial high called by the auctioneer until one bidder accepts the current price.
- *First-price sealed bid*. Bidders submit sealed bids and the highest bidder is awarded the item for the price it bid. Each bidder has only one chance to submit its bid and cannot observe the behavior of other bidders until the auction is closed and results are announced.
- *Second-price sealed bid* (Vickrey auction). Bidders submit sealed bids and the highest bidder wins the item but pays a price equal to the second-highest bid (Vickrey, 1961).

In practice, many variations of the basic forms exist.[14] In addition to the form, auction design involves several issues such as the need for prequalification,[15] guarantees and reserve prices,[16] and biddable factors. These are discussed further in this paper.

Few countries use pure market-based systems to award petroleum E&P rights. Those that do, normally use *first-price sealed-bid auctions*.

Administrative procedures versus auctions

Auctions are thought to be more effective in capturing rent than administrative procedures. Although this may be generally true for most industries, some of the assumptions that are required to make auctions efficient may not be realistic in the context of oil and gas exploration. In particular, uncertainty is a key element of petroleum exploration: both governments and companies do not know if oil will be found, where it will be found, in what quantity, at what cost it will be produced, and at what price it will be sold. Hence, each bidder has a view of the risk and expected value of the acreage on offer, and bids accordingly. Bidders operating in adjacent blocks or

that otherwise have access to private information may have a more accurate view of the true value of the asset, but may still be able to secure the award of the exploration rights with a low bid. In this case, the auction would have failed to maximize rent extraction.[17] Furthermore, even if all bidders had access to all available data, there will still be a difference in interpretation that would lead to different estimates of the true value of the same block.[18] Hence, the bidder with the most optimistic—not necessarily the most accurate—view of the true value of the block will be awarded the exploration rights. This phenomenon is known in the literature as "the winner's curse." Depending on the level of over-estimation, the successful bidder may later realize that the terms and conditions of award render the project not economical.[19] From the viewpoint of the government, if, in the short run, rent capture may have been maximized, in the long run the government may face lacking or suboptimal levels of exploration and a risk of contract renegotiation that, in turn, may affect the credibility of the licensing process.

Because exploration is a risky and expensive activity, it is not unusual for companies to form long-term alliances (for example, to pursue common strategic objectives) or special-purpose alliances (for example, to bid for a particular block) to spread their risk. These alliances take various forms[20] and can be very complex—sometimes involving service companies, or companies that are otherwise competitors in other markets or blocks. The effect of these alliances on the ability of a government to maximize rent extraction through the allocation mechanism depends on the market structure, information asymmetries, as well as rent extraction mechanisms. In general terms, the number of competitors affects the efficiency of an auction. By reducing the number of competitors, joint bidding may reduce the efficiency of the auction as a rent extraction mechanism. Perhaps also for this reason, some governments prohibit or restrict this practice.[21] But studies of auctions conducted in the USGoM observed no dissipation of economic rent, even if leases sold to joint bidders appeared to yield higher rates of return (Hendricks and Porter, 1996; Porter 1995; Mead, 1994). In fact, joint bidding appeared to be associated with higher bonus bids for better quality tracts. In addition, it was also observed that joint bidding enabled small companies to pool their resources in order to compete for better quality tracts; that is, to become more competitive. These studies concluded that concerns over whether joint bidding reduced competition for leases were overrated. This conclusion may, however, not be generalized, as the effect of joint bidding would also depend on the type of allocation mechanism.[22]

Auctions are generally more transparent than administrative procedures. Auctions can be designed in such a way as to make them robust to political and lobbying pressure as well as corruption. In some contexts, this could be an important consideration. The transparency of the procedure and awarding criteria would make it more difficult for the government to unfairly favor one investor or consortium over others. However, transparency may reduce the scope for government control over the industry, such as choosing investors that are more likely to fit the government's social, industrial, and environmental policies; or implementing bilateral investment agreements.[23] In addition (and as noted by Frewer, 2000), a certain level of discretion over the award of future licenses may be a powerful way for a government to influence the behavior of existing investors. Administrative procedures have the advantage of flexibility but, as noted in the paragraph "Administrative procedures" on page 14, they

are more demanding on a government's resources, and, in general, more vulnerable to potential corrupt practices and to political or lobbying pressures.

Finally, auctions offer advantages over other resource allocation systems in that they convey information about how valuable bidders believe the block to be, and which bidder values it most (Afualo and McMillan, 1998). This may be important in under-explored or frontier areas, where information is scarce and the government may not be reasonably confident of the precision of its value estimate.

Biddable or Negotiable Parameters

A wide range of contractual elements may be negotiable or biddable. This depends on a country's laws and regulations, as well as the chosen licensing procedure. Some countries have adopted rather rigid systems whereby only a single term or a limited number of contract terms are negotiable, while others afford much wider discretion to the sector minister, the regulator, or the other government authority tasked with the licensing of E&P rights.

A description of the biddable parameters most commonly used as allocation mechanisms is provided in the following paragraphs.

Signature bonuses

Under a bonus bidding allocation system, the right to develop the resource in a particular area is granted to the investor that offers the highest up-front cash payment. Under hypothetical ideal competitive circumstances, pure bonus bidding schemes would result in the government receiving the present value of the expected economic rents produced by the resource, since different bidders, in trying to win the right to develop the resource, would bid up to the point where their bid (the cash bonus) equals the economic rent they expect to receive from developing the resource. Theoretically, pure bonus bidding approximates the optimum allocation mechanism when the government's objective is to maximize rent capture (Mead, 1994). In practice, as discussed further in this paper, this may not always be true.

Bonus bidding is attractive for governments because it provides an early source of revenue whether or not hydrocarbons are discovered. But it has some downsides, too. As discussed earlier in this paper, although the license being bid for has only one true value, at the time of bidding, nobody knows this value. The more uncertainty there is about the true value, the more likely it is that bidders will reduce their bids. In the end, the government may have captured less than the total value of the economic rent, if the results of E&P activities are better than anticipated—or the bidder may have paid more than the true value of the resource, which, in the long run, may affect the level of competition and future investments. Either way, the allocation process would have been inefficient.

Because the value of the rent could potentially be large, an allocation system based on pure bonus bidding would also limit the number of possible bidders, as smaller companies would not have the financial strength to offer winning bids. Fewer competitors would translate into lower rent capture for the government. Mitigation mechanisms such as joint bidding and reserve prices are discussed further in this paper.

In practice, signature bonuses are not the sole rent extraction mechanism used by governments. As discussed earlier in this paper, even in the USGoM, where a significant portion of the economic rent is received through signature bonuses, the government also receives royalties and corporate income taxes. Cash bonus bidding is generally only contemplated in areas where there is a high probability of success and/or sufficient available information. Furthermore, in countries with less stable investment environments, major reliance on bonus bidding may result in lower rent capture, as investors are likely to discount the bonuses to reflect the perceived risk of contract renegotiation. This is particularly true if a change in government is expected.

Work programs

In work program bidding, oil companies bid a commitment to undertake a specific exploration activity[24] during a set period of time. The length of this period depends on each country's legal and regulatory requirements. Usually, exploration periods vary between six and nine years, and may be divided in two or three sub-periods. Work program bidding is almost exclusively limited to exploration. Very rarely does a work program include a pilot development program or a development plan, as, for instance, in the case of rehabilitation or redevelopment (enhanced oil recovery, EOR) projects. Other examples can be found in non-exploration projects, such as rehabilitation or redevelopment and EOR projects.

From the viewpoint of the investor, work program bidding has some similarities to cash bonus bidding since it represents a cash outflow prior to a discovery. The sum of work program obligations and bonuses represent the risked capital: investors do not know if they will be able to recover their investment. Furthermore, high signature bonuses and high work program commitments increase the exploration thresholds; this is particularly important in frontier areas. Although work program commitments and signature bonuses have some similarities, their effect on investors' profits may be quite different, as bonuses are typically not cost recoverable—but may be tax deductible—while exploration costs are usually recoverable and tax deductible. For the government, although work program bidding does not generate early revenue, it helps ensure that a certain level of exploration will take place.

When the work program is the determining factor in contract (or license) awards, investors have an incentive to bid more than they would otherwise, relative to the technical requirements of a block. This means that the winning bid may be much larger than the optimal bid from a technical point of view. In general terms, the optimal work program is based on factors such as the prospectivity of the area, the technology available, and the expected price of the resource.[25] The optimal work program will form the basis of a competitive bid. However, the actual bid submitted will also be a function of the (perceived) competitiveness of the licensing round. Competitive pressure tends to push bids toward the point where the value of the winning work program bid equals the expected economic rent. Conversely, lack of or low competitive pressure will result in sub-optimal winning work programs.

Finally, it is worth noting that the optimal work program is characterized by flexibility, where the next optimal step is based on new information resulting from the preceding step. This flexibility should be embedded in work program bidding and

related minimum guaranteed work program commitments. In other words, work program commitments should be firm but flexible.

Royalties

In royalty bidding, the investor that offers the highest royalty rate is awarded the rights to explore for and develop the resource in a specific area. From the viewpoint of investors, royalties are less risky than bonus or work program because they are only paid if a discovery is made that results in production. Because no large up-front payment is required, smaller investors are more likely to prefer royalty bidding to pure cash bonus bidding.

Royalties provide an early source of revenue to the government, but they are a rather regressive form of taxation: they are paid by investors as production starts, and usually long before profits are generated. Royalties are often criticized because they can lead to the premature termination of production.[26] This may be particularly true if EOR investments are considered. If the royalty rate is particularly high, production may be precluded entirely, or the block may be relinquished and turned over to the government. The use of progressive royalties—that is, royalty rates that are linked to certain parameters and increase or decrease in response to variations in these parameters—may help to mitigate these risks, especially if the parameters closely reflect project profitability. As discussed further in this paper, however, some level of distortion to investors' decision may still occur.

Profit shares

In profit share bidding, the investor that offers to pay the highest share of potential future profits is awarded the rights to explore for and develop the resource. Profit share bidding may include one or more profit-based mechanisms such as resource rent taxes, a profit oil or profit gas split, and/or special petroleum taxes. Profit share bidding is less likely to distort production decisions than royalty bidding. However, the neutrality of the mechanism (and its efficiency in targeting and capturing the economic rent) depends on its design.[27]

Like royalty bidding, profit share bidding is a conditional payment. As such, it allows investors to transfer part of the risk to the resource owner. Because no up-front payment is required, smaller companies are more likely to bid. Competitive pressure and lower risks will increase the economic rent (Leland, 1978).

A problem with profit share bidding is that tax level differentials between leases will inevitably create incentives to move income and expenses between leases. This can be mitigated through ring-fencing and accounting rules. However, profit shares are more complex to oversee and control than royalties, and require adequate administrative capacity of the government.[28] Compared to royalties, profit sharing delays the timing of rent capture (in this sense, it reduces the NPV of the rent). This can be mitigated through cost recovery limits and accounting rules.

Bundle bids

Particularly in countries where infrastructure needs are high but the government's public expenditure capacity is low and the expectation of low returns (or even losses) deters private investors, bundle bids—such as linking access to petroleum resources

with downstream or infrastructure investments—are becoming more frequent. For example, the bidding parameters may include the rehabilitation or construction of local refineries, or the improvement of local infrastructure incidental to the project area, or other investments depending on the government's development needs and constraints.

Bundle bids have also been used to expedite the development of particular geographical areas or geological basins, or to facilitate the transfer of technology and know-how to small or indigenous companies, or to satisfy the demands of local constituencies. For example, the government may link the award of highly prospective deep offshore blocks to investors on condition that they agree to invest in the exploration and/or development of less attractive blocks in remote or challenged areas.

The effect of these arrangements on the size of the winning bid depends on a number of factors, including the risk profile of the bundle, the bidders' risk aversion, the number of bidders and their relative strategies and strength (for example, new entrants, geopolitical considerations, composition of existing portfolios, and so on), the fiscal regime and/or fiscal incentives and type of ring-fence, and the choice of bidding parameters. In general terms, because less bidders may be interested in bidding for the bundle, this policy may result in less efficient allocation (a lower level of competition and cost inefficiency) than its unbundled alternative.

Finally, the complexity of these arrangements makes it more challenging to evaluate the fairness of the award, and may make them more vulnerable to political and lobbying pressure. This, in turn, may increase the risk of future renegotiation, as the experience of Angola (Box 3.13, Chapter 3) and Nigeria (Box 3.12, Chapter 3) would seem to indicate.

Some Countries' Experience

The following sub-sections contain a description of licensing systems in a selected sample of petroleum producing countries: Australia, the United Kingdom, the United States, Brazil, Mexico, and Yemen. Table 2.3 provides a quick comparison of allocation systems in the sample countries, while a detailed description of each country's allocation policy and system is provided in Appendix IV. Lessons learned are summarized in the paragraph "Lessons learned" on page 23.

The composition of the sample has been largely driven by the availability of information, the length of a country's experience with the allocation of petroleum E&P rights, and the level of development of the petroleum sector. Because long project cycles are among the key features of petroleum E&P activities, observations on the relative efficiency and effectiveness of allocation policies require the availability of relatively detailed information on their application over a medium to long period of time. This type of information is typically not publicly available with respect to developing countries. But specific aspects of allocation policies and practice in select developing countries are discussed in Chapter 3.

Given the lack of publicly available information on the procedures and outcomes of negotiations in open-door systems, this paper focuses on countries that award E&P rights to investors following administrative procedures or auctions.

Table 2.3. Overview of Allocation Systems in Select Countries

Parameter	Australia	United Kingdom	USGoM	Brazil	Mexico	Yemen
Geological setting	Large portion of frontier, immature, and sub-mature areas. Large natural gas reserves potential.	Mostly mature and declining areas. A range of small- to medium-size opportunities for exploration and development. Atlantic margin largely unexploited.	GOM shelf is largely mature, but there is considerable oil and gas potential in deep and ultra-deep water.	Four of the eleven producing basins are considered the most prospective from shelf to deepwater, with giant discoveries still to be found. Numerous frontier basins.	Largely under-explored, with significant hydrocarbons potential in deep and ultra-deep water.	Declining production levels in two main producing basins. The territory is vastly unexplored.
Objective of allocation policy	Primarily to significantly advance the exploration status of the area.	To encourage the best possible prospection, the E&P of the country's petroleum resources under conditions that encourage competition and non-discriminatory access to the resource, taking into consideration the protection of the environment and the interests of other users of the sea.	The expeditious and orderly development of oil and gas resources, subject to environmental safeguards, in a manner consistent with the maintenance of competition and other national needs, including national interest.	To encourage the E&P of the country's petroleum resources in order to maintain self-sufficiency with respect to oil production and to reduce natural gas imports, and to increase the contribution of the sector to local economic development.	Licensing of petroleum E&P is not permitted. Financed public works contracts have been used to attract technically competent investors to help Petroleos Mexicanos (PEMEX) substantially increase the production of natural gas.	To promote exploration and local content, to increase proven reserves to balance the decline in existing fields, and to encourage private sector investment.
Licensing authority	Joint Authority (Ministry of Resources, Energy, and Tourism).	Department of Energy and Climate Change (DECC, Ministry of Trade and Industry).	Minerals Management Service (MMS, Department of Interior).	Agencia Nacional do Petroleo (ANP, Ministry of Mines and Energy)	PEMEX	Petroleum Exploration and Production Authority (PEPA) (Ministry of Oil and Minerals, MOM)
Legal agreement	Exploration permit and production license.	Concessions; different types of licenses depending on whether the area is offshore or onshore, mature or frontier, exploration or production phase.	Exploration, development, and production lease.	Concession agreement.	Financed public works contracts.	Production sharing agreement.
Structure of fiscal regime	Current regime consists of petroleum resource rent tax (rules for transferability of exploration expenditure among projects apply), and corporate income tax in most of the areas of Commonwealth waters.	The current regime consists of a ring-fence corporation tax, a supplementary charge, and a petroleum revenue tax. A ring-fence expenditure supplement applies in special circumstances.	Royalty and corporate income tax.	Royalty, landowner's participation, special petroleum tax ring-fenced at field level, corporate income tax.	Fee for service, corporate tax.	Sliding scale royalty and profit oil split based on daily production levels, cost recovery limit and excess cost oil, the national oil company's carried working interest, and corporate income tax paid by the government on behalf of investor. No ring-fence.

(Table continues on next page)

Table 2.3 (continued)

Parameter	Australia	United Kingdom	USGoM	Brazil	Mexico	Yemen
Allocation system	Administrative procedure (work program bidding).	Administrative procedure (work program bidding).	Multi-object sealed-bid auction.	Multi-object sealed-bid auction.	Administrative procedure.	Administrative procedure.
Bidders' qualification criteria	Applicants must meet threshold standards on financial and technical capability, and demonstrate technical competence through their geological interpretation of the area applied for and their plans for further exploration. The applicants' past performance in Australia or elsewhere is also considered.	Applicants must meet threshold standards on financial capability and environmental management, and demonstrate technical competence through their geological interpretation of the area applied for and their plans for further exploration and appraisal of its potential resources.	Applicants must meet threshold standards on financial and technical capability. A restricted bidders' list contains the name of companies barred from submitting joint bids.	Applicants must meet technical, economic, and legal requirements defined by the ANP. In addition to track record criteria, the ANP specifies accreditation criteria for operators according to the degree of difficulty of the area to be licensed. Ahead of each licensing round, the ANP specifies whether joint bidding is accepted.	Applicants must meet technical and financial requirements established by PEMEX.	Applicants must meet technical and financial requirements established by PEPA.
Bidding parameters	Bidders submit proposed six-year program (of which the first three years are guaranteed) of drilling, surveying and other geophysical analysis, together with indicative costing.	Bidders submit proposed work program for the first exploration period, whose duration depends on the type of license. The type of work to be performed may include geophysical analysis, surveying, and drilling, depending on the type of license.	Cash bonus bidding.	Cash bonus, local content, minimum exploration work program.	Bidders submit proposed work program (which may include exploration, development, maintenance, and abandonment), and associated cost based on a price catalog contained in the regulations.	PEPA establishes minimum requirements for each bidding parameter (currently 33). Bidders can offer improvements on any or all.
Criteria for award	Adequacy of the proposed minimum guaranteed work program to advance the exploration status of the area, soundness of technical assessment supporting the work program, technical and financial adequacy of the applicant to complete the work program, and track record of compliance with the terms of the permits. The joint authority reserves the right to reject bids it considers inadequate, even if they are the highest bids.	Financial adequacy of the operators and/or partners to carry out the project, adequacy of proposed environmental policies, and technical competence of the operator as measured by a mark scheme that analyses the extent of geological evaluation of the block. The DECC reserves the right to reject bids it considers inadequate, even if they are the highest bids.	Bids are examined for technical and legal adequacy. Each valid high bid is analyzed from a fair market value perspective (methodology determined by regulation). The MMS reserves the right to reject bids and to withdraw any blocks from the bid round.	Blocks are awarded to the highest bidder. The ANP establishes the minimum cash bonus and minimum local content per type of block and location. The current weighting of bidding parameters is: cash bonus, 40 percent; minimum work program, 40 percent; local content, 20 percent.	Technical proposals are evaluated and graded. Economic analysis is carried out on valid proposals. Contracts are awarded to the proposals that fulfill all requirements and performance obligations. In case of a tie, the contract is awarded to the lowest bidder.	Blocks are awarded to the highest bidder. But the evaluation criteria, including the weight assigned to each bidding parameter, are not specified. The PEPA reserves the right to reject bids at its discretion, even if they are the highest bids.

Source: Author.

Lessons learned

The experience of the countries analyzed in Appendix IV offers lessons of broader applicability. These are summarized below.

- *The relative maturity of a geological basin affects the level of competition and the size of the winning bid*, whether the form of allocation is an administrative procedure or auction. All things being equal, the availability of information on the geology and drilling success in a specific area allows market participants to better assess the associated level of exploration risk. As a result, risk-averse bidders are encouraged to bid more aggressively, and asymmetry of information between existing players and new entrants is reduced. The majority of the sample countries have made active use of geological, geophysical, and petrophysical knowledge in defining their licensing strategy, including the timing of allocation, the selection of areas to be included in each allocation cycle, the choice of allocation parameters, the definition of reserve prices, the minimum technical and financial requirement for participation by bidders, and so on. The availability of geophysical surveys ahead of a licensing round has proven effective in reducing the bidder's perception of risk in frontier and immature areas. Countries do not normally acquire new surveys at their risk and expense. For example, in Brazil, multi-client surveys[29] are normally used.
- *Expected future oil and gas prices are a significant factor in explaining the variability over time in the number of bids and bid size for the same geological basin, particularly in frontier and immature areas.* Generally, this holds true for both administrative procedures and auctions. However, the magnitude of this effect is greatly affected by the choice of bidding parameters and the type of fiscal system. As the experience of all countries in the sample suggests, particularly in frontier and sub-mature areas, bonus bidding and work program bidding are less attractive during economic downturns and in periods of expected high volatility in oil and gas prices. The expected trend and volatility of oil and gas prices are less relevant in allocation systems that rely mostly on a progressive fiscal system to maximize rent capture. Intuitively, countries that adopt progressive fiscal regimes (that is, fiscal regimes that allow the investor and government to share the risks/rewards of worse/better-than-expected project and economic conditions) should be able to better buffer their long-term allocation efficiency from the volatility of oil and gas prices and the economic cycle.
- *The number of bidding parameters should be limited and should clearly reflect the objectives that the government wishes to pursue through allocation.* Multiple allocation parameters allow governments to pursue multiple objectives at the same time. When multiple parameters are used to allocate petroleum E&P rights, it is important to clearly establish the relative importance of these parameters (see, for example, the case study on Brazil). Some of the selected countries have used multiple biddable parameters to increase the flexibility in commercial and fiscal terms for different geological basins. Yemen is an extreme example of this practice. Depending on the number of biddable

parameters and the government's capacity constraints, this has resulted in complex and difficult-to-administer systems. Given the usually high level of uncertainty and risk associated with exploration activities, better results are often achieved by selecting a limited number of biddable parameters clearly targeted to the objectives of the government allocation policy, and to rely on the fiscal system to maximize rent capture (particularly if progressive fiscal systems are used).

- *Transparent awards improve the efficiency of the allocation system and make it less vulnerable to political and lobbying pressure.* The selected countries use different approaches with respect to the transparency of award: some use clear and publicly disclosed rules for evaluating bids and awarding E&P rights, other disclose principles that are used to evaluate and compare bids; none disclose reserve prices, and all retain a certain level of discretion to reject bids that they consider inadequate and the right to withdraw blocks from the licensing round. Clarity of award criteria improves the transparency and objectivity of the award and allows bidders to structure their offers accordingly. However, a certain level of flexibility in the criteria may be necessary. For example, in work program bidding, an efficient allocation system needs to ensure that blocks are awarded to companies that submit the most appropriate work program bids, not necessarily the most optimistic ones. The utilization of electronic procedures for the preparation, submission, and evaluation of bids reduces the government's administrative workload and the possibility of errors in the evaluation and comparison of bids. This is the case for both administrative procedures and auctions.
- *Work program bidding is often used to directly affect the quality and level of exploration investment in an area.* The minimum technical and financial criteria that bidders need to meet in order to submit their offer are particularly important in work program bidding as they allow a government to select cost-efficient companies whose experience is aligned with the requirement of the government's exploration objectives. This, however, requires a certain level of technical capacity and resources to screen the applicants and evaluate what constitutes an acceptable work program. The government's task is particularly challenging where there is no knowledge of the resource base on which to base the definition of acceptable or optimum work program (see Australia's case study). It is important to note that none of the selected countries uses explicit reserve prices. Even when minimum work programs are defined and disclosed, governments reserve the right to reject bids that equal or better the minimum work program if these are considered inadequate.
- *Cash bonus bidding is generally less efficient in frontier and under-explored areas, especially when the number of bidders is limited and the players are risk averse.* This is particularly true where entry barriers to small firms or joint bidding restrictions apply. Information asymmetries, investors' budget constraints, and market concentration also appear to reduce the efficiency of cash bonus bidding, independent of the geological risk. None of the selected countries uses cash bonus bidding as their primary or sole mechanism to maximize rent

capture. Rather, they mostly rely on the fiscal regime to correct inefficiencies at allocation due to uncertainty about the true value of the blocks.

- *Joint bidding does not imply anti-competitive behavior*. It often represents a substantial part of total bids in both administrative procedure and auctions. This is particularly true in frontier areas and deep-water exploration areas. Studies conducted on the effect of joint bidding in both administrative procedures and auction-based systems indicate its effectiveness as a risk management tool for market participants, with positive effects on competitiveness and the average size of the winning bids. Joint bidding is also used to facilitate entry, especially by smaller firms. The case studies of Brazil, the United Kingdom, Australia, and the USGoM illustrate this point.
- *The use of area-wide licensing or nomination affects bidders' strategies and outcomes as well as the pace of development of the resource base*. In Brazil, the introduction of area nomination (that is, in defining the areas to be included in a licensing round, the government takes into consideration potential bidders' expression of interest in particular areas) and the reduction in block sizes have helped increase the level of competition, and have affected companies' bidding strategies (small companies tend to bid on frontier and under-explored blocks, they bid low but spread their bids wide; oil majors and big consortia tend to bid high and on contiguous blocks). In 1983 the U.S. government's allocation policy changed from area nomination to area wide.[30] Since then, more and more areas are offered at any given licensing round with little prior evaluation. The average high cash bonus, the lease development productivity, and the number of competitive leases (multiple bids) have declined since (except in the more prospective/deep-water blocks), but a wider area is being explored and will hopefully result in a higher level of production over time.
- *Market segmentation—that is, the extent to which different companies specialize in different types of exploration activities and tolerate different risks—is of great relevance to the design of efficient allocation systems*. Under all forms of allocation, system performance may be improved by devising different licensing terms and/or different criteria for award (including different levels of minimum technical and financial qualifications) in areas with different geological risk. The experience of Brazil and the United Kingdom clearly illustrate this point.

