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ENHANCED OIL RECOVERY: THE IMPACT OF POLICY OPTIONS

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With the advent of a new technology like enhanced oil recovery, two interactive factors often inhibit output expansion. First, even with information about prices, costs and production, careful analysis may indicate that initiation of production will not be profitable for early producers. Price factors may be unfavorable or sufficient experience may not have been gained to reduce costs or make production efficient enough to produce an adequate return on invested capital. Second, as in any market situation, the value of numerous variables affecting profitability may be uncertain (now and in the future). In the case of enhanced oil recovery, this factor, coupled with some degree of risk aversion by potential operators, can have a major impact on the speed and degree of process development.

Proposed public policy alternatives are, in reality, attempts to reduce or eliminate these factors in the private decision process and thereby modify the private market solution in hopes of achieving a desired social objective. Since these two factors are obviously interdependent, they enter into both the private and social analysis of a relatively new technology such as enhanced oil recovery. For purposes of the analysis to be carried out here, however, the artifical distinction will be maintained. We first evaluate enhanced recovery processes under the assumption of information certainty; using forecasts of production, price and cost profiles for selected reservoirs. Alternative public policy options, designed to foster private sector development, will be evaluated under this assumption. Then, a second analysis, using subjective probability distributions of key input variables, will be carried out in an effort to ascertain the impact of these and other policy alternatives designed for situations of uncertainty.

Policy options

A number of public policy alternatives are available or have been suggested which could influence the development of production from enhanced oil recovery techniques. Many of these alternatives may impact the criteria used by the private sector in making decisions on whether to develop specific reservoirs for enhanced oil recovery or modify decisions with respect to the optimal process to be installed. The latter can, in turn, affect the amount and distribution of potential enhanced oil production. These and other policy options may also affect constraints which would limit the overall size of enhanced oil recovery production nationally. Regardless of their specific focus, most public policy changes can also be expected to influence the degree of uncertainty perceived by the private sector in future enhanced oil recovery activities.

We will analyze and evaluate a number of these potential public policy actions. The principal proposals can be classified as:

1. Alternative regulated and/or market price levels;

2. Price and/or purchase guarantees for enhanced oil production over the lifetime of a producing facility;

3. Alternative taxation policies including considerations such as depreciation methods, investment tax credit rates, and expensing rules for various categories of investment and operating costs; and

4. Public investment subsidies or direct payment by the government of a percentage of private investment costs.

In addition, all of these alternative strategies can be evaluated for their effects under alternative leasing systems when the reservoirs being considered are located on the public domain.[1] For analytical purposes, we will examine the various options in conjunction with several bidding systems, including the current system and others that could be used, for public domain leasing in the future. These bidding systems include:

1. The current cash bonus system;

2. Royalty systems plus fixed bonus; and

3. Profit share systems plus fixed bonus.

Five alternative price situations were analyzed. First, the current regulated price for new oil (the upper tier price) of $11.62 per barrel was simulated. Second, the average price was assumed to remain at approximately the current value of foreign crude oil landed in the eastern United States ($13.75 per barrel). Third, a price approaching the cost of alternative synthetic fuels ($22.00 per barrel) was assumed (Synfuels Interagency Task Force). Fourth, an intermediate price of $17.00 per barrel was tested. Finally, for the analysis of information uncertainty, an annual price increase of five percent from a $13.75 per barrel base was compared with the results from a uniform $13.75 price level.

For each enhanced oil recovery process, base line evaluations were carried out using these alternative price levels and currently permitted tax procedures (including the 10 percent investment tax credit, expensing of injection chemicals and unit of production depreciation). Then, the following policy alternatives were analyzed:

1. Price subsidies of $1.00 and $3.00 per barrel,

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[1]Another policy option can also be considered for reservoirs located on the public domain. That is, lease terms which mandate enhanced oil recovery installations at a specific time in the production time horizon. Analysis of this option, however, requires data not only on EOR costs and production profiles but on the synergistic effects with primary and secondary production. Since little experience is available on these elements, evaluation of the option would be difficult.

2. Price guarantees of $13.75 per barrel,

3. Investment tax credit of 12 percent,

4. Capitalization and subsequent depreciation of injection chemical costs,

5. Use of an augmented accelerated depreciation method, and

6. Governmental investment subsidy of 15 percent of total investment cost.

Since several of these options (price subsidies and guarantees) are designed to reduce uncertainty, all options were not tested for situations of both information certainty and uncertainty.

Alternative leasing systems for public domain lands tested with the various options included the current cash bonus fixed royalty system, a cash bonus system with a 40 percent fixed royalty and an annuity capital recovery profit share system with a cash bonus bid. In the latter system, investment costs are recovered over eight years at 8 percent interest before the profit share rate of 50 percent is applied.[2]

Analytical approach

All reservoirs in a selected sample were tested using cost and production profiles from research carried out for a recent Office of Technology Assessment study of enhanced oil recovery (Office of Technology Assessment, 1977). The profiles assumed relatively optimistic assumptions about the rate of technological advance in enhanced oil recovery methods and are, thus, labeled the High Process Performance case. Policy options having little impact on this more optimistic situation could not be expected to influence EOR production in other cases. As a check on these results, however, data from the OTA Low Process Performance case (a more pessimistic technological case) were also analyzed. Individual EOR processes were evaluated separately in light of the baseline values and, then, in regard to the policy options discussed above.[3] Evaluations, under both the assumption of information certainty and uncertainty, were carried out through the use of a Monte Carlo discounted cash flow simulation model (Tyner and Kalter, 1976) modified to handle the EOR decision process as viewed by the private sector.

