ATLANTIC OUTER CONTINENTAL SHELF OIL AND GAS RESOURCES: BACKGROUND AND POLICY ISSUES

BY

Thomas H. Stevens and Robert J. Kalter

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Introduction

In 1972 almost 78 percent of the energy consumed in the United States came from two sources: petroleum and natural gas. Imported oil accounted for 7 percent and imported natural gas for just over 1 percent of this total. By 1985, most forecasts expect a moderate decline in the relative importance of petroleum and natural gas but a substantial increase in the imports of these fuel sources.[1]

Fulfillment of such forecasts will mean increasing dependence by the United States on OPEC nations for its energy supplies. The political, economic and national security implications of this dependence have been made increasingly obvious in recent months. Market forces and previous governmental policies have, however, been largely responsible for the shifts that have taken place in the world energy markets.[2] This being the case, properly designed governmental incentives can also assist in reducing United States dependence on foreign supplies if such a course of action is deemed desirable.

One factor that has direct, but not necessarily immediate, implications for domestic petroleum and natural gas production is the strategy adopted by the federal government with respect to the leasing of Outer Continental Shelf (OCS) lands.[3] Recognition of this fact led to several policy announcements

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[1] National Petroleum Council, U. S. Energy Outlook (Washington: 1972), pp. 30-33.

DuPree, Walter G. and James A. West, U. S. Energy Through the Year 2000 (Washington: U. S. Department of the Interior, Dec. 1972).

Kalter, Robert J., Economic Analyses of Fossil Fuel Markets Using Parametric Models (Washington: U. S. Department of the Interior, Dec. 1973).

[2] Kalter, Robert J., The Energy Situation and Outlook: December 1973, Staff Paper 73-25, Cornell Agricultural Economics (Dec. 1973).

[3] In a 1972 study by the National Petroleum Council (NPC), the impact of several OCS leasing and resource management policy options upon potential future domestic production and product prices were examined. The study concluded that if no new offshore lease sales are held due to environmental or other reasons, potential 1985 domestic production of petroleum could be reduced by over 2 million barrels per day, while potential domestic production of natural gas in the same year could be reduced by over 5 TCF. This represents over one-fifth of the potential oil and gas production projected from the lower 48 states in the year 1985. National Petroleum Council, U. S. Energy Outlook, op. cit., pp. 121-130.

in the 1973 Presidential Energy Message.[4] First, the President directed the Secretary of the Interior to take steps which would triple the annual acreage leased in the OCS by 1979. As a result, on July 11, 1973, an accelerated leasing schedule was issued by the Bureau of Land Mangement. Second, the President ordered a study by the Council on Environmental Quality and the Environmental Protection Agency, in conjunction with the National Academy of Sciences, of the environmental impact of oil and gas production from the Atlantic Outer Continental Shelf and the Gulf of Alaska. The President emphasized that no drilling will be undertaken in these areas until a determination has been made of the environmental impact.[5]

However, formation of public policy related to the Atlantic Outer Continental Shelf (AOCS) and other OCS areas must, by necessity, consider potential economic as well as environmental impacts. These include government revenue, consumer prices, balance of payments, regional income and employment in energy related economic sectors, regional income and employment in sectors which may be adversely affected, equity effects and effects on competition. Improved information on all such impacts is a critical element required if appropriate tradeoffs are to be made in the decision-making process.

The impact of AOCS development upon economic objectives will vary depending upon public policies adopted. Relevant policy variables include but are not limited to: (1) the schedule and location of lease sales; (2) the size of lease sales; (3) resource conservation policies adopted; (4) revenue sharing procedures and; (5) lease term options such as installment bonus bidding, royalty bidding or work programs.

A hypothetical example of the relationship between several economic objectives and a particular public policy option is given in the following scenario. Assume that an accelerated lease schedule is implemented in the AOCS area. With an accelerated schedule, there could be a decline in government income received due to lower bids resulting from more sales, a larger volume of acreage offered per time period, and the associated financial constraints. In addition, an accelerated schedule could place a strain upon the equipment and manpower resources available to the industry. Hence, exploration and subsequent production in other domestic fields may decline. Thus, domestic production realized in a given time frame would be uncertain. If more production is forthcoming, a favorable effect upon the balance of payments, consumer energy prices, and income and employment in energy related economic sectors will be realized. However, there may be adverse economic effects upon the commercial fishing and tourism sectors. In addition, given full employment conditions, a particular geographical area may benefit at the expense of another. It is therefore clear that each policy option will lead to tradeoffs which must be made between several economic objectives as well as between economic and environmental components of the relevant

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[4] Nixon, Richard, "Energy Message from the President of the United States," Congressional Record, Vol. 119, No. 62, April 18, 1973., H2886.

[5] *Ibid.*, H. 2888.

social welfare function. The purpose of economic analysis is to provide an improved information base from which such tradeoffs can be established.

Two recent studies have provided partial information of the potential economic impact of the development of AOCS oil and gas resources.[6] Both studies focus upon the Georges Bank area of the AOCS. Figure 1 depicts the AOCS area and the location of other promising exploration regions. The MIT study is restricted to an analysis of the net economic and environmental impacts of Georges Bank resource development upon the New England region. Ahern's study considers national economic objectives including federal revenue and balance of payments considerations. The basic policy issue addressed in both studies is whether or not Georges Bank should be leased for development. Although this issue is of considerable importance, analysis of the economic consequences of the alternative resource management and development policy options discussed above is also required for intelligent decision-making. This type of analysis is applicable not only to decisions related to the development of AOCS resources, but to decisions related to other offshore areas as well. Moreover, economic analysis of AOCS petroleum and natural gas development requires that impacts upon other potential geographical areas of development be considered. For example, given the limited manpower and equipment resources available to the petroleum industry in the short run, investment in one area means that development in other areas is also affected. The objective of the industry is to allocate available resources between alternative investments and over time so as to maximize the present value of net profits. The objective of public policy related to natural resource development is to obtain the maximum net social benefits in present value terms. In both cases, opportunity foregone or postponed is a critical element in the decision-making calculus.

The central policy issues facing the development of OCS leasing strategy therefore are: (1) where to lease; (2) in what time frame to lease; (3) the type of leasing or resource allocation methods to be utilized by the management agency. This paper investigates the known information with respect to AOCS energy resources and potential leasing techniques. As such it serves as background for a longer range effort designed to evaluate the economic implications of an AOCS leasing decision. First, the broad production possibilities of the AOCS region will be examined. Second, current leasing policy and resource management procedures will be discussed and potential leasing and management policy alternatives will be outlined. Finally, a model useful in investigating the direct effects of various leasing policy options will be outlined.

