Changes in Accounting Practices in the Oil and Gas Industry During the 1990s

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Since 1989, the Institute of Petroleum Accounting at the University of North Texas has conducted surveys to determine the extant accounting practices in the oil and gas extractive industry. This is the second in a two-part series which provides a comparison of some of the important accounting practices and how they have changed over time as found by surveys conducted in 1994, 1997, and 1999. (For Part One, see the Fall/Winter 2001 issue of the *Petroleum Accounting and Financial Management Journal*, pp. 1-27.) These surveys were conducted in partnership with PricewaterhouseCoopers L.L.P. In this issue we recap the description and background of the companies who responded to these surveys and report the responses to current practice concerning gas imbalance accounting, crude oil exchange accounting, revenue accruals and finding costs, capitalized interest, and needed changes in financial accounting and income tax rules.*

Background of Responding Companies

On three occasions between 1994 and 1999, the Institute of Petroleum Accounting mailed questionnaires to over 300 privately and publicly held oil and gas companies. The companies responding were predominantly publicly held independent producers (see Table 1 of part one). In terms of size, the public and private companies responding had sales revenues and dollar volumes of crude oil, natural gas, and gas liquids ranging from under $1million

* **Editor's Note:** The surveys referenced in this study were prepared in partnership with PricewaterhouseCoopers L.L.P. Dennis Jennings and Joseph Feiten along with Teddy L. Coe are the authors of the surveys. Permission for the use of this data and information for this article was granted by the Institute of Petroleum Accounting. Part One of this article appeared in the Fall/Winter 2001 issue of the *Petroleum Accounting and Financial Management Journal.*

to in excess of $5 billion. Approximately half of the companies had sales revenue exceeding $100 million. Background information on the responding companies also suggests a growth in oil and gas operations outside the United States. In 1994, 16 (23.2%) of the companies in the sample had oil and gas producing operations outside the United States that accounted for greater than 10% of the company's oil and gas producing assets or sales. Despite a drop in the number of companies responding to the survey in 1999, 21 (46.7%) companies responded as having significant foreign oil and gas operations. However, the most notable change provided in the background information section was the increase in the proportion of the responding companies using successful efforts as the primary accounting method for oil and gas producing activities. The proportion of companies increased from 56.5% of companies in the 1994 survey to 80.0% of companies in the 1999 survey.

Gas Imbalance Accounting

Data provided in Table 9 on gas imbalance accounting highlights movements in reporting of over and under-delivered positions and assessment of collectibility of accounts receivables for under-deliveries. In 1999, a higher proportion of responding companies reported netting of over- and under-delivered positions. This group of companies also indicated that they assessed the collectibility of accounts receivables arising from under-delivered positions more frequently.

Table 9
Gas Imbalance Accounting

Reporting of Over- and Under-delivered Position on Balance Sheet		
1994	No.	%
Gross overproduced and gross underproduced are shown separately	12	57.1
All netted	7	33.3
Netted by gas balancing agreement	2	9.5
Netted by balancing party	0	0.0
Other	0	0.0
Number Responding	21	100.0

Table 9, continued		
1997	No.	%
Gross overproduced and gross underproduced are shown separately	7	41.2
One net imbalance is shown	9	52.9
Netted by gas balancing agreement	0	0.0
Netted by balancing party	1	5.9
Other	0	0.0
Number Responding	17	100.0
1999	No.	%
Gross overproduced and gross underproduced are shown separately	8	42.1
One net imbalance is shown	10	52.6
Netted by gas balancing agreement	0	0.0
Netted by balancing party	1	5.3
Other	0	0.0
Number Responding	19	100.0
Frequency of Assessment of Collectibility of Accounts Receivable or Equivalent Asset Arising from an Under-delivered Status		
1994	No.	%
Quarterly	7	36.8
Annually	7	36.8
Do not assess collectibility until delivery	3	15.8
Other	2	10.5
Number Responding	19	100.0

Table 9, continued		
1997	No.	%
Quarterly	7	36.8
Annually	10	52.6
Do not assess collectibility until delivery	1	5.3
Other	2	10.5
Number Responding	19	100.0
1999	No.	%
Quarterly	9	52.9
Annually	5	29.4
Do not assess collectibility until delivery	2	11.8
Other	1	5.9
Number Responding	17	100.0