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[2]Other leasing systems have been suggested and could be evaluated. For example, variable rate options for both royalty and profit share systems may be desirable alternatives. However, those chosen appear to cover a range of possible results (Kalter, Tyner and Hughes, 1975).

[3]Reservoirs subject to more than one EOR process were not evaluated with respect to the impact of policy options on each process or on process selection. The impact of alternative price levels and decision criteria on process selection was discussed in a previous section but data were not available to carry out a detailed analysis here. Since most policy options were analyzed at the world oil price, this should not impact the results (process selection was generally carried out at this price level).

Analysis of Government Policy Options

For purposes of policy analysis, a sample of up to fifty reservoirs assigned to each EOR process (by geologic and engineering criteria) were selected for initial evaluation. Separate samples for on- and off-shore areas were drawn from reservoirs assigned to a given EOR process by the OTA study. Sample selection was based upon a number of criteria, including regional location, reservoir depth, residual (available for tertiary production) barrels of oil per acre, reservoir size in acres and, in the case of off-shore fields, water depth. For each EOR process evaluated, fields covering a broad range of these characteristics were included. A total of 835 reservoirs, representing over 52 percent of the remaining oil in place in the United States, made up the universe for the OTA study.

After reviewing the range of values taken on by the various selection criteria, it was decided that a sample of twenty-five reservoirs for each EOR process would be adequate to cover the circumstances affecting economical development and provide an appropriate test of the various policy options. The only exception to a sample number of twenty-five was the case of on-shore CO_2 where substantial EOR production is expected. Table 1 displays the number of reservoirs assigned to each process, the number selected for the sample and the percentage of the available universe sampled. Appendix A lists the reservoirs in the overall sample and their various characteristics.

Table 1.--Number and Percent of Reservoirs Sampled by EOR Process

Process	On-Shore					Off-Shore*
	Steam	In Situ	Surfactant	Polymer	CO_2	CO_2
Total Reservoirs Assigned	20	20	92	20	190	294
Sample Size	20	20	25	20	50	25
Percent Sampled	100	100	27	100	26	9

*All reservoirs located off-shore had been assigned to the CO_2 recovery process.

Analysis assuming information certainty

Given the sample selection, the first step in the analysis was to test the potential for profitable EOR development at various price levels under conditions of information certainty. Using production profiles, investment costs (and timing) and operating costs developed for the High Process Performance case, these tests were conducted under the assumptions that private industry would require a 10 percent rate of return on invested capital and that currently permitted tax procedures (state and federal) would be governing.

Thus, a 10 percent investment tax credit, expensing of EOR injection costs, depreciation based on the rate of resource depletion, and current state and federal income tax rates were used.

Table 2 displays the number and percent of each EOR process sample that would be developed at various price levels under these conditions, as well as the percentage of potential EOR production (gross production less that used for EOR purposes) that would result from those developed. For example, development ranges from 6 percent of the fields at $11.62 per barrel for on-shore CO_2 to 95 percent at $22.00 per barrel for polymer. Production ranges from 22 percent of the total possible for on-shore CO_2 at $11.62 per barrel to 100 percent for polymer and in situ at $22.00 per barrel. Current world prices of $13.75 per barrel result in up to 99 percent of possible production from the polymer process to 24 percent of possible EOR off-shore oil production for those reservoirs assigned to the CO_2 process. Overall, 43 to 81 percent of the sample reservoirs are developed over the price range analyzed; with 46 to 82 percent of possible EOR oil being produced.[4]

Of perhaps greater interest, however, is the price elasticity of supply (i.e., the proportionate change in production per proportionate change in price). Table 2 also lists these values (arc elasticities) for the sample over the price range analyzed.[5] Individual EOR processes, as well as total production from all processes, are shown. It is obvious that the price elasticities vary across both process and the range of price changes. In the $11.62 to $22.00 range, the CO_2 and steam processes are price elastic. This is also true of all processes combined. In situ, surfactant and polymer are, however, price inelastic; to the point where higher prices will have little impact on production.

All processes, except off-shore CO_2, exhibit the greatest price elasticity in the low and/or middle price ranges (to $17.00 per barrel). Off-shore CO_2 exhibits its greatest elasticity over the middle price range ($13.75-$17.00 per barrel), with substantial elasticity above $17.00 per barrel. This suggests that the greatest price impact on production will take place in the range of real prices from $11.62 to approximately $17.00 per barrel, except in the high cost off-shore regions. With real (deflated) oil prices expected to increase

[4]Using production estimates based upon the Low Process Performance case would substantially reduce these values. For example, the surfactant process at world oil prices would be implemented on only two reservoirs in the sample (8 percent) and result in 7 percent of the potential net production. Similar calculations could be shown for other processes and price levels. However, the object of this section is an evaluation of policy options. For this purpose, the High Process Performance case is used as a basis with digressions to other cases only if policy conclusions would be affected. Also, the values change considerably when the analysis is conducted at the lower tier (old oil) price of $5.25 per barrel. At this price only 8 percent of the reservoirs with 14 percent of total possible production were developed.

[5]Note that these values relate to ultimate net production and, thus, give no indication of the sensitivity of production profiles (or timing) to price.

