Auctioning Resource Rights

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Annu. Rev. Resour. Econ. 2014. 6:175–90

The *Annual Review of Resource Economics* is online at resource.annualreviews.org

This article's doi:
10.1146/annurev-resource-091912-151752

JEL codes: D44, Q38

Keywords

auctions, leases, oil and gas, royalty

Abstract

We review the issues involved in designing a mechanism for allocating resource rights. We focus on the case of exploration and development rights for oil and gas leases in US federal lands to highlight the trade-offs at play. The main issues concern the design of the lease contract, the design of the auction, and the supply of leases. A distinguishing feature of oil and gas leases is that the mechanism must solve not only the adverse selection problem of selecting the bidder with the highest valuation but also the moral hazard problem of ensuring that right holders make efficient investment decisions.

1. INTRODUCTION

Auctions are often employed to allocate resource rights. The US Department of Interior has employed a first-price sealed-bid format to sell drilling and development rights for offshore oil and gas leases in federal lands on the Outer Continental Shelf (OCS) since 1954. Oil and gas rights have also been auctioned by a number of states in the United States and by governments in Alberta, Brazil, the United Kingdom, Norway, Libya, and Venezuela.

The US Forest Service employs both first-price sealed-bid and open ascending (or English) auction formats to sell timber rights. Winners of Forest Service auctions are obligated to harvest timber on tracts that they acquire within a prespecified time period. In contrast, firms that acquire OCS oil and gas tracts have the right, but not the obligation, to conduct exploratory and developmental drilling.

In 1990, the US Federal Communications Commission (FCC) introduced a multiround simultaneous-auction format to allocate spectrum rights. Variations on these rules have since been employed in many countries to allocate their spectrum.

Resource rights have also been allocated by other mechanisms. One example is administrative hearings, or beauty contests, in which the allocation is based on a public interest assessment. Another example is to allocate the rights on the basis of the outcome of a lottery. In both of these cases, the resource right may be accompanied by various obligations, including prespecified payments or future payments on the basis of profits or revenues. However, if the payments are too high, then the obligations may not be met. If the payments are too low, then there will be a perception that the winners were enriched unjustly at the expense of the taxpayer, and there will be an incentive for potential winners to lobby at administrative hearings. An auction is a preferable allocation mechanism to the extent that the allocation is determined as part of a competitive process, as opposed to a random allocation or an allocation that is subject to the influence of lobbying or political considerations. Bidders are forced to reveal information about their valuations of the resource right, and the seller can use this information to allocate the resource right to the bidder with the highest valuation. An auction also facilitates price discovery so that the government does not need to determine how much the winners of the rights must pay.

It is important, however, that an auction mechanism be well designed. A number of design features are at the discretion of the seller. One set of design features is associated with product definition, as the seller must determine what is being allocated. In the case of timber auctions, the Forest Service must decide how large the tract will be, the tenure of the contract, and any work requirements. In the last case, there is an obligation to cut the timber within the tenure of the contract, and there may also be requirements concerning (*a*) replanting or (*b*) building and maintenance of roads. Similar product design issues arise with oil and gas auctions.

A second set of design features concerns the selling mechanism. If multiple properties are being sold, does the allocation allow only single-unit bidding, or is combination bidding allowed? Combination bids have been allowed in spectrum auctions in the United States and Nigeria (Cramton et al. 2006b) and in auctions to allocate bus routes in London (Cantillon & Pesendorfer 2006). Are bids fixed amounts, known as bonuses, or are bids instead percentage royalty payments on revenues (or profits)? The choice will affect the incentives for investments both before the sale (ex ante) and afterward (ex post). Most OCS oil and gas sales have involved bonus bids, but in the late 1970s there was a brief experiment with bids being royalty rates on profits. Are the properties sold simultaneously or sequentially? OCS oil and gas leases are sold under the former mechanism, and Forest Service timber leases under the latter mechanism. FCC spectrum auctions are simultaneous, but multiround, as opposed to the one-shot, simultaneous OCS oil and gas sales. Is the bidding for a given property done via sealed bidding or an open outcry mechanism? The Forest Service employs both mechanisms to sell timber rights.

In this article, we focus on offshore oil and gas leases to highlight the trade-offs at play. A distinguishing feature of oil and gas leases is that leaseholders have to make costly drilling decisions to determine whether the lease contains an oil and gas deposit and is worth developing. The postauction investment decision introduces another dimension to the design problem. The auction must solve not only the adverse selection problem of selecting the bidder with the highest valuation but also the moral hazard problem of ensuring that leaseholders make efficient drilling decisions. More efficient drilling decisions enhance the value of leases, increase the willingness of bidders to pay for them, and potentially raise auction revenues for the seller.

The remainder of the article is organized as follows. Section 2 describes the economic environment for offshore oil and gas exploration and development. In Section 3, we discuss the objectives of the seller, in this case the US Department of Interior, as mandated by Congress. Section 4 discusses lease design issues, including the issues associated with lease rights, lease size, lease tenure, and lease payments. Section 5 then discusses auction design considerations. In Section 6, we discuss the issues associated with the rate at which offshore lands are made available for leasing. Section 7 contains some concluding remarks.

2. THE ECONOMIC ENVIRONMENT

In this section, we describe the offshore oil and gas lease auctions. We focus on aspects of the economic environment and the exploration process that are pertinent for designing a selling mechanism.