Crude Oil Exchange Accounting

Table 10 provides sample data on responses for survey questions on accounting for crude oil exchanges. Despite the declining number of respondents for these questions, the data does provide some interesting insights on classification of exchange volume imbalances, the carrying value of exchange imbalance asset, and the costing of exchange imbalance assets and liabilities. An increasing number and proportion of responding companies classified balance sheet exchange volume imbalances receivable or payable in crude oil as gross receivables or payables. The number and proportion of companies basing cost of exchange imbalance liability on the average cost of the crude oil received also increased during the period 1994 to 1999.

Table 10
Crude Oil Exchange Accounting

Classification in the Balance Sheet of Exchange Volume Imbalances Receivable or Payable in Crude Oil		
1994	No.	%
As gross receivables or payables	3	17.6
As net receivables or payables	3	17.6
As an inventory adjustment	6	35.3
As grossed deferred charges or credits	1	5.9
As net deferred charges or credits	1	5.9
Other	3	17.6
Number Responding	17	100.0
1997	No.	%
As gross receivables or payables	1	11.1
As net receivables or payables	3	33.3
As an inventory adjustment	4	44.4
As grossed deferred charges or credits	0	0.0
As net deferred charges or credits	1	11.1
Other	0	0.0
Number Responding	9	100.0

Table 10, continued		
1999	No.	%
As gross receivables or payables	5	55.6
As net receivables or payables	1	11.1
As an inventory adjustment	3	33.3
As grossed deferred charges or credits	0	0.0
As net deferred charges or credits	0	0.0
Other	0	0.0
Number Responding	9	100.0
Costing of an Exchange Imbalance Asset		
1994	No.	%
Using the cost of ***crude oil delivered*** that created the imbalance. The cost reflects:		
Average cost of crude oil delivered	10	76.9
LIFO cost	4	30.8
FIFO cost	3	23.1
Other	2	15.4
Using the ***spot price*** (such as a posted price adjusted for transportation costs) for the ***crude oil to be received***:		
Using the spot price when the imbalance occurred	1	7.7
Using the spot price as of the current balance sheet date	2	15.4
Number Responding	13	100.0

Table 10, continued		
1997	No.	%
Using the cost of ***crude oil delivered*** that created the imbalance. The cost reflects:		
Average cost of crude oil delivered	4	44.4
LIFO cost	1	11.1
FIFO cost	1	11.1
Other	1	11.1
Using the ***spot price*** (such as a posted price adjusted for transportation costs) for the ***crude oil to be received***:		
When the imbalance occurred	3	33.3
As of the current balance sheet date	2	22.2
Number Responding	9	100.0
1999	No.	%
Using the cost of ***crude oil delivered*** that created the imbalance. The cost reflects:		
Average cost of crude oil delivered	4	57.1
LIFO cost	2	28.6
FIFO cost	0	0.0
Other	1	14.3
Using the ***spot price*** (such as a posted price adjusted for transportation costs) for the ***crude oil to be received***:		
When the imbalance occurred	1	14.3
As of the current balance sheet date	0	0..0
Number Responding	7	100.0

Table 10, continued		
Carrying Value of an Exchange Imbalance Asset		
1994	No.	%
Cost, as described above in Costing of an Exchange Imbalance Asset	6	42.9
The lower of cost or market value	8	57.1
The value, if any, specified in the exchange agreement for eliminating imbalances via cash payment	0	0.0
Number Responding	14	100.0
1997	No.	%
Cost, as described above in Costing of an Exchange Imbalance Asset	9	100.0
The lower of cost or market value	0	0.0
The value, if any, specified in the exchange agreement for eliminating imbalances via cash payment	0	0.0
Number Responding	9	100.0
1999	No.	%
Cost, as described above in Costing of an Exchange Imbalance Asset	6	85.7
The lower of cost or market value	1	14.3
The value, if any, specified in the exchange agreement for eliminating imbalances via cash payment	0	0.0
Number Responding	7	100.0