Table 2.--EOR Development and Production by Process and Price Level

Process and Price	Sample Size	Number Developed	Percent Developed	Percent Potential Production Developed	Sample Price Elasticity of Supply
Steam					
$11.62/BBL.	20	6	30	41	.99
13.75/BBL.	20	9	45	47	3.10
17.00/BBL.	20	11	55	75	.62
22.00/BBL.	20	14	70	85	
In Situ					
$11.62/BBL.	20	14	70	89	.52
13.75/BBL.	20	16	80	96	.19
17.00/BBL.	20	18	90	100	.00
22.00/BBL.	20	18	90	100	
Surfactant					
$11.62/BBL.	25	14	56	77	.70
13.75/BBL.	25	19	76	85	.00
17.00/BBL.	25	19	76	85	.46
22.00/BBL.	25	22	88	94	
Polymer					
$11.62/BBL.	20	14	70	94	.32
13.75/BBL.	20	17	85	99	.00
17.00/BBL.	20	17	85	99	.05
22.00/BBL.	20	19	95	100	
CO_2--On-Shore					
$11.62/BBL.	50	12	24	22	1.52
13.75/BBL.	50	22	44	27	4.26
17.00/BBL.	50	32	64	50	1.87
22.00/BBL.	50	37	74	71	
CO_2--Off-Shore					
$11.62/BBL.	25	9	36	24	.00
13.75/BBL.	25	9	36	24	2.21
17.00/BBL.	25	15	60	35	1.99
22.00/BBL.	25	19	76	50	
Total					
$11.62/BBL.	160	69	43	46	.88
13.75/BBL.	160	92	58	52	1.78
17.00/BBL.	160	112	70	69	.81
22.00/BBL.	160	129	81	82	

in the future and the physical impossibility of developing all reservoirs simultaneously (due to capital and manpower requirements, as well as logistics), the first priority for encouraging EOR development would appear to be that of allowing prices for EOR production to float with world price. This is further supported by the fact that those EOR processes with the greatest potential also have the greatest price elasticity.

Of the thirty-one fields which did not develop at a \$22.00 per barrel price, twenty-one developed at \$27.50 or below, six between \$27.50 and \$50.00, two between \$50.00 and \$75.00, and two would not develop unless price exceeded \$75.00. As a result, 99 percent of the potential EOR production can be achieved at prices below \$27.50 per barrel. Overall price elasticity is positive (1.35) in the range of \$22.00-\$27.50, but almost zero above \$27.50. By process, fields in all categories developed below \$27.50 while steam, in situ and surfactant comprised the techniques that would not develop the remaining fields at prices below \$50.00 per barrel. The latter, of course, use a portion of recovered oil in the process.

Yet it may be dangerous to generalize from a sample (although our steam and in situ simulations cover all assigned reservoirs). Therefore, to gain additional insight, the supply elasticities calculated from the sample were compared with those based upon all reservoirs assigned to EOR processes in both the Low and High Process Performance cases. Such a comparison cannot be precise because of the different approach used in the overall analysis to address economic calculations. The following differences in method must be understood.

1. The policy sample contains a greater proportion of marginal fields than the universe.

2. The overall analysis provides information at only three price levels (\$11.62, \$17.00 and \$22.00 per barrel).

With these considerations in mind, Table 3 displays the comparison.

In general, the tendencies apparent from the sample are supported when looking at the High Process Performance universe. Surfactant becomes price elastic, along with CO_2 and steam, but on-shore CO_2 appears somewhat less price sensitive and off-shore CO_2 somewhat more price sensitive than in the sample. No evidence is apparent which would argue for a change in the previously discussed conclusions. As would be expected, the Low Process Performance case showed higher price elasticities for a number of the processes. Only in situ remained price inelastic overall, while the price elasticity of steam dropped.

Given the potential impacts of price on EOR development, the next question in a situation of information certainty is whether other public policy options would change the timing or magnitude of EOR introductions. For this question, we analyzed four possible policy changes (three tax considerations and a public investment subsidy to encourage EOR development).

The tax options include the use of a 12 percent investment tax credit (2 percent greater than that currently allowed), accelerated depreciation

Table 3.--Price Elasticity of Supply Comparison

Process	Policy Analysis Sample High Process Performance Case	OTA Total Reservoir Assignment High Process Performance Case	OTA Total Reservoir Assignment Low Process Performance Case
Steam			
Overall ($11.62-22.00/BBL.)	2.32	2.42	1.92
$11.62-13.75/BBL.	.99	1.15	1.23
13.75-22.00/BBL.	2.18	2.18	1.60
In Situ			
Overall ($11.62-22.00/BBL.)	.25	.25	.71
$11.62-13.75/BBL.	.52	.76	1.08
13.75-22.00/BBL.	.10	.00	.38
Surfactant			
Overall ($11.62-22.00/BBL.)	.48	1.47	12.93
$11.62-13.75/BBL.	.70	2.51	8.39
13.75-22.00/BBL.	.28	.59	5.57
Polymer			
Overall ($11.62-22.00/BBL.)	.11	.00	1.06
$11.62-13.75/BBL.	.32	.00	3.23
13.75-22.00/BBL.	.06	.00	.00
CO_2--On-Shore			
Overall ($11.62-22.00/BBL.)	4.64	2.49	5.33
$11.62-13.75/BBL.	1.52	3.34	2.03
13.75-22.00/BBL.	4.22	1.16	4.46
CO_2--Off-Shore			
Overall ($11.62-22.00/BBL.)	2.26	7.06	--
$11.62-13.75/BBL.	.00	3.23	--
13.75-22.00/BBL.	2.84	5.04	--
All Processes			
Overall ($11.62-22.00/BBL.)	1.70	2.02	4.50
$11.62-13.75/BBL.	.88	2.46	2.42
13.75-22.00/BBL.	1.56	1.10	3.39