2.1. The Outer-Continental-Shelf Auction Mechanism

In the United States, the offshore lands are partitioned into blocks or tracts. The tracts in the Gulf of Mexico are typically 5,760 acres or 9 square miles. These tracts are leased to oil and gas firms. The Bureau of Ocean Energy Management (BOEM), a division of the US Department of Interior, administers the offshore leasing program. (Before 2011, the agency was known as the Mineral Management Service, or MMS.) The BOEM holds yearly sales in which it allocates leases to oil and gas firms via an auction. A lease confers on its owner the right, but not the obligation, to drill exploratory wells and to develop any deposits that are found on a given tract. There is a fixed-lease term during which time drilling must begin; otherwise ownership reverts to the government.

Prior to a sale, the BOEM announces that tracts within a designated area are available for leasing. Firms interested in acquiring leases engage in seismic testing and analysis to determine which tracts to bid and how much to bid. They may also negotiate joint bidding agreements with each other.

The leases in a sale are auctioned individually and simultaneously. Each lease is sold by a first-price sealed-bid auction, in which the bid is referred to as a bonus payment. There is an announced minimum bid or reserve price. The winning bidder pays the bonus on the sale date and also pays a fixed royalty rate on any revenues it earns from postsale production. The government does not necessarily accept the highest bid, even one above the reserve price, if it believes that there is not enough competition for the lease.

Potential bidders in a sale face considerable uncertainty. Deposit locations and sizes are unknown. The extent of drilling that may be required is uncertain. Moreover, exploration and production occur over a long horizon, with leases often being productive for more than 40 years, and drilling costs and oil and gas prices are volatile and difficult to predict.

To a large extent, the uncertainty faced by bidders is common value, as opposed to private value. Bidders face similar drilling costs, as drilling rig rental rates are determined primarily by water depth and market conditions. Bidders also value oil and gas deposits similarly, on the basis of wellhead prices. Bidders are unlikely to have private information concerning future prices and costs. But bidders may have different beliefs concerning deposit sizes and locations, depending on the seismic data they obtain and especially on their interpretation of those data.

Potential competition for the leases has varied over time and location. The early years of the OCS program were dominated by large oil and gas companies, with 12 firms submitting the majority of the bids. The number of these firms has fallen because of a number of mergers. In later years, the larger firms have accounted for less than half of the bids in shallow waters, and there has been entry by many smaller firms. In deep water, there has been much less entry, and the remaining larger firms have dominated the bidding (see Haile et al. 2010). There may be barriers to entry for deepwater exploration that are associated with considerable capital requirements, as well as with the necessary expertise (i.e., learning-by-doing).

Despite the potential market power concerns in exploration and development, there is less concern in the downstream market. For practical purposes, the firms appear to be price takers in the market for oil, with prices determined by worldwide demand and supply conditions. The gas market is less integrated, but offshore supplies account for less than a quarter of domestic consumption.

2.2. Acquisition of Seismic Information

Potential bidders must undertake a costly information-gathering process to find deposits and to extract oil and gas efficiently. They first acquire seismic data, which they use to infer the structure and properties of subsurface rock layers and to identify structural anomalies that have the potential to trap hydrocarbons. Any firm that wishes to conduct a seismic survey must obtain a permit to do so from the BOEM. The permits are nonexclusive. Permit holders must submit their seismic data to the BOEM, but the data are kept confidential for at least 10 years.

In the early days of exploration, the bidders would often run their own surveys. The bidders now subcontract the data collection to a relatively small number of geophysical firms that specialize in this activity, reducing costly duplication. These firms license the survey data to oil and gas firms at negotiated prices. The license agreement restricts the licensee's use of the data, in particular the ability to show the data to other oil and gas firms.

The geophysical firms try to anticipate demand for information by running speculative surveys, typically on large areas of potential interest to bidders. Proprietary surveys are commissioned by a consortium of bidders whose identities are known only to the geophysical company. These surveys are geographically more targeted and are tailored to the needs of the bidders, and the reports are exclusive. The geophysical firm is not supposed to reveal the identities of the bidders that have purchased or commissioned its reports, lest bidders learn who their rivals may be in the auction. A reputation for integrity is valuable to the geophysical firm. The data collection process is cumulative, with new and better surveys making older surveys redundant after a few years.

Seismic data have evolved over time. In the early days of offshore exploration, firms would model the substrata in two dimensions (2D), with projections on vertical cuts known as 2D models. With advances in computing power, three-dimensional (3D) models are now often employed. (In econometrics parlance, firms estimate latent models of the substrata to try to fit the seismic data.) 3D models permit more sophisticated drilling, but the analysis is considerably more expensive. But even with 3D models, seismic data analysis does not reveal the true state of the world.

After acquiring seismic data, geophysicists at the oil and gas firms spend a lot of time processing the survey data and reprocessing them as new information (e.g., additional surveys and drilling outcomes) arrives. The methods used by bidders to process the data are a closely guarded secret, and only the bidder knows the results. Bidders read the evidence differently, resulting in heterogeneous, private interpretation of the data. Experience plays an important role, and entrants are at a distinct disadvantage. The observed dispersion in bids suggests that the heterogeneities in interpretation are substantial and important. In the OCS leasing program, the second-highest bid is on average only two-thirds of the highest bid on leases that attract at least two bidders (Haile et al. 2010).