Notes

[1] The consistency of the legal framework with the constitutional foundation is an important factor affecting the security and stability of the legal framework. This issue is significant, in particular because the constitutions of many countries differ significantly in the degree to which they (i) recognize or guarantee private property rights or prohibit private parties or foreigners from acquiring property rights in general, and mineral rights in particular; (ii) vest the authority to grant petroleum rights in the state or provincial governments or agencies rather than the national government; and (iii) vest the authority to regulate specific matters in special agencies (that is, environment protection) or in the executive branch (for example, taxation, foreign exchange, employment, and so on) or in the judiciary (settlement of disputes). Because of the capital-

intensive and long-term nature of petroleum projects, the certainty of rights is particularly important for private investors.

[2] A state's sovereign powers over its natural resources were first recognized under the 1958 Convention on the Continental Shelf. The debate over the scope, extent, and implications of this sovereignty and on the applicability of international law culminated in 1974 with the adoption by the United Nations' General Assembly of the Charter of Economic Rights and Duties of States. In addition, several multilateral and bilateral treaties have been entered into for the promotion and protection of investments that have a bearing on the scope and extent of states' sovereignty over their natural resources. A few countries, most notably the United States and Canada, recognize private ownership of underlying minerals. In these countries, determination of mineral ownership depends upon rules of property. In virtually all other countries, valuable minerals belong to the sovereign. For an overview of the principles of international law affecting states' sovereignty over natural resources, see Smith and others (2000), and Taverne (1996).

[3] Usually, licenses are granted by a government authority on behalf of the state. Certain petroleum regimes recognize the owner of the land as the owner of the subsoil, and allow it to grant licenses within the context of existing legislation.

[4] In other words, the state can alter unilaterally what are described as the "regulatory conditions" of the administrative contract (for a detailed discussion, see, for example, Smith and others, 2000; and Cordero Moss, 1998). The contractual or regulatory nature of an agreement is of extreme significance in evaluating its stability and predictability. The focus should, however, be on the government's track record, as opposed to the legal nature of an agreement.

[5] Concession-type regimes are used, for example, in the United States of America, United Kingdom, France, Norway, Ireland, Spain, Portugal, Chad, Australia, Russia, New Zealand, Colombia, South Africa, and Argentina.

[6] In some countries, such as Nigeria, title transfers before commissioning; that is, when equipment arrives in the country. In some countries, title transfers to the government upon "payout," when the contractor has recovered its investment or the equipment is fully amortized.

[7] Host governments and investors use different system measures to assess the impact of various fiscal systems. This is because, although they share the general objective of maximizing the revenue generated by a project, they also pursue a number of different objectives and face different constraints. Analyzing these objectives and constraints and the related system measures is beyond the scope of this paper. For an in-depth analysis, see Johnston (2003) and Tordo (2007).

[8] In principle, the choice between contracts and concessions should not be affected by fiscal considerations. It should instead depend on the country's administrative capacity or on the objectives of its sector policy.

[9] Although two fiscal systems may have the same overall tax burden, their relative effectiveness and efficiency, and effect on investment decisions, may differ significantly.

[10] The discussion of fiscal systems for hydrocarbons is well covered in the literature; see, for instance, Garnaut and Clunies Ross (1975), Kemp (1987), McPherson and Palmer (1984), Otto (1995), Johnston (1994, 2003), Baunsgaard (2001), and Tordo (2007).

[11] See, for example, Angola's hydrocarbon law.

[12] Further discussed in the paragraph "Work programs" on page 18.

[13] Further discussed in the paragraph "Biddable or Negotiable Factors" on page 17.

[14] The form and features of an auction affect the seller's expected revenue (and buyer's payout) under different circumstances. For an overview of auction types and their application, see McAfee and McMillan (1987).

[15] Prequalification, normally in terms of technical and financial capability, is often required to participate in licensing rounds (discretionary or market based). The definition of minimum criteria allows the government to eliminate "non-serious" bidders. Pre-qualification criteria may

also be used to safeguard special interests. For example, a portion of the area to be licensed or a percentage participating interest in the license could be reserved for local oil companies.

[16] A reserve or reservation price is the minimum (or maximum) price for which an item may be sold (or bought).

[17] This inefficiency can be mitigated by setting a reserve price that equals the government's estimate of the true value of the asset. However, setting the correct reserve price requires the government's knowledge of the asset's characteristics that may not be possible in practice. Reserve prices are discussed later in this paper.

[18] As eloquently stated by Mead (1994), "good geologists may be worth their weight in gold."

[19] From this point of view, cash bonus bidding is less likely to distort investment decisions and project economics going forward because once the bonus is paid, it becomes a sunk cost. However, this depends on the tax and cost recovery treatment of bonuses. This issue is further discussed in the paragraph "Work programs" on page 18.

[20] For example, letters of intention with respect to common areas of interest, joint operating agreements, joint ventures, and so on.

[21] Angola, the United States, Venezuela, and—until recently—Norway are examples of this practice.

[22] This is further discussed in Chapter 3.

[23] Although theoretically possible, it may be difficult or politically unacceptable to address these objectives through the design of explicit and transparent prequalification requirements.

[24] Work program commitments are generally defined by type of work, such as amount and type of seismic data to be acquired, number of exploration wells to be drilled, and so on. A monetary value is normally assigned to each activity. Petroleum agreements usually oblige the license holder (or the contractor, as the case may be) to undertake the minimum work program or pay the correspondent monetary amount to the host government. When the minimum work program is a bidding parameter, the standard monetary value of each unit of work may be defined in the bidding procedure to improve the transparency of the bid evaluation (see, for example, the case of Brazil, discussed in Appendix IV).

[25] High expected future oil prices and good prospectivity are likely to have a positive effect on the optimal work program.

[26] In principle, production would continue until the marginal cost equals the marginal revenue, that is, until producing becomes uneconomic. In the absence of royalties, ceteris paribus, production would last longer.

[27] There is extensive literature on the importance of tax neutrality. Yet, for some countries, pursuing neutrality might be too costly in the short run. The various tax methods that have been designed to achieve neutrality—based on the rate of return (RoR) and R-factor—may come close to the objective even if not perfect. It is important to note that investors have different appetites for risk and different exposures to it. Therefore, universal neutrality is quite difficult to achieve.

[28] The administrative simplicity of royalty may be misleading if, as a result of their regressive nature, royalty bids lead to demands for renegotiation.

[29] Multi-client geophysical and geological surveys are sometimes carried out by service companies on a risk basis—that is, at their risk and expense. The data are then licensed to interested oil companies for a fee. The proceeds of the sale of data licenses are shared between the service company and the government according to the terms of the relevant agreement. These arrangements are often used by governments to improve the market knowledge of the geological potential of areas that are earmarked for inclusion in licensing rounds. The government does not incur any cost related to the acquisition, processing, and marketing of the data (especially when data licensing fees ahead of the area award are not tax deductible or cost recoverable, as the case

may be). In addition, depending on the type of data, the investors' exploration budget is reduced and the pace of exploration activities accelerated.

[30] With area-wide allocation, all areas that are not under lease are offered for bidding at any given licensing round.

CHAPTER 3

The Design of Appropriate Allocation Systems

The design of allocation systems requires the definition of the economic, social, and political objectives that policy makers wish to achieve through the licensing of petroleum exploration, development, and production (E&P) rights. License allocation is, however, only one of the policy tools that can be used to achieve these objectives. Hence, it is important to ensure coordination and coherence with other policy tools, in particular the petroleum fiscal regime and market regulation.

Effective allocation systems take into account: (i) the characteristics of the area to be licensed (such as geology, exploration risk, location, and distance to market); (ii) the structure of the market (such as level of competition, market segmentation, size and strength of the players, access to information, and domestic market); (iii) issues related to the ownership and access to the resource; and (iv) regulatory and institutional frameworks. Exogenous factors such as the expected level and trend of future oil and gas prices, and the competition from other petroleum countries also affect a country's allocation strategy.

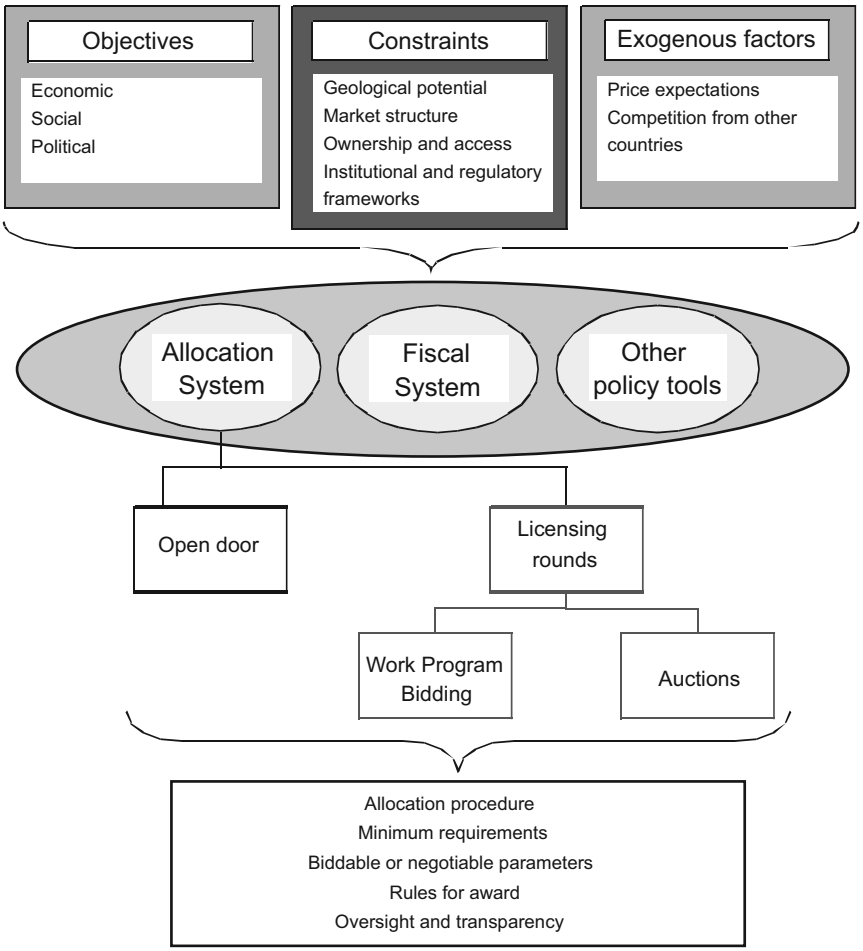
Although broad principles of general application can guide the choice of allocation system, the design needs to be tailored to reflect the set of objectives, constraints, and concerns that are unique to each country. Figure 3.1 schematizes this approach. Indeed, because social and political objectives are so country specific, it is difficult to identify general principles that apply to all countries. Therefore, this chapter will focus on the design of allocation systems to achieve economic objectives.

Allocation System Objectives

From an economic perspective, the government would want an allocation system that:

- Is consistent with the government's petroleum sector policy;
- Favors the selection of the most efficient operator;
- Involves low compliance and administration costs;
- Minimizes distortionary effects; and
- Addresses market deficiencies.

Figure 3.1. Allocation Policy Flow Chart



Source: Author.

Appendix V provides a simplified example of choice of allocation parameters to achieve a specific policy objective, given a specific set of constraints (geological settings, level of government capacity, market structure) and exogenous factors (price expectations). In reality, governments simultaneously pursue a variety of objectives over time, and face a complex set of changing constraints and exogenous factors. The relative priorities among objectives and the interaction among the various constraints and exogenous factors influence the optimal design of allocation systems (including the form of allocation, bidding parameters, bidding procedure).

Consistency with Petroleum Sector Policy

Sector policies include a wide range of objectives. The maximization of the net present value (NPV) of the economic rent from the exploitation of petroleum reserves is among the most common objectives. Other objectives may include inter-temporal equity, job creation, transfer of technology, regional or local development, security of supplies, the

protection of the environment, the promotion of bilateral trade, and non-discriminatory access to petroleum resources or the creation of a national champion/center of excellence.

Some of these objectives can be achieved through the allocation system, while other instruments—including the fiscal regime, the government's saving and spending policies, investment incentives, state participation, and specific regulation—may be more effective. The government would need to ensure coherence among these different policy tools.

A clear definition of the objectives that the government intends to achieve through the allocation system is the first step toward its effective design and implementation. Clarity and transparency of objectives would also facilitate the regular assessment of system performance, and allow adjustment to the relevant parameters as needed to reflect changes in market conditions, government policy, and geological and country risks. Furthermore, the government would need to periodically reassess the impact of its allocation system on the overall macro-economic framework to ensure it encourages the efficient and effective use of resources.

The interaction between fiscal regime and allocation system deserves particular attention for its implications on rent capture and on countries' macro-fiscal frameworks. As discussed in Chapter 1, the preferred alternative for most resource owners is to sell the right to develop the resource. There are a number of ways to do so, for example: (i) the resource owner can sell the right to develop the resource outright, for example, by awarding the right to the investor that is willing to pay the highest pure cash bonus; or (ii) the resource owner can license the right for an agreed-upon share of the revenue to be produced from the resource, for example, by awarding the right to the investor that is willing to offer the highest share of profit from the exploitation of the resource—or the highest royalty, or the highest combination of profit share, royalty and bonus, and so on.

The outright sale of E&P rights presents several practical difficulties that are linked to the uncertainty of petroleum exploration and development activities: neither the bidders nor the government know whether oil and gas will be found, in what quantities, at what cost it will be produced, and at what price it will be sold. Hence, there is a risk that the right to develop the resource in a specific area may be sold for a price that is well below—or well above—the true value of the resource extracted from that area. As discussed in the paragraph "Signature bonuses" on page 17, both outcomes would be unsatisfactory.

For these and other reasons, the licensing of E&P rights usually involves conditional payments, that is, payments linked to the true value of the resource.[1] The fiscal system defines the type and affects the timing and magnitude of these conditional payments. The issue then becomes that of defining which parameter(s) of the fiscal regime, if any, should be biddable or negotiable—and to what extent.[2] In other words, the licensing of E&P rights requires that the government defines both the minimum target price and how best to collect it.

Selecting the Most Efficient Operator

Inefficient E&P increases costs and reduces economic rent. Hence, governments are motivated to ensure that E&P rights are, in the long run, awarded to the most efficient operators.

Some allocation procedures are better than others in ensuring that E&P rights are allocated to the lowest-cost bidder. Administrative procedures depend on evaluating bidders' financial and technological capabilities and proposed work programs. However, authorities often have limited information on bidders' relative cost efficiency. Thus, the system is vulnerable to allocative distortions. Inefficiency in the initial allocation process can be mitigated by allowing the awardees to transfer rights and obligations to more suitable investors. In addition, transfers of E&P rights often occur after the award as a result of portfolio adjustments (when bidders acquire information not previously available).[3]

It is not uncommon for governments to restrict investors' ability to transfer rights and obligations, owing to the importance of ensuring that rights are awarded to technically and/or financially capable companies. Some countries pursue local development objectives through the licensing system, for example, by promoting local ownership through restrictions on local companies' ability to transfer their rights to foreign companies. Box 3.1 provides an example of the use of licensing policy to promote local development.

Box 3.1. Licensing Policy as a Means to Promote Local Content

Local content refers to the development of local skills, technology transfer, use of local manpower, and local manufacturing. Governments can support local content in several ways, including by (i) creating appropriate incentives for local businesses; (ii) making it a requirement for foreign investors; and (iii) setting specific criteria for the allocation of exploration, development, and production (E&P) rights. The value of pursuing political goals through a lease allocation policy must be weighted against a potential reduction in efficiency.

Among the criteria for award announced in the 2000, 2005, and 2006 licensing rounds in **Nigeria**, was the bidders' commitment to the development of Nigerian expertise and know-how as part of their intended operations. In addition, training and local employment obligations were included in petroleum contracts. The local content requirements became more stringent in the 2005 marginal fields licensing round: bidders were required to associate their bids with local content vehicles (LCVs) in the form of Nigerian companies (that is, locally incorporated companies with a majority—usually 60 percent—of Nigerian shareholders). The Nigerian company would provide local goods and services, while the international company would be the technical partner. However, the low uptake shown by the market may indicate that the restrictions were too ambitious, given local capacity levels

In 1997 **Venezuela** launched its third licensing round. Twenty fields were offered under operating service agreement. Five fields were, however, reserved for Venezuelan companies or consortia with a Venezuelan operator.

Depending on a country's fiscal system, transfers of rights among investors may not be tax neutral. This is a particularly important consideration for countries that do not ring-fence at the license or field level. Although secondary markets of E&P rights can be used to partially address inefficiencies in the initial allocation process, the transaction may absorb part of the rent that would otherwise accrue to the government.[4] The potential loss of rent may be mitigated by the increased competitiveness of the licensing round, since allowing transfers of rights, post-allocation, is more likely to encourage bidders who enter only in order to resell. This mitigation would not occur, of course, if non-competitive licensing procedures were used as a primary allocation mechanism. Box 3.2 provides an example of regulatory constraint on the transfer of rights.

Box 3.2. Tax Implications of the Transfer of E&P Rights

Portfolio adjustments are not only motivated by companies' changes in strategy, risk management considerations, and relative efficiency. In some cases, tax optimization may lead companies to trade E&P rights. Tax gains can, therefore, be shared among companies at the expense of the government. To avoid this, **Norwegian** authorities require that all trade be tax neutral (section 10, Petroleum Tax Act). But the constraint involves heavy administrative costs for all parties (Sunnevåg, 2000). In 2002 a regulatory reform was introduced to allow companies to carry forward their losses with an interest. This should reduce the administrative burden, given that, in principle, the rule equalizes the position of companies in a tax-paying position with companies that are not.

Keeping Compliance and Administrative Costs Down

Complex allocation systems may be difficult to administer, and will translate into additional costs that may not be justified by the potential increase in rent capture or may, in fact, decrease rent capture. Furthermore, in determining the NPV of the asset being offered by the government, potential bidders will consider the cost of compliance with the licensing system designed by the government (including requirements related to the conduct of oil and gas operations that may be defined in model contracts). Ultimately, this will translate into lower economic rent. Therefore, the government should be mindful of introducing regulations for which the cost of compliance exceeds the social benefit (Kalu, 1994). Box 3.3 provides an example of administrative complexity.

Box 3.3. Administrative Complexity

Host governments have a clear interest in ensuring that costs are kept as low as possible. Normally, contracts provide for various forms of oversight and control mechanisms. Management committees, procurement procedures, budget approval, and audits are examples of these mechanisms. The thresholds for approval of expenditures are particularly important: low thresholds affect the efficiency of operations.[a]

In **Yemen's** production sharing agreements (PSAs), contractors are not afforded much freedom of operation, and expenditure approval thresholds are normally quite low. Other cost-control and supervision mechanisms are provided for in the contract and in the cost recovery mechanism.[b] Hence, a relaxation of the approval thresholds would likely reduce the government's cost of supervision and the contractors' cost of compliance without sacrificing the overall effectiveness of the cost-control incentive mechanisms.[c]

Notes:
a. Thresholds of US$500,000 or US$1,000,000 are not uncommon.
b. During the exploration period, there is a clear incentive for the contractor to keep costs down: if no discovery is made, exploration expenditure will not be recovered. If a discovery is made, the cost recovery mechanism allows the contractor to recover its investment if sufficient revenue is generated. A cost recovery limit is imposed, which provides an additional incentive to control costs.
c. For details on the structure of oversight committees and levels of approval thresholds, see Gerner and Tordo (2007).

Administrative complexity should also be avoided in the choice of the bidding parameters: comparing competing bids where a large number of fiscal and commercial parameters are negotiable may be difficult, time consuming, and less objective. The cost and time involved in preparing the bid may discourage participation, especially from new entrants, which may affect the level of competition. Box 3.4 describes two different approaches to defining bidding parameters.

Box 3.4. Examples of Bidding Parameters

In **Yemen**, blocks are awarded to the highest bidder following an administrative process. A model memorandum of understanding (MOU) sets the fixed and biddable terms—up to 33 in the most recent bidding rounds—and the reserve price (minimum requirement for each biddable term). Offers that are not at least equal to the minimum requirements are rejected. The criteria for evaluation of the proposals are not publicly stated, and the ministry reserves the right to reject offers without justification.

In the **United States**, tracts are awarded to the bidders that offer the highest cash bonus. The evaluation criteria are clearly stated. The Minerals Management Service (MMS) reserves the right to reject any or all bids and the right to withdraw any block from the sale. Each high bid is first examined for technical and legal adequacy; then each valid high bid is analyzed from a fair market value perspective. Although bonus bidding with fixed royalty is the main allocation procedure, the Secretary of the Interior can propose other systems of bid variables and terms and conditions as appropriate to achieve the policy objective. However, the legislation forbids the use of more than one bid variable.

Discouraging participation is not necessarily a bad policy. Given the level of risk, the capital exposure, and the duration of E&P projects, governments have an interest in ensuring that E&P rights are awarded to technically and financially competent companies. Pre-qualification of bidders in licensing rounds is therefore necessary. However, minimum technical and financial qualifications are usually set forth in hydrocarbon laws or petroleum agreements and apply whether or not governments choose to award E&P rights through competitive tenders or direct award. Non-refundable bidding fees are sometimes used to discourage participation from companies that are not serious market players. Guarantees may be used to discourage frivolous bids. And "use-it-or-lose-it" conditions are usually defined in sector laws and petroleum agreements, to ensure that exploration activities are carried out by the license holders within a set time frame, or the area is released for future licensing. Box 3.5 provides some examples of minimum bidding requirements.

Box 3.5. Minimum Bidding Requirements

In **Yemen**, companies interested in participating in a licensing round are required to submit a letter of intent, technical and financial reports for the last two years, their latest audit report, and a completed and signed company profile. The names of pre-qualified investors are publicly announced by the Petroleum and Exploration Production Authority (PEPA), the regulatory agency. A guarantee (irrevocable letter of credit or check payable to the PEPA) equal to 3 percent of the work program obligation proposed for the first exploration period is also required.

Angola uses a similar approach. Bidders have to pre-qualify. Pre-qualified bidders obtain access to data packages, subject to the payment of a fee specified in the licensing round rules. Each bidder must submit a financial guarantee issued by an Angolan Commercial Bank or a reputable, first-class international bank. The value of guarantee shall correspond to the bidder's share of the value of the proposed work program, calculated on the basis of the share of participating interest that the bidder wishes to acquire in the block for which it is bidding.

In the **United States**, bidders are not asked to submit a guarantee upon submission of the bid. But each high bid submitted must include payment of one-fifth of the bonus bid by a deadline established by the Minerals Management Service (MMS) on the day after bid opening. The remaining four-fifths of the bonus bid and the first year's annual rental for the lease must be paid within a set time from receipt of the lease.

Minimizing Distortionary Effects

The allocation system should avoid the introduction of distortions to investors' decisions. This issue relates to both the allocation procedure and the rent capture mechanisms (bidding parameters and fiscal system). Allocation systems should not distort the awardees' operating decisions. For example, allocation systems that encourage bidders to offer high royalty rates may: (i) lead to premature abandonment of productive blocks; (ii) render secondary and tertiary recovery uneconomical; and (iii) prevent the development of marginal fields. Box 3.6 provides an example of the effect of excessive royalty rates.

Box 3.6. Excessive Royalty Rates

In 1974, the government of the **United States** experimentally sold eight leases under royalty bid conditions. One bid was received at 78.1 percent of gross wellhead value and a lease was issued. Save in the case of a giant discovery, it would have been economically impossible for production to be successful under such conditions. In fact, only one of these leases was ever produced and this occurred because the royalty rate was renegotiated downward in 1990 from the 73.4 percent bid to 25 percent.

Allocation systems that induce bidders to offer work programs that exceed what ordinarily would be required to efficiently explore blocks will ultimately reduce the economic rent, and may lead to future renegotiation to remove uneconomic commitments.[5] On the other hand, a certain trade-off between rent maximization and investment in exploration could be considered as a government's contribution to future sector and economic development. Box 3.7 describes the effect of over-sized work programs on field development.

Box 3.7. Oversized Work Programs

In 1985, **Australia** launched its third licensing round. The 5,280 square kilometer block in the Bonaparte Basin was considered, by all applicants, to be the most prospective vacant area of the Londonderry High Basin. There was a perception of geological similarity to the region containing the Jabiru and Challis discoveries made in 1983 and 1984. The round was very competitive, as new bidding groups that had missed out on an earlier round saw this as an opportunity to gain acreage near Jabiru. The area received five bids and was awarded, with a primary bid of $99 million. The bidding terms did not require a minimum guaranteed program in the first exploration period. As a consequence, when initial wells were drilled without a significant petroleum discovery, the permit holders successfully sought to decrease their work commitments in line with the results they achieved. By 1989 the license holders had concluded that while significant additional potential existed in the permit area, the geological complexity was greater than was evident at the time of their original bid preparation and the permit holders were not willing to continue with the original program (Australian Bureau of Agricultural and Resource Economics, ABARE, 2003).

Finally, allocation systems that encourage bidders to offer profit shares with high marginal takes in favor of the government are more likely to create lower incentives to cost saving, and in some cases may even encourage the investor to spend more than it otherwise would.[6] Box 3.8 provides an example of a fiscal system design that incentivizes cost saving.

Box 3.8. Fiscal Incentives to Cost Saving

In 1995 **Alberta** introduced a new fiscal regime for oil sands projects. The underlying policy objective was to promote investment in oil sands and increase its competitiveness vis-à-vis conventional oil production. The new fiscal regime reduced the minimum royalty rate from 5 to 1 percent and introduced a 25 percent royalty, payable on net project revenues after the investor has recovered all project costs including a return allowance set at the Government of Canada long-term bond rate.a In combination with federal and provincial income taxes, after project payout, the investors would receive a marginal project income of 38 percent, with the balance of 62 percent going to the federal and provincial governments through royalties and the corporate income tax (CIT). Alberta, some argued, could have attempted to capture a greater share of the rent—up to 100 percent. However, cost reduction is a key factor in making oil sands development more attractive. A fiscal regime that captured too much marginal cash flow would have resulted in a reduced incentive for cost reduction and innovation. This is the gold-plating argument: if marginal tax rates are too high, there is an incentive to spend additional cash flow rather than seeing it go to governments through royalties and taxes, which provide no tangible benefit to the project (Masson and Remillard, 1996).

