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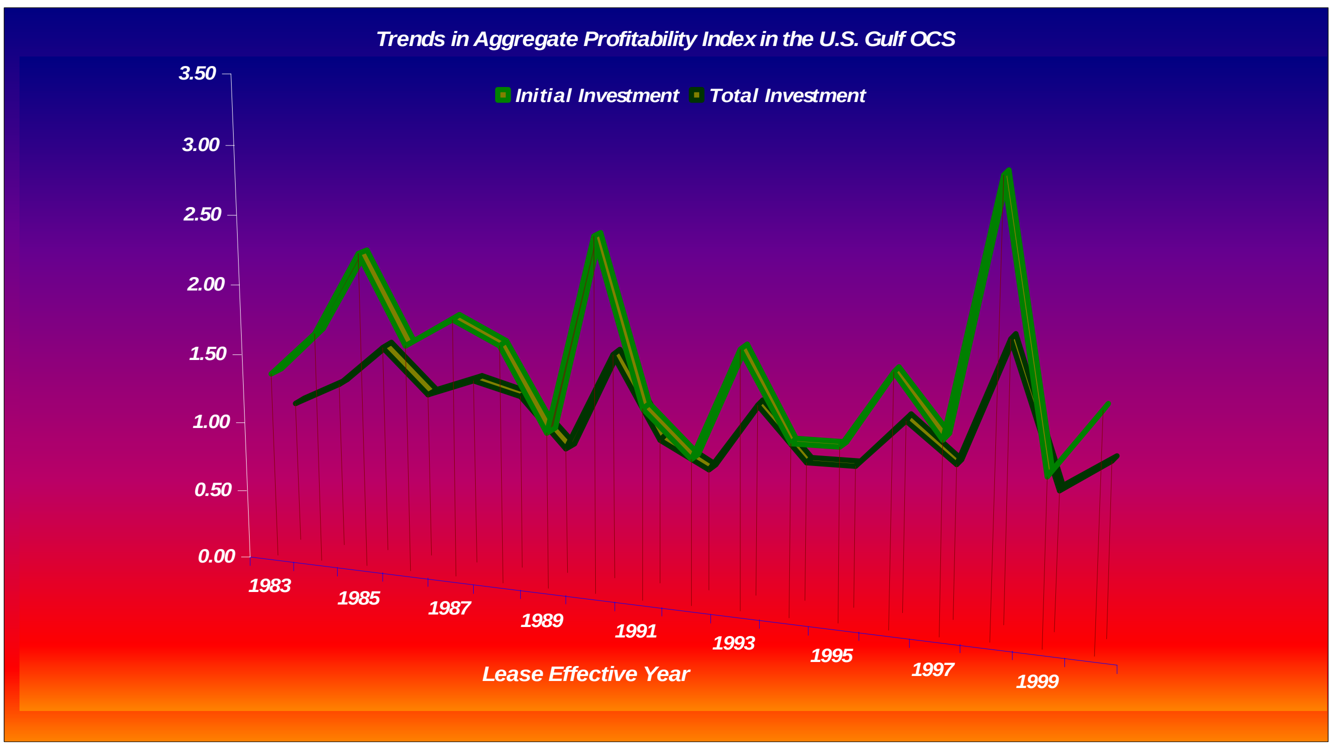
Competition and Performance in Oil and Gas Lease Sales and Development in the U.S. Gulf of Mexico OCS Region, 1983-1999



U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

Cooperative Agreement
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ABSTRACT

This report studies petroleum lease sales and development in the U.S. Gulf of Mexico (GOM) Outer Continental Shelf (OCS) using estimated physical and economic measures of performance in offshore petroleum lease sales and development. The physical performance measures include the prospectivity index, expeditious index, and development productivity. The estimated economic performance measures include a profitability index and internal rate of return.

Empirical analysis of lease specific data suggests that the Gulf OCS is just as attractive to the big four oil and gas integrated firms as it was two decades ago. However, there is evidence of an influx of more players in petroleum lease sales and in the development of the region than there was two decades ago. There is also strong evidence from lease prospectivity results suggesting that the risk of lease development failure rises with firm size and water depth.

Regarding lease development productivity, a declining pattern in productivity with firm size from big to small is unmistakable, as is a declining productivity trend over time. Further, there is evidence of rising lease development productivity with water depth. For all categories of leases, the productivity rate in the early 1980s was significantly higher than productivity rate in the early 1990s, notwithstanding the fact that more leases were issued and drilled in the 1980s than in the early 1990s.

In general, our estimated measures of aggregate economic performance, the profitability index and internal rates of return, are relatively low in comparison to returns in the manufacturing sector during the period. The reported low profitability measures notwithstanding, we find that aggregate annual average rate of return on all leases issued from 1983 to 1994 increases with water depth and across time. The same pattern, however, is not evident in the late 1990s, probably because of data limitations. Also, the aggregate average rate of return increases with firm size leases in the 1980s, but no definitive trend is apparent across firm size in the 1990s.

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EXECUTIVE SUMMARY

Pulsipher et al. (2003) examines the implication of changes in Minerals Management Service (MMS) policy for leasing OCS leases and changes in industry structure for high bonus bid value for OCS leases from 1983 to 1999. However, the study did not evaluate OCS lease performance in terms of aggregate return on investments for leases purchased under the area-wide leasing policy, which began in 1983. The objectives in this study are to appraise the prospectivity and productivity of OCS leases and to estimate measures of competition and economic performance in lease sales and development in the U.S. Gulf of Mexico for leases issued from 1983 to 1999.

Data and Method: The data for this study are primarily from the Minerals Management Service, an agency of the U.S. Department of the Interior. We gathered data on drilling activity, number of wells completed, and on well status from the MMS borehole files. Information on lease status, effective lease date, lease ownership and designated lease operator were retrieved from MMS Leasing Information and Data files (U.S. Department of the Interior, Minerals Management Service, 2006b). Oil and gas production data was obtained from the production information database, and we collected other relevant information on platforms in the Gulf of Mexico from MMS platform masters, platform structures and platform locations files.

Data for estimating drilling and completion costs per lease were collected from several issues of the Joint Association Survey of the U.S. Oil and Gas Producing Industry (American Petroleum Institute, 2003). The aggregate cost estimates for capital expenditures—platform installation and removal and operating or production expenses—were estimated from published public reports and studies. To estimate gross revenue, we collected historical data on lease-specific hydrocarbon production through 2004 for leases acquired by firms during OCS lease sales from 1983 to 1999. We then projected hydrocarbon production on a lease-specific basis to shut down. Using U.S. Energy Information Administration (EIA) adjusted oil and natural gas price trends forecasted for the Gulf of Mexico OCS region in 2004, we then estimated gross revenue as the sum of the product of natural gas prices and gas production and oil prices and oil production.

We have adopted the framework applied in Mead and Sorensen (1980) called discounted cash flow analysis. The framework is formulated to determine, in an aggregate sense, the estimated rate of return earned from investment (1) by leases and (2) by important lease categories in the Gulf of Mexico OCS region. This method is applied to the portfolio of leases acquired and developed since area-wide leasing began in 1983 by high bonus value range, lease sale periods, firm size or type, lease types, water depth, and MMS planning area. Each portfolio of leases is treated as a unique but interdependent investment decision at different points in time such that, if 1983 were the base year, all leases purchased in 1990 would show a 1995 net cash flow as occurring in year 12. Mead and Sorensen (1980) argue that this method of aggregating net cash flow items approximates reality more closely than treating the decisions of firms in subsequent lease sales as if they were independent of prior lease investments.

Lease Ownership Structure and Patterns: Descriptive analysis of data on the changing pattern of lease ownership on the Gulf of Mexico OCS shows a significant influx of new players in the bidding process for leases over the past two decades. This conclusion is based, however, on an evaluation of lease ownership based on the public identity of firms (see Table ES.1). As of 2003, firms not in the top 20 in 1983, with respect to lease ownership, controlled more than 40 percent of all leases issued from 1983 to 1999 in the Gulf of Mexico OCS. However, there is no significant change in the cumulative share of leases owned by the top four firms in 1983. This suggests that the Gulf OCS remains as attractive to the big firms as it was two decades ago.

Further, we analyzed lease ownership on the basis of a unique MMS identifier of lease owners rather than using the public identity of firms. The top four firms in 1983 on the basis of a unique MMS identifier owned just 28.8 percent of leases issued in 1983 and about 16.2 percent of net cumulative leases acquired from 1983 to 1999. This is in contrast with the 44.6 and 40.6 percent we reported earlier for 1983 and 2003, respectively, using public identification. Further, the top 4 firms that owned 23.6 percent of leases acquired between 1983 and 1999, as of 2003, owned just 16.6 percent in 1983.

Table ES.1

Distribution of OCS Leases Issued from 1983 to 1999 by Firm Size and Ranking: PUB vs. MMS Identification

	1983		1999		2003	
1983 Rank	**PUB ID**	**MMS ID**	**PUB ID**	**MMS ID**	**PUB ID**	**MMS ID**
Top 4	44.6	28.8	41.6	15.0	40.6	16.2
Big 5-8	14.1	16.4	5.0	3.8	4.6	3.8
Big 9-20	20.7	25.6	12.5	15.6	13.1	16.5
Non Top 20	20.56	29.19	40.95	65.57	41.65	63.60
1999 Rank						
Top 4	44.6	16.6	41.6	22.0	40.6	22.6
Big 5-8	6.3	9.5	14.2	15.5	12.8	10.3
Big 9-20	10.8	13.5	18.4	22.4	19.4	21.1
Non Top 20	38.31	60.36	25.77	40.12	27.20	45.96
2003 Rank						
Top 4	44.6	16.6	41.6	16.8	40.6	23.6
Big 5-8	6.3	11.6	12.9	15.0	14.1	11.2
Big 9-20	8.9	10.1	18.8	26.0	18.8	22.1
Non Top 20	40.26	61.63	26.78	42.25	26.48	43.13

Physical Measures of Lease Sales and Development Performance: In this report, we define lease sales and development performance in terms of physical measures (lease prospectivity, productivity) and economic measures. The economic measures discussed in this report are calculated on a before income tax basis.

Lease Prospectivity: Lease development index, used as a measure of lease prospectivity in this report, is defined as the multiplicative product of drilled lease ratio and successful drilled lease ratio. Drilled lease ratio is the ratio of the number of leases drilled to the number of leases issued. Successful drilled lease ratio, on the other hand, is measured as a conditional probability parameter. This measure, which can also be defined as one minus drilling failure rate, is the proportion of leases drilled that are producible or productive.

Table ES.2 presents an after-the-fact measure of prospectivity by lease category for leases issued from 1983 to 1999 with reported drilling and production activity as of year end 2004. In the aggregate sense, 26 percent of 13,641 leases issued from 1983 to 1999 reported some drilling activity as of year end 2004. Of the 3,547 leases with reported drilling efforts, 43 percent qualified as producible leases. The drilling failure rate in the aggregate was about 57 percent as at 2004.

The overall aggregate lease development index (the product of the proportion of drilled leases and the proportion of successful drilled leases) for leases issued from 1983 to 1999 was 11.4 percent as of 2004. In other words, approximately one out of nine leases acquired could be expected to produce hydrocarbons in the Gulf of Mexico OCS, *ceteris paribus*. Variations in lease prospectivity within each group are evident in Table ES.2.

- The risk of failure for wildcat leases is higher in the aggregate than the failure rate for drainage leases, but drainage leases are more likely to be prospective than wildcat leases issued from 1983 to 1999. Conceptually, a wildcat lease is defined as a lease with no *a priori* well information to define its productive capacity. On the other hand, a development or drainage lease has sufficiently known geologic information to characterize the production profile of the lease.
- Lease development index decreases with water depth and firm size, but increases with bonus size for leases issued from 1983 to 1999 and developed as of year end 2004.
- The aggregate lease development index for independent firms is nearly three times that for integrated firms because of a proportionately lower drilled ratio and higher drilling failure rate for the latter than the former.
- The aggregate lease development index for leases receiving only one bid from 1983 to 1999 is more than twice the index for leases with at least 2 bids. The drilling ratio of the former is also more than twice the latter, while the drilling failure rate for the latter is nearly 10 percentage points higher than the former.
- The drilling failure rate for joint venture leases is higher than the failure rate for solo leases, however the development index value for joint venture leases is higher because the drilling ratio is significantly higher than that of solo leases over the study period.

Table ES.2

Aggregate Prospectivity of Leases Issued from 1983 to 1999 as of Year End 2004

Group/Lease Category	Leases Issued	Leases Drilled	Leases Producible	Lease Prospectivity: Drilled Ratio (%)	Lease Prospectivity: Development Index (%)	Lease Prospectivity: Drilling Risk (%)
Lease Type						
All	13,641	3581	1553	26.25%	11.38%	56.63%
Drainage	820	290	150	35.37%	18.29%	48.28%
Wildcat	12821	3291	1403	25.67%	10.94%	57.37%
Bidding Structure						
Single Bid	9679	1996	786	20.62%	8.12%	60.62%
≥ 2 Bids	3615	1568	765	43.37%	21.16%	51.21%
Firm Type						
Integrated	7128	1240	386	17.40%	5.42%	68.87%
Independent	6508	2339	1166	35.93%	17.91%	50.15%
Firm Size						
Top 4	5675	907	281	15.98%	4.95%	69.01%
Top 5-8	1937	414	200	21.37%	10.32%	51.69%
Top 9-20	2510	741	334	29.54%	13.30%	54.98%
Non Top 20	3515	1517	737	43.16%	20.97%	51.40%
Water Depth						
< 60m	5365	2116	1018	39.44%	18.97%	51.89%
60m - 200m	2183	768	313	35.18%	14.34%	59.24%
200m - 900m	2143	430	141	20.07%	6.58%	67.21%
>900m	3950	267	81	6.76%	2.05%	69.66%
Bidding Conduct						
Solo Bidder	9231	2150	969	23.29%	10.50%	54.93%
Joint Bidder	4063	1996	786	49.13%	19.35%	60.62%
Bonus Size						
< $200K	3528	419	190	11.88%	5.39%	54.65%
$200K - $400K	3249	521	220	16.04%	6.77%	57.77%
$400K - $1,000K	2749	747	324	27.17%	11.79%	56.63%
> $1,000K	3768	1877	817	49.81%	21.68%	56.47%
Planning Area						
EGOM	347	17	2	4.90%	0.58%	88.24%
CGOM	8213	2473	1137	30.11%	13.84%	54.02%
WGOM	5081	1091	414	21.47%	8.15%	62.05%

Expeditious Development Index: Figure ES.1 reports in months the time interval from lease sale to first drilling activity (spud) and from spud to first production by lease category. These measures are called expeditious development indices. The index offers insights into the perception of owners regarding the economic potential of a given lease.

If lease owners are rational economic beings, then leases with expected high cost of development will be delayed for action. This is evident in Figure ES.1. It took, on average, 77.3 months from effective lease sale time to spud a well on deepwater leases. In contrast, it took on average 26.3 months from sale to spud on leases in the shelf (water depth of 0-200 meters).

Figure ES.1 shows that the average lag in months from lease sales to first lease production increases with water depth and firm size. Further descriptive evaluation of the figure shows that the aggregate lag from sales to production for integrated firms is more than the lag for leases acquired by independent firms from 1983 to 1999 as of 2004.

The difference in the expeditiousness of lease development for leases won through joint bidding and solo bidding is above 4.4 months, on average, from 1983-1999. There is a significant difference in this index between wildcat leases and drainage leases. The expeditious development index from lease sales to lease production is higher, on average, for wildcat leases than for drainage leases by 9.3 months from 1983-1999.

The timing of lease sales is also important. The global market conditions do affect rig availability and hence the delay in activity on leases in petroleum producing regions of the world, including the Gulf of Mexico OCS. Table ES.3 depicts the aggregate trend in expeditious lease development index for leases issued from 1983 to 1999. Declining trends with time in the lag from sales to production on leases are evident in Table ES.3 for all lease categories.

On average, it took about 78.9 months prior to first production on leases sold from 1983 to 1987. In comparison it took approximately 50.3 months on average from sales to production for leases sold from 1995 to 1999. The increase in average lag from sale to production with water depth is also evident in a dynamic sense. It seems, however, that the declining trend with time is not as rapid, on average, for joint venture leases as it is for solo venture leases. For example, the expeditious index for joint venture leases was bigger in magnitude in the early 1980s than for solo leases. The differences had narrowed considerably in the 1990s, on average.

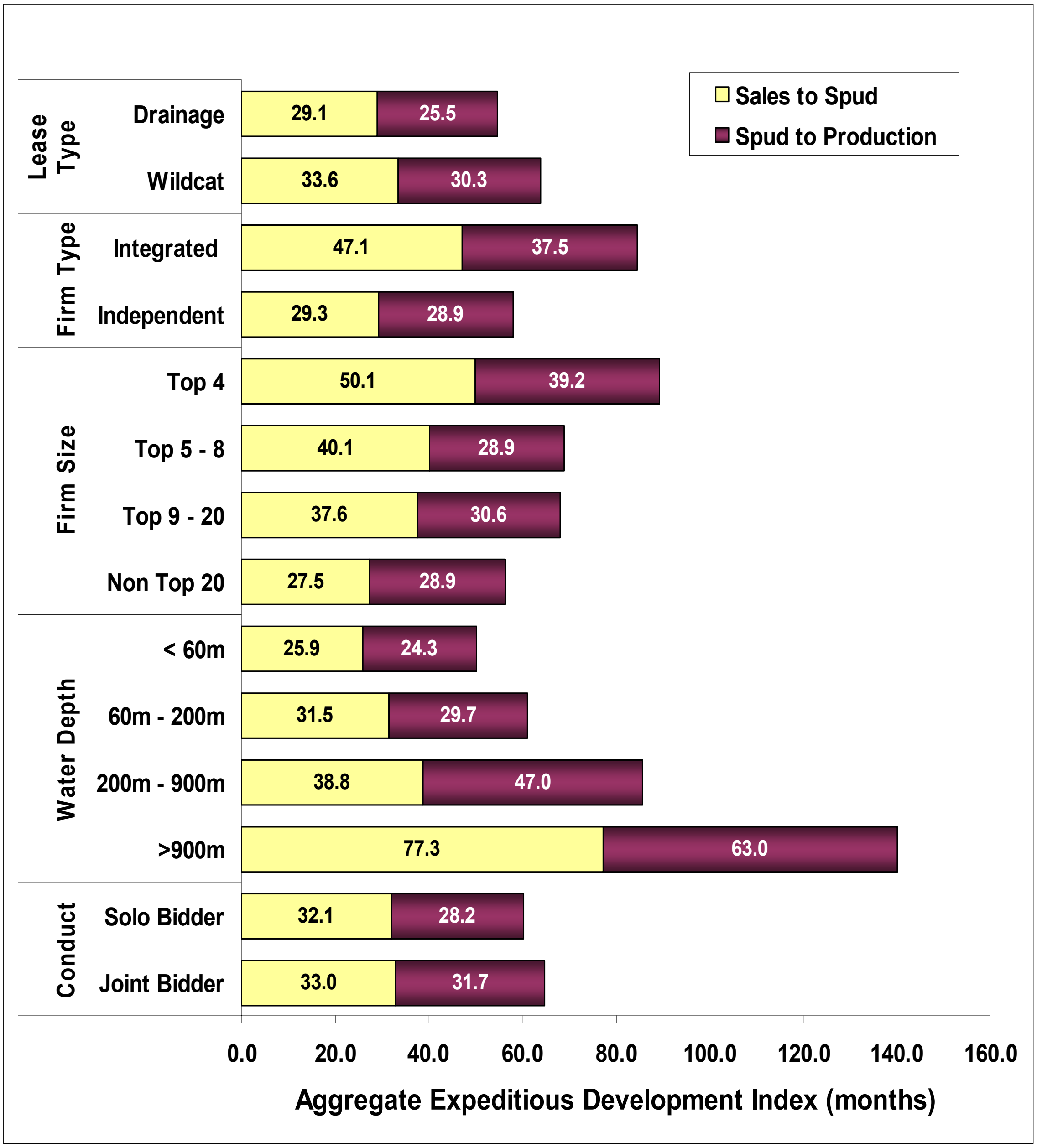

Figure ES.1. Aggregate Expeditious Development Index.

The average lags in months from lease sales to production for leases owned and developed by non top four E&P firms declined from a high of between 69.4 and 82.3 months to values that range between 46.9 and 54.5 months. The top four firms, however, experienced an initial rise in average lag of about 12.2 months from 1983-1989. Subsequently, the lags for the top four firms declined from 73.7 months in the early 1990s to 65.7 months in the late 1990s, on average. In an aggregate sense, Table ES.3 suggests that the lags in months from lease sales to first production for independent firms, on average, have been consistently less than those of integrated firms. Both firm types, however, experienced a declining trend in expeditious index from 1985-1989.

Table ES.3

Aggregate Average Lag in Months from Sales to First Production for Leases Issued from 1983 to 1999

Group	Lease Category	1983-87	1985-1989	1990-1994	1995-1999
Lease Type	*Aggregate*	78.9	75.8	55.7	50.3
	Drainage	56.4	55.9	73.3	30.5
	Wildcat	83.4	79.9	54.5	50.8
Firm Type	*Integrated*	110.2	119.3	70.7	61.2
	Independent	71.6	61.2	56.2	48.0
Firm Size	*Top 4*	115.2	127.4	73.7	65.7
	Top 5 - 8	82.3	82.0	63.9	52.6
	Top 9 - 20	83.8	75.0	65.8	54.5
	Non Top 20	69.4	59.3	54.2	46.9
Water Depth	*< 60m*	59.0	53.2	49.5	41.1
	60m - 200m	74.7	65.7	60.3	47.5
	200m - 900m	128.1	123.0	70.2	54.1
	>900m	180.6	176.9	105.9	99.6
Conduct	*Solo Bidder*	74.6	75.5	52.7	48.9
	Joint Bidder	82.6	74.8	60.3	51.8

Lease Development Productivity Analysis: Lease productivity for the purpose of this report is measured as the ultimate hydrocarbons producible (historical plus projected) for leases issued from 1983 to 1999. No production projections were made for leases not drilled and classified as producible by 2004. The key findings with regard to productivity of OCS leases issued from 1983 to 1999 include the following:

- The overall aggregate productivity per drilled lease in the Gulf of Mexico OCS declined significantly from a high of 4,536 million barrels of oil equivalent (MBOE) for leases issued from 1983 to 1987 to 2,864 MBOE for leases issued in the early 1990s.
- Lease productivity by structure shows a higher productivity ratio for drilled solo venture leases in the 1980s and early 1990s than drilled joint venture leases. The reverse, however, was the case for leases issued in the late 1990s, on average.
- There is strong statistical evidence to suggest that leases receiving at least two bids on the Gulf OCS were more productive than leases that received single bids from 1983 to 1999.
- The lease development productivity rate also seems to show an increasing pattern with water depth in the aggregate sense. Lease development productivity rises with water depth but declines significantly across time.
- A comparison of aggregate lease productivity by bonus size shows a less discernable pattern. In the 1990s, however, there seems to be increasing lease productivity with lease value, as expected.
- The estimated aggregate lease development productivity for integrated firms is significantly greater than productivity of leases issued to independent firms, and aggregate lease development productivity shows a declining pattern by firm size from big to small size firms. A declining trend over time is unmistakable for the top eight firms.
- For all categories of leases, the productivity ratios in the 1980s were significantly higher than productivity ratios in the early 1990s, notwithstanding the fact that more leases were issued and drilled in the 1980s than in the early 1990s (see Figure ES.2).

Economic Measures of Lease Development Performance: For the purpose of this report, we adopted two of the more popular economic performance measures to analyze the performance of OCS leases issued from 1983 to 1999 and developed from 1983 to 2004. The two measures, profitability index and internal rate of return, recognize the time value of money.

Profitability Index: Profitability index (PI) is defined as the ratio of the present value of total income to the present value of total investment. It is a relative measure of the efficiency of an investment. For comparative purposes, we used two representative discount rates in this report for all categories of leases. The first is the average rate of return on revenue before taxes and the historical before-tax average rate of return for corporations in the NAICS manufacturing sector. Therefore, our results do not reflect any cross sectional or time variations in the cost of borrowed capital by firms for projects. Moreover, the values of profitability index we calculated are *ex-ante*.

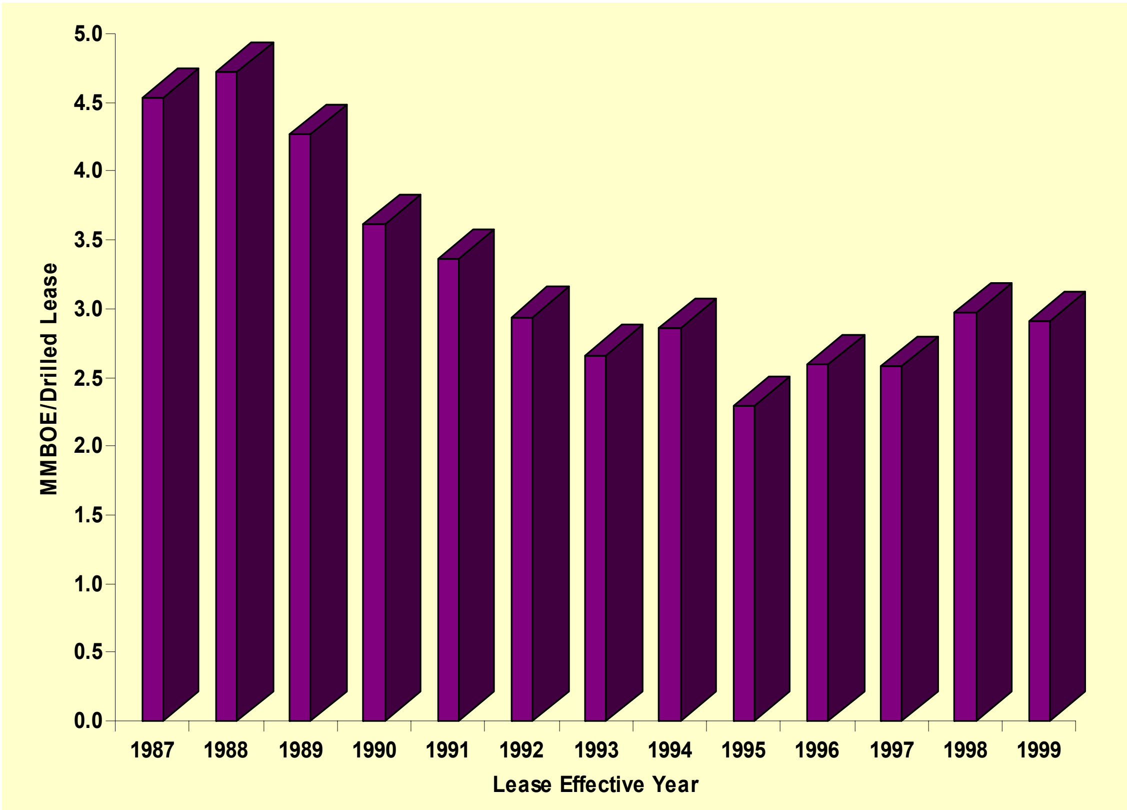

Figure ES.2. Five-Year Average Trend in Aggregate Productivity per Drilled Lease.

The key finding in profitability index analysis is that the estimated indices were significantly low for all categories of leases (see Table ES.4). This finding notwithstanding, we found some notable patterns in this study:

- Profitability index increases, on average, with decreasing discount factors, an indication of how borrowed capital can affect the overall industry economic performance (see Figure ES.3).
- Profitability index rises from the shelf to the slope and the deepwater, just as lease productivity rises from the shelf to the slope and deepwater.
- On average, integrated firms reported higher profitability ratios than independent firms.
- The estimated index for solo bidders on aggregate is higher than the index for joint bidders for leases issued from 1983 to 1999.
- Profitability ratio of leases in the Central Gulf is higher in magnitude than leases in the Western Gulf, but the difference does not seem to be statistically significant.
- It is interesting to note further that the impact of bonus payments, which have been suggested to be regressive in nature, is significant in our analysis with respect to the economic performance of lease development (see Table ES.4).

Table ES.4

Aggregate Profitability Index for Leases Issued from 1983 to 1999 Using Two Discount Factors

		Profitability Index (Total Investment Minus Bonus)		*Profitability Index (Total Investment)*	
Group	**Lease Category**	***17.00%*** [1]	***12.50%*** [2]	***17.00%***	***12.50%***
Lease Type	*Drainage*	**1.03**	**1.41**	0.58	0.74
	Wildcat	**1.20**	**1.77**	0.63	0.84
Structure	*Single Bid*	**1.25**	**1.90**	0.63	0.85
	≥ 2 Bids	**1.16**	**1.65**	0.64	0.83
Firm Type	*Integrated*	**1.33**	**2.13**	0.69	0.96
	Independent	**1.04**	**1.41**	0.57	0.72
Firm Size	*Top 4*	**1.32**	**2.14**	0.70	0.97
	Top 5 - 8	**1.19**	**1.61**	0.63	0.77
	Top 9 - 20	**1.50**	**2.10**	0.76	0.95
	Non Top 20	0.89	**1.22**	0.50	0.64
Water Depth	*< 60m*	0.91	**1.19**	0.52	0.63
	60m - 200m	0.72	0.99	0.43	0.55
	200m - 900m	**1.71**	**2.86**	0.83	**1.16**
	>900m	**4.81**	**7.41**	**1.38**	**1.70**
Conduct	*Solo Bidder*	**1.39**	**1.99**	0.70	0.90
	Joint Bidder	**1.01**	**1.51**	0.57	0.77
Bonus Size	*< $200K*	**2.23**	**3.01**	0.82	**1.01**
	$200K - $400K	**1.54**	**1.98**	0.64	0.77
	$400K - $1,000K	**1.79**	**2.47**	0.79	0.99
	>$1,000K	**1.06**	**1.56**	0.60	0.80
Area	*Aggregate*	**1.18**	**1.73**	0.63	0.83
	EGOM	0.06	0.12	0.04	0.09
	CGOM	**1.26**	**1.84**	0.65	0.86
	WGOM	**1.07**	**1.57**	0.60	0.80

Note: Bolded figures in the above table indicate lease categories with added value to investment, *ceteris paribus*, at the corresponding discount factors.

[1] This represents the historical before taxes average rate of return for corporations in the NAICS manufacturing sector (U.S. Census Bureau, 2004).
[2] Representative average return on revenue (Standard & Poor's NetAdvantage, 2005).

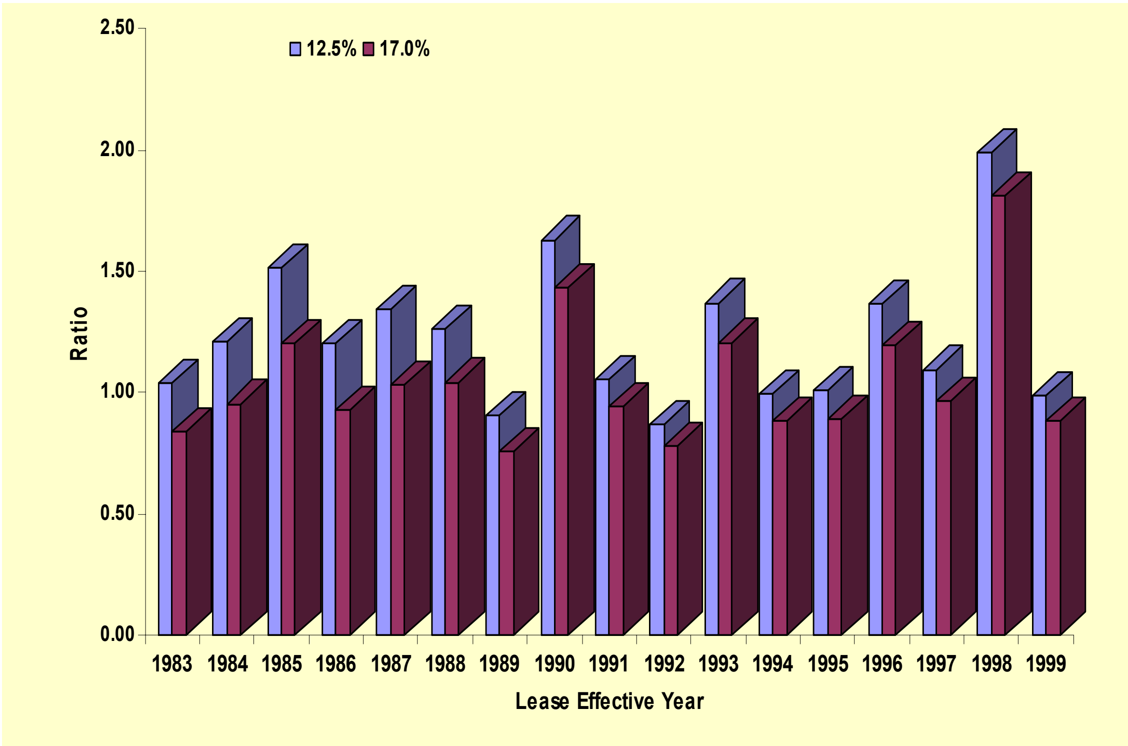

Figure ES.3. Aggregate Trends in Profitability Index Using Two Discount Factors.

