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ABSTRACT

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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 be

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

Table ES.2

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

				Lease Prospectivity		
				Drilled	Development	Drilling
	Leases	Leases		Ratio	Index	Risk
Group/Lease Category	Issued	Drilled	Producible	(%)	(%)	(%)
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.

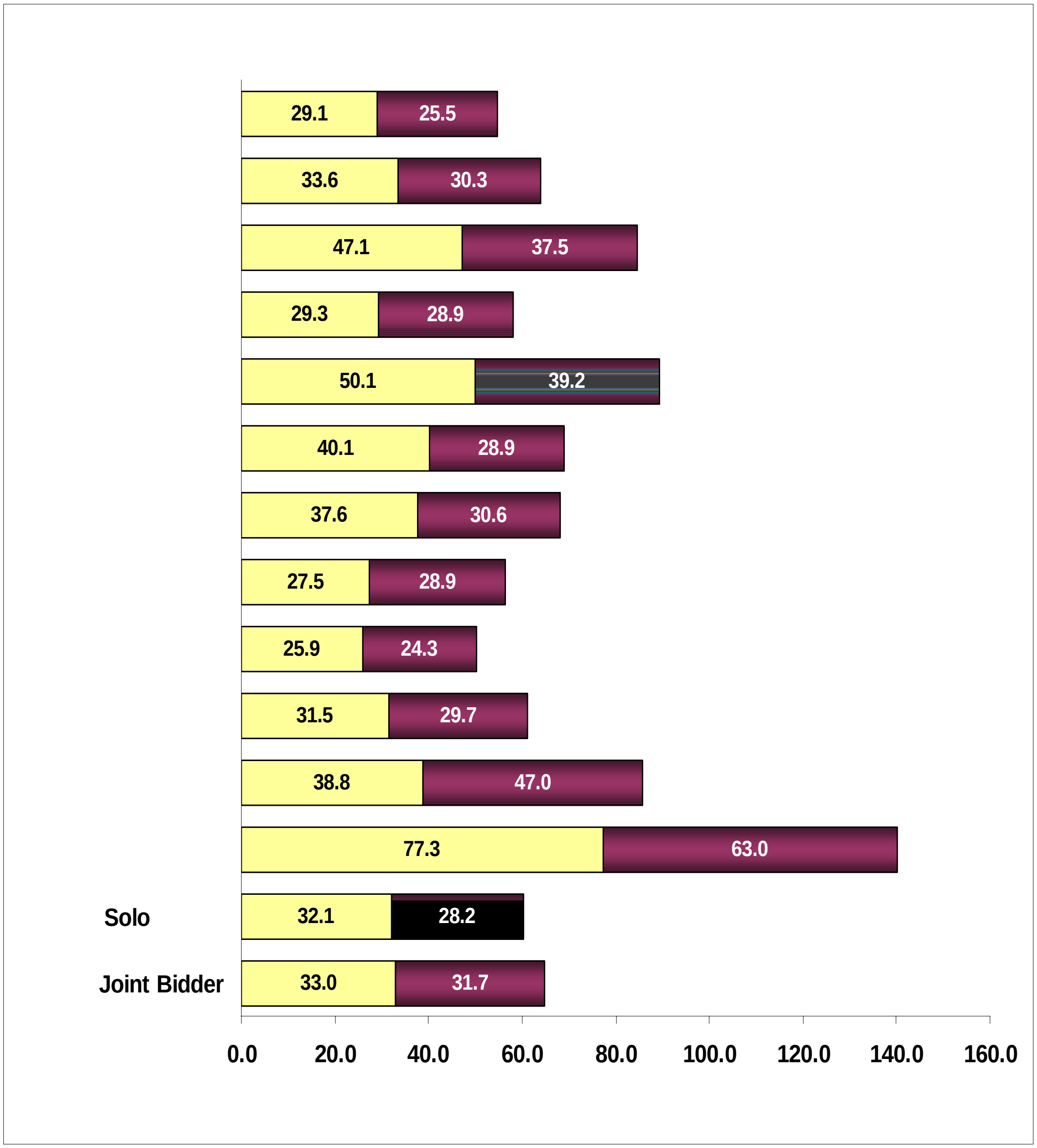
If lease owners are rational economic beings, then leases with expected high cost of development will be delayed for action. This is evident in Figure ES.1. It took, on average, 77.3 months from effective lease sale time to spud a well on deepwater leases. In contrast, it took on average 26.3 months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


29.1
25.5
33.6
30.3
47.1
37.5
29.3
28.9
50.1
39.2
40.1
28.9
37.6
30.6
27.5
28.9
25.9
24.3
31.5
29.7
38.8
47.0
77.3
63.0
Solo
32.1
28.2
Joint Bidder
33.0
31.7
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
160.0

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, *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 sens