2.3. Exploratory Drilling

The second stage of the exploration process involves drilling. After identifying the promising structural anomalies, firms conduct exploratory or wildcat drilling to determine whether they contain hydrocarbons. The outcomes associated with exploratory drilling are uncertain. In the first 29 years of the OCS program, from 1954 through 1982, exploratory wells were drilled on 64% of the tracts sold, and half of those leases were productive (that is, some oil or gas was extracted). Between 1983 and 2002, 27% of the tracts were explored, and slightly less than half of those were productive (Haile et al. 2010).

Deposits and their characteristics are spatially correlated. A field typically covers several tracts, and larger fields may cover an even wider area. Correlation can also arise from common geological features. As a result, the outcome of an exploratory well on a tract is highly informative about the productivity of neighboring tracts. By using hit rates (i.e., whether a lease is productive) as a measure of success, the spatial correlation in success rates on pairs of adjacent tracts in the Gulf of Mexico leased prior to 1982 is estimated to be 0.27 (Onuma 2013).

If a wildcat well is successful, there may then be developmental drilling on neighboring tracts. The outcomes of developmental wells are less uncertain. In the study mentioned above, Onuma (2013) finds that if a wildcat well is productive, then at least one of the adjacent tracts is almost always drilled, and the hit rate on those tracts is 62%, well above the 50% hit rate for wildcat wells. By contrast, if the wildcat well is not productive, then the hit rate for wells on adjacent tracts is only 26%.

Firms have to submit a drill core report on each well to the BOEM. These reports are made public when the lease expires or within 24 months of the drilling date, whichever comes first. Drill cores are not submitted, but firms that want to examine cores can sign an agreement to do so with the lease owner. The drilling core information is especially important for dry holes. When exploratory drilling leads to the discovery of a commercial size deposit, this event is public information because production is observable.

If the tracts in an area have multiple owners, then the spatial correlation in drilling outcomes generates information externalities. These externalities can lead to inefficiencies in drilling: underinvestment because firms may fail to internalize the value of the information spillovers; delay because firms have an incentive to free ride on the information generated by others; and overinvestment because firms may fail to share information or coordinate drilling, especially near the end of the lease term.

The information externalities from exploratory drilling have motivated leaseholders on adjacent tracts to negotiate shared work or acquired interest agreements with each other. These contracts are essentially cross-ownership agreements in which the parties share drilling costs and revenues (if any). The assignment of shares is based on expectations about the location and size of the pool. The agreements also designate an operator in the event a pool is discovered. They are filed with and approved by the BOEM and are made public in a weekly newsletter that everyone in the industry reads avidly. The prevalence of the agreements has varied over time and depth. They occurred infrequently during the first 30 years of the OCS program but became more common after the Area-Wide Leasing (AWL) program was adopted, as described below, especially in deepwater areas, where drill rates are low and drilling costs are high.

Successful wildcat and development wells are converted into production wells. There is a potential common-pool problem if multiple owners have extraction rights and they have not signed a shared work or acquired interest agreement. Owners will overinvest in production wells to obtain a larger share of the pool. Furthermore, if extraction rates are too fast, overall production will be too low, relative to efficient extraction. In the Gulf of Mexico, the common-pool problem is mitigated through mandatory unitization, whereby production is shared equally among the multiple tract owners.

3. SELLER OBJECTIVES

In this section, we briefly discuss the objectives of the seller. The seller has several objectives that may conflict.

One objective of the OCS program is to facilitate efficient exploration and development of the federal offshore lands. Another objective is to ensure that the government earns a fair return on its offshore oil and gas leases and captures some share of the resource rents. The government uses a combination of auctions and royalties to achieve these two objectives. A third objective is to protect the environment.

These three objectives necessarily conflict to some degree. By the adoption of more stringent environmental standards, profits from exploration and development will fall, and with this decrease the potential government share also decreases. If the government tries to capture too large a share of the rents, the incentives of the firms to explore and develop will be reduced. The seller must decide how to trade off the conflicting goals.

In the period from 1954 to 1982, the BOEM gave relatively more weight to the objective of earning rents and did so mainly by limiting the supply of leases. In each of the 44 sales held during this period, the BOEM restricted the areas available for leasing. Potential bidders were invited to nominate tracts in the available areas, and the BOEM would choose tracts on the basis of these nominations, often selecting tracts nominated by multiple bidders. The number of tracts offered in a given sale averaged 175, and the number of tracts sold averaged approximately 80. The selection process was effective because roughly two-thirds of the tracts sold were drilled and half of these tracts were productive.

Beginning in 1983, the BOEM has given exploration and development higher priority by adopting the AWL program. The program dramatically increased the annual supply of leases. The BOEM held one sale each year for each of the Western and Central Gulf of Mexico regions, and in these sales all the tracts not under lease in the region, including deepwater tracts, were available for bid. As a result, the number of tracts offered in a sale increased from a couple of hundred to several thousand per year, and the number of tracts sold increased by more than a factor of four, from 80 to roughly 400 tracts per sale. However, the number of tracts that were drilled only doubled because the drilling rate fell from two-thirds to a quarter. The number of productive tracts per sale also doubled because hit rates did not change very much.

Table 1 presents information on the government's receipts for the periods 1954–1982 and 1983–2002. The revenue numbers in **Table 1** are estimates that are based on actual production and real wellhead prices as of the sale date and are discounted to the sale date by using a 5% real interest rate. Drilling costs are estimates based on American Petroleum Institute surveys; these estimates are also discounted to the sale date. Rents equal discounted revenues less costs. To calculate the

Table 1 Outer-continental-shelf total revenues, rents, and government receipts

Period	Tracts sold (number)	Revenues ($)[a]	Rents ($)[b]	Royalty payments ($)[c]	Bonus payments ($)
1954–1982	3,256	76,161	40,762	12,694	47,695
1983–2002	15,848	116,253	55,780	13,749	16,266

Dollar figures are in millions of 1982 dollars.