Table 10, continued		
Costing of an Exchange Imbalance Liability		
1994	No.	%
Using the cost of ***crude oil received*** that created the imbalance. The cost reflects:	9	69.2
Average cost of the crude oil received	4	30.8
LIFO cost	3	23.1
FIFO cost	2	15.4
Other	0	0.0
Using the ***spot price*** for the ***crude oil to be delivered***:	3	23.1
When the imbalance occurred	1	7.7
As of the current balance sheet date	2	15.4
Other	1	7.7
Number Responding	13	100.0
1997	No.	%
Using the cost of ***crude oil received*** that created the imbalance. The cost reflects:		
Average cost of the crude oil received	4	44.4
LIFO cost	1	11.1
FIFO cost	0	0.0
Other	1	11.1
Using the ***spot price*** for the ***crude oil to be delivered***:		
When the imbalance occurred	3	33.3
As of the current balance sheet date	3	33.3
Other	0	0.0
Number Responding	9	100.0

Table 10, continued		
1999	No	%
Using the cost of ***crude oil received*** that created the imbalance. The cost reflects:		
Average cost of the crude oil received	6	85.7
LIFO cost	1	14.3
FIFO cost	0	0.0
Other	0	0.0
Using the ***spot price*** for the ***crude oil to be delivered***:		
When the imbalance occurred	1	14.3
As of the current balance sheet date	0	0.0
Other	0	0.0
Number Responding	7	100.0

Revenue Accruals and Finding Costs

Table 11 responses on accounting choices for revenue accruals show a shift away from revenue accruals based on prior month actuals and/or actual revenue data to an increased use of production estimates. Data on accounting methods for finding costs indicated that during the survey period an increasing proportion of responding companies computed finding costs for internal use and external disclosures. The proportion of companies computing finding costs for a combination of exploration, development, and proved property acquisition activities increased steadily over the course of the three surveys.

Table 11
Revenue Accruals and Finding Costs

Basis for Estimating Revenue to be Accrued for Current Production Month:		
1994	No.	%
Production department estimate	35	58.3
Prior month actual	14	23.2
Other	11	18.3
Number Responding	60	100.0
1997	No.	%
Production department estimate	15	30.0
Prior month actual	5	10.0
Keep books open for 30 days and use actual as accrual	15	30.0
Annual analysis and change of accrual	0	0.0
Combination of production department estimates and prior month actuals	22	44.0
Other	1	2.0
Number Responding	50	100.0
1999	No.	%
Production department estimate	22	50.0
Prior month actual	3	6.8
Keep books open for 30 days and use actual as accrual	3	6.8
Annual analysis and change of accrual	0	0.0
Combination of production department estimates and prior month actuals	19	43.2
Other	0	0.0
Number Responding	44	100.0

Table 11, continued		
Use of Computation of Finding Costs		
1994	No.	%
Yes, for internal use only	35	51.5
Yes, for internal and external disclosure	22	32.4
No	11	16.2
Number Responding	68	100.0
1997	No.	%
Yes, for internal use only	27	47.4
Yes, for internal and external disclosure	16	28.1
No	14	24.6
Number Responding	57	100.0
1999	No.	%
Yes, for internal use only	20	44.4
Yes, for internal and external disclosure	19	42.2
No	6	13.3
Number Responding	45	100.0

Table 11, continued				
Computation and Disclosure of Finding Costs for:				
1994	Computed		Disclosed	
	No.	%	No.	%
All exploration, development, and proved property activities	28	58.3	14	66.7
Exploration and development activities only	7	14.6	2	9.5
Exploration activities only	1	2.1	0	0.0
Proved property acquisitions only	10	20.8	4	19.0
Other	2	4.2	1	4.8
Number Responding	NA	NA	NA	NA
1997	Computed		Disclosed	
	No.	%	No.	%
All exploration, development, and proved property activities	28	70.0	13	86.7
Exploration and development activities only	14	35.0	2	13.3
Exploration activities only	10	25.0	0	0.0
Proved property acquisitions only	9	22.5	2	13.3
Other	0	0.0	0	0.0
Number Responding	40	100.0	15	100.0