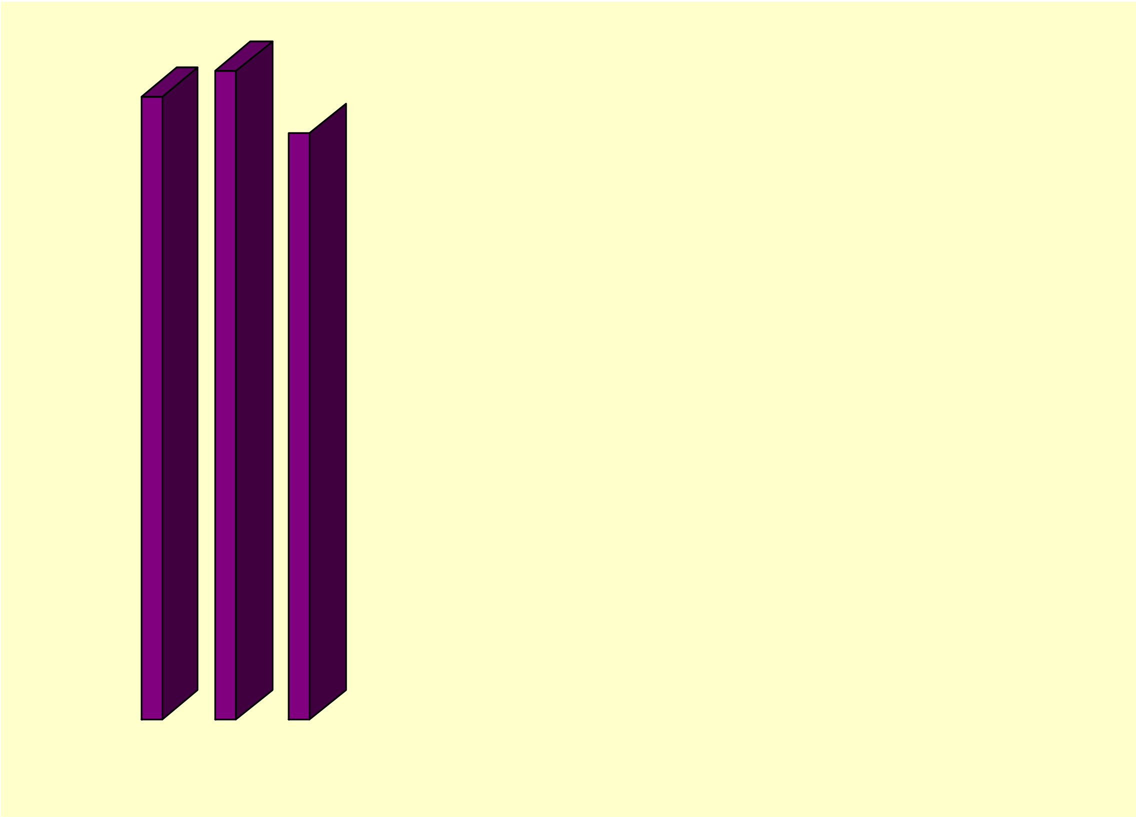


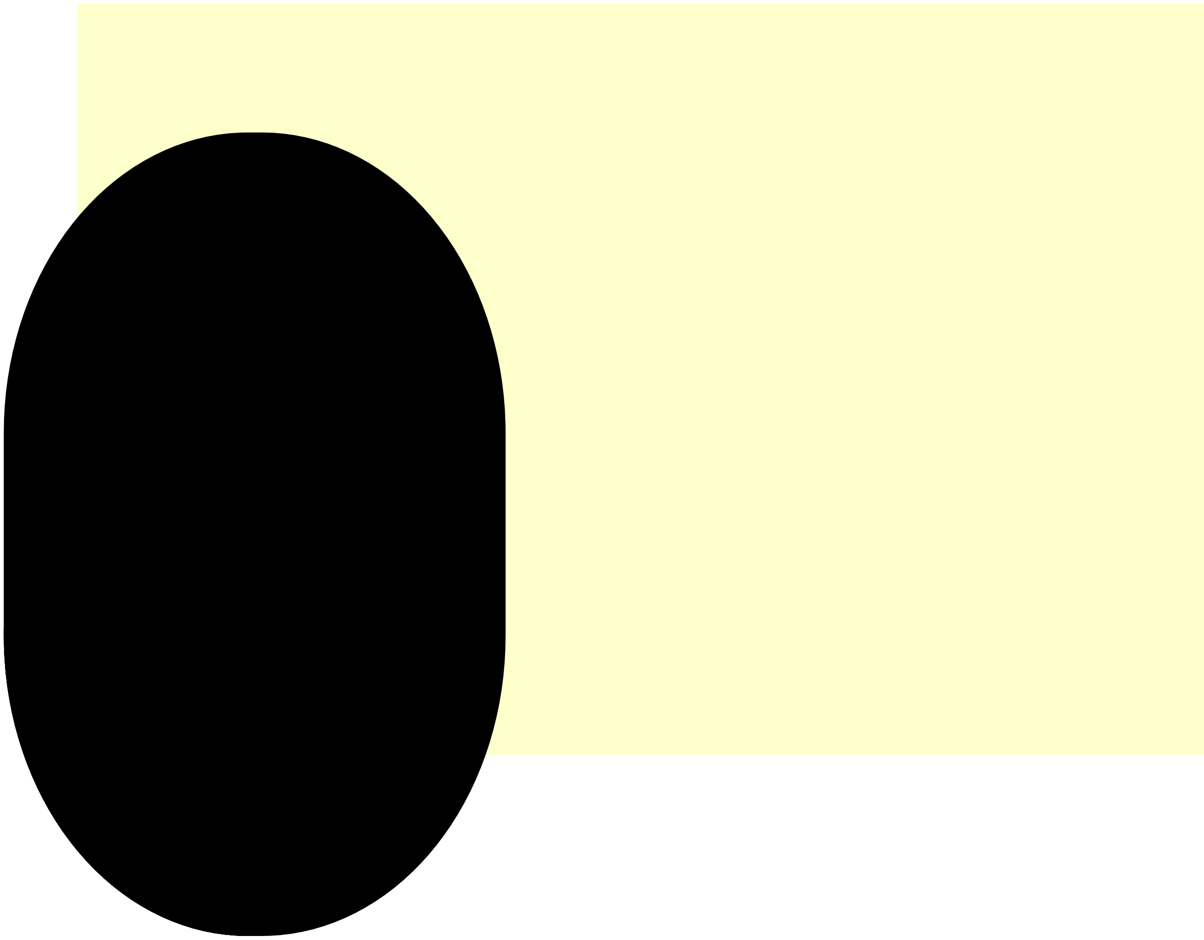
Table ES.4

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).



- 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%

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:

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

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 π = 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 i

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 foril3e.O

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, $0 \le R \le 1$, 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

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 ma16 Tw[(m)8.4(a)-0.ering

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).

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

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

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

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 report

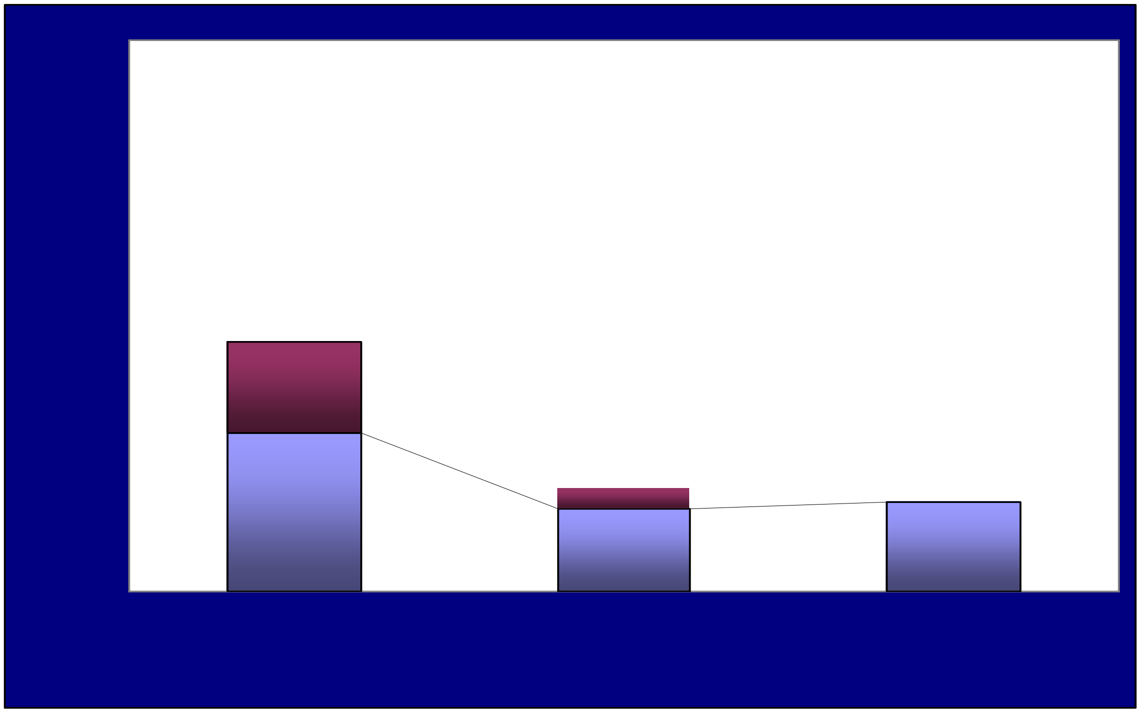
3.2. Analysis of OCS Lease Sales & Development Attributes

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. i1.4(r 90 5)70.1(1-TJ20.576 -1.14