Internal Rate of Return Analysis: Internal rate of return is defined as the discount rate at which the present value of the sum of net cash flow in terms of cash receipts and disbursements is exactly equal to zero. It weights cash receipts rather heavily in the later years of projects, and can be calculated on a before-tax or after-tax basis.

Keeping in mind each portfolio of leases is treated as a unique but interdependent investment decision at different points in time, the overall internal rate of return for all 13,641 leases issued from 1983 to 1999 in the U.S. Gulf of Mexico OCS is estimated as 6.9 percent. This estimate is extremely low in comparison to the rate of return in comparable U.S. industries. The historical before taxes average rate of return for corporations in the NAICS manufacturing sector according to the U.S. Census Bureau is 17 percent.

In general, the estimated rates of return are low for all categories of leases when compared to the return value of 17 percent in the manufacturing sector during the period. The reported low profitability measures in terms of internal rates of return notwithstanding, we found the following significant (see Table ES.5):

- In aggregate, leases issued in 1990-1994 have a higher annual rate of return on average than leases issued in the 1980s. However, leases issued in the late 1990s, on average, have a lower annual rate of return.

- On the other hand, the average rate of return for productive leases from 1990 to 1994 is less than the rate of return in the 1980s and the late 1990s.
- The aggregate average annual rate of return for leases issued in the 1980s is higher for leases with single bids than for leases with at least two bids. The reverse, however is the case for the 1990s.
- From 1983 to 1994, the rate of return rises with water depth and across time for all productive leases. The same pattern is not evident in the late 1990s, probably because of data limitations.
- The aggregate annual average rate of return rises with firm size in the 1980s, but no definitive trend is apparent across firm size in the 1990s.
- The estimated rate of return for all lease developments by the top four firms declined from 12.7 percent in 1985-1989 to 10.7 percent in 1990-1994, and dropped to 5.7 percent for leases issued from 1995 to 1999.
- All leases issued to integrated firms, on average, have a higher rate of return than independent firms across the lease effective year.
- There is evidence to suggest that the rate of return for productive leases in the Western Gulf planning area is higher, on average, than for leases in the Central Gulf over the study period. The evidence, however, does not suggest a similar trend for aggregate rate of return for all leases.

Table ES.5

Annual Average Internal Rate of Return Dynamics, 1983-1999

Group	Lease Category	1983-87	1985-89	1990-94	1995-99	1983-99
Type	Drainage	6.0%	5.4%	10.1%	*	7.8%
	Wildcat	9.2%	9.2%	9.3%	5.2%	7.1%
Structure	Single Bid	10.1%	9.7%	8.7%	4.1%	8.1%
	> 2 Bids	5.5%	8.5%	13.4%	10.1%	9.2%
Firm Type	Integrated	11.0%	12.2%	9.7%	7.4%	9.7%
	Independent	3.4%	5.1%	4.2%	6.7%	4.9%
Firm Size	Top 4	11.6%	12.7%	10.7%	5.7%	5.6%
	Top 5 - 8	4.2%	9.0%	10.7%	4.3%	9.6%
	Top 9 - 20	9.9%	8.0%	13.6%	8.5%	6.9%
	Non Top 20	0.6%	0.9%	1.4%	16.5%	7.2%
Water Depth	< 60m	1.0%	2.0%	1.8%	2.8%	2.1%
	60m - 200m	3.4%	3.4%	9.8%	0.9%	5.5%
	200m - 900m	15.0%	16.5%	13.6%	21.5%	15.9%
	>900m	22.2%	18.7%	27.2%	12.6%	20.6%
Conduct	Solo Bidder	8.8%	8.8%	7.7%	5.4%	13.3%
	Joint Bidder	7.9%	9.7%	19.3%	9.2%	9.6%
Bonus Size	< $200K	25.3%	15.0%	3.9%	13.3%	10.4%
	$200K - $400K	6.3%	4.7%	4.4%	7.2%	5.8%
	$400K - $1000K	10.2%	10.6%	15.3%	6.0%	10.6%
	>$1,000K	6.9%	8.1%	10.1%	9.4%	8.4%
Area	Aggregate	8.1%	8.2%	9.1%	6.2%	7.4%
	CGOM	8.9%	8.6%	6.2%	8.8%	7.6%
	EGOM	0.0%	17.2%	0.0%	0.0%	17.2%
	WGOM	8.2%	9.0%	10.2%	5.2%	9.8%

* Limited data availability.

1. INTRODUCTION

In the 1980s, several studies were conducted using federal OCS lease data to facilitate the understanding of the structure and performance of the OCS oil and gas lease market (Mead and Sorensen, 1980; Teisberg, 1980; Gilley and Karels, 1981; Rockwood, 1983; Mead et al., 1985). These studies were conducted using data on lease sales from 1954 to 1977 under the nomination and tract selection arrangement. The implications of joint ventures, industry structure, and market conditions for federal offshore oil and gas lease sales were well documented in these studies (Saidi and Marsden, 1992).

The structure of the U.S. oil and gas industry, however, has changed significantly over the years (Iledare et al., 1995). Moreover, leasing policy has changed from nomination to area-wide leasing. The leasing policy governing OCS lease sales now allows firms to bid for any OCS tracts that are not currently leased (Moody and Kruvant, 1990). The immediate result of this change in policy was a large increase in the number of leases or tracts awarded at each subsequent lease sale (Pulsipher et al. 2003). Furthermore, the type of bids that can be submitted jointly also changed following the Energy Policy and Conservation Act (EPC) of December 1975 (Millsaps and Ott, 1981). The EPC Act forbade some of the major oil and gas companies from bidding jointly for leases on the OCS, a rule intended to reduce the potential for anti-competitive effects on the OCS bidding system.

Pulsipher et al. (2003) examines the implication of these changes in leasing policy and industry structure to characterize high bonus bid value for OCS leases from 1983 to 1999. The study suggests that joint bidding for OCS leases shows no anti-competitive effects on the value of high bids. The study also shows that the tendency among the large firms, measured in terms of cumulative ten-year production, to offer less than the average high bid value for leases they won is statistically significant. Pulsipher et al. (2003) also suggests that firms tend to bid higher than expected for leases won in the Gulf of Mexico deepwater than they did for leases on the shelf. The value of high bonus bids, according to the study, tends to decline significantly in the years following the collapse of global crude oil prices in 1986 relative to the above average positive change in winning bid value prior to the collapse.

Pulsipher et al. (2003), however, did not evaluate or characterize OCS lease market performance in terms of the return on investments for leases purchased under the area-wide leasing policy, which began in 1983. Thus, the purpose of this study is to analyze the performance in oil and gas lease sales and development from 1983 to 1999. The framework applied for this analysis is similar to that of Mead and Sorensen (1980). In addition to analyzing the competitiveness of OCS leases by lease categories using multiple regression analysis, Mead and Sorensen evaluated the performance of Gulf OCS investments by computing aggregate internal rate of return for various categories of leases.[3]

The framework we have adopted, which was also applied by Mead and Sorensen (1980), is called discounted cash flow analysis. The framework is formulated to determine in an aggregate sense, the estimated rate of return earned from investment by leases and also by important lease categories in the Gulf of Mexico OCS region. The formulation is expressed such that:

$$\pi = \sum_{t=0}^{N} \left(\frac{R(t) - C(t)}{(1+r)^t} \right), \tag{1}$$

where R (t) is estimated gross annual revenue, C (t) is estimated annual total costs, r is the rate of discount such that the internal rate of return is defined as r = r*, which makes $\pi = 0$ (Mead et al., 1983; Newendorp and Schuyler, 2000).

The above equation is applied to a portfolio of leases purchased and developed since area-wide leasing began in 1983 within the framework of field size categories, lease sale periods, firm size, lease types, and for MMS planning area and water depth. Each portfolio of leases is treated as a unique but interdependent investment decision at different points in time such that if 1983 were the base year, all leases purchased in 1990 would show a 1995 net cash flow as occurring in year 12. This method of aggregating net cash flow items approximates the reality more closely than treating the decisions by firms to buying additional leases in subsequent lease sales as independent of prior lease investments (Mead and Sorensen, 1980).

The report is organized as follows: Following the introduction, Section 2 describes the fundamentals of cash flow analysis. Each component of a typical cash flow model is described in this section. Section 3 presents sources and descriptions of data for each cash flow item in the cash flow equation. The section reports descriptive statistics for cash flow variables. Section 4 reports the empirical results. Several measures of performance in lease sales and development are reported in an aggregate sense for all leases by lease category—firm size, planning area, bonus size, water depth, lease market structure and conduct as well as firm type. The empirical results are also presented in this section by lease sale year.

[3] Mead and Sorensen (1980) addressed several important policy issues--the competitiveness of the lease market in the Gulf of Mexico OCS, the significance of firm size, the impact joint bidding and lease classifications--affecting high bid value for leases sold from 1954 to 1969 as Pulsipher et al. (2003) did for leases from 1983 to 1999.

2. CASH FLOW MODEL AND ANALYSIS

2.1. Introduction

Cash flow is fundamental to petroleum exploration and production (E&P) business as it is in all private sector businesses. It represents the fuel that drives the engine of a profitable business venture. By definition, net cash flow (NCF) is the summation of all revenues, expenses, taxes and investments on a period-by-period basis. It can be calculated on an annual basis or cumulatively for a project. It can also be calculated as a before-tax or after-tax business performance parameter. The net cash flow parameter serves as the basic element in the computation of all economic measures that are associated with E&P projects.

The more generalized relationship for net cash flow computation takes the form of equation (1) under a royalty and tax fiscal system, the type governing E&P operations, in the U.S. Gulf of Mexico OCS:

$$NCF_t = (1-A)*[GRR_t - ROY_t - OPX_t - BNX_t - OOX_t] - (1-B)*CPX_t + A*[DPX_t], \quad (2)$$

where,

NCF = Net cash flow,
A, B = Taxation and investment credit rate, respectively,
GRR = Gross revenue,
ROY = Royalty,
OPX = Operating expenses as defined by legislation,
BNX = Signature and/or production bonus payments if tax deductible,
OOX = Other costs, such as environmental fees, rentals, abandonment costs, etc.
CPX = Capital expenditure as defined by legislation,
DPX = Fiscal depreciation and depletion allowance,

2.2. Description of Cash Flow Components

Gross revenues are earnings from crude oil, natural gas and/or natural gas liquids (NGL) sales. Production as well as price forecasts of all hydrocarbons are necessary in order to calculate this cash flow item. The gross revenues in year *t* from hydrocarbon production are defined as (Kaiser and Pulsipher, 2004):

$$GRR_t = P_t^o\, Q_t^o + P_t^g\, Q_t^g, \quad (3)$$

where,

P_t^o, P_t^g = Average oil, gas benchmark price in year *t*,
Q_t^o, Q_t^g = Total oil, gas production in year *t*.

Oil or natural gas price is based on a benchmark expressed as an average over the time horizon under consideration. The total amount of production in year t is expressed in terms of barrels (bbl) of oil, thousand cubic feet (Mcf) of gas, or barrels of oil equivalent[4] (BOE).

Bonuses and rentals are pre-discovery payments to the government or land owners for the right of E&P firms to explore, develop, and produce petroleum through a competitive bidding process. The goal to efficiently explore and develop petroleum in the OCS region may be difficult to accomplish, if the initial cash payment to the government for granting firms the right to explore for oil in the OCS region is either "too high" or "too low" (McDonald, 1979). Thus, bonus value per lease is an important variable to monitor in lease performance evaluation (Iledare et al., 2004).

Rentals represent payments by lease owners to defer E&P operations on the lease for at least a year. Otherwise, the lease expires unless operations begin within a year from the effective lease date, regardless of the primary terms of the lease (Mian, 2002). Rentals, like bonus payments for a lease, are regressive receipts by the government in the sense that they are independent of lease profitability or prospectivity.

Royalty is one of the more common fiscal cost items in cash flow analysis from an operator's perspective. It is based on the value of produced resources and represents payment made in cash or in kind for the right to develop and produce discovered reserves. It is normally calculated as a fraction of gross production and it is independent of any cost of development or on-going operation and irrespective of profitability of the discovery. It is therefore considered a regressive type of tax because it is tied to gross revenue or gross production (Johnston, 2003).

The royalty rate R, $0 \leq R \leq 1$, depends upon the location, the time of lease sales, and the incentive schemes. The federal royalty rate in the U.S. Gulf of Mexico OCS and deepwater is $R = 1/8^{th}$ (12.5%) or $R = 1/6^{th}$ (16.67%). The most recent royalty incentive plan in the Gulf of Mexico is the OCS Deep Water Royalty Relief Act (DWRRA) of 1995. The Act offers minimum royalty suspension volumes by water depth to leases issued as part of an OCS lease sale after November 28, 1995 and before November 28, 2000. Such leases in order to qualify must be located in water depths of 200 meters or deeper and satisfy other stipulations of the Act.[5]

Operating expenditures (*OPEX*) represent the money required to operate and maintain production facilities; to lift the oil and gas to the surface; and to gather, treat, and transport the hydrocarbons. They are direct costs associated with production or injection. There can be no operating costs if there are no production operations.

[4] Barrels of oil equivalent are the amount of natural gas that has the same heat content of an average barrel of oil. One BOE is about 5.62 Mcf of gas.
[5] U.S. Department of the Interior, Minerals Management Service, 2006a.

Typical examples of OPEX items include all variable costs such as the cost of raw materials, management fees, lifting costs, labor costs, environmental costs and community settlements, other hidden costs of doing business, etc. Johnston (2003) suggests that the relationship between annual operating costs and total capital expenditures ranges between 3% and 5% in the Gulf of Mexico shelf. The ratio, however, can approach 20 percent or more in the OCS deepwater.

Mian (2002) classifies operating expenditures into five components. Typically, production costs and evacuation costs can account for more than one-third and a quarter of total operating expenditures, respectively. The other three components—insurance premium, maintenance costs and overhead—account for the remaining 42 percent (Mian, 2002).

Capital expenditures (*CAPEX*) are the expenditures to develop and produce hydrocarbons that are incurred early in the life of a project, and often for several years before any revenue is generated. CAPEX consist of geological and geophysical costs, drilling costs, facility equipment and installation costs, and removal costs. Capital costs may also occur over the life of a project, such as during re-completing wells into a new formation, upgrading existing facilities, etc. These costs are usually considerably smaller in magnitude and duration than are the initial capital expenditures.

Total drilling costs (exploratory and development drilling) account for a significant fraction of the exposed capital associated with oil and gas ventures. In fact, total drilling costs as a fraction of total costs associated with oil and gas development can range from 25 to 50 percent (Johnston, 2003). It is reasonable to infer that as capital costs increase, project viability decreases, *ceteris paribus*.

The technical factors affecting drilling costs include geology, drilling program, and the well type and location (shelf, slope or deep) drilled. The type of well drilled can be expressed in terms of well classification—exploratory or development—or in terms of drilling outcome—successful (oil or gas) or dry. The configurations of wells drilled also significantly affect drilling costs as do rig availability and contractual drilling agreements (Mian, 2002).

The abandonment cost portion of CAPEX is driven by the desire to make oil and gas companies socially responsible. It is required that at the end of the economic life of a fixed structure in the OCS the structure must be removed and abandoned in an environmentally safe manner. Removal and abandonment costs of wells and facilities now constitute a significant component of total costs. While these costs come at the end of the project life, the timing of infrastructure removal and abandonment is significant in a cash flow analysis, especially in present value calculations.

2.3. Net Cash Flow

The purpose of a cash flow analysis is to assess whether or not the revenues generated by the project cover the capital investment and expenditures and whether or not the return on capital investment is consistent with the risk associated with the project and the strategic objectives of the corporation.

The net present value (PV) method for evaluating the profitability of capital investments on leases in the GOM OCS can be represented mathematically by the following equations (Kaiser & Pulsipher, 2004).

$$\mathrm{PV} = \sum_{t=1}^{k} \frac{NCF_t}{(1+D)^{t-1}} . \tag{4}$$

$$\mathrm{IRR} = \{\mathrm{D} \mid \mathrm{PV} = 0\} . \tag{5}$$

D is the (discount) rate that equates the present value of the net cash flow to zero.

The present value of NCF is the product of a discounting process by which all future cash streams are discounted into present value in recognition of the time value of money. The process involves the application of an equal weight to all future incomes. This can be taken literally to mean the process of owning a project at a point in time. That implies that the owner of a project may be willing to let go of a property provided the price offered for the business is greater or equal to the estimated PV. It is thus important to specify the reference period as well as the discounting factor.

The internal rate of return (IRR) computed using equation 5 is a widely accepted measure of project profitability. It is a profitability index that is independent of cash flow and can be calculated on a before-tax or after-tax basis. This index cannot be calculated if all the cash flows are negative; also important, more weights are put on the early cash flows than later ones. In other words, IRR calculations using equation 5 heavily discounts cash flows occurring in the later years of the project.

A profitability index (PI), or investment efficiency ratio normalizes the present value of the project relative to the present value of total investment and is calculated as:

$$\mathrm{PI} = \frac{PV(TR)}{PV(TC)} , \tag{6}$$

where,

TR=Total Operating Cash Flow,

TC=Total Capital Investment.

3. OCS LEASE SALES & DEVELOPMENT DATA

3.1. Sources of Data

The lease-specific data for this study are primarily from the Minerals Management Service, an agency of the U.S. Department of the Interior. Borehole files in the MMS well information database provided data on drilling activity, number of wells completed, and statistics on well status. Information on lease status, effective lease date, lease ownership and designated lease operator were retrieved from MMS Leasing Information Data files (U.S. Department of the Interior, Minerals Management Service, 2006b). Oil and gas production data were obtained from the production information database, and other relevant information on platforms in the Gulf of Mexico were collected from MMS platform masters, platform structures, and platform locations files.

The source of data for estimating drilling costs per lease was the Joint Association Survey (JAS) of the U.S. Oil and Gas Producing Industry (American Petroleum Institute, 2003). The survey reports well drilling costs for various areas of the U.S. JAS reports drilling for different well depth ranges and for four different types of wells—dry, gas, oil and total. We used MMS well production and borehole data to classify OCS wells into well types. For the purpose of this report, wells with no reported production were classified as dry. Further, if the reported gas production over an entire well production history expressed in BOE unit is greater than liquid production, the well is classified as gas. Such wells are classified as oil, otherwise. The aggregate cost estimates for capital expenditures—platform installation and removal and operating or production expenses—are from published public reports and studies.[6]

To estimate gross revenue, first we collected actual historical data on lease-specific hydrocarbon production through 2004 for all leases purchased by firms during OCS lease sales from 1983 to 1999. We then projected hydrocarbon production on a lease-specific basis to shut down, using EIA adjusted oil and natural gas price trends forecasted for the Gulf of Mexico OCS region in 2004. Finally, we estimated gross revenue as the sum of the product of natural gas prices and gas production and oil prices and oil production.

The revenue series has two components. The historical revenue from 1983 to 2004 is based on the adjusted historical oil prices in current dollars reported by the EIA. The projected revenue from 2005 to 2017 for any lease that has not reached its economic life limit is based on projected oil and gas prices in 2004 and projected production using exponential production decline functional approach.

[6] U.S. Energy Information Administration (EIA) Oil and Gas Lease Equipment and Operating Costs, JAS Survey of Drilling Costs, Dismukes et al. (2003) and Kaiser et al. (2004)

3.2. Analysis of OCS Lease Sales & Development Attributes

This section describes and analyzes lease-specific data; these underlie the aggregate and annual lease sales and development performance indicators reported in this report. The overall aggregate and annual aggregate analysis of data are presented by planning area, high bonus size, bidders conduct (joint or solo), water depth, firm size, firm type, bidding structure (single bids or at least two bids), and lease type (wildcat or drainage).

3.2.1. Lease Ownership Structure and Patterns: The changing pattern in lease ownership in the Gulf of Mexico is illustrated in Figures 1-4. Figures 1 and 2 are based on public identity of firms operating in Gulf of Mexico OCS region. Figures 3 and 4 reflect the ownership pattern using MMS unique company identity used in bidding for OCS leases that were issued from 1983-1999.

Figures 1 and 2 show that the top 20 lease owners accounted for about 80 percent of total OCS leases offered for sale in 1983. By 2003, however, the cumulative interest of these top 20 firms was less than 60 percent. This reflects a significant influx of new players in the bidding process for OCS leases over the past two decades. Firms other than the top 20 in 1983 control more than 40 percent of all leases issued from 1983 and 1999 in the Gulf of Mexico OCS in 2003.

The initial ownership of OCS leases in 1983 and the cumulative net interest in leases from 1983 to 1999 for the top 4 did not go down significantly. However, most of the firms who were in the top 5-8 in 1983 have been displaced by the new players in 2003. The cumulative net leases owned by the top 5-8 firms dropped from 14.1 percent in 1983 to less than 5 percent in 2003. On the other hand, the 1983 top four firms owned and controlled about 45 percent of leases issued in 1983 and their share in cumulative net leases from 1983 to 1999 was approximately 41 percent as of 2003. The fact that the share of cumulative leases owned and controlled by the 1983 top four firms remains relatively stable in 2003 bodes well for the Gulf OCS in terms of its attractiveness to the big firms. One question is whether the large and unconditional upfront cash bonus payments for leases created a barrier to entry that favored these big firms, possibly making the bidding process anti-competitive (Pulsipher et al., 2003).

Further evaluation of the lease ownership pattern within the context of any anti-competitive behavior in the bidding process shows that the actual company identity matters in the bidding process. We examined lease ownership on the basis of an assigned MMS unique identifier to lease owners. Figures 3 and 4 depict a completely different pattern of ownership than the one we found using the firm's public identity. For example, the top four firms in 1983 on the basis of MMS unique identifier owned and controlled 28.8 percent of leases issued in 1983 and only 16.2 percent of net cumulative leases issued from 1983 to 1999. Further, the top 4 firms that owned and controlled 23.6 percent of 1983-1999 lease stock or inventory in 2003, controlled only 16.6 percent in 1983.

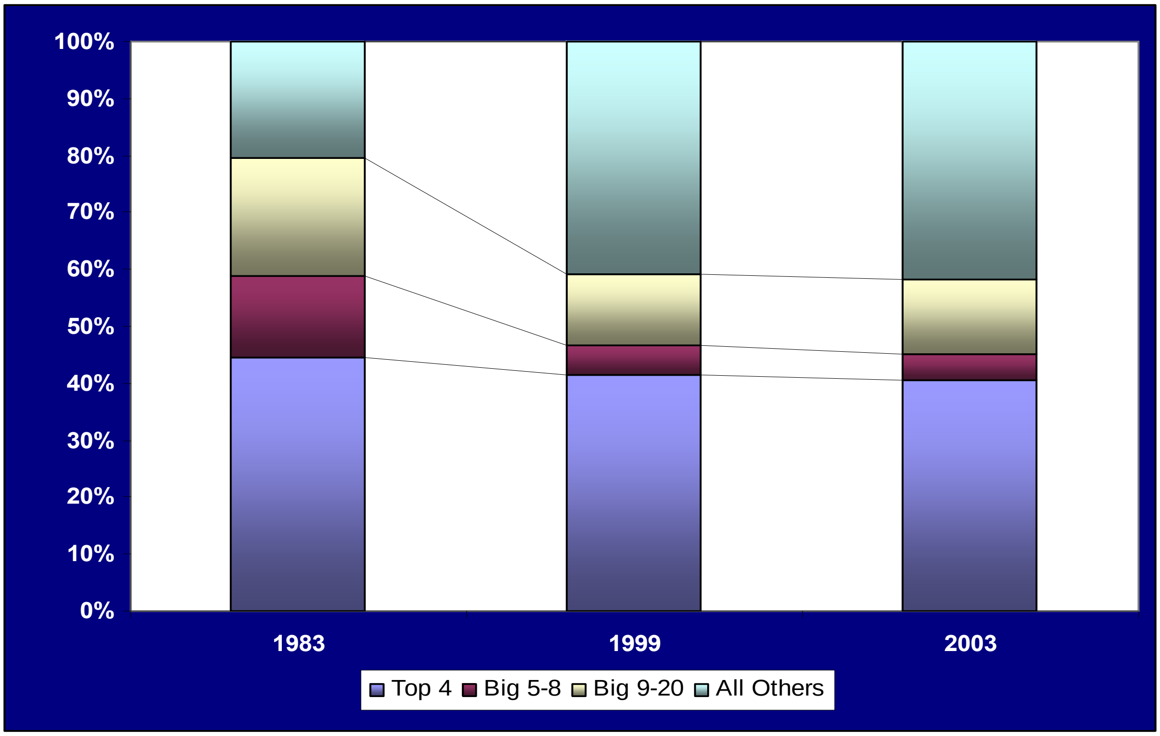

Figure 1. Inventory of Leases Owned and Controlled by 1983 Top Firms for Leases Issued in the U.S. Gulf of Mexico OCS from 1983 to 1999—Public ID.

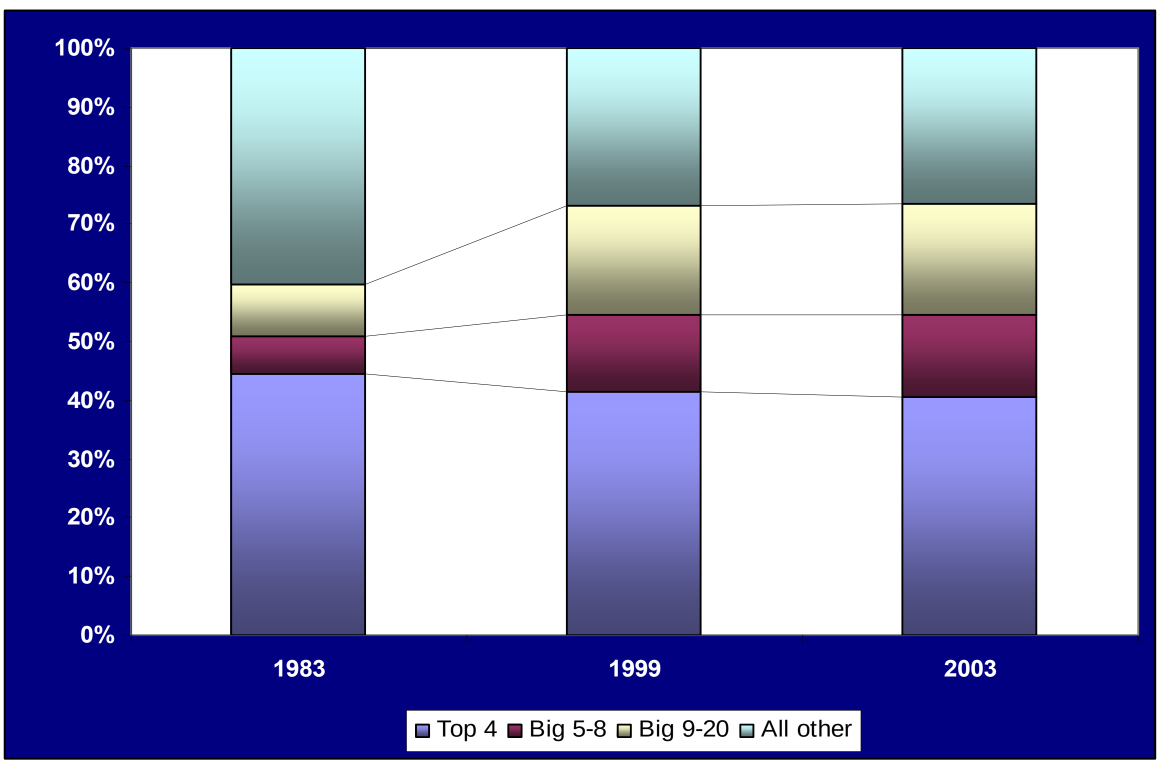

Figure 2. Inventory of Leases Owned and Controlled by 2003 Top Firms for Leases Issued in the U.S. Gulf of Mexico OCS from 1983 to 1999—Public ID.

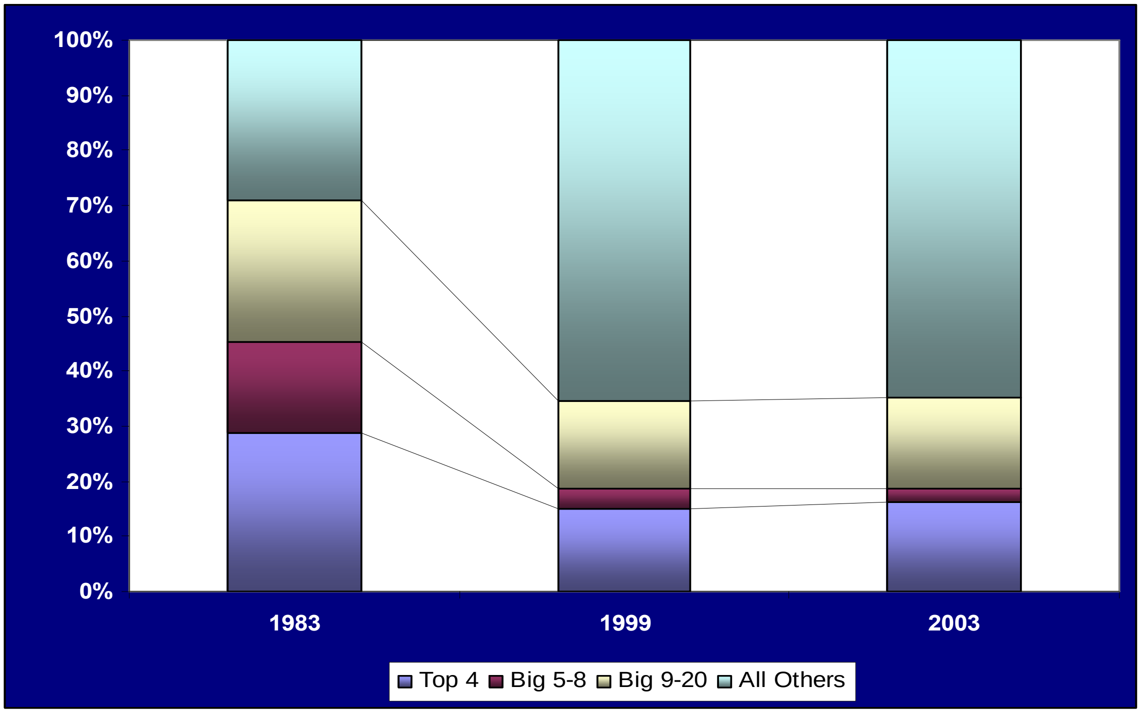

Figure 3. Inventory of Leases Owned and Controlled by 1983 Top Firms for Leases Issued in the U.S. Gulf of Mexico OCS from 1983 to 1999—MMS ID.

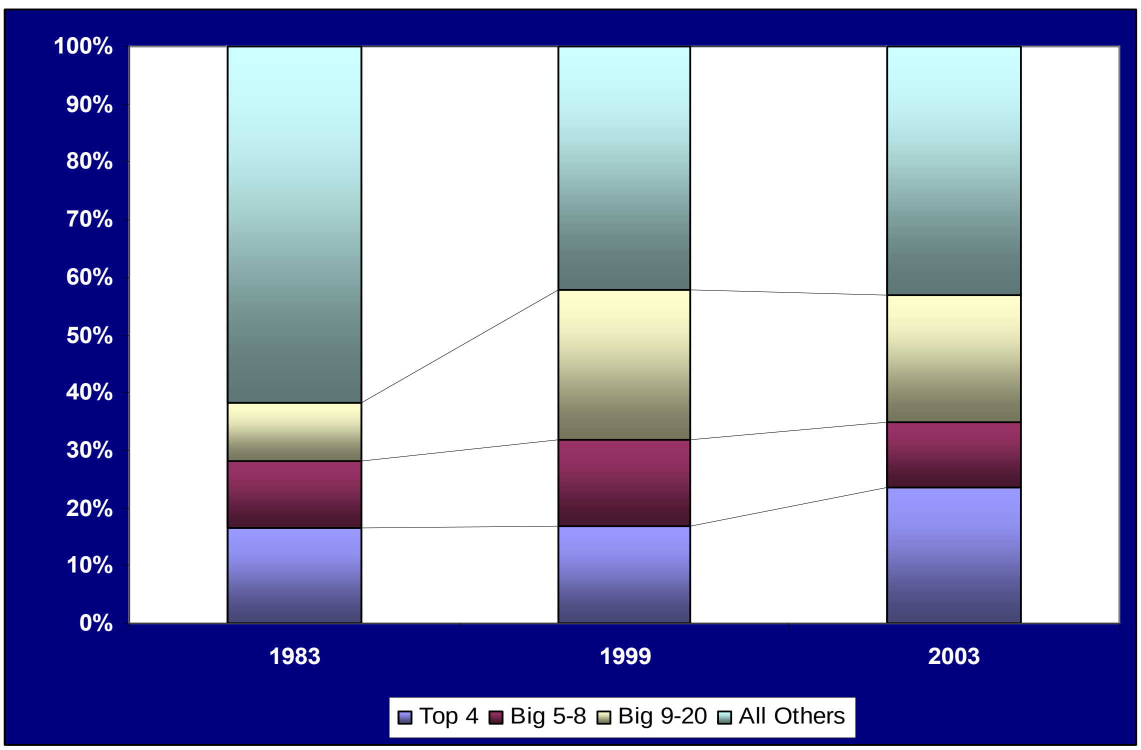

Figure 4. Inventory of Leases Owned and Controlled by 2003 Top Firms for Leases Issued in the U.S. Gulf of Mexico OCS from 1983 to 1999—MMS ID.

