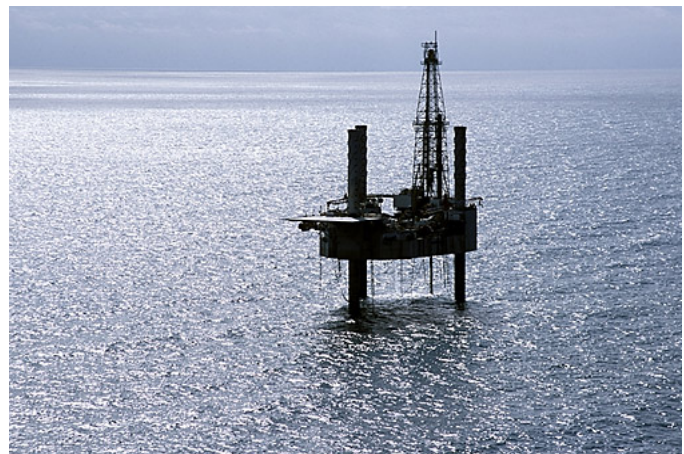


Effects of Royalty Incentives for Gulf of Mexico Oil and Gas Leases

Volume I: Summary



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Chapter 1

Introduction

Project Overview

The Deepwater Royalty Relief Act of 1995 (DWRRA) mandated royalty suspension in significant amounts for leases sold in the central and western Gulf of Mexico on all new deepwater oil and gas leases, meaning those sold from 1996 to 2000 in water depths of 200 meters or more, and for certain pre-Act leases upon application and approval. When this new lease provision expired, the Department of the Interior (DOI), Minerals Management Service (MMS), continued the program, with detailed changes to the incentives, on a sale-by-sale basis. Generally the changes mandated royalty relief on a lease-by-lease basis rather than on a field basis, and the suspension volumes were considerably lower. The shift from Congressional to administrative program created two important tasks for MMS's program office: (1) to assess the actual effects of the program thus far, and (2) to apply knowledge gleaned from item (1) toward designing royalty incentives for future sales.

The MMS has requested that Innovation & Information Consultants, Inc. (IIC, Inc.) perform an independent study and evaluation of the effect of the deepwater royalty relief program as it relates to leasing behavior and activity, exploration activity, and to the extent possible, exploration and development of oil and gas resources in the Gulf of Mexico (GoM).

The project was divided into two tasks. The first task analyzed historical data on leasing and exploration activities in the Gulf of Mexico, and included testing statistically for the significance of royalty relief incentives. We analyzed the value and quantity of deepwater leases sold and the amount of exploration and discovery that has taken place. We have also examined the impacts of the program begun under the Deepwater Royalty Relief Act (DWRRA) in 1996-2000 as well as the MMS administrative program from 2001 to 2003. Due to lack of detailed data on exploration, development and production trends on DWRRA leases, our analysis has focused on the impacts on leasing and exploration activity. The second task of the project involved developing projections of possible future impacts from several alternative programs. This simulation of future impacts begins in 2003, and due to modeling complexities, does not revisit what actually occurred between 1996 and 2002 in terms of royalty incentives even in the no incentive case.

The alternative future programs were provided to us by MMS and included the following:

1. A deepwater royalty relief program that resumes (in the first forecast year) the original provisions of the DWRRA, implemented with a field-based definition of suspension volume and new production requirement. (*DWRR – Field*)
2. A deepwater royalty relief program that resumes the provisions of the DWRRA, but is implemented with a lease-based definition of suspension volume and dropping the new production requirement. (*DWRR – Lease*)

3. A deepwater royalty relief program that continues the program like the current administrative program, with a lease-based definition of suspension volume specified for year 2003 sales. (*Current*)
4. No future royalty relief for deepwater leases beginning in the first model forecast year. (*No Relief*)

One difference between the DWRRA and the post-2000 program is that the former used a “field” definition of the relief volume suspension whereas the latter uses a “lease” definition. In general, a field is a set of pools that are geologically connected and are developed together, and a field can lie in more than one block (and less commonly, a block can cover more than one field). In contrast, a lease is associated with a single block. The DWRRA mandated a specific volume of relief (which varied by water depth), and MMS interpreted the language to mean that the leases in a field share a common suspension volume for that field. After 2000, MMS’s program stipulated volumes be applied to individual leases. These suspension volumes were significantly lower than under the original DWRRA.

This distinction became more important when lessees sued DOI, stating that the DWRRA ought to be interpreted using a lease definition of the suspension volume. On October 4, 2004, the 5th Circuit Court of Appeals upheld a United States District Court ruling in *Santa Fe-Snyder Corporations, et al. v. Norton, et al.* Under the court’s ruling, leases that were issued under the DWRRA (sales between 1996 and 2000) have lease-specific, rather than field-based, royalty suspension volume. In addition, the Court ruled that MMS’s denial of relief to deepwater leases in fields that had other leases with production prior to November 1995 was also invalid. Recent debate includes claims about what the 1996-2000 sales would have generated if, counterfactually, the lease definition had been in place.¹ MMS is interested in assessing whether the generally more generous, lease-based definition of royalty relief will accelerate exploration and subsequent activities and how to structure future leasing programs. In Task 2 IIC, Inc. has projected the effects of the four alternative cases including effects on drilling, discoveries, development, and production and impacts on bonus bids and rentals as well as royalty revenues.

Description of the DWRRA and Administrative Programs

The OCS Deep Water Royalty Relief Act (DWRRA) 43 U.S.C. §1337, enacted by Congress in November 1995, was designed to promote increased exploration and development and increased production on leases found in deepwater areas of the Gulf of Mexico. The legislation provided economic incentives for operators to develop new fields in water depths of 200 meters or more. These incentives included royalty relief (or “suspension” of royalties) for new leases issued between 1996 and 2000 on the initial barrels of oil equivalent (BoE) produced from a deepwater field² as detailed in Table 1-1 below. However, if a lease granted during the DWRRA period produces oil or gas from a field that had production prior to 1996, then that

¹ *Santa Fe-Snyder Corporations, et al. v. Norton, et al.*, 385 F.3d 885 (5th Cir. 2004) and also see *Kerr McGee Oil and Gas Corp. v. MMS*, No. 03-CV-0060, which also relates to the lease versus field definition issue. The government is not appealing these rulings and will soon issue new regulations conforming to these decisions.

² As noted above, the determination of whether leases issued under DWRRA are entitled to relief on a field or a lease basis is the subject of pending litigation.

lease does not obtain royalty relief. Royalty relief can also be obtained on pre-DWRRA leases upon application and approval based on a showing that the field would not be economic to develop and produce without royalty relief.

Table 1-1. Royalty Suspension Volumes (Field-Specific) Under DWRRA, by Water Depth.

<i>Lease Water Depth</i>	<i>RSV (MM BOE)</i>
0-200 m	None
200-400 m	17.5
400-800 m	52.5
800-plus m	87.5

After the DWRRA program expired in 2000, MMS continued the program, making certain modifications to the incentives on a sale-by-sale basis. MMS shifted to a lease-specific basis for computing royalty relief, but lowered significantly the volume of royalty relief offered on a lease-by-lease basis. For example, in the sales since 2000, royalty relief was offered for leases in 800-1600 meter of 9 million BoE and in leases over 1600 meter at 12 million BoE. In some sales, royalty relief of 5 million BoE was also offered for leases in the 400-800 meter water depth. The provisions are shown in Table 1-2.

Table 1-2. Royalty Suspension Volumes (Lease-Specific) Under Post-DWRRA Program, by Sale and Water Depth.

<i>Sale</i>	<i>Year</i>	<i>Lease Water Depth</i>	<i>RSV (MM BOE)</i>
178	2001	800-1600 m	9
		1600-plus m	12
180	2001	800-1600 m	9
		1600-plus m	12
182	2002	400-800 m	5
		800-1600 m	9
		1600-plus m	12
184	2002	400-800 m	5
		800-1600 m	9
		1600-plus m	12
185	2003	400-800 m	5
		800-1600 m	9
		1600-plus m	12
187	2003	400-800 m	5
		800-1600 m	9
		1600-plus m	12
189	2003	1600-plus m	12

Note: Sale 189 related to the Eastern Gulf of Mexico

Estimated Impacts of Royalty Relief Programs³

Based on discussions with MMS staff, this study addressed the effect of the DWRRA and the post-DWRRA programs as contrasted with no relief on the following aspects of lease sales and exploration activity:

- The number of tracts bid on and the number of leases sold;⁴
- The number of participants in lease sales;
- Major versus non-major company participation in lease sales;
- The number of bids per tract;
- The magnitude of the high bids;
- The number of wells drilled and fields discovered.

In addition, this study also investigated the fiscal impact of alternative deepwater royalty programs by projecting for four alternative scenarios the following activities from 2003-2042:

- The number of exploration wells drilled;
- The number of fields discovered;
- The volume of reserves added;
- The quantity and value of future production, including production from new fields;
- The value of royalties paid;
- The number and value of leases sold;
- The volume of royalty-free production (total as well as from new fields only).

MMS administers the leasing program in the U.S. Gulf of Mexico (GoM) as well as the collection of rental and royalty payments on leases granted to companies engaged in exploration and development of oil and gas resources. A lease sale is a sealed bid auction conducted on an

³ Volume II of this report provides extensive detail on the statistical and historical data analyses of lease bidding, bonus bids, and fiscal impacts of various alternative future policy options. Volume I provides a more succinct summary which focuses primarily on policy impacts.

⁴ It must be noted that we have broken out the number of leases sold by water depth based on the maximum water depth of the field in which the lease is located, as opposed to the provisions of the lease that may classify it as qualifying as a lease of a certain water depth.

area-wide basis in the GoM. Sales are typically held annually for Central and Western Gulf areas and on a more sporadic basis for the Eastern Gulf area. The move to area-wide leasing, which occurred in 1983, serves as a useful starting point for much of the historical analysis contained in this report. Prior to 1983, the government had conducted so-called “tract nomination” sales in which the government called on oil companies to nominate promising tracts within an OCS region. The government would then study the nominated tracts and determine whether to offer them for sale. The winning bidder was determined on the basis of the highest cash bonus offered at the time of the sale. The advent of area-wide leasing meant that fewer tracts were evaluated prior to a lease sale, and many more tracts were available for sale at any given lease sale. With this change in the nature of the program in 1983, we have utilized that date as the starting point for most of our data and statistical analyses.⁵

Methodology and Data

For Task 1 of the project, we have employed several different approaches to analyze the impact of royalty relief on leasing, bidding, competition, and exploratory activity. We developed statistical regression models relating various explanatory variables to the number of leases sold as well as the level of competition and the level of bonus bids received. The number of leases sold is influenced by, among other factors, the number of participants in the sale and their leasing objectives. The number of participants is affected by royalty relief, that is, as royalty relief reduces the “price” of acquiring a lease, more buyers are attracted to the sale (and they bid more). At each lease, the bid amounts are co-determined with the number of bids. The theoretical bidding model (patterned after Capen et al. 1971) shows how a bidder decides on the amount to bid after considering his estimate of the underlying tract value (which is affected by royalty relief), the potential competing bids, and the possibility that other bidders estimate the tract value differently. We also treat the number of leases sold separately from the analysis of high bid per tract due to econometric issues, even though theory suggests that these two variables are linked.

We relied heavily on data collected by MMS in its lease history data files as well as public data on oil and gas prices, general economic indicators, and other relevant data. We also tested statistically through multivariate regression analysis impacts on exploration activity as measured by drilling activity and also the filing of exploration plans with MMS. For certain cohorts of leases we attempted to determine the impacts of royalty incentives on exploration activity, although as noted above the lack of sufficient historical data hampered our efforts in this regard. Appendix A to Volume II of this report describes the data used and data sources in more detail.

In Task 2, IIC, Inc. used its Exploration, Development and Production (EDP) model developed for the MMS in a prior study (IIC 2004) to study potential fiscal and resource-based impacts of alternative royalty regimes as applied to deepwater areas in the Gulf of Mexico. MMS provided four specific policy scenarios to IIC, Inc. for analysis as noted above. These represent alternative possible royalty scenarios and the results of our analysis provide policymakers and others at MMS with a range of possible impacts of these scenarios both in

⁵ Other changes have occurred in the leasing program since 1983 but none have been as significant as the move to area-wide leasing and in several of our analyses we control for these other changes.

terms of fiscal impacts (royalty revenue, bonus and rental revenue), as well as impacts on future trends in exploration, development, and production of oil and gas resources in the Gulf.

Summary of Results

In Task 1, our analysis focused on the impacts of royalty relief on leasing activity, particularly the number of leases sold and the high bids per lease.⁶ The primary findings of our econometric analysis of historical data are presented in Tables 1-3 through 1-5. Table 1-3 provides the actual data for leases sold and high bids in deepwater areas of the Central and Western regions of the Gulf for the royalty relief periods. The periods are DWRRA, 1996-2000, and Post-DWRRA, 2001-2003 (the most recent year covered by the data). For instance, in 200-800 meters, the average number of leases sold per year over 1996-2000 was 97. (The number varied substantially year by year, as shown in Volume II.) The average of high bids accepted per tract (in other words, cash bonus bids) was \$0.94 million for the same set of tracts. Thus, total cash bonus averaged ($97 * 0.94 =$) \$91 million per year for this set of tracts.

Table 1-3. Deepwater Lease Sales, Actual Results For Royalty Relief Policy Periods.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Leases Sold Per Year	97	580	99	295
Cash Bonus (High Bid) Per Tract, \$MM	\$0.94	\$0.91	\$0.88	\$0.84
Total Cash Bonus Per Year, \$MM	\$91	\$529	\$87	\$249

Table 1-4 displays the inferred values for the same variables, based on the econometric analysis of the impacts of deepwater royalty relief. Specifically, the econometric model simulated the number of leases sold if the policy period variable was omitted from the model.⁷ Omitting the policy period variable removed from the simulation the influence of the royalty relief policy period; instead, only other factors such as number of bidders, joint bidding behavior, etc., remained to determine the number of leases sold. For instance, without the influence of the royalty relief policy period, leases sold per year in 200-800 meters would have averaged 53 per year (instead of the actual 97) and the average high bid per tract would have been \$0.72 million and this total cash bonus would have averaged \$38 million per year for this set of tracts.

⁶ Multiplied together, the number of leases sold and the higher bid per lease equals total lease bonus revenue.

⁷ In this section, the phrase “policy period variable” and similar expressions allude to the model dummy variables that had the value 1 during policy period years and 0 otherwise. Statistically, dummy variables must be interpreted to represent both the policy and other factors changing at the same time not explicit in the model.

Table 1-4. Inferred Results of Deepwater Lease Sales Assuming No Royalty Relief.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Leases Sold Per Year	53	367	79	221
Cash Bonus (High Bid) Per Tract, \$MM	\$0.72	\$0.58	\$0.92	\$0.73
Total Cash Bonus Per Year, \$MM	\$38	\$214	\$73	\$162

The difference between the actual and the inferred cases is a measure of the influence of the royalty relief period on leases sold, cash bonus per tract, and total cash bonus. The difference is shown in Table 1-5. For instance, the DWRRA period added \$53 million per year to total sale revenues for 200-800 meter. From that number, one can calculate ($53 * 5 =$) \$265 million added revenues in that water depth for the entire DWRRA period.

Table 1-5. Estimated Effects of Royalty Relief Periods on Deepwater Lease Sale Results.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Leases Sold Per Year	44	213	20	75
Cash Bonus (High Bid) Per Tract, \$MM	\$0.22	\$0.33	-\$0.04	\$0.11
Total Cash Bonus Per Year, \$MM	\$53	\$315	\$15	\$87

Two factors that made important contributions to lease sale results are the number of *participants* in sales and the level of *competition* among them. The number of participants was important because royalty relief, by increasing the expected profitability of investing in a lease, tended both to attract more buyers and to increase the lease purchases per buyer. Overall, the number of participants in lease sales has varied considerably from year to year. In Table 1-6, the average number of participants per sale is presented by policy period, for deepwater. For instance, the number of participants, averaging over Central and Western sales from 1996-2000, was 28 in 200-800 meter. Table 1-6 also presents the portion of the actual participants that is attributed to the effects of royalty relief. For instance, 15 of the 28 participants (average for 200-800 meter in 1996-2000) were “added” by the policy period, although the study did not attempt to distinguish between participants who had bid in earlier sales and participants who were completely new to the Gulf of Mexico sales.

Table 1-6. Estimated Effects of Royalty Relief Periods on Participants.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Average Participants Per Sale	28	34	24	23
Participants Per Sale Attributed To Royalty Relief	16	12	9	9

Regarding the type of participant, in the royalty relief periods, a trend toward participation by non-major firms was initiated in the DWRRA period. In 800-plus meter, the average share by majors fell from 82 percent (1983-1995) to 51 percent (1996-2000) to 32 percent (2001-2003). Competition was measured as the number of bids per tract (including tracts where a lease was not awarded). As shown in Table 1-7, the average number of bids per tract in deepwater averaged between 1.27 and 1.48 for the royalty relief periods. It is estimated that the DWRRA period had a positive effect on competition (mainly during 1996-1997), however, the post-DWRRA period was associated with a decline in competition, after accounting for other factors.

Table 1-7. Estimated Effects of Royalty Relief Periods on Competition.

	DWRRA 1996-2000		Post-DWRRA 2001-2003	
	200-800 m	800-plus m	200-800 m	800-plus m
Average Bids Per Tract By Period	1.48	1.46	1.38	1.27
Bids Per Tract Attributed To Royalty Relief	0.06	0.04	-0.07	-0.11

Turning to Task 2, Table 1-8 summarizes the net fiscal effects per barrel of oil equivalent discovered that one can expect from implementing each of the four royalty alternatives.⁸ Net fiscal effects include the sum of royalty, lease and bonus revenue collected between 2003 and 2042, discounted to a 2003 present value using a 12 percent discount rate. In particular, we focus on the amount of foregone royalties necessary to discover each incremental barrel. To perform this analysis we compare the amount of reserves discovered in each policy alternative that provides royalty relief versus the No Relief scenario.

⁸ Task 2 included projections of the future rather than historical statistical analysis and contained two primary components: (1) projections of royalty-paying and royalty-free production from DWRRA and subsequent programs under several policy scenarios, and (2) hypothetical projections that enable the policy analyst to assess the “tradeoff” of production and revenue for alternative deepwater royalty relief policies in general.