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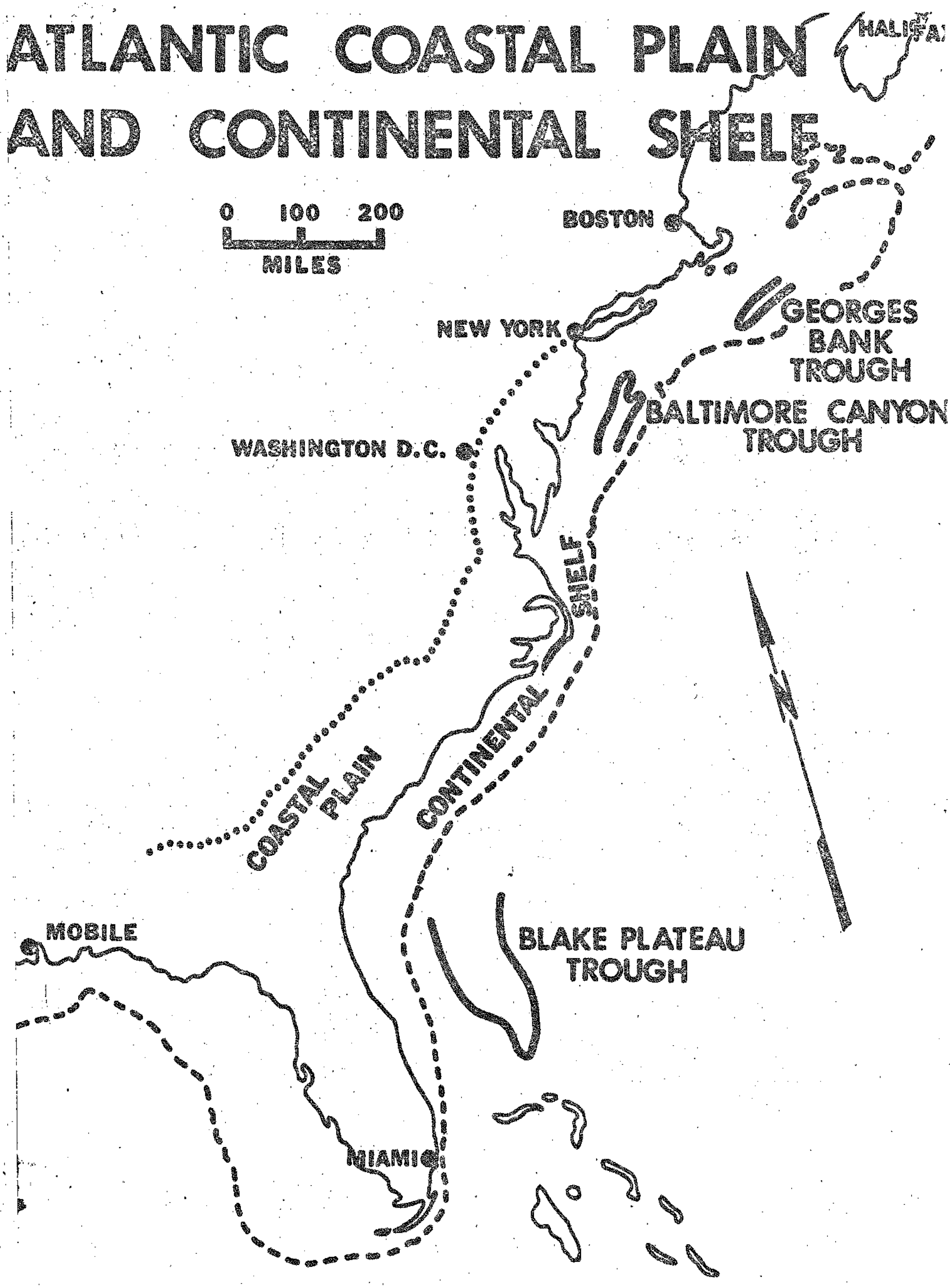
[6]Offshore Oil Task Group. The Georges Bank Petroleum Study, (Cambridge: Massachusetts Institute of Technology, Report MITSG 73-5, February 1, 1973 and Ahern, William A., Jr., Should Georges Bank Be Leased for Petroleum Development, (Cambridge: Unpublished Ph.D. dissertation, Harvard University, May 1973).

ATLANTIC COASTAL PLAIN AND CONTINENTAL SHELF



Atlantic Outer Continental Shelf Production Possibilities

Any comprehensive evaluation of AOCS development and management options requires knowledge of potential AOCS production possibilities. This entails an examination of the physiography and geology of the region in order to arrive at estimates of resource location, fuel type and quality as well as production costs. In order to provide a proper perspective, knowledge of the current and potential status of OCS developments is also required.

What is currently known about AOCS resource location and characteristics is adequately reported in several recent publications.[7] Further analysis of these questions is not necessary for the purposes of this paper. However, an overview of OCS development and its potential will be an aid in understanding the importance of the leasing questions to be addressed.

In 1972 approximately 11 percent of the oil and natural gas produced domestically was extracted from OCS reserves. This compares to approximately 5 percent in 1965. However, less than 2.0 percent of the United States OCS area to the 200 meter water depth had been leased for exploration and development.

Over the 1954-1971 time period a total of 7,253,670 acres of OCS lands were leased. As shown in Table 1, well over one-half of this acreage is located in the Louisiana region of the Gulf of Mexico. Government revenue

Table 1. OCS Lease Sale Summary
(1954-1971)

Region	Number of Leases	Acreage
California	129	678,121
Louisiana	1143	4,762,723
Florida	23	123,480
Texas	264	1,099,493
Oregon & Washington	101	589,853
Total	1660	7,253,670

Source: US Congress, Senate Committee on Interior and Insular Affairs, Outer Continental Shelf Policy Issues, Hearings, Senate, 92nd Congress, 2nd Session, 1972, p. 66.

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[7]Rogers, William B., et al., Petroleum Exploration Offshore From New York (Albany: New York State Museum and Science Service, Circular 46), April 1973.

Maher, John C., Geologic Framework and Petroleum Potential of the Atlantic Costal Plain and Continental Shelf (Geological Survey Professional Paper 659.)

over the 1953-1971 period from OCS lands totaled approximately 6.5 billion dollars. Of this bonuses totaled 4.5 billion dollars, royalties 1.9 billion dollars and other payments .1 billion dollars.[8]

As shown in Table 2 over the 1963 to 1971 period, the majority of permits granted for geological and/or geophysical exploration were also issued in the Gulf Coast area.

Table 2. Permits Granted for Exploration by Region (1963-1971)

Region	Number of Permits
Alaska	178
Atlantic	48
Alabama	59
Florida	139
Louisiana	1701
Mississippi	43
Texas	759
Pacific	177
Total	3,174

Source: US Congress, Outer Continental Shelf Policy, Hearings, op. cit., p.63.

In terms of fossil fuel production, 418,548,946 barrels of crude oil and condensate were extracted from OCS areas in 1971. Of this, 92 percent was produced in the Louisiana area, 7 percent in the California area and 1 percent in the Texas area. In the same calendar year, over 2.7 trillion cubic feet of gas was produced in OCS areas. Of this, 95 percent was produced in Louisiana, less than 1 percent in California and the remainder in Texas.[9]

The emphasis upon Gulf Coast OCS resources exploration and development is expected to continue for the next several years. However, government officials and industry representatives are devoting increasing attention to other OCS areas, notably the Atlantic OCS area and the Gulf of Alaska OCS area. As shown in Table 3, there is evidence that both these areas may contain substantial reserves recoverable under current economic and technological conditions.

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[8] U.S. Congress, Senate Committee on Interior and Insular Affairs, Outer Continental Shelf Policy Issues, Hearings, op. cit.

[9] Ibid.

Table 3. Estimates of Recoverable Oil and Natural Gas Reserves in the Outer Continental Shelf to the 200 Meter Water Depth

Ocs Areas	Estimated Reserves Recoverable Under Existing Economic and Technological Conditions	
	Natural Gas(trillion cubic feet)	Oil(billion barrels)
Gulf of Mexico	300	60
Pacific	38	8
Alaska	271	54
Atlantic	211	42

Source: United States Department of the Interior, Bureau of Land Management, The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the Natural Supply of Petroleum and Natural Gas, (Washington: Government Printing, May 1970) pp. 20 and 49.