using the double declining balance method, and, to evaluate industry's contention that IRS must permit the expensing of injection costs if EOR is to be economically viable, an option where injection costs are 100 percent depreciated. The latter option changed the assumption used in the previous simulations that all injection costs are expensed in the year paid. Depreciation was assumed to take place over the remaining production period in proportion to production. The investment subsidy option calls for the government to pay 15 percent of all initial EOR related investments (deferred investments are paid fully by the producer).

Table 4 displays the result of these tests. All evaluations were made assuming current world market prices ($13.75 per barrel) prevailed. As can be seen the various options have relatively minor impacts on development and, consequently, production. In fact, the 12 percent investment tax credit results in no new development, while the accelerated depreciation option adds one in situ reservoir and increases total net production by only two tenths of one percent over a six year period. On the other hand, an IRS requirement that EOR injection costs be 100 percent depreciated results in thirty (thirty-two percent) less sample reservoirs developed with a 29 percent reduction in total production over a twenty-two year period. The reduced production is concentrated in surfactant with some impact on the steam, polymer and on-shore CO_2 processes. The most powerful of the policy options in encouraging development appears to be the 15 percent investment subsidy. Similar to the current ERDA demonstration program, this would add three developed reservoirs from our sample at current world oil prices and result in a 1 percent increase in net production.[6]

The various options do change the amount of above normal (10 percent rate of return) profit that can be expected from developed fields. Depreciation of injection costs would tend to reduce rates of return and the other options would increase them. If the introduction of EOR to potential reservoirs is paced on the basis of rates of return, this could have an impact on aggregate production profiles and the timing of recovery. The exact impact is difficult to quantify since firms will have different decision criteria and schedules for starts based on those criteria. Assuming that high rates of return would be required initially, however, it is clear that the effect would generally be small (with the exception of injection cost depreciation for the surfactant process). In the near term, the annual step (change) in the rate of return criterion would be sufficiently large that few of the policies analyzed would result in the required degree of change. In later years, as the annual step is reduced, the impact of any policy change on EOR timing is likely to be only one or two years.

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[6]Similar results were obtained when analyzing the Low Process Performance case. The number of reservoirs that developed at a 10 percent rate of return was obviously reduced by a substantial degree. However, the various policy options have little impact on changing these decisions. Taking surfactant as an example of a process which is often marginal, the various options resulted in only one addition to the two fields developed under free market conditions (see footnote 4). That development occurred when a 15 percent investment subsidy was introduced. Required depreciation of injection costs, however, did not affect the decision to develop.

Table 4.--EOR Development by Process and Policy Option

Process	Sample Size	Number Developed				
		$13.75/ BBL.	12% Investment Credit	Accelerated Depreciation	Depreciate Injection Costs	15% Investment Subsidy
Steam	20	9	9	9	6	9
In Situ	20	16	16	17	16	18
Surfactant	25	19	19	19	4	19
Polymer	20	17	17	17	15	17
CO_2--On-Shore	50	22	22	22	13	22
CO_2--Off-Shore	25	9	9	9	9	10
TOTAL	160	92	92	93	63	95

These results, however, need to be compared with the costs of the respective programs. In the case of a 12 percent investment tax credit, the government revenue loss per each incremental barrel of production is obviously infinite, since no new output results. The accelerated depreciation option adds an additional reservoir developed for EOR; increasing production by over 28 million barrels in eight years. At the same time, government revenue actually increases due to the greater production and the changes in the relevant time profiles. The increase per barrel of production, however, is slight; less than one cent per barrel.

As would be expected, requiring the depreciation of injection costs increased government revenue while the 15 percent investment subsidy reduced it. The impacts per barrel of production change were, however, again minor. The cost of the investment subsidy program is the net of the subsidy, itself, and the change in federal tax collections.

In summary, one can argue that none of the policy options are very powerful in encouraging new production nor expensive in terms of government cost per barrel produced. In fact, little appears to be gained (or lost) by attempting to accelerate EOR development to a pace faster than that dictated by the current institutional setting. The question remains, however, whether such policy options are worth potential distortions in efficiency in situations where information uncertainty exists. This question is explored in the next section.

Analysis assuming information uncertainty

To evaluate the question of uncertainty in production, cost and price values, the same sample of reservoirs as discussed previously was used in conjunction with subjection probability distributions on the key input variables. Table 5 lists the variables and the distributions used. The resulting range in production from the reservoirs was substantially less than that resulting from the two cases analyzed for the overall study. This indicates that the degree of uncertainty implicit in the cost and production distributions was less than that expected by technical personnel. Also, the price distribution was defined by resort to the widely held assumption that down-side risk is low. As a result, our policy tests can be considered conservative, in that a policy which will not impact development here is unlikely to have any impact in practice.