Table 1-8. Foregone Royalties per Incremental BOE Discovered for Each Alternative Compared with No Relief Scenario, 2003-2042 Projection.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Present Value Royalty Revenue (mm)	Present Value of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)	Dollar per BOE
DWRR - Field	All	30	4.54	49,005	\$54,901	\$5,300	\$60,201	
			Diifference	1,006			-\$1,989	-\$1.98
DWRR - Lease	All	30	4.54	49,772	\$52,148	\$6,099	\$58,247	
			Diifference	1,773			-\$3,942	-\$2.22
Current	All	30	4.54	48,692	\$56,291	\$4,290	\$60,581	
			Diifference	693			-\$1,608	-\$2.32
No Relief	All	30	4.54	47,999	\$58,367	\$3,823	\$62,190	

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

Table 1-8 indicates a clear trade-off between the increase in reserves discovered and a decrease in royalty revenue collection. On one hand, for this \$30/bbl scenario, all forms of royalty relief lead to an increase in the amount of reserves discovered versus the No Relief scenario. In assessing the results of Table 1-8, it is important to note we are using a simulation of the future to demonstrate the trade-off between incremental discovery effects and revenue collection. The No Relief scenario does not back-cast what *would* have happened between 1996 and 2002 without deepwater royalty relief.

Analysis of projected production data indicates that simulations using royalty relief alternatives increase production from future discoveries. In addition, we realize that along with this increase in production comes a decrease in the amount of royalty revenue collected due to a greater portion of the production enjoying relief from royalties as a result of each policy alternative. While the ultimate cumulative projected production from forecasted discoveries extends far beyond the 2042 forecast cut-off, the amount of reserves discovered allows an investigation into the impacts of each alternative.

One might expect that as royalty relief increases, the amount of foregone royalties would increase per incremental barrel of reserves discovered. Yet, when we consider the present value of additional lease bonus and rental revenue, we actually observe a greater trade-off in terms of reserves discovery and total revenue collection for the Current Program (on a per barrel basis) versus the highest relief scenario, DWRR – Lease. For every additional barrel discovered under the current royalty alternative, \$2.32 is “lost” in royalty revenue. The larger per barrel amount of foregone royalties for the current alternative is largely driven by a minimal change in lease and bonus royalty revenue compared with the No Relief scenario. However, while the current royalty alternative does not appear to generate much excitement at the leasing level, those who find and develop reserves under this program are taking advantage of the royalty incentives – to the point it is “costing” the government more per barrel in lost revenue than the larger royalty relief alternatives.

The rest of this summary report provides more detail on the basis for these findings and conclusions. Chapter 2 discusses the historical analysis of lease sales; Chapter 3 discusses competition and bidding, including our analysis of high bids and the bidding model. In Chapter 4 we focus on impacts on exploration and development, and Chapter 5 describes our future looking programmatic analysis of the four lease program options and resource development and fiscal impacts. Volume II of this report is the detailed technical report and provides more detail on the methods, data, analyses performed, and bases for the conclusions reached in this study. It provides considerably more technical discussion of the various statistical models we employed as well as detail on our analyses of the alternative future leasing programs.

Chapter 2

Leases Sold and Sale Participation

Introduction

In this chapter, we discuss the effect of DWRRA and the post-DWRRA program contrasted with no royalty relief on the following aspects of lease sales:

- The number of tracts bid on and the number of leases sold;
- The number of lease sale participants;
- The role of majors versus non-majors participating in lease sales

We report results from our analysis for three water depth categories:

- *0-200 meters – shallow water:* Deepwater royalty relief does not apply directly to these tracts, but there may be indirect effects.
- *200-800 meters – deepwater:* Although policies provide varying amounts of relief for leases in 200-400 meter versus 400-800 meter, subclasses are combined in order to provide sufficient data points to perform statistical analysis.
- *800+meters – deepwater:* Policies provide a greater amount of royalty relief in this deepwater area.

This chapter presents data on the number of leases sold, leases held, and sale participation, as well as numerous explanatory variables. The policy effects are measured in two ways:

1. Statistics and data analysis that do not involve regression analysis;
2. Regression model that includes policy dummy variables.

Historical Data Analysis

Table 2-1 shows the count of tracts bid on and leases sold in the Central and Western Gulf of Mexico, as well as annual averages.⁹ For instance, the annual average of tracts bid on in 0-200 meter, for the 1983-1995 period, equals $(5993 / 13 =) 461$. In this study, “leases sold” refers to tracts where high bid is accepted.¹⁰ In addition, it must be reiterated that there are

⁹ Data for the Eastern Gulf of Mexico were omitted from most analyses for this study due to only intermittent leasing activity in that area during the study period.

¹⁰ The distinctions between tracts bid on, bids accepted, and leases awarded can be confusing. If the high bid for a tract is not less than the MMS value for the tract, then the high bid is accepted, however, for purposes of this study, bid acceptance is strictly indicated by an element of the MMS database that reports “accepted” or “rejected.” (Between 1983 and 2002, there were 16,371 “accepted” bid instances in the Central and Western Gulf, whereas

slightly different counts of deepwater leases as contrasted with leases with DWRRA relief. For our purposes we categorized leases by water depth as opposed to whether they received royalty relief.¹¹ The difference is small and is discussed in more detail in Chapter 3 of Volume II.

Table 2-1. Tracts Bid On and Leases Sold (Central and Western).

0-200	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	5993	461	5586	430
DWRRA 1996-2000	1974	395	1910	382
Post_DW 2001-2003	1379	460	1347	449
All	9346	445	8843	421
200-800	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	1216	94	1180	91
DWRRA 1996-2000	513	103	485	97
Post_DW 2001-2003	315	105	297	99
All	2044	97	1962	93
800+	Tracts Bid On		Leases Sold	
	Count	Annual Average	Count	Annual Average
Pre-Policy 1983-1995	1778	137	1780	137
DWRRA 1996-2000	3009	602	2900	580
Post_DW 2001-2003	897	299	886	295
All	5684	271	5566	265

The annual averages do not represent the year-by-year variation in tracts bid on or leased. In reality, the variation was substantial, as shown in Figure 2-1. The onset of DWRRA, for instance, was associated with a three-year spike of leases sold. The key implication of this figure is that there are two phenomena that are not represented by the annual averages: (a) policy periods begin by lifting the series from previously low levels, and (b) the rise in the series does not endure for the entire policy period. The companies shifted their focus to deepwater leases, especially after the adoption of DWRRA as Figure 2-1 indicates. Since 1996, over 40 percent of the leases bid on have been ultra-deepwater leases (over 800 meters), another sign of the increasing importance of lease sales in deepwater area of the Gulf of Mexico.

there were 16,185 leases where the high bid was not less than the MMS value.) Lease award normally follows upon bid acceptance, but there are rare instances where legal or other problems prevent award.

¹¹ Even within this category, there is a minor discrepancy. Two different data sources (“LeaseHist” file and “LeaseDetails” file) report a slightly different number of deepwater leases sold.

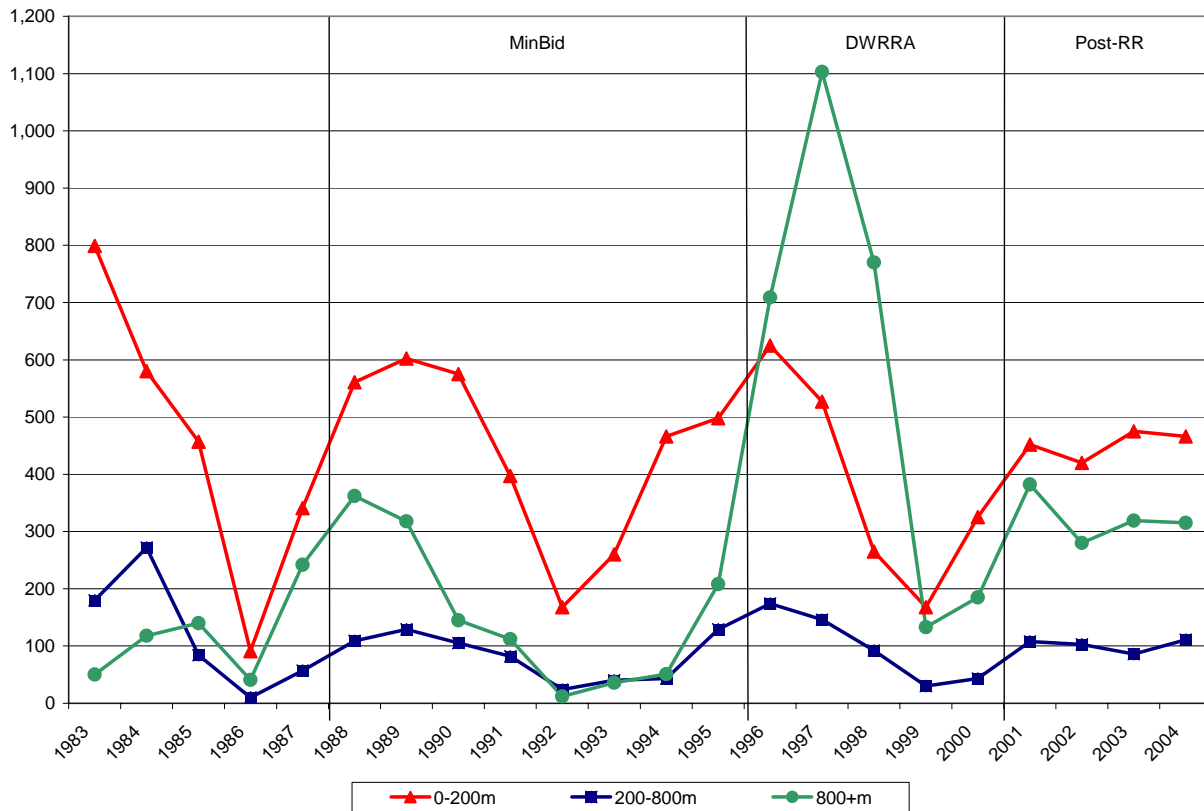


Figure 2-1. Leases Sold (Central and Western), By Depth.¹²

Table 2-2 shows the actual changes from the pre-policy¹³ to policy period of leases sold. These numbers contrast with the simulation impact estimates of the regression analysis later in this chapter. As Table 2-2 shows, in the deepwater areas, the average number of leases sold increased during the policy periods relative to the 1983-1995 period.

Table 2-2. Difference in Average Number of Leases Sold 1983-1995 and Royalty Relief Periods by Water Depth.

	Leases Sold, Annual Average		
	0-200	200-800	800+
DWRRA 1996-2000	-48	6	443
Post_DW 2001-2003	19	8	158

Two factors contributed significantly to lease sale results: the number of *participants* in sales and the level of *competition* among them. Number of participants was important because royalty relief, by increasing the expected profitability of investing in a lease, tended both to attract more buyers and to increase the lease purchases per buyer. Overall, the number of

¹² Certain data are available for 2004 sales, however, it is not sufficient to include in regression analyses.

¹³ “Pre-policy” refers throughout this report to the period from 1983-1995 prior to deepwater royalty relief.

participants in lease sales has varied considerably from year to year. In Table 2-3, the average number of participants per sale is presented by policy period, for deepwater. For instance, the average number of participants, for Central and Western sales from 1996-2000, was 28 in 200-800 meters, an increase of 8 participants per year from the 1983-1995 time period.

At the same time, the number of participants declined in the 0-200 meter area. In addition, non-majors became relatively more important during the DWRRA period. For example, in 800-plus meter range, the average share by majors fell from 82 percent (1983-1995) to 51 percent (1996-2000) and to 32 percent (2001-2003).

Table 2-3. Average Number of Participants for Central and Western Gulf Sales and Difference in Average Number of Participants 1983-1995 and Royalty Relief Periods by Water Depth.

	Participants, Annual Average		
	0-200	200-800	800+
Pre-Policy 1983-1995	64	20	11
DWRRA 1996-2000	58	28	34
Post_DW 2001-2003	54	24	23
	Participants, Difference Mean Between 1983-1995 And Royalty Relief Periods		
	0-200	200-800	800+
DWRRA 1996-2000	-6	8	22
Post_DW 2001-2003	-10	4	12

Regression Analyses of the Number of Leases Sold and Participants

We developed a regression model to test empirically our hypotheses about factors affecting the number of leases sold over time.¹⁴ Table 2-3 provides data on the mean values of the number of leases sold and the number of participants for each period by water depth. As noted in the deepwater areas, the leases sold and number of participants were both higher during the policy periods than prior to 1996. These data also suggest that the number of participants and leases sold cycle in the same pattern and may be determined by some of the same factors. This led us to employ a simultaneous equation model where participants and leases sold are both endogenous variables.

We employed a two-stage least squares (TSLS) model with dummy variables to capture the impact of the royalty relief programs.¹⁵ Our analysis was performed on a pooled data set which included data from each Central and Western Gulf sale between 1983 and 2003, giving us a total of 42 observations. Exogenous (right hand side) variables included the change in leases held in inventory, the percent of all bids that were made by joint and major bidders, the annual change in reserve estimates, a dummy variable to represent Western Gulf sales, and two dummy variables to represent the DWRRA and post-DWRRA periods respectively. Other variables included as instruments in the model include oil price, seismic coverage and the change in GDP.

¹⁴ Chapter 3 of Volume II presents a detailed discussion of the regression models considered and used in this analysis as well as the various dependent variables included in the model.

¹⁵ Chapter 3 to Volume II discusses the various options for specifying the policy dummies.

The results of the two-stage model for 800-plus meters are presented in Table 2-4. Results for other water depths are presented in Chapter 3 of Volume II.

The results in Table 2-4 represent the system of equations with the number of leases sold and participants as the two endogenous variables. When measuring leases sold, only the number of participants is significant at the tested levels. When measuring participants, leases sold, joint bidders, the change in leases held in inventory, and most notably, the two policy variables are significant at the tested levels. For purposes of policy analysis, however, individual estimated parameters are of less importance, with the real focus on the dummy variables and the subsequent simulation runs which measure the effect of the policy by examining the hypothetical case had the policy not existed. The DWRRA dummy variable is equal to one for sales in years 1996-2000 for all water depths. The post-DWRRA dummy variable is equal to one for sales in years 2001-2003 for 0-200 meters and 800-plus meters, and equal to one for sales in years 2002 and 2003 for 200-800 meters. The specification of the dummy variables in this manner represents an average impact over the entire period covered by the dummy and therefore can mask peaks early in the period and troughs later on.

Table 2-4. TSLS Parameters for Leases Sold and Participants, 800-plus meter.

Dependent Variable	Leases Sold		
Root MSE	88.1406	R-Square	0.6761
Dependent Mean	132.5238	Adj R-Sq	0.6206
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-20.8621	-0.4503	0.6539
Participants	6.7705	2.1494	0.0351
Change in Leases Held	0.1327	0.9302	0.3555
Reserve Estimates	0.1261	0.9860	0.3276
WGM	9.0520	0.2814	0.7793
DWRRRA	24.0557	0.3529	0.7253
Post-DWRRRA	-22.4216	-0.3991	0.6910
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRRA, Post-DWRRRA, Seismic Coverage, Oil Price and GDP Change		
Dependent Variable	Participants		
Root MSE	4.2627	R-Square	0.9024
Dependent Mean	18.4048	Adj R-Sq	0.8823
Variable	Parameter Estimate	t Value	Pr > t
Intercept	4.7577	2.8391	0.0059
Leases Sold	0.0288	3.0616	0.0031
Joint Bidders	21.1964	5.8554	0.0000
Change in Leases Held	0.0209	3.2248	0.0019
Reserve Estimates	0.0058	0.9179	0.3619
WGM	-2.0780	-1.4450	0.1530
DWRRRA	9.1272	3.5719	0.0007
Post-DWRRRA	7.7572	3.4732	0.0009
Instruments:	Joint Bidders, Major Bidders, Change in Leases Held, Reserve Estimates, WGM, DWRRRA, Post-DWRRRA, Seismic Coverage, Oil Price and GDP Change		

Table 2-5 shows the results of the policy and non-policy simulations for the number of leases sold. For convenience, the table repeats actual leases sold, and then gives leases sold that the regression analysis attributes to the policy period dummy variable. For example, in 0-200 meters, the DWRRRA period dummy accounts for -6 out of 382 leases sold, averaging over 1996-2000. (Since the policy did not apply to that water depth, this effect is either an indirect effect of the deepwater policy or an associated non-policy effect.) In 800-plus meters, the DWRRRA dummy accounts for 213 out of the 580 leases sold. Thus, in the hypothetical (counterfactual) case of no policy, it is estimated that 367 leases would have been sold, on average per year.

Table 2-5. Policy Period Effects on Leases Sold.

0-200	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	430	0	430
DWRRA 1996-2000	382	-6	388
Post_DW 2001-2003	449	44	405
200-800	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	91	0	91
DWRRA 1996-2000	97	44	53
Post_DW 2001-2003	99	20	79
800+	Annual Actual Leases Sold	Annual Leases Attributed to Policy	Annual Hypothetical Leases Sold (No Policy)
Pre-Policy 1983-1995	137	0	137
DWRRA 1996-2000	580	213	367
Post_DW 2001-2003	295	75	221

Table 2-6 presents the portion of the actual participants that is attributed to royalty relief, based upon the simulation results of the regressions. For instance, 16 participants of the 28 (average for 200-800 meter in 1996-2000) were “added” by the policy period, although the study did not try to distinguish between participants who had bid in earlier sales and participants who were completely new to the Gulf of Mexico sales.

Table 2-6. Estimated Effects of Royalty Relief Periods on Participants.

0-200	Annual Actual Participants	Annual Participants Attributed to Policy	Annual Hypothetical Participants (No Policy)
Pre-Policy 1983-1995	64	0	64
DWRRA 1996-2000	58	-5	64
Post_DW 2001-2003	54	-13	67
200-800	Annual Actual Participants	Annual Participants Attributed to Policy	Annual Hypothetical Participants (No Policy)
Pre-Policy 1983-1995	20	0	20
DWRRA 1996-2000	28	16	12
Post_DW 2001-2003	24	9	15
800+	Annual Actual Participants	Annual Participants Attributed to Policy	Annual Hypothetical Participants (No Policy)
Pre-Policy 1983-1995	11	0	11
DWRRA 1996-2000	34	12	22
Post_DW 2001-2003	23	9	15

Inventory Model

The inventory of leases held by companies appears to have had an impact on subsequent lease sales, and may also explain variations in leases sold within a policy period as well as the fact that many companies appeared to buy more leases than they could possibly have drilled.