[a]The revenue of a productive tract is computed by converting monthly production flows of oil and gas into revenues by using the real wellhead prices at the date of the sale and discounted to the sale date at a rate of 5% per annum.

[b]Rents are equal to total revenue minus total drilling cost. The drilling cost of a tract is based on number, type, and depth of wells drilled and on the American Petroleum Institute annual survey of drilling costs of wildcat and production wells. The costs are discounted to the sale date at a 5% per annum rate.

[c]The royalty payment of a tract is equal to its revenue multiplied by its royalty rate.

estimated royalty payments, one would apply the relevant royalty rate to the estimated discounted revenue. Finally, bonus payments are the winning bids. All the numbers are denominated in 1982 dollars. (See Haile et al. 2010 for more details.)

Bidding in the earlier period was quite competitive. Auction revenue totaled $47.7 billion, or $15 million per tract, and the government earned virtually all the total rents. However, in the later period, auction revenues fell, totaling only $17 billion, or approximately $1 million per tract. The government also earned a substantially smaller share of the expected rents. The reported royalty payment numbers understate the decrease in actual royalty payments per tract because they are calculated on the basis of wellhead prices at the date of sale of the tract. Actual (undiscounted) revenue from royalty payments totaled $60.8 billion (in 1982 dollars) on tracts sold in the earlier period and $31.6 billion on tracts sold in the later period.

The most important federal environmental restriction on exploration and development in the Gulf of Mexico is the ban on these activities in most of the Eastern Gulf. In its first term, the Obama administration announced plans to lift the ban. However, the administration reversed course following the Deepwater Horizon oil spill and instituted a 7-year ban on drilling in the Eastern Gulf.

4. LEASE DESIGN

In the standard theory of auctions, the set of products is treated as given. But as Milgrom (2011) notes, in many real-world auction problems, product definition is not a given but is a choice of the seller. Indeed, the question of what to sell can matter as much as the question of how to sell a product. In the OCS program, the product is a leasing contract, and the choice is the design of that contract. This decision has important implications for auction performance and design.

In this section, we discuss the issues that arise in lease design. How should the resource right of lease be defined? How should the geographical area of the lease be defined? How should the tenure of the lease be defined? And, finally, how should the terms of the lease be defined? We examine the economic trade-offs associated with answering these questions.

The main theme of our discussion is that the lease should be designed to enhance efficiency in wildcat and development drilling. More efficient drilling decisions enhance the value of leases, increase the willingness of bidders to pay for them, and potentially raise auction revenues for the seller. Thus, in contrast to the case of auction design, there is no direct trade-off between efficiency and revenues in lease design. However, as we see below, lease design can generate a trade-off indirectly through its impact on the level of competition.

4.1. Lease Rights

The federal offshore oil and gas lease is an option contract: It gives the holder the right to drill a well during the term of the contract but does not require the holder to do so. If the leaseholder decides to drill a well, then it must submit its drilling plan to the BOEM for approval. If the well leads to the discovery of a commercial deposit, then the lease gives the holder the right to develop and extract the hydrocarbons. As in the case of drilling, leaseholders must submit their production plans to the BOEM for approval.

The issue with option contracts is that leaseholders are unlikely to drill many of the leases they acquire. Bidders will buy leases solely for the value of the option to drill if there is good news, such as discoveries of deposits in the area or increases in oil and gas prices. This option value explains why drilling rates during the AWL period are much lower than in the first 30 years of the OCS program, when supply was restricted to a relatively small number of nominated tracts. Congress recently expressed concern over these low drilling rates, citing them as evidence of speculative buying and hoarding, and argued for lease contracts with stricter work requirements.

The problem with this critique of option contracts is that it ignores the value of the option not to drill as well as the impact of the option value on bidding behavior. Consider a counterfactual world in which the leasing contract is changed so that leaseholders no longer have the option not to drill—that is, they are required to drill their leases. In this case, bidders would tend to bid only for leases that they believed were worth drilling and would tend to wait for the arrival of good news before bidding for other leases. However, leaseholders are likely to invest in too many wells, because they cannot respond to the arrival of bad news, such as dry drilling outcomes in the area or falling prices. Forcing leaseholders to drill wells in these circumstances is costly and reduces the expected value of the leases. As a result, bidders bid less and on fewer leases. Thus, overall leasing rates, development rates, and auction revenues are likely to be lower, although a full analysis would have to take into account information externalities.

4.2. Lease Size

The geographical area of a leasing contract is another factor that affects the efficiency of investment in wells. In the OCS program, the lease is defined on a tract or, in some cases, on half of a tract. This definition is too small for a leaseholder to internalize the value of the information generated by an exploratory well, because the typical deposit lies on several tracts and deposits are spatially correlated. Bidders frequently pursue a land grab strategy in which they bid to acquire a bundle of tracts in an area of interest. However, they generally do not succeed in winning all or even most of the tracts due to competition from other bidders and heterogeneity in lease valuations. Shared work or acquisition agreements struck after the auction by leaseholders can mitigate the inefficiencies that arise from divided ownership. However, private information and the incentive to free ride on the investments of other leaseholders often prevent leaseholders from reaching an agreement (Wiggins & Libecap 1985). And even if they are able to negotiate an agreement, the geographical scope is usually limited to a single prospect and does not allow the parties to capture the value of the information generated for other prospects in the area.