Notes:
a. This approach to royalties was chosen due to the high cost and the associated high risk of oil sands investment. Production-based royalties would have been less sensitive to project profitability than the resource rent royalty. Because oil sands face higher barriers to development than many other types of petroleum (that is, oil sands are less valuable products due to the low American Petroleum Institute [API] gravity; present higher technological risk; require higher capital costs, and higher operating costs; and so on), the additional burden of a significant production-based royalty was considered inappropriate.

Addressing Market Deficiencies

The level of competition is an important aspect of all markets. Gains can be obtained by designing allocation procedures that promote competition. Each design depends on the particular situation. For example, a government can increase the revenue that it hopes to receive from the licensing of petroleum E&P rights by publicizing/providing access to the relevant geological, geophysical, and petrophysical data, particularly ahead of a licensing round.[7] This is because access to information increases competition (that is, risk-averse bidders are induced to bid more aggressively, information asymmetries between companies already operating in the country and new entrants are reduced, and so on).[8] Box 3.9 provides an example of an information strategy aimed at reducing investors' perception of risk.

The level of competition is a function of the number of competitors. Because joint bidding reduces the number of competitors, some argue it may reduce governments' rent. Countries use different approaches to joint bidding: in some countries it is allowed, in others it is restricted, and others prohibit it altogether. Whether or not a country should allow joint bidding depends on various factors, including the structure of its market, the existence of regulations on competition, the characteristics of the acreage on offer, and the type of fiscal regime. In general terms: (i) better quality blocks attract more bidders; (ii) high-risk or high-cost blocks call for risk sharing among investors; (iii) investment-friendly environments attract more and diverse investors, thus making collusion more difficult; and (iv) progressive fiscal systems allow host governments to capture a fair share of the rent after the blocks have been awarded, thus correcting inefficient rent capture due to allocation procedures. Box 3.10 provides examples of various countries' approaches to joint bidding.

Box 3.9. Information and Risk Perception

Ensuring the long-term security of **New Zealand's** electricity supply is a key objective for effectively managing the country's infrastructure. Gas is a critical component of electricity production, contributing approximately 25 percent of total electricity generation. New Zealand's proven gas reserves have steadily declined since the Maui field commenced production in 1976. Subsequent discoveries have failed to offset this decline, and significant new discoveries are needed to meet projected electricity demands.

While onshore and near-shore Taranaki reserves are declining, prospectivity data suggest that there remain significant untapped opportunities in frontier basins. The immature state of exploration in these basins is such that committed and sustained exploration programs will be required. New Zealand has a favorable investment environment (low sovereign risk, efficient administrative regime, attractive fiscal terms, and rising domestic gas prices). But the country lacks international prominence and suffers from insufficient positive perceptions of prospectivity. While junior explorers play a vital role in laying the foundations for exploration (in terms of local knowledge and initial risk taking), greater diversity is needed to help exploit opportunities in frontier areas. The Crown Minerals decided to focus on two priorities: (i) improving knowledge about the geological potential of frontier areas; and (ii) improving marketing and communications to key explorers and investors.

The Crown Minerals' 2007 Petroleum Investment Strategy paper outlines the strategy and objectives of allocation policy as follows: "Improving our knowledge about New Zealand's prospectivity will allow us to actively market investment opportunities to those who can best maximize the commercial opportunities. We will, therefore, develop a program for data acquisition to increase the level and quality of participation in licensing rounds and ensure that this data is readily available to all explorers. We need to target the right information, at the right investors, in a manner that gives them confidence about making an investment in New Zealand. We share a common interest with industry in promoting New Zealand. We will therefore maintain strong relationships with existing domestic explorers and downstream stakeholders. In addition, however, we will actively raise our international profile with selected international explorers. The New Zealand Petroleum Conference will continue to be a showcase event, but other local and international events will be targeted. In addition, we will also initiate direct communication with overseas explorers with the potential and track records suited to contributing to New Zealand's exploration future."

Box 3.10. Joint Bidding or a Forced Marriage?

In 1975, the government of the **United States** issued regulations banning joint bidding in federal Outer Continental Shelf (OCS) lease sales among firms that individually produce more than 1.6 million barrels of oil and natural gas equivalent per day (Energy Policy Conservation Act, EPCA). Empirical research later found that joint bidding in U.S. OCS federal lease sales did not significantly reduce competition (Mead, Moseidjord, and Sorensen, 1984). Similar conclusions were reached by Watkins and Kirkby (1981) for Alberta's licensing rounds. More recent research (Iledare and Pulsipher, 2006) on the effectiveness of the joint bidding restriction policy during the period 1989–99 found that joint bidding in competitive lease sales (that is, two or more bids per lease) is consistently associated with higher average high bonuses, and perhaps enhances competition in the lease market. It is, however, worth noting that the restricted joint bidders list (RJBL) is not the only policy used by the Minerals Management Service (MMS) to maintain competition among bidders. Results from empirical research would seem to indicate that the limited effectiveness of the RJBL may be due to its redundancy.

In **Angola**, joint bidding is prohibited. The bidding procedure requires that bidders submit their bids separately, indicating whether they wish to be operators, and the share of participating interest that they wish to acquire in each of the blocks applied for. The authorities decide the composition of the participating interests in each block and the operatorship (this practice has been dubbed a "forced marriage"). Possible objectives of this policy include: (i) promoting local participation; (ii) lowering entry barriers for small companies; and (iii) reducing the possibility of collusion among participants. Participating interest may also be granted as consideration or collateral for loans, or part of complex upstream/midstream/downstream projects. The downside of a "forced marriage" is that synergy may be lost because bidders do not know who their partners are going to be. Empirical studies have shown that solo bids are usually lower than joint bids.

In **Norway**, the authorities have, until recently, required that the companies apply for licenses individually, after which the authorities decided owner shares and operatorship. The rationale for this policy choice was the ability of the government to introduce checks and balances and to counter the market power of established alliances among companies. The policy has now changed, and group applications are allowed. The rationale is that group applications reduce application costs and result in groups with members that are more suited to each other.

Key Issues in Allocation Systems Design

Open-Door Systems or Licensing Rounds?

Flexibility in allocation policies is generally a desirable feature. As discussed earlier in this paper, efficient allocation policies must take into account the objectives and constraints that are specific to each country, as well as exogenous factors that are common to all or many producing countries (for example, the expected future level of oil and gas prices). These tend to change over time. Furthermore, countries tend to license E&P rights in areas that have different characteristics (including different levels of prospectivity, different distance from final markets, different access to infrastructure, different risk and development costs, different stages of development, and different materiality). Therefore, a single allocation policy will likely not apply to all situations in a given country. For these and other reasons, hydrocarbon laws often make allowances for open-door systems or licensing rounds in particular circumstances[9] or at the discretion of the sector ministry or regulator.

Open-door systems are likely less competitive than licensing rounds and are generally considered less transparent and more vulnerable to corruption. Such systems can, however, be made more transparent through the definition of clear criteria for award, the publication of the outcome of negotiations, and the use of external oversight bodies.

Auctions or Administrative Procedures?

The geological potential of an area to be licensed is a key element for the choice of allocation system and bidding parameters. In areas where there has been little or no exploration activity, the problem is not just that the risks are larger; rather, there is little basis to estimate the risk. In these circumstances that are likely to attract bids from a limited number of companies, an auction may not work efficiently because bidders would apply a high discount rate to determine the expected NPV of the blocks. Therefore, the winning bids would most likely not reflect the true value of the blocks (Frewer, 2000). Moreover, often the most relevant policy objective pursued by governments in frontier and under-explored areas is to improve the understanding of their geological potential. Consequently, in lieu of auctions, some governments choose to allocate E&P rights on the basis of work program bidding, which ensures that a certain level of exploration activity will be carried out in these areas. In most cases, however, both auctions and work program bidding could be considered. There are at least three reasons for this.

First, the extent to which the inefficiency affects rent capture depends on the conditions for licensing, including the structure of the fiscal regime, and not just on the form of licensing system. In general terms, the higher the level of uncertainty, the more the allocation mechanism should be based on both the expected value of the blocks at bidding (observed value) and the actual value of the blocks at project completion (true value). A fiscal regime that provides the government with an adequate share of economic rent under varying conditions of profitability—that is, a progressive fiscal regime—would allow that government to capture additional rent in the future, should the value of the blocks turn out to be higher than anticipated at the bidding stage. The further "downstream" a government goes to extract the rent, the more progressive the fiscal regime.[10] Progressive fiscal regimes reduce project risk. For this reason they tend to elicit higher winning bids than regressive ones, as investors will factor this risk reduction into their determination of the bid.

Second, auctions could be designed with minimum work program requirements. For example, profit share bidding could be combined with a minimum work program. But to establish meaningful work program obligations, the government would have to have a certain level of technical knowledge. Combining bonus bidding with minimum work program obligations may be less advisable because it may: (i) reduce the amount of risk capital available for exploration; (ii) increase the exploration thresholds; and (iii) discourage some companies from bidding. However, if a government chooses bonus bidding, it should consider providing for cost recoverability/tax deduction of the bonus.

Third, the licensing program could offer a limited number of blocks, strategically chosen to prove specific plays or geological concepts. A certain level of efficiency trade-off could be worth considering, with the objective of gradually reducing the perception of risk as more data on the geological potential of the area becomes available.

Which Form of Auction Is More Likely to Lead to Higher Bids?

As mentioned earlier in this paper, when countries use auctions to allocate petroleum E&P rights, they normally choose multi-object sealed-bid simultaneous or sequential auctions. But would a different form of auction lead, ceteris paribus, to higher bids? Indeed, if the government's key objective is to maximize the NPV of the rent, then some forms of auction are more likely to lead to efficient outcomes than others.

- Simultaneous multi-object ascending auctions are more likely than simultaneous multi-object sealed-bid auctions to award the blocks to the bidders that value them most, and are better suited to maximizing the value of complementarities among blocks. But they are more vulnerable to collusion.
- Simultaneous multi-object ascending auctions may be more efficient than simultaneous multi-object sealed-bid auctions in frontier or under-explored blocks because the lack of information will reduce asymmetries among bidders. However, if the government's objective is to maximize exploration, then work program bidding may be more effective.
- Sequential auctions, where blocks are offered sequentially using first-price sealed bids, may result in inefficient allocation and lower revenue than alternative designs for multi-object auctions.[11] Furthermore, the sequence in which the objects are offered in sequential options is important, as it may affect the seller's expected revenue as well as the efficiency of allocation (Pitchik, 1989).

Box 3.11 outlines the key features of sequential auctions.

Box 3.11. Example of Sequential Auction

The **Venezuelan** model allocates the blocks sequentially in a first-price sealed-bid auction. Thus, bidders can respond to the outcome of the previous blocks' offerings. When Venezuela launched its exploration round in 1996, 10 blocks were offered. For all practical purposes, Venezuela had 10 separate license rounds, block by block. On Monday morning, January 22, 1996, bids were opened for the first block, La Ceiba. These licenses were awarded on the basis of a single-parameter bid: the "PEG," which effectively was a profit-based tax. Companies were to bid from 0 to a maximum of 50 percent. Ties were broken by a subsequent bonus bid round, which took place a couple of hours later. Eleven companies bid on La Ceiba, and nine offered the full 50 percent PEG. The ties were broken with a bonus of $103,999,999 from Mobil/Veba/Nippon. That afternoon the next license, Paria West, was awarded to Conoco. This approach was expected to reduce the chances that less prospective blocks would receive no bid, but such was the case for two blocks.

(Box continues on next page)

Box 3.11 (continued)

In a sequential auction, bidders can use the information revealed in previous rounds to decide how to bid in later rounds. In this sense, the informative content is higher than in sealed-bids auctions. There are, however, some downsides. A bidder cannot switch back to an earlier auctioned block if the price of other blocks on offer rises too much in a later auction. Bidders are likely to regret having purchased early at high prices or not having purchased early at low prices. In other words, to bid strategically, bidders must guess what prices will be in future auctions when determining their bids in the current auction. Incorrect guesses may result in an inefficient allocation. In addition, sequential auctions can be difficult to administer and time consuming if a large number of blocks are auctioned.

Are Planning and Commitment Important?

Planning a licensing round

Licensing rounds are not always successful. Why do they sometimes fail? Reasons may include low prospectivity, high political risk, poor legal and regulatory framework, harsh fiscal terms, lack of contextualization, and poor planning. While low prospectivity and high political risk may be difficult to change, it is usually possible to improve laws and regulations, fiscal terms and planning of the licensing round. Indeed, such improvements may be necessary to ensure an adequate level of competition and efficiency of the allocation system.

Some of the key aspects of planning a licensing round include the following:

- *The timing of the round*. Overall market and economic conditions, as well as competing rounds in other countries, may affect not only the efficiency and competitiveness of the round but the choice of areas to be offered for licensing.
- *Environmental and social issues*. The potential environmental and social impact of petroleum E&P activities should be taken into consideration in defining the areas to be included in a licensing round. In particular, the government should: (a) reduce the possibility of conflict among alternative uses of the areas; (b) exclude sensitive areas and/or define clear parameters for evaluation of bids in sensitive areas; (c) give bidders sufficient information to assess the potential environmental and social risk of operating in specific areas; and (d) improve the certainty of rights, and, ultimately, the efficiency and cost of E&P activities after blocks are awarded.
- *Promotion of the area on offer*. Governments have little or no control over the geological and geographical gifts bestowed upon them by nature, but they do have control over the industry's perception of these gifts. Accordingly, they should organize promotional conferences and information sessions that educate potential bidders on both the geotechnical aspects of the area on offer and the legal, fiscal, and regulatory aspects of E&P operations in the relevant country. Clear and unambiguous bidding parameters and evaluation criteria should also be established and disclosed.
- *Access to information*. Licensing procedures, model contracts, and key legal and regulatory instruments should be made publicly available. In most countries, data packages may be accessed for a fee. Some countries, such as Brazil,

provide information on the government's medium-term licensing policy as a means of helping companies to improve the targeting and sequencing of their investment plans, and the acquisition of seismic data in under-explored areas. This policy should be carefully crafted, as it may reduce participation in a licensing round if investors expect better acreage to be offered in subsequent rounds. Market consultations, such as area nomination programs, are often used by governments to improve the design of their licensing strategies.

- *Timetable of the round*. Licensing rounds often require between 7 and 12 months from their launch to the awarding of the contracts. The length of the process depends, inter alia, on the number and complexity of the blocks on offer, the form of offer and bidding criteria, and governments' administrative constraints.

Box 3.12 provides an example of planning problems.

Box 3.12. Issues with the Planning of Licensing Rounds

In the 2005 **Nigeria** licensing round, 78 onshore and offshore blocks were offered, of which 14 were in deep water. The round was launched in August and was expected to close after five months. The licensing round offered access to several types of acreage: (i) frontier blocks onshore (limited interest); (ii) mature onshore Niger Delta blocks (highest interest); (iii) mature shallow water blocks (high interest); and (iv) deep water blocks (high interest). In addition, some blocks had a strategic link between upstream and downstream commitments (LNG-GTL projects, refineries, and one power project). A new concept for developing local content was introduced in the round—LCVs (locally incorporated companies with a majority of Nigerian shareholders) were to be involved in all new licenses as full paying partners with a minimum 10 percent participating interest. Operators were to train and develop LCVs into capable indigenous oil companies, while LCVs had a special responsibility for securing local goods and services.

While the idea sounded promising in theory, it was difficult to implement. First, there was an overwhelming response from LCVs, causing delays as both the government and the international oil companies investigated the candidates. Other challenges followed: (i) the minimum terms for bidding were seen as too tough by many of the oil companies; (ii) some of the more formal bidding parameters were issued at a late stage, including how to select LCVs and the right of first refusal on some blocks; and (iii) a new model production sharing agreement (PSA) was introduced, but it was not made available until shortly before the bidding round; thus, bidders did not have enough time to evaluate all the terms. NNPC did not agree on the model contract, and demanded amendments after the winning bids had been announced. The final list of LCVs was made available on August 8—just 20 days before the bidding conference—and included some dubious prospects: some of the companies were not well known, some had no experience in the oil industry, some had just been created, and some even had a "tarnished" reputation. In addition, during the licensing process, the Nigerian president had entered into strategic deals with Taiwan and Korea that secured their companies the first right of refusal to attractive blocks. This created uncertainty about the fairness of the bidding process. Nigeria received US$2.5 billion in signature bonuses, and more than US$3 billion was committed in work programs, with 42 percent local content. But only 30 of 78 blocks on offer were awarded; some blocks did not receive any bids, and many of the international oil companies did not bid or were disqualified. The successful awardees were given two months to raise the funds for the signature bonuses before the finalization of the PSAs, but many companies could not meet the deadline, which was extended several times. The strategic deals turned out not to work as intended: Taiwan withdrew from the bidding process, and Korea, which had succeeded in negotiating a lower bonus, eventually saw the deal canceled.

The parties' commitment

For the most part, governments use licensing rounds instead of direct negotiations to award E&P rights because licensing rounds reveal information about the true value of the acreage. If a government knew what the acreage was truly worth, it could extract up to 100 percent of the rent from the bidders. But neither governments nor bidders know the true value of the acreage until oil and/or gas is found, produced, and sold. What governments can and should endeavor to know, however, is bidders' estimates of the acreage's true value. To reveal their estimates, bidders must be assured that the government will not renege on its commitment to award the acreage on the basis of the rules announced for the licensing round. Without such an assurance, some bidders may not want to bear the cost of participating in the round and/or may not want to participate in future rounds. This would be economically inefficient for the government.[12] Changing the rules for award during a bid round may produce similar results (see examples in Box 3.13).

Bidders must also honor their commitment to the terms of the government's offer, if awarded. To this end, governments often require bidders to provide performance guarantees and pay penalties should they renege on their offer or default. Box 3.7 describes the risks that governments may incur if they fail to ensure bidders' commitment.

Box 3.13. Changing the Rules of the Game

In 2006 **Papua New Guinea** announced a licensing round with a closing date of April 2007. Some exploration and development activity had taken place, encouraged by oil seeps found in the highlands. Because Papua is mainly considered a petroleum frontier, the licensing round did not attract much interest from industry. So the government decided to change the fiscal terms to include a very attractive 30 percent government take—and up to 20 percent government participation. Although these terms were better than the ones announced at the opening of the round, investors perceived the revamping of the rules as a significant risk. In addition, the licensing round preceded government elections, and investors worried that the new government might reinstate the original terms when it awarded the contracts.

In 2005 **Angola** launched a licensing round for seven offshore blocks. In the prequalification phase, 29 companies qualified as operators and 22 as non-operators. Three blocks (B15, B17, and B18) included relinquished acreage with expected recoverable reserves of approximately 1 billion barrels of oil equivalent an each block. Fixed terms for the three blocks included a 50 percent cost recovery limit, and a 30 percent investment uplift. The profit share ranged between 30 and 80 percent on a rate-of-return-based sliding scale. Corporate tax was 50 percent. The state oil company, Sonangol, had a 20 percent working interest, carried through exploration. Four bidding parameters, which included a participation in a local refinery project (SONAREF), and their relative importance for award were publicly announced (see below). Blocks were ring-fenced. Bonuses and contribution for social projects were not cost recoverable or tax deductible.

Biddable parameters	B15 (%)	B17 (%)	B18 (%)
Signature bonus	50	15	15
Work program	30	15	15
Contribution to social projects	20	0	0
Participation in SONAREF	0	70	70

(Box continues on next page)

Box 3.13 (continued)

Bidders were not allowed to discuss the bids or form consortia; doing either would result in disqualification. However, prior to the announcement of the winning bids, Sonangol Sinopec International (a joint venture between Sonangol and the Chinese national oil company Sinopec) announced its offer to invest US$2.2 billion in SONAREF. This effectively eliminated the need for that bid item for B17 and B18. The deadline for submission of offers was delayed for these two blocks to allow investors to adjust their bids. The two blocks received a high bid of US$1.1 billion each from Sonangol Sinopec International. The consortium, however, had not pre-qualified as an operator. Sonangol announced its choice of consortia and operators: Total was awarded the operatorship and 40 percent interest in B17, and Petróleo Brasileiro (Petrobras) was awarded the operatorship and 30 percent participating interest in B18. Eventually, disagreements between Sonangol and Sinopec on the product slate for SONAREF derailed the refinery project.

Papua New Guinea and Angola offer examples of what happens when rules changed during the bidding process. The market response was much harsher for Papua, but would Angola have obtained even better terms for B17 and B18 had Sonangol Sinopec International not prematurely announced its investment in SONAREF? Unfortunately, we cannot answer this question. What we can, however, say is that geology matters.

What Really Matters for the Design of Licensing Rounds?

In designing an allocation system, the form, the biddable parameters, and the bidding procedure, have a large role in ensuring that the allocation of E&P rights will be efficient. But equally important is the ability of the allocation system to: (i) attract potential bidders; (ii) prevent collusion among bidders; and (iii) resist political and lobbying pressures.

Attracting potential bidders

Because the size of the winning bid is positively correlated with the number of bidders, the allocation system should aim to attract bidders. Some forms of auction are more suited than others to achieve this objective.

In ascending auctions, strong or advantaged bidders may deter entry or depress the bidding of rivals, especially when the cost of entry is high and there are large asymmetries among bidders (Kemperer 2004). In fact, since an ascending auction allows the bidder that values winning the most to over-bid other bidders, such a bidder would normally be expected to win the block. As a result, smaller firms have less incentive to participate, especially if joint bidding is not allowed and the cost of entry is high. Furthermore, ascending auctions are more vulnerable to the winner's curse than other forms of auction. The winner's curse refers to the tendency of the winner to over-estimate the true value of the block; fearing the curse, everyone will bid cautiously except the advantaged firm. Since an advantaged firm has more accurate information than its rivals about the true value of the block, winning does not imply over-estimating the true value of the block. On the contrary: because its rivals are cautious, the advantaged firm generally pays a lower price than it would otherwise be prepared to pay when it does win. It follows that, because ascending auctions are more likely than sealed-bid auctions to be won by the strongest companies, fewer companies may be willing to participate. In the end, ascending auctions may be less profitable than sealed-bid auctions.

The outcome of first-price sealed-bid auctions is more uncertain than that of ascending auctions. An advantaged bidder may still win the block, but its bidding

strategy will, in general, be less aggressive. Since it has only one shot at the block and it wants to maximize its profit, the bidder will offer less than what it could be pushed to bid in an ascending auction. In an ascending auction, the bidder would be willing to continue bidding until the price equals its valuation of the block. In a first-price sealed-bid auction, the bidder will bid slightly more than he expects the second highest bidder to offer and less than its own valuation of the block. Therefore, other bidders may have a better chance to secure the block in a sealed-bid auction than they would in an ascending auction.

In licensing E&P rights, one may expect to find complementarities among leases.[13] In this case, bidders are theoretically more likely to win efficient bundles of blocks in a multi-unit ascending auction than they would in a first-price sealed-bid auction.[14] In practice, though, governments often allow portfolio adjustments to occur after licensing rounds. Since the market will correct the inefficiency of the initial allocation mechanism, governments may not view the design of complex auction forms and procedures as necessary or desirable.

Preventing collusion

The allocation procedure could be designed to reduce the possibility of collusion among bidders—that is, the possibility that bidders may explicitly or tacitly conspire to keep their bids low (McAfee and McMillan 1987; Kemperer 2004). Sealed-bid auctions are less exposed to this risk than ascending auctions because bidders in sealed-bid auctions cannot use their bids to signal to opponents and cannot observe opponents' bids until the auction is closed.[15] Reserve prices can be used to mitigate the risk of collusion and to simulate additional market participants when a low level of competition is expected. Often licensing rounds include reserve prices, or minimum values at which the E&P rights can be granted (for example, a minimum work program, minimum signature bonus, minimum profit share, or minimum royalty). Bids are rejected unless they are equal to or greater than the reserve price.

Setting reserve prices for E&P rights may be difficult given the uncertainty of values, however, particularly in frontier or under-explored areas. If the reserve price is set incorrectly, the allocation system risks being inefficient—a price that is too low may depress the bids and fail to deter collusion, and a price that is too high may prevent the blocks from being leased at all.[16] Robust reserve prices are often opposed by government officials, who fear that if the reserve price is not met and the blocks are not leased, the licensing round will be seen as a failure. However, reserve prices need not be posted. Box 3.14 describes the use of reserve prices in two countries.

Box 3.14. Reserve Prices

In the **United States** the Minerals Management Service (MMS) reserves the right to accept or reject high bids on the basis of its assessment of the fair market value of the lease. The rules for determining the fair market value are public. This procedure allows the MMS to calculate the fair market value after having observed the value estimate of the bidders. In the **United Kingdom** the Department for Business, Enterprise & Regulatory Reform (BERR)—since March 2009, the Department of Energy and Climate Change (DECC)—establishes a low minimum work program for the blocks on offer. The BERR then accepts or rejects winning bids ex post based on the adequacy of the proposals. Under both systems, a reserve price exists, but it is not posted and may depend on the observed bidding.

Resisting external pressure

Licensing rounds are generally more transparent than open-door policies, and auctions are generally more transparent than administrative procedures. Allocation systems can be designed to resist political and lobbying pressure as well as corruption. In general, governments that publicly disclose the objectives of the allocation policy, the allocation procedure, and award criteria are more accountable and less likely to unfairly favor one investor or consortium over others. While such transparency would in some cases require a radical change in attitude among participants (investors, the local elite, and government officials), clear objectives, procedures, and award criteria enable bidders to structure their bids more effectively and may reduce the perception of risk (see Appendix IV). However, as discussed in paragraph "Administrative procedures versus auctions" on page 15, they may reduce government control over the industry. Box 3.15 provides an example of transparency and oversight mechanisms.

A transparent allocation system is not a guarantee of efficiency; rather, efficiency depends on the system's parameters and how well they respond to the government's objectives, constraints, and exogenous factors. Bundle bids pose additional challenges in this respect.