3.2.2. High Bonus Bid Value: The signature bonus paid by oil and gas firms to obtain a right to explore and develop a lease represents the initial cash payment by the winning bidders to the U.S. government. According to several previous studies of MMS lease data, the bonus value depends on several factors, including the perceived worth of the lease measured in terms of the anticipated hydrocarbon reserves and production potential, bidding structure (single bid versus multiple bids), and conduct (solo venture or joint venture). Geology in terms of water depth and economics in terms of prices and costs have also been found to influence the high bonus value (Mead and Sorensen, 1980; Iledare et al., 2004).

According to Figure 5, the aggregate value of high bonus paid per lease from 1983-1999 was $1.208 million. If leases were won through joint venture bidding, the aggregate value of the high bonus bid per lease was $1.943 million per lease, more than twice the average value for leases with solo venture bids. The aggregate bid value per lease for leases receiving at least two bids was more than three times the high bonus bid value per lease for single bid leases. These aggregate lease data seem to suggest that, on average, the top twenty firms tend to pay less signature bonus per lease than do other firms during this study period. Also we found that, on average, independent producers tend to pay less than integrated producers for leases issued from 1983 to 1999.

Table 1 portrays the trend in lease bonus payments for 1983-1999. The table shows a declining trend in the value of high bonus bids over the period. Prior to the collapse of the global oil prices in 1986, the aggregate average value of high bonus bid per lease was $3.223 million. This represents nearly two and a half times the 1986 bid value per lease and nearly five times the three-year average value per lease subsequent to the collapse and in the 1990s. It is interesting to note that the trend in bid value per lease follows a similar pattern for all categories of leases with the exception of leases with high bid bonus values of at least $1 million per lease. The value per lease in this category of leases has increased since the 1986 collapse of the world oil price.

3.2.3. Rental Payments: As mentioned in Section 2, rentals represent payments by lease owners to the government to defer E&P operations on the lease for at least one year. Aggregate rentals offer an insight into the lag between leasing and exploration and development activity on a lease. Low rentals signified prompt development effort on a lease. Figure 6 presents the annual trend in aggregate rental payment per lease for leases issued from 1983 to 1999 in the Gulf of Mexico OCS. Rentals per lease declined steadily from 1986 until 1992, a plausible indication of increasing expeditious development, *ceteris paribus*, during the period. However, rentals rose significantly in the 1990s relative to rental payments in the 1980s. Table 2 shows the five-year average rental value per lease by lease category. Rental payments in all lease categories exhibit rising trends in the 1990s.

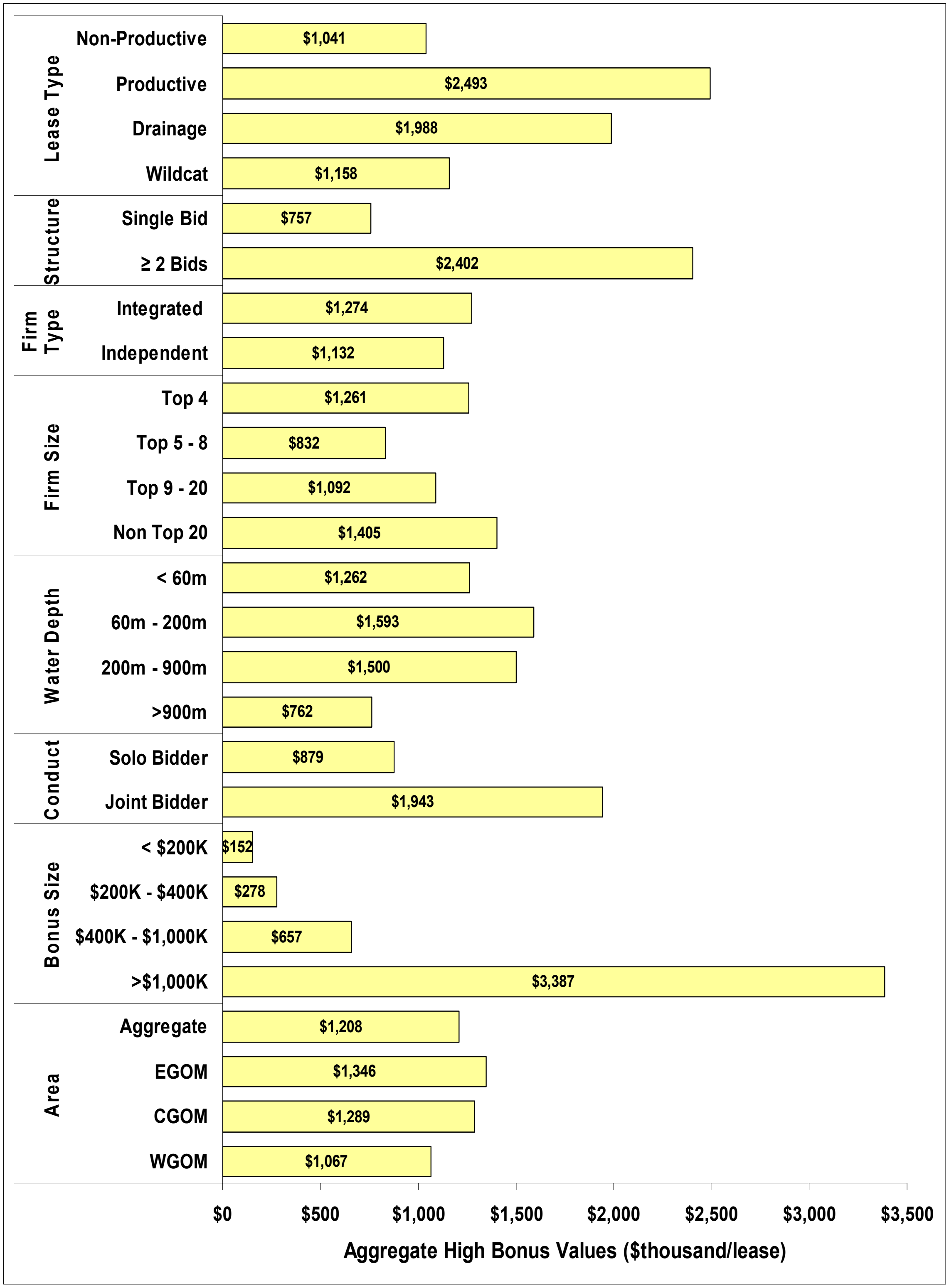

Figure 5. Aggregate High Bonus Values for OCS Leases Issued from 1983 to 1999 ($thousand/lease).

Table 1

Aggregate Average Value of High Bonus Bids per Lease, 1983-1999 ($thousand/lease)

Group	**Lease Category**	**1983-1985**	**1986**	**1987-1989**	**1990-1999**
Lease Type	*Drainage*	$3,616	$1,387	$1,480	$1,424
	Non-Productive	$2,899	$1,217	$562	$587
	Productive	$4,793	$1,844	$1,468	$1,168
	Wildcat	$3,182	$1,269	$579	$632
Structure	*Single Bid*	$2,110	$1,205	$481	$423
	≥ 2 Bids	$5,706	$1,967	$1,237	$1,302
Firm Type	*Integrated*	$3,380	$1,219	$643	$670
	Independent	$3,041	$1,493	$700	$653
Firm Size	*Top 4*	$3,588	$1,203	$617	$538
	Top 5 - 8	$3,089	$790	$300	$472
	Top 9 - 20	$2,122	$1,673	$735	$847
	Non Top 20	$3,453	$1,736	$872	$718
Water Depth	*< 60m*	$3,205	$1,314	$758	$514
	60m - 200m	$3,509	$1,445	$913	$730
	200m - 900m	$3,549	$1,186	$577	$639
	>900m	$1,478	$1,217	$434	$586
Conduct	*Solo Bidder*	$2,899	$1,286	$574	$546
	Joint Bidder	$3,579	$1,397	$955	$928
Bonus Size	*< $200K*	$75	$79	$154	$149
	$200K - $400K	$291	$354	$275	$278
	$400K - $1,000K	$854	$873	$637	$604
	>$1,000K	$3,816	$1,747	$2,287	$2,601
Area	*Aggregate*	$3,223	$1,307	$664	$641
	EGOM	$662	$1,270	$1,324	$41
	CGOM	$3,655	$1,290	$720	$662
	WGOM	$2,626	$1,386	$559	$600

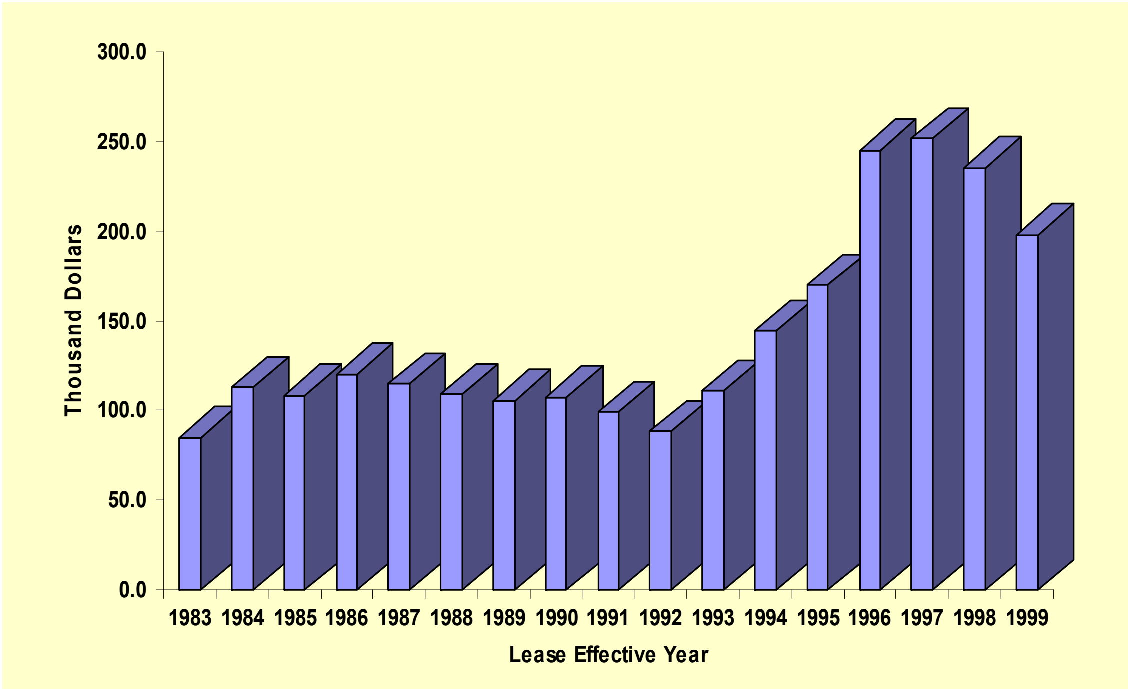

Figure 6. Trend in Aggregate Average Rental for OCS Leases Issued from 1983 to 1999 ($thousand/lease).

<u>3.2.4. Expeditious Lease Development Index:</u> Table 3 reports in months the time interval from lease sale to first drilling activity (spud) and from spud to first production by lease category. These measures are called expeditious development indices. The indices offer insights into how lease owners perceive the economic potential of a given lease. If lease owners are rational economic beings, then leases with expected high cost of development will be delayed for action. This is evident in Figure 7. It took, on average, 77.3 months from effective lease sale time to spud a well on deepwater leases. In contrast, it took on average 26.3 months on leases in the shelf (water depth of 0-200 meters) for all leases issued from 1983 to 1999. It is, of course, important to keep in mind that deepwater drilling requires more complex planning than drilling in the shelf.

The timing of lease sales is also important. The global market conditions do affect rig availability and hence the delay in activity on leases in petroleum producing regions of the world, including the Gulf of Mexico OCS. Figure 8 depicts the aggregate trend in expeditious lease development indices for leases issued from 1983 to 1999. On average, it took about 34 months to spud on leases sold in 1983. In comparison it took approximately 24 months on average to spud a well on leases sold in 1999. Figure 7 portrays a declining trend in the lag between sales and drilling the first well and the lag between drilling and production. This declining trend is also evident in Table 3 for all lease categories. On average, the time to first production after drilling on leases sold in 1983 was approximately 46.5 months. However, the time to production after drilling on average was 15.8 months for leases sold in 1999 as of 2004.

Table 2

Trend in Average Rental Value by Lease Category, 1983-1999
($thousand/lease)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	$115	$112	$123	$164
	Non-Productive	$113	$116	$115	$229
	Productive	$81	$84	$84	$126
	Wildcat	$104	$110	$108	$221
Structure	*Single Bid*	$103	$108	$110	$224
	≥ 2 Bids	$97	$103	$98	$208
Firm Type	*Integrated*	$117	$128	$136	$262
	Independent	$92	$85	$94	$188
Firm Size	*Top 4*	$118	$131	$148	$264
	Top 5 - 8	$92	$80	$82	$187
	Top 9 - 20	$89	$87	$107	$238
	Non Top 20	$103	$95	$95	$183
Water Depth	*< 60m*	$87	$86	$94	$132
	60m - 200m	$102	$98	$93	$134
	200m - 900m	$114	$110	$131	$233
	>900m	$183	$167	$206	$300
Conduct	*Solo Bidder*	$97	$107	$108	$216
	Joint Bidder	$97	$103	$98	$208
Bonus Size	*< $200K*	$31	$69	$105	$198
	$200K - $400K	$46	$81	$115	$232
	$400K - $1,000K	$103	$108	$103	$227
	>$1,000K	$99	$100	$99	$213
Area	*Aggregate*	$108	$112	$110	$220
	EGOM	$111	$170	$46	$0
	CGOM	$100	$106	$102	$213
	WGOM	$103	$107	$120	$232

Table 3

Expeditious Development Index:
(months from sales to spud and spud to production)

Group	Lease Category	1983-87	1985-1989	1990-1994	1995-1999
A: Time from Sale to Spud					
Lease Type	*Wildcat*	36.4	40.0	32.2	29.7
	Drainage	29.7	28.7	39.5	18.9
Firm Type	*Integrated*	50.5	62.4	44.2	39.3
	Independent	33.2	31.6	27.8	27.4
Firm Size	*Top 4*	51.9	66.5	46.8	42.9
	Top 5 - 8	42.8	48.7	41.2	30.9
	Top 9 - 20	42.2	43.6	37.5	32.5
	Non Top 20	31.3	29.6	25.0	26.7
Water Depth	*< 60m*	29.3	27.8	25.8	22.9
	60m - 200m	30.5	31.0	36.0	27.2
	200m - 900m	40.4	46.4	42.9	30.0
	>900m	84.9	93.3	84.2	53.6
Conduct	*Solo Bidder*	32.8	37.3	32.4	28.7
	Joint Bidder	37.9	38.3	29.8	30.9
B: Time from Spud to Production					
Lease Type	*Wildcat*	47.0	39.9	22.3	21.1
	Drainage	26.7	27.2	33.8	11.6
Firm Type	*Integrated*	59.7	56.9	26.5	21.9
	Independent	38.4	29.6	28.4	20.6
Firm Size	*Top 4*	63.3	60.9	26.9	22.8
	Top 5 - 8	39.5	33.3	22.7	21.7
	Top 9 - 20	41.6	31.4	28.3	22.0
	Non-Top-20	38.1	29.7	29.2	20.2
Water Depth	*<60m*	29.7	25.4	23.7	18.2
	60m - 200m	44.2	34.7	24.3	20.3
	200m - 900m	87.7	76.6	27.3	24.1
	>900m	95.7	83.6	21.7	46.0
Conduct	*Solo Bidder*	41.8	38.2	20.3	20.2
	Joint Bidder	44.7	36.5	30.5	20.9

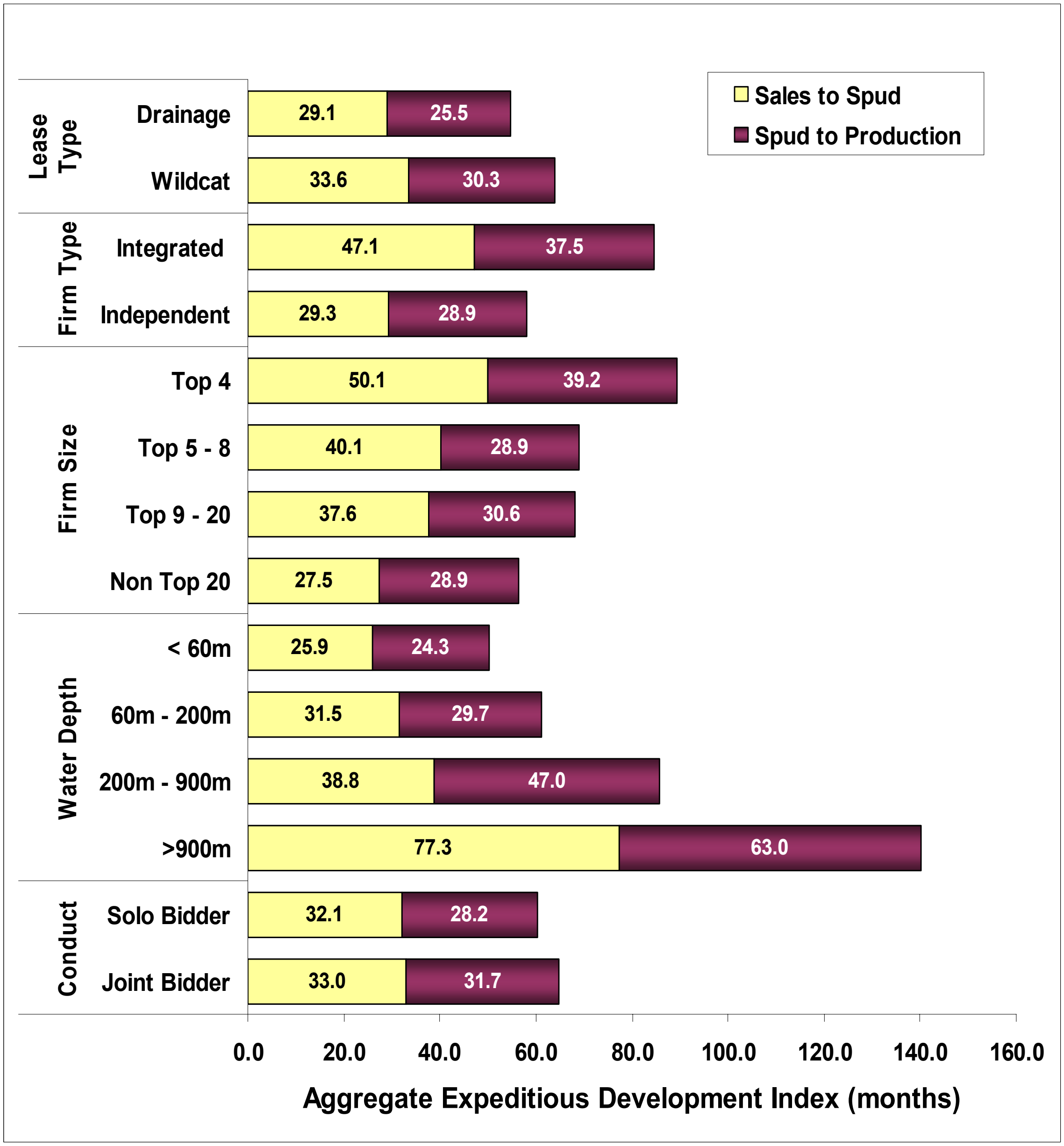

Figure 7. Aggregate Expeditious Development Index, 1983-1999 Leases: Length of Time to Spud and Produce Hydrocarbons by Lease Category.

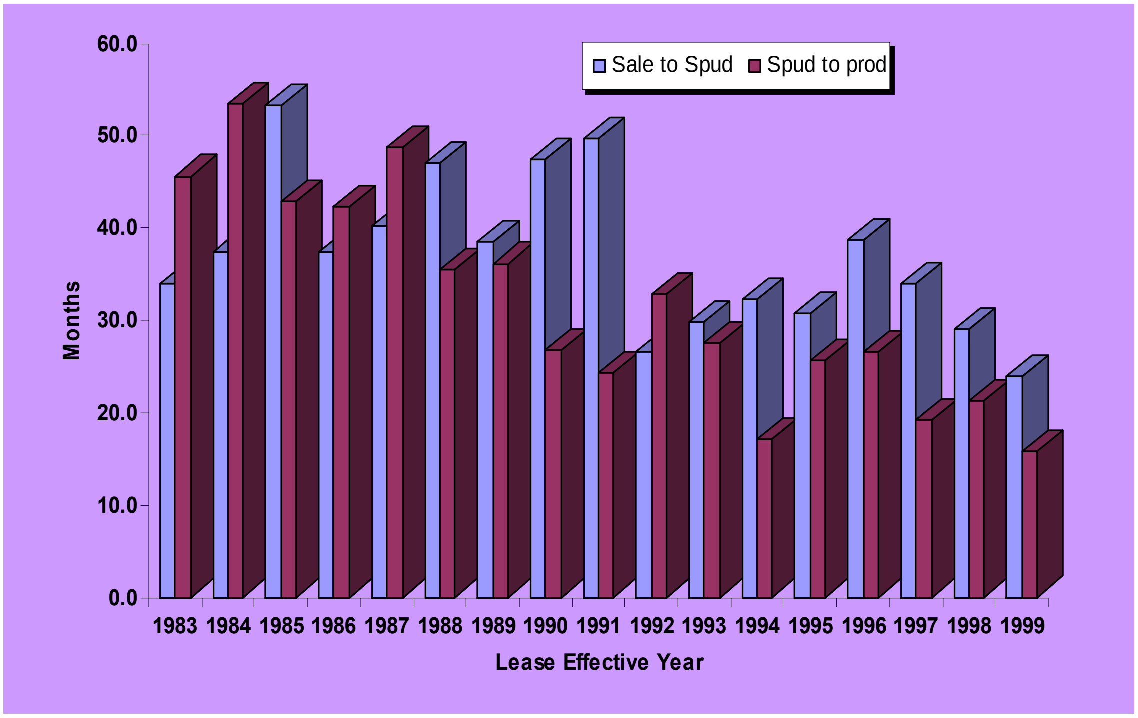

Figure 8. Trend in Aggregate Average Length of Time to Spud and Produce Hydrocarbons on 1983-1999 Leases.

3.3. Gross Revenue & Costs Estimation

This section presents estimated gross revenue from productive leases for OCS leases issued from 1983 to 1999. The estimated lease development costs (which typically consist of drilling costs, production/processing facility installation costs, operating costs, and transportation/evacuation costs) are also reviewed and analyzed in this section. Estimates were made of these technical costs from published reports and records in the absence of publicly available proprietary lease specific cost and revenue data. Data series for revenue and all costs are reported in nominal dollars for the purpose of this report.

3.3.1. Estimated Ultimate Value of Petroleum Production: Since royalty data is proprietary, we have estimated lease specific revenue by multiplying historical annual oil and natural gas production by historical average annual oil and natural gas prices. We used the average annual domestic crude oil first purchase price for Federal offshore published by the EIA. The natural gas price used for estimating gas revenue is Louisiana natural gas wellhead price, also published by the EIA. Revenue based solely on stocks of leases issued from 1983 to 1999, which produced hydrocarbons beyond the historical period (1983-2004) was estimated as a product of projected production and hydrocarbon prices forecasted by the EIA office of oil and gas.

We projected annual oil and gas production using the constant percentage decline equation (Seba, 2003):

$$Q_t = Q_{t-1} * e^{-a\,t}, \qquad (7)$$

where,

Q_t = annual production rate for year t
a = the nominal decline rate, such that for t=1
$e^{-a} = 1 - D = (Q_t / Q_{t-1})$

where,

D = effective decline rate.

We estimated the effective decline rate for leases by water depth. We identified the maximum production in each water depth category and calculated the annual effective rate of decline in subsequent years after peak production. Future production is predicted for each lease using the depth designated decline rate until a stipulated depletion criterion has been satisfied. The depletion criterion is set such that cumulative production does not exceed estimated ultimate recovery (EUR) and leases are shut down when net cash flow is negative in the projection period. For the purpose of this report, EUR is defined as maximum annual production per lease divided by designated effective decline rate for the lease (Iledare and Pulsipher, 2001).

The estimated ultimate gross revenue per productive lease (projected and historical) by lease category is presented in Figure 9. These values are calculated based on the EUR per lease, which helps us to project a year when production on a lease would be terminated. It must be reiterated that the value per lease is calculated for leases issued from 1983 to 1999. In addition, such a lease must have produced hydrocarbon fluids during the historical period of our analysis, 1983-2004. The five-year average trend on the basis of lease effective year by lease category is presented in Table 4 and the overall aggregate average trend by lease effective year is presented in Figure 10.

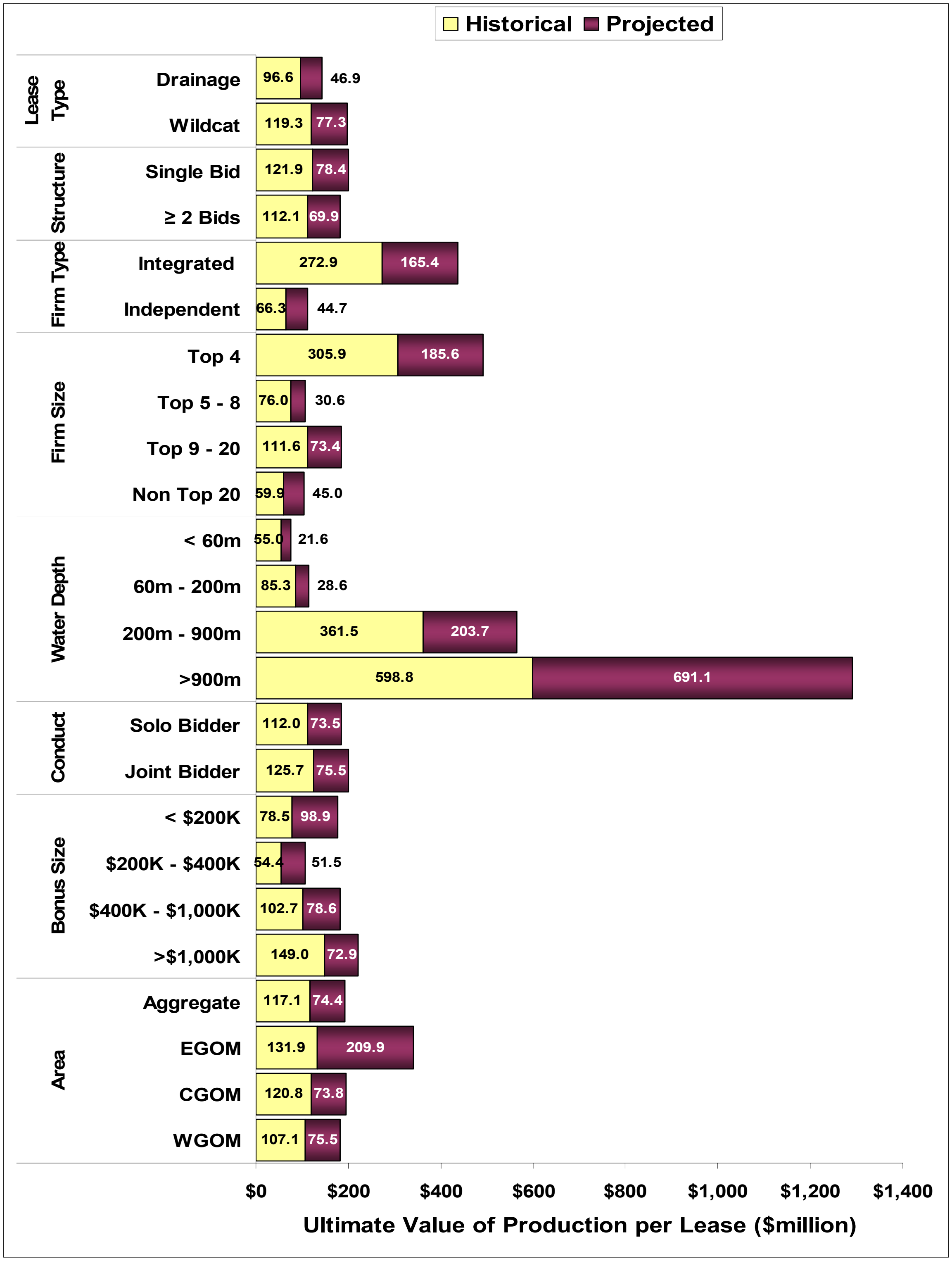

Figure 9. Estimated Ultimate Value of Production per Lease for Productive OCS Leases Issued from 1983 to 1999 ($million).

Table 4

Trend in Estimated Ultimate Value by Lease Category, 1983-1999
(five-year average in $million/productive lease)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	$84.1	$82.8	$110.0	$330.4
	Wildcat	$275.8	$253.0	$152.4	$155.8
Structure	*Single Bid*	$276.8	$249.4	$146.1	$117.2
	≥ 2 Bids	$168.4	$147.2	$144.5	$200.2
Firm Type	*Integrated*	$522.0	$531.3	$336.6	$289.5
	Independent	$86.0	$73.9	$102.7	$147.8
Firm Size	*Top 4*	$608.1	$618.2	$444.6	$263.0
	Top 5 - 8	$108.1	$89.5	$80.1	$97.2
	Top 9 - 20	$160.3	$134.4	$233.4	$254.7
	Non Top 20	$75.9	$69.4	$85.7	$147.0
Water Depth	*< 60m*	$60.8	$55.5	$68.8	$84.4
	60m - 200m	$130.0	$120.3	$88.7	$64.5
	200m - 900m	$772.0	$665.6	$440.2	$351.9
	>900m	$1,523.7	$1,054.3	$1,680.3	$701.4
Conduct	*Solo Bidder*	$261.9	$241.9	$155.2	$145.8
	Joint Bidder	$221.3	$187.2	$129.8	$210.4
Bonus Size	*< $200K*	$169.7	$261.3	$114.0	$96.5
	$200K - $400K	$64.4	$87.6	$69.1	$129.4
	$400K - $1,000K	$239.9	$180.5	$185.8	$127.5
	>$1,000K	$217.7	$193.9	$179.4	$221.8
Area	*Aggregate*	$241.8	$218.1	$149.1	$166.6
	EGOM	$5.9	$130.8	$0.0	$0.0
	CGOM	$257.6	$226.7	$156.1	$163.3
	WGOM	$194.9	$185.9	$149.2	$187.5

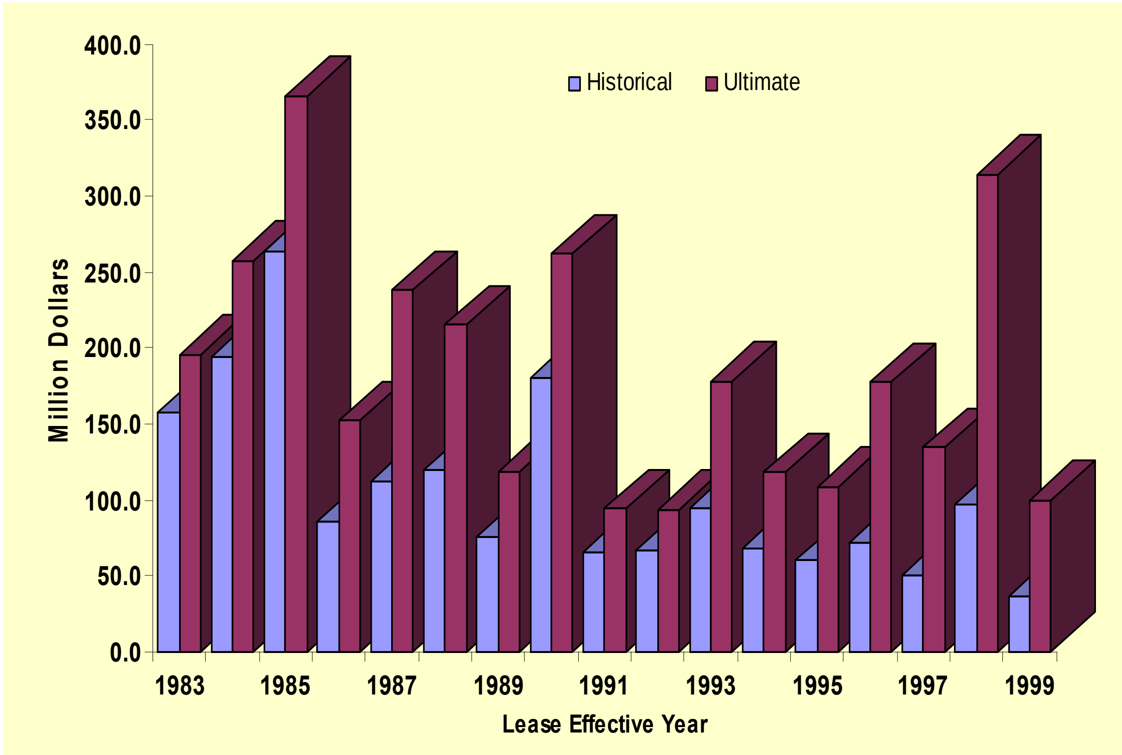

Figure 10. Trend in Aggregate Value of Petroleum Production per Productive Lease for Leases Issued in the Gulf of Mexico OCS Region from 1983 to 1999.