The BOEM could define leases on bundles of tracts. Larger leases would lead to more concentrated ownership of tracts, to more efficient investment, and to greater rents. The main difficulty with implementing this solution is that the BOEM does not have the information to determine which tracts should be bundled into leases. Part of the auction design problem is to get privately informed bidders to express their valuations for the different bundles of tracts and let them determine which bundles are the most valuable. A second issue is that auctions for bundles of tracts may be less competitive than auctions of tracts because only the big oil firms have the budgets to bid for the bundles. Rents would be higher, but the government's share of the rents might be much lower. This concern over the competitiveness of the auction was an important factor in the decision by the BOEM to define the lease on a tract. It is also the reason why the BOEM allowed firms to submit joint bids. In most contexts, joint bidding reduces the number of bidders. However, in the case of oil and gas leases, the BOEM believed that joint bidding would increase the number of bidders by mitigating the financial constraints of small firms. Many joint bids indeed involve partners with no expertise in the industry, whose role appears to be the provision of financial capital.

4.3. Lease Tenure

The leaseholder is given a fixed term to exercise the option to drill a well. The term varies with depth. Until recently, it was 5 years for tracts with water depths less than 200 m, 8 years for tracts with water depths between 200 and 400 m, and 10 years for tracts with water depths greater than 400 m. As part of its response to the concerns expressed by Congress about firms hoarding leases, the BOEM increased the depth cutoffs to 400 m for 8-year leases and to 800 m for 10-year leases. If the lease is not drilled during its term, then the lease expires, and ownership reverts to the government for resale. If the lease is drilled and a deposit is discovered, then the term is extended as long as the lease is productive. The leaseholder can terminate the lease at any time prior to term.

The terms give leaseholders more than enough time to drill a well. Drilling a well takes only a few months, and obtaining a permit to drill also does not take very long. Leaseholders may need to gather more information before the tract is drill ready and to negotiate shared acquisition agreements. But this predrilling activity typically does not take more than a year or so, with the possible exception of very deepwater tracts, where such activity can take longer because the stakes are much higher. In fact, in both deep water and shallow water, many tracts are drilled in the first 2 years of the lease. This situation raises the following question: Should lease terms be finite, and if so, how much time should the leaseholders get to exercise the option to drill?

To obtain some insight into this question, a simple example is helpful. Consider two adjacent tracts in which the unknown state of the world is binary: Either both tracts have deposits, or neither of the tracts has a deposit. The optimal drilling program is to drill one tract first and drill the second only if a deposit is discovered on the first. But suppose that the lease terms are too short to permit sequential drilling. Then too much drilling tends to occur if firms believe that the tracts are worth acquiring, because in this case both tracts are drilled even when they have no deposits. In contrast, too little drilling tends to occur if the firms believe that the tracts are not worth bidding on, because in this case neither tract is drilled even though both tracts may have deposits. More generally, shorter lease terms make it more difficult for leaseholders to drill their leases sequentially and to take advantage of the information generated from the outcomes. As a result, there may be inefficient lack of investment or inefficient duplication of investment (Hendricks & Kovenock 1989).

Suppose next that the lease terms are more than sufficient to drill the tracts sequentially, and assume that different firms acquire the two leases. The problem that arises in this case is that each leaseholder has an incentive to wait and free ride on the drilling investment of the other leaseholder. The noncooperative equilibrium to the game of timing involves strategic delay, frequently to the end of the lease term (Hendricks & Porter 1996). Furthermore, the incentive not to disclose private information can prevent leaseholders from negotiating a shared-interest agreement (Hendricks & Kovenock 1989). These results imply that long lease terms lead to inefficient delay, and they support arguments for shorter terms (Damiano et al. 2012).

The second reason why lease terms should not be too long is heterogeneity in valuations. Leaseholders have the highest valuations at the time of sale. But over time, as new information arrives, other firms may value the leases more highly than the leaseholders do. In particular, some firms may think that a lease is worth drilling when the leaseholder does not. In those cases, the leaseholder should sell the lease. However, the resale market for leases does not function well due to private information and adverse selection (i.e., the leaseholder may know more about the value of the lease than potential buyers do). As a result, potential buyers of the drilling and production rights to a tract typically wait for the existing lease to expire and then bid for the rights, taking into account the fact that the leaseholder allowed its lease to expire. This mechanism for transferring ownership rights is arguably more efficient than a resale market with infinite-life leases. It implies that lease terms should be limited.

4.4. Lease Payments

The leaseholder makes three kinds of payments to the seller: its bid or bonus, which is payable at the time of sale; rental fees that are payable each year until the lease expires or production begins; and royalty payments, which are payable as long as production occurs. The royalty payments are calculated as a fixed percentage of the value of oil and gas extracted. The bonus payment is based on the bidder's ex ante value of the lease, whereas the royalty payments are based on the ex post value of the lease.

For most of the OCS program, the rental rate per acre was sufficiently small such that leaseholders rarely terminated leases prior to expiration. However, in recent sales, the fees have increased, with rental rates accelerating sharply with the age of the lease. The idea is to encourage leaseholders to either drill their leases quickly or relinquish them so that the BOEM can sell them to bidders that are willing to drill them. As we discuss above, the problem with this kind of policy is that it reduces the option value of the lease and hence reduces bids and auction revenues.