Table 11, continued				
1999	Computed		Disclosed	
	No.	%	No.	%
All exploration, development, and proved property activities	28	77.8	12	75.0
Exploration and development activities only	14	38.9	3	18.8
Exploration activities only	8	22.2	0	0.0
Proved property acquisitions only	8	22.2	1	6.3
Other	2	5.6	1	6.3
Number Responding	36	100.0	16	100.0

Capitalized Interest and Other Matters

Responses to questions on capitalization of interest in Table 12 provide companies choices for expenditure thresholds, length of project for capitalization, capitalization of interest for unproved leasehold costs, and the beginning point for interest capitalization. A decreasing proportion of companies indicated establishment of expenditure thresholds before capitalizing interest on individual projects or programs. Although six months or less remained the most common choice as the minimum length for a project before companies would capitalize interest, the period did see an increase in companies using one year as a minimum. An increasing number and proportion of respondents indicated that their companies capitalize interest on unproved leasehold costs if exploratory activity is in progress. A higher proportion of companies started to capitalize interest when the lease was acquired, and fewer companies waited for exploration activity to begin.

On other matters, a decreasing proportion of the responding companies indicated ownership in gas gathering, treatment, or processing facilities serving more than one field. In addition, a lower proportion of the companies that own these facilities included these in "oil and gas producing activities" for financial reporting. Data in Table 12 also shows the increasing proportion of responding companies receiving income from contracting out excess capacity in offshore production pipelines.

Table 12
Capitalized Interest and Other Matters

Establishment of an Expenditure Threshold Before Interest Capitalized on Individual Project or Program:		
1994	No.	%
Yes	29	53.7
No	25	46.3
Number Responding	54	100.0
1997	No.	%
Yes	23	44.2
No	29	55.8
Number Responding	52	100.0
1999	No.	%
Yes	16	38.1
No	26	61.9
Number Responding	42	100.0
Minimum Length of Project/Program Before Interest Capitalized Assuming Expenditure Threshold Exceeded:		
1994	No.	%
Six months or less	20	52.6
One year	8	21.1
Two years	1	2.6
Other	9	23.7
Number Responding	38	100.0

Table 12, continued		
1997	No.	%
Six months or less	19	50.0
One year	12	31.6
Two years	3	7.9
Other:		
Three years	1	2.6
When capitalizable interest > $100,000	1	2.6
Do not capitalize interest	1	2.6
Unexplained	1	2.6
Number Responding	38	100.0
1999	No.	%
Six months or less	15	48.4
One year	13	41.9
Two years	2	6.5
Other	1	3.2
Number Responding	31	100.0
Companies Capitalizing Interest on Unproved Leasehold Costs When Exploratory Activity in Progress:		
1994	No.	%
Yes	13	26.5
No	36	73.5
Number Responding	49	100.0

Table 12, continued		
1997	No.	%
Yes	13	25.5
No	38	74.5
Number Responding	51	100.0
1999	No.	%
Yes	15	38.5
No	24	61.5
Number Responding	39	100.0
Beginning Point for Interest Capitalization		
1994	No.	%
When the lease is acquired	8	24.2
When some exploration activity on the acquired lease occurs	6	18.2
When the first well is spudded	7	21.2
Other	12	36.4
Number Responding	33	100.0

Table 12, continued

1997	No.	%
When the lease is acquired	9	25.7
When some exploration activity on the acquired lease occurs	3	8.6
When the first well is spudded	6	17.1
When significant activity begins such as platform construction	9	25.7
When development plan is committed to	3	8.6
Other:		
When expenditures begin	2	5.7
Do not capitalize interest (wells take only six weeks to complete)	1	2.9
Calendar quarter following initial expenditure	1	2.9
Unexplained	1	2.9
Number Responding	35	100.0
1999	No.	%
When the lease is acquired	13	38.2
When some exploration activity on the acquired lease occurs	1	2.9
When the first well is spudded	4	11.8
When significant activity begins such as platform construction	10	29.4
When committed to the development plan made	4	11.8
Other: When expenditures begin	4	11.8
Number Responding	34	100.0