From the inspection of Table 3, it is seen that the Atlantic OCS area may offer almost as much potential as the Gulf area. However, estimates such as those presented in Table 3 are subject to a large degree of speculation. This is particularly true of the AOCS area where virtually no exploratory work has been undertaken. In fact, it must be said that recoverable AOCS reserves of natural gas range from 0 to 211 plus trillion cubic feet, while recoverable AOCS oil reserves range from 0 to 42 plus billion barrels. Estimates of potential as compared to recoverable AOCS gas reserves range to a high of 423 trillion cubic feet, while estimates of potential AOCS oil reserves range to a high of 182 billion barrels.[10]

The OCS Leasing System

Conceptually, a public leasing system should begin with a planning process and culminate with the development of administrative rules, regulations, guidelines and procedures. Ideally, the planning process is iterative so that the administrative system is continually adjusted in response to changing economic, social and environmental conditions. In order to systematically discuss the current OCS leasing system, it is necessary to outline both the current planning process utilized as well as the administrative procedures flowing from this process.

[10] William Ahern, Jr., Should Georges Bank Be Leased for Petroleum Development, op. cit., pp. 12-17. Potential reserves may be eventually recoverable depending upon economic and technological conditions.

The Leasing Planning Process: The planning process consists of several distinct yet interrelated elements. The first of these is a concise definition of the relevant objective function which encompasses the principle goals and objectives to be achieved. Subsequent elements include a definition of policy variables or the means of achieving the defined goals and objectives; an information base consisting of resource supply data and demand projections; the formulation and evaluation of alternative programs designed to achieve the specified objectives and; an evaluation of program performance. Ideally the output of the process provides the basis for the definition of desirable changes in policy and also establishes the data and information base upon which administrative decisions are founded.

The Objective Function: The Outer Continental Shelf Lands Act of 1953 (P. L. 212) provides for the jurisdiction of the United States over the submerged lands of the Outer Continental Shelf. In addition, the Act delegates to the Department of the Interior (DOI), the principle administrative and planning responsibilities for the development and management of OCS energy resources. The Act also sets forth three general objectives related to the leasing of OCS lands for energy development: (1) conservation of the resource; (2) receipt of a fair market value for leased resources; and (3) orderly and timely resource development. In addition to the three objectives set forth in P. L. 212, environmental legislation has added a fourth major objective: protection of the natural environment.[11]

Thus, the leasing planning process involves the maximization of a multiple objective social welfare function of the following general form:

$$1.\quad S\text{-}W = f\,(b_1x_1,\ b_2x_2,\ b_3x_3,\ b_4x_4,\ \ldots,\ b_mx_m).$$

where x_1 = resource conservation
x_2 = government revenue
x_3 = resource development
x_4 = protection of the environment
x_m = other implicit objectives

The tradeoffs or relative weights between the components of this function are represented by b_1 through b_4 and b_m respectively.

Policy Variables: In addition to providing the foundation for the objective function specified above, the Outer Continental Shelf Lands Act, either by ommission or mandate specifies the principle policy variables by which the leasing objectives can be achieved. As mandated by statute, leases must be allocated through a competitive sealed bidding system. However, bidding may be either on the basis of cash bonus or a royalty. Royalty payments, as

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[11] National Environmental Policy Act of 1969; The Federal Water Pollution Control Act Ammendments of 1972; and The Marine Protection, Research and Sanctuaries Act of 1972.

stipulated, must exceed 12.5 percent of the value of production. The Act does not specify the total acreage to be offered for sale or the frequency of sales, but it does mandate maximum individual lease tract sizes of 5,760 acres. It also provides for the establishment of conservation regulations to prevent waste of energy resources, but specific procedures are not set forth.[12]

Therefore, given existing legislation, the principle policy planning variables include: (1) selection of lands for lease; (2) the size of lease sales; (3) the frequency of sales; (4) the bidding variable; (5) conservation regulations; and (6) determination of royalty above the minimum specified level.

With regard to the first variable, exploratory activities conducted by private industry currently determined to a large extent which OCS areas are selected for leasing. As stated by the Public Land Law Review Commission:

> Although the Outer Continental Shelf Lands Act authorizes the Secretary to issue leases either upon the Department's motion or upon a request describing the area and expressing an interest in leasing, departmental nominations have played a relatively minor role in the selection of areas for lease, apart from drainage sales.[13]

Historically, the DOI has also played a passive role in the determination of the size and frequency of lease sales. According to official statements, the analysis of when and how much oil and gas resources are to be offered for lease is determined in part by an examination of projected OCS production in relation to projected demand.[14] However, in the past the number of tracts offered and the interval between sales has varied considerably. As stated by the Public Land Law Review Commission:

> There has been no affirmative policy and the timing of sales appears to have been a function of industry demand and varying administrative pressures for increasing revenue to meet the fiscal requirements of the Federal Government.[15]

The DOI has always utilized a cash bonus resource allocation system; the royalty rate has historically remained at 16 2/3 percent; and federal conservation regulations have not been promulgated. In summary, the DOI has

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[12]For a detailed discussion see: Public Land Law Review Commission, op. cit.

[13]Public Land Law Review Commission, op. cit., p. 87.

[14]U. S. Department of the Interior, Bureau of Land Management, Draft Environmental Impact Statement - OCS Sale 32 (Washington: Bureau of Land Management, 1973), p. 4.

[15]Public Land Law Review Commission, op. cit., p. 119.

not attempted to plan for the systematic development of OCS energy resources. This is due in part to a general scarcity of adequate planning data.[16]

Planning Data and Information: Presently, much of the necessary planning data and information related to energy resources is collected by private industry and industry associations. Under the present institutional arrangements, the industry is not required to submit geological or geophysical information on unleased areas to the Federal Government. Thus, planning data is limited to that which the government gathers itself or can purchase from the industry.[17] A consequence of this situation is that the government cannot effectively select areas for lease, or effectively evaluate tracts nominated by the industry or their subsequent bids. Moreover, existing data on energy demand is generally deficient as a basis for comprehensive planning and policy making with regard to OCS development.[18] Other data and information problems exist due to the lack of a comprehensive national energy policy and the absence of coordination between offshore development and land use planning programs.

Alternative Program Formulation and Program Evaluation: As a result of the limited information base and the inability of federal decision makers to properly define the relative weights for a leasing strategy objective function, almost no evaluation of alternative leasing programs has been carried out by DOI or the Office of Management and Budget. Consequently, the interdependence of policy variables and the potential impact of their manipulation (both separately and in concert) is not fully understood. This is especially true of the magnitude of such impacts with respect to possible objectives, but often encompasses the direction of the impact as well. The lack of an analytical framework for evaluating alternative leasing policies in an ex ante sense has also inhibited ex post program evaluation. The leasing policy model to be discussed in the final section of this paper is an attempt to provide a preliminary framework for both types of analysis.

Administrative Procedures: As a result of the lack of a comprehensive OCS planning process, the administrative leasing procedures outlined below are designed to react to the initiative of private industry. Thus, the procedures relate primarily to the mechanics of leasing and the preparation of Environmental Impact Statements.

At the outset, it is important to note that within the Department of the Interior, the Bureau of Land Management (BLM) is responsible for implementation of leasing objectives, while the Geological Survey (USGS) has the responsibility for the issuance of permits for pre-leasing exploratory activities

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[16] D. E. Kash and I. L. White, Energy Under the Oceans (Norman: University of Oklahoma Press, 1973) p. 118.

[17] Ibid, pp. 152-157.