The royalty rate has traditionally been one-sixth on shallow water tracts and one-eighth on deepwater tracts. In 1995, the Deepwater Royalty Relief Act (DRRA) exempted deepwater tracts from royalty payments on initial production up to a cap that increased with depth. The relief policy was designed to encourage drilling and production in deepwater areas. More recently, the BOEM increased royalty rates on new leases, hoping to increase revenues. But the effect of royalty rates on revenues is far from obvious because higher royalty rates reduce the incentive of firms to bid for leases and to drill them. Revenues from auctions will fall as bidders bid less and on fewer leases; revenues from royalties will increase on productive leases but may decrease overall because there are likely to be fewer productive tracts. This trade-off between royalty rates and revenues raises the following questions: Should the royalty rate be positive, and if so, how high should it be?

The literature offers two reasons for why royalty rates should be positive. McAfee & McMillan (1986) show that the reduction in risk associated with higher royalty rates can lead to more aggressive bidding when bidders are risk averse. Riley (1988) studies the risk-neutral case and establishes a similar result in a more general affiliated values environment. He shows that making part of the leaseholder's payment contingent on ex post value reduces the asymmetries in bidder valuations and intensifies their bidding. This effect is also present when bidders are risk averse. Thus, in these models, royalty rates are procompetitive because they reduce private information rents of the bidders in the auction.

When the BOEM initially set royalty rates, the motivation was to enhance competition, but not for the reasons given above. The intent was to reduce the up-front payments that firms had to make so that risk-averse, financially constrained firms could more easily participate in the sale and bid in more auctions. Thus, significantly positive royalty rates would intensify bidding by increasing the number of bidders in each auction.

Royalty fees should also be used in the absence of competition. From 1954 to 1982, bidding was quite competitive. The average number of bids per tract sold was 3.24, and the average winning bid was a little more than $15 million. By contrast, from 1983 to 2002, competition levels and bids were much lower. Haile et al. (2010) report that the average number of bids per tract sold was 1.38 and that the average bid was a little less than $1 million. Auction revenue fell by roughly two-thirds, from $47.7 billion to $16.2 billion. Total (undiscounted) royalty revenue from leases sold in the period also fell, but by only a half, from $60.8 billion to $31.6 billion. Thus, in the latter period, the main source of lease revenue to the government was royalty payments.

The main argument against royalty rates is that they distort the investment decisions of leaseholders. Tracts should be drilled if the expected revenues from drilling exceed the costs. But the leaseholders are willing to drill tracts only if expected revenues net of royalty payments exceed the costs. Hence, marginal tracts are not drilled and marginal fields are not developed because the leaseholder has to share the returns with the government. In addition, productive leases are abandoned too soon on the basis of the present value net of royalty payments as opposed to the gross present value.

How important is the distortion from existing royalty rates? The DRRA provides an excellent experiment for quantifying the efficiency and revenue trade-offs of higher royalty fees. It exempted royalty fees on initial production on deepwater tracts. The amounts exempted were 17.5 million barrels of oil equivalent (MMBOE) for tracts with water depths between 200 and 400 m, 52.5 MMBOE for tracts with water depths between 400 and 800 m, and 87.5 MMBOE for tracts with water depths greater than 800 m. **Table 2** reports the number of tracts sold, the average winning bid, the ratio of tracts drilled to tracts sold (the drilling rate), and the ratio of productive tracts to tracts drilled (the hit rate) in the 2 years before and after the DRRA took effect. The table indicates that the royalty relief had a major impact. The number of tracts sold, winning bids, the number of tracts drilled, and the number of productive tracts increased substantially, with the biggest changes occurring in the very deepwater tracts.

An alternative design of royalty payments would be to specify royalties as a fraction of profits, instead of as a fraction of revenues. If costs were measured correctly, then there would be no distortion of ex post investment decisions. However, the concerns with respect to the distortion of ex ante investment, and those with respect to the effect on bid levels, would remain. Moreover, monitoring and measuring costs, for example, deciding whether expenses are reasonable, would be difficult. As in the setting in which a regulated firm earns a given rate of return on its costs, the

Table 2 The impact of the Deepwater Royalty Relief Act: outcomes two years before (1994–1995) and after (1996–1997)

	Tracts sold (number)		Average winning bid ($)[a]		Drilling rate		Hit rate	
Water depth (m)	Before	After	Before	After	Before	After	Before	After
0–200	1,012	1,187	478,869	497,314	.31	.27	.60	.54
200–400	63	112	360,646	626,104	.27	.23	.53	.46
400–800	115	228	353,640	795,300	.17	.19	.55	.27
>800	262	1,851	196,834	495,286	.13	.07	.34	.51

[a]Dollar figures are in 1982 dollars.

regulator has to decide which costs to allow, and there will be distortions to the extent that the regulated firm has private information about its costs.

5. AUCTION DESIGN

In this section, we describe the considerations that affect the choice of the selling mechanism, and we discuss the trade-offs associated with various aspects of the mechanism. The key issues are associated with geographic complementarities, the winner's curse, and financial constraints.

If there are geographic complementarities, values are superadditive across tracts. We argue above that there are local complementarities between tracts because of the information spillovers associated with spatially correlated tract values. A firm that owns several adjacent tracts internalizes these externalities and makes efficient investment decisions. As a result, the value of owning the adjacent tracts as a bundle exceeds the sum of the values of owning the tracts individually.