Firms generally hold “target” levels of inventory of leases in a given area, and as leases either leave inventory because they become productive or are returned to the government, this influences the level of lease sales. Given the significance of lease inventories, we developed a more detailed theory of lease inventory behavior that incorporates an options approach.¹⁶

Firms operating in the Gulf of Mexico often buy the drilling rights to tracts that they never drill.¹⁷ Any attempt to explain this behavior as rational must base the explanation upon the uncertainty faced by the firms. Companies may justify the purchase of a tract as an option to drill with uncertain information rather than as a purchase of a tract currently worth drilling. This makes sense in deepwater where the cost of drilling is often higher than the cost of buying the tracts. A firm buys tracts which, on a fully costed basis, have value only because of the chance that in the future they may become worth drilling. New information from other drilling or improved diagnostic technology may increase the probability of finding economic quantities of oil sufficient to make the tract worth drilling. In addition, policy initiatives such as DWRRA may also increase the value of a tract which may cause a firm to increase its optimal inventory level. As noted it appears that DWRRA caused this effect.

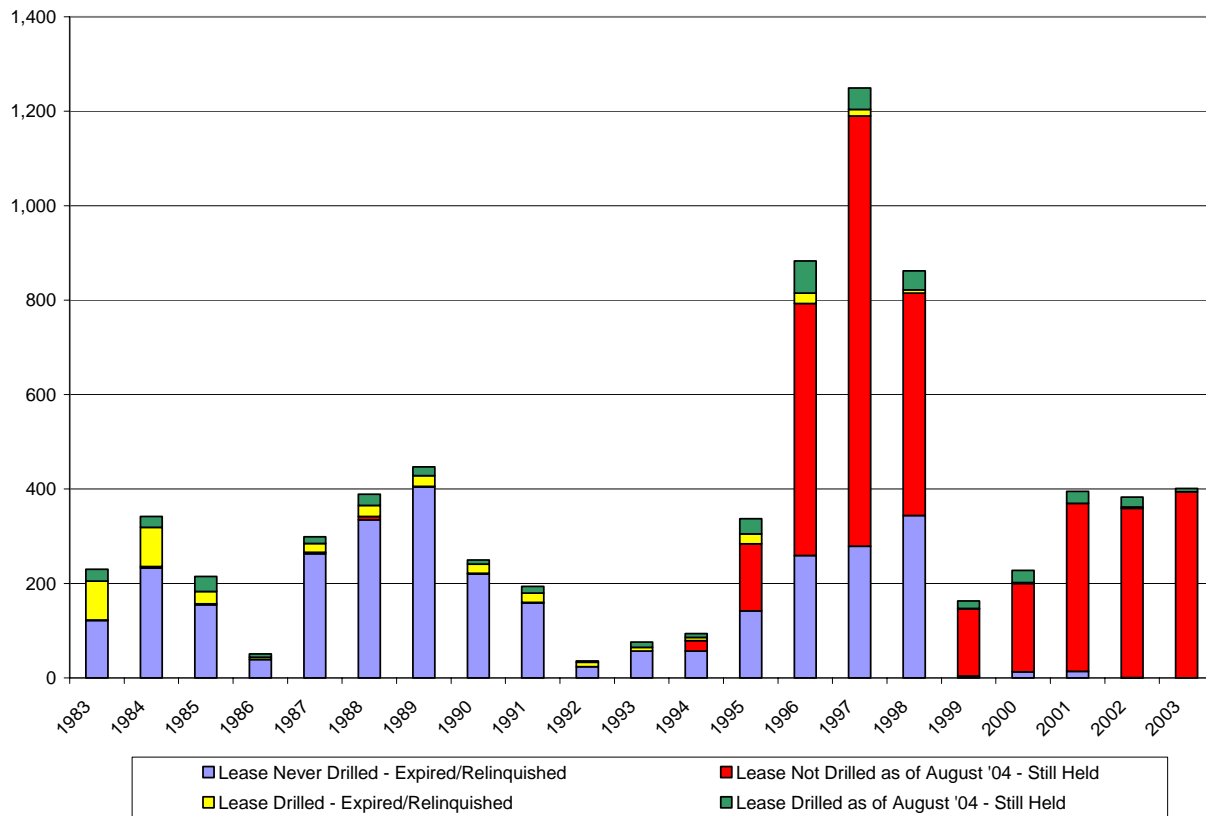


Figure 2-2. Inventory of Used and Unused Leases by Sale, 200-plus meter.

¹⁶ This options inventory model is discussed in detail in Chapter 3 of Volume II.

¹⁷ Tyson (2004) indicates that only 6.5 percent of deepwater leases issued from 1996-2000 have been drilled to date.

The tract inventory model supports what was actually happening in the deepwater environment after the implementation of the DWRRA. As Figure 2-2 shows, the number of deepwater leases held in inventory increased dramatically during the initial years of the DWRRA before reaching a plateau in 1999. This is consistent with the tract inventory model, where a change in input parameters to model royalty relief leads to a higher optimal inventory, providing companies with a new inventory objective and leading to the sale of more leases.¹⁸

Conclusion

Our statistical analysis confirms that the number of leases sold was influenced in a positive manner by the DWRRA and the post-DWRRA administrative program. We estimate that DWRRA caused an increase of 213 ultra deepwater (800-plus meter) leases sold (on average) and an increase of 12 participants in these lease sales. During the post-DWRRA program, the increase in leases sold (relative to no relief) was 75 additional leases sold in ultra deepwater (800-plus meter) and 9 additional participants.

¹⁸ We also examined the inventory held by individual companies and noted that the upward trend in leases held after the DWRRA was primarily driven by a few major companies followed by others in later sales.

Chapter 3

Lease Sale Competition and Lease Sale Bids

Introduction

In this chapter, we review historical data on competition and high bids for Gulf of Mexico OCS leases, and the effects of royalty relief on these elements of lease bidding. Competition is defined as *the number of bids per tract*.¹⁹ We measure high bids as the high bid per lease as well as the high bid per acre. We treat these two topics together because the number of bids and high bid amounts are determined together in our model. We analyze the factors that influence:

- The number of bids per tract (competition);
- The level of high bids;
- Through regression analysis we estimate the effect of royalty relief on the number of bids and the level of high bids.

In developing a theoretical understanding of the bidding process and the determinants of bid levels, we began our analysis with a comprehensive review of the literature on bidding and lease sales. Chapter 2 of Volume II²⁰ describes this literature review and the portions of the literature relevant to our analyses. We have also relied on prior research studies that modeled the bidding process as a foundation for our development of possible hypotheses about the impact of royalty relief on the bidding process as well as the basis for some of the models we have applied to provide insight into the lease bidding process.

Analysis of Data on Competition for Offshore Leases

Perhaps the most obvious feature related to competition and offshore leasing is the lack of vigorous competition for individual leases. Figure 3-1 indicates that almost three quarters of the leases sold between 1983 and 2003 attracted only a single bidder. Furthermore, less than 10 percent of all leases sold attracted more than two bidders. When viewed over time this trend has remained relatively constant since the initiation of area-wide leasing and has approximated 1.42 bidders per lease. With the advent of DWRRA, there was a slight increase in competition as the average number of bidders increased from 1.42 to over 1.49, but after three years trended back below the long-run average. The post-DWRRA period shows a decline in competitive activity to 1.33 bidders, which is less than the 1983-1995 period.

¹⁹ A “tract” means an offshore block when it is offered for lease, and a “lease” means the contract giving rights to that block. Thus a block is given a new tract number each time it is offered for sale. A lease number is assigned when it receives a successful bid in the lease sale.

²⁰ For sake of brevity we do not discuss the literature in detail in this chapter, but merely reference relevant articles and refer the reader to Chapter 2 of Volume II for a detailed discussion of the literature.

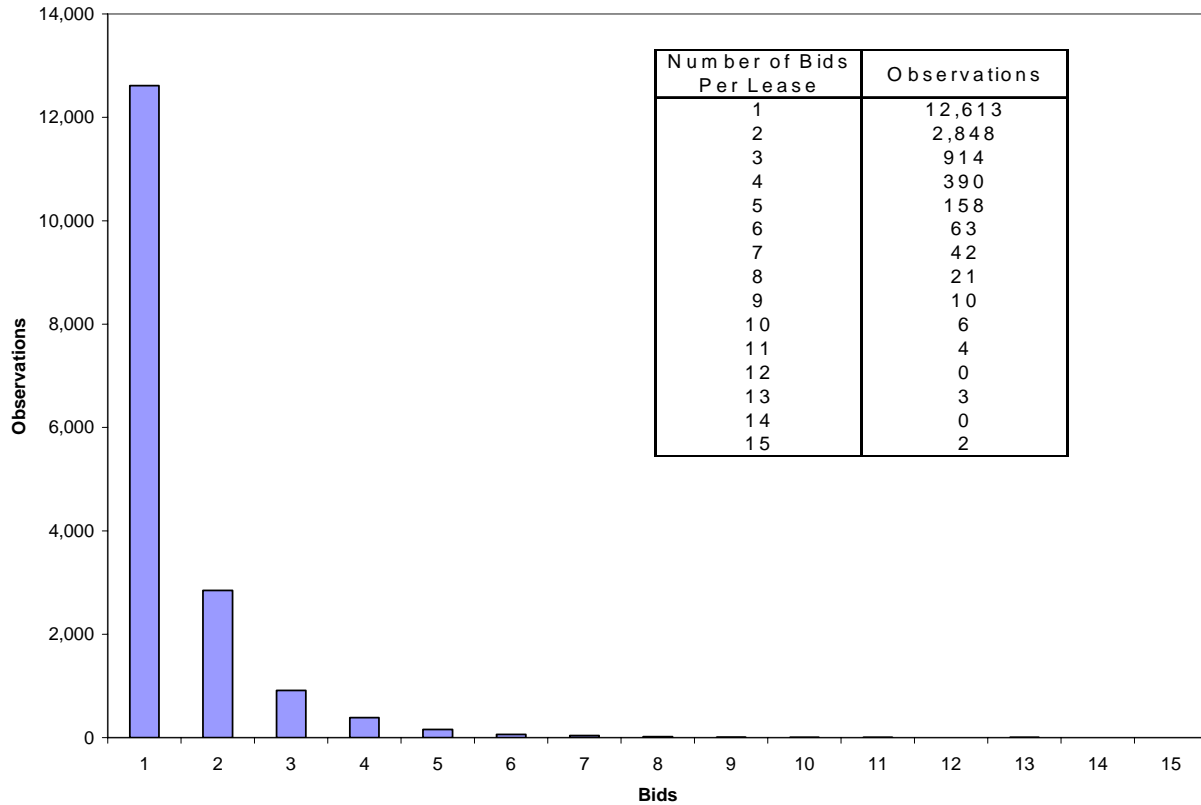


Figure 3-1. Distribution of Number of Bidders, Central and Western Gulf, All Depths 1983-2003.

Table 3-1. Mean Bids Per Tract, by Depth and Period.

	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003
0-200 m	1.51	1.52	1.37
200-800 m	1.41	1.48	1.38
800-plus m	1.20	1.46	1.27
All	1.43	1.49	1.33

This apparent lack of competition must be tempered by an understanding that MMS also plays a role as a “potential competitor.” Through its bid adequacy procedure MMS can reject bids that it deems as being too low, particularly those for which only a single bid is received. The data on MMS’s rejection rate shows that MMS does not reject a large percentage of bids. As shown in Table 3-2, less than 5 percent of all bids were rejected from 1983-2003. In ultra-deepwater, the rejection rate was virtually zero until the mid 1990s. However, during the DWRRRA period, the rejection rate for both 200-800 meter and 800-plus meter leases increased, only to decrease again in the post-DWRRRA period.

Table 3-2. MMS Bid Rejection Rate by Period and Depth.

	Pre-Policy 1983-1995	DWRRRA 1996-2000	Post_DW 2001-2003	1983-2003
0-200 m	7.09%	2.88%	0.28%	5.17%
200-800 m	3.14%	5.46%	3.69%	3.66%
800-plus m	2.25%	5.71%	1.34%	2.35%
All	5.54%	3.96%	2.25%	4.26%

Given that bidding on individual leases is not highly competitive and MMS does not reject a large number of bids, the question remains whether the level of competition itself has an impact on the level of the bonus bids and whether programmatic changes such as royalty relief have affected competition. The literature finds generally that there is a positive relationship between the number of bidders for a lease and the resulting bonus.²¹ This is tempered to some extent by the winner's curse.²² Our analysis of lease bidding data confirms earlier findings that the high bid increases with an increase in the number of bidders. The data indicate that the average number of bidders tend to increase as the size of the lease sale increased.

Statistical Analyses of Competition

Following the lead of the prior literature on bidding, we developed regression analyses in which we posited various possible relationships between the number of bidders and possible explanatory variables. These included:

- Quality of the lease as measured by MMS in its bid adequacy procedure whether it was “viable”;
- A dummy variable for leases that were being bid on a second time;
- A dummy variable for whether the tract had previously been leased and returned to the available inventory of tracts held by MMS;
- Whether joint ventures or “major” bidders submitted a bid for the lease;
- The number of participants in a lease sale;
- A time series variable for each lease sale;
- Water depth of the lease;
- A dummy variable for whether there was “seismic” coverage at the time of the lease sale;
- Planning (geographic) area of the lease;
- The number of tracts offered in a lease sale;
- The probability of a tract receiving one or more bids in a sale;

²¹ See for example, Mead et al. (1980); U.S. GAO (1985); U.S. DOI (1985); Moody and Krivant (1990).

²² The “winner's curse” is caused by competition for a tract of uncertain value. The winning bidder is normally the bidder who has overestimated the value of the tract the most. (Capen 1971)

- Policy dummy variables including the minimum bid amount, the change in rental rates, DWRRA and the post-DWRRA program.²³

Competition was measured as the number of bids per tract (including tracts where lease was not awarded). Table 3-3 provides regression results from an ordered probit model for 800-plus meters, where the dependent variable takes on one of three values: 1 for single-bid leases, 2 for leases with exactly 2 bids, and 3 for leases with 3 or more bids. The results of this regression, along with similar regressions for the other water depth categories (see Chapter 4, Volume II), allow us to simulate the effects of policy on competition. The results of the multiple-bid probability model with and without policy, and the subsequent effect of each respective policy are summarized in Table 3-4 below. It is estimated that the DWRRA period had a positive effect on competition (mainly 1996-1997), however, only in 800-plus meter do both policies have a positive effect on competition, with an increase of 6.2 percent and 4.0 percent in the multi-bid probability respectively for the DWRRA and post-DWRRA policies. In shallow water, both policies had a negative effect on competition.²⁴

Table 3-3. Ordered Probit Parameter Estimates, 800-plus meter.

Variable	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept 1	3.8920	188.5678	0.0000
Intercept 2	4.6264	262.2201	0.0000
Area Block Sequence	-0.4504	125.9631	0.0000
High Bid by Joint Bidder	-0.1759	17.5808	0.0000
High Bid by Major Bidder	0.0925	4.6429	0.0312
Participants in Lease Sale	-0.0175	18.5789	0.0000
Bid Probability	-1.5744	4.4214	0.0355
Tracts Offered (1000s)	-0.4935	61.2687	0.0000
Viable	-0.7418	236.7850	0.0000
WGM	-0.3317	10.6512	0.0011
DWRRA	0.0014	0.0003	0.9869
Post-DWRRA	-0.0175	0.0309	0.8604
Likelihood Ratio index (Pseudo-R2)		0.1008	

²³ Appendix D to Volume II contains a listing and description of all variable names.

²⁴ We are left to interpret the meaning of the low correlation coefficients of our models. As noted the data indicate that a very large proportion of all bids are single bids. It is highly likely that competition, as measured by multiple bids for a single lease, is a randomly distributed variable across the universe of leases available for sale. Our results are also not terribly different from those of prior analysts in terms of explanatory power. The GAO study (1985) reported correlation coefficients on its number of bids regressions in the range of .21 to .28 and Moody and Kruvant (1990) obtained an even lower R² (.17) on their competition (number of bidders) model. Each of these models did find that tract quality was significant as do our models. Better quality leases will tend to attract more competition, but there are few such high quality leases across an entire planning area.

Table 3-4. Simulation Results of Impact of Policy Period on Competition.

Depth	Probability of Multiple Bids					
	DWRRA			Post-DWRRA		
	w/o Policy	w/ Policy	Effect of Policy	w/o Policy	w/ Policy	Effect of Policy
0-200 m	31.2%	27.5%	-3.7%	38.1%	21.5%	-16.6%
200-800 m	22.1%	27.9%	5.7%	27.4%	24.3%	-3.1%
800-plus m	18.4%	24.6%	6.2%	12.7%	16.7%	4.0%

Historical Data: High Bids

In this study, bonus revenue is computed on the basis of the total of high bids accepted (that is, for leases sold). The historical data are given in the following tables. Table 3-5 shows the high bids placed or accepted over the periods indicated, and it also provides the annual average. Table 3-6 shows the high bids per tract and per acre on both placed and accepted bids.²⁵ These tables include high bids on a per acres basis, which are computed as the high bids per tract divided by the high bids per acre. Although acres-per-tract might appear to be a small detail, the fact is that average tract size varies among different tracts, and it is accounted for explicitly in these tables.²⁶

²⁵ The high bid on any lease is determined as the highest value offered by any bidder on a particular lease. High Bid Per Tract Placed is the sum of the dollar amount of high bids on all leases receiving bids in OCS sales; High Bid Per Tract Accepted is the sum of the dollar amount of high bids that were accepted by the MMS through their bid adequacy procedure for all leases receiving bids in OCS sales; High Bid Per Acre Placed is the sum of the dollar amount of high bids on all leases receiving bids in OCS sales divided by the total acreage of all leases receiving bids; High Bid Per Acre Accepted is the sum of the dollar amount of high bids that were accepted by the MMS through their bid adequacy procedure for all leases receiving bids in OCS sales divided by the total acreage of all leases receiving bids.