Table 5.--Input Variables and Subjective Probability Distributions Used for Monte Carlo Simulations

Variable	Value
Price (/BBL.)	
Original Value	$13.75
Mean of Price Change Distribution	0.0
Standard Deviation of Price Change Distribution	0.01
Production	
Triangular Contingency Distributions	
Minimum	-.30
Most Likely	-.10
Maximum	0.05
Investment and Operating Cost	
Triangular Contingency Distributions	
Minimum	-.05
Most Likely	0.0
Maximum	0.1
Number of Monte Carlo Interations	200

Table 6 summarizes these evaluations. It was assumed throughout that the question of uncertainty would be evaluated at price levels approximating current world values. Because of the minor impacts exhibited in the previous analysis by most tax options, they were dropped from further consideration. Two other options, designed to reduce uncertainty, were added. They included a price guarantee whereby the government would assure a market price that did not fall below $13.75 per barrel and an actual price subsidy (payment by the government over and above market price) of $3.00 per barrel of EOR oil produced. A $1.00 per barrel subsidy was also evaluated but is not displayed

Table 6.--Monte Carlo Simulation of Policy Option Impacts in Reducing Uncertainty

EOR Process and Policy	Sample Size	Number of Reservoirs Developed						Percent Potential Net Production Developed					
		Probability of Less Than Normal Profit						Probability of Less Than Normal Profit					
		0%	1-25%	26-50%	51-75%	76-99%	Total	0%	1-25%	26-50%	51-75%	76-99%	Total
Steam													
Base Case	20	3	1	2	--	4	10	31	1	8	--	29	69
Price Guarantee	20	3	1	2	--	4	10	31	1	8	--	29	69
Price Subsidy	20	3	3	2	1	3	12	31	9	4	2	35	81
Investment Subsidy	20	3	3	--	1	3	10	31	9	--	2	27	69
In Situ													
Base Case	20	10	2	--	2	4	18	69	1	--	19	11	100
Price Guarantee	20	10	2	1	2	3	18	69	1	9	13	8	100
Price Subsidy	20	11	2	3	2	--	18	69	11	17	3	--	100
Investment Subsidy	20	11	1	3	1	2	18	69	1	22	5	3	100
Surfactant													
Base Case	25	2	4	6	3	4	19	1	16	49	11	8	85
Price Guarantee	25	2	4	7	2	4	19	1	16	50	10	8	85
Price Subsidy	25	2	12	4	1	1	20	1	76	8	--	3	88
Investment Subsidy	25	2	4	8	3	2	19	1	16	60	2	6	85
Polymer													
Base Case	20	11	3	--	1	2	17	78	16	--	2	2	98
Price Guarantee	20	11	3	--	1	2	17	78	16	--	2	2	98
Price Subsidy	20	14	2	1	--	--	17	94	3	2	--	--	99
Investment Subsidy	20	11	3	1	2	--	17	78	16	2	2	--	98
CO_2--On-Shore													
Base Case	50	4	3	4	4	7	22	12	2	5	11	11	41
Price Guarantee	50	4	4	3	4	7	22	12	4	3	11	11	41
Price Subsidy	50	9	11	2	2	7	31	16	22	2	1	6	47
Investment Subsidy	50	4	6	4	5	6	25	12	6	9	10	5	42
CO_2--Off-Shore													
Base Case	25	7	2	--	--	--	9	21	4	--	--	--	25
Price Guarantee	25	7	2	--	--	--	9	21	4	--	--	--	25
Price Subsidy	25	9	--	--	3	4	16	24	--	--	7	7	38
Investment Subsidy	25	7	2	--	--	2	11	21	4	--	--	6	30
Total													
Base Case	160	37	15	12	10	21	95	23	5	14	8	16	66
Price Guarantee	160	37	16	13	9	20	95	23	6	14	7	16	66
Price Subsidy	160	48	30	12	9	15	114	24	26	5	2	15	72
Investment Subsidy	160	38	19	16	12	15	100	23	9	19	6	13	70

because of its negligible impact. In all evaluations, current tax rules (10 percent investment credit, expensing injection costs and unit of production depreciation) and a 10 percent rate of return were assumed.

The simulations provide interesting insight into the potential profitability of EOR development. Overall, it appears that up to 23 percent of the developable EOR reservoirs (and 23 percent of the producible oil) would be available at current market prices with zero chance of a less than normal profit to the operator. The remainder of the fields with some chance of profitability are spread more or less uniformly over the probability of less normal profit categories. These remaining reservoirs, however, contain differential amounts of recoverable oil with concentrations contained in the 26-50 and 75-99 percent chance of loss categories. Only 66 percent of the sample's producible EOR oil has some probability of being profitably exploited under the conditions simulated.

The policy options analyzed have little effect on these results. Only the $3.00 price subsidy adds a significant number of reservoirs to those potentially developed (20 percent), but this results in only a 6 percent increase in potential oil production. The impact is concentrated in the CO_2, steam and surfactant processes, with a 12 percent increase in production from steam, a 13 percent increase in offshore CO_2 production, a 6 pereent increase in on shore CO_2 production and a 3 percent increase in surfactant production. The 15 percent investment subsidy adds 5 percent to the potential reservoir development but only 4 percent additional oil. Only CO_2 processes were affected, however. In most cases, reservoirs added to those that would be potentially developed are in the high risk (76-99 percent chance of loss) category.