Box 3.15. Transparency Mechanisms

In 2005 **Nigeria** launched a licensing round that differed from previous rounds. Local content received more emphasis, and transparency and oversight mechanisms were introduced to ensure that no departure from due process would occur. To this end, Nigeria invited independent observers from four countries—Brazil, the United Kingdom, the United States, and Norway—to monitor the licensing round. The request was unusual; none of the countries had previously been involved in monitoring another country's licensing round. The observers were given unrestricted ability to comment, and access to all relevant information. Out of 70 blocks on offer, 30 were finally awarded. The international observers found that the licensing round was open and transparent, but a post mortem evaluation conducted by the observers six months after the closing of the licensing round noted the opacity surrounding the fulfillment of the award conditions. The mixed results were mainly due to the confusion on the bidding terms, and too ambitious expectations for local content.

What Does This Mean in Practice?

> *There is frequently excessive focus on sophisticated theory at the expense of elementary theory; too much economic knowledge can sometimes be a dangerous thing. Too little attention is paid to the wider economic context, and to the dangers posed by political pressures. Superficially trivial distinctions between policy proposals may be economically significant, while economically irrelevant distinctions may be politically important.*
>
> *Kemperer, 2003*

There is a large body of academic literature on auction theory and how to design systems to maximize the value of petroleum E&P bids. Yet the licensing of petroleum E&P rights is usually done through a simple simultaneous sealed-bid round. It would seem that governments could do better to improve rent capture at allocation. So why don't they get more creative? There are several possible reasons.

First, risk and uncertainty are key features of oil and gas exploration. Since nobody knows the true value of the blocks at the time of bidding, sharing the risk is socially desirable. Governments and bidders would be better off if the allocation mechanism allowed rent capture to be based on both the expected value of the blocks at bidding and the actual value of the blocks at project completion. In other words, an efficient fiscal system would allow governments to capture a fair share of the rent after the blocks have been awarded, thus correcting inefficiencies at bidding.

Second, the more risk-averse bidders are, the more likely it is that sealed bids will capture the rent more efficiently than ascending auctions (Maskin and Riley, 1984). A bidder's risk aversion will, in principle, increase as the ratio between the value of the bid and the total value of the bidder's asset increases. Hence, ascending auctions may not substantially increase rent capture in frontier areas, which tend to attract small companies specialized in exploration with relatively high risk exposure. More mature areas attract bigger companies with larger market power and larger budgets. In this case, the efficiency of the auction may have a lot to do with its ability to avoid collusion and encourage entry. Once again, simple, simultaneous sealed-bid auctions would adequately address the problem.

Third, while there is a positive correlation between the number of bidders and the size of the winning bids, the size of the winning bid is also strongly correlated with the quality of the blocks. Better quality blocks attract more bidders; more bidders increase the winning bid. When there is a large number of potential bidders for whom entry to the auction is easy, auction design may not matter as much.

It follows that, although more complex bidding forms might in some cases increase rent capture at bidding, materiality considerations (that is, the marginal gain) and the existence of market mechanisms (that is, joint bidding and secondary markets) and fiscal mechanisms (that is, progressive fiscal regimes) to correct inefficiencies at bidding, may be among the reasons why petroleum producing countries often opt for simple multi-object sealed-bid rounds to award E&P rights.

Notes

[1] As stated by Leland (1987): "Excessive risk aversion by firms incurs social costs. Investment in exploration and development will be insufficient. Production from leases (given a fixed production capacity) is likely to be too rapid, since risks resulting from future price uncertainty will be reduced. In addition to distorting exploration, development, and production decisions, risk aversion leads to over-discounting for risk and, therefore, to lower bids on tracts. The government will get less economic rent than it would if socially efficient production and bidding decisions were made. And competition and, consequently, economic rent will be reduced if small firms are subject to capital constraints because of risk-averse lenders."

[2] For example, the government could decide to sell the E&P rights to the bidders that offer the highest-profit oil and gas share, all other parameters of the fiscal system being equal. Alternatively, the government could decide to award the rights to the bidders that offer the most adequate exploration program, while all fiscal parameters are fixed. In all cases, the government could define a minimum level of fiscal parameter(s) or a minimum exploration work program, below which the E&P rights will remain unsold (reserve prices are discussed further in Chapter 3).

[3] For example, the result of geophysical surveys or drilling activity carried out in the license area (or neighboring area) may lead the license holder to review its evaluation of the geological risk or

of the optimal work program. As a result, the license holder may decide to divest by transferring its rights to another company or to reduce its risk by transferring part of its rights to another company.

[4] In other words, the transferor (in industry terms, the company farming out) would aim to at least recover all costs incurred by it to obtain the award (and subsequently to implement the petroleum contract), and at best obtain an information premium. The transferee (or "farminee") would likely be willing to pay a premium in exchange for a reduction in the project's risk, brought about by the additional information obtained and/or produced by the transferor.

[5] See Mead (1994). The advantages and disadvantages of work program bidding are discussed further in this paper.

[6] For a detailed discussion on cost saving incentives in fiscal systems design, see, for example, Johnston (2003), Tordo (2007), Gerner and Tordo (2007).

[7] Studies on the effect of information asymmetries on the bid price for oil and gas rights in the USGoM have shown the importance of access to information by market participants. See Porter (1995) and McAfee and McMillan (1987).

[8] While bidder profits decrease as the number of bidders increases, better information increases expected profits (Sunnevåg, 2000).

[9] For example, when licensing rounds result in single bids.

[10] Signature bonuses (which are paid before a discovery is made) and royalties (which are paid whether or not a field yields a positive result) are the most regressive forms of rent extraction.

[11] Examples of inefficient allocation and reduced revenue capacity of sequential auctions are discussed in Hausch (1986), Krishna (1993). Sunnevåg (1994) presents an application to offshore lease licensing.

[12] It is important to note that the use of progressive fiscal system and renegotiation clauses in petroleum agreements allow both governments and successful bidders to deal with changing circumstances. Thus, if the licensing conditions are properly designed, commitment should not be an issue.

[13] For example, assume that two block are offered in a licensing round. A company may value acquiring E&P rights in both blocks more than it values acquiring E&P rights in either one of them.

[14] The possible application of multi-unit ascending auctions to petroleum E&P is discussed in Sunnevåg (2000) and Cramton (2007).

[15] The effect of collusion and its sustainability are extensively discussed in the literature on industrial economics. For an application of these concepts to auctions see, for example, Kemperer (2004), Sunnevåg, (2000), and Porter (1995).

[16] The correct level of a reserve price in a common-value auction varies with the type of auction and with the number of bidders; usually, but not always, it increases with the number of bidders. Reserve prices have been widely covered in the literature. See, for example, Milgrom and Weber (1982), Robinson (1984), McAfee and McMillan (1987), and Kemperer (2004).

CHAPTER 4

Conclusions

What Type of Allocation System Is Best?

There is no model allocation policy or system appropriate for all governments and all circumstances. Optimal design requires the definition of the economic, social, and political objectives that policy makers aim to achieve through the allocation of petroleum E&P rights. Some of these objectives may be more effectively achieved by combining allocation systems with other policy tools, in particular the fiscal system and market regulation. Therefore, it is important to ensure coordination and coherence among different policy tools.

The state of the economy and its development needs are among the key drivers of countries' allocation policies as they affect, inter alia, the goals of petroleum depletion policies (such as production rates, and pace and type of exploration), the role of private investors and their access to petroleum resources, and the choices related to inter-temporal distribution of the rent. The latter is particularly important as it directly affects the objectives of the allocation policy and the structure and elements of the fiscal regime for petroleum activities (for example, rent maximization versus social and environmental considerations, social discount rate and the timing of rent capture, and so on).

Not all factors affecting the design of efficient allocation systems can be controlled or influenced by governments. A country's geological potential is a prime example of an independent factor: geology is a gift of nature. The geological potential determines countries' relative ability to attract investors and to extract the rent. Countries with limited prospectivity have limited options, and generally limited negotiation power. Nonetheless, countries can try to affect the perception of prospectivity and reduce information asymmetries among market participants through the strategic use of geological, geophysical, and petrophysical data. This entails: (i) the definition of appropriate policies for the acquisition and management of geotechnical data (such as work program obligations, multi-client speculative seismic surveys, and petroleum data banks); and (ii) the definition of the country's promotional strategy (such as, blocks' delineation, dissemination of information on the country's geological potential, the choice of areas to be licensed at any given time, and relinquishment policies).

Global market and economic conditions, including the expected level and trend of future oil and gas prices, play an important role in shaping investors' strategies and attitude toward risk. Although governments have, at best, limited influence on these factors, they can respond to changes in market and economic conditions by defining suitable allocation strategies. They could, for example, (i) offer limited frontier acreage during economic downturns to increase competition and rent capture; (ii) increase the

progressivity of the fiscal system to reduce investors' risk without forfeiting the possibility of higher revenue when economic conditions improve; (iii) favor work programs over signature bonuses in the bidding parameters of licensing rounds; and (iv) design the allocation system to increase the level of competition among participants and reduce the possibility of collusion.

Country-specific objectives and constraints tend to change over time, as do exogenous factors common to all or most countries. In addition, countries tend to license E&P rights in areas that have different characteristics. It follows that a single allocation policy will not apply to all situations in a given country. In fact, countries often adopt a range of allocation policies, including open-door systems and various forms of licensing rounds. Auctions are generally considered more efficient than administrative procedures or direct negotiations in allocating E&P rights, but the relative efficiency depends on the context and the design parameters.

Why Do So Many Systems Look So Similar?

When auctions or administrative procedures are used, more often than not, governments opt for simple simultaneous multi-object sealed-bid rounds. Although more complex bidding forms might increase rent capture at bidding, the potential marginal gain is often limited owing to the high level of uncertainty and risk that characterize most petroleum E&P projects. Furthermore, market mechanisms, such as joint bidding and secondary markets are widely used in the petroleum sector to correct inefficiency at the time of allocation. Last but definitely not least, the fiscal regime is the primary instruments relied upon by governments to collect the economic rent generated by petroleum E&P activities. *In fact, at the time of allocation, neither the government nor the investors know the true value of the blocks being offered for licensing. Progressive fiscal systems allow them to reduce the risk and to correct inefficiencies due to imperfect information at the time of allocation.*

Is System Design Important?

The form, biddable parameters, and bidding procedure of the allocation system all have a large part in ensuring its efficiency, but its success heavily depends on its attractiveness to potential investors, its robustness against collusion, and its resilience in the face of political and lobbying pressures. A government's technical and administrative capacity should also be taken into consideration when designing an allocation system, as should other policy instruments (such as the fiscal regime and market regulation) that may be used to achieve specific objectives.

Finally, reliability matters. One of the main reasons for a government to use auctions instead of other allocation systems to award E&P rights is that auctions are more likely to reveal information about the true value of the acreage. But if a government has a historical lack of commitment to awarding the acreage on the basis of the rules announced for the licensing round or repeatedly reneges on contractual terms, this is likely to deter bidders from revealing their estimate of the true value of the acreage, and may discourage some bidders from participating. The result would be economically inefficient for the government.

Appendixes

APPENDIX I

Life Cycle of a Typical Oil and Gas Project

The stages of a typical oil and gas project can be described as follows (Tordo, 2007):

i. Exploration. During the exploration phase, geological and geophysical surveys (such as seismic surveys and core borings) are acquired. The data so acquired are processed and interpreted and, if a play appears promising, exploratory drilling is carried out. Depending on the location of the well, a drilling rig, drill ship, semi-submersible, jack-up, or floating vessel will be used.

ii. Appraisal. If hydrocarbons are discovered, further delineation wells are drilled to establish the amount of recoverable oil, production mechanism, and structure type. Development planning and feasibility studies are performed and the preliminary development plan is used to estimate the development costs.

iii. Development. If the appraisal wells are favorable and the decision is made to proceed, then the next stage of development planning commences, using site-specific geotechnical and environmental data. Once the design plan has been selected and approved, contractors are invited to bid for tender. Normally, after approval of the environmental impact assessment by the relevant government entity, development drilling is carried out and the necessary production and transportation facilities are built.

iv. Production. Once the wells are completed and the facilities are commissioned, production starts. Workovers[1] must be carried out periodically to ensure the continued productivity of the wells, and secondary and/or tertiary recovery2 may be used to enhance productivity at a later time.

v. Abandonment. 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 abandon. Planning for abandonment generally begins one or two years prior to the planned date of decommissioning (or earlier, depending on the complexity of the operation).

Notes

[1] Any operation performed on a well subsequent to its completion.

[2] In the first stage of hydrocarbon production, natural reservoir energy—such as gasdrive, waterdrive, or gravity drainage—displaces hydrocarbons from the reservoir into the wellbore and

up to the surface. Initially, the reservoir pressure is considerably higher than the bottomhole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to the surface. However, as the reservoir pressure declines because of production, so does the differential pressure. When the reservoir pressure is so low that the production rates are not economical, or when the proportions of gas or water in the production stream are too high, secondary or tertiary recovery methods may be used. Secondary recovery consists of injecting an external fluid, such as water or gas, into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. Tertiary recovery (or enhanced oil recovery) involves the use of sophisticated techniques that alter the original properties of the oil. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.

APPENDIX II

Main Fiscal Instruments: Advantages and Disadvantages

Instrument	How does it work	Advantages/ Disadvantages	
		Host government	Investors
Bonuses	Paid by the investor upon the occurrence of a specific event (contract signature, discovery, declaration of commerciality, commissioning of facilities, start of production, and/or reaching target production levels)[1]	• Up-front revenue stream • Easy to administer	• Increase the project risk[2] • Commerciality bonuses increase the economic cut-off rate of a project
Royalties	Based on either the volume ("unit" or "specific" royalty) or the value ("ad valorem" royalty) of production or export	• Up-front revenue stream as soon as production starts • Reasonably predictable • Easy to administer • May distort investment decision[3]	• May distort level of recovery • Reduce the economic life of a project • May deter investment
Ring-fencing	Refers to the delineation of taxable entities[4]	• Protects level of current tax revenues • Levels the playing field	• Does not incentivize exploration and investment activities
Corporate income tax	Taxes are payable when annual revenues exceed a certain measure of costs and allowances. The applicable rate is fixed, and may be the same or higher than other industries	• Part of the normal tax system • May be paid by the government or its national oil company on behalf of the investor[5]	• Because the rate is fixed, corporate taxes are relatively regressive (that is, their burden remains the same at different levels of profitability) • Investors are not affected by changes in the tax rate when the tax is paid by the government on their behalf
Progressive income tax	Uses stepped tax rates linked to prices, volumes, values, and so on. These are add-ons to conventional corporate income tax	• Allows government to partake in project upsides • Enhances the volatility of government revenue • Provides income to the government only when target return or target payback is reached	• Parameters are not necessarily linked to the project's rate of return. The tax is progressive but not necessarily neutral

Instrument	How does it work	Advantages/ Disadvantages	
		Host government	Investors
Resource rent tax	Ties taxation more directly to project's profitability (R-factor or rate of return, RoR)	• Provides income to the government only when target return or target payback is reached • Key issue: defining an efficient target rate	• Relatively neutral for investment decisions[6]
Government participation	Includes range of options: from carried interests to full equity	• Non-economic reasons (control, transfer of technology) • Increases administrative complexity and risk • Exercise of the right for the most attractive projects • Rent capture versus efficient taxation	• If on concessional terms: reduces cash flow and increases investment risk • May lead to suboptimal investment decisions • Reduces company lifting entitlement and "bookable barrels"
Cost recovery limit	Defines the percentage of net crude oil that can be used for cost recovery. Carry forward of unrecovered costs may be limited or unlimited.	• Similar to royalties but less regressive • Provides the government with a share of production in each accounting period • More difficult to administer than royalties	• By delay cost recovery, it affects the project's rate of return. • May discourage the development of marginal fields if limit is set too low
Profit oil/gas split	Revenue remaining after deduction of royalty and cost recovery. This is split between the government and the investors, in most cases, according to a sliding scale	• Allows to tailor fiscal package without changing overall fiscal framework • Frequently linked to production: easier to calculate but insensitive to changes in price and costs	• Sliding scale profit oil/gas splits lower the project specific risk especially if linked to the R-factor/RoR • Flexibility is more likely to encourage the development of marginal fields

Source: Author.

Notes

[1] The maximum level of a bonus depends on several factors, such as the overall fiscal terms, the characteristics of the asset, the country political risk, and the risk profile of the investors.

[2] Bonuses affect the project risk by increasing the exploration and development economic thresholds. To compensate for the risk, higher bonuses are balanced by lower royalties, taxes, production sharing, and/or government shares.

[3] Royalties have a tendency to distort the levels of recovery, although this effect is relevant only when the royalty is the most important part of the tax rent and when important differences in quality occur in crude oil and gas produced from a given contract area. In particular: (i) unit royalties reduce the effective price by the same nominal amount each year. Therefore, if future prices are expected to increase, investors will have an incentive to delay production; and (ii) ad valorem royalties reduce the discounted price of crude oil and gas by the same percentage in each year. Therefore, if the prices are expected to rise in real terms, investors would prefer increasing production (subject to technical considerations) in the present.

[4] While corporate income tax normally applies at the company level, in the petroleum sector the taxable entity is often the contract area or the individual project. When ring-fencing applies at the contract area or project level, income derived from one area/one project cannot be offset against losses from another area/project. However, some countries allow exploration costs to cross the fence.

[5] In this case, the tax is structured as if paid directly by the contractor for home country tax credit purposes.

[6] This depends on how close the target rate is to the investor's discount rate, which in turn reflects the project risk and the investor's corporate profile (Tordo, 2007).

APPENDIX III

World Average Fiscal Terms

Area	Block sizes range from extremely small for development/enhanced oil recovery (EOR) projects to very large blocks for exploration. Typical exploration block sizes are on the order of 250,000 acres (1,000 square kilometers) to over a million acres (>4,000 square kilometers).
Duration	Exploration: Typically three phases, totaling 6 to 9 years. Production: Between 20 to 30 years (usually at least 25 years).
Relinquishment	Exploration: 25 percent after 1st phase, 25 percent of "original" area after 2nd phase (this is most common, but there is wide variation).
Exploration obligations	Includes seismic data acquisition and drilling; sometimes contract requirements can be very aggressive in terms of monetary value and timing, depending on the situation; all blocks are different.
Royalty	World average is around 7 percent; most systems have a royalty or an effective royalty rate (ERR) due to the effect of a cost recovery limit.
Profit oil split	Most profit oil splits (approximately 55–60 percent) are based upon a production-based sliding scale; others (around 20–25 percent) are based upon an R-factor or RoR system.
Cost recovery limit	Average 65 percent; typically, production sharing agreements (PSAs) have a limit and most are based on gross revenues; some (perhaps around 20 percent) are based on net production or net revenues (net of royalty); over 20 percent have no cost recovery limit. Approximately half of the world's PSAs have no depreciation for cost recovery purposes (but almost all do for tax calculation purposes).
Taxation	World average corporate income tax is approximately 30–35 percent. But many PSCs have taxes paid "in lieu"—"for and on behalf of the contractor"—out of the national oil company's share of the profit oil.
Depreciation	World average is 5-year straight-line decline for capital costs; usually, depreciation begins "when placed in service" or "when production begins."
Ring-fencing	Most countries (55 percent) erect a ring-fence or a modified ring-fence (13 percent) around the contract area and do not allow costs from one block to be recovered from another nor do they allow costs to "cross the fence" for tax calculation purposes.
Government participation	Countries with PSCs usually are more likely to include government participation in their system. When governments do participate the typical percentage is around 30 percent. Approximately half of the countries with the option to participate do not reimburse "past costs."

Source: Daniel Johnston (2009).

APPENDIX IV

Select Countries' Experience

Australia

Licensing policy

The Joint Authority of the Commonwealth and State/Northern Territory governments is responsible for the administration of the Offshore Exploration Acreage Release Program ("Release Program"). The Release Program is guided by the Offshore Petroleum Strategy, which is under the responsibility of the Department of Industry, Tourism, and Resources. The number, size, and location of release areas are established by the Joint Authority, after consultation with the exploration industry and other interested parties. Acreage is currently released once a year and oil companies are invited to submit bid applications on the released areas.

Applications include a technical assessment of the area, a work program, and evidence of the technical and financial resources of the applicants. The work program consists of a proposed six-year program of drilling, surveying, and other geophysical analysis, together with indicative costing. Since the early 1990s, companies are required to *guarantee* the first three years of their proposed work program.

Bids are assessed primarily on the basis of the work program proposed for the first three years. The Joint Authority awards exploration permits bids that, in its opinion, are most likely to further the petroleum potential of the area. The Joint Authority reserves the right to reject bids which it considers inadequate, even if they are the highest bids.[1]

Exploration permits provide the successful bidder with an exclusive right to explore the permit area for six years. The exploration period may be extended twice for a further five years at each extension, at the request of the permit holder, and as long as the permit is in good standing. At each renewal, 50 percent of the permit area must be relinquished. In the event of a commercial discovery, the permit holder may apply for a production license and is entitled to all profits (after taxes and royalties) from the production and sale of commercial reserves. In the event of the discovery of non-commercial reserves that are likely to become commercial within fifteen years, the permit holder may postpone development and production under a retention lease that is reassessed every five years.

Australia has a concessionary system. The fiscal regime includes a 40 percent petroleum resource rent tax (PRRT) on projects' petroleum income, and a 30 percent corporate tax. The PRRT was introduced in 1987 to replace royalties and crude oil excise in most areas of Commonwealth waters (between 300 and 200 nautical miles seaward of the low water line along the coast). The fiscal regime is defined in sector

regulation and is not the object of negotiation between the government and investors. Fiscal incentives are used from time to time to affect investment decisions without affecting the integrity of the fiscal regime.[2]

Licensing history

In 2003 the Australian Bureau of Agricultural and Resource Economics (ABARE) carried out an analysis of the factors that determine the variations in size of work program bids, with the objective to propose improvements to the existing licensing policy where needed (Maritz, 2003). The study covered the period between 1985 and 1999 during which a total of 430 areas were released for work program bidding[3] in frontier, immature, sub-mature, and mature areas.[4] The average take-up rate was 44.7 percent.[5] The take-up rate was considerably higher for mature than frontier areas (70 percent versus 30 percent).

Not surprisingly, the guaranteed work program bid (the first three years of the exploration work program bid) was a larger percentage of the total work program bid for immature areas than it was for frontier areas (51.3 percent versus 36.7 percent), and the average size of the work program was directly correlated to the maturity of the area.[6]

Over the study period, joint bidding accounted for 75 percent of all bids and 65 percent of all permits awarded. There was no indication that joint bidding had reduced competition among bidders.

Expected future oil prices explained approximately 6.5 percent of the variability in area specific total work program bids,[7] and were more relevant to frontier and immature areas. The most important factor in explaining the variability in area-specific primary work program bids was the geological maturity of the basin (11 percent); an additional 6.5 percent was explained by discoveries in the previous three years. In line with auction theory and empirical observations in other industries and countries, a large portion of the overall variability in area-specific primary work program bids was explained by the number of participants (32 percent of the overall variability).

General observations

The current licensing policy (work program bidding) is premised on the assumption that the overall success of an area Release Program is determined by the number (and type) of areas that are taken up, as well as by the size of the bids received for areas that are taken up.[8] Hence, the primary objective of the Release Program is to design an allocation strategy that maximizes the level of exploration activity in frontier, immature, sub-mature, and mature areas (Maritz, 2003).

The market response to the release of frontier acreage over the period of the study would seem to indicate a preference for lower-risk areas.[9] The downward trend in oil prices that characterized the period of observation may in part explain the prudent attitude of the bidders. This is particularly true when clear market segmentation (that is, the presence of companies that specialize in specific segments of the exploration market) is observed,[10] as companies with higher-risk and less diversified portfolios may find it more difficult to raise sufficient funding to finance the guaranteed work program in times of low or downward trending oil prices. This may suggest that during economic downturns or when oil and/or gas prices are otherwise expected to fall, the release of frontier (and immature) areas should be limited so as to increase

competition among bidders. The government could also seek to acquire additional geological and geophysical surveys in frontier areas that are earmarked for release, possibly through the negotiation of multi-client surveys with service companies that offer this kind of arrangement.[11] The availability of additional information on the geological potential of these areas will decrease the investors' risk and is likely to provide useful guidance for the design of the Release Program.[12] Eventually, as more information on the geological potential becomes available—that is, frontier and immature areas graduate to sub-mature status—the licensing policy may shift from encouraging exploration (work program bidding), to maximizing the NPV of the economic rent (bonus/royalty/profit share bidding).

Notes

[1] This is an example of undisclosed reserve price.

[2] In Australia under the Petroleum Resource Rent Tax Assessment Act 1987, capital or operating costs that directly relate to the petroleum project are deductible in the year they are incurred. Expenditures include exploration, development, operating and closing activities. Undeducted expenditures are compounded forward at a variety of set rates depending on the nature of those expenditures and the time that they are incurred prior to the granting of a production license. The legislation was substantially altered in 1990 to allow undeducted exploration expenditure incurred after that date to be transferred to other projects. Simultaneously, the carry-forward rate of undeducted general projects expenditures was significantly reduced from the long-term bond rate plus 15 percentage points to the long-term bond rate plus 5 percentage points. In 2004 the government introduced a 150 percent incentive to assist exploration in nominated frontier areas. In 2006 the government introduced various regulatory amendments to reduce compliance costs, improve administration, and eliminate inconsistencies. The regime was found to have been reasonably effective in promoting the exploration and development of oil and gas in marginal fields, and high-cost/high-risk areas (http://ret.gov.au).

[3] During the same period of time, eight areas were released for cash bidding.

[4] The maturity of the area is an important indicator of the likelihood of discovering an economic volume of petroleum (that is, prospectivity of the area). In addition to maturity and basin geology, Maritz used the following parameters to determine the relative maturity of the areas included in the bid rounds:

Parameter	Frontier	Immature	Sub-mature	Mature
Proportion of petroleum discovered in the area with probability greater than 50%	No discovery	<20 per cent	20Ğ50 per cent >	50 per cent
Average 2D seismic grid spacing	sparse	>5 km	2Ğ5 km	<2 km
Extent of 3D seismic surveys	Nil	Nil	Some may have been undertaken	Undertaken in part of the region
Exploration wells per 1000 sq. km	Very few or none	1 well	1-10 wells	>10 wells

Source: Department of Industry, Tourism and Resources (1999).