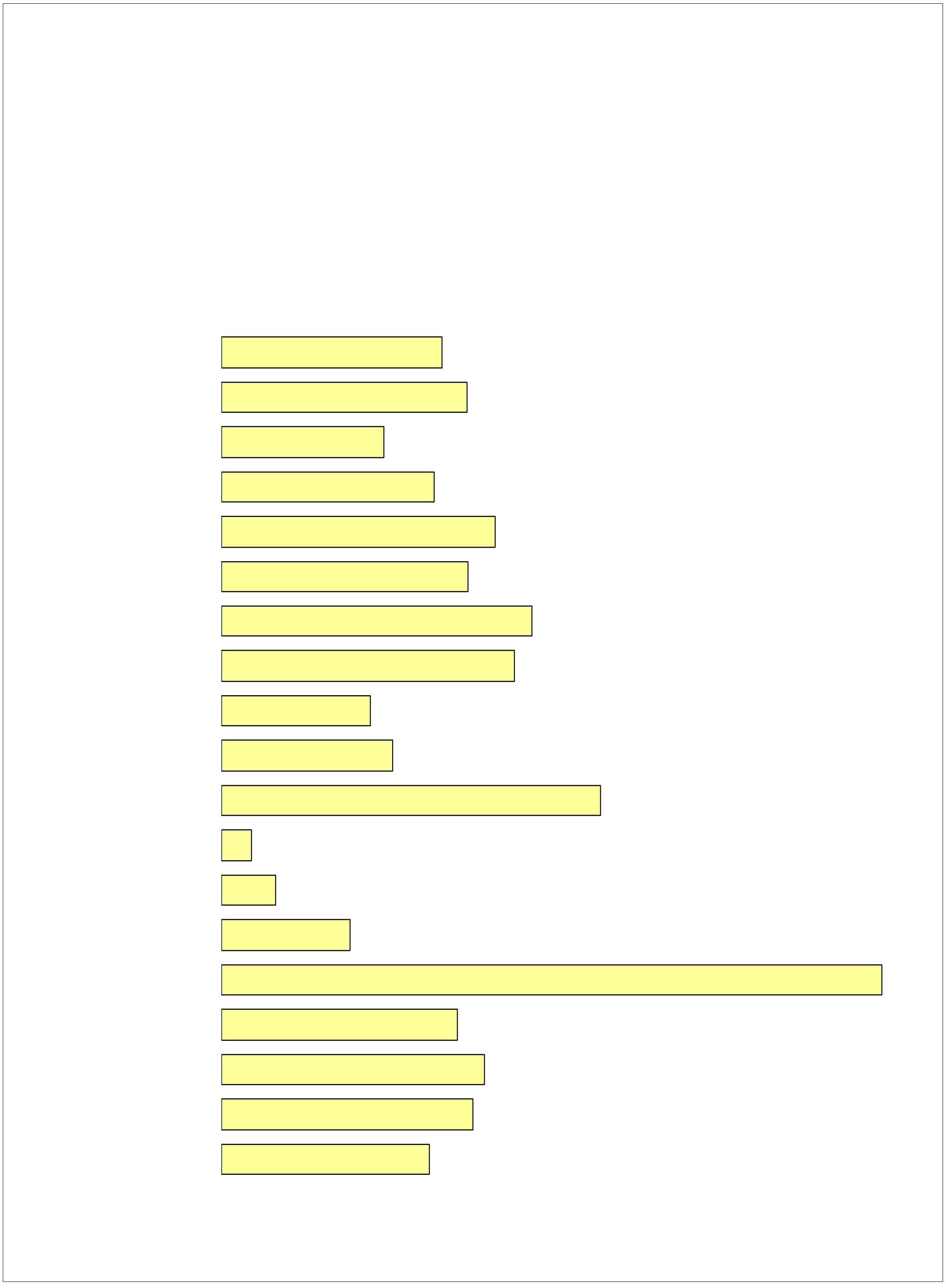


Table 1

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

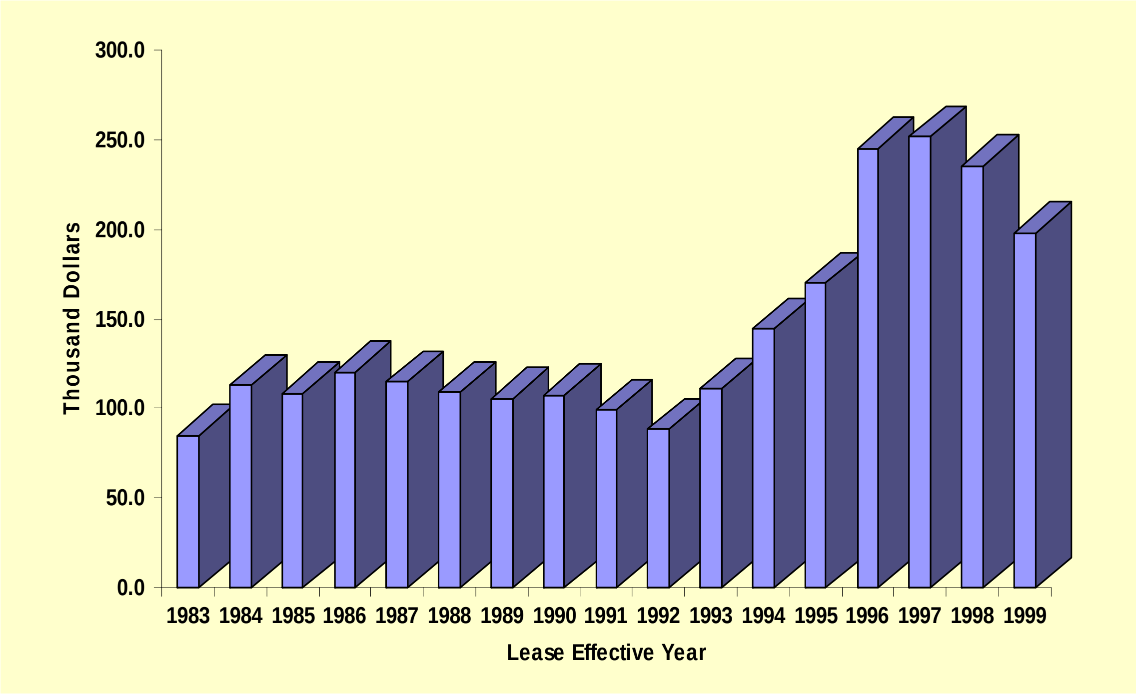


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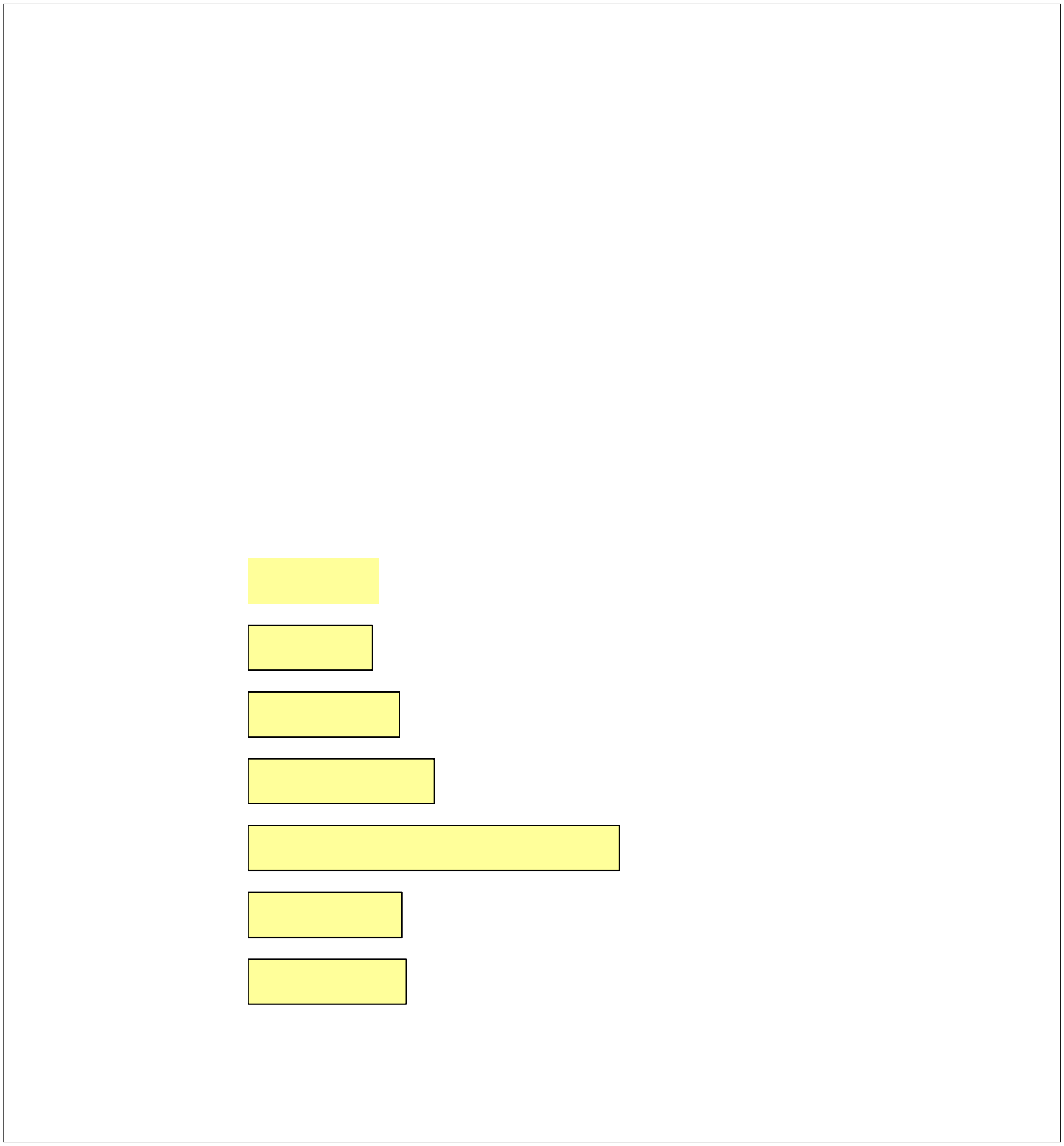
Figure 6. Trend in Aggregate Average Rental for OCS Leases Issued from

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

T o p 4



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.