All options, however, have some impact on reducing the risk of development for those reservoirs that are potential candidates under current market conditions. Again, the most successful policy in this regard is the $3.00 price subsidy, with 55 percent of the potential production classified below 50 percent probability of a less than normal profit. This is a 31 percent improvement over the base case and compares to a 2 percent improvement for the price guarantee option and a 21 percent gain for the investment subsidy. The price subsidy also has a tendency to move reservoirs one or two categories lower on the risk scale whereas the other options push a field to the next lowest category (if any change is forthcoming).

The impacts of the various policy options on individual EOR processes are similar to the overall results. The greatest addition to potential EOR reservoirs and total production results from the price subsidy option. Production potential increases 52 percent for off-shore CO_2, 17 percent for steam and 15 percent for on-shore CO_2. The other processes show a negligible change in production potential. Again, however, this increased potential is added to the higher risk categories for each process. The reduction in risk for potential production (from the base case) is greatest for all options with respect to the on-shore CO_2 process, followed by in situ and surfactant. The price subsidy option, for example, causes a 110 percent improvement in potential on-shore CO_2 production classified below 50 percent probability of a less than normal profit (the comparable figures for other processes are: 38 percent for in situ, 29 percent for surfactant, 10 percent for steam, 5 percent for polymer and no change for off-shore CO_2).

Although increases in potential EOR production (from all risk categories) do not appear substantial for any of the options designed to reduce uncertainty, the possibility of changing the risk of development for those reservoirs included in the base case warrents further investigation of a price subsidy. To accurately assess this option the potential benefits of increased EOR production must be balanced against government costs. However, both the extent of increased production and the corresponding costs are difficult to quantify. Since the decision to produce EOR oil from any of the risky fields (those with a positive chance of a less than normal profit) depends on a producer's risk preference function, one must ascertain the appropriate decision rule used by the private sector to make development decisions before an accurate assessment can be made. Given that these decision rules will vary by individual firm and may change within a firm as a result of policy options like subsidies, government cost is difficult, if not impossible, to quantify. The cost of the $3.00 subsidy to all produced EOR oil must be offset by any increase in federal tax revenue and, in the case of off-shore fields, royalties collected. Without knowledge of the before and after impacts under varying risk conditions and decision criteria this can only be an educated guess. For a range of possible conditions, the net present value cost appears to be in the area of $1.50 to $2.00 per barrel.

Society must determine whether the additional expected cost is outweighed by the benefits earlier production of EOR would cause, and whether postponement of EOR production will ultimately lead to a higher cost of recovered oil (due to increased investment and operating costs required to apply EOR processes to older fields). An alternative policy might also be suggested. That is, the targeting of subsidies to fields that are economically marginal under current conditions. The costs of such a policy would depend on the criteria used for selecting such areas and the other parameters discussed above.

The preceding analysis assumes that EOR oil will achieve a market price of $13.75 per barrel and that such a price will continue, in real terms, throughout the productive life of an EOR project. Evaluation of this assumption could lead to the conclusion that the results discussed above are an inaccurate representation of the future reality. If EOR oil prices are deregulated and world market prices maintain a moderate, but consistent, real growth rate much of the uncertainty exhibited in the profitability of EOR projects may be eliminated.

To test this possibility, an analysis was performed on the sample which assumed an average annual real price increase of 5 percent (randomly selected from a normal price change distribution with a standard deviation of 3 percent). Although one could assume little down side risk for price because of world market conditions, no constraint was imposed in the test. Thus, the results may be conservative. Table 7 displays the price deregulation impact and compares it to the $13.75 price base case and the $3.00 price subsidy situation (from Table 6). It can be seen that the price deregulation scenario test equalled or exceeded the results of the price subsidy in reducing uncertainty for all EOR processes. Overall, price deregulation led to a 34 percent increase in field development over the base case and an 11 percent increase over the price subsidy situation. Moreover, substantial shifts

Table 7.--Monte Carlo Simulation of EOR Oil Price Deregulation

EOR Process and Policy	Sample Size	Number of Reservoirs Developed					
		Probability of Less Than Normal Profit					
		0%	1-25%	26-50%	51-75%	76-99%	Total
Steam							
Base Case	20	3	1	2	--	4	10
Price Subsidy	20	3	3	2	1	3	12
Price Deregulation*	20	3	5	3	2	--	13
In Situ							
Base Case	20	10	2	--	2	4	18
Price Subsidy	20	11	2	3	2	--	18
Price Deregulation*	20	11	5	--	2	--	18
Surfactant							
Base Case	25	2	4	6	3	4	19
Price Subsidy	25	2	12	4	1	1	20
Price Deregulation*	25	6	13	--	1	2	22
Polymer							
Base Case	20	11	3	--	1	2	17
Price Subsidy	20	14	2	1	--	--	17
Price Deregulation*	20	14	3	--	--	2	19
CO_2--On-Shore							
Base Case	50	4	3	4	4	7	22
Price Subsidy	50	9	11	2	2	7	31
Price Deregulation*	50	18	5	4	6	4	37
CO_2--Off-Shore							
Base Case	25	7	2	--	--	--	9
Price Subsidy	25	9	--	--	3	4	16
Price Deregulation*	25	9	--	--	3	6	18
Total							
Base Case	160	37	15	12	10	21	95
Price Subsidy	160	48	30	12	9	15	114
Price Deregulation*	160	61	31	7	14	14	127

*Assumes an annual price change distribution which is normal with a 5 percent mean and a 3 percent standard deviation.

in the uncertainty category took place for individual fields which were formerly in high risk (greater than 50 percent chance of loss) situations. The impact of price deregulation is felt uniformly across EOR processes with only in situ not participating in the effect.