[5] More precisely, 22.1 percent of the areas received multiple bids, 22.6 percent received at least one bid, while 55.3 percent received no bids.

[6] The average work program bid in frontier areas was more than five times less than the average bid in mature areas. Sub-mature and mature areas had very similar results in terms of average work program and distribution between the first and second exploration periods.

[7] The explanatory relevance of expected future oil prices is likely to increase in periods of high volatility. It is also worth noting that Maritz used a proxy measure of expected oil prices and not the bidders' estimates (which are of course not a publicly available data).

[8] There may be some trade-off between quantity (the number of areas taken up) and quality of the bids received.

[9] Only 30 percent of the frontier areas received at least one bid. The average size of the work program bid was around $5 million/square kilometers (in 1999 Australian dollars), with 36 percent guaranteed in the first exploration phase. The average primary bid shrinks considerably if the Bonaparte and the Browse basin are excluded from the calculation.

[10] See the analysis of bidders' profile in Martiz, 2003.

[11] Multi-client geophysical and geological surveys are discussed in Chapter 2, endnote 29.

[12] For example, the data could be used to define the location, size, and sequencing of areas for release.

United Kingdom

Licensing policy

The law governing the development of hydrocarbons in the United Kingdom is the Petroleum Act 1998. The law vests all rights to the nation's petroleum resources in the Crown. But the Secretary of State (for Energy and Climate Change; that is, the government) can grant E&P licenses over a limited area and for a limited period.[1] The Department of Energy and Climate Change (DECC) is the authority responsible for granting licenses for the exploration, development, and production of hydrocarbons in Great Britain, or beneath the United Kingdom territorial sea and Continental Shelf, and issuing regulations related thereto.[2]

The policy objective of the U.K. government is to "encourage the best possible prospection, exploration, and production of the country's petroleum resources under conditions that encourage competition and non-discriminatory access to the resource, taking into consideration the protection of the environment and the interests of other users of the sea."[3] Most licenses are issued through competitive licensing rounds on the basis of work program bidding. But particular cases may present compelling reasons to issue a license out-of-round.[4]

Licenses are awarded at the Secretary of the DECC's discretion. Applicants are judged against the background that they fully meet the general objective of encouraging expeditious, thorough, and efficient exploration to identify the oil and gas resources of the United Kingdom. The criteria used to make this judgment are set out in regulations. Applicants must meet threshold standards of financial capability and environmental management. They should also demonstrate technical competence through their geological interpretation of the area applied for and their plans for further exploration and appraisal of its potential resources.

Most licenses follow a standard format, but conditions may be amended to suit special scenarios. Licenses are granted at the discretion of the Secretary of the DECC. There are basically three types of licenses, depending on whether the area is offshore or onshore:

- Exploration licenses grant non-exclusive exploration rights in areas below the low-water line, and which are not covered by a production license.[5] The duration of the license is three years.
- Production licenses grant exclusive E&P rights in areas in the territorial sea and Continental Shelf. They cover relatively small areas—typically a couple of hundred square kilometers. Production licenses include traditional licenses, "promote" licenses,[6] frontier licenses,[7] and licenses specially drafted to cover the redevelopment of a decommissioned field.
- Petroleum exploration and development licenses grant exclusive E&P rights in "landward areas," that is, areas landward of the baseline of the territorial sea.

Production licenses and petroleum exploration and development licenses are valid for a sequence of periods, called terms. The first term is four years (six years for frontier licenses) and covers exploration activities. The license expires automatically at

the end of the first term unless the conditions for entry into the second term are fulfilled. The second term, which covers appraisal and development activities, is four years for production licenses and five years for exploration and development licenses. The third term is 18 years for production licenses and 20 years for exploration and development licenses, and covers production activities. Completion of the agreed exploration work program by the end of the first term and the relinquishment of at least 50 percent of the original license area are preconditions for entry into the second term, and approval of a development plan by the end of the second term is a precondition for entry into the third term.

In the 1990s the government launched the fallow blocks initiative. Its objective was to encourage licensees who have not been actively exploring or developing the areas under license from previous licensing rounds, to bring forward plans to either explore or develop or surrender their licenses. According to assessments carried out by the regulator, the initiative has proven generally successful.[8]

The fiscal regime applicable to oil and gas exploration and extraction has undergone significant changes over time. The current regime consists of a ring-fence corporation tax,[9] a supplementary charge,[10] and a petroleum revenue tax.[11] A ring-fence expenditure supplement applies in special circumstances.[12] The marginal tax rate on new fields is 50 percent, while the marginal tax rate on fields paying petroleum revenue tax is 75 percent.

Licensing history

The United Kingdom has a long licensing history. The introduction of the licensing regime was triggered by the fuel demands of the First World War. But the first onshore license was only issued in 1935. Offshore licensing began with the North Sea boom of the 1960s. The Ministry of Power issued the first offshore license in 1964, and by 2007 its successor, the Department of Trade and Industry, had issued approximately 1,500 licenses.

The average up-take rate for the period 1964–2007 was 43 percent, and the award rate (that is, the percentage of applications that received the regulator's approval) was 91 percent. While publicly available data do not permit an assessment of the quality of the proposed work program, the relatively high award rate would seem to indicate that work program proposals and the technical and financial capability of the applicants were considered adequate by the regulator in the vast majority of cases.[13]

In addition to work program bidding, a relatively small number of blocks have been awarded on a cash bonus basis (4th, 8th, and 9th licensing rounds). These blocks were in relatively mature areas where lower-risk and better exploration prospects were expected to command a premium. Also, a few blocks were awarded on a flat-fee basis (7th licensing round). The up-take rate for cash bonus blocks were much higher than work program blocks, possibly reflecting the relative attractiveness of the blocks. But compared to work program blocks, the number of bidders per block was relatively low—two to three bidders per block on average—raising concerns about the competitiveness of the auction. There was no clear difference in the size and frequency of discoveries between auction and work program blocks (Frewer, 2003).

In 2003 the government introduced the "promote" license to encourage small companies with knowledge and expertise but limited funding, to enter blocks on a

shorter term than the exploration license basis, for a reduced initial fee. Analysis carried out by the government in 2006 with respect to the 54 promote licenses awarded in 2003 found that 24 licenses (44 percent) had been given approval to continue into the next phase of the license. The promote initiative was found to have secured an additional £90 million (US$157 million) for further exploration of the UKCS (Whaley, 2006).

General observations

The current licensing policy is premised on the assumption that work program bidding yields better quality bids than other methods. In addition, unlike cash bonus auctions, it does not divert significant sums of money away from exploration work, and it gives a much better expectation that a license will be awarded to the bid that promises to optimize the exploitation of the country's petroleum resources.[14]

According to some (Fraser, 1991; Kretzer, 1993), the ranking of petroleum projects by work programs does not necessarily reflect the ranking by expected profitability and is likely to lead to over-capitalization (or under-capitalization), depending on the level of competition and the cost-price ratio—that is, low cost-price ratios encourage bidders to increase the size of the proposed work programs above the optimum levels in an effort to win the award. The effect is emphasized by high levels of competition. It follows that work program bidding results in increased per unit costs in resource extraction. Furthermore, because companies' exploration budgets are limited, a system of allocation that ties up scarce capital in over-sized work programs limits the total number of blocks that can be explored at any given time.

The UKCS is generally considered a mature basin. But a wide range of opportunities for exploration and development activities still exist. Many of these opportunities are likely to be small to medium in size. The challenges and risks presented by these opportunities are sometimes considerable.[15] Because companies have generally limited exploration budgets, they tend to focus their resources on core areas or on plays of sufficient value to make a substantial impact on their business. As discussed in the case of Australia, market segmentation—the extent to which different companies specialize in different types of exploration activities and tolerate different risk levels—is of great relevance to the design of efficient licensing systems. In the United Kingdom, while work program bidding remains the key allocation methods, the type of licenses (and related work program requirements) have been adjusted to take into consideration both the geological risk of specific areas and the applicants' technical and financial competence. According to the regulator, the licensing system has been generally successful in achieving the government's policy objective. However, the amount of data in the public domain is not sufficiently detailed to assess whether the licensing system encouraged applicants to propose oversized work programs, and whether the recently introduced flexibility in licensing terms (traditional, promote, and frontier licenses) has contributed to more efficient and thorough exploration and exploitation. Given the policy relevance of these issues for the United Kingdom and other producing countries with similar geological and market conditions, more research is warranted.

Finally, while the "promote" and frontier initiatives might well have encouraged further investment in exploration, they also raise some important questions about the

sustainability of the related exploration investment. Most of the new entrants that have been so successfully attracted by the new licensing system are small- to medium-size companies. The relatively small size of commercial discoveries,[16] the aging North Sea infrastructure,[17] and rising development costs are likely to affect these companies' ability to raise funding adequate to develop the "promote" blocks, and may make them more susceptible to variations in oil prices. The current financial crisis may contribute to exposing these vulnerabilities.

Notes

[1] There is a long history of licensing in the U.K. The licensing regime was created under the impetus of the fuel demands of the First World War. But the first onshore license was issued only in 1935. Offshore licensing began with the North Sea boom of the 1960s. The Ministry of Power issued the first offshore license in 1964, and its successor the Department of Trade and Industry issued the one-thousandth license in 1999.

[2] Before March 5, 2009, the Department for Business, Enterprise and Regulatory Reform (BERR) was the responsible authority.

[3] As set forth in Directive 94/22/EC and implemented by the Hydrocarbons Licensing Directive Regulations 1995. See https://www.og.berr.gov.uk/upstream/licensing/overview.htm for more details.

[4] Out-of-round licenses have been granted for example on grounds of urgency (when a drilling rig may be available within a specific time frame), or when competition for a particular area was not likely (generally because the acreage can only be of interest to a company whose existing license covers adjoining acreage).

[5] If the holder of an exploration license wants to explore acreage covered by a petroleum license, it will need the agreement of the holder of the production license.

[6] The "promote" license was introduced in 2001 to provide small companies with an opportunity to apply for unlicensed blocks and, if successful, evaluate the potential on an exclusive basis for a reduced rental fee. A promote license provides a period of time during which licensees are able to work up potential prospects—primarily using existing data—without the commitment to undertake substantial seismic or drilling at an early stage. If the licensees do not have the resources to support a substantial work program they can sell on to a competent operator (or bring in) partners within the first two years to continue for a further two years for a well to be drilled under the terms of a traditional license. See the BERR's website for details.

[7] The frontier license was introduced in the 22nd round (2004) by the BERR to allow companies to explore large areas with the proviso of a mandatory 75 percent relinquishment at the end of the first term. This is known as the "screening phase" and is conducted within two years. The second term (following relinquishment) lasts for four years, in which time the substantive work program (that is, drilling) is carried out. Further relinquishment is necessary to enter a third term, which lasts for six years. Like the Promote U.K. system, the fees for the first term are only 10 percent of the traditional licenses; however, frontier licenses tend to apply to difficult or unexplored areas, for example, particularly deep waters. See the BERR's website for details.

[8] See the BERR's website for details: https://www.og.berr.gov.uk/.

[9] The ring-fence corporation tax is calculated in the same way as the standard corporation tax, applicable to all companies with the addition of a "ring-fence" and a 100 percent first-year allowance for virtually all capital expenditure (other differences exist for capital allowances and losses). The current rate for non-ring-fence profits is 28 percent, and 30 percent for ring-fence profits.

[10] The supplementary charge was introduced in 2002 and is an additional charge of 20 percent (10 percent prior to January 1, 2006) on a company's ring-fence profits excluding finance costs.

[11] The petroleum revenue tax is a field-based tax charged on profits arising from individual oil fields. The current rate is 50 percent. This tax, which was abolished for all fields given development consent on or after March 16, 1993, is deductible as an expense against corporation tax and the supplementary charge.

[12] Companies that do not yet have any taxable income for corporation tax or the supplementary charge against which to set their exploration, appraisal, and development costs and capital allowances, are granted a ring-fence expenditure supplement. The supplement increases the value of unused expenditure carried forward from one period to the next by a compound 6 percent a year for a maximum of six years. It applies to all unrelieved expenditure from January 1, 2006.

[13] The transparency of the award system has been recently improved. Potential applicants for licenses receive information from the BERR on the "mark scheme" criteria that will be used to assess applications. In addition, the work programs of successful applicants are published, and unsuccessful applicants can request more detailed feedback on the evaluation of their proposals.

[14] See the BERR's website at https://www.og.berr.gov.uk/upstream/licensing/licawards.htm.

[15] For example, complex geology, smaller structural traps, and subtle stratigraphic plays, often coupled with sparse or outdated data.

[16] Commercial discoveries in the North Sea are now much smaller than 30 years ago, the average field being 30 million barrels of oil equivalent, compared with Brent and Forties, whose reserves were estimated at over 2,500 million barrels.

[17] Most new fields are too small to support their own pipelines and production facilities and most will rely on existing installations for their economic development. At the same time, the declining production base of the fields that once supported the development of these installations pushes the license holders to maximize the return on investment on aging infrastructure by limiting further capital investment. This raises the issue of who should bear the cost of improvements.

United States

Licensing policy

The Outer Continental Shelf (OCS) Lands Act requires the Department of the Interior (DOI) to prepare a five-year program that specifies the size, timing, and location of areas to be assessed for federal offshore natural gas and oil leasing.[1] It is the role of the DOI (through the Minerals Management Service, MMS) to ensure that the U.S. government receives fair market value for acreage made available for leasing and that any oil and gas activities conserve resources, operate safely, and take maximum steps to protect the environment.

The federal government's stated policy objective is the expeditious and orderly development of oil and gas resources, subject to environmental safeguards, in a manner consistent with the maintenance of competition and other national needs, including national interest.[2]

The OCS oil and gas leases are awarded by the Secretary of the Interior to the highest responsible qualified bidder or bidders by competitive bidding, under regulations promulgated in advance. Licensing methods are clearly defined in the OCS Lands Act and include a cash bonus bid combined with a fixed or variable royalty and/or a fixed net profit share determined by the Secretary of the Interior, or variable royalty bid and a fixed work program determined by the Secretary of Interior, or a work program bid and a fixed cash bonus and fixed royalty determined by the Secretary of the Interior, or a net profit share bid and a fixed cash bonus determined by the Secretary of the Interior. Table A.1 summarizes the combination of biddable and non-biddable parameters allowed by law. The Secretary of the Interior can, however, propose other systems of bid variables, terms, and conditions as appropriate to achieve the policy objective, except that no such bidding system or modification shall have more than one bid variable.[3]

Table A.1. Alternative Bid Design

	NON BIDDABLE PARAMETERS					
BIDDABLE PARAMETER	Fixed Cash Bonus	Fixed work commitment for exploration in $ value	Fixed Royalty	Sliding scale royalty	Royalty suspension	Fixed Net Profit Share (no less than 30 percent of production)
Cash Bonus			X			
				X		
						X
			X			X
			X		X	
Exploration work commitment	X					
	X		X			
Variable royalty		X				
	X					
Net Profit Share	X					

Source: Author.

The OCS oil and gas lease sales are currently held on an area-wide basis with annual sales in the Central and Western Gulf of Mexico (GoM) with less frequent sales held in the Eastern GoM and offshore Alaska. Prior to 1983, oil companies were called upon to nominate tracts in the OCS region that they would be interested in bidding for ("tract nomination"). The government would then study the nominated tracts and determine whether to offer them for sale. Since the start of the area-wide leasing, fewer tracts are evaluated prior to a lease sale and many more tracts are offered for sale at any given lease sale.

Leases are granted for an initial period of five years (or up to ten years in special cases defined in the OCS Lands Act), and entitle the lessee to explore, develop, and produce the oil and gas contained within the lease area, conditioned upon due diligence requirements and the approval of the development and production plan required under the OCS Lands Act. If a discovery is made within the initial period of the lease, the lease is extended for as long as oil and/or natural gas is produced in paying quantities or approved drilling operations are conducted. Leases are granted on a competitive basis unless the Secretary determines, after public notice of a proposed lease, that there is no competitive interest.

After adoption of a five-year leasing program, the usual first step in the sale process for an individual area is to publish simultaneously in the federal register a call for information and nominations[4] and a notice of intent to prepare an environmental impact assessment. Once comments are received, and the environmental impact assessment is completed, the area for lease is selected and a final notice of lease sale is issued. The entire process—from the call and notice to the sale—may take two or more years (MMS, 2006).

Sealed bids submitted by qualified bidders are publicly opened and read. The federal government reserves the right to reject any and all bids, and to withdraw any block from the sale. Each high bid is first examined for technical and legal adequacy.[5] Each valid high bid is then analyzed from a fair market value perspective.[6]

Revenues from the OCS leasing consist of bonuses,[7] royalties[8] or profit shares, and rentals.[9] A portion of the rentals are deposited in an offset account that contributes to the funding of the MMS activities. The bonuses, royalties or profit shares, and the remainder of the rentals are deposited in the U.S. Treasury. Additionally, the OCS leases are subject to federal income tax laws.[10] Licenses are not ring-fenced.

Licensing history

In 1954 the first offshore oil and natural gas lease sale was held by the federal government. As of March 2008, 206 lease sales have taken place (85 percent of which were tracts in the GoM), and a total 27,704 tracts, averaging approximately 5,000 acres (20 square kilometers), have been leased.[11] The bidding process has mostly been organized as cash bonus bidding with a fixed royalty. Two types of leases exist:

- Confirmed or wildcat tracts refer to areas whose geology is not well known and where no wells have been drilled; and
- Drainage or development tracts refer to areas that contain known oil and gas deposits. Developmental leases are often reofferings of previously sold tracts with leases that were relinquished because no exploratory drilling was done,

or reofferings of tracts where previous bids were rejected by the MMS as inadequate. Drainage leases are usually more valuable than developmental leases and information asymmetries are more acute (Porter, 1995).

In 1978 the U.S. Congress passed an amendment of the OCS Land Act requiring that at least 20 percent and at most 60 percent of the acreage be offered using leasing systems other than the cash bonus bidding with fixed royalty.[12] The legislation, which expired in 1983, aimed to favor small companies whose entry in the market and participation in the auctions might have been deterred by the high bonuses offered by larger companies (Rockwood, 1983).

Since 1975 the MMS publishes—normally every six months—restricted bidders' lists that contain the names of companies barred from submitting joint bids for the following six months or until the publication of a new list. The list is intended to inhibit collusion and promote competition.

The maximum size of a tract is 5,760 acres, unless the Secretary of the Interior finds that a larger area is necessary to comprise a reasonable economic production unit. The average number of tracts awarded per sale increased from approximately 300 to more than 5,000 when the licensing process changed from nominations to area wide in 1983 (Iledare, Pulsipher, Olatubi, and Mesyanzhinov, 2004).

A detailed database of all lease sales is available on the MMS website. Public disclosure of lease-related data includes complete bidding information, bidding companies, tract characteristics, and whether oil and gas production occurred before the end of the exploration period.

General observations

The economic efficiency of the U.S. OCS licensing system (cash bonus bidding) has been the object of several studies. Most of the literature produced between the mid-seventies and early nineties focused on the comparison of alternative methods for licensing oil and gas rights with the aim to determine which method was more likely to ensure the efficient allocation of petroleum rights and the maximization of the rent.[13] These studies came to the overall conclusion that the cash bonus bidding system in the U.S. OCS provides outcomes that are closer than alternative systems to profit maximizing behavior *under competitive market conditions*.[14]

More recently, the MMS carried out a study of the performance of the licensing system and its adequacy to changed prospectivity and market conditions (MMS, 2007). The study confirmed the findings of earlier research with respect to the changing structure of the market, with a much larger influx of new players than there was two decades ago, and a larger share of the leases controlled by firms that are not in the top 20 (see also Iledare and Pulsipher, 2006). The study further noted a declining pattern in lease development productivity over time, and with firm size from big to small. Furthermore, the study found that aggregate economic performance, measured in terms of profitability index and internal rates of return, was relatively low during the period 1983–99 in comparison to returns in the manufacturing sector during the same period.

The average high cash bonus has been declining since the introduction of the area-wide policy. A recent study on the determinants of cash bonuses[15] over the period

1983–99 observed that: (a) the mean value of high bids increases as competition increases; (b) large firms tend to offer more than the average high bid value for leases that they win; (c) deepwater leases command higher cash bonuses than leases on the shelf, probably because of larger discoveries and higher success ratios observed in deepwater; and (d) there was no evidence of market concentration. Overall, although the average number of bids per lease for competitive leases decreased over time[16] and competitive leases accounted for approximately 50 percent of total leases,[17] the study concluded that the area-wide leasing program does not seem to have affected the effectiveness of the cash bonus system in the U.S. OCS.[18]

Finally, a recent study of joint bidding restrictions policies suggests that the imposition of restrictions on some E&P firms may have reduced bidding effectiveness for petroleum leases in the OCS (Iledare and Pulsipher, 2006). Joint bidding did not seem to indicate anti-competitive behavior, and was found to be consistently associated with higher average high bids. Similar conclusions were reached in earlier studies. The data suggests that joint bidding is used to spread the risk associated with higher bonus bids for better quality tracts, and to facilitate entry, especially by smaller firms (see, for example, Leland, 1978; Moody and Kruvant, 1988; and Mead, 1994).

Overall, most of the currently existing empirical studies indicate that cash bonus bidding has worked reasonably well in the U.S. OCS in terms of rent capturing, avoiding collusion, promoting exploration, and attracting new investors. The U.S. experience is particularly useful in highlighting the circumstances in which cash bonus bidding may not work well, such as in cases of:

- Few bidders
- Market concentration
- Entry barriers for small firms
- Restrictions on joint bidding
- Information asymmetries
- Risk aversion leading to low bids
- Budget constraints

Political risk and a history of lacking government commitment to apply the terms established at allocation may also be relevant for some countries. It is worth noting that even in the United States, cash bonus bidding is not relied upon as the sole or principal source of rent extraction.

Notes

[1] The criteria to be followed by the Secretary of the Interior are set out in the OCS Land Act.

[2] OCS Lands Act, section c 1332 (3).

[3] OCS Lands Act, section 1337 (a) (1) (I).

[4] The call serves several functions: (i) it informs the public of the area under consideration for oil and natural gas leasing; (ii) it solicits comments from all interested parties on areas or subjects that should receive special attention and analysis; (iii) it invites potential bidders to indicate areas and levels of interest; (iv) it invites public input regarding possible advantages and

disadvantages of potential oil and natural gas leasing, exploration, and development to the region and the nation.

[5] Legal bids are those that comply with MMS regulations (30 CFR 256) and the notice of sale, for example, equal or exceed the specified minimum bid.

[6] Basically, high bids are compared with the MMS' estimate of resource economic values. Additionally, the MMS may take into account the number and value of other lower bids from the same sale and on the same tract in its evaluation of the high bid. A detailed description of the fair market value criterion can be found in Federal Register/Vol. 64, No. 132/Monday, July 12, 1999/Notices.

[7] Each high bid submitted must include payment of one-fifth of the bonus, bid by a deadline set forth on the day after bid opening. The remaining four-fifths of the bonus bid and the first year's annual rental for the lease must be paid within a set time from receipt of the lease.

[8] Royalty rates vary between 12.5 and 20 percent in state waters (within 300 miles from the watermark). Tracts located on the continental shelf pay 16.7 percent royalty rate, while deepwater blocks pay 12.5 percent. Royalty relief may apply from 200 meter water depth and above, depending on the volume of production and subject to price thresholds defined by law (Royalty Relief Act 1995). In 2007 royalty rates for new deepwater blocks awarded after July 2007 was increased to 16.67 percent. In 2008 the royalty rates for all new leases—regardless of water depth—was increased to 18.75 percent (Federal Register, 2008).

[9] Rentals are paid annually until the lease is surrendered or production begins.

[10] The current federal income tax rate is 35 percent.

[11] Sale 206 collected the largest total amount of high bids in U.S. offshore licensing history. The sale took $3.67 billion in apparent high bids, besting the previous all-time peak total of $3.47 billion set in 1983. The sale's largest offer was $105 million made by Anadarko Petroleum, Murphy Oil, and Samson Offshore for Green Canyon Block 432. The lowest of the top-ten high bids was Statoil Hydro's $68.5 million. Overall 1,057 bids across 615 tracts were made. Deepwater clearly dominated Sale 206, capturing all of the top-ten highest bids and accounting for the most fiercely contested blocks that attracted six or more offers each; two deepwater tracts each received 10 bids. Deep gas prospects in shallow water also attracted more multimillion-dollar bids than previous shallow-water sales, thanks to the handful of discoveries made in recent years (Platts, 2008). Soaring oil price levels, recent exploration successes, and the government's emphasis on security of supply played a key role in companies' bidding strategies.

[12] During the years 1980–83 the MMS experimented with four alternative bidding systems. The first was a cash bonus bid with a sliding scale royalty. Under this scheme, firms bid a cash bonus but the royalty rate varies, depending on the rate of production. As production increases, the royalty rate rises from the conventional 16.67 percent to various levels, depending on which version of this bidding system was used in a given sale. The maximum royalty rate ranged from 50 to 65 percent of the value of production. With higher royalty rates, bonus bids can be expected to be lower, and more firms might participate. The second alternative used a cash bonus bid with a fixed net profit share. The bonus bid determines the winner of the lease, but the firm agrees to pay the government a fraction of net profits received on production instead of a royalty. The firm first recovers its capital costs at an agreed upon rate and then splits the operating profits (oil and gas revenues minus operating costs) with the government at fixed profit share rates ranging from 30 to 50 percent. Finally, the government experimented with two variants of the cash bonus bid system in which the royalty rates were set at 12.5 percent and 33 percent as opposed to the traditional 16.67 percent (Moody, 1994).