[18] Ibid, p. 188.

and for the supervision and regulation of exploration, development, and production activities after leases are issued. Because of this latter function, they are also primarily responsible for data collection activities.

The administrative system is implemented by the DOI through a procedure consisting of eight major components or procedural steps. The first of these, "the proposed schedule" is utilized by the BLM to determine the timing and initiation of sale procedures. As noted above, the DOI has historically played a rather passive role in this process.

The second component is the "call for nominations" which is an official notice to the industry to nominate tracts which may be offered for lease. Calls for nominations are issued for large contiguous areas and the industry is allowed a period of from 60 to 90 days to submit tract nominations. After nominations have been received, specific tracts are selected by the Department of the Interior for offering. The selection process includes an examination of geologic, engineering and economic information. In addition, tract leasing history, nomination patterns, the degree of competition, and environmental factors are considered. The selected tracts are then published in the Federal Register.

Next, a draft Environmental Impact Statement (EIS) is prepared, public hearings are held, and a final EIS is completed. Throughout the preparation of the EIS, coordination is maintained with other federal agencies. Liason is also provided with state and local groups, as well as with universities. The final EIS is submitted to the Council on Environmental Quality (CEQ).

After the EIS component of the procedure, a "Pre-Sale Evaluation" is undertaken by the Department of the Interior. In essence, the evaluation entails an estimate of the economic value of the tracts offered for lease.

As mandated by statute, the sale is made on the basis of competitive sealed bidding. Following the sale, the DOI undertakes a post sale analysis in order to determine whether leases should be issued. The emphasis of this analysis is upon the receipt of a fair market value. Subsequent to this analysis, a decision to accept or reject the high bid is made. All high bids rejected are subject to appeal to the Board of Land Appeals.

Summary: From the above discussion it is obvious that the leasing policy variables identified do not directly enter either the planning or administrative processes utilized by the Federal Government. To a large extent, leasing policy is determined by two factors: (1) pressure by private industry and (2) receipt of a fair market value for leased resources. Recently, however, public as well as academic debate has focused upon the role of the Federal Government in the planning for and development of outer continental shelf energy resources.[19] Specifically, the debate has centered around alternatives to the present system and their expected impacts.

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[19] See: U. S. Congress, Senate Interior and Insular Affairs Committee, Hearings on Oversight on Outer Continental Shelf Lands Act, 92nd Congress, 2nd Session (Washington: Government Printing Office, 1972); and D. E. Kash and I. L. White, op. cit.

Leasing Policy Issues and Alternatives

As a result of Presidential directives and the increasing domestic energy shortfall, formulation of alternatives to the present outer continental shelf leasing system must be investigated and evaluated. The discussion below will focus upon the issues and alternatives related to federal-state jurisdiction, the selection of lands for lease, the determination of the frequency and size of lease sales, the system of lease allocation, and resource conservation.

Jurisdictional Issues: The development of oil and gas resources of the OCS began as early as 1897 in areas adjacent to the states of California, Texas, and Louisiana. During the 1897 to 1937 period, the states assumed jurisdiction over submerged lands and leases were granted by states for development. In 1937 a Senate resolution was passed which directed the Attorney General of the United States to claim ownership of submerged lands. Debate over state-federal territorial rights continued through 1947 when the Supreme Court decreed that the United States held ownership of submerged lands underlying the Pacific Ocean in the California area. This decision was followed by similar rulings which rejected the ownership claims of Texas and Louisiana to submerged lands adjacent to their coasts.[20]

In 1953, the Submerged Lands Act returned jurisdiction over submerged lands to the states. However, the lands conferred to the states by the Act were limited to areas out to 3 miles from the coastline of the states on the Atlantic and Pacific and 9 miles on the Gulf of Mexico. Three months later, the Outer Continental Shelf Lands Act was enacted. This Act established federal jurisdiction over lands outside those ceded to the states by the Submerged Lands Act.[21]

Debate and litigation continues, however, as to federal-state territorial jurisdiction. This issue may play an important role in the development of the AOCS. As pointed out by Kash and White.

> Atlantic coast states do not have state agencies with the oil and gas expertise of those in California, Louisiana and Texas. Thus, a wider potential administrative latitude exists for establishing state-federal intergovernmental cooperation. However, anticipated jurisdictional problems

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[20] Public Land Law Review Commission, Study of Outer Continental Shelf Lands in the United States, (Springfield, Virginia: National Technical Information Service, 1969) p. 84.

[21] Public Land Law Review Commission, op. cit., p. 84-85 and Chapter 3. For a discussion of National-International Institutional Issues and History see: Public Land Law Review Commission, op. cit. and D. E. Kash, I. L. White, et al. Energy Under the Oceans, (Norman, Oklahoma: University of Oklahoma Press, 1973) pp. 205-218.)

> along the Atlantic Coast may result in conflict and delay, possibly to the point of forestalling OCS petroleum resource development.[22]

This prediction has materialized as New York, along with 12 other Atlantic Coast states recently filed a suit before the Supreme Court claiming jurisdiction over the mineral rights of offshore resources. This legal action began on April 1, 1969, "when the federal government initiated suits against thirteen eastern states to enjoin acts of proprietorship over the seabed further than three miles from their coasts."[23] Thus, the basic issues of territorial jurisdiction and hence ownership of resources potentially worth "trillions of dollars" remains an unsettled issue.

In addition to questions of territorial jurisdiction, other potential jurisdictional issues include pipeline rights of way, coastal zone management and protection of tidal wetlands. As stated by the Public Land Law Review Commission:

> The OCS Lands Act does not authorize the condemnation of rights-of-way across state lands or of sites for onshore facilities where these are necessary or desirable for the efficient operation of OCS leases.[24]

Jurisdictional Alternatives: The Outer Continental Shelf Lands Act has not been totally successful in the resolution of jurisdictional issues. Several factors may account for the continued dispute. Historically, arguments have been advanced that OCS activities have had an adverse fiscal and environmental impact upon coastal states. Thus, revenue sharing of OCS proceeds has been suggested as a means to mitigate opposition to OCS development.[25] Such a solution has been successfully adopted by Australia through enactment of a program which divides OCS revenues between the Commonwealth and the states.[26]

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[22] D. E. Kash and I. L. White, op. cit., p. 207.

[23] For a detailed discussion of the history of territorial jurisdictional disputes and suggested solutions, see: James W. Corbitt, Jr., "The Federal-State Offshore Oil Dispute," William and Mary Law Review, Vol. 11, 1970, p. 759.

[24] Public Land Law Review Commission, op. cit., p. 126

[25] James W. Corbitt, Jr., "The Federal-State Offshore Oil Dispute," William and Mary Law Review, Vol. 11, 1970, p. 769.

[26] Ibid. Under the Australian program, forty percent of revenues accrue to the Commonwealth and sixty percent to the states.

With regard to the United States, two alternatives are obvious: (1) compensatory payments to states; and (2) direct revenue sharing. The first alternative would require the Federal Government to compensate states for net fiscal burdens and for environmental damages not covered by company liability. There is, however, substantial debate as to the magnitude of net fiscal burdens accruing to coastal states as a result of OCS development. Arguments have been advanced that state governments must provide public services, with no hope of compensatory tax collections, in order to accommodate OCS activities. However, it has also been argued that OCS development induces an increase in state revenue through the generation of increased regional economic activity and, thus, state taxes. The net fiscal burden imposed by OCS development remains an unsettled issue, which has not been subjected to quantification.