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	

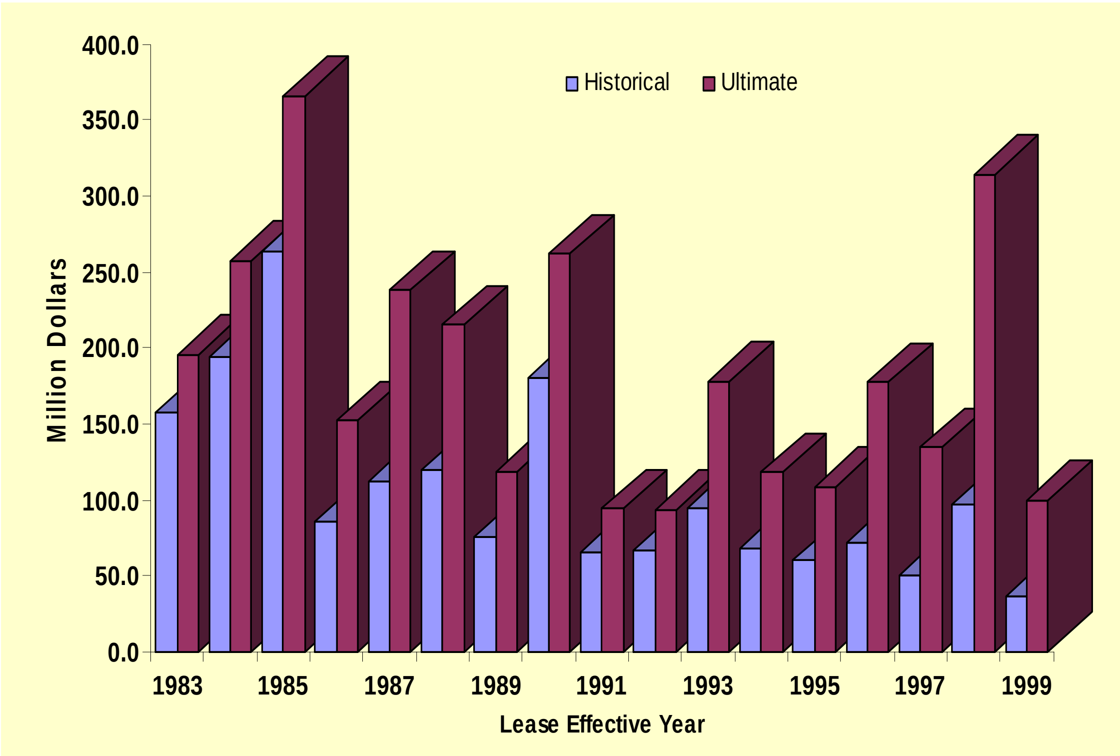


Figure 10. Trend in Aggregate Value of

of production for deepwater leases issued dur

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.

Table 5

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

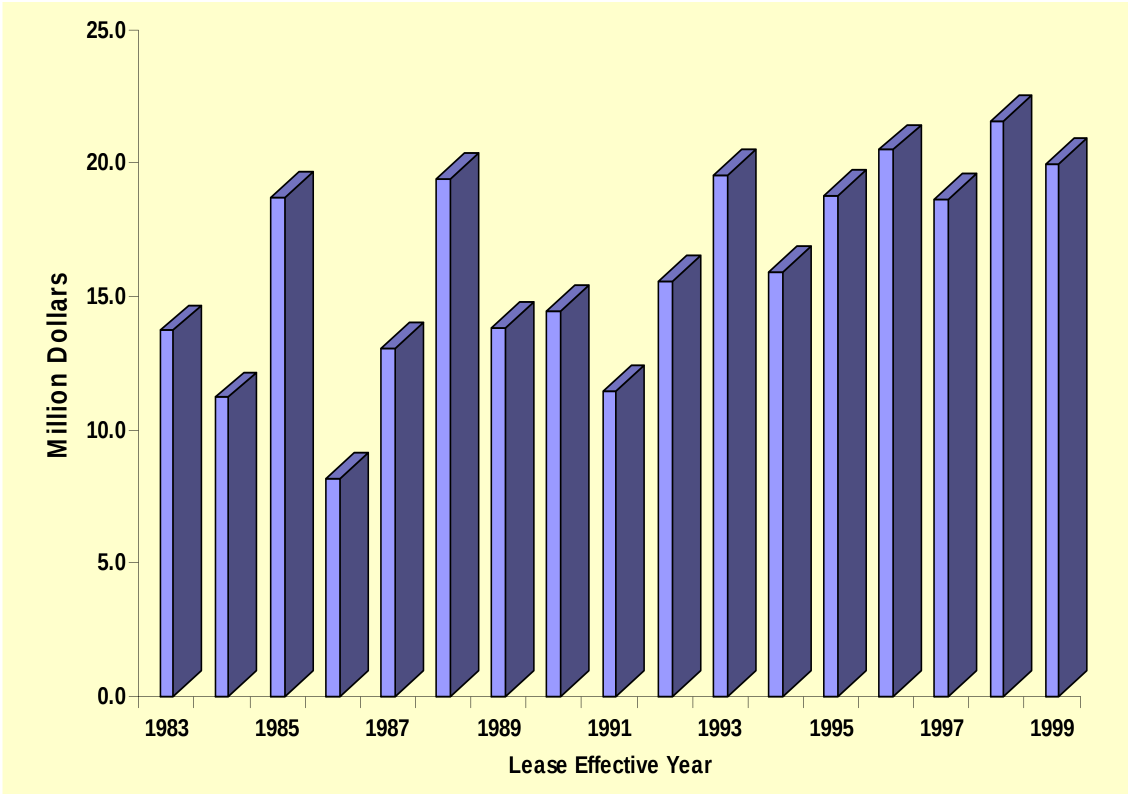


Figure 12. Trends in Aggregate Estimated Drilling Costs per Lease for Leases Issued in the Gulf of Mexico OCS Region from 1983 to 1999.