Table 12, continued			
Inclusion of Gas Gathering, Treatment, or Processing Facilities Serving More Than One Field in "Oil and Gas Producing Activities" for Financial Reporting:			
1994	Gathering	Treatment	Processing
	No.	No.	No.
N/A	11	15	15
Yes	31	27	25
No	9	9	11
Number Responding	51	51	51
1997	Gathering	Treatment	Processing
	No.	No.	No
N/A	11	20	19
Yes	32	22	18
No	5	3	8
Number Responding	48	45	45
1999	Gathering	Treatment	Processing
	No.	No.	No
N/A	17	15	16
Yes	12	9	10
No	8	12	12
Number Responding	37	36	37

Table 12, continued		
Recording of Income from Contracting Our Excess Capacity in Offshore Production Pipelines:		
1994	No.	%
Not applicable to our company	40	80.0
Oil and gas revenue (including for FAS 69 disclosures)	1	2.0
Other revenue	6	12.0
Credit capitalized pipeline costs	0	0.0
Credit lease operating expense	3	6.0
Number Responding	50	100.0
1997	No.	%
Not applicable to our company	41	82.0
Oil and gas revenue (including for FAS 69 disclosures)	1	2.0
Other revenue	3	6.0
Credit capitalized pipeline costs	0	0.0
Credit lease operating expense	5	10.0
Number Responding	50	100.0
1999	No.	%
Not applicable to our company	26	63.4
Oil and gas revenue (including for FAS 69 disclosures)	2	4.9
Other revenue	8	19.5
Credit capitalized pipeline costs	0	0.0
Credit lease operating expense	5	12.2
Number Responding	41	100.0

Needed Rule Changes

The 1994, 1997, and 1999 surveys asked respondents to rate the need for a list of changes in financial accounting and income tax rules. Table 13 provides the average ratings with a score of 1 representing most needed and a rating of 4 for not needed. During the three survey periods, respondents consistently expressed the highest need for elimination of the alternative minimum tax, an overhaul and simplification of income tax rules for exploration and production activities, and provision of tax incentives for marginal wells. Changes consistently rated as least needed include the adoption of one overall accounting method, uniform ceiling/impairment rules, and modification of SFAS 121. The respondents clearly expressed a preference for stability in accounting practices.

Table 13
Needed Rule Changes

1994		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Change use of current prices for ceiling test	2.48	17	11	9	17
Adopt for all companies one overall accounting method such as successful efforts or full cost	3.14	7	8	14	30
Adopt a uniform ceiling test for all companies including those using successful efforts accounting	3.05	2	11	26	18

Table 13, continued

1994		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Modify the ceiling to more closely approximate the fair market value	2.76	7	15	17	16
Require a standardized finding cost disclosure	3.20	3	8	24	26
Require a standard financial accounting method for gas imbalances	3.20	1	6	32	20
Specify financial accounting for net profit interests	3.54	0	4	17	33
Eliminate the alternative minimum tax	1.95	24	18	11	5
Overhaul and simplify income tax rules for exploration and production activities	2.09	17	24	12	5
Provide tax incentives for marginal wells	2.03	19	21	15	3

Table 13, continued

1994		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Update the 1979 SEC definition of proved reserves to conform with the current SPE/SPEE definition	2.73	6	12	28	9
Adoption of international accounting standards for exploration and production activities	3.35	1	3	25	23
Please, no changes to financial rules. Changes are too costly and disruptive.	3.64	3	1	2	30
Please no changes to tax rules. Changes are too costly and disruptive.	3.85	0	1	3	29

Table 13, continued

1997		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Change the use of current prices for the full cost ceiling	3.1	7	4	5	22
Adopt for all companies one overall accounting method such as successful efforts or full cost	3.1	5	7	13	20
Adopt uniform ceiling/impairment rules for all companies	3.0	4	7	19	14
Modify FAS 121 to allow grouping properties by country or company	3.0	6	8	11	20
Require a standardized finding cost disclosure	3.1	1	13	11	21
Require a standard financial accounting method for gas imbalances	3.2	1	9	14	19
Amend accounting for P&A costs and liabilities	3.6	1	1	10	30

Table 13, continued					
1997		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Form an industry committee to address petroleum financial accounting rules and interpretations not addressed by the FASB	3.3	0	9	15	23
Update the 1979 SEC definition of proved reserves to conform with the current SPE/SPEE definition	2.7	8	7	`8	10
Adopt international accounting standards for exploration and production activities	3.5	1	1	14	23
Eliminate the alternative minimum tax	1.8	23	12	10	1
Overhaul and simplify income tax rules for exploration and production activities	2.2	10	18	13	4
Provide tax incentives for marginal wells	2.2	12	18	9	7