A program to share a fixed proportion of OCS revenues with coastal states could have a significant impact upon the federal revenue obtained from leasing activities. Moreover, in the AOCS area north of Chesapeake Bay, the determination of which states receive revenue is extremely difficult. In some cases, three or more states could claim to be adjacent to potential development areas. This situation could result in considerable litigation.

Lease Allocation Issues: As outlined previously, the current lease allocation system consists of a cash bonus bidding procedure. According to its proponents:

> This system has the economic advantage of substituting market forces for administrative judgments, and because a bonus must be paid before the lease is issued, (20%), it tends to insure the selection of an efficient producer. Presumably, the more efficient the producer, the lower his cost and the higher his bid.[27]

The system does, however, have economic disadvantages to private firms in that a substantial investment is required before knowledge of production potential is obtained. Moreover, the bonus system may force several competing firms to undertake exploratory activities in the same area. The private market nature of the bonus bidding system also diminishes the opportunity for the achievement of social objectives other than the maximization of government revenue. For example, alternative systems such as an administrative system could allow for the sale of leases at less than a "fair market value" in order to achieve other social objectives. As Kauffman points out:

> ... under a competitive bidding system the price is set in the market place, and it is difficult to adjust terms to achieve national objectives other than revenue raising.[28]

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[27] Alvin Kauffman, "International Offshore Leasing Practices," Journal of Petroleum Technology, Vol. 22, March 1970, p. 248. This assumes all bidders have the same knowledge as to the potential value of the tract.

[28] Ibid., p. 248.

Questions of competition and equity have also been raised with regard to the present cash bonus bidding system. In essence, the system requires a substantial initial capital investment, which results in a bias in favor of the major petroleum companies. Historically, major companies, individually or in combination, have controlled approximately 81 percent of leased acreage and 97 percent of production, while independents have controlled only 19 percent of the acreage and 3 percent of the production.[29]

The impact of the bonus bidding system upon OCS production is another issue which has not been resolved. William A. Vogely of the Interior Department, has stated that, "The amount of oil and gas that will flow from the OCS in the next 10 years is primarily a function of the size and timing of the lease sales, not the leasing system.[30] However, opponents of the system argue that the present cash bonus system retards the development of offshore oil and gas production and that OCS investment would become more attractive under alternative systems of lease allocation such as a deferred bonus bid system or a royalty bid system.[31] Such alternatives it is argued would release capital for immediate exploration and development[32] offshore and permit the exploration of more alternatives within a given time frame.

Finally, the lease term has become an issue. The Outer Continental Shelf Lands Act requires a lease term of five years, and so long thereafter as authorized operations are conducted. The Public Land Law Review Commission concluded that the five year term has been adequate in the past. However, in some outer continental shelf areas, drilling operations may only be feasible for portions of a given year.[33] This situation can result in areas such as the AOCS or the Gulf of Alaska where oceanographic and weather conditions may be severe and where drilling in very deep waters may ultimately be necessary. Under these conditions, a longer lease term may be desirable.

Alternative Systems of Lease Allocation: Many alternative systems of lease allocation have been proposed. As stated by the Public Land Law Review Commission:

> Although the issuance of . . . leases with fixed royalty through bonus bidding has returned substantial revenues to the federal government, greater flexibility in lease terms and the means by which leases are allocated might benefit the federal government by encouraging additional exploration and development.[34]

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[29] Richard Corrigan, "Energy Report," National Journal, July 8, 1972, p.1112.

[30] Ibid., p. 1116.

[31] Ibid., p. 1110.

[32] "Cash-Bonus Bidding Seems Entrenched," Oil and Gas Journal, June 26, 1972, p. 34.

[33] Public Land Law Review Commission, op. cit., pp. 123-124.

[34] Ibid., p. 132.

Alternative lease systems include: (1) installment bonus bidding; (2) royalty bidding; (3) a change in the royalty system; and (4) a negotiated concession system. Options two and three could be implemented under existing statutes. The first and fourth options would, however, require new legislation.

According to its proponents, an installment bonus system might increase the rate of OCS energy development because the initial capital requirement would be reduced. Under this system, cash payments are made at specific intervals. Two options are possible: (1) installment payments with the right to terminate and; (2) installment payments without the right of termination. However, in either case, government revenue could be substantially affected. The effect on government revenue depends, however, on two opposing forces. The first is that since the government shares the risk, higher bonus bids might be expected. In opposition, however, nonproductive leases would create little revenue.

Royalty bidding has been suggested as another approach to resource allocation which would free capital for immediate exploration and development.[35] There is also a contention, but no data to support the hypothesis, that government returns on a present value basis would be larger than those received through the present system. This is based on the assumption that bonus bids are sharply discounted for risk. Department of the Interior officials have, however, calculted that a 70 percent royalty would have to be imposed to equal the government revenue realized under the existing system.[36]

A royalty system carries with it an inherent resource conservation problem. The bonus bid represents a "sunk cost" which does not enter into the decision whether or not or how fast to produce. On the other hand, a royalty bid may lead to early abandonment of marginal fields since the royalty affects the producer's income per unit extracted.

Changes in the royalty system have also been suggested as an alternative to the present fixed rate. Two options are available under existing legislation: (1) increases in the royalty rate; and (2) establishment of a sliding scale of royalty rates. An increase in the royalty rate could conceivably lead to a decrease in bonus bids, thus reducing the initial capital requirements. However, the extent to which capital would be released is in doubt.[37] A sliding royalty system, on the other hand, could be utilized in conjunction with a cash bonus bid to provide a system with the flexibility to respond to changing energy and financial situations. It is possible that the royalty rate could be linked to government objectives in such a way as to provide an automatic adjustment mechanism which would respond to changes in the level of achievement of relevant objectives. As such the system operation could be somewhat analogous to the built-in adjustment mechanism provided by the federal income tax structure.

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[35] "Cash-Bonus Bidding Seems Entrenched," Oil and Gas Journal, June 26, 1972, p. 34.

[36] Richard Corrigan, op. cit., p. 1112.

[37] D. E. Kash and I. L. White, op. cit., p. 181.

Most countries other than the United States utilize a negotiated concession system for OCS leasing.[38] In other words, the government makes an admimistrative determination on leasing as opposed to the market system utilized in the United States. Such a system has economic advantages as well as disadvantages. For example, there is no duplication on the part of the industry in the collection of data and information. The major advantage to the government is that the system is flexible to achieve objectives other than government revenue. However, the administrative cost is substantial.[39] In addition, procedures to insure expeditious development of the resource must be incorporated into the system. Aside from economic considerations, it is obvious that a negotiated concession system is wrought with political difficulties. Thus, there appears to be little interest in this alternative at the present time.[40]

The impacts of the alternative leasing options discussed above are speculative in nature at this time. The pros and cons given for each have been based largely upon subjective judgment. There is virtually no empirical data or analytical models available by which the impacts of the various systems can be determined. Thus, a major focus in the future needs to be the development of analytical models and to empirically derive the impacts of alternative energy resource allocation systems.

The Location, Size and Frequency of Lease Sales: The amount of OCS production realized, as well as government revenue, is a direct function of the size, frequency and location of lease sales. It may be anticipated that an accelerated schedule with the addition of leasing in new areas will lead to more petroleum production. On the other hand, there could be an associated decline in government revenue received due to lower bids as a result of more sales and a larger total volume of acreage being offered. There is evidence that:

> Successive Secretaries of Interior have pursued a policy of pacing out the development of OCS oil and gas resources, with leases being parcelled out at a rate that has kept the offshore industry hungry and bonuses high.[41]

Moreover, the leasing schedule has been sporadic. As stated by Thomas D. Barrow, President of Humble Oil and Refining Company, "the leasing schedule has caused a feast-or-famine cycle for industries operating offshore.[42]

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[38] A. L. Kauffman, op. cit., p. 248.