[13] Hughart (1975) found that the allocation to the highest bidder is not optimal when one bidder has superior information; Reece (1978) found that the value of the bids decreases as the number of competitors decreases and the uncertainty about the value of the tracts increases; Ramsey

(1980) suggested that the government should limit the number of licenses issued when the number of bidders is less than three or four as lack of competition would reduce government revenue; Gilley and Karels (1981) found that the number of individual bids decreases as the number of bidders increases; Mead, Moseidjord, and Sorenson (1984) found that drainage leases earn a higher after-tax internal rate of return than wildcat leases, and concluded that there are gains from superior information; Porter (1995) concluded that bidding on wildcats was relatively competitive, and the government probably captured a reasonable share of the rents; Mead, Moseidjord, and Sorenson (1984) and Mead (1994) concluded that a pure bonus bidding system approximates an optimal system, given the objectives of maximizing and collecting the NPV of the economic rent. However, policy changes were recommended to improve the U.S, bonus bidding system—that is, by eliminating the fixed royalty rate to avoid early abandonment of the fields, eliminating the five-year rule for drilling, avoiding regulations that do not pass the cost-benefit test, and eliminating restrictions against the entry of foreign companies.

[14] "A variety of considerations conspire to make the actual environment diverge from the perfect market paradigm" (Leland, 1978).

[15] Cash bonuses are affected by various factors, including the number of bidders, the perceived prospectivity of the lease, the size of the bidding firms, the bidding method (joint or solo), and the bidding structure (multiple or single bids).

[16] The average number of bids per lease was 2.70 in the period 1983–99, down from 3.56 bids per lease in the period 1954–73, and 2.96 bids per lease in the period 1973–77.

[17] This percentage has recently declined to about 30 percent of total bids (Central GoM, Sale 198, MMS, 2006).

[18] Iledare, Pulsipher, Olatubi and Mesyanzhinov, 2004. It is worth noting that the econometric model developed by the authors captures some of the important determining factors affecting high bonus bids (the model explains approximately 34 percent of the expected variation in the relative value of high bonus bids).

Brazil

Licensing policy

The development of hydrocarbons in Brazil is governed by the Petroleum Law Number 9478, August 6, 1997 (PL/97).[1] The federal government owns the petroleum, natural gas, and other fluid hydrocarbon accumulations existing in the national territory, which includes the onshore area, the territorial waters, the continental shelf, and the exclusive economic zone. But the Agencia Nacional do Petroleo (ANP) is the authority responsible for granting E&P rights through competitive licensing rounds, and monitoring contract implementation.[2]

The policy objectives of the Brazilian government are: (a) to encourage the E&P of the country's petroleum resources in order to maintain self-sufficiency with respect to oil production and to reduce natural gas imports, and (b) to increase the contribution of the sector to local economic development (ANP, 2007).

Petroleum E&P activities are carried out under concession agreements, which are the only form of agreement allowed by law.[3] The concessionaire undertakes the risk of exploration and, if successful, is the sole owner of the production at the point of measurement, subject to the payment of relevant taxes and fees. The exploration period varies between three and ten years depending on the block, and is divided into two or three sub-periods.[4] The minimum work program, corresponding financial guarantees, and relinquishment obligations for each sub-period are detailed in annexes to the relevant concession agreements. If a discovery is considered commercial, the company must submit a development plan to the ANP for approval, specifying forecast work and outlays that will be necessary before starting production. The duration of the production period is 27 years, renewable on conditions determined by the ANP. The most recent version of model concession agreement is published on the regulator's website.

Concessions are granted through competitive bidding processes—multi-object sealed-bid auctions—to companies that comply with the technical, economic, and legal requirements defined by the ANP. Law Nr. 11097/2005 and subsequent implementing regulations set forth clear guidelines for the design and management of bidding rounds, including prior disclosure of the contractual and fiscal terms applicable to the blocks on offer, the criteria to be followed for the evaluation of the technical and financial capacity and legal status of the bidders, and the criteria for bid evaluation.[5]

The key elements of the fiscal regime are defined in PL/97 and decree Nr.2705/98. They include:

- *Cash bonus*. This is a biddable term in licensing rounds. But the ANP defines the minimum cash bonus per type and location of blocks.
- *Ten percent royalty* on oil and natural gas production, to be paid monthly, in local currency, as from the start of commercial production of each field. The royalty rate may be reduced by the ANP to a minimum of 5 percent depending on technical and financial considerations. The applicable rate is specified in the relevant bidding documents.

- *Landowner's participation*. This varies from 0.5 to 1 percent and is applied to oil and natural gas production according to criteria established by the ANP.
- *Special petroleum tax or special participation*. This is calculated on the gross margin from production at field level, after the deduction of royalties, exploration investments, operational costs, depreciation, and taxes. The special participation is levied in case of high production levels or high profitability and can reach a maximum 40 percent.
- *Corporate tax, state and municipal taxes, and social contribution*, in accordance with the relevant tax legislation.
- *Surface fees*. Calculated with respect to the area under concession and expressed in fee per square kilometer. Higher fees apply during the production phase.

The cash bonus is a biddable parameter (together with the minimum exploration work program and the local content). All other parameters of the fiscal regime, as well as the other terms of the model concession agreement, are fixed.

Licensing history

The promulgation of PL/87 ended the state's monopoly over oil and gas activities. Although Petróleo Brasileiro (Petrobras) was not privatized, the company had to compete with all other players in the market. Under the new law, Petrobras was granted rights to all oil and gas fields producing at that time, as well as blocks where it had made commercial discoveries or significant exploration investments. In 1998 Petrobras signed licensing contracts for 115 exploration blocks and 282 fields in development or production. At the time of conversion, the area licensed to Petrobras covered approximately 7 percent of the country's total sedimentary basins with petroleum potential. The remaining areas were returned to the ANP for offer in future competitive licensing rounds.

The first licensing round was held in 1999. Since then the ANP has designed and managed ten licensing rounds. The organization of licensing rounds involves a number of steps, including:

- Definition of the blocks to be offered
- Public announcement of the round
- Publication of the model concession agreement
- Public hearings
- Information sessions on technical and environmental issues
- Information sessions on fiscal terms
- Companies' expressions of interest
- Collection of participation fees
- Access to data packages
- Companies' qualification process
- Evaluation of the bids and the announcement of awards
- Signature of concession agreements

Licensing rounds are held every year. The announcements specify whether companies are allowed to submit their proposal individually or jointly. Bidding parameters are established by the ANP for each licensing round. Cash bonus and local content were the only bidding parameters for the first four licensing rounds. From the fifth licensing round onwards, in addition to cash bonus and local content, companies bid the minimum exploration work program commitment.

The evaluation criteria are determined by the ANP, and have evolved over time in response to the government's policy objective. The law mandates the ANP to take into consideration minimum work programs and bonuses in evaluating the bids. In case of a tie, the ANP shall allocate the relevant block to Petrobras provided it is not bidding in consortium with other enterprises. While cash bonuses were the key determinants in the first four licensing rounds (85 percent weight), local content became more relevant in the fifth licensing round (40 percent weight, while cash bonus and work program were each assigned 30 percent weight). The bid evaluation criteria used in the most recent licensing rounds assign a 40 percent weight to each cash bonus and work program, and a 20 percent weight to local content (itself broken down between E&P phases).[6] In addition, the ANP establishes the minimum cash bonus and minimum local content per type of block and location.

The first licensing round in 1999 marked the end of the state's monopoly over petroleum E&P activities. The opening of the sector to private companies attracted the interest of oil majors and some large independents. From the second licensing round—which specifically targeted marginal accumulations—onwards, large independents and Brazilian companies started to play a more relevant role. In order to support the development of local enterprises, as well as to intensify competition, the third licensing round included blocks in ultra-deep waters and onshore mature areas. The block size was reduced according to estimated exploratory risk. The fourth round occurred during an economic downturn, which explains the relative low market uptake. The fifth licensing round saw the introduction of important changes in the licensing system:

- Geological basins were divided in sectors, and block sizes were redefined according to their location (the average size of blocks located in onshore mature basins became 30 square kilometers; the average size of offshore blocks was 180 square kilometers for water depth below 400 meters; and 720 square kilometers for water depth above 400 meters);
- The minimum exploration work program became a bidding parameter; and
- The criteria for evaluation of bids were amended, giving an equal weight to cash bonuses and minimum work programs, and increasing the weight of local content from 15 to 40 percent.

The round elicited a rather low level of participation and competition, perhaps in part due to the uncertainty about the impact of the change in rules. The licensing procedure was further refined in round six, providing a more targeted offer in line with the priorities of Brazil's sector policy (that is, support the participation of small enterprises, encourage exploration in new frontiers, and increase investment in high-potential areas in order to reach self-sufficiency in oil production). The seventh

licensing round was structured around two licensing concepts: intensify exploration in the most promising geological basins and provide investment opportunities for small enterprises in inactive areas with marginal petroleum accumulations. Bidding parameters were established accordingly. The round was quite successful, attracting a large number of small and medium enterprises interested in acquiring low-risk acreage as an entry into Brazil's petroleum sector. The rising level of oil prices, coupled with the perceived high prospectivity of the acreage on offer, saw a rebound in participation of the oil majors and large independents. The eight licensing round was suspended on its first day through the intervention of the judiciary, on alleged violation of free market principles by the ANP in establishing a limit on the maximum number of winning bids that each company could have in some of the basins on offer. The ANP's policy aimed to limit the market power of large and medium-size oil companies in order to create more competition. The move was, however, challenged by a group of companies on the grounds that it distorted competition and was beyond the mandate of the ANP. The judicial award is still pending. The ninth licensing round was affected by the announcement of a giant discovery off the coast of Rio de Janero, the Tupi field. Potential reserves were initially estimated by Petrobras at 5–8 billion barrels of oil equivalent, making it the largest-ever deepwater oilfield discovery. The field is located in the so-called "pre-salt" area, below a thick salt layer and more than 4,000 km below the sea bed, under a series of layers of rock and salt. Until then, Brazil's reserves had been found in post-salt formations—above the salt layer. This opened the possibility that similar formations might be found in the Santos basin. This prompted the ANP to withdraw 41 blocks from the licensing round. In fact, given the size of potential discoveries, the existing licensing terms were considered inadequate to provide the government with a fair share of revenue. Furthermore, the government felt that a different form of contract, namely a PSC, and the creation of a new national oil company, would have granted more control to the government over the development of these strategic reserves. The record signature bonuses of the ninth licensing round reflected in large part the high level of oil prices and rising expectations going forward. This was not, however, the bidding strategy of the only two oil majors that participated in this round (Petrobras and Statoil Hydro).[7] Awaiting a policy decision with respect to the licensing conditions of offshore acreage, the tenth licensing round included a combination of new frontier and mature areas (4.2 percent of the total area on offer) in seven onshore basins, most of which—with the exception of the Paraná basin—attracted multiple offers. Companies' bidding strategies was more prudent (that is, generally focusing on work programs more than cash bonuses), likely reflecting downward expectations in oil prices, and the risk profile of the blocks. With the exception of Petrobras, large oil companies were not very active in this round, possibly awaiting more attractive future bidding rounds for offshore acreage. Table A.2 provides an overview of the results of the licensing rounds held to date.

Table A.2. Overview of Brazil's Licensing Rounds

Licensing Rounds	Round 1	Round 2	Round 3	Round 4	Round 5	Round 6	Round 7	Round 8	Round 9	Round 10
	1999	2000	2001	2002	2003	2004	2005*	2006	2007	2008***
Bidding basins	8	9	12	18	9	12	14		9	7
Total Blocks on offer	27	23	53	54	908	913	1,134		271	130
Blocks awarded	12	21	34	21	101	154	240		109	54
Percentage award/offer	44.4%	91.3%	64.2%	38.9%	11.1%	16.9%	21.2%	S	40.2%	41.5%
Total area on offer (sq. km)	132,178	59,271	89,823	144,106	162,392	202,739	397,600	U	73,079	70,000
Total awarded area (sq. km.)	54,660	48,074	48,629	25,289	21,951	39,657	171,007		45,370	48,154
of which onshore:	-	*10,227*	*2,363*	*10,620*	*697*	*2,846*	*163,272*	S	*31,951*	*48,154*
Percentage area awarded	41.4%	81.1%	54.1%	17.5%	13.5%	19.6%	43.0%		68.8%	68.8%
Qualified companies	38	42	42	29	11	24	44	P	62	40
Bidding companies	14	27	26	17	6	21	30		42	23
Successful companies	11	16	22	14	6	19	41	E	36	17
Number of bids	21	75	57	33	107	186	381	N	n/a	92
Avg block size (sq. km)	4,895	2,577	1,695	2,669	179	222	351		270	538
Avg winnind Bid (R$M/sq. km.)	5.88	9.74	12.23	3.65	17.81	68.39	16.28	D	75.88	14.55
High bonus bid (R$Million)	134.16	116.28	117.74	15.15	7.92	82.30	160.18		344.09	13.64
Total bonus bids (R$Million)	321.66	468.26	594.94	92.38	27.45	665.20	1,085.80	E	2,109.41	89.41
Total minimum work commitment (R$Million) **					363.50	2,046.78	1,697.96		1,333.18	611.15
Avgerage local content:								D		
- Exploration phase	25.0%	42.0%	28.0%	39.0%	79.0%	86.0%	74.0%		69.0%	79.0%
- Development and production phase	27.0%	48.0%	40.0%	54.0%	86.0%	89.0%	81.0%		77.0%	84.0%

Source: ANP web-site.

Notes: ** Exploration blocks only*

*** Refers to values after contract signature*

**** Average local content estimated by the authors.*

General observations

Since the opening of the petroleum sector to private companies, the investment in petroleum exploration and development activities has substantially increased. This has arguably fast-tracked the achievement of Brazil's self-sufficiency goal with respect to oil production. In addition, the ANP's active and dynamic regulatory policy has played an important role in: (a) supporting competition; (b) removing barriers to the participation of small and medium-size companies; (c) encouraging the development of a strong national oil service sector; and (d) improving the transparency and predictability of regulatory intervention.

The procedure designed by the ANP to determine the financial, technical, and legal qualifications of companies interested in participating in licensing rounds deserves special mention. In addition to the usual methodology for assessing companies' track record, the ANP has defined specific accreditation criteria for operators according to the degree of difficulty of the area to be licensed, thus allowing the participation of different type of companies as well as financial participation as non-operators.[8] Tax incentives[9] and the progressive harmonization of federal, municipal, and state taxation have also contributed to improve investment environment and reduce the cost of operations. This is particularly important in blocks situated in ultra-deep water or for challenging geological structures.

The introduction of area nomination and the reduction of block sizes increased competition and affected companies' bidding strategies. In particular, an analysis of companies' behavior in the past bidding rounds highlights the tendency of oil majors and strong consortia to bid high, although with focus on work programs rather than cash bonuses, and to bid for contiguous acreage. Small companies tend to bid low and spread their bids widely. Oil majors, including Petrobras, tend to bid solo, and very often win. Companies' accreditation criteria and minimum licensing terms established by the ANP clearly reflect and affect the diversity of market participants and their strategies.

Bids are submitted online. This reduces the ANP's administrative workload, as well as the possibility of bid evaluation errors. Bidding parameters and evaluation criteria are defined and disclosed by the ANP ahead of each licensing round. Regulations and predetermined procedures ensure objectivity in bid evaluations.

The de-monopolization of the petroleum sector has allowed the country to accelerate the exploration and development of its petroleum resources while still maintaining firm control of the sector through the regulation and direct participation of the national oil company. Petrobras' extensive knowledge of and operating experience in Brazil's petroleum basins allows it to remain the largest individual holder of concessions, and to maintain a majority interest in most other concessions. The eighth licensing round aimed to reduce Petrobras' market advantage by limiting the number of concessions that could be awarded to the same operator in specific basins. If allowed by the judiciary, this would provide the ANP with further tools to control the structure of the market and the transfer of technology and knowledge among market participants, thus reducing the asymmetry of information. This will ultimately result in stronger competition and improve the efficiency of the licensing system in maximizing the NPV of the rent at the time of award. Improvements to the fiscal system may also be warranted, not only on account of the latest discoveries, but

also to improve its flexibility and adaptability to varying operational and market conditions.

The ANP's policy aimed at improving the knowledge of Brazil's hydrocarbon potential by introducing regulatory changes that favored the acquisition of seismic data by service companies on a risk basis also served to reduce the perception of risk and information asymmetries among bidders. As a result, Brazil has one of the most extensive geophysical, geological, and petrophysical data banks in the world, which constitutes a valuable national patrimony.

Finally, Brazil's main challenge is likely to arise from its most recent opportunities. The Tupi discovery was followed by other large finds in the Santos basin. In December 2007, Petrobras announced an even bigger discovery—the Sugar Loaf field—followed by a large natural gas discovery, Jupiter, in January 2008. Following these discoveries, preliminary ANP estimates put the size of potential reserves in the Santos basin at 80 billion of oil equivalent. Production estimates for Tupi alone would increase current oil output by 1 million b/d from current averages of around 1.9 million b/d. Technical and financial challenges affect the development of these pre-salt areas which, if commercially viable, will put Brazil among the world's largest producers and exporters of oil, and are likely to affect the demand/supply balance.[10]

The relevance of these discoveries has triggered ample debate in Brazil, and prompted the government to set up a task force to propose amendments to the current licensing policy. The task force is exploring alternative taxation options for companies operating in sub-salt areas,[11] as well as changes in the form of agreement. The outcome, some argue, may affect the way private companies are allowed to participate in the sector, that is, the level of future openness, transparency, and efficiency of the sector. The jury is still out. The current sharp economic downturn[12] may affect the development of these discoveries, as well as the type of regulatory changes that may be put forward by the task force.

Notes

[1] Until 1995 petroleum activities were a state monopoly. Constitutional Amendment Number 9/1995 relaxed the restrictions against private participation in the oil and gas sector, and paved the way for PL/97.

[2] PL/97 created the Agencia Nacional do Petroleo (ANP) to regulate the oil and gas sector, and the Conselho Nacional de Política Energética (CNPE) to assist and advise the president and the minister of mines and energy in the development of Brazil's national energy policy.

[3] Petroleum activities shall be regulated and inspected by the federal government and may be carried out, through concession or authorization, by enterprises established under Brazilian laws, having their headquarters and administration in Brazil (PL/87).

[4] The PL/87 sets no upper limit. The most common arrangement is 3+2+2. The concession expires if at the end of the exploration period no commercial discovery has been made. Relinquishment obligations are specified in the concession agreement. However, the concessionaire has the option to relinquish all or part of the area covered by the concession ahead of its natural term.

[5] Different criteria are established for onshore blocks, shallow water blocks, and deepwater blocks.

[6] The seventh licensing round established different criteria for marginal fields: cash bonuses and minimum work obligations were the only bidding parameters, with 25 percent and 75 percent

weight, respectively. The policy was intended to provide incentives to explore and develop these fields by reducing costs and providing more operational flexibility to the investors.

[7] Shell Oil and ENI, frequent players in Brazil's bidding rounds, did not participate.

[8] Similar but less sophisticated methods are used in other producing countries.

[9] For example, the extension to 2020 of the reduction in import and production tax that was introduced during the fourth licensing round.

[10] The stability of the salt layers, once drilled, and the change in temperature while oil travels to the surface from a depth of over 4,000 meters are among the cited technical difficulties. Associated development costs are estimated at some order of magnitude above the current average ultra-deep water developments.

[11] Petrobras, British Gas, Shell, Exxon, Amerada Hess, Repsol, and Galp currently hold petroleum rights in sub-salt areas. The group includes three of a handful of companies worldwide that have the technical capacity to carry out difficult deep-water developments.

[12] The tightness of the financial market is likely to hinder investment, and the expectation of substantially lower oil prices changes the economics of the development compared to the forecast at the time of discovery.

Mexico

Licensing policy

The ownership of hydrocarbon resources is vested in the nation.[1] Ownership by the nation is inalienable and imprescriptible, and the exploitation, use, or appropriation of hydrocarbons is carried out by the nation, through its national oil company—Petróleos Mexicanos and its subsidiaries ("PEMEX"). No concession or contract can be granted to private companies, even if incorporated in Mexico. PEMEX was created in 1938 following the nationalization of the petroleum industry.

The "Ley reglementaria del articulo 27 constitucional en el ramo del petroleo" (November 29, 1958, as amended) provides for PEMEX to conduct the exploitation, refining, transportation, processing, and distribution of oil, gas, and products (considered as strategic activities by the Constitution). PEMEX has the right to enter into contracts with natural and legal persons, for the provision of services and works that enable it to better perform its activities. However, in accordance with the law, PEMEX's contractors must be paid in cash. In no event can the compensation for such services and works be established in kind (as percentage of products) or as percentage participation in the result of the exploitation.[2]

The state oil company is regulated by the government through a federal agency, the Department of Energy (Secretaría de Energía, or SENER), and its budget is authorized annually by the Department of Finance and Public Credit (Secretaría de Hacienda y Crédito Público, or SHCP). There is another government body established by decree in 1993, the Regulatory Energy Commission (Comisión Reguladora de Energía, CRE), whose scope of influence is vested with powers to regulate the natural gas and power sectors.

Proved oil and gas reserves are estimated at, respectively, 13,774 million barrels and 14,407 billion cubic feet. Currently, approximately 74 percent of oil production comes from offshore, most from a single large oilfield, Cantarell.[3] Production has been steadily declining since 2004. The majority of gas production comes from the northern part of Mexico. Production has been growing—but not enough to keep pace with growing national energy needs.

Faced with growing energy demands, fiscal sustainability concerns, and a very limiting legal framework, the government and PEMEX have been striving to find ways to access the technology and capital necessary to more efficiently exploit known reserves and find new ones.[4]

Licensing of petroleum E&P rights is not permitted by law. To overcome this limitation, PEMEX has used financed public works contracts (FPWCs)—also known as multiple service contracts—to procure the services necessary to carry out natural gas E&P activities. This pseudo-licensing practice has, however, resulted in significant bureaucratic delays and complex management and oversight arrangements. Reforms were launched in 2008 to provide more flexibility to PEMEX and improve the attractiveness of the petroleum sector to foreign investors.

The licensing policy objectives (PEMEX, 2002) with respect to natural gas are to:

- Substantially increase the national production of natural gas as soon as possible to assure the electric generation program's viability;

- Produce more gas at a lower cost than the import cost;
- Attract investments to complement PEMEX's program; and
- Solve the lack of PEMEX's technical personnel required to manage a greater amount of contracts under the current scheme.

Licensing history

There are three types of contracting procedures:

- Public tender is the most common and allows for multiple bids based on strict procedures.
- Invitation is used when products or services are small and a tender would be inefficient (usually three bids are requested).
- Direct award is used when only one source can provide the desired product or service.

All contracts related to oil E&P follow the normal public procurement procedures.[5] FPWCs follow a simplified procurement procedure under the Public Works Law. FPWCs are public works contracts that allow for the consolidation or bundling of services within the same contract. The FPWCs are used by PEMEX to bolster the exploitation of natural gas fields, with the objective of reducing dependence on expensive gas imports from the United States. One of the significant characteristics of this contractual scheme is that the contractor only receives cash payments based upon the fixed prices for the finished works and services rendered, such as seismic processing and interpretation, geological modeling, fields engineering, production engineering, drilling, facility design and construction, facility and well maintenance, and natural gas transportation services. PEMEX maintains ownership at all times of all hydrocarbon reserves discovered and extracted, as well as the entire infrastructure in place. FPWCs have a duration of up to 15 years, depending on the life of the field, and are divided into three sub-periods (development, reactivation, and maximum recovery). Corporate taxes apply at the same rate as other industrial sectors (27 percent since 2007). No ring-fence applies. In addition, dispute resolution can be referred to international arbitration.

Contractors are required to provide training to PEMEX's employees in the technologies that are relevant to the performance of the services. The contract provides for the joint ownership—by PEMEX and the contractor—of any technology that is developed during the contract term.

Three types of work can be carried out under a fee-for-service arrangement:

- Development
- Infrastructure
- Maintenance

The bid process is governed by International Trade Agreements and the Public Works Law, and involves four steps:

- *Call for bids*, published in the Official Gazette and on the Government Procurement Electronic System (compraNET). The tender document includes description of the works, technical evaluation criteria, economic evaluation criteria, criteria for award, technical requirements, and a model contract.
- *Admission and evaluation of proposals*. Technical and economic proposals are submitted by bidders in two separate envelopes. Technical proposals are evaluated and graded. Proposals that do not conform to the requirements are rejected. Results of the evaluation are communicated to the bidders before opening the economic proposals of technically accepted bids. A report is issued on the economic analysis of the proposals, and the date, time, and venue for the bidding final resolution is established.
- *Award and final decision*. The award is made to the proposal that fulfills all requirements and performance obligations. In the case of a tie, the contract will be awarded to the bidder with the lowest price proposal.
- *Contract signature*. This is a public event attended by civil society representatives and public officials of the Secretaría de Contraloría y Desarrollo Administrativo (SECODAM), and results are published.

In July 2003, PEMEX launched the first upstream gas bidding round. Seven blocks were offered for E&P activities, with a prospective acreage of 13,300 square kilometers. Only five were awarded with an expected investment of US$4.3 billion. The bidding process was efficient and transparent. The take-up and market response was, however, hindered by various factors, including the impossibility of booking reserves, the small size of the contracts and the limited potential upsides, changes in the natural gas market that reduced the attractiveness of the pricing formula, the complexity of the contracts, excessive qualification criteria, and heavy bureaucracy.

Lessons learned from the first FPWC round allowed the government to improve the strategy for the second bidding round in 2004. Qualification criteria were established with the objective to increase participation in the bidding round. Terms and conditions were improved to incentivize the execution of the works, and the bureaucratic process was streamlined. Four blocks were offered. The round included acreage in the Burgos Basin that did not receive bids in the first round (Padera-Anahuac and Ricos blocks) and newly available areas in the Sabinas Basin (Pirineo and Monclova blocks). Notwithstanding the improvements in the conditions of contract and administrative process, results from the round were mixed. The Ricos block received no bids, while PEMEX later cancelled a successful bid on the Monclova block (Energy Information Administration, EIA, 2005).

In August 2006, PEMEX launched the third international tender for blocks in the Burgos basin. Two contracts were awarded in 2007 for the Nejo and Monclova blocks. No bids were received for the Euro block. Table A.3 summarizes the results of the three bidding rounds.