Figure 9 shows that the ultimate aggregate value of production per lease for OCS productive leases issued from 1983 to 1999 was $191.5 million. The average value of production per lease by year end 2004, however, was $117.1 million. For leases won through joint venture bidding, aggregate value of production as of 2004 was $125.7 million per productive lease, about 10 percent higher than the aggregate production value for productive leases with solo venture bids. The estimated ultimate value per lease for joint venture leases was $201.2 million.

The aggregate production value for productive leases receiving at least two bids was less than the production value per lease for single bid leases, on average. In an aggregate sense, the lease data seems to suggest that, on average, integrated firms generated significantly more revenue per lease than independent firms during this study period. The supposition can be avowed with respect to the estimated value of production per lease at the projected end of OCS leases issued from 1983 to 1999.

The ultimate value of petroleum production per lease in the Gulf of Mexico OCS (0-200 meters) region was less than $200 million in the aggregate per productive lease. The value per productive lease in the OCS slope (200-900 meters), on the other hand, was about $565 million for leases issued from 1983 to 1999. The records show that the value of production for deepwater leases issued during this period was about $1.29 billion per productive lease.

Table 4 shows the trend in the ultimate value of production for different categories of leases issued from 1983 to 1999. The trend portrayed is by lease effective year. The table shows no distinctive trend in the aggregate ultimate value of production over the period (see also Figure 10). However, the five-year average aggregate ultimate value per productive lease increases with water depth for all lease effective periods. The rising trend is also evident with respect to high bonus size. The records in Table 4 suggest that the aggregate average value of production per lease rises with rising high bonus, *ceteris paribus*. The Central Gulf (CGOM) planning area has a higher ultimate production value per lease in an aggregate sense than in the Western Gulf (WGOM) planning area. The only exception is for leases issued from 1995 to 1999.

3.3.2. Costs of Drilling and Development of Oil & Gas Leases: The task of estimating the total development costs on a lease-specific basis was arduous. Instead, we chose to view all development cost components—drilling and completion, production infrastructures and operating expenses—as aggregated averages for each lease category.

Drilling Costs. We developed drilling cost estimates using Joint Association Survey of the U.S. Oil and Gas Producing Industry (JAS) of drilling costs. JAS reports well drilling costs for various areas of the U.S. by year, type, and depth category. Data on Federal Offshore Louisiana only began to appear separately in 1991. Prior to 1991, the data was combined with Louisiana state offshore data. A close examination of the relationship between Louisiana state offshore drilling cost per foot and Federal offshore drilling cost per foot reveals some near perfect correlations. Thus, in order to preserve data continuity, we used drilling cost data for the entire Louisiana offshore waters.

Further, JAS reports drilling costs for 11 different well depth ranges and for four different types of wells—dry, oil, gas, and total. The costs of drilling a gas well on a lease are generally higher than the costs to drill an oil well on a lease. In addition, the costs of drilling a dry well are significantly less than the costs of drilling either an oil or gas well. For the purpose of this report, we have classified leases and wells with no production on leases issued between 1983 and 1999 as of December 31, 2004 as dry. Wells with reported production were classified as gas if the volume of gas produced over the entire well production history in BOE is greater than the volume of oil produced in BOE. Otherwise, such a well or lease was classified as an oil producer.

Using MMS well production and borehole information data, we classified wells accordingly and developed two cost estimates. The first estimates were based on JAS total drilling costs per well. Wells of the same type and of the same depth range were assigned the same costs from JAS data. The second drilling cost estimates were based on the actual footage drilled per well. In this case, the reported cost per foot by well type, depth range and year was multiplied by the actual well footage drilled. For the purpose of this report we used the average of the two cost estimates.

Figure 11 presents the aggregate average drilling costs by lease category for leases issued from 1983 to 1999. The dynamics of drilling costs per lease are presented in Table 5. The aggregate and annual estimated drilling trends are presented in Figure 12.

As expected, drilling expenditures per lease increase with depth. The cost of drilling per lease on the OCS also rises with time as evident in Table 5. This also is not surprising. Rig utilization in the most recent period is at a higher rate than the previous ones as offshore daily rig costs continue to climb. For nearly all categories of leases the estimated drilling costs per lease from 1995 to 1999 are significantly higher, on average, than the costs in previous periods.

Facility Installation and Removal Costs. MMS Study 2003-018 (Dismukes et al., 2003) reported platform installation costs for four water depth categories. The depth categories are the shelf (0-60 meters and 60-200 meters); the slope (200-900 meters); and the deep (>900 meters). We developed a deflator index from EIA production platform operating costs. This index expresses the annual operating costs from 1983 to 1999 as a fraction of the 1999 operating costs. This constructed index was then used to extrapolate the 1999 platform costs for the entire period.

We have imposed the implicit assumption that the temporal dynamics of platform installation costs follow a similar pattern with the operating costs dynamic. The trend in estimated costs of platforms that we imposed in subsequent analysis is presented in Table 6. These platform cost variations are based on water depth variation and no consideration has been given to platform size.

The MMS study cited above also reported platform removal costs for four water depth categories. We projected platform removal costs using the operating platform expenditure index. We adopted the standard removal practice for lack of enough data on platform removal methods and calculated the removal costs we used in this report as the weighted average of the four pile and eight pile costs.

The trend in estimated platform installation cost per lease, in an aggregate sense, is presented in Figure 13. There was a decline trend in our estimates in the early 1980s until the collapse of crude oil prices in 1986. Subsequently, the estimated platform installation cost rose steadily to its highest value in 1994 and leveled off, on average, from 1995-1998.

Table 7 presents the estimated platform removal costs we imposed for subsequent analysis and Figure 14 presents the trend in the estimated aggregate platform removal costs per lease over the study period by lease effective year. The values reported in Table 7 are removal costs per lease for leases issued during the period by lease category. For example, the aggregate platform removal cost per lease for leases issued from 1983 to 1987 was estimated as $2.258 million and $2.008 million for leases issued from 1995 to 1999.

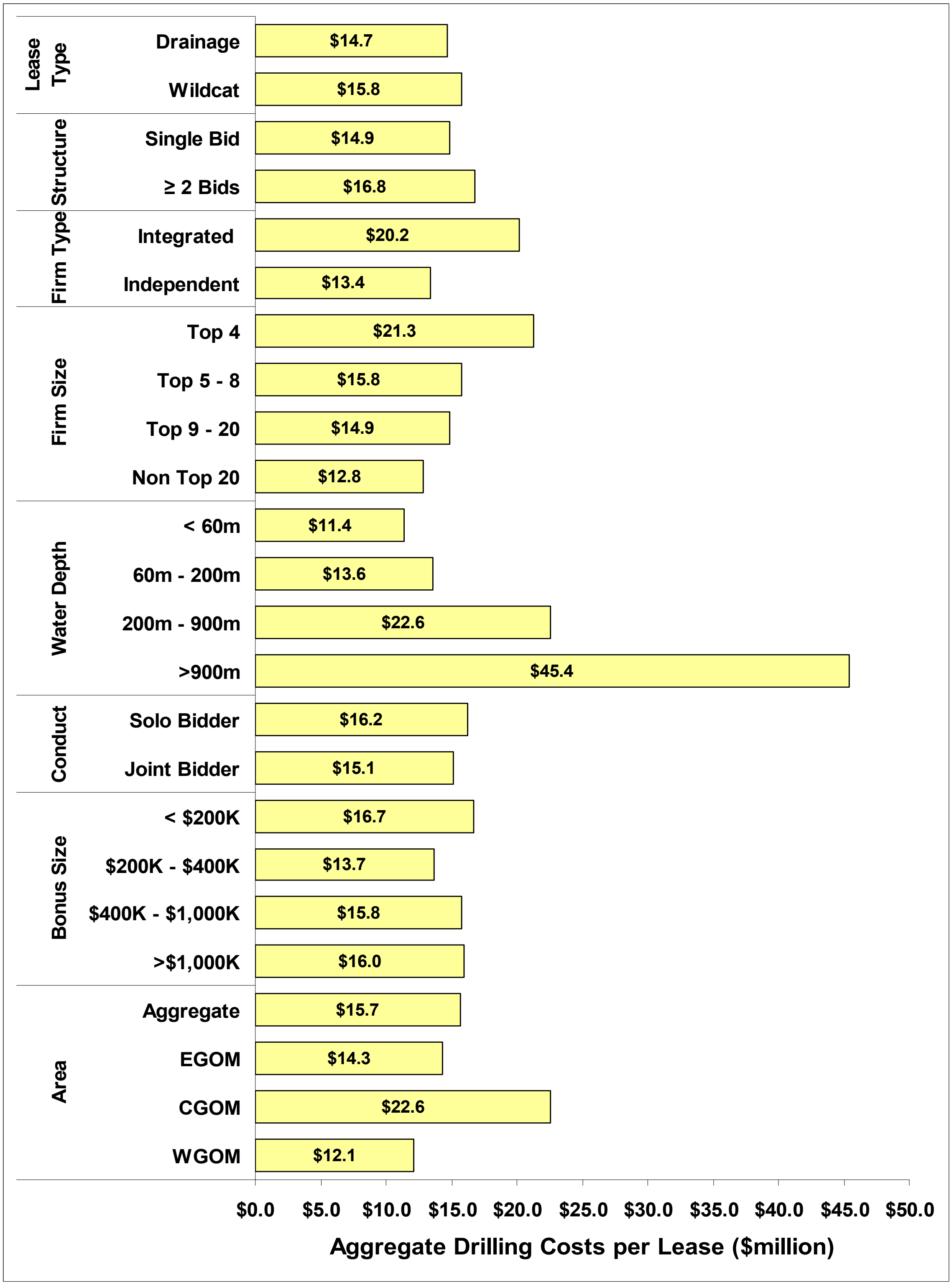

Figure 11. Estimated Aggregate Drilling Costs per Lease for OCS Leases Issued from 1983 to 1999.

Table 5

Trend in Estimated Aggregate Drilling Costs by Lease Category, 1983-1999 (five-year average in $million/lease)

Group	**Lease Category**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**
Lease Type	*Drainage*	$11.939	$13.747	$15.266	$27.043
	Wildcat	$13.825	$15.997	$14.875	$19.614
Structure	*Single Bid*	$12.975	$16.091	$13.887	$17.849
	≥ 2 Bids	$14.552	$14.829	$16.315	$21.369
Firm Type	*Integrated*	$16.703	$23.792	$21.832	$25.166
	Independent	$10.659	$10.390	$12.575	$18.381
Firm Size	*Top 4*	$18.028	$25.530	$22.858	$25.285
	Top 5 - 8	$12.398	$13.472	$14.100	$20.119
	Top 9 - 20	$9.513	$12.359	$17.143	$22.002
	Non Top 20	$11.366	$10.486	$11.401	$17.166
Water Depth	*< 60m*	$11.865	$11.519	$11.247	$15.606
	60m - 200m	$11.963	$11.652	$15.249	$15.648
	200m - 900m	$19.872	$35.165	$25.442	$22.817
	>900m	$43.932	$46.435	$56.469	$40.668
Conduct	*Solo Bidder*	$14.516	$16.554	$15.728	$18.210
	Joint Bidder	$12.762	$13.724	$13.027	$22.868
Bonus Size	*< $200K*	$16.411	$18.773	$16.385	$15.037
	$200K - $400K	$10.043	$12.535	$11.643	$16.830
	$400K - $1,000K	$12.992	$13.814	$14.161	$20.086
	>$1,000K	$13.715	$16.388	$17.884	$23.019
Area	*Aggregate*	$13.604	$15.655	$14.895	$19.750
	EGOM	$13.640	$18.743	$0.000	$0.000
	CGOM	$15.659	$17.012	$16.839	$20.224
	WGOM	$9.882	$12.764	$9.186	$21.619

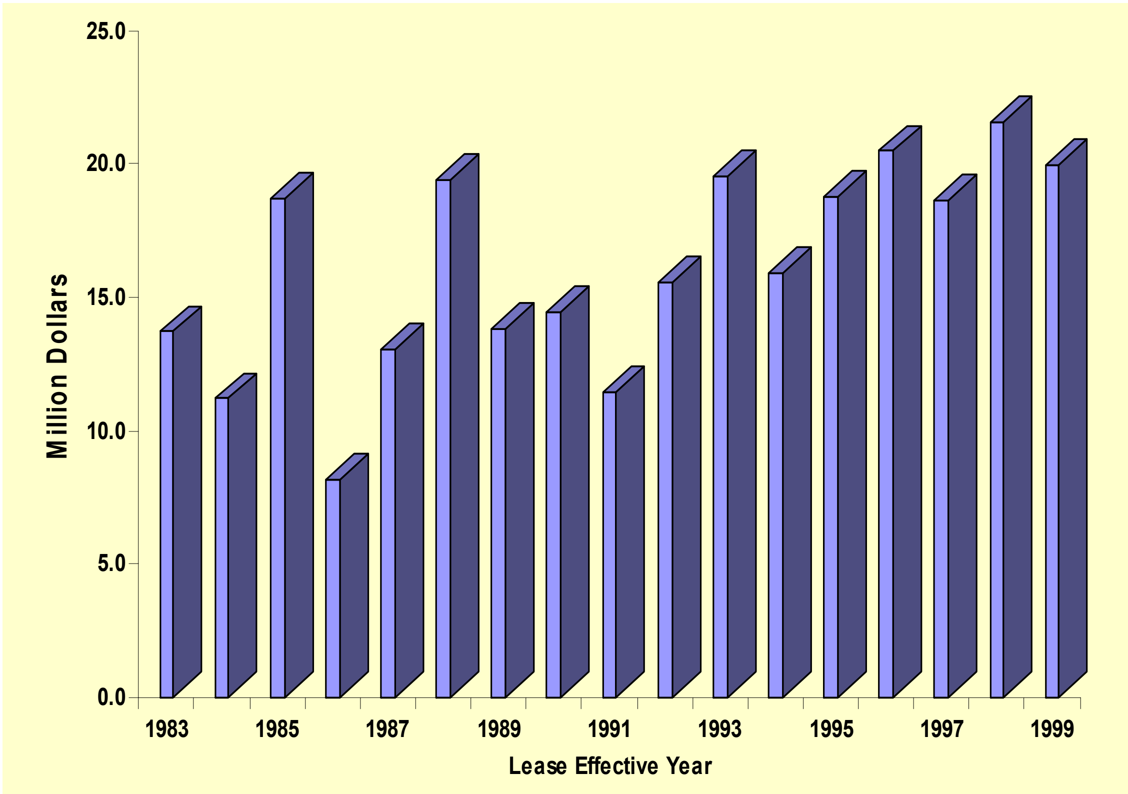

Figure 12. Trends in Aggregate Estimated Drilling Costs per Lease for Leases Issued in the Gulf of Mexico OCS Region from 1983 to 1999.

Table 6

Trend in Estimated Total Platform Installation Costs, 1983-1999
($million)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	$19.683	$21.390	$19.602	$37.729
	Wildcat	$23.122	$21.128	$26.217	$25.172
Structure	*Single Bid*	$21.998	$19.033	$23.608	$21.837
	≥ 2 Bids	$23.510	$24.377	$28.108	$28.192
Firm Type	*Integrated*	$27.067	$17.325	$26.762	$16.973
	Independent	$20.092	$22.672	$25.612	$27.007
Firm Size	*Top 4*	$27.834	$17.754	$24.997	$16.986
	Top 5 - 8	$18.550	$21.225	$26.185	$23.053
	Top 9 - 20	$17.552	$23.681	$30.333	$26.472
	Non Top 20	$22.928	$21.495	$23.738	$27.592
Water Depth	*< 60m*	$19.812	$19.470	$19.960	$21.659
	60m - 200m	$32.465	$35.871	$43.435	$44.612
	200m - 900m	$32.072	$22.956	$33.694	$18.870
	>900m	$19.205	$8.096	$21.460	$23.811
Conduct	*Solo Bidder*	$21.963	$22.370	$25.335	$23.776
	Joint Bidder	$23.379	$18.768	$26.805	$29.421
Bonus Size	*< $200K*	$15.812	$15.258	$25.759	$20.502
	$200K - $400K	$14.900	$17.388	$20.153	$20.806
	$400K - $1,000K	$19.997	$17.814	$25.976	$23.993
	>$1,000K	$23.481	$24.533	$30.419	$31.649
Area	*Aggregate*	$22.654	$21.176	$25.776	$25.545
	EGOM	$19.977	$19.997		
	CGOM	$23.723	$21.930	$26.269	$27.303
	WGOM	$20.395	$19.558	$23.978	$20.057

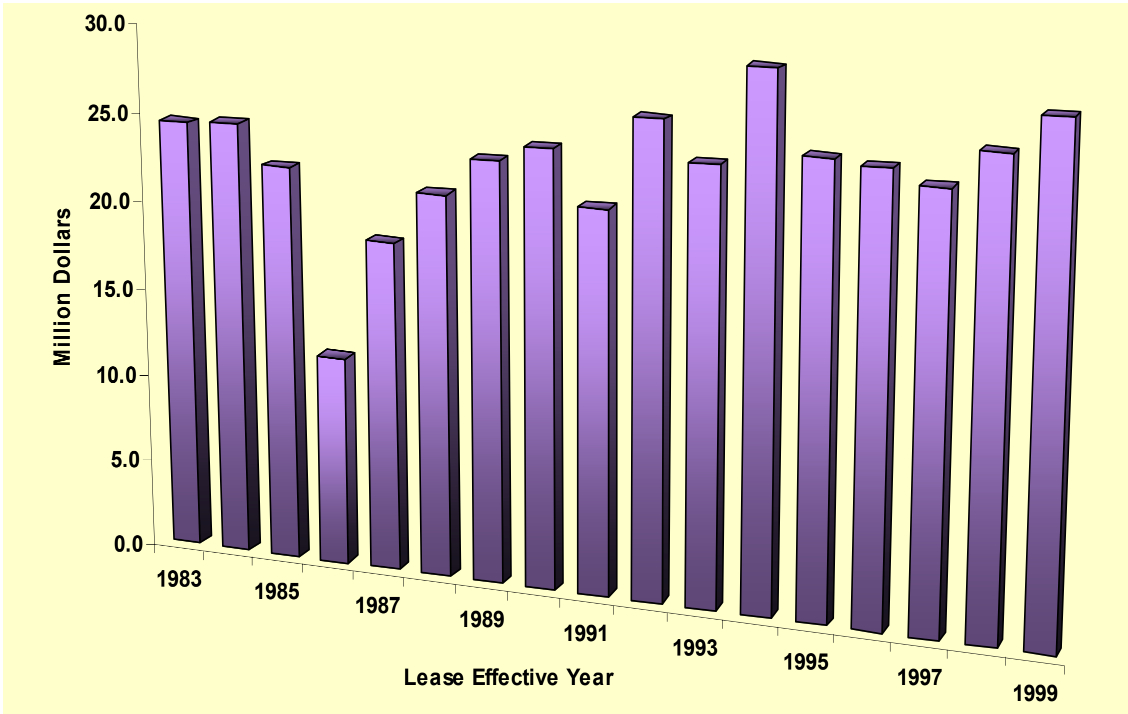

Figure 13. Estimated Aggregate Platform Installation Costs per Lease from 1983 to 1999.

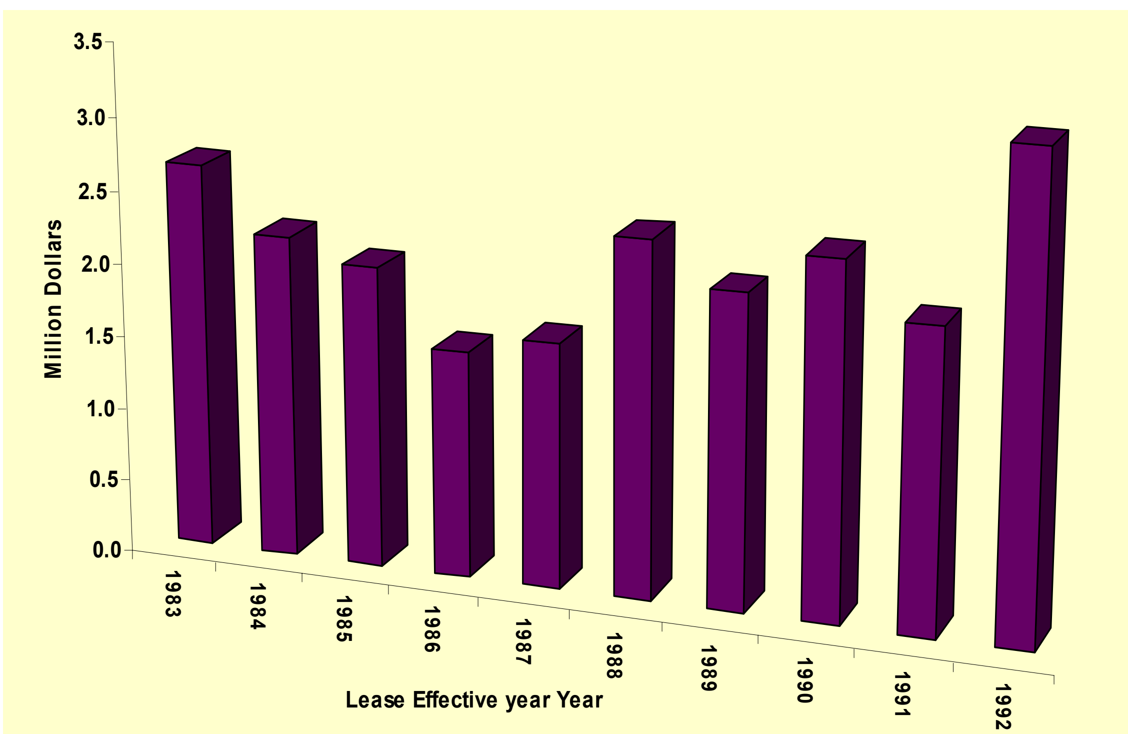

Figure 14. Trend in Aggregate Removal Cost per Lease for Leases Issued from 1983 to 1999.

Table 7

Estimated Platform Removal Expenditures for Leases Issued from 1983 to 1999 ($million)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	$2.227	$2.407	$2.294	$2.299
	Wildcat	$2.263	$1.968	$2.460	$1.999
Structure	*Single Bid*	$2.054	$1.706	$2.040	$1.767
	≥ 2 Bids	$2.522	$2.552	$2.888	$2.180
Firm Type	*Integrated*	$1.612	$0.954	$1.681	$0.892
	Independent	$2.628	$2.483	$2.631	$2.197
Firm Size	*Top 4*	$1.657	$0.829	$1.523	$1.005
	Top 5 - 8	$2.261	$1.823	$1.600	$1.860
	Top 9 - 20	$1.933	$1.998	$2.637	$1.362
	Non Top 20	$2.894	$2.679	$2.857	$2.442
Water Depth	*< 60m*	$2.468	$2.398	$2.714	$2.612
	60m - 200m	$1.907	$2.180	$2.217	$1.846
	200m - 900m	$2.577	$1.228	$2.108	$0.601
	>900m	$0.419	$0.190	$0.618	$0.221
Conduct	*Solo Bidder*	$2.127	$2.107	$2.440	$1.998
	Joint Bidder	$2.395	$1.937	$2.470	$2.030
Bonus Size	*< $200K*	$0.697	$1.067	$2.186	$1.468
	$200K - $400K	$2.050	$1.637	$2.379	$1.727
	$400K - $1,000K	$1.869	$1.900	$2.445	$2.091
	>$1,000K	$2.373	$2.410	$2.700	$2.344
Area	*Aggregate*	$2.258	$2.048	$2.449	$2.008
	EGOM	$2.047	$0.000	$0.000	$0.000
	CGOM	$2.282	$2.226	$2.506	$2.193
	WGOM	$2.208	$1.643	$2.239	$1.429

3.3.3. Lease Operating Expenditures: The procedure we adopted in this study for estimating operating costs per lease is purely empirical. Typically, the EIA periodically produces reports on platform operating costs. We attempted initially to estimate for every lease the operating costs from EIA data on different types of platforms in water depth of 100 ft to 600 ft. The EIA operating costs assume daily oil production of 11,000 barrels per day and 40,000 Mcf. The resulting estimates yielded an extremely low per unit cost of production in the range of $1.70 per barrel for oil and $0.50 per Mcf for gas. These costs also do not include the costs of transporting oil/gas or the construction of relevant infrastructure.

Hence, to maintain data stability, we estimated lease operating costs (production, evacuation, insurance, fixed costs and overhead) as a fraction of lease equipment and installation costs (Mian, 2002; Johnston, 2003). According to Mian (2002), lease operating expenses can be classified into five elements—production costs, evacuation costs, insurance, maintenance costs and overhead. Mian (2002) also suggests that, on average, production costs can account for about 35 percent of the total operating expenses, while evacuation costs may account for about 23 percent. The other three elements account for 43 percent.

Further, Johnston (2003) suggests that the relationship between operating costs and total capital costs in the Gulf of Mexico shelf can range from 3-5 percent and more than 20 percent in the deepwater. Using this rationale, we developed operating cost coefficients by water depth in dollars per BOE, in order to be able to assign OPEX to every productive lease in the OCS for leases issued from 1983 to 1999.

The trend in estimated lease operating expenditures that we imposed in subsequent analysis is presented in Table 8 by lease category. Figure 15 presents aggregate OPEX imposed on our subsequent analysis by lease category. These estimates have been based on the fixed relationship between operating cost per BOE and platform installation costs per BOE, and they are standardized by water depth. This means that for a given year and at a specified water depth, we imposed a unit cost per BOE for all lease categories producing from this water depth range in that period. Figure 16 presents trends in aggregate lease operating expenditures (historical & projected ultimate) by lease effective year period.

Table 8

Trend in Estimated Lease Operating Expenditures
(five-year average in $million/productive lease)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	\$16.3	\$17.5	\$20.4	\$70.0
	Wildcat	\$59.8	\$53.8	\$30.9	\$31.9
Structure	*Single Bid*	\$59.3	\$53.3	\$29.6	\$23.9
	≥ 2 Bids	\$36.8	\$30.8	\$29.0	\$40.9
Firm Type	*Integrated*	\$114.1	\$115.2	\$73.0	\$64.2
	Independent	\$17.9	\$14.7	\$19.7	\$29.7
Firm Size	*Top 4*	\$133.8	\$134.7	\$96.2	\$55.1
	Top 5 - 8	\$21.9	\$17.9	\$15.7	\$16.7
	Top 9 - 20	\$34.3	\$27.2	\$47.6	\$56.8
	Non Top 20	\$15.4	\$13.7	\$16.3	\$29.8
Water Depth	*< 60m*	\$11.5	\$10.1	\$12.1	\$14.0
	60m - 200m	\$28.8	\$26.1	\$17.8	\$12.9
	200m - 900m	\$170.5	\$145.5	\$99.3	\$80.0
	>900m	\$326.2	\$227.7	\$348.2	\$165.5
Conduct	*Solo Bidder*	\$57.8	\$52.6	\$31.3	\$28.7
	Joint Bidder	\$45.6	\$37.2	\$26.5	\$46.0
Bonus Size	*< \$200K*	\$38.4	\$57.2	\$22.6	\$19.6
	\$200K - \$400K	\$10.7	\$15.0	\$13.1	\$26.0
	\$400K - \$1,000K	\$51.4	\$37.5	\$37.6	\$26.0
	>\$1,000K	\$46.9	\$41.5	\$35.7	\$45.5
Area	*Aggregate*	\$52.2	\$46.4	\$30.2	\$34.3
	EGOM	\$1.1	\$29.9	\$0.0	\$0.0
	CGOM	\$55.3	\$47.8	\$31.7	\$33.2
	WGOM	\$43.2	\$40.7	\$30.0	\$39.9

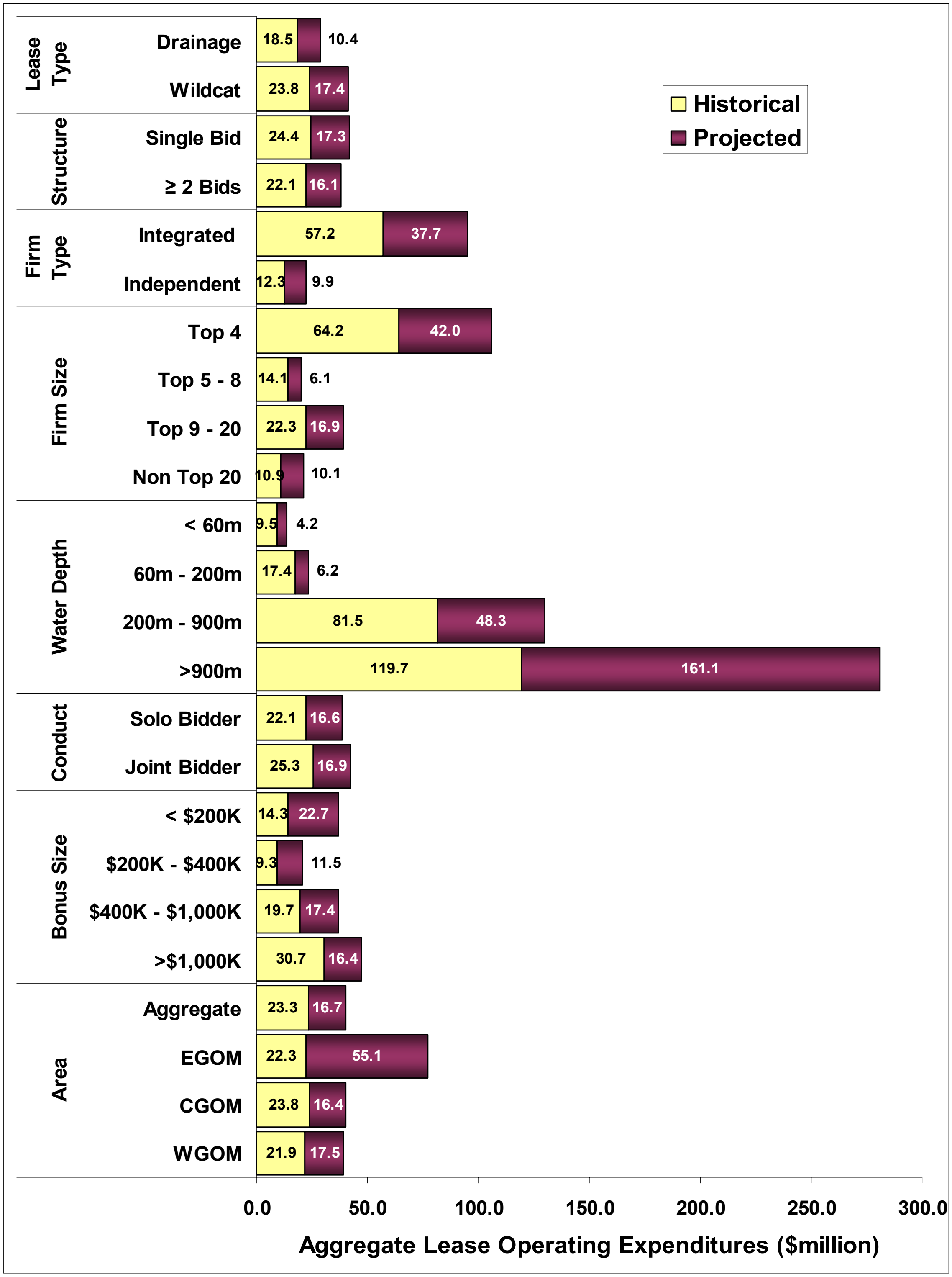

Figure 15. Estimated Aggregate Lease Operating Expenditures for Productive OCS Leases Issued from 1983 to 1999 ($million).