²⁶ A “full sized” tract size is 5,760 acres, but since some tracts are not full-sized, the average tract size is generally smaller.

Table 3-5. Total High Bids Placed and Accepted.

0-200	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$9,070.23	\$697.71	\$8,503.54	\$654.12
DWRRA	\$1,172.53	\$234.51	\$1,154.38	\$230.88
Post-DWRRA	\$614.77	\$204.92	\$602.49	\$200.83
All	\$10,857.54	\$517.03	\$10,260.41	\$488.59
200-800	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$2,536.86	\$195.14	\$2,506.28	\$192.79
DWRRA	\$478.10	\$95.62	\$464.53	\$92.91
Post-DWRRA	\$277.80	\$92.60	\$267.29	\$89.10
All	\$3,292.76	\$156.80	\$3,238.10	\$154.20
800+	High Bids Placed \$MM		High Bids Accepted \$MM	
	Total	Annual Average	Total	Annual Average
Pre-Policy	\$1,166.46	\$89.73	\$1,164.64	\$89.59
DWRRA	\$2,745.25	\$549.05	\$2,655.36	\$531.07
Post-DWRRA	\$756.93	\$252.31	\$740.58	\$246.86
All	\$4,668.63	\$222.32	\$4,560.58	\$217.17

Table 3-6. High Bids Placed and Accepted Per Tract and Per Acre.

0-200 m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$1,508,186	\$327.30	4608	\$1,522,295	\$330.09	4612
DWRRA	\$594,590	\$126.98	4683	\$604,389	\$129.08	4682
Post-DWRRA	\$446,135	\$96.51	4623	\$447,613	\$96.85	4622
All	\$1,159,498	\$251.15	4617	\$1,160,417	\$251.16	4620
200-800 m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$2,089,667	\$380.08	5498	\$2,123,967	\$386.13	5501
DWRRA	\$933,796	\$169.40	5512	\$957,794	\$173.97	5506
Post-DWRRA	\$881,920	\$154.42	5711	\$912,250	\$159.71	5712
All	\$1,613,309	\$292.40	5517	\$1,653,780	\$299.69	5518
800-plus m	Mean High Bids Placed			Mean High Bids Accepted		
	Per Tract	Per Acre	Acres Per Tract	Per Tract	Per Acre	Acres Per Tract
Pre-Policy	\$653,477	\$114.59	5703	\$654,290	\$114.73	5703
DWRRA	\$911,437	\$160.51	5678	\$915,643	\$161.33	5676
Post-DWRRA	\$842,905	\$146.64	5748	\$835,873	\$145.43	5748
All	\$819,778	\$143.93	5696	\$819,365	\$143.90	5694

A summary of the change in high bids accepted, computed as the policy period minus the 1983-1995 “pre-policy” period, is shown in Table 3-7. The change is computed in this way in order to contrast it with the policy effects estimated by means of regression models with dummy variables shown below. The mean high bids per acre fell from the 1983-1995 “pre-policy” period to lower means in the royalty relief periods, except for the 800-plus meter water depth class. In 800-plus meter, the change from 1983-1995 “pre-policy” mean was positive for the DWRRA period and positive by a smaller amount for the post-DWRRA period. In interpreting this table, it is important to bear in mind that the period averages do not reveal how the variables changed over the periods. For instance, the 1983-1995 averages are lifted by the relatively higher bids placed in the first portion of that period. A different picture would emerge from showing a sub-period preceding the policy periods. These details are examined in Chapter 5 of Volume II.

Table 3-7. High Bids, Difference of 1983-1995 and Royalty Relief Periods.

0-200 m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$1,522,295	\$330.09	NA	NA
DWRRA	\$604,389	\$129.08	-\$917,906	-\$201.02
Post-DWRRA	\$447,613	\$96.85	-\$1,074,682	-\$233.24
200-800 m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$2,123,967	\$386.13	NA	NA
DWRRA	\$957,794	\$173.97	-\$1,166,174	-\$212.16
Post-DWRRA	\$912,250	\$159.71	-\$1,211,717	-\$226.42
800-plus m	High Bids Accepted Per Tract	High Bids Accepted Per Acre \$/a	Difference in High Bids Per Tract	Difference in High Bids Per Acre \$/a
	Mean	Mean	Policy-Pre-Policy	Policy-Pre-Policy
Pre-Policy	\$654,290	\$114.73	NA	NA
DWRRA	\$915,643	\$161.33	\$261,353	\$46.60
Post-DWRRA	\$835,873	\$145.43	\$181,583	\$30.69

Statistical Analysis of High Bids

As noted in Chapter 2 of Volume II, we rely on the regression models developed by Mead et al. (1980), Moody and Kruvant (1990), and Farrow (1987) among others as the starting point for our analysis. Although we presented results on the number of bids as a single equation model, the number of bids and the level of the high bid are determined together and therefore we employ a two-stage least squares model to explain high bids and the number of bidders jointly. Two-stage least squares regression is appropriate because it avoids the possibility of inconsistent estimation.²⁷ We use the average winning bid per acre as the most reliable measure of our

²⁷ The two-stage model we applied generally followed the approach used by Moody and Kruvant (1990) with one important distinction. Moody and Kruvant (1990) estimate a three stage model, in which their first equation is intended to explain when a tract was bid on or not. They were trying to account for the supply of leases whether the

dependent variable. Our lease bidding model hypothesizes that high bids will be a function of three sets of variables including competition (number of bidders), the quality or value of the tract, and the cost to develop the tract. The results of the two-stage least squares regression (TSLS) for 800-plus meters are shown in Table 3-8. The number of leases sold and the number of bids are our two endogenous variables. Explanatory variables in the model include:²⁸

- A dummy variable representing Western Gulf leases;
- Whether the lease had previously been leased and returned to inventory;
- A dummy variable for whether the tract on which the lease was located was classified by the MMS as a “Drainage/Development” tract;
- Whether the high bid on the lease was placed by a joint venture bidder;
- Whether the tract had previously been leased and returned to the available inventory of tracts held by MMS;
- The minimum bid per acre requirement based on the water depth of the lease;
- The water depth of the lease;
- A dummy variable for whether seismic coverage was available at the time of the lease sale;
- A dummy variable for whether the tract on which the lease was located was classified as “viable” by the MMS;
- The total number of tracts offered in the lease sale;
- The WTI spot price at the time of the lease sale;
- Dummy variables to represent DWRRA and post-DWRRA policy periods.

movement to area wide leasing, i.e., a much larger supply of leases had an impact on the bidding process. Although we could have added all of the no-bid leases to our data sets, the supply of leases under area wide leasing has remained relatively constant and MMS lacks much lease specific data on no bid leases

²⁸ Mean values for each of the independent variables tested in the model are presented in Chapter 4 of Volume II.

Table 3-8. Two-Stage Least Squares Regression Results for High Bids, 800-plus meter.

Dependent Variable	LN(High Bid Per Acre)		
Root MSE	0.9166	R-Square	0.0797
Dependent Mean	4.2928	Adj R-Sq	0.0779
Variable	Parameter Estimate	t Value	Pr > t
Intercept	3.6493	51.7226	0.0000
LN(Bids)	2.3707	19.1581	0.0000
WGM	0.0896	3.1478	0.0016
Released	0.5786	5.1997	0.0000
Drainage/Development	0.2053	0.9695	0.3323
Area Block Sequence	-0.0256	-0.6676	0.5044
MinBid Per Acre	0.0109	23.2395	0.0000
Water Depth	-0.0001	-6.0457	0.0000
Seismic Coverage	-0.1861	-3.0169	0.0026
Bid Probability	-1.6653	-5.0803	0.0000
DWRRA	0.5151	7.7791	0.0000
Post-DWRRA	0.3623	5.7331	0.0000
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, MinBid Per Acre, Water Depth, Seismic Coverage, Bid Probability, DWRRA, Post-DWRRA		
Dependent Variable	LN(Bids)		
Root MSE	0.3614	R-Square	0.1903
Dependent Mean	0.1929	Adj R-Sq	0.1885
Variable	Parameter Estimate	t Value	Pr > t
Intercept	-0.7729	-7.4731	0.0000
LN(High Bid Per Acre)	0.0280	1.5183	0.1290
WGM	0.0369	1.6607	0.0968
Released	0.0322	0.7144	0.4750
HB by Joint Bidder	0.0458	3.5957	0.0003
Drainage/Development	-0.0778	-0.9291	0.3529
Area Block Sequence	0.1564	12.3785	0.0000
Viable	0.2337	12.5017	0.0000
Water Depth	0.0000	3.4205	0.0006
Oil Price	0.0057	3.8056	0.0001
Tracts Offered (1000s)	0.0984	6.2055	0.0000
Bid Probability	1.0097	8.6656	0.0000
DWRRA	0.0130	0.6440	0.5196
Post-DWRRA	-0.0872	-2.7034	0.0069
Instruments:	WGM, Released, Drainage/Development, Area Block Sequence, Viable, MinBid Per Acre, Water Depth, Seismic Coverage, Oil Price, Tracts Offered, Bid Probability, DWRRA, Post-DWRRA		

The policy period dummy variables take on the value of 1 for any lease that was bid on in a lease sale that took place during each respective policy period. Therefore, the interpretation of the policy variable is highly dependent on the sign of the coefficient on the variable. The positive sign on the coefficient for the DWRRA policy variable in the LN(High Bid Per Acre) portion of the TSLS regression implies that after other factors have been accounted for, high bids

were higher during the DWRRA period in 800-plus meters. Likewise, the negative sign on the post-DWRRA variable in the LN(Bids) portion of the regression indicates that there were fewer bids per lease in the post-DWRRA period in 800-plus meters, i.e., less competition. Based on the results of the TSLS regression, we can simulate the effect of these policies on the average High Bid per Acre. This is done by estimating results for a hypothetical situation had the policies not existed.

Table 3-9 presents the results of the policy simulation. It shows the effects of royalty relief on the high bids per acre.²⁹ It is striking that, while the DWRRA program has estimated effects which are positive (as expected), the post-DWRRA period has counter-intuitive negative effects in 200-800 meter. Why is that? First, *competition* is an important determinant of average high bids, according to the regression model. Competition for a tract was reduced during the post-DWRRA period, thus leading to lower bids. Second, factors such as declining geologic potential of tracts offered and other factors cancel the effect of royalty relief *per se*, and this can cause policy period dummies to have negative impact.

Table 3-9. Policy Period Effects On High Bid Per Acre.

0-200	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$330.09	\$0.00	\$330.09
DWRRA	\$129.08	\$13.76	\$115.32
Post-DWRRA	\$96.85	-\$16.52	\$113.37
200-800 m	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$386.13	\$0.00	\$386.13
DWRRA	\$173.97	\$39.69	\$134.28
Post-DWRRA	\$159.71	-\$7.02	\$166.73
800-plus m	Annual Actual High Bid Accepted Per Acre	Annual High Bid Per Acre Attributed to Policy Variable	Annual Hypothetical High Bid Per Acre (No Policy)
Pre-Policy	\$114.73	\$0.00	\$114.73
DWRRA	\$161.33	\$57.85	\$103.48
Post-DWRRA	\$145.43	\$19.26	\$126.16

Finally, the results of the total high bids are shown in Tables 3-10 through 3-12. Table 3-10 shows the actual total high bids (or cash bonus revenues). For instance, in 0-200 meter for the “pre-policy” period, 1983-1995:

1. \$330.09 high bid per acre times 4,612 acres per tract equals \$1,522,295 high bid per tract, annual average for the period,

²⁹ The table is based on actual high bids accepted (per lease), as distinct from high bids placed (per tract). However, policy simulations were run on regressions that included all high bids *placed*. The policy impact difference is minimal.

2. 428 leases sold times \$1,522,295 equals \$652,010,727 total high bids (cash bonus revenue), annual average for the period,
3. \$652,010,727 total per year times 13 years in period equals \$8.5 billion high bids (cash bonus revenues) for the entire period

Table 3-10. Actual Total High Bids (Cash Bonus Revenue) at Leases Sold.

0-200	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	430	\$330.09	4612	\$1,522,295	\$654,118,520	13	\$8,503,540,761
DWRRA	382	\$129.08	4682	\$604,389	\$230,876,580	5	\$1,154,382,901
Post-DWRRA	449	\$96.85	4622	\$447,613	\$200,978,336	3	\$602,935,009
200-800 m	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	91	\$386.13	5501	\$2,123,967	\$192,790,858	13	\$2,506,281,156
DWRRA	97	\$173.97	5506	\$957,794	\$92,905,972	5	\$464,529,862
Post-DWRRA	99	\$159.71	5712	\$912,250	\$90,312,764	3	\$270,938,293
800-plus m	Annual Actual Leases Sold	Actual High Bid Accepted Per Acre	Acres Per Tract	Actual High Bid Accepted Per Tract	Annual High Bids At Leases Sold	Years In Period	Period Total High Bids At Leases Sold
Pre-Policy	137	\$114.73	5703	\$654,290	\$89,587,403	13	\$1,164,636,241
DWRRA	580	\$161.33	5676	\$915,643	\$531,072,948	5	\$2,655,364,738
Post-DWRRA	295	\$145.43	5748	\$835,873	\$246,861,120	3	\$740,583,361

Table 3-11 shows the hypothetical (counterfactual) total high bids (or cash bonus revenues) as computed from the regression analysis. The computation is the same as for actual high bids. And finally, Table 3-12 provides the effects of policy on period total high bids (cash bonus revenues), computed as the difference of actual (with relief) and hypothetical (without relief) cash bonus revenues. In the end, the combined effect of royalty relief policy on high bid revenues is positive for all deepwater depth classes and royalty relief periods.

Table 3-11. Hypothetical (No Policy) High Bids (Cash Bonus Revenues).

0-200	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	430	\$330.09	4612	\$1,522,295	\$654,118,520	13	\$8,503,540,761
DWRRA	388	\$115.32	4682	\$539,978	\$209,614,910	5	\$1,048,074,552
Post-DWRRA	405	\$113.37	4622	\$523,962	\$212,316,074	3	\$636,948,222
200-800 m	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	91	\$386.13	5501	\$2,123,967	\$192,790,858	13	\$2,506,281,156
DWRRA	53	\$134.28	5506	\$739,292	\$39,000,524	5	\$195,002,620
Post-DWRRA	79	\$166.73	5712	\$952,369	\$75,067,163	3	\$225,201,490
800-plus m	Annual Hypothetical (No Policy) Leases Sold	Annual Hypothetical (No Policy) High Bid Per Acre	Acres Per Tract	Annual Hypothetical High Bid Per Tract	Annual Hypothetical (No Policy) High Bids	Years In Period	Period Hypothetical (No Policy) High Bids
Pre-Policy	137	\$114.73	5703	\$654,290	\$89,587,403	13	\$1,164,636,241
DWRRA	367	\$103.48	5676	\$587,329	\$215,423,506	5	\$1,077,117,530
Post-DWRRA	221	\$126.16	5748	\$725,159	\$159,957,125	3	\$479,871,376

Table 3-12. Effect of Policy on Total Cash Bonus Revenues.

0-200	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$8,503,540,761	\$8,503,540,761	\$0
DWRRA	\$1,154,382,901	\$1,048,074,552	\$106,308,349
Post-DWRRA	\$602,935,009	\$636,948,222	(\$34,013,213)
200-800 m	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$2,506,281,156	\$2,506,281,156	\$0
DWRRA	\$464,529,862	\$195,002,620	\$269,527,242
Post-DWRRA	\$270,938,293	\$225,201,490	\$45,736,803
800-plus m	Period Total High Bids at Leases Sold	Period Hypothetical (No Policy) High Bids	Total High Bid Attributed to Policy Variable
Pre-Policy	\$1,164,636,241	\$1,164,636,241	\$0
DWRRA	\$2,655,364,738	\$1,077,117,530	\$1,578,247,208
Post-DWRRA	\$740,583,361	\$479,871,376	\$260,711,985

The Bidding Model

The theoretical model we use to analyze bidding for deepwater tracts is largely the widely used decision-theoretic simulation model first described by Capen et al. (1971). Our model, however, includes the role of the MMS as well as the roles of the bidder's competitors. The bidding model takes the viewpoint of a single bidder competing for a tract of uncertain value against uncertain competition. The model provides the bidder a random estimate of the value of the tract with a known, unbiased, log-normally distributed error distribution. The model is strictly proportional. In particular, the bidder's strategy is characterized as a fraction (not a general function) of her estimate. The model assumes that the bidder makes an estimate of its competition. For each competitor, it assigns a probability to its bidding, a probability distribution of its random, log-normally distributed estimate, and a deterministic or random distribution of its proportional bidding strategy. The model uses a Monte Carlo simulation of the auction, and calculates the bidder's expected gain or loss for a wide range of bidding fractions. From this, it is easy to select the fraction that produces the highest expected return.³⁰

We have considered the effect of three types of MMS policies in the model. First, deepwater royalty relief is handled by including its effect in the true value of the tract. Thus, if royalty relief adds 10 percent to the expected value of a tract, that 10 percent is included in the tract value in the model. The second MMS policy in the model is the MMS's bid adequacy process. The model treats MMS as another bidder, except that it is a "bidder" whose likelihood of participation depends upon the number of other bids received and its "bid" depends upon those bids. The third MMS policy is the minimum bid per acre. While a substantial number of deepwater tracts have values low enough to be within an order of magnitude of the minimum bid per acre, a large fraction of the *value* of offshore tracts lies outside this range. However, even within the range, some numerical experimentation has shown that even a relatively small chance of competition or, to a lesser extent, MMS bid evaluation is often sufficient to cause bidders to respond to that potential competition rather than to try to bid at the minimum level. Thus, the model seems to be reasonable for bids relatively near the minimum bid level.

We modeled royalty relief by adjusting the tract value, although we do normalize this value to maintain the scale independence of the bidding model. Inclusion of royalty relief has no effect on the optimal bid fraction, although it will tend to change our optimal expected value and average tract value to true value at the optimal bid fraction. The optimal bid fraction has not changed. The results of the bidding model show that bidders are discounting the value of royalty relief consistent with the optimal bid fraction.