Table 6

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

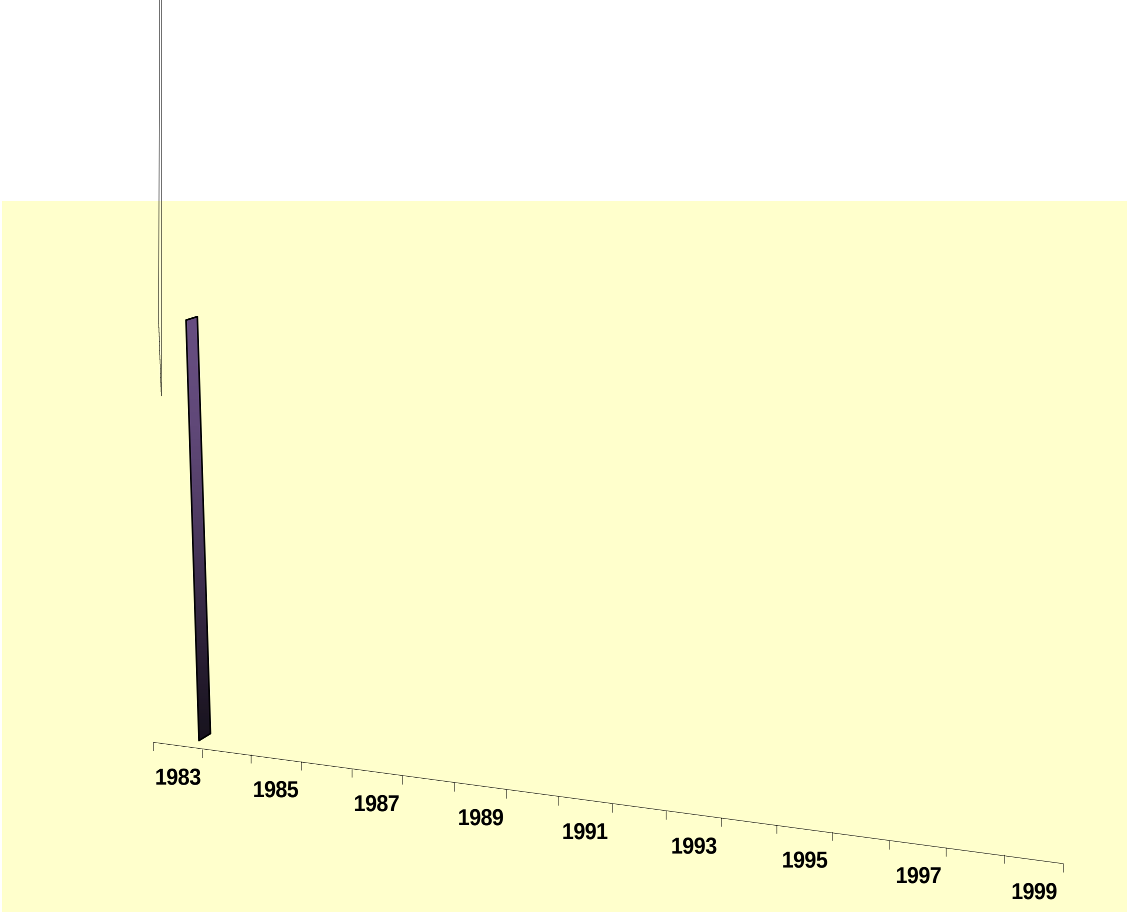

1983
1985
1987
1989
1991
1993
1995
1997
1999

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

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 EIAEra

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

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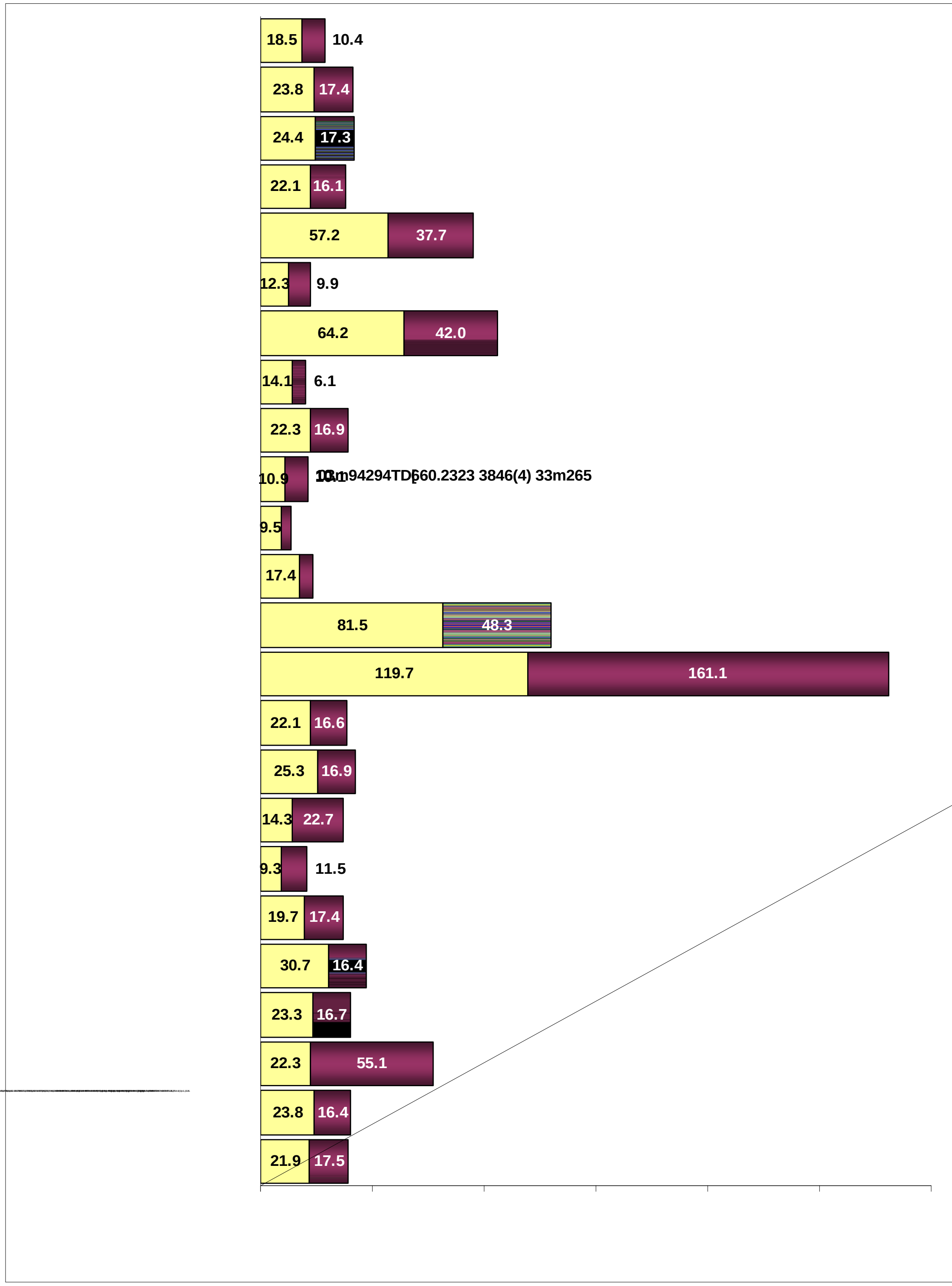
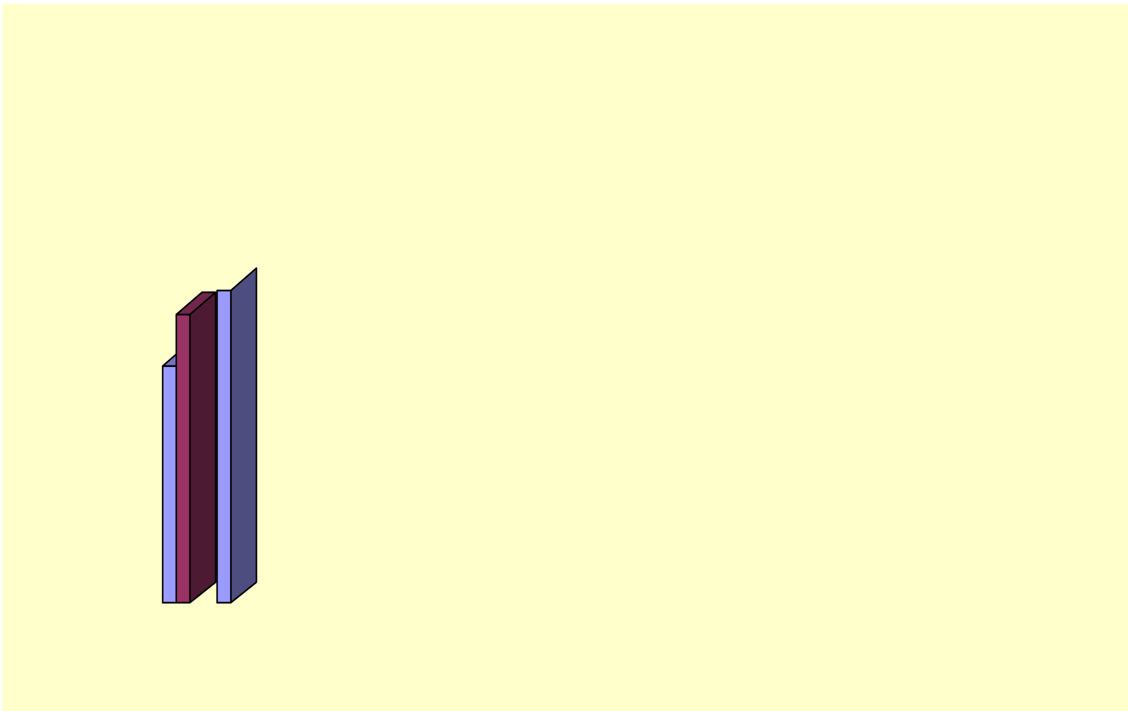