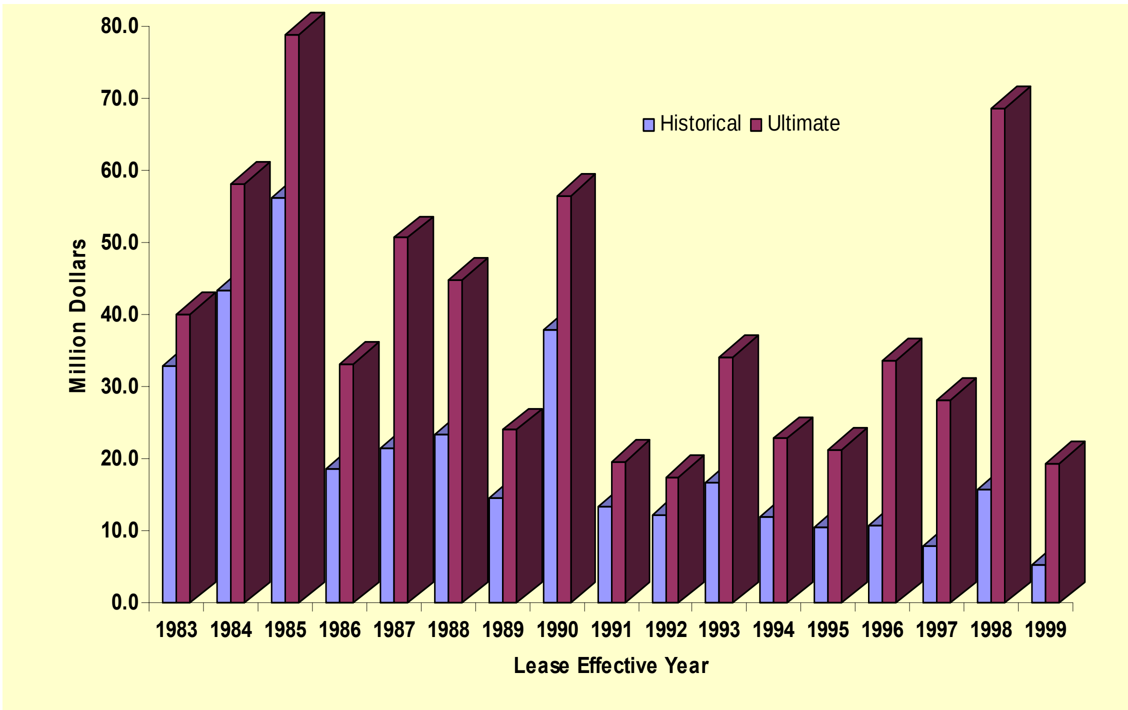

Figure 16. Trends in Aggregate Lease Operating Expenditures per Productive Lease for Leases Issued in the Gulf of Mexico OCS Region from 1983 to 1999.

4. MEASURES OF PERFORMANCE OF OCS LEASE SALES & DEVELOPMENT

4.1. Introduction

Section 4 describes aggregate measures of performance of lease sales and developments in the Gulf of Mexico OCS for leases issued from 1983 to 1999. The measures—prospectivity and productivity indices—described in this section are by no means exhaustive. Thus, for the purpose of this report, we have defined lease sales and development performance in terms of lease prospectivity or productivity and economic indicators. The economic indicators or measurements discussed in this report are all before tax performance parameters.

4.2. Lease Prospectivity and Productivity Analysis

4.2.1. Lease Prospectivity Measures: Prospectivity as a measure of lease sales and development performance in this report is defined first as the ratio of number of leases drilled to number of leases issued, henceforth referred to as drilling ratio. Second, prospectivity is measured as a conditional probability parameter. This measure is subject to the occurrence of drilling activity on the lease over the historical period of the study, 1983-2004. It indicates the proportion of number of leases drilled that are producible or productive, henceforth referred to as drilling success ratio. Finally, we defined an overall lease development index as the multiplicative product of drilled ratio and drilling success ratio.

Figure 17 shows the drilling ratio for leases issued from 1983 to 1999 as well as drilling success ratio by lease category at the end of 2004. In the aggregate sense, 26 percent of leases issued (13,641) from 1983 to 1999 reported some drilling activity by year end 2004. Of the leases (3,547) with reported drilling efforts, 43 percent qualified as producible leases. The overall aggregate lease development index (the product of the proportion of drilled leases and the proportion of successful drilled leases) for leases issued from 1983 to 1999 was 13.8 percent at the end of 2004.

Thirty percent of leases issued during this period in the Central Gulf of Mexico (CGOM) OCS recorded drilling activity and 46 percent of these drilled leases are productive. In comparison, 21 percent of leases issued in the Western Gulf planning area recorded any drilling activity from 1983 to 2004 and about 38 percent of drilled leases were producible as of the end of 2004. Operating cost estimates are expressed in nominal dollars.

Table 8 shows a rising trend in operating expenses with water depth and increasing firm size. There is, however, a noticeable decline over time in the aggregate. The operating expenses are significantly higher for integrated firms than for independent operators in the OCS.

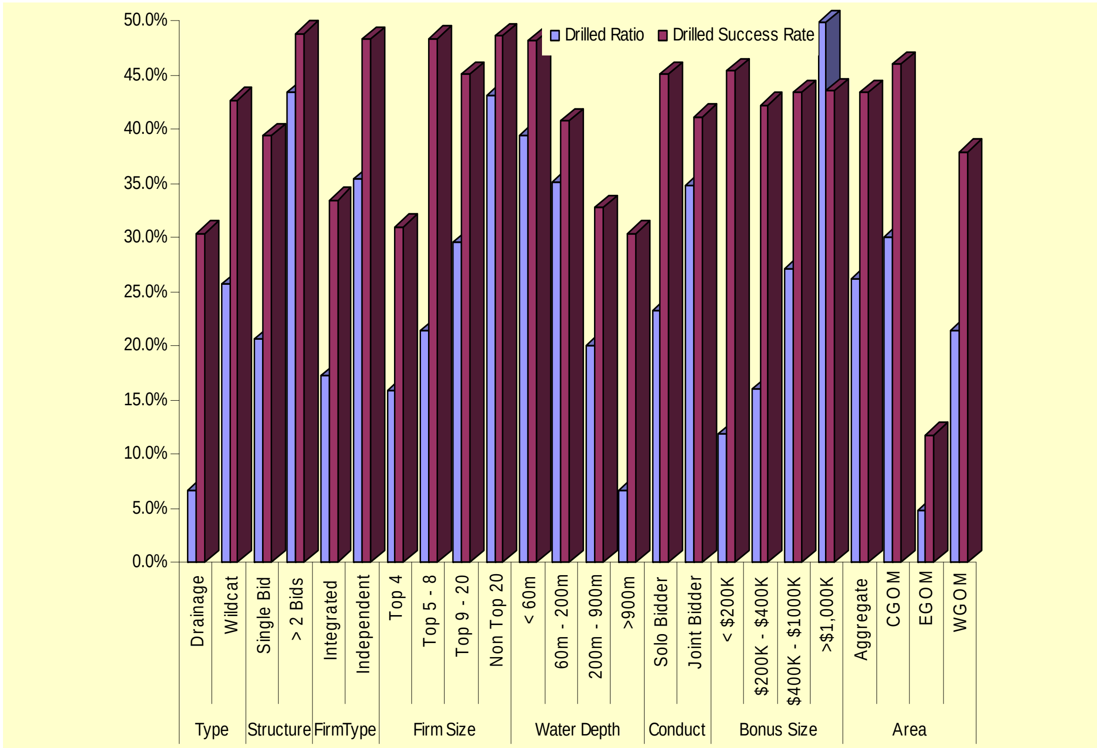

Figure 17. Drilling and Successful Drilling Ratios for Leases Issued from 1983 to 1999.

Drilled ratio rises with firm size, but decreases with water depth as evident in Figure 17. The non top 20 firms drilled about 43 percent of leases they purchased during this period and 49 percent of the drilled leases qualified as producible leases. The top four, on the other hand, drilled 16 percent of leases issued to them and recorded 31 percent of drilled leases as producible leases.

The aggregate proportion of drilled leases that were producible declines with water depth just as does the proportion of drilled leases relative to leases issued. As a result, the overall lease development success rate declines quite significantly with water depth. It is noted, however, that while only 7 percent of leases issued in water depth deeper than 900 meters recorded some drilling efforts, 30 percent of these relatively few drilled leases in this water depth range qualified as producible leases as of the end of 2004. This may likely be due to the high economic potential of deepwater leases and the desire to recoup as quickly as possible the expended capital investments on these leases.

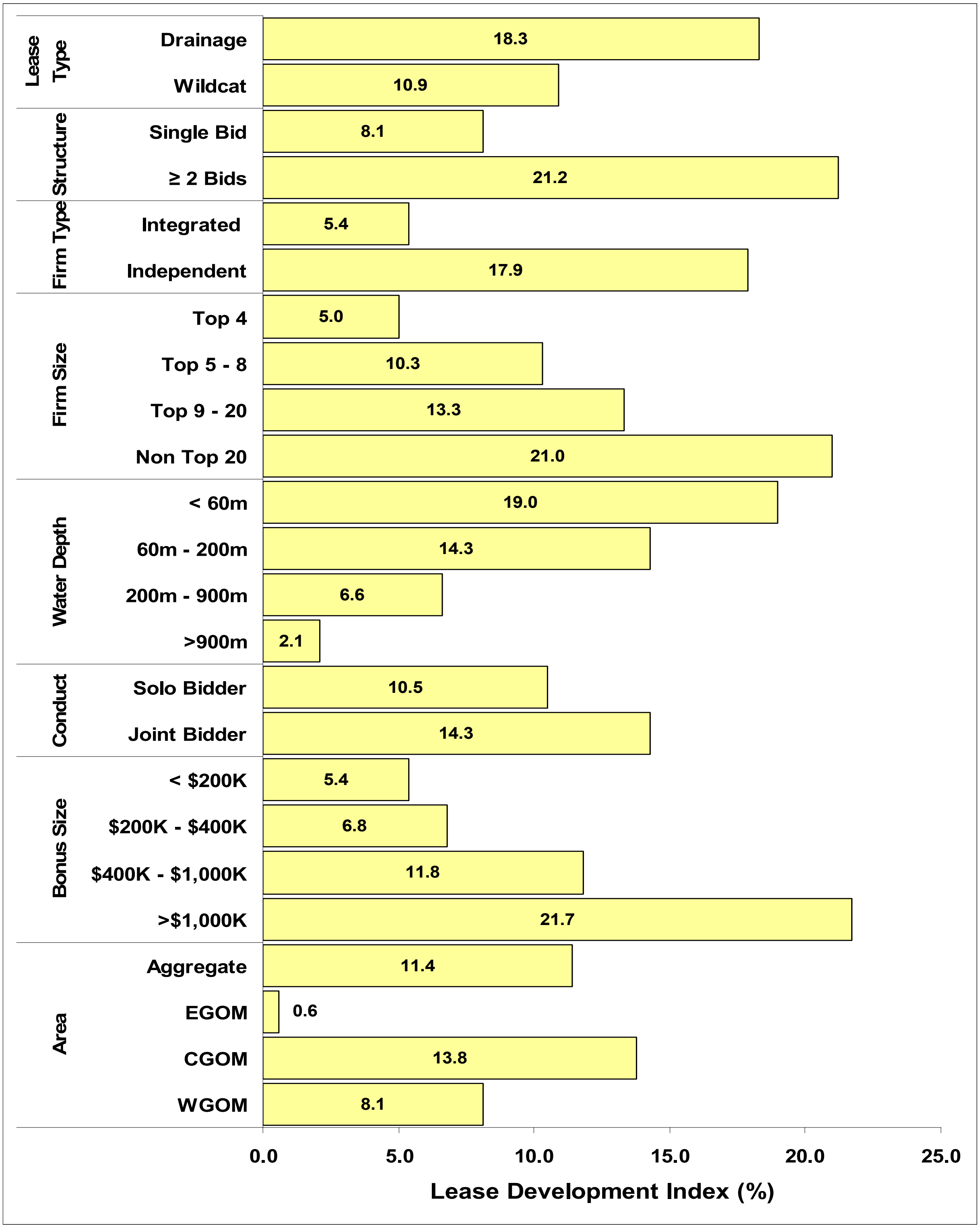

Figure 18. Lease Development Index for Leases Issued from 1983 to 1999 as of 2004.

Further evaluation of Figure 17 also suggests significant differences between measures of lease development performance for leases owned by integrated firms and those owned by independent firms. The aggregate proportion of drilled leases relative to leases issued from 1983 to 1999 was 35 percent as of 2004 for independent firms, more than twice the 17 percent for integrated firms. However, the ratio of producible leases to drilled leases as of 2004 was 48 percent for independent firms and 33 percent for integrated. The ratio of the number of drilled leases to number of leases issued for leases with at least two bids (43 percent) was also significantly higher than the 21 percent recorded for single bid leases.

The aggregate lease development index as of 2004 for leases issued from 1983-1999 is presented in Figure 18 by lease category. As previously discussed, this parameter is estimated as the multiplicative product of lease drilled ratio and producible leases drilled ratio. It indicates the likelihood that a lease in a given category issued during our study period qualified as a producible lease.

The lease development index for leases located in the Central Gulf planning area was 13.8 percent as of 2004. The lease development ratio was only 8.1 percent as of 2004 in the Western planning area and 11.4 percent for the entire Gulf of Mexico OCS. In other words, as of 2004, only one out of nine leases issued from 1983 to 1999 was producible.

Further, 14 percent of joint venture OCS leases issued from 1983 to 1999 qualified as producible leases as of 2004 in comparison to only 10.5 percent of solo venture leases. The aggregate development success rate for leases with at least two bids (21.2 %) was significantly more than twice that of leases with a single bid (8.1). In other words, it is twice as likely for leases with competitive bids to be producible than it is for leases with just a single bid.

Lease development index as defined above also seems to decline with water depth in the aggregate. For leases in water deeper than 900 meters, the development index recorded was only 2 percent. The index for water depth in the range of 200-900 meters was 7 percent. The index for the shelf 0-200 meters ranges from 14 percent to 19 percent as of 2004. The low index for water depth deeper than 900 meters is likely due to the fact that leases in deepwater have longer primary term than those in the shelf and the slope. Further, the low index may be due to technical constraints and complex planning requirements.

A comparison of lease development index to bonus size indicates rising lease development rate with high bonus bid values. The aggregate development index for leases with bonus value per lease greater than \$1 million as of 2004 was 22 percent and the rate for leases with bonus value less than \$200,000 per lease was 5 percent. The higher the bonus value for a lease the more likely it seems the lease will be producible in an aggregate sense.

The estimated aggregate lease development index by firm type shows that integrated firms' lease development index was just one-third of independents' lease development index of 17.9 percent. Further, an evaluation of development index by firm size shows that 21 percent of leases purchased by the non top 20 firms were successful as of 2004 while the top four firms reported 5 percent lease development index during this period.

The trends in leases issued, leases drilled, and leases producible are presented in Table 9. Table 10 presents the corresponding aggregate ratios of drilled leases to leases issued, producible leases to leases drilled (lease drilling success rate), and drilled producible leases to leases issued (lease development index). The ratios reported in Table 10 were estimated from Table 9 by effective lease years.

It is evident from Table 10 that the trend in drilled ratio in the Gulf of Mexico OCS declined significantly from a high of 42.6 percent for leases issued in the early 1980s to 29 percent for leases issued in the early 1990s. The declining trend is also evident in the Central Gulf planning area as well as in the Western planning area. In fact for all categories of leases, the drilled ratios in the early 1980s were significantly higher than drilled ratios in the early 1990s, despite the fact that more leases were issued in the 1980s than in the early 1990s.

The drilled ratios in the late 1990s were significantly lower than previous periods, probably because of two reasons. The number of leases issued during the period was significantly higher and several of the leases may still be in the primary lease term period as at 2004. This not withstanding, we found in Table 10 some notable patterns in our dynamic analysis of drilled ratios.

- Drilled ratio increases with bonus size across the period.
- Drilled ratio decreases with water depth across the period.
- Drilled ratio for joint venture leases was greater than that for solo venture leases across the period.
- Across time, drilled ratio increases with firm size.
- Independent firms drilled higher proportion of leases purchased across time than integrated firms.

The trends in successful drilled leases portray different patterns across the periods. For example, the majority of the lease categories reported higher success rates for leases issued from 1985 to 1989 than for leases issued from 1990 to 1994. The exceptions are leases issued to integrated firms, the top 5-8 firms, leases in water depth of 60-200 meters, leases with bonus value below $200,000, and in the $400,000 to $1 million range.

For the most part, the record shows that nearly every lease category reported higher drilled success rate for leases issued from 1995 to 1999 than leases issued from 1990 to 1994. The exceptions are leases issued to integrated firms, leases purchased by the top 9-20 firms, and leases in the slope (200-900 meters) during these periods.

Table 9

Leases Issued from 1983 to 1999, Drilled and Producible as of 2004

		Leases Issued				Leases Drilled				Leases Producible			
Group	**Lease Category**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**
Lease Type	*Drainage*	465	343	177	37	172	147	40	16	80	78	22	13
	Wildcat	2,982	3,108	2,432	5,546	1,296	820	716	858	507	354	306	416
Structure	*Single Bid*	2,295	2,594	1,847	4,012	874	617	442	402	329	254	171	177
	≥ 2 Bids	934	758	669	1,571	579	345	314	472	257	177	157	252
Firm Type	*Integrated*	1,931	2,142	1,188	2,501	645	374	221	150	223	134	75	46
	Independent	1,516	1,309	1,420	3,079	823	593	534	723	364	298	252	383
Firm Size	*Top 4*	1,722	1,813	824	2,114	555	291	119	117	168	95	32	44
	Top 5 - 8	277	297	409	1,081	117	84	116	143	60	33	57	73
	Top 9 - 20	555	581	608	993	289	195	169	185	135	103	74	77
	Non Top 20	893	760	767	1,392	507	397	351	429	225	201	163	236
Water Depth	*< 60m*	1,574	1,445	1,426	1,531	865	592	487	466	410	285	213	258
	60m - 200m	745	623	493	602	315	195	171	179	81	73	81	107
	200m - 900m	699	469	386	799	210	62	76	119	55	26	31	43
	>900m	429	914	304	2,651	78	118	22	110	41	48	3	21
Conduct	*Solo Bidder*	1,729	2,516	1,907	4,022	697	651	523	585	297	294	229	292
	Joint Bidder	1,500	836	609	1,561	756	311	233	289	289	137	99	137
Bonus Size	*< $200K*	207	944	981	1,584	27	134	161	123	13	53	69	67
	$200K - $400K	167	736	705	1,788	22	117	207	193	11	50	80	88
	$400K - $1,000K	649	700	489	1,271	214	229	195	232	83	86	83	117
	>$1,000K	2,206	972	341	940	1,190	482	193	326	479	242	96	157
Area	*Aggregate*	3,447	3,451	2,609	5,583	1,468	967	756	874	587	432	328	429
	EGOM	218	99	93	0	15	5	0	0	1	1	0	0
	CGOM	1,879	2,039	1,680	3,418	936	651	564	644	398	302	258	328
	WGOM	1,350	1,313	836	2,165	517	311	192	230	188	129	70	101

Table 10

Drilling Ratio, Drilling Success Ratio and Lease Development Index as of 2004

		Drilled Ratio				Drilling Success Ratio				Lease Development Index			
Group	**Lease Category**	**1983-87**	**1985-1989**	**1990-1994**	**1995-1999**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**	**1983-1987**	**1985-1989**	**1990-1994**	**1995-1999**
Lease Type	*Drainage*	37.0%	42.9%	22.6%	43.2%	46.5%	53.1%	55.0%	81.3%	17.2%	22.7%	12.4%	35.1%
	Wildcat	43.5%	26.4%	29.4%	15.5%	39.1%	43.2%	42.7%	48.5%	17.0%	11.4%	12.6%	7.5%
Structure	*Single Bid*	38.1%	23.8%	23.9%	10.0%	37.6%	41.2%	38.7%	44.0%	14.3%	9.8%	9.3%	4.4%
	≥ 2 Bids	62.0%	45.5%	46.9%	30.0%	44.4%	51.3%	50.0%	53.4%	27.5%	23.4%	23.5%	16.0%
Firm Type	*Integrated*	33.4%	17.5%	18.6%	6.0%	34.6%	35.8%	33.9%	30.9%	11.5%	6.3%	6.3%	1.9%
	Independent	54.3%	45.3%	37.6%	23.5%	44.2%	50.3%	47.2%	52.9%	24.0%	22.8%	17.7%	12.4%
Firm Size	*Top 4*	32.2%	16.1%	14.5%	5.5%	30.2%	32.6%	27.2%	37.5%	9.7%	5.2%	3.9%	2.1%
	Top 5 - 8	42.3%	28.2%	28.4%	13.2%	51.0%	39.5%	49.4%	51.0%	21.6%	11.1%	14.0%	6.7%
	Top 9 - 20	52.1%	33.6%	27.7%	18.6%	46.5%	52.9%	44.0%	41.4%	24.2%	17.8%	12.2%	7.7%
	Non Top 20	56.8%	52.3%	45.8%	30.8%	44.4%	50.6%	46.5%	55.0%	25.2%	26.4%	21.3%	16.9%
Water Depth	*< 60m*	55.0%	41.0%	34.2%	30.4%	47.4%	48.1%	43.7%	55.4%	26.0%	19.7%	14.9%	16.9%
	60m - 200m	42.3%	31.3%	34.7%	29.7%	25.7%	37.4%	47.4%	59.8%	10.9%	11.7%	16.4%	17.8%
	200m - 900m	30.0%	13.2%	19.7%	14.9%	26.2%	41.9%	40.8%	36.1%	7.9%	5.5%	8.0%	5.4%
	>900m	18.2%	12.9%	7.2%	4.1%	52.6%	40.7%	13.6%	19.1%	9.6%	5.3%	1.0%	0.8%
Conduct	*Solo Bidder*	40.3%	25.9%	27.4%	14.5%	42.6%	45.2%	43.8%	49.9%	17.2%	11.7%	12.0%	7.3%
	Joint Bidder	50.4%	37.2%	38.3%	18.5%	38.2%	44.1%	42.5%	47.4%	19.3%	16.4%	16.3%	8.8%
Bonus Size	*< $200K*	13.0%	14.2%	16.4%	7.8%	48.1%	39.6%	42.9%	54.5%	6.3%	5.6%	7.0%	4.2%
	$200K - $400K	13.2%	15.9%	29.4%	10.8%	50.0%	42.7%	38.6%	45.6%	6.6%	6.8%	11.3%	4.9%
	$400K - $1,000K	33.0%	32.7%	39.9%	18.3%	38.8%	37.6%	42.6%	50.4%	12.8%	12.3%	17.0%	9.2%
	>$1,000K	53.9%	49.6%	56.6%	34.7%	40.3%	50.2%	49.7%	48.2%	21.7%	24.9%	28.2%	16.7%
Area	*Aggregate*	42.6%	28.0%	29.0%	15.7%	40.0%	44.7%	43.4%	49.1%	17.0%	12.5%	12.6%	7.7%
	EGOM	6.9%	5.1%	0.0%	0.0%	6.7%	20.0%	0.0%	0.0%	0.5%	1.0%	0.0%	0.0%
	CGOM	49.8%	31.9%	33.6%	18.8%	42.5%	46.4%	45.7%	50.9%	21.2%	14.8%	15.4%	9.6%
	WGOM	38.3%	23.7%	23.0%	10.6%	36.4%	41.5%	36.5%	43.9%	13.9%	9.8%	8.4%	4.7%

A declining trend in aggregate lease development ratio for leases issued from 1983 to 1999 is evident from Table 10. The aggregate ratio declined from 11.5 percent from 1983 to 1987 to 6.3 percent for leases purchased by integrated firms from 1990 to 1994. In addition, lease development ratio for leases purchased by these firms from 1995 to 1999 was 1.9 percent as of 2004. In comparison, lease development ratio for leases purchased by independent firms as of 2004 dropped from 24.0 percent in the 1983-1987 period to 17.7% from 1990 to 1994 and 12.4 percent from 1995 to 1999. Over the study period, lease development ratios for joint venture leases were higher than the development ratios for solo venture leases. The declining trends in these ratios over the period are, however, evident for both categories of leases.

Lease development ratio increases with bonus size and the ratios declined quite significantly with effective lease year. Similarly, we found that development ratio for E&P firms differs significantly across the period and size. The development ratio for the top four firms declined from 9.7 percent for leases issued from 1983 to 1987 to 2.1 percent for leases issued from 1995 to 1999; whereas, the ratio for leases purchased from 1983 to 1987 by the non top 20 firms dropped from 25.2 percent to 16.9 percent for leases issued from 1995 to 1999.

4.2.2. Lease Development Productivity Analysis: Lease productivity for the purpose of this report is measured as the ultimate hydrocarbons produced (historical plus projected) from leases issued from 1983 to 1999. We estimated ultimate hydrocarbon recovery as the ratio of maximum hydrocarbons produced in barrels of oil equivalent to estimated declining rate.

Figure 19 shows the aggregate lease productivity for drilled leases issued from 1983 to 1999. Productivity is measured here as the ratio of cumulative hydrocarbon production over the life of drilled leases in a lease category to number of drilled leases in that category. The estimated values reported in Figure 19 are based, however, on producible leases from 1983 to 2004 for which we could make projections. No production projections were made in this study for leases not drilled and classified as producible as of year end 2004.

The overall lease productivity for leases located in the Central Gulf planning area is significantly different from productivity for leases issued from 1983 to 1999 in the Western Gulf planning area. The overall lease development productivity is estimated as 2.22 million BOE per drilled lease in the Western planning area, 2.87 million BOE per drilled lease in the Central Gulf of Mexico OCS, and the aggregate productivity per drilled lease in the entire Gulf of Mexico OCS was 2.66 million BOE.

Productivity for joint venture OCS leases issued from 1983 to 1999 is currently estimated as 2.78 million BOE. In comparison, the productivity for solo venture leases is estimated as 2.60. The overall aggregate development productivity for leases with at least two bids (2.96 million BOE) is also significantly different from lease productivity for leases with a single bid (2.44 million BOE). In other words, there is statistical evidence to suggest that leases with multiple bids on the Gulf OCS were more productive than leases that received single bids from 1983 to 1999.

Lease development productivity rate as defined above also seems to show some definitive declining pattern with water depth in the aggregate sense. For leases in water depth deeper than 900 meters, the development productivity rate is estimated as 7.74 million BOE per drilled lease. The rate for leases in the range of 200-900 meters is estimated as 5.63 million per drilled lease. The productivity for leases in the shelf 0-200 meters ranges from 1.68 million BOE to 1.94 million BOE per drilled lease.

A comparison of aggregate lease productivity by bonus size shows some discernable patterns as well. The aggregate productivity for leases with bonus value per lease greater than $1 million is estimated as 3.53 million BOE per drilled lease and the rate for leases with bonus value less than $200,000 per lease is estimated as 1.51 million BOE. As observed earlier in this report, it may be true that the higher the bonus value of a lease the more likely it is to be a producible lease. It also seems that a rising lease productivity can be expected with a rising lease bonus value, *ceteris paribus*.

The estimated aggregate lease development productivity for integrated firms is significantly greater than productivity of leases issued to independent firms. Further, an evaluation of aggregate lease development productivity by firm size shows a declining pattern from big to small size firms. In the aggregate, productivity of drilled leases purchased from 1983 to 1999 for the non top 20 firms (3.80 MMBOE) is about one-half of that for the top four firms (7.26 MMBOE per drilled lease).

Trends in development productivity per drilled leases for leases issued from 1983 to 1999 in the Gulf of Mexico OCS are presented in Table 11. The overall aggregate productivity per drilled lease in the Gulf of Mexico OCS declined significantly from a high of 4.536 MMBOE for leases issued from 1983 to 1987 to 2.864 MMBOE for leases issued in the early 1990s. The declining trend is also evident in the Central Gulf planning area as well as in the Western planning area. In fact for all categories of leases, the productivity ratios in the early 1980s were significantly higher than productivity ratios in the early 1990s, notwithstanding the fact that more leases were issued and drilled in the 1980s than in the early 1990s.

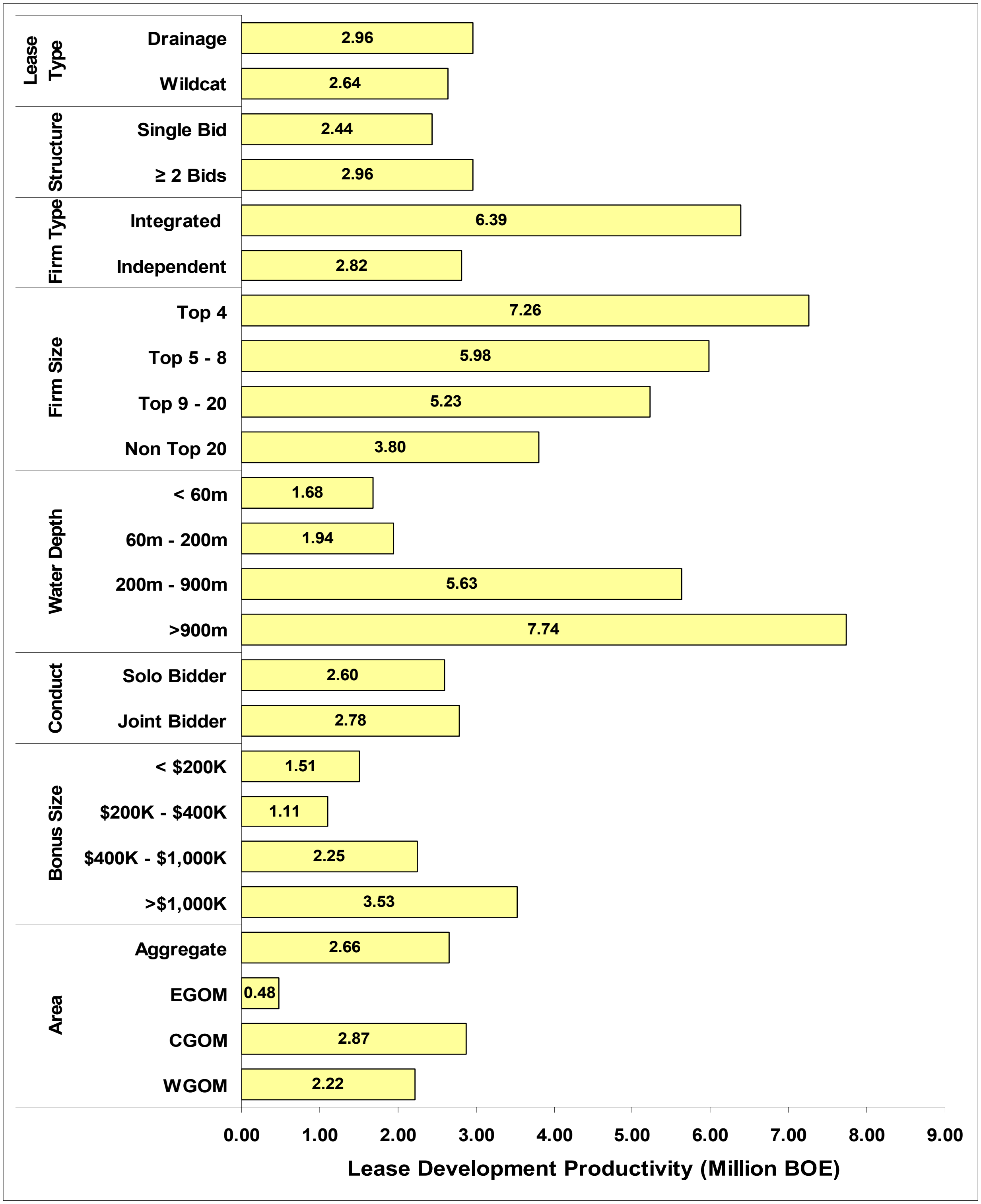

Figure 19. Lease Development Productivity for Leases Issued from 1983 to 1999.

Further evaluation of lease productivity by structure shows higher productivity ratios for drilled solo venture leases in the 1980s and early 1990s than drilled joint venture leases. The reverse, however, was the case for leases issued in the late 1990s, on average. The productivity ratio for drilled joint venture leases issued from 1995 to 1999 was estimated as 3.438 MMBOE. In comparison, the ratio for solo venture leases drilled was 2.640 MMBOE for leases issued from 1995 to 1999.