[39] Ibid., p. 248.

[40] "Cash-Bonus Bidding Seems Entrenched," Oil and Gas Journal, June 26, 1972, p. 34.

[41] D. E. Kash and I. L. White, op. cit., p. 171.

[42] U. S. Congress, Senate Committee on Interior and Insular Affairs, OCS Policy Issues, Hearings, op. cit.

As noted previously, the DOI has played a very passive role in the process of the selection of lands for lease, and the size and frequency of lease sales. Prior to President Nixon's 1973 Energy Message, the only leasing schedule which had been formulated by the Department of the Interior was published in 1971. To many observers, in light of environmental issues and the current and projected domestic energy shortfall, this is no longer desirable.

In the 1973 Energy Message, the President directed the Secretary to develop a long term leasing program based upon the nation's energy, economic and environmental objectives.[43] The formulation of such a program will require an analysis of the impacts of alternative lease strategies. Such an analysis must consider:

1. Inclusion of additional objectives in the decision making calculus.

2. Estimation of and public disclosure of the impacts of alternative schedules upon the relevant objectives.

3. Improved information of OCS production potential and energy demand.

With regard to the objectives pertinent to the decision making process, economic efficiency, balance of payments, consumer prices, and regional income are all relevant. The inclusion of these economic objectives would complement and clarify the present economic objectives of "orderly resource development" and government revenue.

Empirical estimation of the impact of alternative schedules is necessary since management decisions are often made without a consideration of the full range of alternatives and their associated impacts. Public disclosure of such information could facilitate the decision making process throughout.

As noted previously, data and information on energy reserves, resources and energy demand are generally deficient as a basis for comprehensive planning and policy making with regard to OCS energy development. Several options have been suggested with regard to geological and geophysical data, including:[44]

1. Governmental collection of geological data.

2. Industry submission of all data to the USGS or BLM.

3. Combinations of the above.

Resource Conservation: Energy resource conservation is also a policy issue with regard to OCS development. As defined by McDonald, the socially desirable function of resource conservation is, "to achieve or maintain from the point

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[43] Richard Nixon, Congressional Record, Vol. 62, No. 119, H. 2888.

[44] D. E. Kash and I. L. White, op. cit., pp. 152-157.

of view of society, the maximum present value of the natural resource."[45] Given this definition, optimum development takes place to the point where no gain can be obtained from shifting production from one time period to another. The economic optimum rate of development includes consideration of how fast a given reservoir should be depleted. This involves a consideration of the number of wells to be drilled in a given reservoir and the rate of development associated with each well. Administrative determination of the number of wells to be drilled and production restrictions directly impact the time stream of production, production costs, industry income and government revenue. Historically, production restrictions and the unitization requirements of coastal states have generally been applied to OCS lands under federal jurisdiction.[46] However, for frontier areas such as the AOCS, federal guidelines have not been developed nor have procedures been promulgated by individual states.

The important aspect of conservation regulation is the potential impact upon the time stream of production and production costs. In the past, production quotas have been applied to allocate production over time and among many producers. These quotas have been based upon a dual concept of: (1) the maximum efficient rate of production from the standpoint of the physical characteristics of the reservoir; and (2) maintenance of a preferred product price through production restrictions based upon market demand. Given present market conditions, the latter concept does not apply and the time stream of production is essentially based upon the physical characteristics of the field. This ignores the economic concepts of conservation. In addition, the relationship between production and production cost is largely ignored in the present conservation system. As stated by the Public Land Law Review Commission:

> Continuation of the present system . . . without recognition of operating costs could reduce individual operator margins to the point where further development of outer continental shelf resources beyond a given water depth will become unattractive and reduce bonus bids and competition for them.[47]

<u>Additional Considerations</u>: Additional policy issues relevant for empirical analysis include: (1) deregulation of natural gas prices; (2) extension of the investment credit to exploratory wells; and (3) adjustments in the depletion-allowance system.

Each of these issues relates directly to the complex system of economic and institutional incentives underlying the production of oil and natural gas. For example, deregulation of natural gas prices may provide an economic incentive to increase exploratory activities and hence production.

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[45] Stephen L. McDonald, <u>Petroleum Conservation in the United States: An Economic Analysis</u> (Baltimore: John Hopkins Press, 1970), p. 71.

[46] Public Land Law Review Commission, <u>op. cit.</u>, p. 122.

[47] Public Land Law Review Commission, <u>op. cit.</u>, p. 122.

Summary: Over the past several years debate has focused upon many aspects of the current Outer Continental Shelf leasing system. This debate has tended to center upon the tradeoffs implicit in the current leasing and management system between government revenue, environmental protection, and the desire to develop domestic energy resources. As stated by Kash and White:

> There seems to be ample evidence that the pace of OCS leasing has been determined more by a desire for revenue than on the basis of an assessment of the portion of total energy requirements that is desirable to obtain from the OCS.[48]

John D. Emerson, a petroleum economist at the Chase Manhattan Bank presents the situation as follows:

> The first thing we need to do is to sit down and say, what are our objectives - money for the treasury or more oil and gas.[49]

Although many alternatives to the present leasing system have been proposed, there is a total lack of quantitative analysis between the alternatives and the relevant objective function. An analytical model to fill this void will be discussed next.

A Model for AOCS Leasing Policy Analysis

The model formulated here is based upon micro-economic concepts. Its purpose is to estimate the impact of changes in leasing policy variables upon defined economic objectives. At this point, the model is specified in gross detail. Refinements to increase the scope and analytical resolution will be the focus of further research. The model is specified to be consistent with industry wide decisions related to the bidding for and production of oil and natural gas from the Atlantic Outer Continental Shelf. No attempt is made to model individual company behavior with respect to OCS activity. The following discussion is divided into three sections. First, the model is specified. Second, requirements for model application to the AOCS region will be explored. Third, several hypothetical examples of model implementation will be provided, the sensitivity of results to changes in relevant parameters tested, and linkages between the model and policy options investigated.

Model Derivation: Assume a fossil fuel reservoir with fixed reserves R.[50]

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[48] D. E. Kash and I. L. White, op. cit., p. 188.

[49] Richard Corrigan, op. cit., p. 1110.

[50] R is defined as reserves that may be recovered given the present state of technology but without utilization of advanced recovery techniques. Given this definition, the decision to produce and the level of initial capacity is based solely upon economic considerations. Future decisions concerning advanced recovery methods depend on reservoir data acquired during initial production, price and costs factors at the time such recovery is required and additional reserves expected to be acessable due to investment in these methods.