We tested the model for other policy impacts.³¹ For example, we analyzed MMS as a potential competitor in high-value tracts and we do this by modeling MMS participation in the single-bid, high value tract by estimating the probability that the MMS will have a significant evaluation. Not surprisingly, the assurance of the MMS as a competitor leads to an increase in

³⁰ It is worth noting that the model is a "common value" model. This means that the tract is worth the same amount to whichever competitor wins it. The model allows for the "winner's curse" phenomenon caused by competition for a tract of uncertain value. Indeed, Capen et al. is known for having put that term into the academic literature.

³¹ These are discussed in considerably more detail in Chapter 5 of Volume II.

the optimal bid fraction. The increase in the bid fraction is consistent with what one would expect to observe in a sale with increased competition.

Conclusion

The econometric analysis of OCS lease sale data allowed us to estimate the hypothetical dollar amount of the income attributable to the two royalty relief policies that spanned the eight-year period between 1996 and 2003.³² Using two distinct regression models, one measuring the number of leases sold per year and the other measuring the high bid per lease, we were able to quantify the effect of these two policies by including dummy variables to represent lease sales, and bids on leases during these two distinct time periods. Once we determined our best models, which included all relevant independent variables, we were able to run a simulation, which allowed us to determine the hypothetical number of leases sold and average high bid had the policies not existed. The results of the two models collectively provided us with an estimate of the total dollar amount attributed to the two relief policies, shown in Table 3-13. We estimate that the Deepwater Royalty Relief Policy contributed \$1.9 billion in lease revenue over the 1996-2000 time period, and the post-Deepwater policy contributed \$.27 billion in lease revenue from 2001-2003.³³

Table 3-13. Cumulative Effect of Policy on Lease Bonus Revenue, 1996-2003, All Water Depths.

Policy	Time Period	Added Lease Bonus Revenue
DWRRA	1996-2000	\$1,954,082,798
Post-DWRRA	2001-2003	\$272,435,575
All Policy	1996-2003	\$2,226,518,373

³² Remember that these estimates only cover the income attributable to sales in the Central and Western Gulf.

³³ Table 3-12 indicates that the Post-DWRRA program actually contributed negatively to the Leasing Revenue for 0-200 meter, bringing down the total effect of the policy.

Chapter 4

Exploration Activity

Introduction

In this chapter we discuss the possible impacts of royalty relief on exploration and development related to leases sold during the DWRRA period. Royalty relief may influence not only the leasing process, but also subsequent activity related to exploration, development, and production of oil and gas resources. For example, royalty relief may create incentives to drill sooner in certain areas or to explore deepwater areas more intensively. Greater emphasis on exploration may lead to accelerated rates of discoveries and subsequent production. Such impacts are important to understand as they have implications for future policy direction.

Unfortunately, limited information exists on the effects of royalty relief on exploration and discovery for leases that were sold during the DWRRA period. Data contained in this chapter (and Chapter 6 of Volume II) are current through August 2004. New drilling activity and new discoveries are continually emerging and exploration activity in the Gulf is constantly changing. Furthermore, leases sold in water depths greater than 800 meters have a ten-year lease term, and therefore, even leases sold in the first year of the DWRRA (1996) have not yet expired and thus limited information exists about impacts for leases sold in these water depths. Leases sold in the 200-400 meter range have five-year terms and therefore some exploration and discovery information is known about these leases at least for the 1996-1998 period. Finally, leases in the 400-800 meter range have eight-year terms and thus only a limited amount of information is known about these leases that were sold during DWRRA.

In this chapter we focus on the following aspects of exploration activity:

- Number of exploration wells drilled;
- Number of exploration plans filed;
- Number of leases drilled;
- Number of new fields discovered.³⁴

Historical Data Analysis

Exploration activity may be measured by the number of exploration wells (wildcat and other) drilled, the size and number of new discoveries, and the number of development/exploration plans filed with MMS. We do not expect that the size and number of new discoveries or the advent of actual production will be helpful given the lag between lease sales and ultimate discoveries and first production dates (up to 15 years, especially in deepwater). For example in water depths greater than 200 meters for leases that have been sold

³⁴ We were unable to estimate statistically the effects of royalty relief on new field discoveries due to lack of data.

since 1995, only 67 out of 4,366 leases have production on them, 32 of which are in ultra deepwater (800-plus meters).³⁵ This does not indicate the ultimate production we might see from these cohorts of lease sales, but rather indicates the lag between lease sales and the date of first production. With regard to exploration activity, we hypothesize that drilling activity in a given water depth may be a function of the following factors: oil/gas prices (price cycles), technology, availability of drilling rigs, state of information regarding resource potential, availability of infrastructure such as pipelines, platforms, and subsea tie-ins, age of the lease and time to expiration, number of leases sold, level of high bids, lease program variables such as DWRRA. We used two important measures of exploration activity: drilling activity and filing of exploration plans with MMS. Most prior studies have focused on drilling activity, but we believe that exploration plans might provide an “earlier” view of a company’s intent to develop a lease, and therefore be helpful for purposes of this study.

Table 4-1 shows three measures of exploration activity broken out by time period and water depth: the average number of leases drilled, the average number of leases filing exploration plans, and the average number of leases either having drilled and/or filed an exploration plan. As expected, in the more recent time periods, and in deeper water, there is less overall exploration activity, particular in 800-plus meter, where only 10 percent of DWRRA leases and 4 percent of post-DWRRA leases have either drilled or filed an exploration plan with MMS. This is predominantly attributable to the lag between the purchase of a lease and the commencement of exploration activity on the lease.

Table 4-1. Mean Number of Leases Drilled and/or Filing Exploration Plans, By Period and Depth.

	Mean Leases Sold	Mean Leases Drilled	Percent of Leases Drilled	Mean Leases Filing E-Plans	Percent of Leases Filing E-Plans	Mean Leases Drilled OR Filed E-Plan	Percent of Leases Drilled OR Filed E-Plan
0-200 m							
Pre-Policy 1983-1995	430	181	42%	170	40%	227	53%
DWRRA 1996-2000	382	109	28%	113	31%	144	38%
Post-RR 2001-2003	449	75	17%	56	14%	97	22%
200-800 m							
Pre-Policy 1983-1995	91	25	27%	19	22%	31	34%
DWRRA 1996-2000	97	16	17%	22	24%	25	26%
Post-RR 2001-2003	99	9	9%	6	6%	11	11%
800-plus m							
Pre-Policy 1983-1995	137	19	14%	22	17%	27	20%
DWRRA 1996-2000	580	32	5%	45	8%	58	10%
Post-RR 2001-2003	295	10	3%	7	3%	13	4%

Data on leases drilled is current as of August 2004

Figure 4-1 shows the total number of leases and the number of leases that have been drilled by lease sale cohort year and by water depth. This figure indicates an increase in drilling activity in 200-plus meter leases for leases sold in the year before and directly after the implementation of royalty relief. The decline in the years thereafter is not surprising given the delays between lease sales and initial exploratory effort.

³⁵ Data are from “Field Names Master List Part Two,” publicly available on the Minerals Management Services website. The data file we relied upon was last updated June 23, 2005.

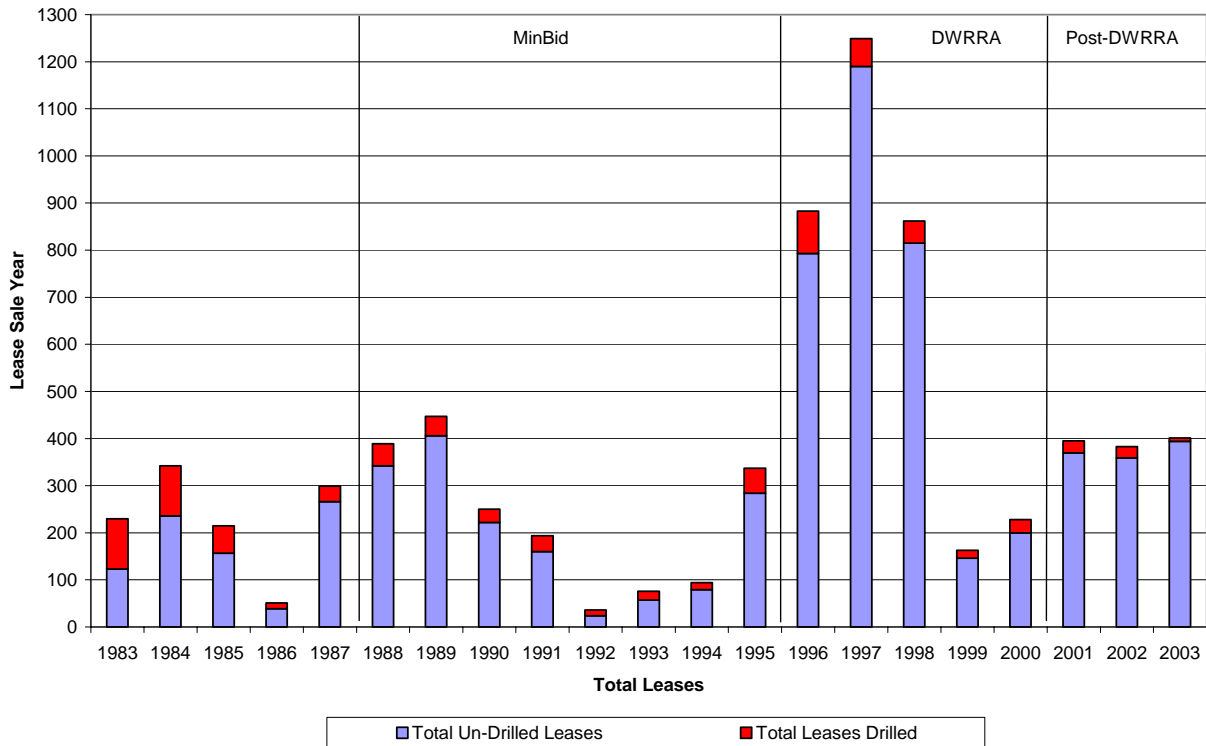


Figure 4-1. Total Leases Drilled by Lease Year Cohort, 200-plus meter.

To illustrate the lag between when a lease is sold and when exploration activity is typically initiated, Figure 4-2 shows the lag between when a lease is sold and when the first exploratory well (e-well) is drilled on that lease for different water depth categories. As can be seen in shallow water, almost 50 percent of the leases are drilled within the first two years after the lease sale. In the 200-800 meter zone the trend is similar, however in ultra deepwater (800+ meter), the lag grows significantly such that it takes five years before 50 percent of the leases have the first e-well drilled. Furthermore, in those leases where an e-well is drilled, 20 percent are not drilled until the last year or later of the lease term.³⁶ This figure confirms the lag especially in deepwater between lease sale and initial exploration effort; this lag makes the analysis of the effect of DWRRA on exploration effort all the more difficult.

³⁶ A lessee can apply for an extension of lease term if it intends to conduct exploratory activity; therefore approximately 10 percent of deepwater leases are not drilled until *after* 10 years. Note that even five- and eight-year term leases exhibit initial drilling activity past the expected lease term expiration due to this phenomenon.

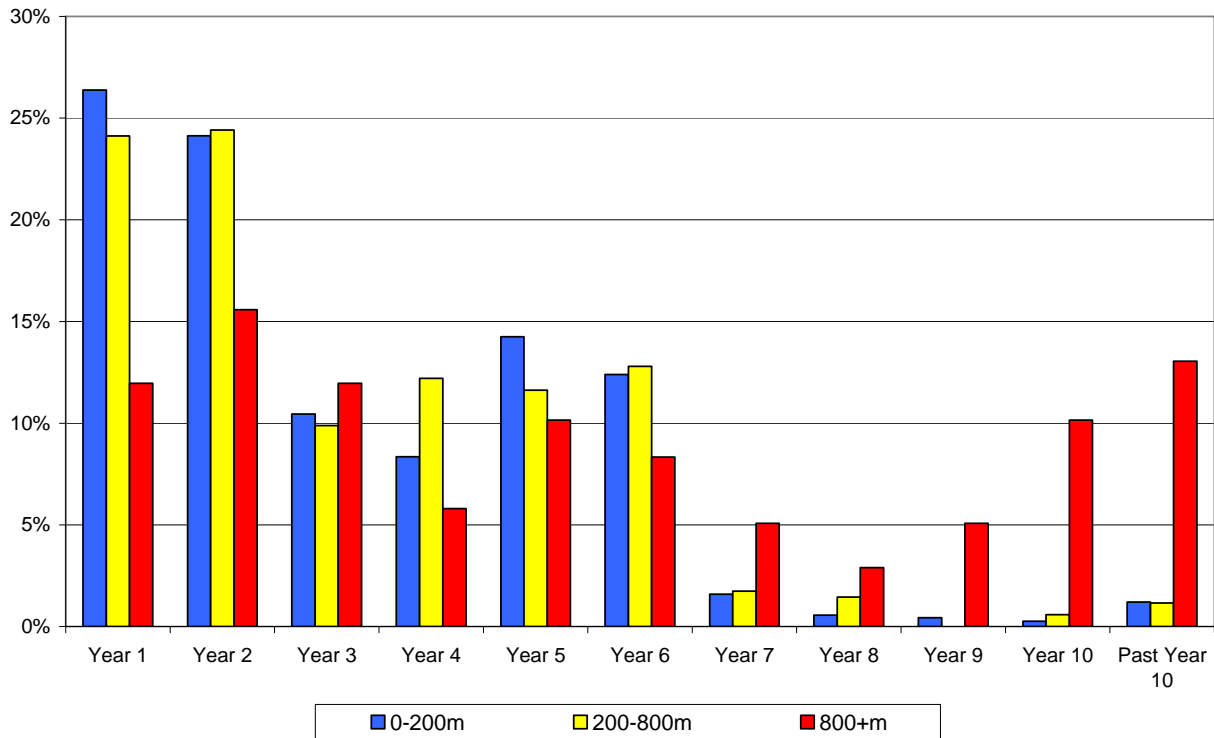


Figure 4.2. Distribution by Year After Lease Award of First E-Well Drilled, 1983-2002.

Figure 4-3 shows another measure of exploratory activity, the number of exploration plans filed. As one might expect, this figure shows a pattern quite similar to that in Figure 4-1, although it appears that the number of e-plans filed tends to lead the number of e-wells drilled as shown by the greater number of e-plans filed for leases sold between 1998 and 2001. Nevertheless, this figure confirms the data in Figure 4-1 that show a modest increase in exploration activity for leases sold directly after the implementation of royalty relief.

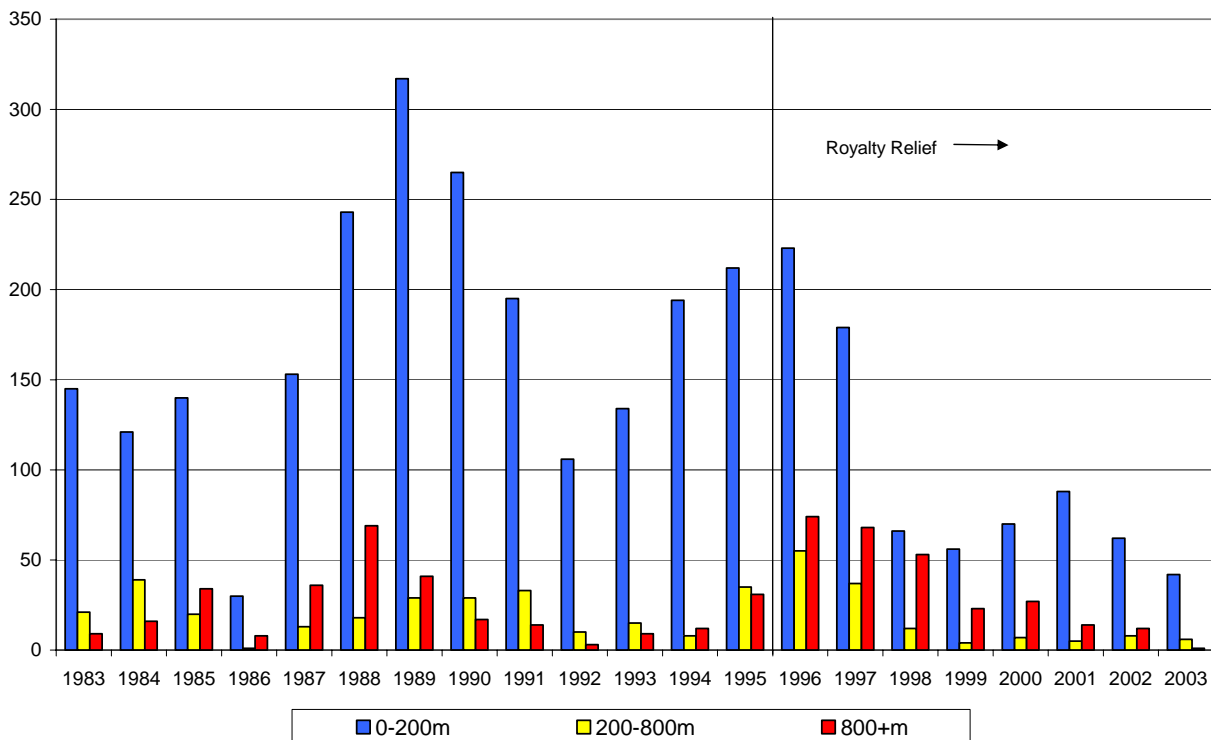


Figure 4.3. Total Number of Exploration Plans Filed by Lease Sale Year.

The data indicate that lease sales that attracted a larger number of bidders and or higher bids might attract more intensive exploratory activity. We also examined whether there was any correlation between the size of a lease sale and the intensity of drilling activity. There was no significant correlation between the size of the lease sale (at any water depth)³⁷ and the amount of drilling activity. Exploration activity in general did not seem highly correlated with lease variables. Recent indications (*Petroleum Economist* 2004) suggest that there has been a significant slow-down in exploration activity in the Gulf, including in deepwater:

Over the last two years, the number of rigs operating in water depths of 1,000-4,999 feet has slipped steadily. At the peak of activity, in 2001, the rig count in that water-depth range averaged 41 and about 2000 wells were drilled. Since 2002, the average number of rigs operating in the sector has declined by 29% and the number of wells drilled is down by 37%, the MMS reports.