Table A.3. Bidding Rounds Summary

Block	Signature date	Contractor	Contract amount (US$ millions)
Reynosa-Monterrey	November 14, 2003	Repsol Exploración México, S.A. de C.V.	$2,437
Cuervito	November 21, 2003	PTD Servicios Múltiples, S. de R.L. de C.V., a consortium comprised by Petróleo Brasileiro, S.A. (Petrobras), Teikoku Oil Co., Ltd. and D&S Petroleum	260
Misión	November 28, 2003	Servicios Múltiples de Burgos, S.A. de C.V., a consortium comprised by Tecpetrol (a subsidiary of Techint Group) and Industrial Perforadora de Campeche, S.A. de C.V.	1,036
Fronterizo	December 8, 2003	PTD Servicios Múltiples, S. de R.L. de C.V., a consortium comprised by Petróleo Brasileiro, S.A. (Petrobras), Teikoku Oil Co., Ltd. and D&S Petroleum	265
Olmos	February 9, 2004	Lewis Energy México, S. de R.L. de C.V.	344
Pandura-Anáhuac	December 9, 2004	Industrial Perforadora de Campeche, S.A. de C.V. and Compañía de Desarrollo y Servicios Petroleros, S.A. de C.V.	900
Pirineo	March 23, 2005	Monclova Pirineo Gas, S. de R.L. de C.V., a consortium comprised by Constructora Industrial Monclova, Materiales la Gloria, Alianz Petroleum, Steel Serv., Suelopetrol, NCT, Estudios y Proyectos and Petrotesting Colombia	645
Nejo	April 3, 2007	Iberoamericana de Hidrocarburos, S. A. de C. V.	911.5
Monclova	April 20, 2007	GPA Energy, S. A. de C. V:	433.5
		Total	**$7,232**

Source: PEMEX Exploration and Production.

As of December 31, 2007, nine contracts had been awarded under the FPWC program, for a total amount of US$7,232 million. During 2007, through the FPWC program, 52 wells were drilled, 55 wells were completed, and 1,392 square kilometers of three-dimensional seismic information was acquired, among other projects. The projects carried out in 2007 represented an investment of approximately US$275 million. At the end of 2007, natural gas production in the nine blocks listed in Table A.3 reached 236 million cubic feet per day.

General observations

FPWC rounds do not involve the licensing of E&P rights. Although the balance of risk and rewards differs from the traditional licensing rounds, most of the considerations that apply to the design of successful work program bidding or auctions are the same. For this reason, Mexico's experience with the FPWCs may be helpful to countries that face similar regulatory and capacity constraints.

Attracting foreign investment into the upstream petroleum industry is a key policy priority for the government. The FPWC was an ingenious solution to allow PEMEX to access capital and technology without ceding the ownership and control of natural gas resources. FPWC were created to address some of PEMEX's key challenges in the development of the countries' large natural gas reserves: (a) limited execution and financing capacity; (b) complex and restrictive legal framework; and (c) limited access to new technology. The attempt was somewhat successful but still inadequate to attract the investment needed to significantly increase exploration and development of the northern gas fields. The attraction of FPWCs has likely been more strategic than

economic, that is, a way for companies to position themselves and build up knowledge of working and operating in Mexico while hoping for future sector openings.[6]

While bidding procedures and awarding criteria were clear and transparent, the complexity of the contract and its rigidity were at odds with the characteristics and the dynamic nature of the activities it was meant to govern. Change orders had to go through complex administrative procedures and several levels of authorization, with clear implications on efficiency and results. The rigidity of the fee for service structure eliminated contractors' incentives for improving performance.[7] The oversight of contract implementation required considerable use of one of PEMEX's most limited resources: project management.

Limited industry participation—that is, limited competition—means that PEMEX may not have minimized the cost of service acquisition. Given PEMEX's severe capacity constraints, however, important savings are likely to have been achieved through improved efficiency, reduced dependence on natural gas imports, and reduced financing needs. Removing the barriers to investment would ultimately consolidate and improve these gains.

Mexico's experience helps to highlight the limitation of licensing policy as a principal instrument for achieving complex policy goals. The reform of the hydrocarbons sector launched by the government in 2008[8] provides for more flexibility in contracting that may help to overcome some of the challenges of the FPWCs.[9]

Notes

[1] Article 27 of the Constitution.

[2] The "Ley Orgánica de petróleos mexicanos y organismos subsidiarios" (July 16, 1992, as amended), establishes five subsidiaries of PEMEX, one per type of activity (see art 3). Strategic activities are those conducted by PEMEX Exploration and Production, PEMEX Refining, and PEMEX Gas and Petrochemicals. Only these companies can conduct strategic activities. These companies are entitled to enter into all kinds of contracts with third parties, provided that they maintain the control and ownership of hydrocarbons, in accordance with existing laws and regulations.

[3] The Cantarell field was discovered in 1976 in the Bay of Campeche. By 2006 the field had produced 11,429 billion barrels of oil, but production levels started to decline in 1995. Production enhancement techniques have been applied to shore up production levels. PEMEX expects production to continue declining until 2012, when it should stabilize at about 500,000 barrels per day (less then one-fourth its peak production); Energy Bulletin, http://www.energybulletin.net/node/1651.

[4] Many industry observers have highlighted PEMEX's sustainability risks. The company has upstream potential in the deepwater GOM but reportedly lacks access to the technology and management skills that are needed to develop the resources. Oil production is declining and gas imports continue to grow. The Mexican government relies on PEMEX to fund approximately 40 percent of its budget, thus leaving the company with insufficient cash flow to support its operations. Debt levels are already extremely high.

[5] Procurement procedures are overseen by the Secretaría de Función Pública (SFP), a department of the Ministry of Public Function responsible for public expenditures, procurement, and management. The processes are governed by the law of Public Works and Related Services (Ley de Obras Publicas y Servicios Relacionados), and the Law of Acquisitions, Leases, and Services of the Public Sector (Ley de Acquisiciones, Arrendamientos y Servicios de Sector Publico).

[6] http://www.woodmacresearch.com/marketing/downloads/Implications_of_MSCs_BN%20Americas_8Jan04.pdf

[7] For example, if the contract contemplates the drilling of 60 wells, the contractor receives payment whether or not the wells produce. The risk lies entirely with PEMEX, but so does the potential reward.

[8] Among the proposed measures, the government is developing a model by which it can attract foreign participation in (i) Mexico's deepwater exploration, (ii) the technically difficult Chicontepec field complex, and (iii) the Southeast Basins. Particular care is being given to honor the existing constitutional and legal framework.

[9] "Concerning contracts related to productive activities of the hydrocarbon industry, procurement shall be subject to the rules established in the law and to the rules issued by the Board of Directors, rather than to the general procurement framework applicable to other public entities. Public bids carried out in accordance with the law shall include stages in which contract prices may be negotiated pursuant to the rules issued by the Board of Directors. Contracts may include clauses that allow amendments to such contracts in order to include price adjustments as a result of the inclusion of more advanced technology in the project, variations in market prices of supplies and equipment, and the acquisition of new information that may increase efficiency in the project. Clauses concerning prices may establish additional compensation when the contractor saves time in the performance of the works as a result of PEMEX benefiting from better technologies or from greater value in the project. Nevertheless, the text of the Law confirms the prohibitions that limit private participation in E&P in Mexico to mere service contracts. Contractors may not gain any form of title on the reserves, and price compensation shall be paid strictly in cash, barring the possibility of agreeing on payment by way of percentages of production, sales take, or oil revenues of PEMEX. In accordance with these prohibitions, the law expressly bars production sharing agreements, risk service, and other similar agreements." Miriam Grunstein, Thompson and Knight, 2008. http://lawandenvironment.typepad.com/law_and_the_environment/2008/12/energy-reform-in-mexico-what-does-it-mean.html.

Republic of Yemen

Licensing policy

Article 8 of the Constitution establishes the state's ownership of natural resources. Yemen does not have a unique sector law: the Petroleum Law 25 of 1976 that was in force in southern Yemen before the country's unification is no longer applicable. Therefore, the right to explore and produce oil is granted to companies by means of PSAs negotiated by the Ministry of Oil and Minerals (MOM) on behalf of the state. These PSAs embody all the terms and conditions that govern the relationship between the contractor and the state with respect to petroleum exploration, development, and production operations in the country.

The MOM ensures the application of contracts, formulates policies, and implements the government's decisions on the pace of petroleum sector development by making available areas for exploration, and granting rights to explore for, develop, and produce hydrocarbons. In carrying out its duties, the MOM is assisted by the Petroleum Exploration and Production Authority (PEPA), the upstream regulatory agency. The agency manages the country's data bank, supervises oil companies' activities in the country, prepares and conducts licensing rounds, and negotiates the terms of the PSAs on behalf of the MOM.

The state, through its national oil company, participates directly in the sector. A negotiable percentage interest, carried through exploration and development, is generally reserved for the national oil company[1] under the most recent PSAs.

Oil revenues fund over 70 percent of the state's budget. Confirmed deposits are expected to be largely exhausted within a decade. Oil output has been steadily declining in recent years, down to about 300,000 barrels per day from the 2002 peak level of 460,000 barrels per day. MOM's goal for the petroleum industry involves increasing oil production and oil exports. In order to realize this goal, oil exploration activity has accelerated since 1997, after a downturn following Yemen's civil war. The recent dramatic fall in oil prices has made this imperative even more pressing, at the same time making it more challenging to achieve. The sector policy's objectives are publicly disclosed[2] and aim to promote exploration and local content. The key actions envisaged by the government to accomplish these objectives are summarized as follows:

- Increase proved reserves to balance the decline in existing fields.
- Promote exploration in new areas.
- Review the PSA terms and procedures in line with international petroleum industry practice.
- Grant tax and customs exemptions and free transfer of funds.
- Encourage the private sector to play an important role in all stages of hydrocarbon development.
- Encourage the development of marginal fields through the reduction of investment requirements by:
    - Providing public access to existing infrastructure at nominal rates;

- Creating new investment opportunities jointly or severally with the private sector in upstream projects (PSA, gas, petroleum services) as well as downstream projects (transportation, refining);
- Facilitating the transfer of technology by participating directly in petroleum operations through carried interests;
- Encouraging the Yemenization of international companies operating in the country by developing plans for the replacement of the expatriate workforce;
- Improving the control of petroleum costs through the establishment of operating committees.

The right to explore for and produce oil in specific areas is generally awarded to contractors through licensing rounds. Unsolicited expressions of interest and direct award are also possible. Periodically, the PEPA publishes a list of open blocks that the government intends to offer to potential investors. This may include exploration blocks and producing blocks.[3] After receiving an expression of interest for open blocks and relevant company information (including audited financial statements),[4] potential qualified[5] investors are granted access to the relevant technical data.[6] A guarantee equal to 3 percent of the work program obligation proposed for the first exploration period is established by all bidders in favor of the PEPA. A model PSA and a model memorandum of understanding (MOU) are included in the tender documentation, and sometimes published on the PEPA's website. The biddable parameters are summarized in Table A.4.

Blocks are awarded to the highest bidder following the administrative process. The criteria to be used by the government in ranking and evaluating the 33 bidding elements contained in the Model MOU and the relative importance of the bidding parameters are not publicly announced. Furthermore, the MOM has the right to reject any submitted offer without any justification.

An MOU containing all relevant commercial terms is negotiated between the PEPA and the winning companies. After signature, the parties have approximately two months to finalize the terms of the production sharing contract.

Many elements of the fiscal package are negotiable, but the model MOU and the model PSA provide the general structure of the fiscal policy and some boundary conditions for setting the level of the relevant parameters. The fiscal terms may include signature, commerciality and production bonuses, sliding scales royalty and profit oil split based on daily production levels, cost recovery limit and excess cost oil, and the national oil company's carried working interest. Corporate taxes are paid by the government on behalf of the investors, and there is no ring-fencing.

Licensing history

The first licensing round was launched in January 2004. Six onshore blocks (two in the Saba'tayn basin and four in the Masila basin) were offered covering a total 9,520 square kilometers. While 30 companies expressed an interest in participating, 18 pre-qualified, and only 11 actually submitted a bid. Four blocks received a total of 17 bids, and were awarded to the highest bidders (3 companies) in June 2004. A total of $5.5 million was received in signature bonuses. The total work program commitment included two-dimensional and some three-dimensional seismic, and 13 exploration wells.

Table A.4. Biddable Parameters

Parameter	Bid Items
Exploration period	***Lengths and number of sub-periods***
First Exploration Period	a. Term b. Work Program Commitment c. Minimum Expenditure d. Relinquishment Obligations
First Exploration Period Extension	e. Term f. Work Program Commitment g. Financial Commitment
Second Exploration Period	h. Term i. Work Program Commitment j. Minimum Expenditure k. Relinquishment Obligations
Second Exploration Period Extension	l. Term m. Work Program Commitment n. Financial Commitment
Royalties	o. Royalty rates are linked to a sliding scale based on reaching daily production targets (oil, gas)[(a)]
Bonuses (to be paid annually for the duration of the contract)	p. Signature q. Commercial Discovery (oil, gas) r. Daily production targets (oil, gas) s. Training t. Institutional u. Social Development Bonus v. Research and Development Contribution w. Data Bank Development Contribution
Cost Recovery Limit	Expressed in percentage of net production
Amortization rates	Maximum rates for Exploration, Development and Operating Expenditure set in MOU
Excess Cost Oil	Percentage to be paid directly to the State
Production Sharing	Sliding scale linked to reaching daily production targets (oil, gas)
Carried Interest through exploration and development	In percentage of total exploration and production interest
Duration of Production phase	20 years[(b)]
Duration of Production phase extension	5 years max duration. New contract terms to be negotiated
Fixed Tax	3% of exploration expenditure

Notes:
(a) In some cases the royalty rate for gas and LPG production is flat.
(b) In some cases the duration of the production phase for gas is subject to discussion between the MOM and the investors during the negotiation of the relevant PSA.

The second licensing round was announced in January 2005. Seven onshore blocks covering a total of 34,328 square kilometers in four different geological basins were offered, including the Qusa (Masila basin), which had not received bids in the first licensing round. Out of 27 companies that expressed an interest in the round, only 20 prequalified, and 11 submitted bids. All 7 blocks were awarded to 4 companies, with signature bonuses totaling US$12.654 million. The exploration work program obligations were more intense, with a total of approximately 10,000 line kilometers of two-dimensional seismic, 3,000 square kilometers of three-dimensional seismic, and 29 wells. Four of the seven blocks are located in rather remote exploration areas.

In September 2005 the PEPA announced its third licensing round. Fourteen blocks were offered, including frontier, immature, and sub-mature blocks in 9 geological basins, covering a total surface of 100,315 square kilometers. Sixty-three companies expressed an interest in participating in the bidding round, but only 34 prequalified, and 12 actually submitted bids. Eight blocks—covering 55 percent of the total surface on offer—were awarded to five companies. The total exploration commitment included some two- and three-dimensional seismic, and 23 exploration wells.

The fourth licensing round was launched in August 2007. Eleven offshore blocks, all but two previously explored, were on offer (a total 175,943 square kilometers). Fifteen companies pre-qualified. The bidding round was initially postponed, in part due to international concerns about security and sky-rocketing insurance rates.[7] In November 2008, the government announced the suspension of the licensing round. Falling oil prices, the appointment of a new minister of petroleum, and insufficient data on the blocks on offer were cited among the factors that affected industry interest (Upstream, 2008).

General observations

Although oil production started in Yemen in 1986, its territory remains vastly under-explored. Yemen's economic dependence on oil revenue and declining production levels from fields located in two main producing basins have lead the government to actively promote the exploration and development of new oil and gas reserves, as well as the enhanced recovery of existing fields. The utilization of natural gas for power generation is of particular importance for the country's economic growth and diversification. But the lack of infrastructure, insufficient local market, institutional constraints, issues related to ownership and use of associated and non-associated natural gas, and the structure of the industry[8] have proven particularly challenging obstacles to development.

Considering Yemen's geological and country risks, licensing rounds have been reasonably successful. In an effort to attract investors, while ensuring the maximization of the government's economic rent, the government has established a flexible, but ultimately complex, bidding system in which a large number of fiscal and commercial parameters are biddable. In other words, while the PEPA defines minimum requirements for each of the bidding parameters (up to 33), bidders can offer improvement on any or all of them. Intuitively, a government would maximize its share of benefits by "letting the market work." However, when almost all the parameters are biddable, comparing alternative offers can be a difficult and time-consuming exercise, and will inevitably involve a certain level of subjectivity.[9]

Transparency with respect to the evaluation criteria that will be applied by the government in selecting the winning bids will ultimately improve the efficiency of the bidding process. This is particularly true in the case of Yemen, where multiple policy objectives are pursued by the government through the licensing policy, that is, the maximization of the NPV of the rent, the promotion of local content and transfer of technology, and the promotion of exploration through the setting of guaranteed minimum work obligation for the first and second exploration period. Knowing the hierarchy and relative importance of these objectives will allow bidders to structure appropriate bids, reduce administrative time for reviewing the proposals, and improve confidence in the fairness of the allocation system.

Notes

[1] The Yemen Oil and Gas Company (YOGC) is a state-owned enterprise that intervenes in different stages of the sector value chain through its six affiliates. In particular, the Yemen Company (YC) holds production rights in blocks 32, 53, and in a number of exploration blocks; Yemen Gas Company (YGC) is responsible for the development and utilization of the country's gas resources; Yemen Oil Company (YOC) is responsible for managing government participation in oil-producing joint ventures with international companies; Yemen Petroleum Company (YPC) is responsible for the countrywide distribution and marketing of petroleum products (except liquid petroleum gas, LPG); Aden Refinery Company (ARC) and Marib Refinery Company (MRC) are the two government-owned refineries.

[2] See the PEPAs' website for more details at www.pepa.com.ye.

[3] In case of producing blocks, service contracts may be considered.

[4] Companies interested in participating in a licensing round are required to submit a letter of intent, technical and financial reports for the last two years, their latest audit report, and a completed and signed company profile.

[5] The pre-qualification of potential investors based on their technical and financial capabilities is carried out by the PEPA. The names of pre-qualified investors are publicly announced by the PEPA.

[6] Data fees and other access condition may apply.

[7] Instability in Somalia triggered a spike in piracy that disrupted maritime shipping in the Gulf of Aden.

[8] Mainly small or medium-size oil companies. For a detailed discussion of the barriers to the development of a natural gas sector in Yemen, see Gerner and Tordo (2007).

[9] A detailed modeling of the proposals would require estimates of oil/gas prices, prospect sizes and recovery factors, success ratios, production and engineering solutions, costs and investments, discount factors, and so on that are necessary to determine the discounted cash flow and expected monetary value associated with alternative proposals. This can be quite difficult when little information is available on the hydrocarbons potential of a block. In addition, the structure of the fiscal system may distort the evaluation.

APPENDIX V

Allocation Systems Design: Example

Policy objectives	Geological Settings	Government capacity	Bidding parameters	Remarks
Increase the level of exploration activity	• No or very few discoveries in the area • Little or no geological information • Few or no exploration wells in the area	• Low technical capacity • Low bid evaluation capacity	• Fiscal parameters (e.g., royalty, profit share)	• **Minimum bidders' qualification criteria** (financial, technical, operations track record) are especially important in work program bidding, and when the government has limited administrative capacity. • **Progressive fiscal regimes** reduce the perception of risk. Hence, the higher the risk and uncertainty, the more progressive the fiscal regime. The government's revenue risk aversion and time preference also affect the type and relative importance of the fiscal instruments included in the fiscal regime (i.e., its relative progressiveness and/or neutrality). • Especially when the government has capacity constraints or inadequate capacity to evaluate bids, **administrative complexity** should be avoided, including by defining simple bidding parameters, and clear and transparent award criteria. • In under-explored or frontier areas, where information is scarce and the government may not be reasonably confident of the precision of its value estimate, royalties and/or profit share bidding, possibly combined with a **relinquishment policy** that expedites exploration, may be more efficient than work program bidding. • **Improving the knowledge of the geological potential** (e.g., through the acquisition of multi-client surveys) in under-explored or frontier areas ahead of a licensing round may reduce the bidders' perception of risk, and improve the efficiency of the government's allocation strategy (location and size of areas, timing, procedure, bidding parameters, promotion, etc.). This may be particularly valuable if work program bidding is envisaged. • If the **level of competition is low** some restrictions on joint bidding could be considered when bidders are large companies, or long- established consortia, and anti-trust regulation is insufficient. Joint bidding policies need to be carefully crafted, as allowing joint bidding may in fact increase the participation of small/medium companies that would not otherwise be in a position to bid. Limiting the number of blocks on offer would also increase competition, especially if the **expected price** is low and/or trending downward.
		• Good technical capacity • Good bid evaluation capacity	• Work program bidding • Work program combined with royalty or profit share bidding	
	• Some discoveries in the area • Reasonable amount of geological data • Some exploration wells in the area	• Low technical capacity • Low bid evaluation capacity	• Fiscal parameters (e.g., bonus, royalty, profit share)	
		• Good technical capacity • Good bid evaluation capacity	• Work program combined with bonus or royalty or profit share bidding	
Maximize rent capture	• No or very few discoveries in the area • Little or no geological information • Few or no exploration wells in the area	• Low technical capacity • Low bid evaluation capacity	• Fiscal parameters (e.g., royalty, profit share)	
		• Good technical capacity • Good bid evaluation capacity		
	• Some discoveries in the area • Reasonable amount of geological data • Some exploration wells in the area	• Low technical capacity • Low bid evaluation capacity	• Fiscal parameters (e.g., bonus, royalty, profit share)	
		• Good technical capacity • Good bid evaluation capacity		

Glossary

Allocation system. A process by which the right to explore, develop, and/or produce oil and gas is awarded by governments to investors.

Area nomination. In defining the areas to be included in a licensing round, governments take into consideration potential bidders' expression of interest in particular areas.

Area-wide allocation. All areas that are open to oil and gas exploration and production activities and are not already licensed to investors are offered for bidding in any given licensing round.

Ascending bid (English auction). An auction in which the price is raised until only one bidder remains.

"Back-in option." The right of a government to directly participate in the costs and benefits of a petroleum contract at a later time (usually after a commercial discovery). Approximately 50 percent of the countries that exercise their right to "back in" do not reimburse the exploration expenditure incurred by the initial working interest parties.

Bonuses. Money paid by the investor upon the occurrence of a specific event (contract signature, discovery, declaration of commerciality, commissioning of facilities, start of production, and/or reaching of target production levels).

Bundle bids. The allocation of oil and gas exploration and production rights is linked with downstream or infrastructure investments. Bidding parameters may include the rehabilitation or construction of local refineries, the improvement of local infrastructure incidental to the project area, and other investments, depending on the government's development needs and constraints.

Carried interest. When one party agrees to pay for a portion or all of the pre-production costs of another party (the "carried" party) under a license in which both own a portion of the working interest, subject to contractual terms for recovering costs.

Cash bonus bidding. A process in which the right to develop a resource in a particular area is granted to the investor that offers the highest up-front cash payment.

Concession agreement. An exclusive license granted to a qualified investor. A concession grants an oil company (or a consortium) the exclusive right to explore for and produce hydrocarbons within a specific area (called the license area, block, or tract, depending on local laws) for a given time. The company assumes all risks and costs associated with the exploration, development, and production of petroleum in the area

covered by concession. Often a license fee or bonus is paid to the government. The government's compensation for the use of the resource by the investor will typically include royalty and tax payments if hydrocarbons are produced.

Corporate income tax. Tax payable when annual revenues exceed a certain measure of costs and allowances. The applicable rate and the definition of taxable income are established in a country's regulation.

Cost recovery limit. Defines the percentage of crude oil that can be used for cost recovery ("cost oil"). If costs exceed the cost recovery limit, the difference may be carried forward for recovery in subsequent periods. In some countries, excess cost oil goes directly to the government.

Descending bid (Dutch auction). An auction in which the price is lowered from an initial high until one bidder accepts the current price.

Direct award. See open-door systems.

Dutch disease. Refers to the problems experienced by an economy in response to an increase in revenues from natural resources, causing a rise in inflation and appreciation of the real exchange rate. This in turn makes the non-resource sectors less competitive.

Economic rent (resource rent). The surplus value after all costs (including normal returns) have been accounted for; that is, the difference between the price at which the resource can be sold and its respective extraction and production costs, including normal return (basic return equivalent to the rate of interest on risk-free long-term borrowing plus a margin necessary to compensate for the technical, commercial, and political risks associated with the investment).

Effective royalty rate. Defined as the minimum share of revenue (or production) that the government might expect to receive in any given accounting period from royalties and its share of profit oil. If the contract or concession agreement has no cost recovery limit and no royalty, the government may receive nothing in a given accounting period. This can happen even with profitable fields in the early years of production when exploration and development costs are being recovered.

Exploration threshold analysis helps to decide whether or not to attempt exploration efforts. The threshold is estimated by making assumptions about the probability of success and the value of the reserves that may result from successful efforts. Expected price and costs, reservoir characteristics, and the country's fiscal system all affect the determination of threshold field size. Due to the different level of risk, exploration thresholds are several orders of magnitude larger than development field size thresholds.

First-price sealed-bid auction. An auction in which bidders submit sealed bids, and the highest bidder is awarded the item for the price bid. Each bidder has only one chance to submit its bid and cannot observe the behavior of other bidders until the auction is closed and results are announced.

Frontier areas are those that are unexplored or lightly explored (for example, Western Australia and the Barents Sea). Classifications vary widely across regions and are

usually based on the availability of geological and geophysical data, the number of wells drilled, and the probability of success.

Government participating interest. Usually a working interest carried through exploration (rarely through development); that is, investors bear the risk and cost of exploration (and development, as the case may be) and the government/national oil company's share of cost is paid out of production according to a procedure specified in the petroleum contract.

Licensing round. A competitive bidding process for the allocation of oil and gas exploration and production rights.

Local content. Refers to the development of local skills, technology transfer, and the use of local manpower and local manufacturing.

Market segmentation. The extent to which different companies specialize in different types of exploration activities and tolerate different risks.

Minimum criteria. See pre-qualification.