One solution to nonadditive values is to allow combination bidding, whereby a bidder can submit a single bid for a package of tracts. Such bids reduce the exposure problem, as a bidder would not face the risk of acquiring only a subset of the desired tracts, and therefore increase rents. But there is a practical problem with implementing a package bidding option. The optimal bundling of tracts is unknown, so bundles cannot be specified ex ante. If one were to permit package bids on any subset of tracts, the number of possible combinations would be too large to be practical.

To the extent that there is a common uncertain component of tract valuations, and if potential bidders have private information about this component, then the bidders must account for the winner's curse. In the case of offshore leases, seismic information is an imperfect indicator of tract value, and firms have differential interpretations of the seismic data, so the winner's curse is a concern.

A standard solution to mitigate winner's curse problems is to make as much information as possible available to the bidders. The seller could release all available information before the sale, such as seismic data for the area and well records for adjacent tracts that were previously drilled. The seller could also adopt a multiround auction format, analogous to the format employed by the FCC in spectrum auctions. Multiround auctions also have the potential to solve the complementarities problem, as they facilitate the assembly of a bundle of tracts in the course of the bidding. If bidders are asymmetric and bidding is competitive, then the allocation is more likely to be efficient. Bidders are also less likely to suffer ex post regret from overpayment or from losing narrowly. Moreover, multiround auctions enhance competition by allowing financially constrained bidders to be potential bidders on many more leases.

Another alternative to allocate multiple tracts would be a sequential mechanism, whereby individual tracts are sold one at a time. A multiround simultaneous sale is preferable to both a sequential sale and a one-shot simultaneous sale for several reasons. First, the multiround simultaneous mechanism generates more information. Bidders observe the standing prices on all tracts, and they can respond to this information in making decisions about which tracts to pursue and how much to bid for them. A simultaneous sale is also more flexible in that bidders can switch to backup combinations of tracts if their first-choice combinations become too expensive. The allocation of tracts is therefore more likely to be efficient. In addition, in a multiround simultaneous sale, similar tracts are likely to sell for similar prices.

An undesirable feature of a multiround mechanism is that bidders may try to hide their valuations by using a snake-in-the-grass strategy. This strategy entails not bidding seriously until the end of the auction process. If all bidders adopt this strategy, bids are not informative. The auction never ends if there is no fixed deadline, or there is a flurry of bidding at the deadline. The FCC auction design addressed this concern by specifying bidder activity rules. These rules force bidders to bid with increasing sincerity, as a bidder's eligibility to participate in a given round decreases if the bidder does not maintain activity.

There is also a concern that it is easier for a subset of bidders to collude in a multiround mechanism. They may tacitly subdivide tracts among themselves, with the understanding that bidding in another's territory would trigger retaliatory bidding in one's own territory. A tacitly collusive outcome may be more difficult to achieve if signaling possibilities are limited. For example, the seller may limit the amount of information revealed at the end of each round. There may be limited discretion in the choice of bid increments, through either a fixed increment or a limited choice of increments.

All firms were allowed to bid jointly prior to 1975. After 1975, joint bids involving two or more of the (then) eight largest oil and gas companies (where large is determined by world oil and gas production) were banned, although these firms were free to participate in joint bids with other firms. The rationale has been that joint bids enhance competition by facilitating participation by financially constrained bidders. In practice, a number of joint bid partners appear to be venture capitalists, and so joint bids may have served the intended purpose. However, there is a concern that joint bids may also reduce competition in some instances, especially when the number of potential bidders is limited. For example, few companies have the expertise necessary to explore and develop offshore leases in very deep waters. Similarly, in the case of drainage tracts, some of the adjacent tracts have been leased and drilled. The owners of the neighboring leases may have better information than other potential bidders do. In that case, a joint bid among the neighbors could result in much lower bids. The prohibition on joint bids involving two or more large firms may prevent anticompetitive joint bids in some instances, but it is a crude tool.

The seller must also decide whether to set a reserve price (i.e., a minimum bid) and whether to keep the reserve price secret. The BOEM has typically announced a common reserve price for all tracts in a sale but has retained the right to reject individual high bids if they are deemed inadequate. For practical purposes, this is a secret reserve price with a known lower bound equal to the publicly announced minimum bid. A secret reserve price is advantageous if competition is limited, either because the number of potential bidders is small or because of collusion. In those instances, the secret reserve price induces more aggressive bidding, in comparison with bidding when there is just the low announced minimum bid. However, there is a trade-off to the extent that the incentives for information acquisition ex ante are dampened.

In summary, auction design affects the set of properties sold and the division of rents between the seller and the buyers. More generally, the auction designer should also account for the effect of the bidding instrument on the incentives to make investments in information gathering ex ante and ex post.

6. SUPPLY OF LEASES

An important issue that we turn to now is the supply of tracts and the trade-offs associated with this decision. Before 1983, the MMS limited both the number and location of tracts in a sale by selecting the areas that were available for leasing. In addition, bidders were required to nominate tracts in the selected areas to ensure that they would be included in the sale. One consequence of this procedure was that most of the leases were drilled. Since 1983, bidders have been free to bid on any tract not under lease in Gulf regions that are not subject to the moratorium. The widespread availability of tracts has generated a lot of speculative bidding and much lower drill rates, but it has also increased the rate of exploration and development.