4. MEASURES OF PERFORMANCE OF OCS LEASE SALES & DEVELOPMENT

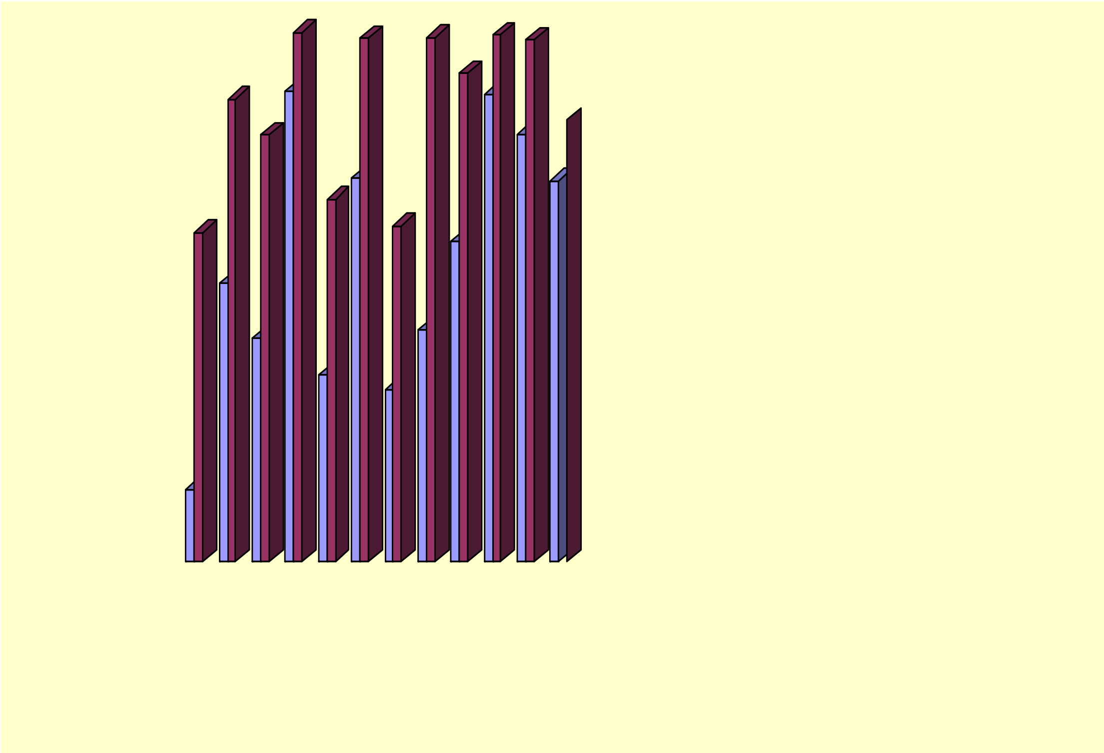
4.1. Introduction

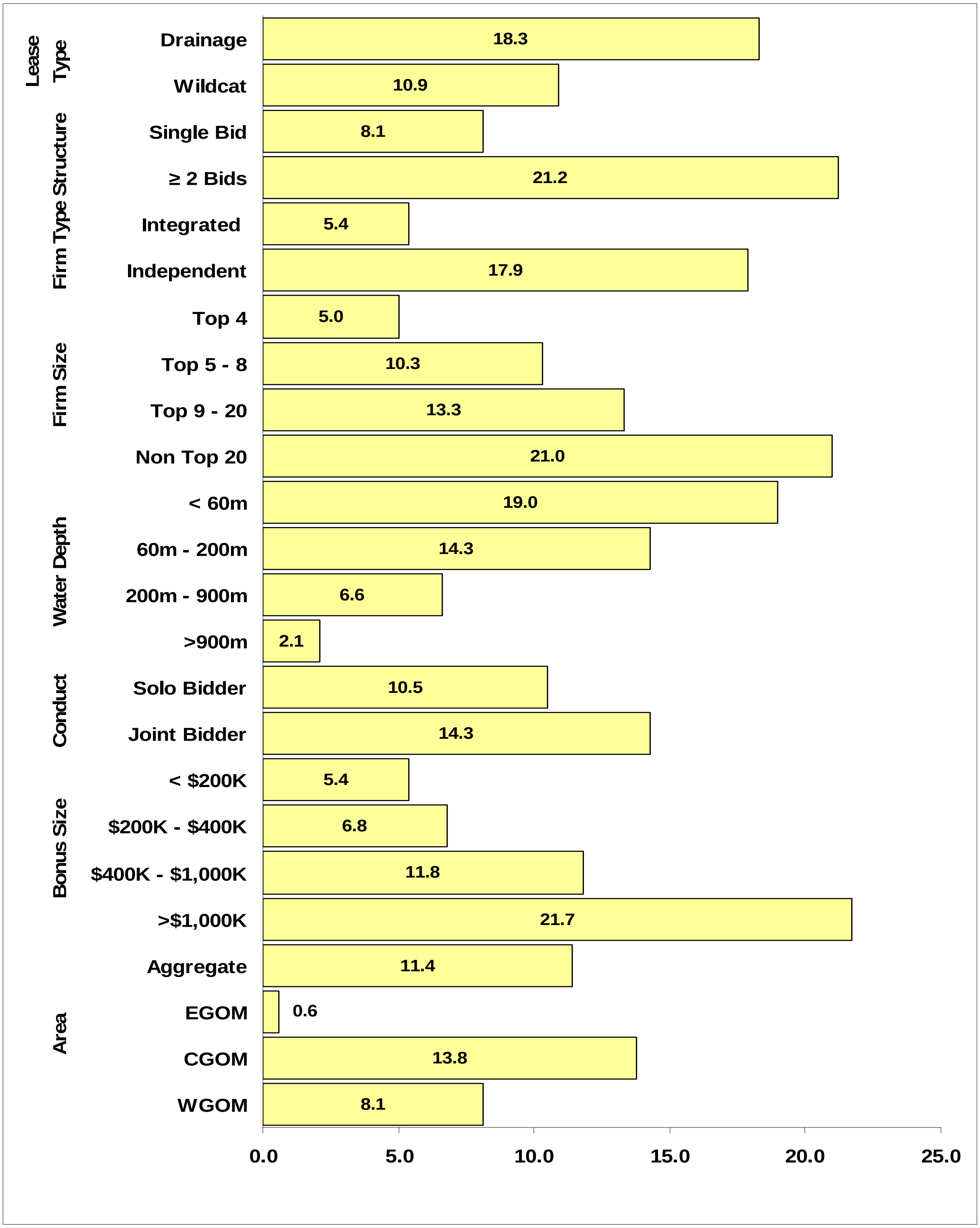
Section 4 describes aggregate measures of performance of lease sales and developments in the Gulf of Mexico OCS for leases issued from 1983 to 1999. The measures—prospectivity and productivity indices—described in this section are by no means exhaustive. Thus, for the purpose of this report, we have 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





Lease Type
Drainage 18.3
Wildcat 10.9
Firm Type Structure
Single Bid 8.1
≥ 2 Bids 21.2
Integrated 5.4
Independent 17.9
Firm Size
Top 4 5.0
Top 5 - 8 10.3
Top 9 - 20 13.3
Non Top 20 21.0
Water Depth
< 60m 19.0
60m - 200m 14.3
200m - 900m 6.6
>900m 2.1
Conduct
Solo Bidder 10.5
Joint Bidder 14.3
Bonus Size
< $200K 5.4
$200K - $400K 6.8
$400K - $1,000K 11.8
>$1,000K 21.7
Area
Aggregate 11.4
EGOM 0.6
CGOM 13.8
WGOM 8.1
0.0
5.0
10.0
15.0
20.0
25.0

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

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						

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.

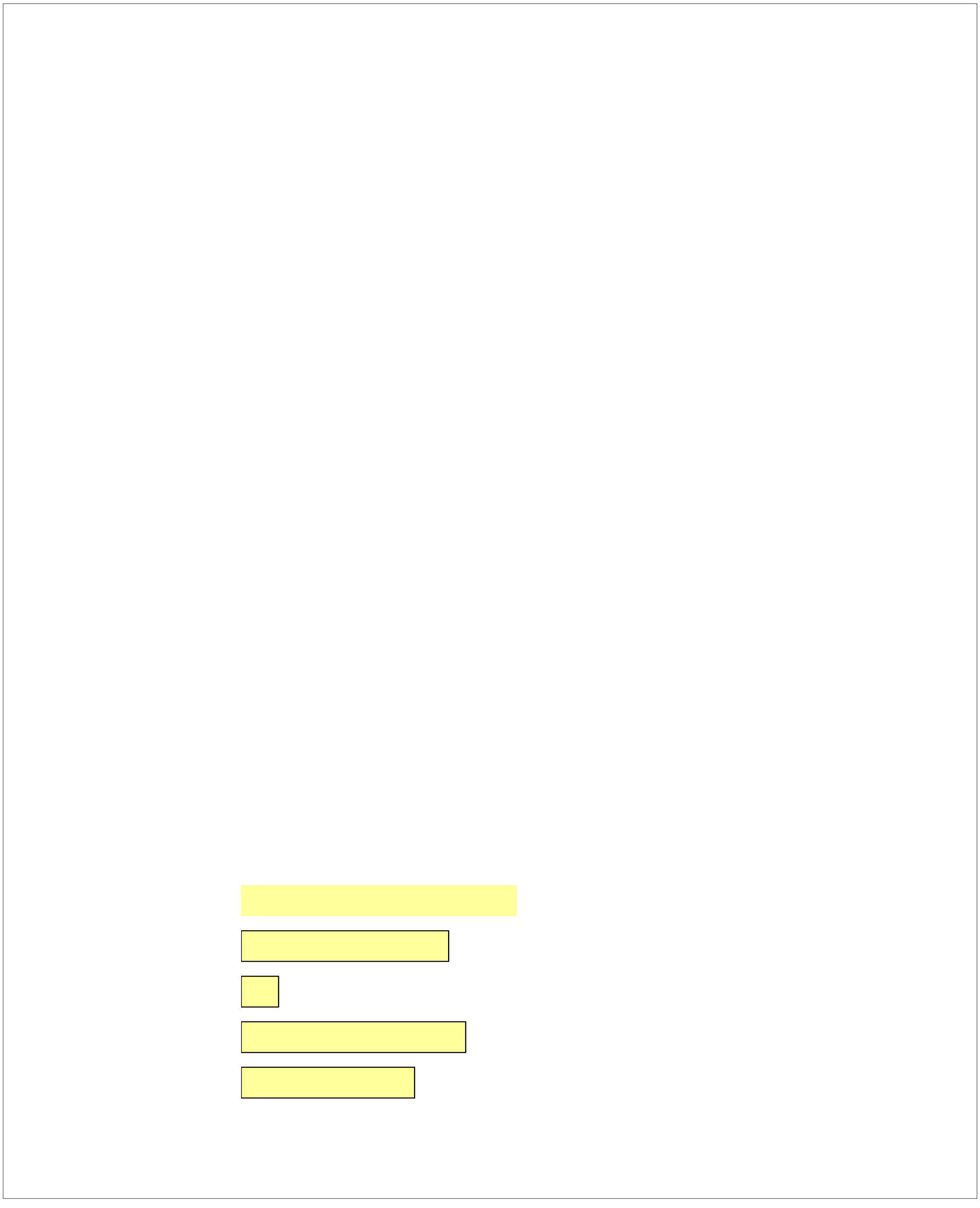
Lease development ratio increases with bonus size and the ratios declined quite significantly with effective lease year. Similarly, we found that leases with multiple bids on the Gulf OCS were more productive than leases that received single bids from 1983 to 1999.