Thus, if a moderate annual increase in real oil prices obtained for EOR production could be expected, special government policies to reduce uncertainty may not be required. An equal or greater impact can be obtained by the simple action of price deregulation.

Impact of alternative OCS leasing systems

With the widespread current interest in OCS leasing activity, increased attention has been focused on alternative leasing systems. Currently, the United States uses, almost exclusively, a cash bonus bidding procedure where the winning bidder on an OCS tract is the firm who offers the government the highest front-end payment for exploration and development rights (the cash bonus). This bid amount is not returnable if recoverable resources are not found and, therefore, has no impact on subsequent development and production decisions (including the use of EOR technology). In addition to the cash bonus, a royalty on gross production value of 16.67 percent is required by the government. The previous analysis of policy options assumed this method was in use for the off-shore CO_2 cases.

However, because of the substantial uncertainty that exists in off-shore development and the capital requirements of cash bonus bidding, suggestions (Kalter and Tyner, 1975) have been made that would use alternative systems; thereby spreading risk to the government, reducing capital requirements and encouraging competition. As a result, government revenue may increase with little or no loss in production. Such alternative leasing systems make greater use of contingency payments (government receives revenue only upon actual production) and usually employ an augmented royalty rate or a profit share technique. Often the cash bonus is retained as the bid variable, however, to reduce speculation. The higher contingency payments, expected if production takes place, act to reduce the magnitude and importance of the bonus.

Two such systems are analyzed here and were described above. The question of EOR viablity under the alternative systems was considered when compared to the current system. Table 8 details the results of this analysis. It is clear that high fixed royalties will inhibit EOR development by increasing the risk of less than normal profits and making some fields uneconomic for EOR purposes. This result confirms earlier studies on the impact of high royalties for primary and secondary production (Kalter, Tyner and Hughes, 1975). However, the profit share system also has a tendency to increase the risk of a less than normal profit. This is at variance with previous results on primary and secondary production and indicates that the profit share rate (50 percent) has been set too high for EOR development on marginal fields. One option in both situations would be the use of a variable rate royalty or profit share approach, so that rates would automatically be reduced for marginal fields and increased in situations of higher productivity. The variable rate could depend on either the amount of production or the revenue level in each situation. If experiments with new leasing systems are contemplated, their ultimate impacts on EOR production should be considered along with traditional production profiles.

Table 8.--Monte Carlo Simulation of OCS Leasing Systems and EOR Potential

EOR Process and OCS Leasing System	Sample Size	Probability of Less Than Normal Profit					
		0%	1-25%	26-50%	51-75%	76-99%	TOTAL
		Number of Fields Developed					
CO_2--Off-Shore							
Current	25	7	2	--	--	--	9
40% Royalty	25	2	1	1	1	3	8
50% Profit Share	24	4	3	2	--	--	9
		Percent Potential Net Production Developed					
CO_2--Off-Shore							
Current	25	21	4	--	--	--	25
40% Royalty	25	3	6	4	1	9	23
50% Profit Share	25	13	8	4	--	--	25

APPENDIX A

Reservoir Sample

Table 1.--Policy Sample of Reservoirs by Selection Characteristics

Field	Reservoir	Location	Reservoir Size (Acres)	Reservoir Depth (Feet)	Residual Oil (MBBLS/Ac)	Off-Shore Water Depth (feet)
			On-Shore			
Andector	Ellenburger	Texas	6049	8545	19	
Archer Co. Regular	Strawn-Gunsight	Texas	25570	1350	29	
Avery Island	Deep	Louisiana	259	15000	27	
Avery Island	Medium	Louisiana	974	9000	79	
Baxterville	Lower Tuscaloosa Massive	Mississippi	6400	8672	59	
Bay Springs	Lower Cotton Valley	Mississippi	1760	14561	288	
Belridge South	Tulare	California	8850	1704	102	
Big Sand Draw	Tensleep	Wyoming	714	7105	263	
Big Sandy	Bartlesville	Kansas	1240	1230	32	
Bijou	D Sand	Colorado	1180	6080	5	
Brea Olinda	Olinda Area	California	1674	4112	123	
Buena Vista	Front Area	California	3580	3904	103	
Caddo Pine	Nacatoch	Louisiana	32000	1035	26	
Caddo Pine	Paluxy	Louisiana	32000	2760	26	
Caillou Island	Medium	Louisiana	7673	8900	22	
Caprock	Queen	New Mexico	22640	3050	14	
Cat Canyon	Old Area Pliocene	California	2980	3043	47	
Cat Canyon	Sisquor Area Others	California	1120	3200	198	
Clay City Consolidated	Aux Vases	Illinois	29760	2940	5	
Coalinga	Temblor	California	19282	2500	111	
Coles Levee North	Richfield Main Western	California	3580	9278	106	
Cooke Co. Regular	Strawn	Texas	6100	850	46	
Cowden North	Grayburg	Texas	30870	4400	33	
Cowden South	San Andres-Grayberg	Texas	19200	5050	20	
Coyote East	Anaheim	California	901	4177	243	