It is also evident from Table 11 that lease development productivity rises with water depth across the period. The productivity of leases issued from 1983-1999 in the OCS shelf (0-200 meters) ranges from 2.169 and 2.440 to 1.684 and 2.418 MMBOE in the 1980s. The estimated development productivity ratios for leases in the Gulf OCS slope (200-900 meters) and OCS deep (water depth greater than 900 meters) range from 8.072 to 10.671 MMBOE and 16.929-27.819 MMBOE, respectively. The decline pattern, on average, is evident from the 1980s to the 1990s for leases issued in the shelf, the slope, and the deep waters over the periods.

Lease productivity ratios for E&P firms by type show some significant differences. Integrated firms had higher aggregate productivity than independents for leases issued from 1983 to 1999. In addition, the declining trend in productivity for both firm types from the 1980s to the 1990s is clearly identifiable. Further, development productivity rate by firm size shows a rising productivity rate with firm size. A declining trend over time is unmistakable for the top eight firms. There is however, no discernable pattern in productivity trend for the top 8-20 and non top 20 firms. Productivity rate for leases issued to the top four firms declined from 8.609 MMBOE for 1985-1989 leases to 4.794 for 1990-1994 leases and 3.291 for 1995-1999 leases. Similarly, the productivity rate for leases issued to the top 5-8 firms also declined from 3.991 MMBOE for 1983-1987 leases to 1.977 for 1995-1999 leases.

4.3. Profitability of OCS Lease Development

There is probably no perfect economic performance measure which guarantees a perfect exploration and production investment decision outcome. In fact, there is no general consensus on the names and definitions of E&P economic performance measures (Mian, 2002; Newendorp and Schuyler, 2000; Seba, 2003).

The more popular economic measures of E&P performance can be divided into two broad categories. Measures in the first category are those which ignore the time-value of money. These measures include undiscounted net profit, undiscounted pay out and benefits-to-cost-ratios using undiscounted cash flows. The second category of economic performance measures, however, recognizes the time value of money. These measures consist of internal rate of return, net present value profit, and profitability index.

In this report, we adopted two of the more popular economic performance measures to analyze the performance of OCS leases issued from 1983 to 1999 and developed from 1983 to 2004. The two measures, profitability index and internal rate of return, recognize the time value of money, and we estimated them on a before-tax basis.

Table 11

Trend in Productivity by Lease Category, 1983-1999
(aggregate annual average in million boe/drilled lease)

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	2.899	2.797	2.685	12.927
	Wildcat	4.753	4.532	2.874	2.717
Structure	*Single Bid*	4.516	4.441	2.272	1.921
	≥ 2 Bids	4.681	3.958	3.696	3.741
Firm Type	*Integrated*	6.180	7.145	5.177	4.150
	Independent	3.249	2.452	1.908	2.649
Firm Size	*Top 4*	7.259	8.609	4.794	3.291
	Top 5 - 8	3.991	2.038	1.808	1.977
	Top 9 - 20	3.532	3.323	4.387	3.249
	Non Top 20	2.257	2.018	1.831	2.964
Water Depth	*< 60m*	2.440	1.684	1.513	1.800
	60m - 200m	2.169	2.418	1.946	1.379
	200m - 900m	8.072	10.671	9.746	4.171
	>900m	27.819	16.929	16.135	8.688
Conduct	*Solo Bidder*	5.112	4.616	2.923	2.640
	Joint Bidder	4.093	3.538	2.730	3.438
Bonus Size	*< $200K*	12.673	5.138	2.056	1.851
	$200K - $400K	2.278	1.789	1.350	2.332
	$400K - $1,000K	4.264	3.047	3.345	2.445
	>$1,000K	4.498	5.208	4.675	3.966
Area	*Aggregate*	4.536	4.268	2.864	2.904
	EGOM	0.085	4.422	0.000	0.000
	CGOM	5.046	4.568	3.212	2.876
	WGOM	3.741	3.638	1.841	2.983

4.3.1. Lease Profitability Index: According to Seba (2003), the profitability index is the oldest and in all probability the most popular economic performance indicator in the global oil and gas industry. It is a measure, expressed in present value terms, of the benefits created per unit of investment expenditure. It is a dimensionless ratio of the present value of total income to the present value of total investments.

The exact definition and method of calculating and reporting the profitability index vary from organization to organization. Mian (2002) lists such variation as present value ratio, present value index, discounted profit to investment ratio or investment efficiency.

For the purpose of this study, the profitability index (PI) is defined as the ratio of the present value of total income to the present value of total investment. It is a relative measure of the efficiency of an investment. By this definition, a lease investment with positive present value of net cash flow (NCF) is expected to have a PI value that is greater than 1. Similarly, a lease investment with negative cash flow will have a PI value less than 1. Generally speaking, a PI value of 1 is an indication that an investment is neither making money nor losing money.

Table 12 presents estimated PI values using present values of future operating cash flow and investments. The reported PI values are calculated based on the entire life cycle of leases issued from 1983 to 1999 in the Gulf of Mexico OCS using two discount factors. The first discount factor represents the historical before taxes average rate of return for corporations in the NAICS manufacturing sector (U.S. Census Bureau, 2004). The second discount factor is the representative average return on revenue (Standard & Poor's NetAdvantage, 2005).

For PI calculation we have used either the PV of initial investments (signature bonus plus drilling costs plus development costs) or the PV of all expenditures. For comparative analysis of the impact of signature bonus on lease profitability, we also calculated the PI value using initial investment less bonus values and total cost less high bonus value paid for leases issued from 1983 to 1999 (see Table 13).

The selection of discount rate for discounting purposes is usually a difficult process. Most commonly, the discount rate used should not be less than the interest rate paid on borrowed capital or the hurdle rate, which represents in a generic term, the minimum acceptable rate of return.

For comparative purposes, we used two representative discount rates in this report for all categories of leases. The first is the before-tax average rate of return on revenue and the second is the historical before-tax average rate of return for corporations in the NAICS manufacturing sector. Therefore, our results do not reflect any cross sectional or time variations in the cost of borrowed capital by firms for projects. Moreover, these profitability indices are *ex-ante* or after the effect parameters.

Table 12

Aggregate Profitability Index for Leases Issued from 1983 to 1999 Using Two Discount Factors

		Profitability Index (Initial Investment)		Profitability Index (Total Investment)	
Group	**Lease Category**	***17.00%*** [7]	***12.50%*** [8]	***17.00%***	***12.50%***
Lease Type	*Drainage*	0.67	0.89	0.58	0.74
	Wildcat	0.75	**1.05**	0.63	0.84
Structure	*Single Bid*	0.74	**1.07**	0.63	0.85
	≥ 2 Bids	0.75	**1.02**	0.64	0.83
Firm Type	*Integrated*	0.83	**1.24**	0.69	0.96
	Independent	0.65	0.85	0.57	0.72
Firm Size	*Top 4*	0.83	1.26	0.70	0.97
	Top 5 - 8	0.74	0.93	0.63	0.77
	Top 9 - 20	0.92	**1.22**	0.76	0.95
	Non Top 20	0.56	0.75	0.50	0.64
Water Depth	*< 60m*	0.58	0.73	0.52	0.63
	60m - 200m	0.48	0.64	0.43	0.55
	200m - 900m	**1.05**	**1.61**	0.83	**1.16**
	>900m	**2.04**	**2.78**	**1.38**	**1.70**
Conduct	*Solo Bidder*	0.83	**1.13**	0.70	0.90
	Joint Bidder	0.66	0.94	0.57	0.77
Bonus Size	*< $200K*	**1.04**	**1.33**	0.82	**1.01**
	$200K - $400K	0.77	0.95	0.64	0.77
	$400K - $1,000K	0.97	**1.27**	0.79	0.99
	>$1,000K	0.69	0.98	0.60	0.80
Area	*Aggregate*	0.74	**1.03**	0.63	0.83
	EGOM	0.04	0.09	0.04	0.09
	CGOM	0.77	**1.06**	0.65	0.86
	WGOM	0.71	0.99	0.60	0.80

Note: Bolded figures in the above table indicate lease categories with added value to investment, *ceteris paribus*, at the corresponding discount factors.

[7] This represents the historical before taxes average rate of return for corporations in the NAICS manufacturing sector (U.S. Census Bureau, 2004).
[8] Representative average return on revenue (Standard & Poor's NetAdvantage, 2005).

Table 13

Aggregate Profitability Index for Leases Issued from 1983 to 1999 Using Two Discount Factors Minus the Bonus

		Profitability Index (Initial Investment Minus Bonus)		Profitability Index (Total Investment Minus Bonus)	
Group	**Lease Category**	***17.00%*** [9]	***12.50%*** [10]	***17.00%***	***12.50%***
Lease Type	*Drainage*	**1.03**	**1.41**	0.87	**1.02**
	Wildcat	**1.20**	**1.77**	0.93	**1.12**
Structure	*Single Bid*	**1.25**	**1.90**	0.88	**1.10**
	≥ 2 Bids	**1.16**	**1.65**	0.96	**1.13**
Firm Type	*Integrated*	**1.33**	**2.13**	**1.13**	**1.39**
	Independent	**1.04**	**1.41**	0.75	0.89
Firm Size	*Top 4*	**1.32**	**2.14**	**1.15**	**1.43**
	Top 5 - 8	**1.19**	**1.61**	0.90	1.00
	Top 9 - 20	**1.50**	**2.10**	1.00	**1.18**
	Non Top 20	0.89	**1.22**	0.68	0.81
Water Depth	*< 60m*	0.91	**1.19**	0.73	0.83
	60m - 200m	0.72	0.99	0.65	0.76
	200m - 900m	**1.71**	**2.86**	**1.37**	**1.66**
	>900m	**4.81**	**7.41**	**1.82**	**2.08**
Conduct	*Solo Bidder*	**1.39**	**1.99**	0.94	**1.12**
	Joint Bidder	**1.01**	**1.51**	0.90	**1.10**
Bonus Size	*< $200K*	**2.23**	**3.01**	0.90	**1.08**
	$200K - $400K	**1.54**	**1.98**	0.73	0.85
	$400K - $1,000K	**1.79**	**2.47**	0.95	**1.13**
	>$1,000K	**1.06**	**1.56**	0.94	**1.15**
Area	*Aggregate*	**1.18**	**1.73**	0.92	**1.11**
	EGOM	0.06	0.12	0.17	0.32
	CGOM	**1.26**	**1.84**	0.92	**1.11**
	WGOM	**1.07**	**1.57**	0.93	**1.12**

Note: Bolded figures in the above table indicate lease categories with added value to investment, *ceteris paribus*, at the corresponding discount factors.

[9] This represents the historical before taxes average rate of return for corporations in the NAICS manufacturing sector (U.S. Census Bureau, 2004).
[10] Representative average return on revenue (Standard & Poor's NetAdvantage, 2005).

Using 17% discount factor, the PI values we calculated by dividing operating cash flows over the entire life of leases by total investments on leases issued from 1983-1999 are less than 1.0 for nearly all lease categories. The only exceptions are leases in water depth greater than 900 meters. With a discount factor of 12.5%, the profitability index of two additional lease categories added positive benefits to total investments. However, the positive benefits added to these two lease categories are only marginal (1.16 for leases in the slope (200-900 meters) and leases with high bonus value of less than $200,000).

The profitability index for several categories of leases added positive benefits to initial investments using 17 percent discount factor (see bold font cells in Table 12). The positive benefits added for the most part are also only marginal for several of these lease categories. Several other lease categories add benefits to initial investments (bonus, drilling and installation costs) when we discounted operating cash flow by 12.5 percent. The results suggest the sensitivity of the choice of discount rate in the determination of project viability.

The effects of the signature bonus on the lease profitability index are reflected in Table 13 in comparison to Table 12, *ceteris paribus*. Only one lease category, leases in water depth greater than 900 meters, reported a PI value, with respect to total investments, greater than 1 for discount factor of 17 percent. On the other hand, four lease categories have PI values, with respect to total investment less bonus, which are greater than 1.

The reported low profitability indices, notwithstanding, we found some notable patterns in Tables 12 and 13.

- Profitability index increases, on average, with decreasing discount factors, an indication of how borrowed capital can affect the overall industry economic performance.
- Profitability rises from the shelf to the slope and the deepwater just as lease productivity rises from the shelf to the slope and deep waters.
- On average, integrated firms reported higher profitability ratio than independent firms.
- The estimated index for solo bidders on aggregate is higher than the index for joint bidders for leases issued from 1983 to 1999.
- Profitability ratio of leases in the Central Gulf is higher in magnitude than leases in the Western Gulf, but the difference does not seem to be statistically significant.
- It is interesting to note further that the impact of bonus payment, which has been suggested to be regressive in nature, does not significantly alter some of the above stated patterns.

Tables 14 and 15 show the trends in profitability index by lease effective period for leases issued from 1983 to 1999. The trends in aggregate profitability index by lease effective year are portrayed in Figure 20. The tables and figure show some distinctive variations in profitability across both lease effective year and across time.

Table 14

Aggregate Average Profitability Index of Initial Investments for Leases Issued from 1983 to 1999 at 12.5 Percent Discounting

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	0.96	1.06	1.33	3.46
	Wildcat	1.96	1.93	1.61	1.68
Structure	*Single Bid*	2.02	2.01	1.69	1.53
	≥ 2 Bids	1.24	1.17	1.47	1.84
Firm Type	*Integrated*	2.66	2.89	2.41	4.52
	Independent	1.03	0.98	1.24	1.57
Firm Size	*Top 4*	2.83	3.03	2.64	7.71
	Top 5 - 8	1.74	1.88	1.17	1.30
	Top 9 - 20	1.60	1.35	2.13	2.30
	Non Top 20	0.84	0.88	1.11	1.57
Water Depth	*< 60m*	0.87	0.87	1.07	1.15
	60m - 200m	1.15	1.12	1.32	0.80
	200m - 900m	4.95	4.73	2.83	4.72
	>900m	7.24	5.91	5.31	3.82
Conduct	*Solo Bidder*	1.83	1.74	1.71	1.68
	Joint Bidder	1.78	1.73	1.33	1.79
Bonus Size	*< $200K*	3.48	3.56	1.39	1.72
	$200K - $400K	1.01	1.24	1.08	1.83
	$400K - $1,000K	2.32	2.07	1.90	1.51
	>$1,000K	1.54	1.42	1.56	1.80
Area	*Aggregate*	1.76	1.73	1.61	1.75
	EGOM	0.74	21.15	0.00	0.00
	CGOM	1.80	1.79	1.61	1.61
	WGOM	1.71	1.59	1.49	2.24

Table 15

Aggregate Average Profitability Index of Total Investments for Leases Issued from 1983 to 1999 at 12.5 Percent Discounting

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	0.79	0.85	1.05	1.58
	Wildcat	1.35	1.35	1.18	1.26
Structure	*Single Bid*	1.38	1.38	1.24	1.17
	≥ 2 Bids	0.96	0.92	1.08	1.32
Firm Type	*Integrated*	1.64	1.76	1.51	2.18
	Independent	0.84	0.80	0.99	1.20
Firm Size	*Top 4*	1.70	1.81	1.61	2.57
	Top 5 - 8	1.22	1.25	0.92	1.05
	Top 9 - 20	1.14	1.01	1.41	1.53
	Non Top 20	0.71	0.73	0.90	1.16
Water Depth	*< 60m*	0.73	0.73	0.89	0.98
	60m - 200m	0.89	0.87	1.03	0.69
	200m - 900m	2.17	2.08	1.51	2.24
	>900m	2.77	2.61	2.44	1.97
Conduct	*Solo Bidder*	1.27	1.24	1.24	1.28
	Joint Bidder	1.27	1.24	1.01	1.20
Bonus Size	*< $200K*	1.52	1.88	1.07	1.24
	$200K - $400K	0.85	0.99	0.89	1.37
	$400K - $1,000K	1.51	1.38	1.32	1.11
	>$1,000K	1.13	1.06	1.13	1.31
Area	*Aggregate*	1.26	1.24	1.18	1.29
	EGOM	0.65	4.13	0.00	0.00
	CGOM	1.28	1.28	1.18	1.21
	WGOM	1.18	1.12	1.08	1.50

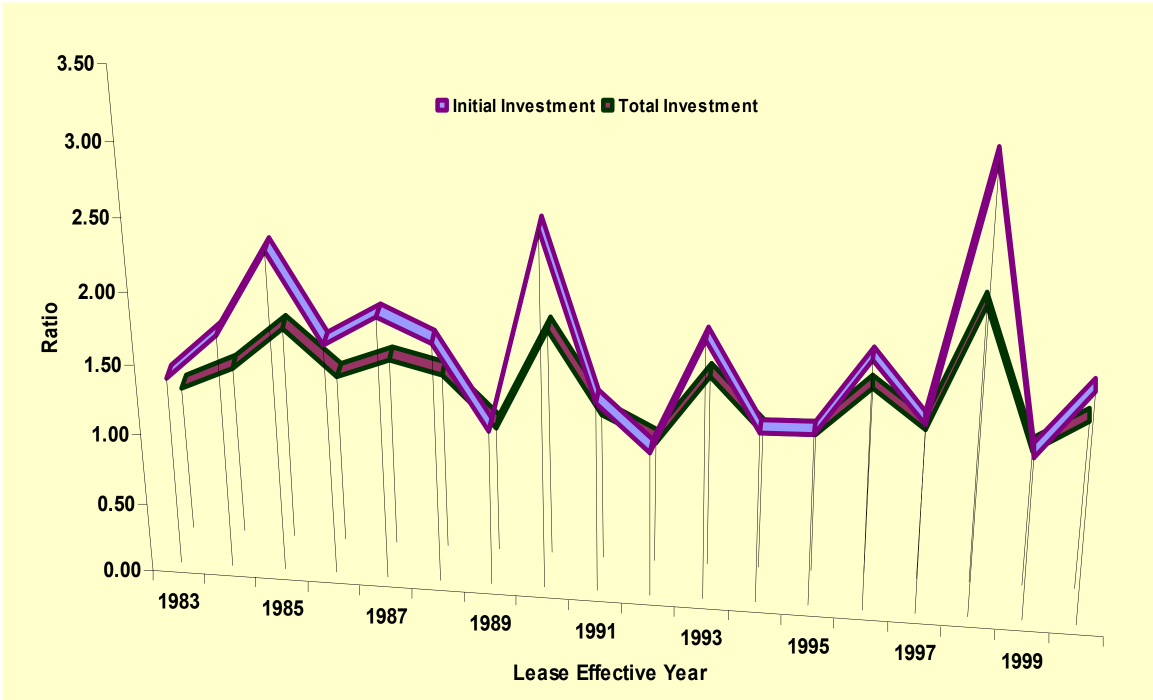

Figure 20. Aggregate Average Profitability Index of Initial Investments (PVI) and Total Investments (PVT) for Leases Issued from 1983 to 1999 at 12.5% Discounting.

The overall aggregate profitability index with respect to total investments declined a little from 1.26 for leases issued from 1983 to 1987 to 1.18 for leases issued in the early 1990s. The declining trend is similar in the Central Gulf planning area as well as in the Western planning area. However, we found no discernable pattern of variations in profitability index across time (see Figure 20).

For example, profitability index with respect to total investments for solo venture leases shows no discernable pattern over the period. Profitability index for joint venture leases declined from 1.27 to 1.20 during the period. The profitability index for leases issued to integrated firms rose from 1.64 for leases issued from 1985 to 1989 to 2.18 for leases issued from 1995 to 1999. In comparison, the index for leases purchased by independent firms increased from 0.80 for leases issued from 1985 to 1989 to 1.20 for leases issued from 1995 to 1999.

Further, the profitability index increases with firm size in the 1980s. There is however, no discernable pattern in profitability trend in the 1990s. The profitability index for leases issued to the top four firms declined from 1.81 for 1985-1989 leases to 1.61 for 1990-1994 leases and rose to 2.57 for 1995-1999 leases. Similarly, the profitability index for leases issued to the top 5-8 firms also declined from 1.25 for 1985-1989 leases to 0.92 for 1990-1994 leases and then rose to 1.05 for 1995-1999 leases.

4.3.2. Internal Rate of Return Analysis: Internal rate of return is a widely accepted measure of profitability. It is defined as the discount rate at which the net present value of a series of streams of cash flow (composed of cash receipts and disbursements) reduces to zero. The rate of return concept introduces time value of money into profitability analysis, weights rather heavily cash receipts in the later years of projects, and can be calculated on a before-tax or after-tax basis.

As mentioned earlier, each portfolio of leases is treated as a unique but interdependent investment decision at different points in time such that if 1983 were the base year, all leases purchased in 1990 would show a 1995 net cash flow as occurring in year 12. This method of aggregating net cash flow items approximates the reality more closely than does treating the decisions by firms to buy additional leases in subsequent lease sales to be independent of any prior lease investments (Mead and Sorensen, 1980).

Keeping in mind the above aggregating approach or assumption, the overall internal rate of return for all 13,641 leases issued from 1983 to 1999 is estimated as 6.9 percent. This estimate is extremely low in comparison to the rate of return in comparable U.S. industries. The historical before taxes average rate of return for corporations in the NAICS manufacturing sector according to the U.S. Census Bureau is 17 percent. The reason for this low return is most likely due to the number of leases that are producible (1,567 out of 13,641). The return for productive leases, on the aggregate, is also low at 13.0 percent. A pictorial view of internal rates of return for productive and all leases by lease category is presented in Figures 21 and 22.

For leases issued in the Central Gulf planning area from 1983 to 1999, the estimated internal rate of return is 7.3 percent for all leases and 12.9 percent for productive leases. The rate of return for leases issued from 1983 to 1999 in the Western Gulf planning area is estimated as 6.4% for all leases and 13.4% for productive leases. Leases issued in water depth deeper than 900 meters have the largest aggregate rate of return (20.9 percent) followed by leases issued in the slope (200-900 meters). The aggregate rate of return in the slope according to our estimators is 12.5 percent. The rate of return for leases in the shelf (0-200 meters) is negative because these leases suffered a net loss in present value.

The aggregate rate of return for leases receiving at least two bids is less than the return for leases that received a single bid. The difference is about 1.6 percent in magnitude. The difference in magnitude between the aggregate rate of return for leases issued to integrated firms and that for independent firms from 1983 to 1999 is also statistically significant.

It must be emphasized that the estimated rates are low numbers for all categories of leases when compared to the return value of 17 percent in the manufacturing sector during the period. Thus, we can say that with the exception of leases in the deepwater, all categories of leases issued from 1983 to 1999 suffered a net loss in present value in an aggregate sense.

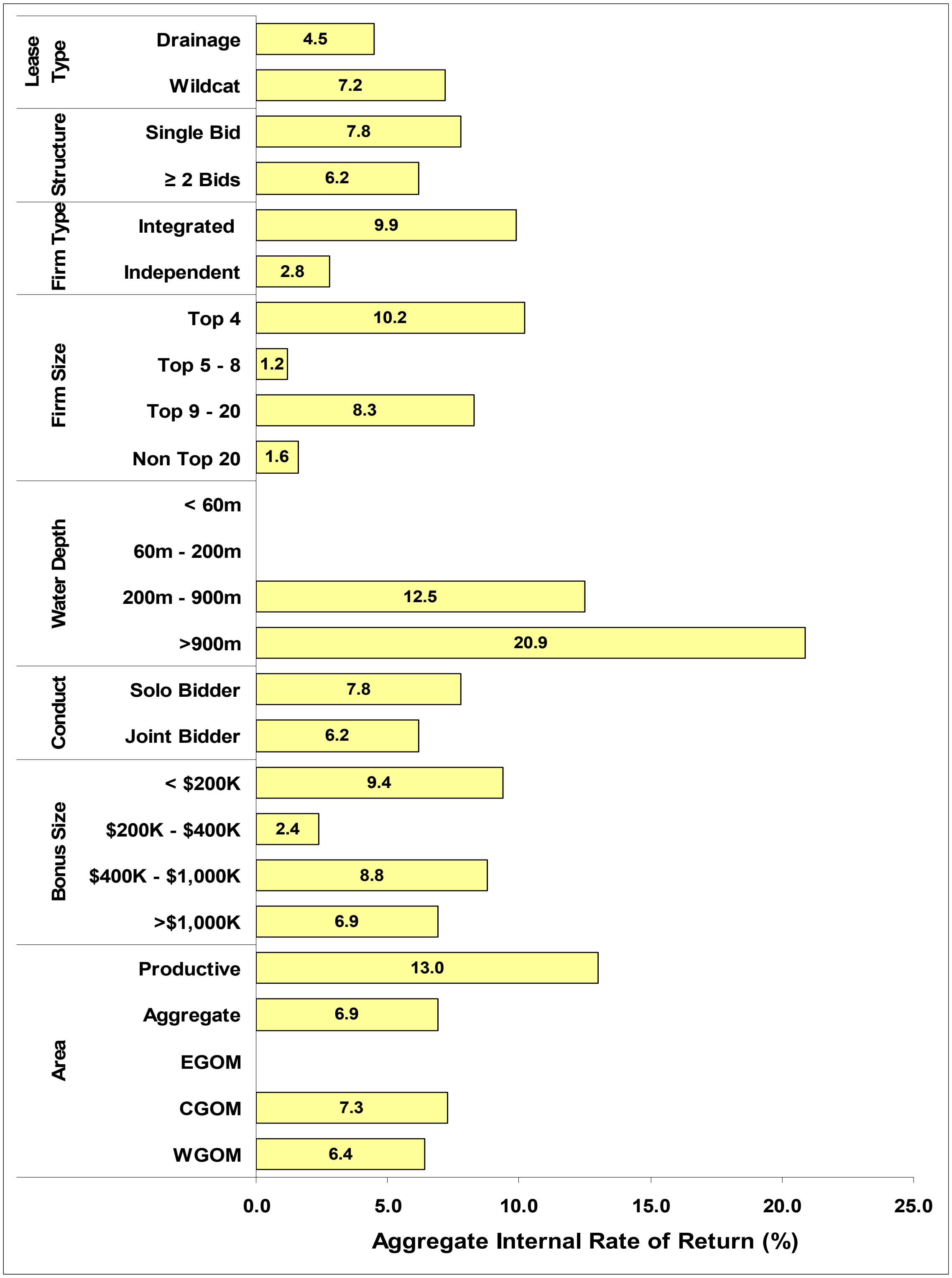

Figure 21. Aggregate Internal Rate of Return for Leases Issued from 1983 to 1999.

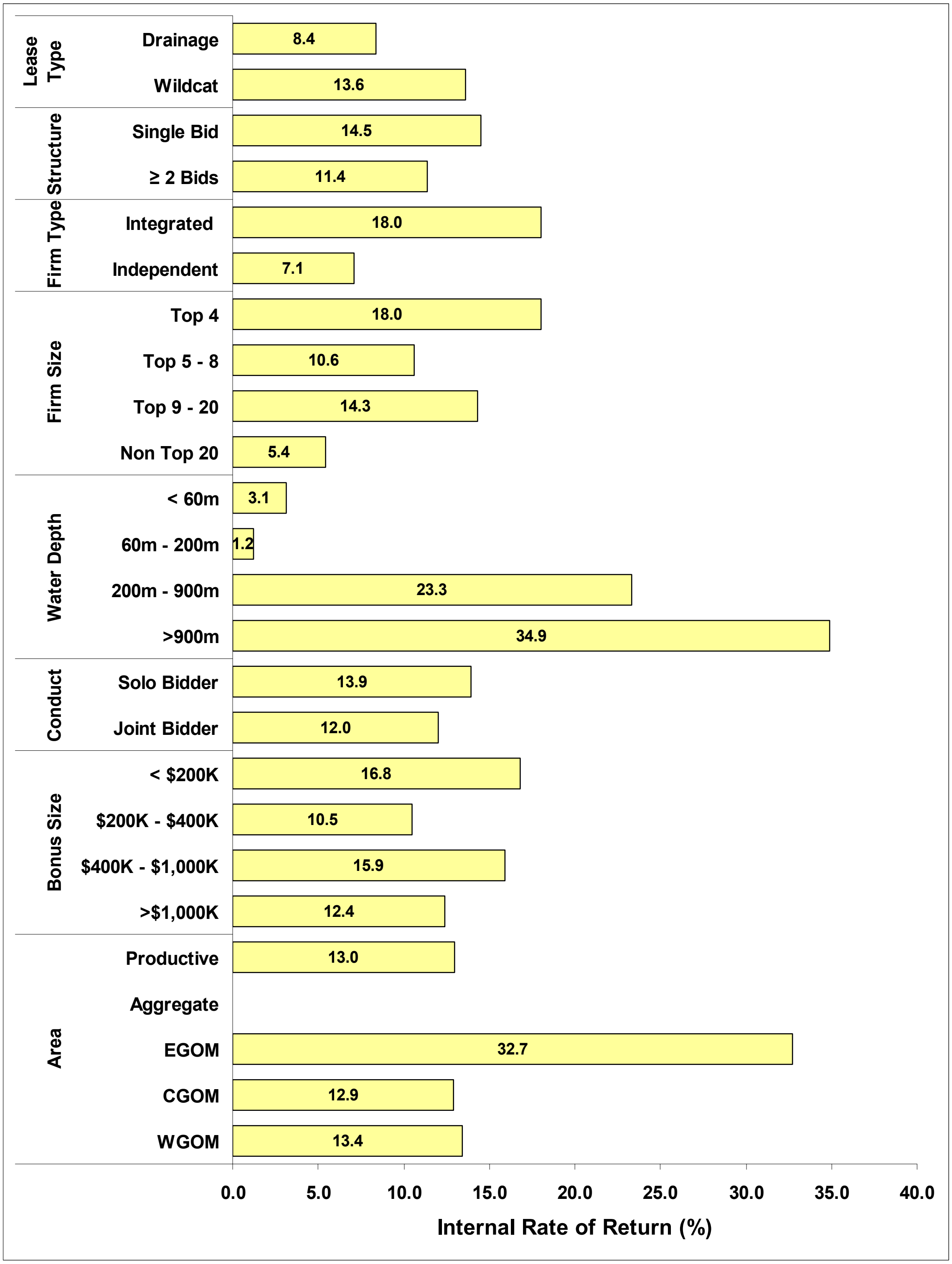

Figure 22. Internal Rate of Return for Productive Leases Issued from 1983 to 1999.

Tables 16 and 17 show the trends in internal rates of return by lease effective year for all leases issued from 1983 to 1999. The trends in aggregate average internal rates of return for all leases by lease effective year and lease category are portrayed in Figures 23 and 24. The tables and figures show some distinctive variations in rates of return across the lease effective year and lease category.

In the aggregate, leases issued in 1990-1994 have a higher annual rate of return on average than leases issued in the 1980s. However, leases issued in the late 1990s, on average, have a lower annual rate of return. On the other hand, the average rate of return for productive leases from 1990 to 1994 is less than the returns in the 1980s and the late 1990s. One reason for this is likely a higher proportion of unproductive leases issued in the early 1990s than in the late 1990s and 1980s.

The reported low profitability measures in terms of internal rate of return notwithstanding, we found some of the following findings significant:

- The aggregate average annual rate of return for leases issued in the 1980s is higher for leases with single bids than for leases with at least two bids. The reverse, however was the case in the 1990s. The same pattern is also evident when rates of return are computed for productive leases only.

- From 1983 to 1994, rate of return rises with water depth and across time for all leases. The same pattern is not evident in the late 1990s, probably because of data limitations.

- The aggregate annual average rate of return rises with firm size in the 1980s, but no definitive trend is apparent across firm size in the 1990s.

- The estimated rate of return for all lease developments by the top four firms declined from 12.7 percent from 1985 to 1989 to 10.7 percent from 1990 to 1994 and dropped to 5.7 for leases issued from 1995 to 1999.

- All leases issued to integrated firms, on average, have higher rate of return than independents across lease effective year.

- There is evidence to suggest that the rate of return for productive leases in the Western Gulf planning area is higher, on average, than for leases in the Central Gulf over the study period. The evidence, however, does not suggest a similar trend for aggregate rate of return for all leases.

- As is evident in Figure 24, there is a significant difference in the annual aggregate rate of return for all leases issued from 1983 to 1999 that were productive at year end 2004.

- Leases issued in 1998 recorded the highest aggregate internal rate of return over the life cycle of the productive leases (see Figure 23).