The cumulative output from R may be represented by an exponential decoy function of the form:[51]

$$1. \quad R = \int_0^T q_o \, e^{-at} \, dt$$

where: q_o = initial capacity installed

a = decline rate influenced by physical characteristics as well as conservation regulations

T = time horizon

When "T" is large, which corresponds to the normal case for oil and gas production, equation 1 reduces to:

$$2. \quad R = q_o \, / \, a$$

The cumulative present barrel equivalent output (PBE) from R may be expressed as:

$$3. \quad PBE = \int_0^T q_o^{-at} \, e^{-rt} \, dt$$

where: r = a discount rate

As "T" approaches infinity, equation 3 reduces to:

$$4. \quad PBE = \frac{q_o}{a+r}$$

Referring back to equation 2, "a" in equation 4 may be replaced by the term $q_o \, / \, R$. Thus:

$$5. \quad PBE = \frac{q_o}{(q_o/R)+r}$$

Given R, a decision on the optimum level of initial capacity, "q_o," must be made. Economic theory indicates that this decision will be based upon anticipated marginal cost and marginal revenue in present value terms. Marginal cost is defined to include the present value of: (1) investment

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[51]The basic physical relationships described in this section are based upon the works of: Paul G. Bradley, The Economics of Crude Petroleum Production (Amsterdam, North-Holland, 1967); M. A. Adelman, The World Petroleum Market (Baltimore: John Hopkins Press, 1973); and M. L. Baughman, Dynamic Energy System Modelling (Cambridge: MIT, 1972).

costs; (2) operating costs; and (3) royalties.[52] As the present value of anticipated operating and royalty costs are equivalent to an investment made today, these may logically be included in the determination of the optimum capacity to install. Other expense items, such as corporate income taxes, do not theoretically affect the marginal cost schedule in the short run and, thus, are omitted from the analysis.[53]

Investment costs can be defined as a direct function of the initial capacity installed. Thus:

$$6. \quad I = b\, q_o$$

where: b = investment cost per unit of initial capacity.

The present value of anticipated royalty and operating costs may be represented by:

$$7. \quad I' = \int_0^T K\, q_o\, e^{-(a+r)t}\, dt \; + \; \int_0^T \lambda P\, q_o\, e^{-(a+r)t}\, dt$$

where K = operating costs per unit

λ = royalty rate

P = price

Equation 7 simply states that the present value of operating and royalty costs are obtained by multiplying per unit costs by the PBE value.[54] Thus, as T approaches infinity, equation 7 becomes:

$$8. \quad I' = K\frac{q_o}{(q_o/R)+r} \; + \; \lambda P\, \frac{q_o}{(q_o/R)+r}$$

Total cost, "C," equals I + I' or:

$$9. \quad C = b\, q_o + K\frac{q_o}{(q_o/R)+r} \; + \; \lambda P\, \frac{q_o}{(q_o/R)+r}$$

Marginal costs are derived by taking the derivative of "C" with respect to q_o. Thus:

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[52]Previous formulations by others (See footnote 51) do not include royalty costs, and operating costs are often ignored. However, those formulations were not derived to analyze leasing policy.

[53]R. A. Musgrave, The Theory of Public Finance (New York: McGraw-Hill, 1959).

[54]For the purpose of exposition, P and K are assumed to be constant over time. In the actual model execution, P could be expressed by: $P_t = P_o\, e^{xt}$ to account for expected price changes. Similarly K could be expressed by: $K_t = K_o\, e^{\theta at}$, in order to account for changes in per unit cost as "R" is depleted through production.

$$10.\quad MC = \frac{d\,C}{d\,q_o} = K\,\frac{r\,R^2}{(q_o + r\,R)^2} + \lambda P\,\frac{r\,R^2}{(q_o + r\,R)^2} + b$$

Total present value revenue (PVR) is expressed by:

$$11.\quad PVR = \int_0^T P\,q_o\,e^{-(a+r)t}\,dt$$

As T approaches infinity, equation 11 becomes:

$$12.\quad PVR = P\,\frac{q_o}{(q_o/R)+r}$$

By differentiating equation 12 with respect to q_o, marginal present value revenue becomes:

$$13.\quad MR = \frac{d\,PVR}{d\,q_o} = P\,\frac{r\,R^2}{(q_o + r\,R)^2}$$

By equating marginal revenue with marginal cost, we obtain:

$$14.\quad P\,\frac{r\,R^2}{(q_o + r\,R)^2} = K\,\frac{r\,R^2}{(q_o + r\,R)^2} + \lambda P\,\frac{r\,R^2}{(q_o + r\,R)^2} + b$$

Equation 14 reduces to:

$$15.\quad P\,(1 - \lambda) = \frac{b(q_o + r\,R)^2}{r\,R^2} + K$$

By solving equation 15 for q_o, the optimum level of initial capacity to install q_o*, becomes:

$$16.\quad q_o* = R\left(\sqrt{\frac{r[\,P\,(1-\lambda) - K]}{b}} - r\right)$$

Given the optimum level of initial capacity economical to install, q_o*, a bonus bid may be determined by taking the difference between present value revenue and present value costs where costs are defined to include a target rate of return on invested capital. Thus:

$$17.\quad B = \int_0^T P\,q_o*\,e^{-(a+r)t}\,dt - [\,b\,q_o* + \int_0^T K\,q_o*\,e^{-(a+r)t}\,dt + \int_0^T \lambda P\,q_o*\,e^{-(a+r)t}\,dt]$$

The bid, B, equals the economic rent to the resource under competitive conditions.

The production function may then be represented by:

$$18. \quad q_t = q_o{*}\, e^{-at}$$

Equations 16, 17 and 18 form the heart of the model. The optimum level of capacity to install is determined by equation 16. The bid and total government revenue can be estimated from equation 17, and annual production by equation 18. To this basic framework a number of refinements and extensions can be incorporated. For example, the bid equation can be modified to incorporate considerations of bidding strategy.[55] Other possible additions will be discussed below.

Application to the AOCS Region: Information on reserves, costs, discount rates and prices is required to implement the model specified. As indicated above, accurate estimates of reserves are not presently available for the AOCS or specific areas within the AOCS. Thus, R in equation 16 must be replaced by an estimate of reserves, ER. Others have suggested that the spatial occurrence of ER may be represented by a Poisson process and the size of individual reservoirs by a log-normal distribution. ER occurring in any unit of space, "S," might then be represented by the sum of log-normal random variables where the number in the sum is determined by a Poisson process.[56] Thus, ER in any given time period becomes a direct function of both the size and location of the lease sale. Moreover, ER will change with the level of technology.

Similarly, operating costs are viewed as expected per unit costs. If operating costs increase with reservoir depletion, a separate calculation is required (see footnote 54). As oil and natural gas are treated separately in the implementation of the model, the determination of cost levels presents a special problem due to the existence of joint costs in oil and natural gas production.[57]

The appropriate discount rate for model inplementation is the rate of return on capital expected by the private sector. This rate represents the opportunity cost of alternative investments that could be undertaken and, thus, provides an indication of the marginal value of resources to be utilized. Since the objective of the model is to forecast industry-wide decisions, the

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[55]See: Keith C. Brown, Bidding for Offshore Oil (Dallas: Southern Methodist University Press, 1960); P. B. Crawford, "Texas Offshore Bidding Patterns," Journal of Petroleum Technology, March 1970; E. C. Capen, et al., "Competitive Bidding in High-Risk Situations," Journal of Petroleum Technology, June 1971.

[56]See: Russel S. Uhler and Paul G. Bradley, "A Stochastic Model for Determining the Economic Prospects of Petroleum Exploration Over Large Regions," American Statistical Association, June 1970.

[57]See: U. S. Department of the Interior, The Role of Petroleum and Natural Gas from the Outer Continental Shelf, (Washington: Government Printing Office, 1970).

opportunity cost of private sector investment at the margin is the conceptually correct rate. Because the rate of return may differ between industries due to different risks, taxes and subsidies, the preferred rate to use in conjunction with the lease model is that relevant to those involved in offshore leasing.[58] This will permit improved estimates of the government revenue and production to be expected from private sector development of public lands.