Despite this decline in drilling, there have been several new major discoveries in deepwater. By the end of 2003, there were 86 deepwater projects that had begun production, a five-fold increase over the number on stream in 1997 (*Petroleum Economist* 2004). Figure 4-4 shows the percentage of field discoveries by field size category for leases sold before DWRRA

³⁷ Correlation coefficients ranged from .10 to .15 at different water depths regarding the relationship between the number of leases sold and the number of leases drilled.

compared with during and after DWRRA. As can be seen there are more fields discovered in the size 8-10 range as well as the very large 13-17 field size range during DWRRA, although this is partially a function of the few total number of fields discovered for leases sold in the 1996-2001 time period. The greater percentage of fields found in the size 8-10 range does support the idea discussed in Chapters 2 and 3 that royalty relief tends to make “marginal” fields more profitable. Table 4-1 presents data on the fields discovered in deepwater areas that are attributable to leases sold during the DWRRA period.

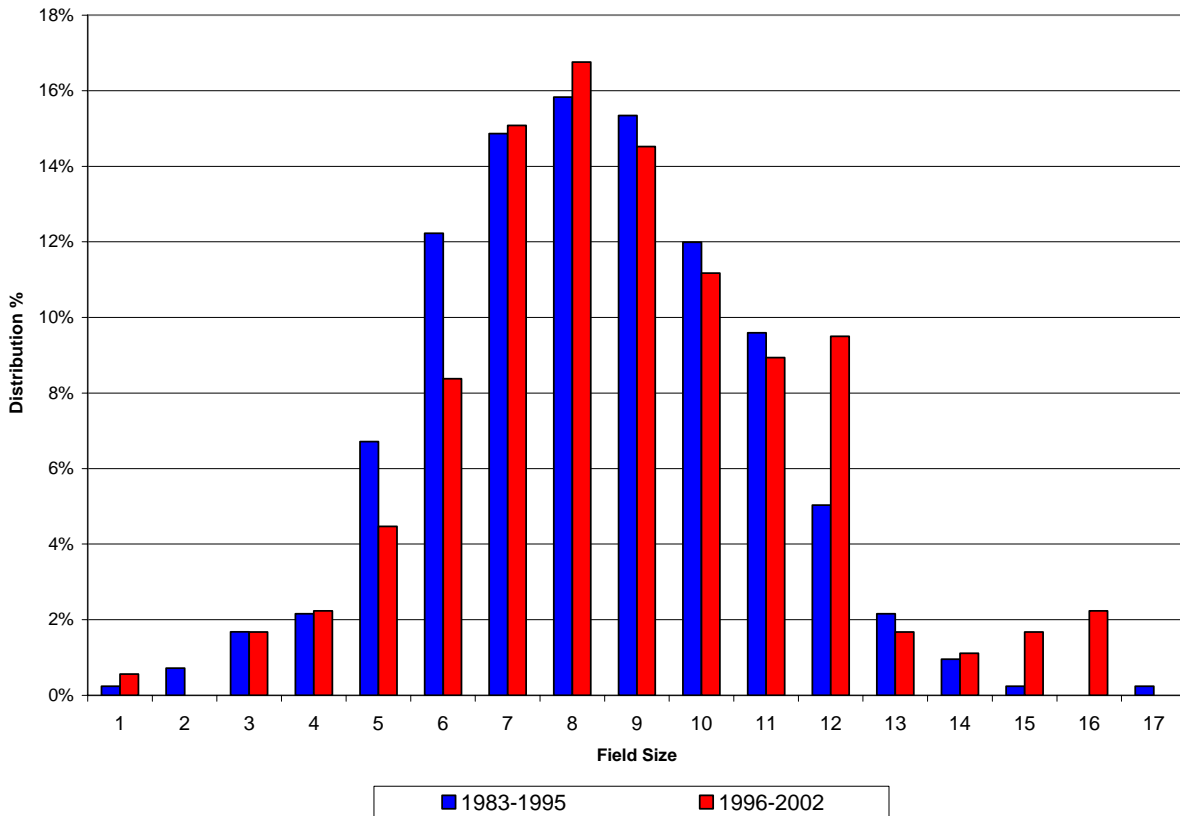


Figure 4.4. Percentage of Field Discoveries by Field Size Before and During Deepwater Royalty Relief.

Table 4-2. Fields Discovered in Deepwater (>200 meter) Attributable to DWRRA Leases.

Field	Water Depth	Sale Year	Discovery Year*	Field Size**
AT037	2458	2000	2001	11
EB158	251	1996	2001*	NA
EB168	296	1996	1997	9
EB205	415	1996	2001	10
EB421	853	1996	2001	10
EB430	836	1997	2000	8
EB579	1046	1997	2002	13
EB597	1035	2000	2001	10
EB668	1174	2001	2003*	NA
EB759	1279	1998	2003	11
EW878	564	1997	2000	11
GB179	259	1996	1997	9
GB197	262	1997	2003*	NA
GB205	510	2001	2002*	NA
GB367	339	1996	1999*	NA
GB668	977	1996	2000	13
GB700	1319	1997	2004*	NA
GB877	1639	1999	2001	7
GC114	853	1998	1999	9
GC177	573	1996	1999	9
GC178	566	2003	2004*	NA
GC243	960	1998	2001	13
GC282	879	1996	2001	12
GC339	1079	2000	2001	15
GC379	1195	2001	2001	14
GC507	1323	2001	2002*	NA
GC608	1350	1997	2000	12
GC646	1355	1998	2004*	NA
MC066	403	2002	2002	14
MC252	1614	1997	1999	11
MC299	1904	2000	2001	12
MC305	2249	1998	1999	12
MC348	2295	1998	1999	12
MC509	1367	2000	2001	11
MC555	1516	2000	2001	9
MC582	698	1996	1998	14
MC728	1685	1996	2002	12
MC751	501	2001	2002	12
MC773	1738	1998	1999	12
MC849	1180	1999	2002	13

* For these particular fields, the "Discovery Year" is actually the year in which the discovering lease was assigned to the field.

**Data not available to determine field size.

Technology has also played an important role by significantly increasing the depths at which companies can now drill. In the last ten years, companies have increased both the water

depth they are able to operate in by a factor of almost 60 percent and also the maximum wellbore depth they are able to drill by 39 percent. Recent literature also supports the theory that technology has played a major role in companies' ability to explore in deeper water depths.³⁸ The data analysis suggests that technology plays an important role in determining exploration activity, especially in deepwater areas. Lease variables seem to have little impact, at least in terms of exploratory activity.

Statistical Analysis

To analyze statistically the relationship between royalty relief and exploration activity, we developed several models of drilling activity. None of these models performs particularly well or were able to explain much of the variation in the number of wells drilled or the number of exploration plans filed with MMS, our two dependent variables. The best approach given limited time-series data to assess DWRRA impacts was a model in which the decision to drill was modeled as a two-part decision. The first part was to model which particular leases are drilled over the lifetime of the lease term, and the second part was to model the factors that affect those leases that are actually drilled and which ones produce discoveries and whether royalty relief played a role in either of those events. To model the first part, we employed a probit regression model that attached a probability to whether a lease would be drilled or not with that probability being a function of a number of different variables. These variables included trends in oil prices, certain lease sale variables such as high bid, number of bidders, and majors as winning bidder, as well as tract type, tract quality (viable), block history, water depth, time trend, and lease program dummy variables. The dependent variable was whether a lease was drilled and alternatively whether an exploration plan had been filed for that lease.

The model results for leases sold in all water depths and each planning area indicated that tract type had the strongest influence on the likelihood that a lease would be drilled. Table 4-3 presents the results of the probit model for 800-plus meters where the dependent variable takes on the value of 1 if the lease has been drilled. Other variables were positive and significant including competition, high bid, lagged oil price, and whether the lease was on a block in which prior leases had been sold. Water depth, sale date, and majors were significant and had negative coefficients, indicating that these factors made it less likely a lease would be drilled.

³⁸ This is confirmed by a recent study by Iledare (2000), which found that changes in technology have had a significant effect on drilling and the productivity of drilling.

Table 4-3. Probit Parameter Estimates for Leases Drilled, 800-plus meter.

McFadden R-squared	0.2072	Obs with Dep=0	4061
Dependent Mean	0.0957	Obs with Dep=1	430
Root MSE	0.2668	Total obs	4491
Variable	Parameter Estimate	Chi-Square	Pr > ChiSq
Intercept	0.0128	0.0055	0.9407
High Bid by Major Bidder	-0.3399	25.2570	0.0000
High Bid	0.0000	149.8046	0.0000
Oil Price	-0.0226	11.7325	0.0006
Repeat Block	0.5995	65.7068	0.0000
Water Depth	-0.0003	26.7248	0.0000
WGM	-0.3530	29.5221	0.0000
DWRRRA	-0.5946	56.6366	0.0000

The sign on the coefficient for the DWRRRA dummy variable was negative in the model in which wells drilled was the dependent variable, but positive and significant when exploration plans was the dependent variable. While the data are very limited, the fact that exploration plans are filed before drilling takes place provides some indication that over time, the sign on the DWRRRA dummy may change in the well drilled regression, but at this point it appears that the data are too limited to conclude much about the impact of royalty relief on exploration activity. One possible explanation for the negative coefficient on the DWRRRA dummy is that the lease sales during the DWRRRA period produced many more leases in deepwater areas, and thus a relatively low percentage of total deepwater leases have actually been drilled at this point in time than was the case for deepwater leases sold in the pre-DWRRRA period. The lack of sufficient time-series data on exploration activity on leases sold in deepwater areas during the royalty relief period means that any interpretation of these results is fraught with difficulty.

This idea is substantiated when looking at simulation results of the hypothetical situation had no policy existed (as presented in Table 4-4). In all cases, the models, which are based on regression results performed by water depth, estimate that the probability of a lease drilling would actually *increase* had the policy not existed. For example, in 800-plus meters, the model predicts that 13 percent of leases would have drilled had no policy existed, compared to the actual probability of only 5 percent. Similar results are achieved using exploration plans as the dependent variable. These results, as well as regression results for all water depths, are presented in Chapter 6 of Volume II.

Table 4-4. Simulation Results of Probability of Lease Drilling Without Policy.

0-200	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	42%	0%	42%
DWRRA	28%	-7%	35%
200-800	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	27%	0%	27%
DWRRA	17%	-10%	27%
800+	Annual Actual Probability of Lease Drilling	Annual Probability of Lease Drilling Attributed to Policy Variable	Annual Hypothetical Probability of Lease Drilling (No Policy)
Pre-Policy	14%	0%	14%
DWRRA	5%	-8%	13%

The second stage of the model provided even less meaningful results. We modeled discoveries as a probability distribution over the leases for which drilling had taken place, i.e., the subset of drilled leases). In all cases the royalty relief dummy variable was not significant, and the explanatory power of the regression was low. Given the strong likelihood that we would be unable to produce a model in which the royalty relief variable would attain any significance, we did not attempt to develop this model any further.

Conclusion

The time frame for analyzing the impact of royalty relief on exploration and development is too limited to be able to generate any meaningful conclusions that stand up to statistical scrutiny. The data suggest some increase in drilling activity on leases sold during the first few years of the DWRRA, but the data are too limited at this point in time to be able to generalize about impact. The first few years of the DWRRA program were also characterized by an increase in oil prices, which also may have stimulated drilling activity. Further, the dramatic technological progress achieved in drilling depths and operating in deeper and deeper water depths clearly stimulated exploration activity in deepwater. Therefore, it is difficult to isolate the impact of royalty relief on exploration activity even for leases whose terms have expired.

Chapter 5

Fiscal Effects of Alternative Royalty Relief Programs

Introduction

In this chapter, we present projections of possible future impacts from several alternative royalty relief programs. The alternative future programs were provided to us by MMS and included the following:

1. A deepwater royalty relief program that resumes (in the first forecast year) the original provisions of the DWRRA, implemented with a field-based definition of suspension volume and new production requirement. (*DWRR – Field*)
2. A deepwater royalty relief program that resumes the provisions of the DWRRA, but is implemented with a lease-based definition of suspension volume but drops the new production requirement. (*DWRR – Lease*)
3. A deepwater royalty relief program that continues the program as the current administrative program, with a lease-based definition of suspension volume specified for year 2003 sales. (*Current*)
4. No future royalty relief for deepwater leases beginning in the first model forecast year. (*No Relief*)

The study investigated the fiscal effect of the alternative deepwater royalty programs by projecting, for each alternative scenario, the following activities over a 40-year period commencing with 2003:

- Number of exploratory wells drilled;
- Fields discovered;
- Reserves discovered;
- Total oil and gas production;
- Oil and gas production from fields discovered after 2002;
- Royalty-free oil and gas production; and
- Bonus, rental and royalty revenue.

We used the IIC, Inc. EDP model³⁹ developed for the MMS to determine all impacts with the exception of rental and bonus revenue. The EDP model is a comprehensive forecasting program that employs a variety of inputs including the existing resource base, the undiscovered resource base, resource prices, cost parameters, and federal regulatory constraints and policy programs. Figure 5-1 provides a general overview of the EDP model and the interaction among different inputs and model components.

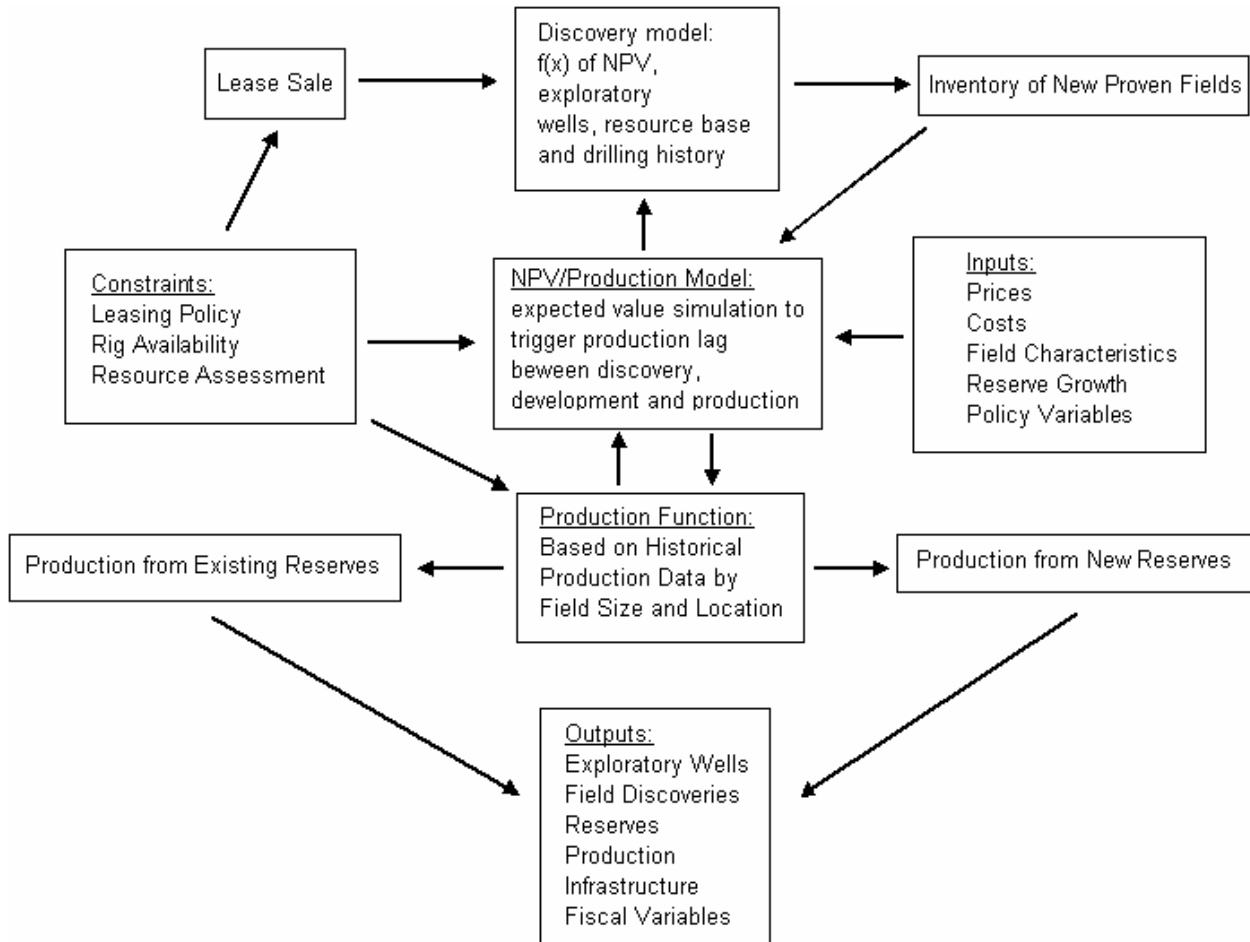


Figure 5-1. Overview of IIC, Inc. EDP Model.

The EDP model is easily configured to handle a variety of resource distributions. For the current study, the discovered and undiscovered resource estimates are based on the MMS National Assessment and supplemental data provided by the MMS Gulf of Mexico Resource and Evaluation Department. The resource distributions were provided at a level of detail sufficient to categorize individual fields by planning area and water depth category.⁴⁰ In addition, we relied upon MMS guidance for the appropriate selection of certain model parameters, including

³⁹ This model was developed for MMS in a prior study. See IIC, Inc. (2004).

⁴⁰ We employ three planning areas (Central, Western and Eastern) and seven water depth categories (0-60, 60-200, 200-400, 400-800, 800-1600, 1600-2400, and 2400+ meters).

discount rate, resource price scenarios, reserve growth parameters, federal leasing policy, and production calibration factors.

The EDP model makes a comprehensive forecast of Gulf of Mexico offshore oil and gas activities starting with the year 2003. The projections of each royalty alternative commence with 2003 and activities that occurred prior to the first projection year have not been altered. For example, when projecting offshore oil and gas activities associated with the alternative that provides no relief, this applies only to lease sales commencing in 2003. We have not retroactively changed the leasing policy associated with deepwater royalty relief prior to 2003 to model what would have happened had royalty relief programs never been instituted.