Table 16

Aggregate Annual Average Internal Rates of Return for All Leases Issued from 1983 to 1999 in the Gulf of Mexico

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	6.0%	5.4%	10.1%	*
	Wildcat	9.2%	9.2%	9.3%	5.2%
Structure	*Single Bid*	10.1%	9.7%	8.7%	4.1%
	≥ 2 Bids	5.5%	8.5%	13.4%	10.1%
Firm Type	*Integrated*	11.0%	12.2%	9.7%	7.4%
	Independent	3.4%	5.1%	4.2%	6.7%
Firm Size	*Top 4*	11.6%	12.7%	10.7%	5.7%
	Top 5 - 8	4.2%	9.0%	10.7%	4.3%
	Top 9 - 20	9.9%	8.0%	13.6%	8.5%
	Non Top 20	0.6%	0.9%	1.4%	16.5%
Water Depth	*< 60m*	1.0%	2.0%	1.8%	2.8%
	60m - 200m	3.4%	3.4%	9.8%	0.9%
	200m - 900m	15.0%	16.5%	13.6%	21.5%
	>900m	22.2%	18.7%	27.2%	12.6%
Conduct	*Solo Bidder*	8.8%	8.8%	7.7%	5.4%
	Joint Bidder	7.9%	9.7%	19.3%	9.2%
Bonus Size	*< $200K*	25.3%	15.0%	3.9%	13.3%
	$200K - $400K	6.3%	4.7%	4.4%	7.2%
	$400K - $1,000K	10.2%	10.6%	15.3%	6.0%
	>$1,000K	6.9%	8.1%	10.1%	9.4%
Area	*Aggregate*	8.1%	8.2%	9.1%	6.2%
	EGOM	0.0%	17.2%	0.0%	0.0%
	CGOM	8.9%	8.6%	6.2%	8.8%
	WGOM	8.2%	9.0%	10.2%	5.2%

* Limited data availability.

Table 17

Aggregate Annual Average Internal Rates of Return for Productive Leases Issued from 1983 to 1999 in the Gulf of Mexico

Group	Lease Category	1983-1987	1985-1989	1990-1994	1995-1999
Lease Type	*Drainage*	5.0%	7.3%	9.6%	*
	Wildcat	15.1%	14.7%	11.4%	15.0%
Structure	*Single Bid*	15.7%	15.6%	13.1%	11.6%
	≥ 2 Bids	10.2%	11.7%	8.7%	16.9%
Firm Type	*Integrated*	18.6%	20.7%	22.1%	57.0%
	Independent	5.9%	5.4%	7.1%	12.9%
Firm Size	*Top 4*	19.1%	21.0%	24.9%	*
	Top 5 - 8	15.6%	17.2%	15.0%	17.8%
	Top 9 - 20	12.5%	9.3%	22.3%	23.6%
	Non Top 20	2.3%	2.3%	4.7%	14.8%
Water Depth	*< 60m*	3.5%	3.2%	4.6%	7.0%
	60m - 200m	7.9%	7.2%	10.1%	0.0%
	200m - 900m	28.8%	29.1%	27.9%	*
	>900m	32.1%	31.6%	50.5%	34.7%
Conduct	*Solo Bidder*	14.0%	13.4%	16.2%	15.2%
	Joint Bidder	13.6%	15.1%	6.9%	19.7%
Bonus Size	*< $200K*	34.3%	21.8%	11.9%	24.5%
	$200K - $400K	9.1%	9.1%	5.1%	18.3%
	$400K - $1,000K	19.1%	20.8%	18.5%	16.4%
	>$1,000K	11.7%	10.0%	10.1%	16.5%
Area	*Aggregate*	13.8%	13.3%	11.4%	15.7%
	EGOM	0.0%	88.4%	0.0%	0.0%
	CGOM	14.1%	13.7%	11.4%	17.0%
	WGOM	15.3%	14.1%	13.9%	20.6%

* Limited data availability.

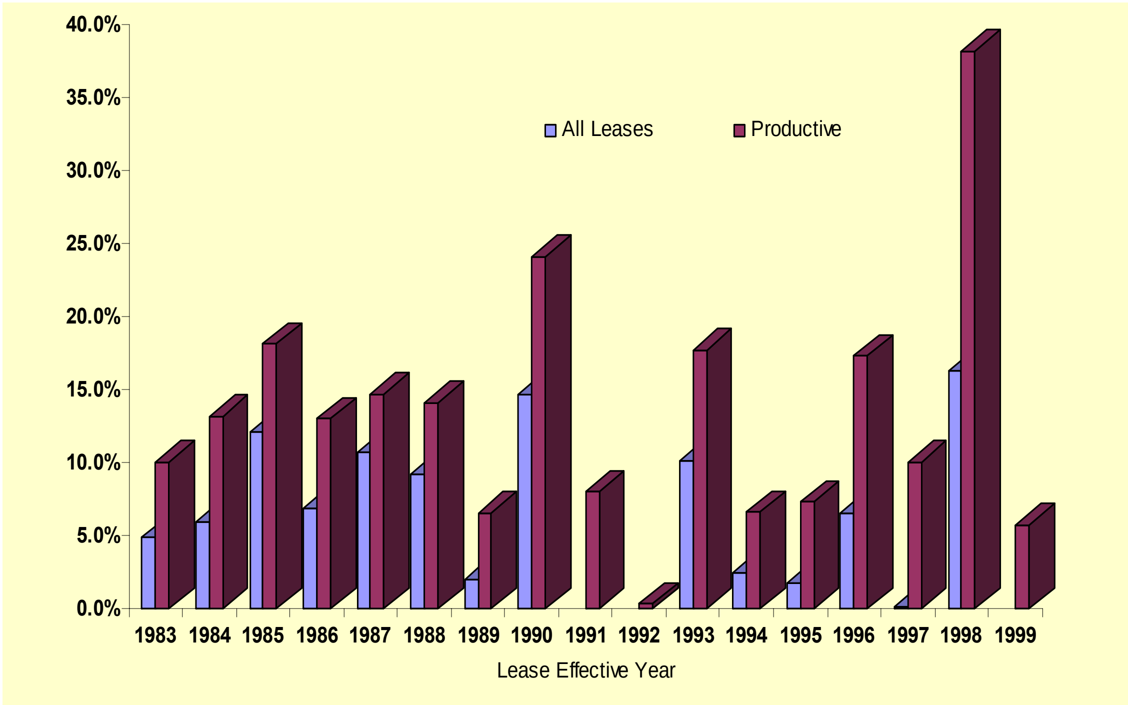

Figure 23. Trend in Aggregate Internal Rate of Return.

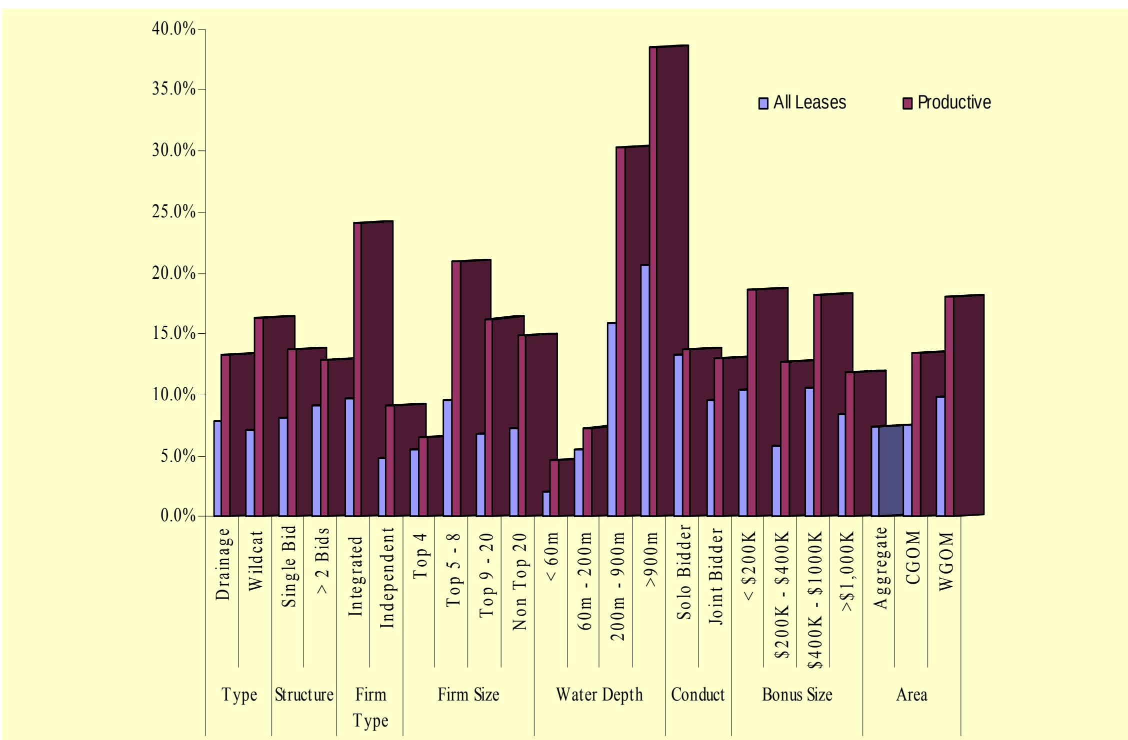

Figure 24. Aggregate Average Internal Rates of Return for All and Productive Leases Issued from 1983 to 1999.

5. SUMMARY & CONCLUSIONS

The emphasis in this study is to estimate physical and economic performance measures to characterize lease sales and development in the U.S. Gulf of Mexico. We estimated the lease development index, lease productivity, and the expeditious index as measures of physical performance in lease sales and development, and the lease profitability index and aggregate internal rates of return for lease categories. In an overall sense, the study provides a well-balanced empirical analysis of the performance in petroleum lease sales and development in offshore Gulf of Mexico.

To further address lease development issues, variables considered as central in the determination of the expected value of, or realized values from, lease development were incorporated in the study. Such variables include water depth, bidding structure and conduct, bonus size, E&P firm type and size as well as the Gulf planning area. The framework adopted in this paper is such that each annual portfolio of leases is treated as a unique but interdependent investment decision by firms at different points in time. Thus, in an aggregate sense, the rates of return earned from investment by leases, and also by important lease categories in the Gulf of Mexico OCS region, are estimated. Summary statistics of estimated physical and economic measures of lease sales and development for all categories of leases are presented in Tables A.1-A.20 in the Appendix.

This study shows there is a significant influx of new players into the Gulf of Mexico OCS for oil and gas lease development. However, there is empirical evidence suggesting that attractiveness of the Gulf of Mexico to the four big oil and gas firms remains strong.

Regarding prospectivity of OCS in terms of lease development index, we found that of the 13,641 leases issued from 1983 to 1999, 26 percent reported some drilling activity as of 2004. Of those 3,467 leases reporting drilling activity from 1983 to 1994, MMS qualified 43 percent as producible leases. The drilling failure rate in the aggregate was about 57 percent as of 2004. The overall aggregate lease development index (the product of the proportion of drilled leases and the proportion of successful drilled leases) for leases issued from 1983 to 1999 was 11.4 percent as of 2004. In other words, approximately one out of nine leases produced hydrocarbons in the Gulf of Mexico OCS. Variations in lease prospectivity within the group are evident in Table 18.

Table 18

Aggregate Prospectivity Measures for All Leases Issued from 1983 to 1999

Lease Category	Leases Issued	Prospectivity Index: Drilled Ratio (%)	Prospectivity Index: Producible Ratio (%)	Prospectivity Index: Drilling Risk (%)	Expeditious Index, Avg. Lag from Sales: to Spud (Months)	Expeditious Index, Avg. Lag from Sales: to Prod (Months)
Lease Type						
All	13,641	26.25%	11.38%	56.63%	32.8	62.7
Drainage	820	35.37%	18.29%	48.28%	29.1	54.6
Wildcat	12821	25.67%	10.94%	57.37%	33.6	63.9
Structure						
Single Bid	9679	20.62%	8.12%	60.62%	n/a	n/a
≥ 2 Bids	3615	43.37%	21.16%	51.21%	n/a	n/a
Firm Type						
Integrated Firms	7128	17.40%	5.42%	68.87%	47.1	84.6
Independent Firms	6508	35.93%	17.91%	50.15%	29.3	58.1
Firm Size						
Top 4	5675	15.98%	4.95%	69.01%	50.1	89.2
Top 5-8	1937	21.37%	10.32%	51.69%	40.1	69.0
Top 9-20	2510	29.54%	13.30%	54.98%	37.6	68.2
Non Top 20	3515	43.16%	20.97%	51.40%	27.5	56.4
Water Depth						
< 60m	5365	39.44%	18.97%	51.89%	25.9	50.2
60m - 200m	2183	35.18%	14.34%	59.24%	31.5	61.1
200m - 900m	2143	20.07%	6.58%	67.21%	38.8	85.8
>900m	3950	6.76%	2.05%	69.66%	77.3	140.3
Conduct						
Solo Bidder	9231	23.29%	10.50%	54.93%	n/a	n/a
Joint Bidder	4063	49.13%	19.35%	60.62%	n/a	n/a
Bonus Size						
< $200K	3528	11.88%	5.39%	54.65%	39.9	65.4
$200K - $400K	3249	16.04%	6.77%	57.77%	36.2	55.6
$400K - $1,000K	2749	27.17%	11.79%	56.63%	34.7	59.8
>$1,000K	3768	49.81%	21.68%	56.47%	27.3	58.7
Area						
EGOM	347	4.90%	0.58%	88.24%	n/a	n/a
CGOM	8213	30.11%	13.84%	54.02%	n/a	n/a
WGOM	5081	21.47%	8.15%	62.05%	n/a	n/a

Table 19

Aggregate Performance Measures for All Leases Issued from 1983 to 1999

	Leases Issued	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
Lease Category			**Historical**	**Ultimate**	**Historical**	**Ultimate**	
Lease Type							
All	13,641	$1,208	$13,452	$21,999	$581	$5,879	6.94%
Drainage	820	$1,988	$17,786	$26,419	$35	$5,218	4.52%
Wildcat	12821	$1,158	$13,175	$21,716	$616	$5,921	7.18%
Structure							
Single Bid	9679	$757	$10,002	$16,435	$874	$4,968	7.76%
≥ 2 Bids	3615	$2,402	$23,907	$38,820	$24	$8,979	6.24%
Firm Type							
Integrated Firms	7128	$1,274	$14,778	$23,734	$3,542	$9,341	9.92%
Independent Firms	6508	$1,132	$12,008	$20,114	($2,652)	$2,099	2.76%
Firm Size							
Top 4	5675	$1,261	$15,146	$24,334	$4,078	$10,071	10.22%
Top 5-8	1937	$832	$7,968	$11,177	($1,562)	$386	1.20%
Top 9-20	2510	$1,092	$14,891	$24,694	$737	$6,753	8.32%
Non Top 20	3515	$1,405	$12,724	$22,289	($3,978)	$1,535	1.62%
Water Depth							
< 60m	5365	$1,262	$10,560	$14,703	($2,850)	($583)	-
60m - 200m	2183	$1,593	$12,264	$16,375	($4,281)	($1,985)	-
200m - 900m	2143	$1,500	$23,787	$37,189	$7,463	$15,882	12.49%
>900m	3950	$762	$12,430	$26,777	$4,196	$13,574	20.86%
Conduct							
Solo Bidder	9231	$879	$11,912	$19,731	$596	$5,422	7.80%
Joint Bidder	4063	$1,943	$18,034	$28,862	$749	$7,507	6.19%
Bonus Size							
< $200,000	3528	$152	$4,316	$9,753	($546)	$2,840	9.36%
$200K - $400K	3249	$278	$3,751	$7,299	($1,525)	$619	2.39%
$400K - $1,000K	2749	$657	$12,178	$21,499	$136	$5,919	8.81%
> $1,000K	3768	$3,387	$32,469	$48,350	$3,994	$13,866	6.87%
Area							
EGOM	347	$1,346	$760	$1,970	($1,772)	($1,038)	-
CGOM	8213	$1,289	$16,835	$27,121	$985	$7,386	7.33%
WGOM	5081	$1,067	$8,850	$15,088	$89	$3,914	6.35%

Table 20

Aggregate Economic Performance Measures for Productive Leases

Lease Category	Leases Issued	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
			Historical	Ultimate	Historical	Ultimate	
Lease Type							
Productive	1,567	$2,493	$117,103	$191,506	$24,985	$71,099	13.03%
Drainage	151	$4,537	$96,584	$143,466	$12,063	$40,206	8.41%
Wildcat	1,416	$2,275	$119,292	$196,629	$26,363	$74,393	13.57%
Structure							
Single Bid	794	$1,401	$121,931	$200,342	$33,234	$83,150	14.55%
≥ 2 Bids	771	$3,619	$112,093	$182,018	$16,362	$58,350	11.41%
Firm Type							
Integrated Firms	386	$4,693	$272,902	$438,276	$109,753	$216,847	17.96%
Independent Firms	1179	$1,763	$66,282	$111,028	($2,695)	$23,532	7.07%
Firm Size							
Top 4	281	$5,401	$305,881	$491,453	$128,323	$249,352	17.99%
Top 5-8	203	$1,320	$76,025	$106,654	$3,807	$22,399	10.61%
Top 9-20	335	$1,826	$111,571	$185,017	$22,642	$67,711	14.32%
Non Top 20	747	$1,999	$59,874	$104,882	($7,001)	$18,941	5.41%
Water Depth							
< 60m	1030	$2,397	$55,002	$76,584	($4,819)	$6,990	3.10%
60m - 200m	314	$2,310	$85,265	$113,842	($12,483)	$3,482	1.16%
200m - 900m	141	$3,555	$361,526	$565,215	$154,081	$282,031	23.25%
>900m	82	$2,580	$598,785	$1,289,847	$320,841	$772,590	34.87%
Conduct							
Solo Bidder	982	$1,854	$111,980	$185,479	$23,797	$69,162	13.86%
Joint Bidder	583	$3,571	$125,683	$201,143	$26,817	$73,913	12.02%
Bonus Size							
< $200K	194	$146	$78,496	$177,358	$9,204	$70,768	16.81%
$200K - $400K	224	$286	$54,408	$105,863	($2,268)	$28,825	10.52%
$400K - $1,000K	326	$676	$102,693	$181,295	$19,139	$67,905	15.85%
> $1,000K	821	$4,373	$149,018	$221,905	$38,351	$83,661	12.39%
Area							
EGOM	2	$2,050	$131,898	$341,823	$73,966	$201,273	32.67%
CGOM	1145	$2,555	$120,759	$194,537	$25,589	$71,502	12.89%
WGOM	420	$2,328	$107,067	$182,528	$23,105	$69,380	13.38%

The time interval from lease sale to first drilling activity (spud) and from sales to first production by lease category is called expeditious development index in this report. Our study shows evidence of declining trends over time in the average lag from sales to production on leases issued from 1983 to 1999. On average, it took about 78.9 months prior to first production on leases sold from 1983 to 1987. In comparison it took approximately 50.3 months on average from sales to production for leases sold from 1995 to 1999.

Variations in the expeditious development index are evident in Table 18. The average time lag from sales to spud increases with firm size just as the average time lag from spud to production also increases with firm size. As the average water depth of a lease increases so does the average time lag from sales to first production on the lease. The time interval between sales to first drilling and between first drilling to first production decreases as the signature bonus payment increases. Independent producers, according to our empirical analysis, tend to attain first production after lease sales more quickly than integrated firms.

Regarding productivity as a measure of physical performance of lease development in the Gulf of Mexico, we found evidence that the overall aggregate productivity per drilled lease declined significantly from a high of 4,536 MBOE for leases issued from 1983-1987 to 2,864 MBOE for leases issued in the early 1990s. Further, for all categories of leases, the productivity ratios in the early 1980s were significantly higher than productivity ratios in the early 1990s, notwithstanding the fact that more leases were issued and drilled in the 1980s than in the early 1990s.

A comparison of aggregate lease productivity to lease category shows some discernable patterns. For example:

- The aggregate productivity for leases seems to increase with rising lease bonus value, *ceteris paribus*.
- Lease development productivity tends to rise with water depth in the Gulf of Mexico OCS.
- Lease productivity ratios for E&P firms by type show some significant differences. Integrated firms had higher aggregate productivity than independents for leases issued from 1983 to 1999. In addition, the declining trend in productivity for both firm types from the 1980s to the 1990s is clearly identifiable.
- Further, development productivity rate by firm size shows a rising productivity rate with firm size. A declining trend over time is unmistakable for the top eight firms.

In this report, we adopted two of the more popular economic performance measures to analyze the performance of OCS leases issued from 1983 to 1999 and developed from 1983 to 2004. The two measures, profitability index and internal rate of return, recognize the time value of money, and we estimated them on a before-tax basis.

For comparative purposes, we used two representative discount rates in this report to calculate profitability indices for all categories of leases. The key finding in the profitability index analysis is that the estimated indices were significantly low for all categories of leases. This finding notwithstanding, we found that the impact of bonus payment, which has been suggested to be regressive in nature, is significant on the economic performance of lease development. Several lease categories were found to have added value to capital investment if signature bonus payments were excluded in the calculation of the profitability index.

The profitability index for several categories of leases added positive benefits to initial investments using 17 percent discount factor. The positive benefits added for the most part are also only marginal for several of these lease categories. However, when we discounted operating cash flow by 12.5 percent, several lease categories added value to the investment. The results suggest that the choice of discount rate in the determination of project viability is significant.

Finally, the overall internal rate of return for all leases issued from 1983 to 1999 is estimated as 6.9 percent. This estimate is extremely low in comparison to the rate of return in comparable U.S. industries. The reason for this low return is most likely due to the number of productive drilled leases (1,567 out of 13,641). The return for productive leases, on the aggregate, is also low at 13.0 percent. The low profitability measures in terms of internal rates of return notwithstanding, we found that in the aggregate, leases issued in the early 1990s have a higher annual rate of return on average than leases issued in the late 1980s.

There is evidence to suggest that the rate of return for productive leases in the Western Gulf planning area is higher, on average, than for leases in the Central Gulf over the study period. The evidence, however, does not suggest a similar trend for aggregate rate of return for all leases.

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APPENDIX

TABLES

Table A.1

Aggregate Performance Measures for Leases Issued from 1983 to 1999 with Bonus Value < $200K

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Bonus Size	*< $200K*	3,528	$152	$4,316	$9,753	($546)	$2,840	9.36%
Firm Size	*Top 4*	1608	$167	$5,218	$12,386	$984	$5,564	17.24%
	Top 5-8	685	$128	$2,639	$4,530	($1,861)	($759)	-
	Top 9-20	459	$126	$3,604	$8,566	($327)	$2,842	10.14%
	Non Top 20	776	$156	$4,351	$9,607	($2,683)	$372	1.04%
Conduct	*Solo Bidder*	2954	$151	$4,228	$9,895	($591)	$2,949	9.51%
	Joint Bidder	574	$153	$4,771	$9,021	($312)	$2,277	8.47%
Firm Type	*Integrated Firms*	1887	$164	$5,066	$11,814	$911	$5,229	17.10%
	Independent Firms	1641	$138	$3,455	$7,382	($2,221)	$93	0.32%
Lease Type	*Drainage*	56	$146	$3,733	$5,469	($2,072)	($1,027)	-
	Wildcat	3472	$152	$4,326	$9,822	($521)	$2,902	9.60%
Water Depth	*< 60m*	1443	$143	$2,598	$4,705	($1,604)	($403)	-
	60m - 200m	491	$141	$4,605	$7,674	($2,636)	($887)	-
	200m - 900m	456	$162	$4,158	$8,783	$48	$2,935	12.24%
	>900m	1138	$163	$6,435	$17,439	$1,460	$8,521	21.71%
Structure	*Single Bid*	3303	$151	$4,128	$9,486	($452)	$2,897	9.77%
	≥ 2 Bids	225	$156	$7,075	$13,665	($1,917)	$1,996	4.99%
Planning Area	*CGOM*	2128	$148	$5,361	$11,286	($768)	$2,925	8.58%
	WGOM	1400	$158	$2,729	$7,422	($208)	$2,711	11.06%

Table A.2

Aggregate Performance Measures for Leases Issued from 1983 to 1999 with Bonus Value of $200K - $400K

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Bonus Size	*$200K - $400K*	3,249	$278	$3,751	$7,299	($1,525)	$619	2.39%
Firm Size	*Top 4*	1378	$294	$1,911	$4,241	($834)	$639	3.50%
	Top 5-8	494	$225	$3,972	$5,600	($1,980)	($1,047)	-
	Top 9-20	598	$253	$6,094	$12,728	($689)	$3,407	9.82%
	Non Top 20	778	$300	$5,057	$9,611	($3,083)	($481)	-
Conduct	*Solo Bidder*	2482	$276	$3,689	$6,865	($1,493)	$425	1.80%
	Joint Bidder	767	$283	$3,952	$8,703	($1,626)	$1,248	3.79%
Firm Type	*Integrated Firms*	1690	$287	$1,921	$4,066	($1,012)	$328	1.87%
	Independent Firms	1558	$266	$5,730	$10,800	($2,071)	$946	2.69%
Lease Type	*Drainage*	72	$276	$13,069	$20,903	$1,219	$5,892	11.00%
	Wildcat	3177	$278	$3,540	$6,990	($1,587)	$500	1.97%
Water Depth	*< 60m*	1143	$279	$5,631	$9,140	($2,055)	($81)	-
	60m - 200m	409	$279	$6,506	$9,308	($2,421)	($764)	-
	200m - 900m	434	$273	$5,035	$16,475	($243)	$7,002	16.19%
	>900m	1263	$278	$717	$1,828	($1,195)	($493)	-
Structure	*Single Bid*	2612	$274	$2,619	$4,733	($1,743)	($501)	-
	≥ 2 Bids	637	$293	$8,393	$17,820	($629)	$5,211	10.40%
Planning Area	*CGOM*	1982	$279	$4,911	$8,991	($1,819)	$623	2.05%
	WGOM	1267	$276	$1,936	$4,651	($1,064)	$613	3.21%

Table A.3

Aggregate Performance Measures for Leases Issued from 1983 to 1999 with Bonus Value of $400K - $1,000K

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Bonus Size	*$400K - $1,000K*	3,249	$657	$12,178	$21,499	$136	$5,919	8.81%
Firm Size	*Top 4*	1378	$333	$5,275	$9,630	$928	$3,754	11.80%
	Top 5-8	494	$265	$5,753	$8,781	($24)	$1,852	10.28%
	Top 9-20	598	$213	$6,330	$12,084	$741	$4,366	13.61%
	Non Top 20	778	$152	$2,310	$3,815	($732)	$107	0.79%
Conduct	*Solo Bidder*	2482	$648	$9,916	$16,799	($472)	$3,782	6.85%
	Joint Bidder	767	$674	$16,904	$31,318	$1,407	$10,384	11.39%
Firm Type	*Integrated Firms*	1690	$297	$8,781	$15,956	$1,504	$6,147	11.94%
	Independent Firms	1558	$177	$11,963	$20,627	($1,389)	$3,777	5.98%
Lease Type	*Drainage*	72	$689	$6,936	$9,124	($2,536)	($1,424)	-
	Wildcat	3177	$656	$12,350	$21,904	$224	$6,159	9.10%
Water Depth	*< 60m*	1143	$668	$11,293	$15,905	($2,016)	$555	1.08%
	60m - 200m	409	$670	$14,461	$19,301	($2,991)	($324)	-
	200m - 900m	434	$681	$18,276	$35,220	$6,697	$17,597	19.01%
	>900m	1263	$625	$9,312	$23,047	$1,251	$10,112	17.66%
Structure	*Single Bid*	2612	$662	$11,354	$20,194	$700	$6,384	9.27%
	≥ 2 Bids	637	$647	$13,775	$24,027	($955)	$5,018	7.70%
Planning Area	*CGOM*	1982	$660	$13,878	$23,439	$103	$6,057	8.43%
	WGOM	1267	$650	$9,302	$18,217	$192	$5,686	9.63%

Table A.4

Aggregate Performance Measures for Leases Issued from 1983 to 1999 with Bonus Value > $1,000K

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Bonus Size	*> $1,000K*	3,768	$3,387	$32,469	$48,350	$3,994	$13,866	6.87%
Firm Size	*Top 4*	1378	$3,958	$45,677	$65,490	$15,203	$28,318	10.02%
	Top 5-8	355	$3,265	$20,855	$26,140	($1,789)	$1,514	1.82%
	Top 9-20	851	$2,593	$27,206	$39,247	$1,685	$8,832	6.54%
	Non Top 20	1182	$3,316	$24,404	$41,675	($5,634)	$4,410	2.28%
Conduct	*Solo Bidder*	1936	$2,982	$36,098	$54,052	$6,111	$17,177	8.40%
	Joint Bidder	1832	$3,815	$28,634	$42,325	$1,756	$10,367	5.31%
Firm Type	*Integrated Firms*	1903	$3,685	$40,689	$59,044	$12,153	$24,146	9.72%
	Independent Firms	1863	$3,074	$24,108	$37,479	($4,314)	$3,402	2.19%
Lease Type	*Drainage*	258	$4,166	$48,709	$71,220	$3,459	$17,038	6.00%
	Wildcat	3510	$3,330	$31,275	$46,669	$4,033	$13,633	6.96%
Water Depth	*< 60m*	1598	$3,372	$21,583	$28,018	($5,147)	($1,739)	-
	60m - 200m	767	$3,634	$20,514	$26,085	($7,096)	($4,034)	-
	200m - 900m	769	$3,486	$51,427	$70,718	$17,521	$29,483	11.72%
	>900m	634	$3,007	$51,377	$99,405	$24,041	$55,912	23.14%
Structure	*Single Bid*	1951	$2,515	$28,576	$40,371	$6,783	$14,481	8.01%
	≥ 2 Bids	1817	$4,323	$36,649	$56,918	$998	$13,206	5.86%
Planning Area	*CGOM*	2375	$3,610	$39,220	$59,118	$5,539	$17,995	7.43%
	WGOM	1393	$3,006	$20,960	$29,991	$1,359	$6,827	5.21%

Table A.5

Aggregate Performance Measures for Leases Issued from 1983 to 1999 in Water Depth < 60m

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Water Depth	*< 60m*	5,365	$1,262	$10,560	$14,703	($2,850)	($583)	-
Firm Size	*Top 4*	1321	$1,887	$9,586	$11,260	($2,055)	($1,092)	-
	Top 5-8	944	$603	$9,399	$13,135	($788)	$1,371	3.61%
	Top 9-20	1033	$994	$9,731	$12,941	($1,901)	($178)	-
	Non Top 20	2066	$1,290	$12,125	$18,502	($4,760)	($1,337)	-
Firm Type	*Integrated Firms*	1730	$1,758	$9,136	$10,725	($2,191)	($1,291)	-
	Independent Firms	3633	$1,022	$11,239	$16,602	($3,157)	($237)	-
Lease Type	*Drainage*	433	$2,237	$17,298	$20,510	($2,326)	($747)	-
	Wildcat	4932	$1,176	$9,968	$14,193	($2,896)	($569)	-
Conduct	*Solo Bidder*	3605	$923	$9,609	$13,728	($2,647)	($365)	-
	Joint Bidder	1638	$2,011	$13,426	$17,925	($3,346)	($945)	-
Bonus Size	*< $200K*	1443	$143	$2,598	$4,705	($1,604)	($403)	-
	$200K - $400K	1143	$279	$5,631	$9,140	($2,055)	($81)	-
	$400K - $1,000K	1059	$668	$11,293	$15,905	($2,016)	$555	1.08%
	> $1,000K	1598	$3,372	$21,583	$28,018	($5,147)	($1,739)	-
Structure	*Single Bid*	3639	$815	$6,337	$8,541	($2,329)	($1,162)	-
	≥ 2 Bids	1604	$2,280	$20,929	$29,783	($4,083)	$850	0.80%
Planning Area	*EGOM*	122	$1,228	$162	$243	($2,203)	($2,172)	-
	CGOM	3422	$1,297	$11,859	$16,969	($3,637)	($827)	-
	WGOM	1821	$1,199	$8,814	$11,414	($1,416)	($19)	-

Table A.6

Aggregate Performance Measures for Leases Issued from 1983 to 1999 in Water Depth of 60m - 200m