Table 13, continued

1997		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Please, no changes to financial rules. Changes are too costly and disruptive.	3.4	3	2	2	17
Please, no changes to tax rules. Changes are too costly and disruptive.	3.5	3	1	0	18
Other:	1.0	2	0	0	N/A
1999		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Change the use of current prices for the full cost ceiling	2.8	6	8	5	14
Adopt one overall accounting method for all companies such as successful efforts or full cost	3.1	5	4	11	17
Adopt uniform ceiling/impairment rules for all companies	3.1	4	4	13	16

Table 13, continued					
1999		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Modify FAS 121 to allow grouping properties by country or company	3.1	4	6	11	17
Require a standardized finding cost disclosure	3.0	3	11	11	15
Require a standard financial accounting method for gas imbalances	3.2	0	6	19	14
Amend accounting for DR&A costs and liabilities	3.6	0	4	9	26
Form an industry committee to address petroleum financial accounting rules and interpretations not addressed by the FASB	3.0	1	9	19	11
Update the 1979 SEC definition of proved reserves to conform with the current SPE/SPEE definition	2.6	3	13	18	3

Table 13, continued					
1999		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Adopt international accounting standards for exploration and production activities	3.2	1	5	15	15
Eliminate the alternative minimum tax	1.9	16	14	8	2
Overhaul and simplify income tax rules for exploration and production activities	2.3	7	18	13	4
Provide tax incentives for marginal wells	2.3	10	17	9	6
Please, no changes to financial rules. Changes are too costly and disruptive.	3.4	4	2	2	20
Please, no changes to tax rules. Changes are too costly and disruptive.	3.2	3	2	1	18

Table 13, continued					
1999		Most Needed (1)	Greatly Needed (2)	Needed (3)	Not Needed (4)
	Average	No.	No.	No.	No.
Other:					
Use average price for period not end-of-year price for standardized measure	1.0	1	0	0	n/a
Capitalize G&G costs for successful efforts firms	3.0	0	0	1	n/a
Revise rules for 3-D seismic	3.0	0	0	2	n/a
Modify FAS 133 to better reflect the petroleum industry	1.0	1	0	0	n/a

Conclusion

The surveys published by the Institute of Petroleum Accounting provide an opportunity for academics and practitioners to examine and compare the accounting practices of companies in the U.S. oil and gas industry. This two-part study has highlighted changes in a number of important accounting practices for the sample of companies who participated in three surveys conducted by the Institute during the 1990s.

Changes discussed in Part One of this study included: an increase in the use of the successful efforts method of accounting, a higher proportion of companies reporting oil and gas producing operations outside the United States, capitalization of 3-D seismic development costs by an increasing proportion of successful efforts companies, a shift towards aggregation of DR&A costs at a field level, and an increase in the number and proportion of companies accounting for net profit interests. Other important changes in accounting practices illustrated in Part One were an increasing proportion of companies recognizing crude oil in lease tanks and produced natural gas held in storage as inventory in financial statements, the use of LIFO as the most common method for determining the reported cost of crude oil and natural gas inventories, the large scale adoption of SFAS 121, the variety of discount rates used in determination of fair value for implementation of SFAS 121, and changes in supplemental disclosures provided by oil and gas companies.

Part Two of this study highlighted changes in accounting practices and in companies' desire for accounting and tax rule changes. Changes in accounting practices outlined included: growth in the proportion of companies reporting netting of over- and under-delivered positions, increased frequency of assessment of accounts receivable from under-delivered positions, a higher number and proportion of companies using average cost in the costing of the imbalance liability for crude oil exchange accounting, increasing number of companies computing finding costs for internal and external disclosures, movement in accounting for capitalized interest towards less use of expenditure thresholds, and longer minimum project length for capitalization and capitalization after exploration leases are acquired. Rule changes desired by the companies surveyed during the 1990s generally focused on simplification of tax laws and stability in accounting rules.