Each EDP model forecast provides results containing the same set of outputs, regardless of changes in the input assumptions, and employs a consistent set of terminology. For this study:

- *Exploratory wells drilled* refer to the number of exploratory wells drilled to find previously undiscovered fields. Exploratory wells in the EDP model can be viewed as “wildcats” in the purest sense, as they discover only new fields, not new reservoirs in existing fields.
- *Fields discovered* represent the expected number of previously undiscovered fields discovered as a result of exploratory well drilling.
- *Grown reserves discovered* are the total amount of reserves found with each new field discovery. Data provided by the MMS Resource and Evaluation Department indicate that fields typically “grow” over time from their initial resource estimate, through in-field reservoir discovery and reserves appreciation. Grown reserves represent the ultimate resource estimate, including the amount of reserves discovered over time, in addition to the original reserve estimate.
- *New fields* are fields projected to be discovered in the forecast period (2003-2042). These discoveries are forecasted by the model and are also labeled as *model discoveries*.
- *New production* represents production from fields that are discovered between 2003 and 2042. These include model discoveries on leases let prior to 2003.
- *Existing fields* are field discoveries that occurred prior to the first projection year (2003). Existing fields retain any royalty relief given by the DWRRA or Post-Act programs, unchanged by the royalty relief scenario under investigation. Discoveries associated with years 2003-2005 are “future” for purposes of this study, and the forecast of these years does not necessarily match the historical record for these years.
- Financial variables are computed in constant dollars, and *present value* variables are computed using a discount rate of 12 percent.

- *Price thresholds* represent price levels which royalty relief is foregone, regardless of remaining suspension volumes, when the annual resource price exceeds the threshold level.

The EDP model was not used to calculate rental and bonus revenue under the different royalty relief scenarios. For these two variables, we constructed an exogenous model, relying on the results of our historical lease sales and bidding analyses to estimate the future number of leases sold and bonus bids, which then allows the estimation of future rental payments and bonus revenue.⁴¹ We developed projections for a variety of Gulf of Mexico regions under several oil and gas price scenarios. In addition, we performed several sensitivity analyses to gauge the impact that price thresholds would have on the future fiscal effects of each program for each price scenario.

Royalty Relief Programs

The MMS provided us with information concerning the four alternative royalty relief programs. Each program was implemented at the beginning of the projection period. For fields discovered on leases sold prior to the projection period, we employed the actual historical royalty program in place at the time of the lease sale. If a field was discovered from a lease awarded between 1996 and 2000, the original DWRRA suspension volumes were used, while fields discovered on leases sold in 2001 relied upon the current program.⁴² Fields discovered on leases let during the projection period rely on the particular alternative program under investigation.

Table 5-1 shows the royalty suspension volumes for each of the four royalty relief programs. The first program extends royalty relief for future lease sales according to the provisions outlined in the original DWRRA. These provisions specify certain royalty relief volumes on a field-level basis according to specific water depths. The second and third alternative royalty relief programs involve computing suspension volumes on a lease basis, as opposed to a field basis. The second program, listed in Table 5-1, applies the original DWRRA program but on a lease basis. Under the third alternative program, fields are assigned suspension volumes in a manner consistent with the second program alternative, but on a significantly reduced scale, according to the current royalty relief program. The fourth program eliminates all future royalty relief. Under this scenario, any and all fields discovered from lease sales occurring in the future would not be eligible for royalty relief. Each alternative royalty relief program was assumed to last the duration of the projection period.

⁴¹ This exogenous model is described in Chapter 7 of Volume II.

⁴² MMS provided remaining royalty suspension volumes for existing fields. For this study, we have not adjusted these remaining suspension volumes despite the recent Kerr-McGee and Santa Fe court rulings. Remaining suspension volumes for existing fields remained consistent throughout each royalty alternative forecast. In addition, we have not considered the impact of production requirements for lease-based relief attributed to future field discoveries.

Table 5-1. Royalty Suspension Volumes under the Four Programs.

Program	Field or Lease Basis	Suspension Volume (mmBOE) by Water Depth (meters)				
		0-200	200-400	400-800	800-1600	1600+
DWRR - Field	Field	0	17.5	52.5	87.5	87.5
DWRR - Lease	Lease	0	17.5	52.5	87.5	87.5
Current	Lease	0	0	5	9	12
No Relief	Not Applicable	0	0	0	0	0

Analysis of Alternative Royalty Relief Programs

As noted we utilized both our EDP model and a separate lease bonus and rental revenue model to compute the impacts of each alternative program.⁴³ The EDP model analyzed each program alternative using two different price scenarios. These alternative price scenarios, provided to us by MMS, are shown in Table 5-2.

Table 5-2. Price Inputs Provided by the MMS.

Scenario	Oil Price (\$/bbl)	Gas Price (\$/mcf)
1	\$30.00	\$4.54
2	\$46.00	\$6.96

One other issue concerning prices relates to the price thresholds. When royalty relief price thresholds are exceeded, fields with suspension volumes do not receive relief on oil and/or gas produced, thus foregoing the relief.⁴⁴ In order to test the sensitivity of the results to price thresholds, we ran the EDP model using each price scenario and relief program but included periods where the price thresholds were exceeded. The decision to test specific sensitivity periods was based on discussion with the MMS regarding expectations of when price thresholds would be exceeded. The price paths in the EDP model are defined explicitly by the user. In that sense, the user is establishing simple mean expectations of the future under a stochastic price model. The MMS periodically reviews the price thresholds and it is reasonable, given the uniformity of the user-defined price path, to assume periods where the price threshold might be exceeded.⁴⁵

Results

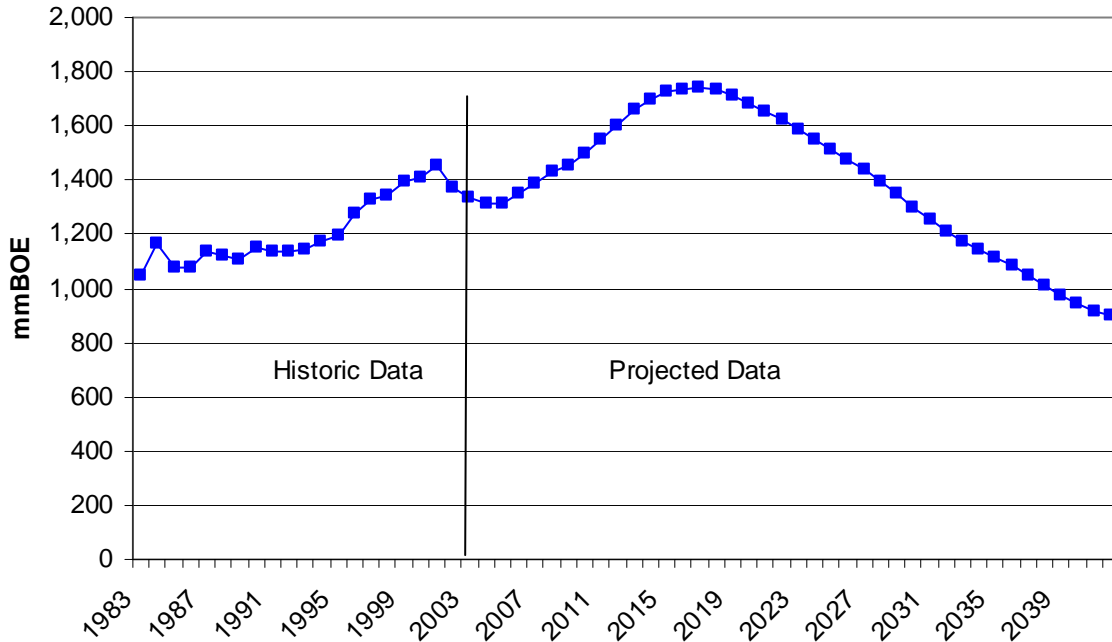
The first step was to ensure that the projected results were not unreasonable given actual historical data and reasonable expectations of the future. As shown in Figure 5-2, the future expected production trend indicates a rise in the overall level of production, followed by a steady

⁴³ Chapter 7 of Volume II contains a detailed discussion of each of these models, assumptions, input parameters, and outputs.

⁴⁴ Litigation aimed at overturning the DWRR price threshold as implemented by the MMS is possible in the future.

⁴⁵ Also as a result of discussions with the MMS, we investigated the possibility that price thresholds were not applicable for certain leases granted in 1998 and 1999. We tested the significance of this issue by comparing the maximum relief, high price, threshold exceeded case with one in which fields attributed to leases let in 1998 and 1999 were not subject to those price thresholds. The difference was minimal based on our analysis and we did not pursue the issue for all different price and royalty program combinations.

decline after the volume peaks in 2017. The primary reason for the observed increase is a series of large fields that are known, but not currently producing, as of the first model year. As these large fields begin production, they build up to a peak before declining.⁴⁶



Assuming \$30/bbl Price Scenario, "Current" Royalty Relief Alternative

Figure 5-2. All Gulf of Mexico Production.

The main objective of the study was to observe the differential impacts among the royalty alternatives at the different price scenarios. Clear delineations were observed between the two price scenarios, however we limit the presented results to those observed using the price scenario of \$30/bbl and \$4.54/mcf, oil and gas price respectively. Table 5-3 shows the results for the offshore oil and gas activity under each royalty alternative.⁴⁷

⁴⁶ Another factor leading to the rise in production is a corresponding increase in exploratory drilling during the late 1990s and the initial model years.

⁴⁷ All results include only the sum of values over the 40-year projection period (2003-2042), and do not include historical results prior to the first model year.

Table 5-3. Effects of Alternative Royalty Scenario on Activities at All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Discovered Fields	Exploratory Wells Drilled	Reserves Discovered (mmBOE)
DWRR - Field	All	30	4.54	672	7,607	49,005
DWRR - Lease	All	30	4.54	678	7,675	49,772
Current	All	30	4.54	669	7,568	48,692
No Relief	All	30	4.54	664	7,509	47,999

Table 5-3 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Gas Production (Bcf)	Total Oil Production (mmBbl)	Royalty-Free Gas Production (Bcf)	Royalty-Free Oil Production (mmBbl)
DWRR - Field	All	30	4.54	151,590	28,871	23,918	5,577
DWRR - Lease	All	30	4.54	152,869	29,204	39,937	9,669
Current	All	30	4.54	151,009	28,725	16,628	3,766
No Relief	All	30	4.54	149,715	28,379	9,163	1,789

Table 5-3 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Paying Gas Production (Bcf)	Royalty-Paying Oil Production (mmBbl)	Total Royalty Revenue (mm)	Present Value Royalty Revenue (mm)
DWRR - Field	All	30	4.54	127,672	23,293	\$314,661	\$54,901
DWRR - Lease	All	30	4.54	112,932	19,535	\$265,258	\$52,148
Current	All	30	4.54	134,380	24,959	\$334,762	\$56,291
No Relief	All	30	4.54	140,552	26,590	\$357,946	\$58,367

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

There are several notable differences among the four royalty alternatives. As the amount of relief increases, we observe a corresponding increase in the overall amount of exploratory well drilling, field and reserve discovery, total oil and gas production, as well as the amount of production exempt from royalties. The highest relief scenario, DWRR – Lease, enjoys a significant amount of royalty-free production compared with the overall production (Table 5-4). Not surprisingly, the total royalty revenue collected under the DWRR – Lease program is significantly lower than the No Relief scenario.

Table 5-4. Comparison of Royalty-Free Production for All Fields, Offshore Gulf of Mexico.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Production (mmBOE)	Total Royalty-Free Production (mmBOE)	Percent of Total Production that is Royalty-Free
DWRR - Field	All	30	4.54	55,844	9,833	17.6%
DWRR - Lease	All	30	4.54	56,405	16,775	29.7%
Current	All	30	4.54	55,594	6,725	12.1%
No Relief	All	30	4.54	55,019	3,420	6.2%

A differential analysis shows that although the amount of royalty-free production increases as royalty relief volumes rise, the *present value* of royalty payments does not experience the same magnitude of change. As depicted in Table 5-5, the amount of foregone royalty revenue by instituting the maximum relief scenario, DWRR – Lease, represents a 10.7

percent reduction compared with the No Relief scenario, despite an almost four-fold increase in the amount of royalty-free production.

Table 5-5. Comparison of Effects of Royalty Alternatives with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Percent Change in Total Production	Percent Change in Royalty-Free Production	Percent Change in Total Royalty Revenue Collection	Percent Change in Present Value of Royalty Revenue Collection
DWRR - Field	All	30	4.54	1.5%	187.5%	-12.1%	-5.9%
DWRR - Lease	All	30	4.54	2.5%	390.5%	-25.9%	-10.7%
Current	All	30	4.54	1.0%	96.6%	-6.5%	-3.6%

Note: Values in \$2003. Present value at 12%

The magnitude of changes between the different royalty relief alternatives is somewhat obscured in the previous three tables by examining results concerning all fields. Table 5-6 presents similar forecast results limited only to fields discovered by the model. Removing results attributable to the fields that existed prior to 2003, the first projection year, allows a comparison of how each royalty alternative influences expected activity in the forecast period.

Table 5-6. Effects of Alternative Royalty Scenario on Activities for New Fields Only.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	New Gas Production (Bcf)	New Oil Production (mmBbl)	Royalty-Free New Gas Production (Bcf)	Royalty-Free New Oil Production (mmBbl)
DWRR - Field	All	30	4.54	96,521	16,356	19,682	5,088
DWRR - Lease	All	30	4.54	97,800	16,689	35,701	9,180
Current	All	30	4.54	95,940	16,210	12,393	3,277
No Relief	All	30	4.54	94,646	15,865	4,927	1,300

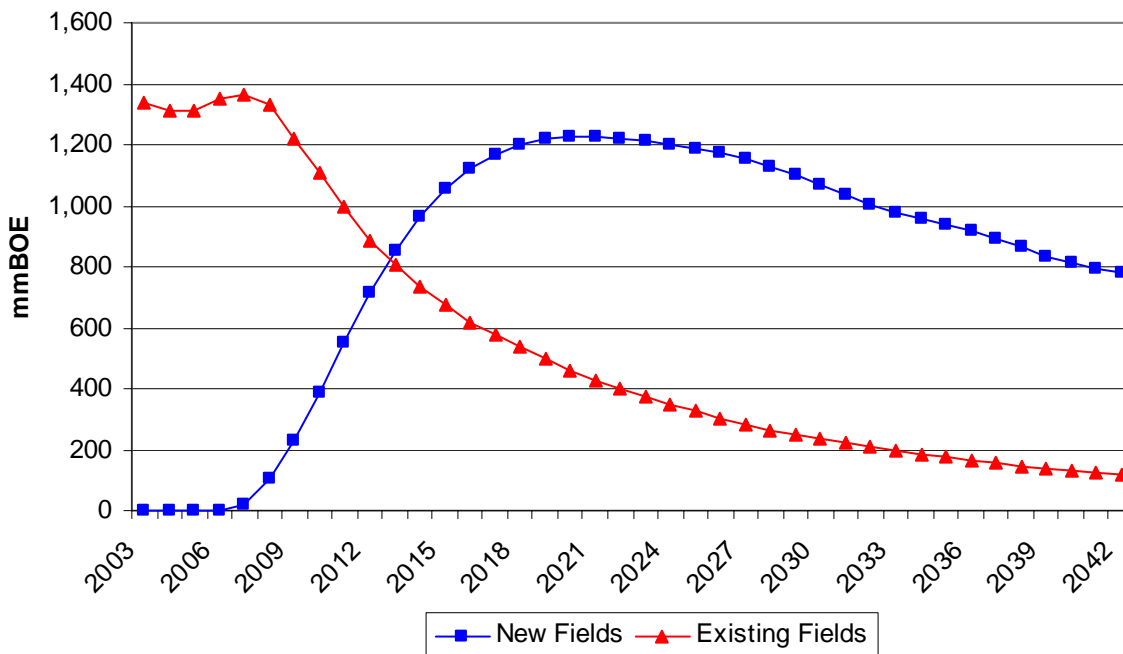
Table 5-6 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Paying New Gas Production (Bcf)	Royalty-Paying New Oil Production (mmBbl)	New Field Total Royalty Revenue (mm)	Present Value of New Field Total Royalty Revenue (mm)
DWRR - Field	All	30	4.54	76,839	11,268	\$194,445	\$16,114
DWRR - Lease	All	30	4.54	62,099	7,509	\$145,042	\$13,361
Current	All	30	4.54	83,547	12,933	\$214,546	\$17,504
No Relief	All	30	4.54	89,719	14,565	\$237,730	\$19,580

Note: Values in \$2003. Present value at 12%.

A significant portion of future production and royalty collection is attributable to fields that have yet to be discovered. Although the amount of undiscounted total royalty revenue attributable to future discoveries is substantial, the present value of the royalty revenue from new fields represents a much smaller percentage due to the fact new field production is not expected for several years into the future. Figure 5-3 illustrates the production effect, by comparing the time-series of existing field production, with the production expected from model discoveries. Initial new field production does not begin until 2007, corresponding with field discoveries

projected to occur in 2003. Figure 5-3 is representative of the \$30/bbl scenario and the current royalty relief alternative, but a similar pattern holds true across each different royalty alternative.



Assuming \$30/bbl Price Scenario, "Current" Royalty Relief Alternative

Figure 5-3. All Gulf of Mexico Production, Separated by Field Discovery.

Any assessment of the fiscal impact of each different royalty alternative is incomplete without inclusion of bonus and rental income associated with future lease sales under each alternative. We developed an exogenous lease bonus-rental model to determine the present value of future cash flows for rental and lease bonus revenue earned by OCS lease sales in the 40-year projection period for the four royalty relief program scenarios.

The primary input into the front-end model is the estimate of the number of leases sold in each of the 40 years of the projection period. The initial year (2003) value for the number of leases sold is based upon historical averages of leases sold, as well as implications from regression results. In each subsequent year, the new estimate of leases sold is based on the total number of tracts offered in the sale, a value determined from the number of leases sold in the prior year, as well as newly expired, drilling and producing leases. Initial year values for each of the four scenarios are determined as follows:

- DWRRRA-Field – Initial year value takes the no relief value and adds the average number of leases added per year by the Deepwater Royalty Relief Policy (1996-2000), as determined by regression results.

- DWRRRA-Lease – Initial year value takes half of the difference between the DWRRRA-Field and Current scenario initial year values, and adds that difference to the larger of the two values.⁴⁸
- Current – Initial year value takes the no relief value and adds the average number of leases added per year by the Post-Deepwater Policy Period (2001-2003), as determined by regression results.
- No Relief – Initial year value is based on the mean value of leases sold per year in Central and Western Gulf sales between 1983 and 1995.