Multi-client survey. Geophysical and geological surveys are sometimes carried out by service companies at their own risk and expense. The data are then licensed to interested oil companies for a fee. The proceeds of the sale of data licenses are shared between the service company and the government according to the terms of the relevant agreement. These arrangements are often used by governments to improve the market knowledge of the geological potential of areas that are earmarked for inclusion in licensing rounds. The government does not incur any cost related to the acquisition, processing, and marketing of the data.

Net present value. The present value of expected future cash flows. The discount rate should be a function of the riskiness of the estimated cash flows.

Open-door system (*also known as* a negotiated procedure). An allocation system in which licenses are awarded as a result of negotiations between the government and interested investors through solicited or unsolicited expressions of interest.

Participating interest. An undivided percentage interest that each investor owns at any particular time in the rights and obligations of a petroleum contract.

Pre-qualification. A measure of technical and financial capability, often required to participate in licensing rounds (discretionary or market based). The definition of minimum criteria allows the government to eliminate "non-serious" bidders. Pre-qualification criteria may also be used to safeguard special interests.

Production sharing contract (PSC). An agreement concluded between one or more (usually foreign) oil companies and a state party. The state party may be the state itself—represented by its government—or a state authority (such as a government ministry or a special department or agency) or the national oil company. Like a concession, a PSC grants an oil company or consortium (the "contractor") the right to explore for and produce hydrocarbons within a specified area and for a limited time period. Unlike a concession, a PSC provides the investor with the ownership of its

share of production only at the delivery point or export point (as defined in the contract).

Profit oil/gas split. Revenue remaining after the deduction of royalties and recoverable costs; this is split between the government and the investors, in most cases according to a sliding scale.

Profit share bidding. The investor that offers to pay the highest share of potential future profits is awarded the rights to explore for and develop the resource. Profit share bidding may include one or more profit-based mechanisms such as resource rent taxes, a profit oil or profit gas split, and/or special petroleum taxes.

Progressive fiscal regime. A fiscal regime that provides the government with an adequate share of economic rent under varying conditions of profitability.

Progressive income tax. Utilizes stepped tax rates that are linked to prices, volumes, values, and so on (these are add-ons to conventional corporate income tax).

Progressive royalties. Royalty rates that are linked to certain parameters and increase or decrease in response to variations in these parameters and help mitigate the risks associated with the pre-mature termination of production.

Project payback refers to the period of time required for the return on an investment to "repay" the sum of the original investment.

Proved reserves. The estimated quantities of crude oil and gas that are claimed to be recoverable under existing economic and operating conditions.

Public tender. The most common type of contracting procedure; allows for multiple bids based on strict procedures.

R-factor. The ratio of cumulative after-tax receipts to cumulative expenditures (capital expenditures and operating costs).

Rate of return. The ratio of money gained or lost on an investment relative to the amount of money invested.

Reserve *or* **reservation price**. The minimum (or maximum) price for which an item may be sold (or bought).

Resource rent (economic rent). The surplus value after all costs (including normal returns) have been accounted for; that is, the difference between the price at which the resource can be sold and its respective extraction and production costs, including normal return (basic return equivalent to the rate of interest on risk-free long-term borrowing plus a margin necessary to compensate for the technical, commercial, and political risks associated with the investment).

Resource rent tax. Tax on a projects' petroleum income, which ties taxation more directly to the project's profitability (R-factor or rate of return). In its pure form, taxes are deferred until all expenditures have been recovered and the project has yielded a predefined target return. Then a very high marginal tax is applied to all subsequent operating revenue.

Ring-fencing. Refers to the delineation of taxable entities.

Royalties provide an early source of revenue to the government, but they are a rather regressive form of taxation; they are paid by investors as production starts, and usually long before profits are generated. Based on either the volume ("unit" or "specific" royalty) or the value ("ad valorem" royalty) of production or export, the royalty is normally a percentage of the proceeds of the sale of the hydrocarbons.

Royalty bidding. The investor that offers the highest royalty rate is awarded the rights to explore for and develop the resource in a specific area.

Second-price sealed-bid (Vickrey) auction. Bidders submit sealed bids and the highest bidder wins the item but pays a price equal to the second-highest bid.

Secondary and/or tertiary recovery. Secondary recovery consists of injecting an external fluid, such as water or gas, into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. Tertiary recovery (or enhanced oil recovery) involves the use of sophisticated techniques that alter the original properties of the oil. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir.

Sequential auction. A type of auction in which blocks are offered sequentially using first-price sealed bids. The sequence in which the blocks are offered in sequential options is important, as it may affect the seller's expected revenue as well as the efficiency of allocation

Service agreement (SA). Under an SA, the state hires the contractor to perform exploration and/or production services within a specified area, for a specific time period. The state maintains ownership of petroleum at all times, whether in situ or produced. The contractor does not acquire any ownership rights to petroleum, except where the contract stipulates the right of the contractor to be paid its fee "in kind" (with oil and/or gas) or grants a preferential right to the contractor to purchase part of the production from the government.

Signature bonus bidding. See cash bonus bidding.

Straight-line depreciation. Assets are depreciated in many ways over their expected life (useful life of equipment, economic life of the reservoir). The straight-line method provides for equal annual deductions.

Surface fees. Calculated with respect to the area under concession or contract and usually expressed in fee per square kilometer. Higher fees apply during the production phase.

Taxable income. Investor's share of revenue net of royalties, and investor's share of allowable costs as defined in a country's regulations and/or relevant petroleum agreement.

Uncertainty refers to the range of probability that certain conditions may exist or occur.

Winner's curse. The tendency of the winner to over-estimate the true value of a block. Even if all bidders had access to all available data, there would still be a difference in interpretation that would lead to different estimates of the true value of the same block. Hence, the bidder with the most optimistic—not necessarily the most accurate—view of the true value of the block will be awarded the exploration rights.

Work program bidding. Work programs are generally defined by the type of work, such as amount and type of seismic data to be acquired, number of exploration wells to be drilled, and so on. A monetary value is normally assigned to each activity. Petroleum agreements usually oblige the license holder (or the contractor, as the case may be) to undertake the minimum work program or pay the correspondent monetary amount to the host government. In work program bidding, exploration and production rights are awarded to the bidder that offers the highest minimum work.

Working interest. The owner bears the cost of exploration, development, and production of an oil and gas field and, in return, is entitled to a share of production from that field.

Workover. Any operation performed on an oil well subsequent to its completion.

References

Abel, M., L. A. Silva, J. A. Campbell, and L. F. De Ros. 2005. "Knowledge Acquisition and Interpretation Problem-Solving Methods for Visual Expertise: A Study of Petroleum-Reservoir Evaluation." *Journal of Petroleum Science and Engineering* 47 (1–2): 51–69.

Afualo, V., and J. McMillan. 1998. "Auction of Rights to Public Property." *The New Palgrave Dictionary of Economics and Law*. New York: Peter Newman.

Anenih, O. 2003. *The UK Petroleum Production Licence—Is it a Contract or Regulation and Does it Matter?* Dundee, United Kingdom: University of Dundee, Centre for Petroleum and Mineral Law and Policy.

ANP (Agência Nacional do Petróleo, Gás Natural e Biocombustíveis). *Relatório de Gestão 2007*. [http://www.anp.gov.br/conheca/rel_gestao.asp]

Ashton, P. K., L. O. Upton III, and M. H. Rothkopf. 2005. "Effects of Royalty Incentives for Gulf of Mexico Oil and Gas Leases." *OCS Study*, Volume 1, Summary, MMS2004-77, U.S. Department of Interior.

Ausubel, L., and P. R. Milgrom. 2002. "Ascending Auctions with Package Bidding." *Advances in Theoretical Economics* 1 (1): 1–42. Berkeley Electronic Press.

Bacon, R., and S. Tordo. 2005. "Crude Oil Price Differentials and Differences in Oil Qualities: A Statistical Analysis." ESMAP Technical Papers Series 081. Energy Sector Management Assistance Program, Washington, D.C.

Ballin, P. R., K. Aziz, and A. G. Journel. 1993. "Quantifying the Impact of Geological Uncertainty on Reservoir Performing Forecast." Symposium on Reservoir Simulation, SPE 25238, February, New Orleans, LA.

Baunsgaard, T. 2001. "A Primer on Mineral Taxation." IMF Working Paper WP/01/139. International Monetary Fund, Washington, D.C.

Bergson, A. 1938. "A Reformulation of Certain Aspects of Welfare Economics." *Quarterly Journal of Economics* 52: 310–34.

Blake, A. J., and M. C. Roberts. 2006. "Comparing Petroleum Fiscal Regimes under Oil Price Uncertainty." *Resources Policy* 31 (3): 95–105.

Bunter, M. 2002. *The Promotion and Licensing of Petroleum Prospective Acreage*. The Hague, Netherlands: Kluwer Law International.

CEE (Center for Energy Economics). 2006. "Deepwater Developments in Brazil." Case studies from CEE's "New Era in Oil, Gas & Power Value Creation" Program, Bureau of Economic Geology, The University of Texas at Austin.

Chaves, H. A. F., and M. E. Lewis. 1994. "From Data Gathering to Resources Assessment: A Holistic View of Petroleum Geology." *Journal of Natural Resources Research* 3 (1): 72–82.

Chu U Kalu, T. 1994. "Designing Optimal Regulatory Policy Strategies for the Oil Industry." *Resources Policy* 20 (3): 183–91.

Cordero, Moss G. 1998. "Contract or Licence? Regulation of Petroleum Investment in Russia and Foreign legal Advice." *Journal of Energy and Natural Resources Law* 16: 186–99.

Cramton, P. 2000. "Auctions Versus Discretion in the Licensing of Oil and Gas Acreage." In *The International Experience: Markets, Regulations, and the Environment*. London: Imperial College Press.

———. 2007. *How Best to Auction Oil Rights, in Escaping the Resource Curse*. New York: Columbia University Press.

Cunha, A. L. 2007. "The Tupi Discovery and Possible Impacts on the Brazilian Legal Framework." *Oil, Gas and Energy Law Intelligence, Energy Politics* 3 (XII).

Date-Bah. S. K. 1994. "Promoting Petroleum Exploration in Namibia." *Resources Policy* 20 (4): 265–71.

Davidson, L. B., and J. E. Davies. 1995. "Simple, Effective Models for Evaluating Portfolios of Exploration and Production Projects." SPE 30669, SPE Annual Technical Conference and Exhibition, Texas.

Demirmen, F. 2001. "Subsurface Appraisal: The Road from Reservoir Uncertainty to Better Economics." SPE 68603, SPE Hydrocarbon Economics and Evaluation Symposium, April 2–3, Dallas.

DISR (Department of Industry, Science and Resources). 1999. *Australian Offshore Petroleum Strategy—A Strategy to Promote Petroleum Exploration and Development in Australian Offshore Areas*. Canberra: DISR.

Dos Santos, E. M, and C. A. de Almeida Corria. 2005. "Should the Brazilian National Petroleum Agency Explore New Contracting Formulas?" [http://www.petrolab.com.br/portugues/download/CONCESSION%20X%20PSCS.doc]

Dyer, M. J. 2006. "Brazil—Competitive Landscape and Current Opportunities." *PESGB Monthly Newsletter*, November, Petroleum Exploration Society Great Britain, London.

EIA (Energy Information Administration). 2005. *Mexico Country Brief Analysis*. U.S. Department of Energy. [http://www.eia.doe.gov/]

Fraser, R. 1991. "Licensing Resource Tracts: A Comparison of Auction and Discretionary Systems." *Resources Policy* 17 (4): 271–83.

———. 1993. "On the Neutrality of the Resource Rent Tax." The Economic Society of Australia, *The Economic Record* 69 (204): 56–60.

Frewer, G. 1998. "An Analysis of the Relationship between Uncertainty-Reducing Exploration and Resource Taxation." *Resources Policy* 24 (4): 199–205.

Furtado, R., and S. B. Suslick. 2003. "Bidding as a Proxy Estimation of Real Block Value in the New Offshore Frontiers: The Brazilian Case." American Association of Petroleum Geologists, International Conference and Exhibition, Barcelona.

Garnaut, R., and Ross A. Clunies. 1975. "Uncertainty, Risk Aversion, and the Taxing of Natural Resource Projects." *Economic Journal* 85 (2): 272–87.

Gerner, F., and S. Tordo. 2007. "Republic of Yemen. A Natural Gas Incentive Framework." Energy Sector Management Assistance Program, Formal Report 327/07, World Bank, Washington, D.C.

Gilbert, R. J. 1979. "The Social and Private Value of Exploration Information." In J. B. Ramsey, ed., *The Economics of Exploration for Energy Resources*. Greenwich, CT: Jai Press Inc.

Gilley, O., and G. Karels. 1981. "The Competitive Effects in Bonus Bidding, New Evidence." *Bell Journal of Economics* 12 (2): 637–48.

Grayson, C. J. 1960. *Decisions under Uncertainty, Drilling Decisions by Oil and Gas Operators*. Boston: Harvard Business School, Division of Research.

Harris, D. P. 1990. *Mineral Exploration Decisions: A Guide to Economic Analysis and Modeling*. New York: J. Wiley.

Haush, D. 1986. "Multi-Object Auctions: Sequential Versus Simultaneous Sales." *Management Science* 32: 1599–610.

Hayek, F. A. 1945. "The Use of Knowledge in Society." *The Freeman: Ideas on Liberty*, The Foundation for Economic Education, New York. .

Hendricks, K., and R. H. Porter. 1996. "The Timing and Incidence of Exploratory Drilling on Offshore Wildcat Tracts." American Economic Association, *American Economic Review* 86 (3): 388–407.

Hicks, J. 1939. "The Foundations of Welfare Economics." *Economic Journal* 69: 696–712.

Hyne, N. 2001. *Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production*, Second edition. Tulsa, Oklahoma: PennWell Corporation.

Hughart, D. 1975. "Informational Asymmetry, Bidding Strategies, and the Marketing of Offshore Petroleum Leases." *Journal of Political Economy* 83: 969–86.

Iledare, O. O., and M. Kaiser. 2007. *Competition and Performance in Oil and Gas Lease Sales and Development in the U.S. Gulf of Mexico OCS Region, 1983–1999*. U.S.

Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

Iledare, O. O., and A. G. Pulsipher. 2006. "Joint Bidding Restriction Policy for Selective E&P Firms in the US Gulf of Mexico OCS: How Persuasive is its Effectiveness?" *Energy Policy* 35 (2): 3126–33.

Iledare, O. O., A. G. Pulsipher, W. O. Olatubi, and D. V. Mesyanzhinov. 2004. "An Empirical Analysis of the Determinants and Value of High Bonus Bids for Petroleum Leases in the U.S. Outer Continental Shelf (OCS)." *Energy Economics* 26 (1): 239–59.

Jara, J. J., G. Lagos, and J. E. Tilton. 2008. "Using Exploration Expenditures to Assess the Climate for Mineral Investment." *Resources Policy* 33 (3): 179–87.

Johnston, D. 1994. *International Petroleum Fiscal Systems and Production Sharing Contracts*. Tulsa, Oklahoma: PennWell Books.

———. 2003. *International Exploration Economics: Risks and Contract Analysis*. Tulsa, Oklahoma: PennWell Books.

Johnston, D., D. Johnston, and T. Rogers. 2008. *International Petroleum Taxation*. Houston, Texas: Independent Petroleum Association of America.

Julius, D., and A. Mashayekhi. 1990. *The Economics of Natural Gas: Pricing, Planning and Policy*. Oxford, United Kingdom: Oxford University Press.

Kaldor, N. 1939. "Welfare Propositions in Economics and Interpersonal Comparisons of Utility." *Economic Journal* 49: 549–22.

Kemp, A. 1987. *Petroleum Rent Collection Around the World*. Halifax, Nova Scotia: The Institute for Research on Public Policy.

Kemperer, P. 2003. "Using and Abusing Economic Theory." *Journal of the European Economic Association* 1: 272–300.

———. 2004. *Auctions: Theory and Practice*. Oxford University, Princeton, New Jersey: Princeton University Press.

Kretzer, U. M. H. 1993. "Allocating Oil Leases. Overcapitalization in Licensing Systems Based on Size of Work Programme." *Resources Policy* 19 (4): 299–311.

———. 1994. "Exploration Prior to Oil Lease Allocation. A Comparison of Auction Licensing and Allocations Based on Size of Work Programme." *Resources Policy* 20 (4): 235–46.

Krishna, K. 1993. "Auctions with Endogenous Values: The Persistence of Monopoly Revisited." *American Economic Review* 83: 147–60.

Krishna, V. 2002. *Auction Theory*. San Diego, United States: Academic Press.

Leland, H. E. 1978. "Optimal Risk Sharing and the Leasing of Natural Resources, with Application to Oil and Gas Leasing on the OCS." *The Quarterly Journal of Economics* 92 (3): 413–37.

Mariano, J., and E. La Rovere. 2006. "Oil and Gas Exploration and Production Activities in Brazil: The Consideration of Environmental Issues in the Bidding Rounds Promoted by the National Petroleum Agency." *Energy Policy* 35: 2899–911.

Maritz, A. 2003. *Work Program Bidding in Australia's Upstream Oil and Gas Industry, 1985–99*. Canberra: Australian Bureau of Agricultural and Resource Economics, Commonwealth of Australia.

Maskin, E., and J. Riley. 1984. "Optimal Auctions with Risk-averse Buyers." *Econometrica* 52: 1473–1518.

———. 2000. "Asymmetric Auctions." *Review of Economic Studies* 67: 439–54.

Masson, R., and B. Remillard. 1996. "Alberta's New Oil Sands Royalty System." Royalty and Tenure Branch, Policy Division, Alberta Department of Energy, Edmonton, Alberta, Canada.

McAfee, R. P., and J. McMillan. 1987. "Auctions and Bidding." *Journal of Economic Literature* XXV (June): 699–738.

McPherson, C. P., and K. Palmer. 1984. "New Approaches to Profit Sharing in Developing Countries." *Oil and Gas Journal*, June 25.

Mead, W. J. 1994. "Toward An Optimal Oil and Gas Leasing System." *Energy Journal* 15 (4): 1–18.

Mead, W. J., A. Moseidjord, and P. E. Sorensen. 1984. "Competitive Bidding under Asymmetrical Information: Behavior and Performance in Gulf of Mexico Drainage Lease Sales, 1959–1969." *Review of Economic Statistics* 66 (3): 505–08.

Milgrom, P. 2004. *Putting Auction Theory to Work*. Cambridge, United Kingdom: Cambridge University Press.

Milgrom, P. R. 1985. "Auction Theory." Cowles Foundation Discussion Papers 779, Cowles Foundation, Yale University.

Milgrom, P. R., and R. J. Weber. 1982. "A Theory of Auctions and Competitive Bidding." *Econometrica* 50 (5): 1089–122.

Ministry of Economic Development. 2007. *Petroleum Investment Strategy*. New Zealand: Crown Minerals.

MMS (Minerals Management Service). 2006. *Leasing Oil and Natural Gas Resources. Outer Continental Shelf*. U.S. Department of the Interior, Economics Division.

Mokedi, A. 2006. *Local Content Developments in the Oil and Gas Sector*. Nigeria: Udo-Udoma and Belo-Osagie Barristers and Solicitors. [www.uubo.org]

Moody, C. E. 1994. "Alternative Bidding Systems for Leasing Offshore Oil: Experimental Evidence." *Economica* 61: 345–53.

Moody, C. E., and W. J. Kruvant. 1988. "Joint Bidding, Entry, and the Price of OCS Leases." *RAND Journal of Economics* 19 (2): 276–284.

Olsen, W. H. 2005. *The Nigerian Bidding Round 2005: An Observer's Reflections on Transparency Issues*. London, United Kingdom: The Chatham House.

Otillar, S. P., and K. A. McQuaid. 2008. "Recent Developments in Brazil's Oil and Gas Industry: Brazil Appears to be Stemming the Tide of Resource Nationalism." *Houston Journal of International Law* (Spring 2008).

Otto, J. M. 1995. "Legal Approaches to Assessing Mineral Royalties." In *Taxation of Mineral Enterprises*. London: Graham and Trotman.

Pareto, V. 1927. *Manuel d'Economie Politique*, Second Edition. Paris, France: Girard.

Pitchik, C. 1989. "Budget-Constrained Sequential Auctions with Incomplete Information." STICERD Discussion Paper No. TE/89/201, London School of Economics.

Porter, R. H. 1995. "The Role of Information in U.S. Offshore Oil and Gas Lease Auctions." *Econometrica* 63 (1): 1–27.

Ramsey, J. B. 1980. *Bidding and Oil Leases*. Greenwich: JAI Press.

Rao, R. D. 2002. "Modeling Optimal Exploitation of Petroleum Resources in India." *Resources Policy* 28 (1): 133–44.

Razak, R. A., and D. F. Dundar. 2001. "Evaluation and Selection Processes of Petroleum Exploration and Development Projects: An Empirical Study." In *Management of Engineering and Technology*, PICMET '01, Portland International Conference, Portland.

Reece, D. K. 1978. "Competitive Bidding for Offshore Petroleum Leases." *Bell Journal of Economics* 9 (2): 369–84.

Robinson, M. S. 1984. "Oil Lease Auctions: Reconciling Theory with Practice." UCLA Economics Working Paper 340, Department of Economics, University of California.

Rockwood, A. 1983. "The Impact of Joint Ventures on the Market for OCS Oil and Gas Leases." *Journal of Industrial Economics* 31 (4): 453–68.

Rose, P. R. 1987. "Dealing with Risk and Uncertainty in Exploration: How Can We Improve?" *American Association of Petroleum Geologists (AAPG) Bulletin* 71 (1): 1–16.

———. 1992. "Chance of Success and its Use in Petroleum Exploration." In R. Steinmetz, ed., *The Business of Petroleum Exploration*. American Association of Petroleum Geologists (AAPG) Treatise of Petroleum Geology, Handbook of Petroleum Exploration, Chapter 7: 71–86.

———. 2001. "Risk Analysis and Management of Petroleum Exploration Ventures." *American Association of Petroleum Geologists (AAPG) Methods in Exploration Series* 12 (178).

Samuelson, P. A. 1947. *Foundations of Economic Analysis*, 1983 edition. Cambridge, Mass: Harvard University Press.

Smalley, P. C., S. H. Begg, M. Naylor, S. Johnsen, and A. Godi. 2008. "Handling Risk and Uncertainty in Petroleum Exploration and Asset Management: An Overview." *AAPG Bulletin* 92 (10): 1251–61.

Smith, E., O. Anderson, G. Conine, J. Lowe, and B. Kramer. 2000. *International Petroleum Transactions*, Second Edition. Denver, United States: Rocky Mountain Minerals Law Foundation.

Sunnevåg, K. J. 1998. "An Option Pricing Approach to Exploration Licensing Strategy." *Resources Policy* 24 (1): 25–38.

———. 2000. "Designing Auctions for Offshore Petroleum Lease Allocation." *Resources Policy* 26 (1): 3–16.

———. 2002. "Auctions Combined with Ex Post Taxation—Expected Revenue When Three Parties Want A Piece of the Cake." *Resources Policy* 28 (4): 49–59.

Suslick, S. B., and D. J. Schiozer. 2004. Risk Analysis Applied to Petroleum Exploration and Production: An Overview." *Journal of Petroleum Science and Engineering* 44 (2): 1–9.

Taverne, B. G. 1996. *Co-Operative Agreements in the Extractive Petroleum Industry*. The Hague, Netherlands: Kluwer Law International.

Tordo, S. 2007. "Fiscal Systems of Hydrocarbons: Design Issues." Working Paper 123/07, World Bank, Washington, D.C.

Vickerey, W. 1961. "Counterspeculation, Auction-s, and Competitive Sealed Tenders." *Journal of Finance* 16 (March) (1): 8–37.

Walde, T. W. 1992. "Investment Policy and Investment Promotion in the Minerals Industries." Centre for Petroleum and Mineral Law and Policy Professional Papers No. PP2, University of Dundee, Dundee, United Kingdom,

Webb, S. C. 1976. *Managerial Economics*. Boston, MA: Houghton Miffin.

Whaley, J. 2006. Twilight Years for the North Sea? GEO ExPro. [http://www.geoexpro.com/sfiles/2/41/6/file/ExplorationExploitation_44-46.pdf]

Eco-Audit

Environmental Benefits Statement

The World Bank is committed to preserving Endangered Forests and natural resources. We print World Bank Working Papers and Country Studies on postconsumer recycled paper, processed chlorine free. The World Bank has formally agreed to follow the recommended standards for paper usage set by Green Press Initiative—a nonprofit program supporting publishers in using fiber that is not sourced from Endangered Forests. For more information, visit www.greenpressinitiative.org.

In 2008, the printing of these books on recycled paper saved the following:

Trees*	Solid Waste	Water	Net Greenhouse Gases	Total Energy
355	16,663	129,550	31,256	247 mil.
*40 feet in height and 6–8 inches in diameter	Pounds	Gallons	Pounds CO_2 Equivalent	BTUs

green press INITIATIVE

Petroleum Exploration and Production Rights: Allocation Strategies and Design Issues is part of the World Bank Working Paper series. These papers are published to communicate the results of the Bank's ongoing research and to stimulate public discussion.

Many governments rely on oil companies to efficiently exploit natural resources. Governments have the challenging task of deciding which companies should be awarded exclusive rights to explore, develop, and produce their petroleum resources, and on what conditions such rights should be awarded. This paper analyzes the available evidence on the advantages and disadvantages of various systems used by petroleum-producing countries to allocate petroleum exploration, development, and production rights, and considers the policy implications of each system. The experience of six petroleum-producing countries is presented in detail, and numerous other examples are provided to derive lessons of wider applicability. The paper presents various conclusions for policy makers about the optimal design of allocation systems.

World Bank Working Papers are available individually or on standing order. This World Bank Working Paper series is also available by subscription to the World Bank e-Library (www.worldbank.org/newelibrary).

THE WORLD BANK
1818 H Street, NW
Washington, DC 20433 USA
Telephone: 202 473-1000
Internet: www.worldbank.org
E-mail: feedback@worldbank.org

ISBN 978-0-8213-8167-0

9 780821 381670 90000

SKU 18167