Over the past 25 years, we have conducted a series of empirical studies (Hendricks & Porter 1988, 1992, 1996; Hendricks et al. 1994, 2003, 2008; Haile et al. 2010) on the OCS leasing program. Our results suggest that the mechanism for allocating leases worked reasonably well prior to 1983. Most of the auctions were competitive, auction revenues were high, and the government captured most of the economic rents through a combination of bonus and royalty payments. The mechanism has not performed nearly as well since 1983. Most of the auctions have not been competitive, auction revenues have been low, and a large share of the economic rents has been captured by the bidders, especially on deepwater tracts.

Interpreting these results as evidence of a trade-off between supply and revenues is tempting. But it is not obvious why making more tracts available in a sale would cause auctions to become less competitive. In the standard model of auctions, a firm participates whenever its expected returns conditional on winning at the reserve price are positive. This participation rule does not depend on the number of tracts in the sale unless there are diseconomies of scale. So what source of diseconomies of scale could explain why an increase in the supply of available tracts lowers participation rates?

Two possible sources of diseconomies of scale are financial constraints and drilling capacity constraints. However, these constraints do not appear to have been major factors. The total amounts that firms bid have been generally lower for sales since 1983 than for sales before 1983. The number of rigs is limited, and their rental prices fluctuate with overall activity, so drilling costs are convex in the number of active rigs. But in the deep water, the firms have 10 years to smooth out their drilling activity, which seems more than sufficient to deal with any short-run diseconomies of scale.

A third, more plausible, possibility is diseconomies in the acquisition of information. Exploration is a sequential, spatial, and cumulative process. Each year, firms invest in seismic surveys and exploratory wells. The information generated by these investments contributes to the firms' stock of knowledge and helps determine their investments in subsequent years. Thus, the benefit to a firm from its investments in information in any given year depends on its current stock of knowledge. The marginal return is almost surely decreasing in the amount invested because the additional dollars will be spent learning about locations that are increasingly further away from the well-explored areas or about increasingly more marginal locations in those areas.

The data provide some support for the above hypothesis. In addition to deciding each year which locations to drill and survey, each firm also has to decide which tracts to acquire. The incentive to buy now and wait until new information arrives is quite strong, especially for deepwater tracts, for which the lease terms are 10 years. This incentive implies that, in the absence of any diseconomies of scale, firms should have purchased leases to all the available tracts in 1983 and in subsequent years as tracts became available due to leases expiring or terminating. But this did not happen; instead, the number of leases purchased is less than 10% of the available tracts in most years. Diseconomies in the acquisition of information are an obvious explanation for the relatively low leasing rates. Changes in technology could have been a factor because improvements in seismic techniques and drilling technology have allowed firms to explore deeper waters in the Gulf. But these changes operate in the longer run and, in any case, should have been included in the option value that makes tracts worth acquiring sooner rather than later.

Diseconomies explain why firms focus their information-gathering activities on a relatively small number of tracts. Prior to 1983, they had to concentrate their investments in information on the several hundred tracts that the government made available in a sale. This restriction on the choice set of firms had the effect of reducing the dispersion in their estimates and of making the auctions quite competitive. But since 1983, firms have been free to select among thousands of available tracts. Heterogeneity in interpretations of data has made firms more likely to select different sets of tracts in which to invest in information gathering and analysis, and as a result, the auctions have become less competitive.

The supply of tracts may also affect when firms choose to invest in information. That most of the tracts sold in sales before 1983 were drilled implies that bidders knew which tracts were worth drilling when they bid. That is, bidders made their investments before the sale. They also did not anticipate receiving postsale information that would cause them to change their mind about which tracts should be drilled. By contrast, since 1983, there has been a lot of speculative bidding, especially on deepwater tracts. This fact suggests that bidders waited until after they won tracts to obtain the information needed to make them drill ready.

7. CONCLUDING REMARKS

We argue above that the OCS auctions are well designed in many respects but that some improvements are possible. In this section, we summarize the preceding discussion.

The OCS lease contracts seem reasonably well designed. Leaseholders have the option not to drill the lease, and they should have this option because of information spillovers. The lease size achieves a good balance between the need for competition and the need for efficient exploration and development. Similarly, the lease terms are long enough for leaseholders to achieve the efficiency gains of drilling an area sequentially but are generally short enough to discourage delay and hoarding. However, the 10-year lease term on deepwater tracts may be too long. Royalty rates are low, as they should be, because they distort exploratory drilling and development decisions. If there is sufficient competition, the optimal royalty rate may be zero.

We favor using a multiround ascending-bid auction with activity rules to sell the oil and gas leases, for many of the same reasons that this format was adopted by the FCC to sell spectrum licenses. This format enhances both revenues and efficiency by helping bidders solve the problem of geographical complementarities, by allowing them to use their budgets to bid on more tracts, and by mitigating the winner's curse.

The expansion in the supply of leases since 1983 under the AWL program has resulted in a lower government share but in more overall activity. Before 1983, the restricted supply of leases resulted in more competition for those leases and in more presale investment in information. Government revenues were higher, but there was probably more duplication of presale investment. The choice of the number of leases to make available for sale involves a trade-off between the objectives of expedited development and a fair return for the taxpayer.

Our discussion focuses on offshore oil and gas auctions and on the trade-offs that result from various auction design choices. In other settings, there are analogous trade-offs, but the relative importance of the different considerations depends on the individual circumstances. For example, uncertainty about deposit sizes plays an important role in oil and gas auctions, and such uncertainty may not be important in other contexts such as timber auctions.

DISCLOSURE STATEMENT

The authors are not aware of any affiliations, memberships, funding, or financial holdings that might be perceived as affecting the objectivity of this review.

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Annual Review of
Resource Economics

Volume 6, 2014

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