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.



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

Table 11

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

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**

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

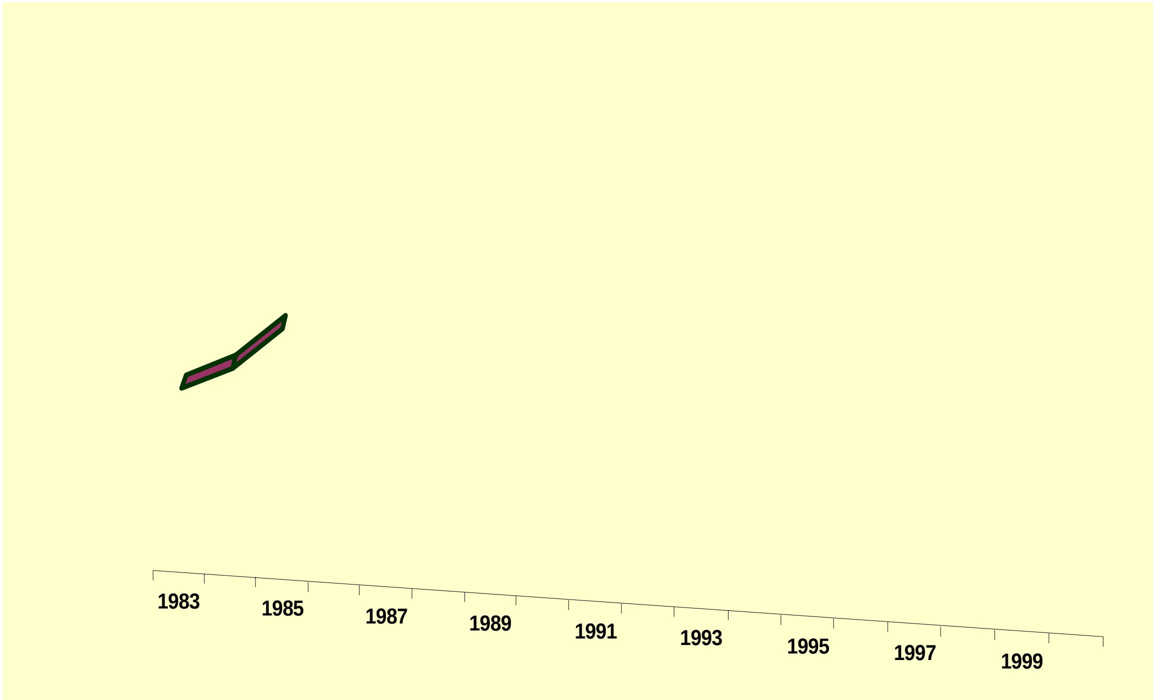
Table 14

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

Table 15

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


1983
1985
1987
1989
1991
1993
1995
1997
1999

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).