Given the model formulation, prices are specified exogenously. In the case of oil, foreign oil becomes the marginal source, and its projected price is utilized in equations 16 and 17. Natural gas prices will depend on governmental policy with respect to wellhead price regulation. Due to the nature of the bidding process, all prices are viewed as expected as opposed to actual.

The magnitude of reserves, expected prices and costs are subject to varying degrees of risk and uncertainity. As pointed out by Adelman, three general categories of risk may be distinguished: (1) geological; (2) engineering; and (3) political.[59] Geological and engineering risk concern the size of reserves as well as anticipated development cost. Political risk, on the other hand, relates to the probability of changes in government policies which impact product prices as well as cost. An example is the probability of deregulation of natural gas wellhead prices.

Conceptually, risk and uncertainty associated with natural phenomena may be taken into account through probability analysis. However, this is not the case for political risk since the required probability distributions are subjective in nature. Sensitivity analysis is one technique by which political risk may be incorporated into the analysis.

Risk due to natural phenomena may be accounted for by a calculation of an average value weighted by the probability of outcome. Other possible approaches include the calculation of an expected value or an exogenous adjustment of the discount rate. The choice among these alternatives is dictated by the type of risk involved and the availability of appropriate probability distributions. For example, risk may be acturial in the sense that there are a large number of similar decisions to be made and that major importance is attached to the overall result of all decisions. In this case, the expected value approach could be utilized. Under other circumstances, this technique is not appropriate.

Several additional items related to model implementation warrant brief consideration. The first of these is the specification of appropriate time lags between the bid and actual production. Although some

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[58]Theoretically risk can be handled in several different ways (see following discussion). Use of a risk free rate of return will be necessary if other techniques are incorporated in the model.

[59]M. A. Adelman, op. cit., pp. 54-55.

historical data is available upon which time lags may be estimated,[60] the actual specification will require additional analysis. Second, the introduction of a capital budget constraint into the model may be necessary due to the time lag between expenditures and the receipt of revenue. However, there is some evidence that capital can be readily obtained to meet foreseeable increases in domestic petroleum resource development. Thus, the form of a capital constraint also requires additional analysis. Of greater importance, is the possibility of a short-run constraint in the form of drilling and production equipment, and skilled manpower. In the long run, as activity intensifies, the real cost of these inputs may increase significantly. Given a subsidiary analysis, these factors can be included within the framework of the model.[61]

Examples of Model Implementation: Model operation and the relationship of model results to relevant leasing variables can be shown through several hypothetical examples. For this purpose, the model is exercised with the input variables shown in Table 1. Seven test cases are utilized. Cases I and II are identical except for the royalty rate. Cases III and IV utilize the royalty rates for Cases I and II, respectively, but assume an increase in acreage leased so that ER increases. Finally, Cases V, VI and VII use the basic inputs for Case I but vary the price, investment costs and operating costs, respectively.

For Case I (with a royalty rate of 16 2/3 percent), the initial capacity economical to install is 103.30 million barrels per year (assuming no conservation restrictions). The estimated bonus bid equals $1,067,889,000 and the present value of government revenue totals $1,404,502,000.

Now assume that the royalty rate is increased to 50 percent. For Case II, the initial capacity economical to install falls significantly to 65.83 million barrels, and the bid falls to $432,242,000 dollars, while total government revenue is reduced to $1,301,695,000 in present value terms. In essence a higher royalty rate reduces initial production. Therefore, in present value terms, government revenue is reduced. Because of a high decline rate and high product prices, however, the reduction in total government revenue is not as substantial at the 10 percent discount rate.

Next, assume an increase in the leasing schedule such that more acres in a given year are offered for sale. This would tend to increase expected reserves, ER, in any given year and hence an increase in total government revenue may be anticipated. However, several factors may tend to qualify this conclusion. First, the increase in potential production, if substantial,

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[60] U. S. Department of the Interior, op. cit.

[61] An equipment constraint would result in a delay in production. Hence, the bid calculated via equation 17 will be reduced. The ratio of unexplored areas leased to rigs available might be utilized as a variable functionally related to production delays.

Table 1. Input Variables for Hypothetical Model Runs (Oil)

Variables	Units	Case I	Case II	Case III	Case IV	Case V	Case VI	Case VII
ER	MMBBL.	400	400	600	600	400	400	400
b	\$/BBL. of q_o*	4.00	4.00	4.00	4.00	4.00	4.00	5.00
K[a]	\$/BBL.	.70	.70	.70	.70	.70	1.05	.85
λ	%	16 2/3	50	16 2/3	50	16 2/3	16 2/3	16 2/3
r	%	10	10	10	10	10	10	10
P	\$/BBL.	7.00	7.00	7.00	7.00	4.00	7.00	7.00

[a]Includes a 10 percent return on invested capital.

may tend to lower expected prices which would have a negative impact upon the bid. Second, an increase in acreage offered may tend to increase the level of risk. Finally, an accelerated leasing schedule may tend to raise investment costs per unit of capacity due to an increase in the demand for equipment.

By way of example, Case III assumes that ER is increased to 600 million barrels and expected price remains at \$7.00 per barrel. All other assumptions are also the same as Case I. The initial capacity economical to install is 154.94 million barrels and the bid totals \$1,601,923,000. Total government revenue is calculated to equal \$2,106,865,000 on a present value basis. Thus, under the conditions described above, an acceleration in the leasing schedule results in a substantial increase in government revenue over the base case. Production is also increased significantly.

Case IV provides an initial capacity of 98.75 million barrels, a bonus bid of \$1,304,181,000 and total present value government revenue of \$1,952,545,000. The result is a relationship between Cases III and IV similar to that described for Cases I and II.

Case V assumes a price of \$4.00 per barrel and all other variables equivalent to Case I. The result is a drop in initial capacity to 62.632 million barrels and reduced bids of \$391,232,000. Total present value government revenue was reduced by over 60 percent to \$553,696,000. This results from a 33 percent price reduction.

If it is assumed that operating costs per unit increase 50 percent due to more stringent safety or conservation regulations, the initial capacity economical to install becomes 98.323 million barrels, while the bid is calculated to equal $965,984,000. Total government revenue is estimated to equal $1,297,523,000 in present value terms. Thus, the impact is to postpone production into future time periods which in turn reduces the present value of government revenue (vis-a-vis the base case).[62]

Finally, assume that unit investment costs rise to $5.00 as a result of leasing in areas of greater water depth. Under this condition, the initial capacity economical to install falls to 86.28 million barrels. The bid is reduced to $929,233,000 (13 percent), while total government revenue is reduced to $1,247,784,000 (11 percent) of the base case.

Summary: As demonstrated above, the model is useful for the determination of the direct impacts of several leasing policy variables upon government revenue as well as production. Given subsidiary analysis, the model results and data inputs are also useful for estimating impacts upon consumer prices and other relevant economic objectives. Areas in which subsidiary analysis or model expansion could be utilized include the addition of an opportunity cost analysis with regard to alternative potential sources of petroleum and natural gas. Such an analysis would be useful for the estimation of the relative economic efficiency of AOCS development. Additional analysis is also desirable in order to estimate the domestic price impact of incremental AOCS production. As noted above, expected price impacts related to potential production may feed back into the bidding process. Finally, additional analysis is required with regard to the probability of the occurrence of reserves, equipment and manpower constraints, financial constraints, and the specification of appropriate time lags.

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[62] However, a more sophisticated analysis is required to determine the effect of changes in conservation regulations upon the total resource that may be recovered.