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Water Depth	*60m - 200m*	2,183	$1,593	$12,264	$16,375	($4,281)	($1,985)	-
Firm Size	*Top 4*	640	$2,188	$8,459	$9,929	($3,040)	($2,205)	-
	Top 5-8	261	$997	$14,385	$18,187	($4,265)	($2,144)	-
	Top 9-20	581	$1,269	$14,197	$17,994	($2,436)	($241)	-
	Non Top 20	701	$1,532	$13,347	$20,244	($6,922)	($3,141)	-
Firm Type	*Integrated Firms*	903	$2,013	$9,536	$11,088	($2,542)	($1,663)	-
	Independent Firms	1280	$1,293	$14,189	$20,104	($5,492)	($2,196)	-
Lease Type	*Drainage*	213	$2,291	$14,989	$18,895	($2,733)	($540)	-
	Wildcat	1970	$1,517	$11,970	$16,102	($4,448)	($2,141)	-
Conduct	*Solo Bidder*	1374	$1,123	$11,413	$16,076	($3,848)	($1,217)	-
	Joint Bidder	716	$2,390	$15,490	$19,075	($5,174)	($3,221)	-
Bonus Size	*< $200K*	491	$141	$4,605	$7,674	($2,636)	($887)	-
	$200K - $400K	409	$279	$6,506	$9,308	($2,421)	($764)	-
	$400K - $1,000K	423	$670	$14,461	$19,301	($2,991)	($324)	-
	> $1,000K	767	$3,634	$20,514	$26,085	($7,096)	($4,034)	-
Structure	*Single Bid*	1441	$995	$9,712	$12,471	($2,604)	($1,033)	-
	≥ 2 Bids	649	$2,803	$19,690	$27,388	($8,074)	($3,838)	-
Planning Area	*EGOM*	93	$2,406	$0	$0	($3,796)	($3,796)	-
	CGOM	1395	$1,703	$17,243	$22,879	($4,292)	($1,125)	-
	WGOM	695	$1,263	$3,913	$5,511	($4,324)	($3,468)	-

Table A.7

Aggregate Performance Measures for Leases Issued from 1983 to 1999 in Water Depth of 200m - 900m

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Water Depth	*200m - 900m*	2,143	$1,500	$23,787	$37,189	$7,463	$15,882	12.49%
Firm Size	*Top 4*	1095	$1,648	$25,894	$36,149	$9,490	$16,002	12.78%
	Top 5-8	206	$1,161	$7,506	$9,020	($454)	$429	1.51%
	Top 9-20	428	$1,131	$35,645	$59,744	$13,587	$28,884	19.02%
	Non Top 20	413	$1,656	$14,089	$30,713	($281)	$9,844	7.14%
Firm Type	*Integrated Firms*	1391	$1,613	$27,095	$39,515	$9,808	$17,597	13.21%
	Independent Firms	751	$1,289	$17,691	$32,929	$3,134	$12,730	10.69%
Lease Type	*Drainage*	120	$1,033	$16,442	$20,261	$5,993	$8,522	12.91%
	Wildcat	2023	$1,528	$24,223	$38,193	$7,551	$16,318	12.47%
Conduct	*Solo Bidder*	1351	$1,063	$20,824	$31,401	$7,181	$13,787	15.25%
	Joint Bidder	710	$2,410	$32,171	$52,497	$8,988	$21,827	10.52%
Bonus Size	*< $200,000*	456	$162	$4,158	$8,783	$48	$2,935	12.24%
	$200K - $400K	434	$273	$5,035	$16,475	($243)	$7,002	16.19%
	$400K - $1,000K	402	$681	$18,276	$35,220	$6,697	$17,597	19.01%
	> $1,000K	769	$3,486	$51,427	$70,718	$17,521	$29,483	11.72%
Structure	*Single Bid*	1543	$892	$14,084	$24,295	$3,611	$10,008	12.09%
	≥ 2 Bids	518	$3,418	$56,456	$81,484	$20,290	$36,063	13.00%
Planning Area	*EGOM*	82	$834	$0	$0	($1,081)	($1,081)	-
	CGOM	1056	$1,937	$32,790	$50,626	$10,885	$22,107	12.66%
	WGOM	1005	$1,096	$16,268	$26,104	$4,565	$10,725	12.51%

Table A.8

Aggregate Performance Measures for Leases Issued from 1983 to 1999 in Water Depth > 900m

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Water Depth	*>900m*	3,950	$762	$12,430	$26,777	$4,196	$13,574	20.86%
Firm Size	*Top 4*	2619	$556	$15,090	$29,510	$6,649	$16,222	22.89%
	Top 5-8	526	$1,034	$2,394	$5,032	($2,046)	($143)	-
	Top 9-20	468	$1,056	$8,160	$26,897	($1,250)	$10,493	16.49%
	Non Top 20	336	$1,530	$13,395	$39,425	$2,445	$18,738	17.57%
Firm Type	*Integrated Firms*	3103	$638	$13,933	$27,600	$5,700	$14,773	22.20%
	Independent Firms	846	$1,217	$6,934	$23,788	($1,317)	$9,191	14.09%
Lease Type	*Drainage*	54	$914	$35,716	$117,156	$16,643	$68,413	32.25%
	Wildcat	3896	$760	$12,108	$25,524	$4,023	$12,814	20.53%
Conduct	*Solo Bidder*	2901	$622	$10,861	$23,488	$3,665	$11,862	20.72%
	Joint Bidder	999	$1,179	$17,366	$37,012	$5,851	$18,876	21.25%
Bonus Size	*< $200K*	1138	$163	$6,435	$17,439	$1,460	$8,521	21.71%
	$200K - $400K	1263	$278	$717	$1,828	($1,195)	($493)	-
	$400K - $1,000K	865	$625	$9,312	$23,047	$1,251	$10,112	17.66%
	> $1,000K	634	$3,007	$51,377	$99,405	$24,041	$55,912	23.14%
Structure	*Single Bid*	3056	$506	$12,443	$23,735	$4,945	$12,553	22.15%
	≥ 2 Bids	844	$1,701	$12,833	$38,602	$1,619	$17,662	17.57%
Planning Area	*EGOM*	50	$505	$4,880	$13,080	$1,912	$6,928	15.36%
	CGOM	2340	$737	$16,670	$33,889	$6,424	$17,828	21.62%
	WGOM	1560	$807	$6,314	$16,547	$927	$7,406	18.29%

Table A.9

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to the Top Four Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Size	*Top 4*	5,675	$1,261	$15,146	$24,334	$4,078	$10,071	10.22%
Bonus Size	*< $200K*	1608	$167	$5,218	$12,388	$985	$5,565	17.24%
	$200K - $400K	1378	$294	$1,911	$4,241	($834)	$639	3.50%
	$400K - $1,000K	1076	$690	$10,917	$19,929	$1,920	$7,769	11.80%
	> $1,000K	1378	$3,959	$45,684	$65,501	$15,205	$28,323	10.02%
Water Depth	*< 60m*	1321	$1,887	$9,586	$11,260	($2,055)	($1,092)	-
	60m - 200m	640	$2,189	$8,465	$9,935	($3,042)	($2,206)	-
	200m - 900m	1095	$1,649	$25,900	$36,157	$9,493	$16,006	12.78%
	>900m	2619	$556	$15,088	$29,506	$6,648	$16,220	22.89%
Lease Type	*Non-Productive*	5394	$1,045	$0	$0	($2,394)	($2,394)	-
	Productive	281	$5,400	$305,860	$491,420	$128,314	$249,335	17.99%
	Drainage	363	$1,769	$17,425	$26,631	$4,232	$10,024	9.22%
	Wildcat	5311	$1,226	$14,991	$24,179	$4,068	$10,075	10.31%
Structure	*Single Bid*	4319	$759	$12,041	$19,864	$3,808	$9,017	11.86%
	≥ 2 Bids	1120	$3,205	$30,087	$46,109	$6,251	$16,303	8.53%
Conduct	*Solo Bidder*	4,411	$1,012	$13,109	$20,978	$3,579	$8,653	10.92%
	Joint Bidder	1,028	$2,340	$27,114	$43,670	$7,451	$18,512	9.63%
Planning Area	*EGOM*	235	$1,205	$1,036	$2,778	($1,286)	($221)	-
	CGOM	3234	$1,426	$20,701	$33,406	$6,150	$14,504	11.10%
	WGOM	2205	$1,024	$8,509	$13,337	$1,614	$4,672	8.30%
Firm Type	*Integrated Firms*	5675	$1,261	$15,146	$24,334	$4,078	$10,071	10.22%

Table A.10

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to the Top 5-8 Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Size	*Top 5-8*	1,937	$832	$7,968	$11,177	($1,562)	$386	1.20%
Bonus Size	*< $200K*	685	$128	$2,638	$4,529	($1,861)	($759)	-
	$200K - $400K	494	$225	$3,975	$5,603	($1,981)	($1,047)	-
	$400K - $1,000K	356	$549	$11,904	$18,170	($50)	$3,831	10.28%
	>$1,000K	355	$3,266	$20,861	$26,148	($1,790)	$1,514	1.82%
Water Depth	*< 60m*	944	$603	$9,402	$13,139	($788)	$1,372	3.61%
	60m - 200m	261	$996	$14,373	$18,172	($4,262)	($2,143)	-
	200m - 900m	206	$1,163	$7,514	$9,030	($455)	$429	1.51%
	>900m	526	$1,033	$2,392	$5,027	($2,044)	($143)	-
Lease Type	*Non-Productive*	1734	$775	$0	$0	($2,191)	($2,191)	-
	Productive	203	$1,320	$76,036	$106,670	$3,807	$22,403	10.61%
	Drainage	85	$1,502	$8,301	$9,780	($3,902)	($3,216)	-
	Wildcat	1853	$802	$7,952	$11,240	($1,455)	$551	1.75%
Structure	*Single Bid*	1429	$498	$5,748	$8,602	($1,438)	$326	1.20%
	≥ 2 Bids	461	$1,826	$15,612	$20,230	($1,846)	$865	1.79%
Conduct	*Solo Bidder*	1440	$551	$6,535	$9,597	($2,039)	($198)	-
	Joint Bidder	450	$1,688	$13,343	$17,338	$69	$2,555	4.23%
Planning Area	*EGOM*	47	$1,255	$420	$628	($2,554)	($2,473)	-
	CGOM	1178	$836	$10,171	$14,314	($1,385)	$1,181	2.87%
	WGOM	712	$798	$4,820	$6,686	($1,790)	($739)	-
Firm Type	*Integrated Firms*	593	$1,186	$6,135	$8,982	($914)	$1,057	2.49%
	Independent Firms	1345	$676	$8,770	$12,137	($1,847)	$90	0.31%

Table A.11

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to the Top 9-20 Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Size	*Top 9-20*	2,510	$1,092	$14,891	$24,694	$737	$6,753	8.32%
Bonus Size	*< $200K*	459	$126	$3,602	$8,562	($327)	$2,840	10.14%
	$200K - $400K	598	$253	$6,096	$12,732	($689)	$3,409	9.82%
	$400K - $1,000K	549	$547	$16,250	$31,022	$1,902	$11,209	13.61%
	>$1,000K	851	$2,592	$27,197	$39,234	$1,685	$8,829	6.54%
Water Depth	*< 60m*	1033	$994	$9,734	$12,945	($1,902)	($178)	-
	60m - 200m	581	$1,268	$14,185	$17,978	($2,434)	($241)	-
	200m - 900m	428	$1,129	$35,604	$59,674	$13,571	$28,851	19.02%
	>900m	468	$1,057	$8,168	$26,922	($1,251)	$10,503	16.49%
Lease Type	*Non-Productive*	2175	$979	$0	$0	($2,636)	($2,636)	-
	Productive	335	$1,827	$111,624	$185,107	$22,653	$67,743	14.32%
	Drainage	177	$1,355	$17,316	$21,285	($646)	$1,686	2.19%
	Wildcat	2333	$1,072	$14,705	$24,950	$843	$7,137	8.87%
Structure	*Single Bid*	1627	$725	$10,971	$19,250	$1,039	$6,268	9.65%
	≥ 2 Bids	830	$1,849	$23,512	$36,920	$272	$8,208	7.06%
Conduct	*Solo Bidder*	1415	$823	$11,387	$20,059	($315)	$5,027	7.85%
	Joint Bidder	1042	$1,488	$20,398	$32,230	$2,266	$9,499	8.74%
Planning Area	*EGOM*	53	$490	$0	$0	($1,250)	($1,250)	-
	CGOM	1511	$1,238	$17,018	$25,793	$187	$5,472	6.76%
	WGOM	947	$894	$12,324	$24,309	$1,726	$9,240	11.07%
Firm Type	*Integrated Firms*	464	$1,622	$22,700	$33,852	$5,481	$12,471	11.49%
	Independent Firms	2047	$972	$13,113	$22,605	($338)	$5,453	7.20%

Table A.12

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to the Non Top 20 Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Size	*Non Top 20*	3,515	$1,405	$12,724	$22,289	($3,978)	$1,535	1.62%
Bonus Size	*< $200K*	776	$156	$4,352	$9,609	($2,684)	$372	1.04%
	$200K - $400K	778	$300	$5,054	$9,606	($3,081)	($481)	-
	$400K - $1,000K	767	$737	$11,175	$18,457	($3,541)	$516	0.79%
	> $1,000K	1182	$3,316	$24,402	$41,673	($5,634)	$4,410	2.28%
Water Depth	*< 60m*	2066	$1,290	$12,128	$18,506	($4,761)	($1,337)	-
	60m - 200m	701	$1,533	$13,352	$20,252	($6,924)	($3,142)	-
	200m - 900m	413	$1,656	$14,089	$30,714	($281)	$9,844	7.14%
	>900m	336	$1,532	$13,409	$39,467	$2,448	$18,758	17.57%
Lease Type	*Non-Productive*	2768	$1,244	$0	$0	($3,162)	($3,162)	-
	Productive	747	$1,999	$59,860	$104,858	($6,999)	$18,937	5.41%
	Drainage	195	$3,159	$23,004	$37,921	($5,428)	$3,164	1.70%
	Wildcat	3320	$1,302	$12,122	$21,373	($3,893)	$1,440	1.61%
Structure	*Single Bid*	2303	$933	$8,139	$12,880	($3,310)	($658)	-
	≥ 2 Bids	1200	$2,242	$21,648	$40,563	($5,194)	$5,865	3.63%
Conduct	*Solo Bidder*	1962	$859	$13,560	$24,154	($3,508)	$2,586	2.85%
	Joint Bidder	1541	$2,046	$11,758	$20,086	($4,525)	$292	0.30%
Planning Area	*EGOM*	12	$8,461	$0	$0	($10,786)	($10,786)	-
	CGOM	2287	$1,351	$14,705	$25,749	($4,542)	$1,820	1.74%
	WGOM	1217	$1,438	$9,124	$16,002	($2,852)	$1,118	1.48%
Firm Type	*Integrated Firms*	397	$1,190	$13,141	$25,296	$254	$7,601	8.89%
	Independent Firms	3117	$1,433	$12,675	$21,913	($4,518)	$763	0.81%

Table A.13

Aggregate Performance Measures for Solo Venture Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Conduct	*Solo Bidder*	9,231	$879	$11,912	$19,731	$596	$5,422	7.80%
Firm Size	*Top 4*	4411	$1,012	$13,109	$20,977	$3,578	$8,653	10.92%
	Top 5-8	1440	$551	$6,535	$9,598	($2,039)	($198)	-
	Top 9-20	1415	$823	$11,389	$20,062	($315)	$5,028	7.85%
	Non Top 20	1962	$859	$13,559	$24,152	($3,507)	$2,586	2.85%
Bonus Size	*< $200K*	2954	$151	$4,228	$9,895	($591)	$2,949	9.51%
	$200K - $400K	2482	$276	$3,689	$6,865	($1,493)	$425	1.80%
	$400K - $1,000K	1859	$648	$9,916	$16,799	($472)	$3,782	6.85%
	> $1,000K	1936	$2,982	$36,098	$54,052	$6,111	$17,177	8.40%
Firm Type	*Integrated Firms*	5123	$994	$12,637	$20,499	$3,114	$8,153	10.77%
	Independent Firms	4105	$735	$11,014	$18,785	($2,541)	$2,023	3.11%
Lease Type	*Drainage*	278	$1,669	$27,378	$35,683	($441)	$4,099	3.59%
	Wildcat	8953	$854	$11,432	$19,236	$628	$5,463	8.06%
Water Depth	*< 60m*	3605	$923	$9,609	$13,728	($2,647)	($365)	-
	60m - 200m	1374	$1,123	$11,413	$16,076	($3,848)	($1,217)	-
	200m - 900m	1351	$1,063	$20,824	$31,401	$7,181	$13,787	15.25%
	>900m	2901	$622	$10,861	$23,488	$3,665	$11,862	20.72%
Planning Area	*CGOM*	5536	$940	$14,937	$24,322	$914	$6,709	8.08%
	WGOM	3695	$787	$7,381	$12,854	$120	$3,493	7.12%
Structure	*Single Bid*	7060	$603	$8,687	$14,426	$574	$4,176	7.77%
	≥ 2 Bids	2171	$1,774	$22,400	$36,985	$668	$9,476	7.85%

Table A.14

Aggregate Performance Measures for Joint Venture Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Conduct	*Joint Bidder*	4,063	$1,943	$18,034	$28,862	$749	$7,507	6.19%
Firm Size	*Top 4*	1028	$2,341	$27,127	$43,690	$7,454	$18,521	9.63%
	Top 5-8	450	$1,687	$13,338	$17,333	$69	$2,554	4.23%
	Top 9-20	1042	$1,489	$20,404	$32,239	$2,267	$9,501	8.74%
	Non Top 20	1541	$2,046	$11,761	$20,091	($4,526)	$292	0.30%
Bonus Size	*< $200K*	574	$153	$4,771	$9,021	($312)	$2,277	8.47%
	$200K - $400K	767	$283	$3,952	$8,703	($1,626)	$1,248	3.79%
	$400K - $1,000K	890	$674	$16,904	$31,318	$1,407	$10,384	11.39%
	> $1,000K	1832	$3,815	$28,634	$42,325	$1,756	$10,367	5.31%
Firm Type	*Integrated Firms*	1720	$2,118	$23,453	$36,905	$5,654	$14,531	9.30%
	Independent Firms	2342	$1,805	$14,062	$22,968	($2,837)	$2,368	2.46%
Lease Type	*Drainage*	195	$3,584	$34,407	$56,717	$3,930	$17,945	6.99%
	Wildcat	3868	$1,860	$17,209	$27,458	$588	$6,980	6.09%
Water Depth	*< 60m*	1638	$2,011	$13,426	$17,925	($3,346)	($945)	-
	60m - 200m	716	$2,390	$15,490	$19,075	($5,174)	($3,221)	-
	200m - 900m	710	$2,410	$32,171	$52,497	$8,988	$21,827	10.52%
	>900m	999	$1,179	$17,366	$37,012	$5,851	$18,876	21.25%
Planning Area	*CGOM*	2677	$2,009	$20,761	$32,910	$1,134	$8,786	6.48%
	WGOM	1386	$1,815	$12,768	$21,043	$5	$5,035	5.38%
Structure	*Single Bid*	2619	$1,169	$13,547	$21,850	$1,682	$7,106	7.76%
	≥ 2 Bids	1444	$3,346	$26,172	$41,580	($943)	$8,233	4.72%

Table A.15

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to Integrated Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Type	*Integrated firms*	7128	$1,274	$14,778	$23,734	$3,542	$9,341	9.92%
Firm Size	*Top 4*	5675	$1,261	$15,147	$24,336	$4,079	$10,072	10.22%
	Top 5-8	593	$1,187	$6,140	$8,989	($915)	$1,058	2.49%
	Top 9-20	464	$1,623	$22,715	$33,874	$5,485	$12,479	11.49%
	Non Top 20	397	$1,189	$13,128	$25,271	$253	$7,593	8.89%
Bonus Size	*< $200K*	1887	$164	$5,066	$11,814	$911	$5,229	17.10%
	$200K - $400K	1690	$287	$1,921	$4,067	($1,012)	$328	1.87%
	$400K - $1,000K	1364	$680	$10,879	$19,769	$1,863	$7,617	11.94%
	> $1,000K	1903	$3,685	$40,696	$59,054	$12,155	$24,151	9.72%
Water Depth	*< 60m*	1730	$1,758	$9,134	$10,722	($2,190)	($1,291)	-
	60m - 200m	903	$2,012	$9,532	$11,083	($2,541)	($1,662)	-
	200m - 900m	1391	$1,613	$27,093	$39,512	$9,808	$17,596	13.21%
	>900m	3103	$637	$13,931	$27,597	$5,700	$14,772	22.20%
Lease Type	*Productive*	387	$4,684	$272,347	$437,385	$109,530	$216,406	17.96%
	Drainage	461	$1,775	$15,686	$23,886	$3,227	$8,380	8.28%
	Wildcat	6667	$1,239	$14,715	$23,722	$3,564	$9,407	10.05%
Structure	*Single Bid*	5278	$780	$11,792	$19,584	$3,354	$8,502	11.50%
	≥ 2 Bids	1566	$2,949	$27,361	$41,599	$5,095	$13,979	8.35%
Conduct	*Solo Bidder*	5123	$994	$12,636	$20,497	$3,114	$8,152	10.77%
	Joint Bidder	1720	$2,118	$23,451	$36,901	$5,654	$14,530	9.30%
Planning Area	*CGOM*	4129	$1,440	$19,941	$32,022	$5,327	$13,207	10.80%
	WGOM	2715	$1,027	$8,379	$13,364	$1,357	$4,505	8.03%

Table A.16

Aggregate Performance Measures for Leases Issued from 1983 to 1999 to Independent Firms

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Firm Type	*Independent Firms*	6508	$1,132	$12,008	$20,114	($2,652)	$2,099	2.76%
Firm Size	*Top 5-8*	1345	$676	$8,772	$12,140	($1,848)	$90	0.31%
	Top 9-20	2047	$972	$13,116	$22,610	($338)	$5,454	7.20%
	Non Top 20	3117	$1,432	$12,673	$21,910	($4,517)	$763	0.81%
Bonus Size	*< $200K*	1641	$138	$3,455	$7,382	($2,221)	$93	0.32%
	$200K - $400K	1558	$266	$5,729	$10,799	($2,071)	$946	2.69%
	$400K - $1,000K	1384	$633	$13,467	$23,221	($1,564)	$4,252	5.98%
	>$1,000K	1863	$3,073	$24,103	$37,473	($4,314)	$3,401	2.19%
Water Depth	*< 60m*	3633	$1,022	$11,241	$16,604	($3,157)	($237)	-
	60m - 200m	1280	$1,293	$14,194	$20,111	($5,494)	($2,197)	-
	200m - 900m	751	$1,289	$17,694	$32,934	$3,135	$12,732	10.69%
	>900m	846	$1,217	$6,937	$23,798	($1,318)	$9,195	14.09%
Lease Type	*Productive*	1179	$1,763	$66,270	$111,008	($2,695)	$23,528	7.07%
	Drainage	359	$2,249	$20,485	$29,675	($4,046)	$1,174	0.91%
	Wildcat	6150	$1,066	$11,512	$19,554	($2,570)	$2,153	2.96%
Structure	*Single Bid*	4400	$728	$7,858	$12,661	($2,100)	$732	1.44%
	≥ 2 Bids	2046	$1,975	$21,293	$36,745	($3,829)	$5,194	3.98%
Conduct	*Solo Bidder*	4105	$735	$11,015	$18,787	($2,541)	$2,023	3.11%
	Joint Bidder	2342	$1,805	$14,063	$22,969	($2,837)	$2,368	2.46%
Planning Area	*EGOM*	62	$1,924	$0	$0	($2,974)	($2,974)	-
	CGOM	4080	$1,130	$13,706	$22,185	($3,393)	$1,518	1.88%
	WGOM	2366	$1,113	$9,391	$17,066	($1,365)	$3,236	4.68%

Table A.17

Aggregate Performance Measures for Drainage Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Lease Type	*Drainage*	820	$1,988	$17,786	$26,419	$35	$5,218	4.52%
Firm Size	*Top 4*	363	$1,771	$17,444	$26,660	$4,236	$10,035	9.22%
	Top 5-8	85	$1,494	$8,258	$9,728	($3,881)	($3,199)	-
	Top 9-20	177	$1,358	$17,347	$21,323	($648)	$1,689	2.19%
	Non Top 20	195	$3,154	$22,974	$37,871	($5,421)	$3,160	1.70%
Bonus Size	*< $200K*	56	$146	$3,733	$5,469	($2,072)	($1,027)	-
	$200K - $400K	72	$276	$13,069	$20,903	$1,219	$5,892	11.00%
	$400K - $1,000K	87	$689	$6,936	$9,124	($2,536)	($1,424)	-
	> $1,000K	258	$4,166	$48,709	$71,220	$3,459	$17,038	6.00%
Water Depth	*< 60m*	433	$2,237	$17,298	$20,510	($2,326)	($747)	-
	60m - 200m	213	$2,291	$14,989	$18,895	($2,733)	($540)	-
	200m - 900m	120	$1,033	$16,442	$20,261	$5,993	$8,522	12.91%
	>900m	54	$914	$35,716	$117,156	$16,643	$68,413	32.25%
Structure	*Single Bid*	293	$1,505	$16,753	$21,746	($848)	$1,986	2.22%
	≥ 2 Bids	180	$4,009	$52,287	$81,157	$4,956	$22,537	7.48%
Planning Area	*EGOM*	347	$1,346	$760	$1,970	($1,772)	($1,038)	-
	CGOM	317	$2,644	$34,616	$54,026	$1,261	$12,977	6.21%
	WGOM	156	$2,081	$21,456	$24,702	$1,564	$3,366	3.49%
Conduct	*Solo Bidder*	278	$1,669	$27,378	$35,683	($441)	$4,099	3.59%
	Joint Bidder	195	$3,584	$34,407	$56,717	$3,930	$17,945	6.99%
Firm Type	*Integrated Firms*	461	$1,775	$15,692	$23,895	$3,228	$8,383	8.28%
	Independent Firms	359	$2,248	$20,475	$29,660	($4,044)	$1,174	0.91%

Table A.18

Aggregate Performance Measures for Wildcat Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Lease Type	*Wildcat*	12,821	$1,158	$13,175	$21,716	$616	$5,921	7.18%
Firm Size	*Top 4*	5311	$1,226	$14,992	$24,180	$4,068	$10,076	10.31%
	Top 5-8	1853	$802	$7,950	$11,238	($1,455)	$550	1.75%
	Top 9-20	2333	$1,072	$14,705	$24,949	$843	$7,137	8.87%
	Non Top 20	3320	$1,302	$12,122	$21,374	($3,893)	$1,440	1.61%
Bonus Size	*< $200K*	3472	$152	$4,326	$9,822	($521)	$2,902	9.60%
	$200K - $400K	3177	$278	$3,540	$6,990	($1,587)	$500	1.97%
	$400K - $1,000K	2662	$656	$12,350	$21,904	$224	$6,159	9.10%
	> $1,000K	3510	$3,330	$31,275	$46,669	$4,033	$13,633	6.96%
Water Depth	*< 60m*	4932	$1,176	$9,968	$14,193	($2,896)	($569)	-
	60m - 200m	1970	$1,517	$11,970	$16,102	($4,448)	($2,141)	-
	200m - 900m	2023	$1,528	$24,223	$38,193	$7,551	$16,318	12.47%
	>900m	3896	$760	$12,108	$25,524	$4,023	$12,814	20.53%
Structure	*Single Bid*	9386	$733	$9,792	$16,269	$927	$5,062	8.07%
	≥ 2 Bids	3435	$2,318	$22,420	$36,602	($234)	$8,269	6.09%
Planning Area	*EGOM*	0	$0	$0	$0	$0	$0	0.00%
	CGOM	7896	$1,234	$16,122	$26,041	$974	$7,162	7.44%
	WGOM	4925	$1,035	$8,451	$14,783	$42	$3,931	6.53%
Conduct	*Solo Bidder*	8953	$854	$11,432	$19,236	$628	$5,463	8.06%
	Joint Bidder	3868	$1,860	$17,209	$27,458	$588	$6,980	6.09%
Firm Type	*Integrated Firms*	6667	$1,239	$14,715	$23,723	$3,564	$9,408	10.05%
	Independent Firms	6150	$1,066	$11,512	$19,554	($2,570)	$2,153	2.96%

Table A.19

Aggregate Performance Measures for All Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Lease Type	*All*	13,641	$1,208	$13,452	$21,999	$581	$5,879	6.94%
	Drainage	820	$1,988	$17,786	$26,419	$35	$5,218	4.52%
	Wildcat	12821	$1,158	$13,175	$21,716	$616	$5,921	7.18%
Firm Size	*Top 4*	5675	$1,261	$15,146	$24,334	$4,078	$10,071	10.22%
	Top 5-8	1937	$832	$7,968	$11,177	($1,562)	$386	1.20%
	Top 9-20	2510	$1,092	$14,891	$24,694	$737	$6,753	8.32%
	Non Top 20	3515	$1,405	$12,724	$22,289	($3,978)	$1,535	1.62%
Water Depth	*< 60m*	5365	$1,262	$10,560	$14,703	($2,850)	($583)	-
	60m - 200m	2183	$1,593	$12,264	$16,375	($4,281)	($1,985)	-
	200m - 900m	2143	$1,500	$23,787	$37,189	$7,463	$15,882	12.49%
	>900m	3950	$762	$12,430	$26,777	$4,196	$13,574	20.86%
Bonus Size	*< $200K*	3528	$152	$4,316	$9,753	($546)	$2,840	9.36%
	$200K - $400K	3249	$278	$3,751	$7,299	($1,525)	$619	2.39%
	$400K - $1,000K	2749	$657	$12,178	$21,499	$136	$5,919	8.81%
	> $1,000K	3768	$3,387	$32,469	$48,350	$3,994	$13,866	6.87%
Firm Type	*Integrated Firms*	7128	$1,274	$14,778	$23,734	$3,542	$9,341	9.92%
	Independent Firms	6508	$1,132	$12,008	$20,114	($2,652)	$2,099	2.76%
Structure	*Single Bid*	9679	$757	$10,002	$16,435	$874	$4,968	7.76%
	≥ 2 Bids	3615	$2,402	$23,907	$38,820	$24	$8,979	6.24%
Conduct	*Solo Bidder*	9231	$879	$11,912	$19,731	$596	$5,422	7.80%
	Joint Bidder	4063	$1,943	$18,034	$28,862	$749	$7,507	6.19%
Planning Area	*EGOM*	347	$1,346	$760	$1,970	($1,772)	($1,038)	-
	CGOM	8213	$1,289	$16,835	$27,121	$985	$7,386	7.33%
	WGOM	5081	$1,067	$8,850	$15,088	$89	$3,914	6.35%

Table A.20

Aggregate Performance Measures for Productive Leases Issued from 1983 to 1999

Group	Lease Category	Number	Average Bonus ($M) per Lease	Aggregate Gross Value of Production ($M) Per Lease		Undiscounted Aggregate Net Cash Flow ($M) Per Lease		IRR (%)
				Historical	Ultimate	Historical	Ultimate	
Lease Type	*Productive*	1,567	$2,493	$117,103	$191,506	$24,985	$71,099	13.03%
	Drainage	151	$4,537	$96,584	$143,466	$12,063	$40,206	8.41%
	Wildcat	1416	$2,275	$119,292	$196,629	$26,363	$74,393	13.57%
Firm Size	*Top 4*	281	$5,401	$305,881	$491,453	$128,323	$249,352	17.99%
	Top 5-8	203	$1,320	$76,025	$106,654	$3,807	$22,399	10.61%
	Top 9-20	335	$1,826	$111,571	$185,017	$22,642	$67,711	14.32%
	Non Top 20	747	$1,999	$59,874	$104,882	($7,001)	$18,941	5.41%
Water Depth	*< 60m*	1030	$2,397	$55,002	$76,584	($4,819)	$6,990	3.10%
	60m - 200m	314	$2,310	$85,265	$113,842	($12,483)	$3,482	1.16%
	200m - 900m	141	$3,555	$361,526	$565,215	$154,081	$282,031	23.25%
	>900m	82	$2,580	$598,785	$1,289,847	$320,841	$772,590	34.87%
Bonus Size	*< $200K*	194	$146	$78,496	$177,358	$9,204	$70,768	16.81%
	$200K - $400K	224	$286	$54,408	$105,863	($2,268)	$28,825	10.52%
	$400K - $1,000K	326	$676	$102,693	$181,295	$19,139	$67,905	15.85%
	> $1,000K	821	$4,373	$149,018	$221,905	$38,351	$83,661	12.39%
Firm Type	*Integrated Firms*	386	$4,693	$272,902	$438,276	$109,753	$216,847	17.96%
	Independent Firms	1179	$1,763	$66,282	$111,028	($2,695)	$23,532	7.07%
Structure	*Single Bid*	794	$1,401	$121,931	$200,342	$33,234	$83,150	14.55%
	≥ 2 Bids	771	$3,619	$112,093	$182,018	$16,362	$58,350	11.41%
Conduct	*Solo Bidder*	982	$1,854	$111,980	$185,479	$23,797	$69,162	13.86%
	Joint Bidder	583	$3,571	$125,683	$201,143	$26,817	$73,913	12.02%
Planning Area	*EGOM*	2	$2,050	$131,898	$341,823	$73,966	$201,273	32.67%
	CGOM	1145	$2,555	$120,759	$194,537	$25,589	$71,502	12.89%
	WGOM	420	$2,328	$107,067	$182,528	$23,105	$69,380	13.38%

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.