Once the number of leases sold is determined, the lease bonus revenue and rental revenue can be computed. The rental revenue is determined by taking the rental rate for the particular water depth and multiplying that value by inventory⁴⁹ of un-drilled leases, which is estimated based on the value for the number of leases sold.⁵⁰ The lease bonus revenue is determined by multiplying the number of leases sold by the average high bid for that particular scenario and water depth. The average high bid remains constant over the 40-year period. It is determined from the regression results, with the values for each scenario being computed in the same manner as the leases sold.⁵¹

Table 5-7 presents the combined fiscal effects for each alternative royalty scenario, given the price scenario of \$30/bbl and \$4.54/mcf, oil and gas price respectively.

Table 5-7. Total Fiscal Effects of Alternate Royalty Scenario on Activities for All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Present Value		
				Present Value of Royalty Revenue (mm)	of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)
DWRR - Field	All	30	4.54	\$54,901	\$5,300	\$60,201
DWRR - Lease	All	30	4.54	\$52,148	\$6,099	\$58,247
Current	All	30	4.54	\$56,291	\$4,290	\$60,581
No Relief	All	30	4.54	\$58,367	\$3,823	\$62,190

Note: Values in \$2003. Present value at 12%.

As we increase the amount of royalty relief, we observe a corresponding decrease in the present value of total royalty revenue collected. Part of this decline is offset by an increase in the additional bonus and rental revenue derived from increased activity in lease sales. However, the

⁴⁸ There are no historical data from which to measure such a policy, however we estimate this policy to have the largest effect of the three, thus modifying the value of leases sold to exceed that of the other two policies.

⁴⁹ The inventory of undrilled leases is determined by taking the current previous year's starting inventory, adding new leases sold in the previous year, and subtracting any leases that expire or begin drilling or go into production. The timeframe in which leases expire or begin drilling or producing is based upon historical averages.

⁵⁰ The rental rate is charged on a per acre basis. Therefore, we multiplied the rental rate by the median acreage for leases sold by water depth from 1983 to 2003.

⁵¹ For the "Current" relief scenario, the post-DWRRRA dummy variables were insignificant in the high bid regression results in 0-200 meters and 200-800 meters. Therefore, for those two water depth categories we used the average high bid from the "No Relief" price scenario.

foregone royalty collection is never fully recovered by the increase in the lease and rental revenue, when compared to the No Relief scenario. Table 5-8 illustrates the net impact of the three alternatives that include royalty relief compared with the one program that does not allow any future royalty relief.

Table 5-8. Comparison of Fiscal Effects of Royalty Alternatives with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	"Loss" in	"Gain" in	Net Impact (mm)	Percent of Total Revenue Foregone for Royalty Relief
				Present Value Royalty Revenue (mm)	Present Value Lease and Bonus Revenue (mm)		
DWRR - Field	All	30	4.54	(\$3,465)	\$1,477	(\$1,989)	-3.2%
DWRR - Lease	All	30	4.54	(\$6,218)	\$2,276	(\$3,942)	-6.3%
Current	All	30	4.54	(\$2,075)	\$467	(\$1,608)	-2.6%

Similar forecast results were developed for each royalty alternative at the higher price case. The most significant difference between the different price scenarios involves the expected royalty revenue. There is a large variation in future royalty revenue because it is a direct multiplicative function of oil and gas prices. The relationship among the two cases is also exaggerated somewhat by the difference in future discoveries and reserves discovered. In the higher price case, we expect more exploratory well drilling, a greater number of fields discovered leading to a higher amount of reserves discovered, and subsequently higher production and royalty revenue.

From a program standpoint, we also compare future impacts across different royalty relief programs as shown in Table 5-9 for the higher price scenario. These results are independent of price thresholds, i.e., we have assumed that the price threshold would never be exceeded. Table 5-9 also includes the fiscal results from the lease bonus rental model and thus provides comprehensive estimated fiscal impacts.⁵²

⁵²Table 5-9 indicates that the results of the lease bonus rental model are the same across both price assumptions. The regression analyses of lease sales and bonus bids found that oil price was not a significant explanatory variable, and as such, the lease bonus rental model should not be expected to be sensitive to different price scenarios.

Table 5-9. Effects of Alternative Royalty Scenario on Activities at All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Total Gas Production (Bcf)	Total Oil Production (mmBbl)
DWRR - Field	All	46	6.96	57,510	173,134	33,092
DWRR - Lease	All	46	6.96	58,062	174,240	33,382
Current	All	46	6.96	57,281	172,734	32,992
No Relief	All	46	6.96	56,644	171,638	32,699

Table 5-9 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Free			
				Gas Production (Bcf)	Royalty-Free Oil Production (mmBbl)	Royalty-Paying Gas Production (Bcf)	Royalty-Paying Oil Production (mmBbl)
DWRR - Field	All	46	6.96	29,801	7,113	143,334	25,979
DWRR - Lease	All	46	6.96	47,944	11,747	126,296	21,635
Current	All	46	6.96	21,233	4,988	151,501	28,003
No Relief	All	46	6.96	11,442	2,397	160,196	30,302

Table 5-9 (continued)

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Total Royalty Revenue (mm)	Present Value Royalty Revenue (mm)	Present Value of Lease Bonus and Rental Revenue (mm)	Total Present Value of Fiscal Variables (mm)
				DWRR - Field	All	46	6.96
DWRR - Lease	All	46	6.96	\$454,533	\$85,112	\$6,099	\$91,212
Current	All	46	6.96	\$577,720	\$92,864	\$4,290	\$97,154
No Relief	All	46	6.96	\$625,735	\$97,367	\$3,823	\$101,190

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

Table 5-9 illustrates the different results from the alternative royalty regimes for the \$46/bbl scenario. As expected, the previously obtained results from the \$30/bbl scenario tend to fall below the higher price results for each royalty program alternative. In both the \$30/bbl and \$46/bbl price scenarios, the maximum present value of revenue is associated with a program of no relief.

In assessing differences among the royalty relief alternatives in the \$30/bbl price scenario, the greatest difference lies between the DWRRRA suspension volumes applied on a lease basis (DWRRRA-Lease) and eliminating future royalty relief altogether (No Relief). Inclusion of fields discovered prior to the model projection period obscures to a large extent the differences between implementing each alternative royalty relief program in the future. We expect the existing fields to continue development and production regardless of policy initiatives directed at stimulating exploration in the future. Therefore, it is important to investigate the change in production and royalty revenue attributable to model discovered fields only, which is shown in Table 5-10. The difference between the no-relief and maximum relief scenarios is striking, not only in the production difference, but in the present value of future royalty relief. In the \$30/bbl price scenario, we observe an increase in production of only 4.2 percent, associated with a decrease in the present value of new field royalty revenue of approximately 32 percent.

Table 5-10. Comparison of Effects Between Maximum Relief Scenario (DWRR – Lease) and No Relief for New Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Free			Present Value of
				New Production (mmBOE)	New Production (mmBOE)	Royalty-Paying New Production (mmBOE)	New Field Royalty Revenue (mm)
DWRR - Lease	All	30	4.54	34,091	15,532	18,559	\$13,361
No Relief	All	30	4.54	32,706	2,177	30,529	\$19,580
Difference				1,385	13,355	-11,970	(\$6,218)
Percent Change				4.2%			-31.8%
DWRR - Lease	All	46	6.96	42,072	19,035	23,038	\$25,639
No Relief	All	46	6.96	40,926	3,190	37,736	\$37,893
Difference				1,146	15,845	-14,698	(\$12,254)
Percent Change				2.8%			-32.3%

Note: Values in \$2003. Present value at 12%.

Table 5-11 summarizes the net fiscal effects per barrel of oil equivalent discovered that one can expect from implementing each of the four plans. In particular, we focus on the amount of foregone royalties necessary to discover each incremental barrel. In this case, we assume that the No Relief scenario represents the minimum baseline to calculate these effects.

Table 5-11. Foregone Royalties per Incremental BOE Discovered for Each Alternative Compared with No Relief Scenario.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Present Value Royalty Revenue (mm)	Present Value of	Total	Dollar per BOE
						Lease Bonus and Rental Revenue (mm)	Present Value of Fiscal Variables (mm)	
DWRR - Field	All	30	4.54	49,005	\$54,901	\$5,300	\$60,201	
Difference				1,006			-\$1,989	-\$1.98
DWRR - Lease	All	30	4.54	49,772	\$52,148	\$6,099	\$58,247	
Difference				1,773			-\$3,942	-\$2.22
Current	All	30	4.54	48,692	\$56,291	\$4,290	\$60,581	
Difference				693			-\$1,608	-\$2.32
No Relief	All	30	4.54	47,999	\$58,367	\$3,823	\$62,190	

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

The results portrayed in Table 5-11 raise several interesting points. We observe a clear trade-off between the increase in discovery of reserves and a decrease in royalty revenue collection. On one hand, for this \$30/bbl price scenario, all forms of royalty relief lead to an increase in the amount of reserves discovered versus a No Relief scenario. However, as the amount of royalty relief increases, the present value of royalty revenue collected decreases, despite the additional reserves discovered, and potential additional production.

One might expect that as royalty relief increases, the amount of foregone royalties would increase per incremental barrel of reserves discovered. Yet, when we consider the present value of additional lease bonus and rental revenue, we actually observe a greater trade-off in terms of reserves discovery and total revenue collection for the current program on a per barrel basis. For

every additional barrel discovered under the current royalty alternative, \$2.32 is “lost” in royalty revenue. The larger per barrel amount of foregone royalties for the current alternative is largely driven by a minimal change in lease and bonus revenue compared with the No Relief scenario. In other words, the current alternative is estimated to generate less bonus revenue to offset the loss in royalty revenue. The current royalty alternative does not appear to generate much excitement at the leasing level, and those who find and develop reserves under this program are taking advantage of the royalty incentives – to the point it is “costing” the government more per barrel in lost revenue than the larger royalty relief alternatives.

We also examined the data specific to water depth categories. This is particularly relevant given that there are variations in the royalty relief programs across water depths. Table 5-12 presents forecast results for each royalty alternative separated by water depth. There are relatively few differences in the results for the shelf region for each royalty alternative. This is not surprising, as prior deepwater royalty initiatives and the alternatives considered here do not involve suspension volumes for shallow regions.⁵³

Table 5-12. Effects of Alternative Royalty Scenario on Activities at Different Water Depth Categories, All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Reserves Discovered (mmBOE)	Total Production (mmBOE)	Total Royalty-Free Production (mmBOE)	Present Value Royalty Revenue (mm)
DWRR - Field	Shelf	30	4.54	10,382	15,573	226	\$25,480
DWRR - Lease	Shelf	30	4.54	10,377	15,573	226	\$25,480
Current	Shelf	30	4.54	10,385	15,573	226	\$25,480
No Relief	Shelf	30	4.54	10,385	15,573	226	\$25,480
DWRR - Field	Slope	30	4.54	4,507	5,884	1,025	\$6,191
DWRR - Lease	Slope	30	4.54	4,536	5,912	1,772	\$5,657
Current	Slope	30	4.54	4,479	5,861	570	\$6,598
No Relief	Slope	30	4.54	4,464	5,848	383	\$6,787
DWRR - Field	Deepwater	30	4.54	34,115	34,386	8,582	\$23,230
DWRR - Lease	Deepwater	30	4.54	34,859	34,919	14,777	\$21,011
Current	Deepwater	30	4.54	33,828	34,160	5,928	\$24,213
No Relief	Deepwater	30	4.54	33,149	33,598	2,810	\$26,099

Note: Values in \$2003. Present value at 12%. Reserves are ultimate (grown) amounts.

We observe the majority of the differences are driven by changes in the deepwater environment particular to each royalty alternative. However, it is interesting to note that even in the slope region, implementation of a royalty relief program will stimulate additional reserve discovery and field production. It is important to remember that viewing results from all fields, including both existing and new fields, masks the nature of program differences. A large, significant portion of the production difference between the programs is derived from future

⁵³ For this study we have not considered the future impact of deep gas initiatives instituted by the MMS. However, several existing fields have deep gas suspension volumes and we account for these volumes in our existing resource distribution. As a result, certain royalty-free volumes appear in the Shelf region. We recognize that we are understating the ultimate amount of royalty-free production in the Shelf region, considering future discoveries in this region may be able to take advantage of the deep gas initiatives.

discoveries of deepwater fields. Table 5-13 analyzes the forecast results limited to new field discoveries between 2003 and 2042.

Table 5-13. Effects of Alternative Royalty Scenario on Slope and Deepwater Activities, New Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Royalty-Free			Present Value
				New Production (mmBOE)	New Production (mmBOE)	Royalty-Paying New Production (mmBOE)	of New Field Royalty Revenue (mm)
DWRR - Field	Slope	30	4.54	3,690	783	2,907	\$2,394
DWRR - Lease	Slope	30	4.54	3,718	1,530	2,188	\$1,859
Current	Slope	30	4.54	3,667	327	3,339	\$2,801
No Relief	Slope	30	4.54	3,654	141	3,513	\$2,990
DWRR - Field	Deepwater	30	4.54	21,872	7,808	14,064	\$6,994
DWRR - Lease	Deepwater	30	4.54	22,405	14,003	8,402	\$4,775
Current	Deepwater	30	4.54	21,646	5,155	16,491	\$7,977
No Relief	Deepwater	30	4.54	21,084	2,037	19,047	\$9,863

Once again we note as the amount of relief volume increases, so does the amount of new production and naturally, the level of royalty-free production. Perhaps most striking is the difference between royalty-free production and royalty-paying production when considering the maximum relief scenario, DWRR – Lease. The amount of royalty-free production in the DWRR – Lease scenario is nearly double the royalty-free production in the DWRR – Field scenario, and is almost seven times the amount in the No Relief scenario.

Price Thresholds

Thus far, the results presented in this chapter have not included consideration of the effect of hitting the price thresholds inherent in the royalty relief programs. In periods of high oil and gas prices, price thresholds serve to rescind the royalty relief available to leases and/or fields. In addition, the oil and gas production during these periods cannot be “banked” for future relief. Volumes produced are deducted from the lease or field remaining royalty suspension volume. It is very difficult to accurately predict when price thresholds would be exceeded, particularly when examining two succinct price series, as we are currently using. In order to show the impacts of price thresholds, we elected to perform sensitivity analyses under each price scenario and royalty program assumption.

For each price scenario, we assumed there would be a specified amount of time at the beginning of the model run when actual prices would exceed the price thresholds. This assumption was based on discussions with the MMS, in which they indicated that the level of the price thresholds would often be reconsidered after a period of time, e.g., five years. Furthermore, we assumed that in the \$30/bbl price scenario, the period of time where price thresholds were exceeded would be less than that for the high price scenario. To test the sensitivity of our results to price thresholds, we ran our model assuming that price thresholds would be exceeded for five and eight years for the \$30/bbl and \$46/bbl price scenarios respectively. Table 5-14 presents the results of our sensitivity analyses for price thresholds.

Table 5-14. Comparative Effects When Price Thresholds are Exceeded in Each Royalty Alternative, All Fields.

Royalty Scenario	Water Depth	Oil Price (\$/bbl)	Gas Price (\$/mcf)	Present Value Total	Present Value Total	Difference (mm)	Percent Reduction
				Royalty Revenue when Price Thresholds Exceeded (mm)	Royalty Revenue when Price Thresholds Not Exceeded (mm)		
DWRR - Field	All	30	4.54	\$57,222	\$54,901	\$2,321	4.06%
DWRR - Lease	All	30	4.54	\$54,469	\$52,148	\$2,321	4.26%
Current	All	30	4.54	\$58,612	\$56,291	\$2,321	3.96%
No Relief	All	30	4.54	\$60,688	\$58,367	\$2,321	3.82%
DWRR - Field	All	46	6.96	\$95,499	\$90,172	\$5,327	5.58%
DWRR - Lease	All	46	6.96	\$90,395	\$85,112	\$5,283	5.84%
Current	All	46	6.96	\$98,208	\$92,864	\$5,345	5.44%
No Relief	All	46	6.96	\$102,860	\$97,367	\$5,493	5.34%

Note: Values in \$2003. Present value at 12%.

At first glance, it seems striking that the net difference for the four alternative programs is the same for the \$30/bbl price scenario but not for the \$46/bbl price scenario. This is a direct result of the inherent lags in lease to drilling, and drilling to production. Even with a five-year period of price thresholds being exceeded, model discoveries have still not begun production. In addition, there is a slight difference in how the net present values are calculated for the high price scenario. In the \$30/bbl lower price scenario, it was assumed that the price thresholds would never be met, from an operator's point of view. However, based on discussions with the MMS, we decided to alter this assumption in the \$46/bbl price scenario. When calculating net present values for discoveries in years where the price thresholds were exceeded, the operator would assume that he or she would never receive royalty relief, leading to lower net present values of field discoveries. The impact is seen in the difference in expected royalty revenue between alternative royalty relief programs. For example, under the maximum royalty relief scenario, the eight-year price threshold period would lead to an additional \$5.28 billion in revenue collections, as opposed to an additional \$5.49 in the No Relief scenario.

Conclusion

The purpose of Task 2 of this project was to investigate relative differences between alternative deepwater royalty relief programs in the Gulf of Mexico. We performed numerous simulations that projected future exploration, development and production over a 40-year period for each alternative royalty program. The results show that royalty relief accelerates projected exploration and production activity and the more generous the royalty relief program, the greater our expectation of accelerated exploration, development, and production activity. We also note that the projections were very sensitive to price, and price assumptions, not royalty relief, had the largest impact on the relative levels of exploration and discovery activity. Alternatively, leasing and bidding behavior appear to be relatively insensitive to price.

We also made an economic assessment of the financial impact of implementing a royalty relief program. Our findings show that although royalty relief stimulates exploration, development, and production, there is a corresponding loss, sometimes significant, in the amount of royalty revenue collected. This loss is offset to some extent by an increase in lease bonus and rental revenue collected by the government in future lease sales. We observed that the larger the

relief, the greater loss in foregone royalty per BOE discovered and BOE produced. Third, the issue is complicated by the inclusion of price thresholds. In periods where price thresholds are exceeded, we observe a decrease in the royalty revenue collected, although in the lower price scenarios we generally do not observe variation in our expected exploration activity. We did not attempt to predict when price thresholds were exceeded, but rather tested the sensitivity of the results to periods of lower price thresholds.

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The Department of the Interior Mission

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



The Minerals Management Service Mission

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

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

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