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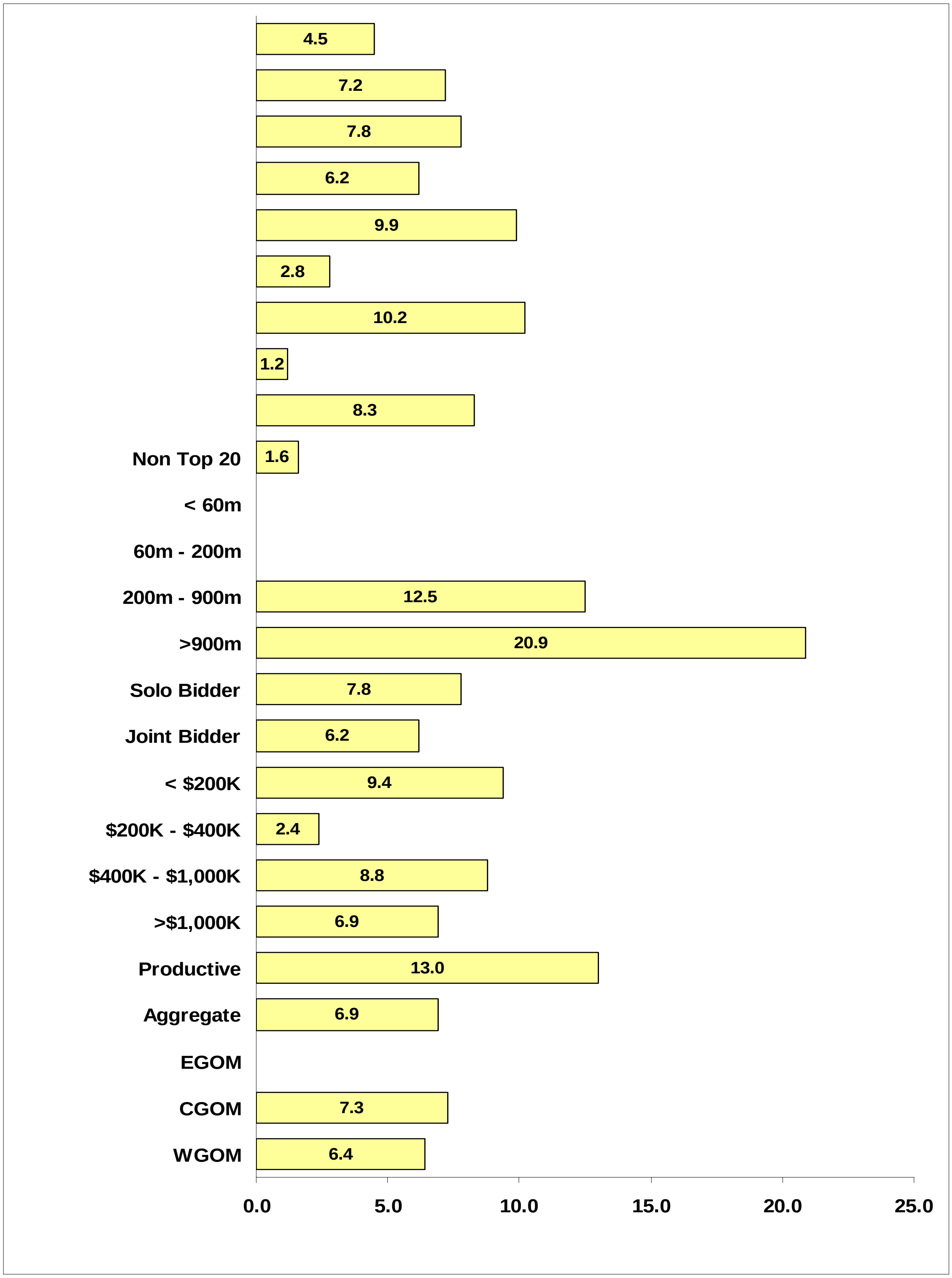
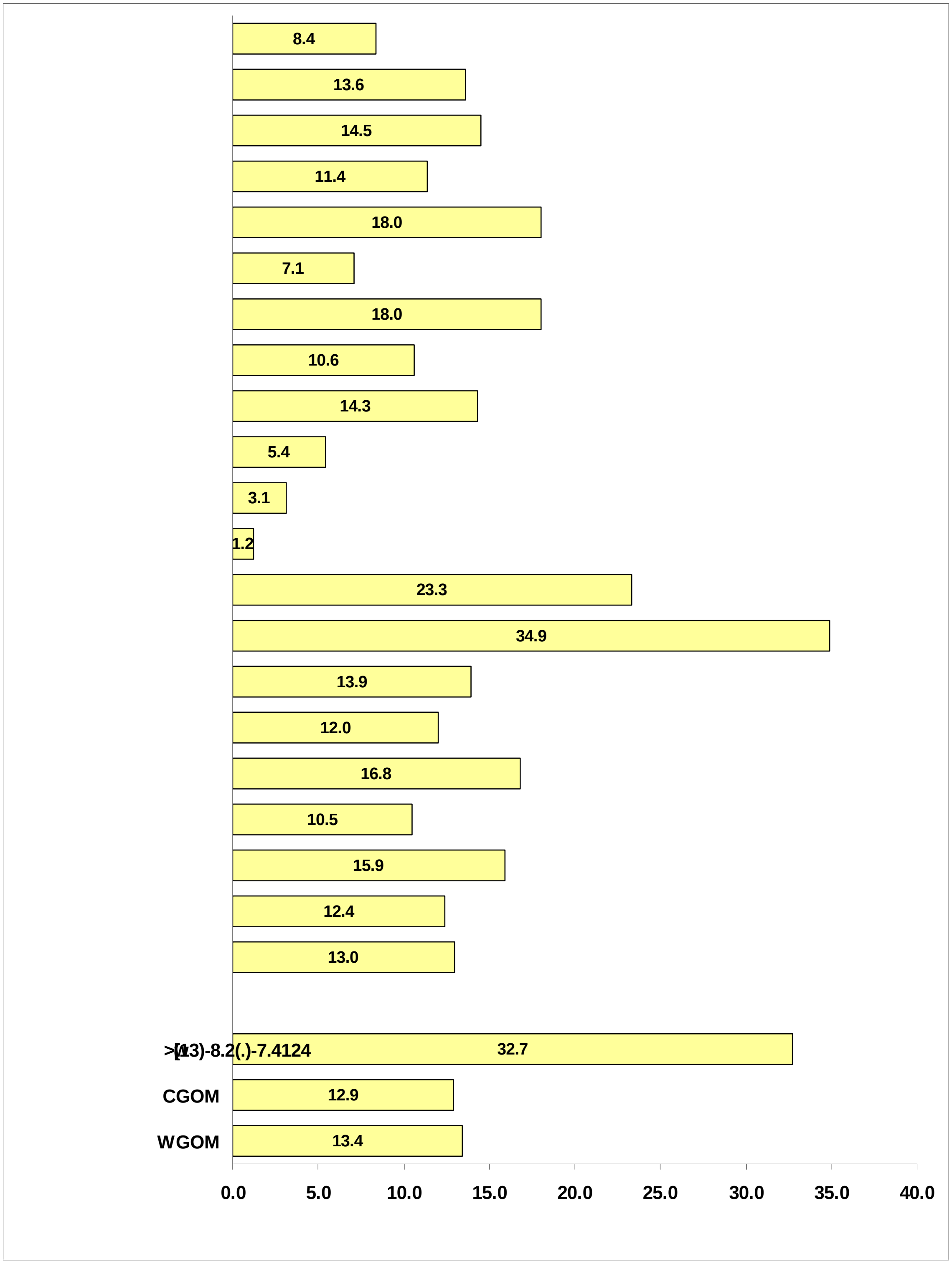


4.5
7.2
7.8
6.2
9.9
2.8
10.2
1.2
8.3
Non Top 20
1.6
< 60m
60m - 200m
200m - 900m
12.5
>900m
20.9
Solo Bidder
7.8
Joint Bidder
6.2
< $200K
9.4
$200K - $400K
2.4
$400K - $1,000K
8.8
>$1,000K
6.9
Productive
13.0
Aggregate
6.9
EGOM
CGOM
7.3
WGOM
6.4
0.0
5.0
10.0
15.0
20.0
25.0


8.4
13.6
14.5
11.4
18.0
7.1
18.0
10.6
14.3
5.4
3.1
1.2
23.3
34.9
13.9
12.0
16.8
10.5
15.9
12.4
13.0
32.7
CGOM
12.9
WGOM
13.4
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0

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 l

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%

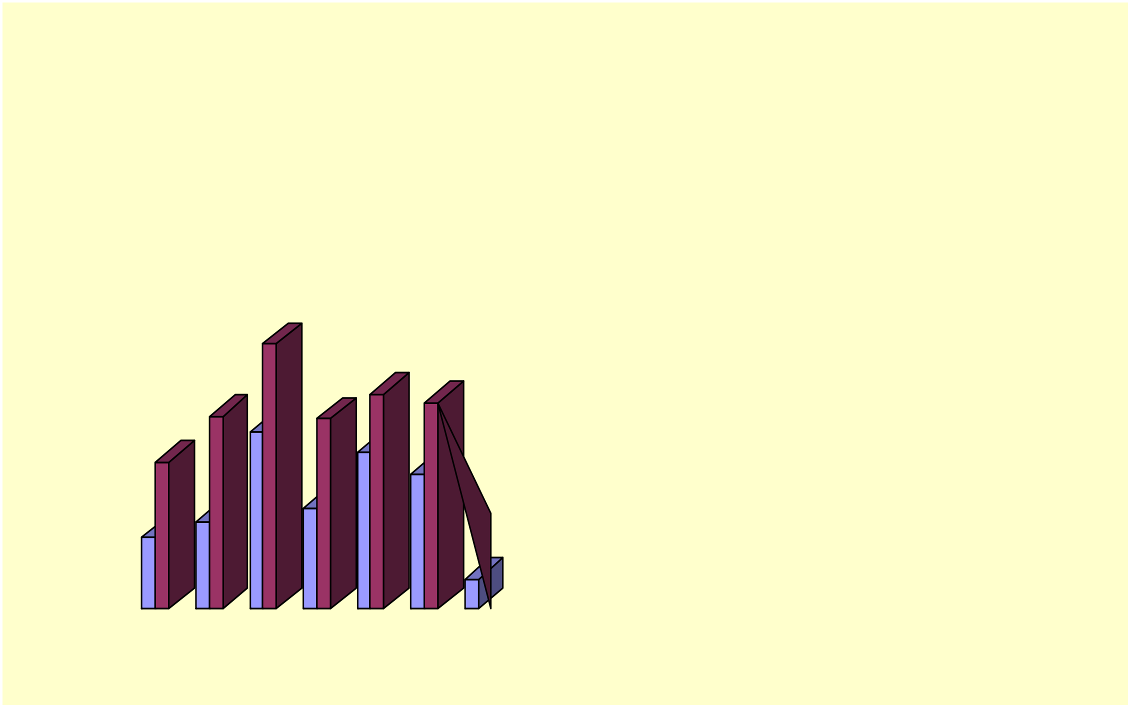
* Limited data availability.

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.



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

Table 18

Aggregate Prospectivity Measures for All Leases Issued from 1983 to 1999

	Leases Issued	Prospectivity Index			Expeditious Index
		Drilled Ratio	Producible Ratio	Drilling	Avg. Lag from Sales

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							

[redacted]

Table 20

Aggregate Economic Performance Measures for Productive Leases

	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							
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%

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

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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%

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.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%

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	

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	

Table A.7

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

				Aggregate Gross Value of Production	Undiscounted Aggregate Net Cash	

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%

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*							

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	

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	

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%

Lease Type *33494.88*

Table A.13

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

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*							

Table A.15

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

				Aggregate Gross Value of Production	Undiscounted Aggregate Net Cash	

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%

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)		

Table A.20

Aggregate Performance Measures for Productive Leases Issued from 1983 to 1999

			Average Bonus	Aggregate Gross Value of Production ($M) Per Lease	Undiscounted Aggregate Net Cash Flow ($M) Per Lease	IRR

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.