Field	Reservoir	Location	Reservoir Size (Acres)	Reservoir Depth (Feet)	Residual Oil (MBBLS/Ac)	Off-Shore Water Depth (Feet)
Cut Bank	Kootenai	Montana	49000	2900	9	
Cymric	Carneras	California	2960	3887	66	
Cymric	Tulare	California	2990	1225	62	
Delaware-Childress	Bartlesville	Oklahoma	6831	620	19	
Dillinger Ranch	Upper Minnelusa B	Wyoming	1500	9100	14	
Dollarhide	Devonian	Texas	7266	10817	18	
Dominquez	First East Central	California	745	4352	61	
Dominquez	3-4-5 East	California	745	5805	68	
Earlsboro	Earlsboro	Oklahoma	11040	3500	50	
Elk Hills	Upper Main	California	15800	2967	57	
Elwood	Vaqueras	California	445	3650	767	
Empire ABO	ABO	New Mexico	9800	6022	48	
Eola-Robberson	Pontotoc	Oklahoma	---	10434	126	
Flat Rock	Bartlesville	Oklahoma	6418	1350	10	
Foster	Grayburg-San Andres	Texas	14000	4300	38	
Foster-Reno Oil City	Venango First	Pennsylvania	27000	531	17	
Frannie	Tensleep	Wyoming	1180	2600	36	
Fruitvale	Chanac-Kernco Main	California	2635	4008	125	
Fullerton	San Andres	Texas	5000	4785	10	
Fullerton	8500	Texas	3745	8658	76	
Garland	Tensleep	Wyoming	3800	4328	40	
Gas City	Red River	Montana	1305	9139	17	
Gilbertown	Eutaw	Alabama	2145	3380	27	
Goldsmith	San Andres-Grayburg	Texas	30000	4300	15	
Government Wells North	North	Texas	8500	2000	21	
Grand Bay	Medium	Louisiana	4775	9160	29	
Grass Creek	Curtis	Wyoming	5880	3800	15	
Greeley	Rio Bravo-Vedder	California	1780	11497	162	
Griffithsville	Blrea	West Virginia	12000	2500	15	
Hackberry-West	Medium	Louisiana	1780	6340	25	

Field	Reservoir	Location	Reservoir Size (Acres)	Reservoir Depth (Feet)	Residual Oil (MBBLS/Ac)	Off-Shore Water Depth (Feet)
Hamilton Dome	Tensleep	Wyoming	1800	2688	148	
Heidelberg	East Eutau	Mississippi	4640	4687	34	
Heidelberg	West Eutau	Mississippi	2000	4961	18	
Hepler	Bartlesville	Kansas	1140	600	8	
Hilight	Muddy-Minnelusa	Wyoming	26000	10355	22	
Howard-Glasscock Yates	Seven Rivers-Queen	Texas	13400	1350	32	
Hull Merchant	Yequa	Texas	4800	5000	41	
Huntington Beach	North Area Tar Balsa	California	5640	2867	232	
Inglewood	Vickers	California	1133	2154	614	
Iola	Bartlesville	Kansas	1656	918	42	
Jay	Smackover	Florida	14000	15470	28	
Kermit	Permian-Yates	Texas	13000	2800	14	
Kern Front	Main	California	5000	2168	97	
Kern River	Kern River Sands	California	9535	1007	368	
Kraft-Prusa	Arbuckle	Kansas	10900	3281	20	
Lake Barre	Deep	Louisiana	1108	15000	1	
Lawrence	Cypress	Illinois	22010	1356	24	
Lindsay North	Bromide	Oklahoma	3700	11000	19	
Little Beaver	Red River	Montana	1910	8499	14	
Little Beaver (East)	D Sand	Colorado	1160	5060	4	
Little Buffalo Basin	Tensleep	Wyoming	1500	4600	56	
Long Beach	Old Area Upper Pools	California	1270	4320	2141	
Lost Hills	Main	California	3950	1928	81	
Main Consolidated	Pennsylvanian	Illinois	59400	879	8	
Magnolia	Smackover	Arkansas	4675	7500	47	
Maljamar	Grayburg-San Andres	New Mexico	11840	4000	24	
McElmo Creek	Desert Creek	Utah	12000	5485	20	
McElroy	Grayburg	Texas	30000	2900	71	

Field	Reservoir	Location	Reservoir Size (Acres)	Reservoir Depth (Feet)	Residual Oil (MBBLS/Ac)	Off-Shore Water Depth (Feet)
McKittrick	Upper Main	California	1430	1190	392	
Mexia	Woodbine	Texas	3800	3100	26	
Midway-Sunset	Potter	California	24370	1687	183	
Montebello	Baldwin	California	905	3513	535	
Moran Southeast	Bartlesville	Kansas	4460	830	14	
Mt. Paso	Vedder	California	3805	1388	155	
New Harmony	Cypress	Illinois	10840	2500	6	
Oakdale Northwest	Red Fork	Oklahoma	12160	4800	5	
Orcutt	Monterey Point Sal	California	3600	3487	154	
Oyster Bayou	Frio-Seabreeze	Texas	1690	8200	43	
Pierce Junction	Frio	Texas	3800	5000	25	
Pine	Interlake	Montana	13320	8400	11	
Plum Bush Creek	J Sand	Colorado	3180	4984	6	
Prentice	Clearfork 6700	Texas	8400	6450	21	
Rangely	Wever	Colorado	24540	6200	48	
Red River, West	Gunsight	Oklahoma	327	1575	28	
Richfield	East and West Area	California	1610	4000	351	
Rincon	Hobson-Tomson-Miley	California	1560	3900	185	
Rincon	Oak Grove Others	California	468	8301	142	
Rincon	Padre Canyon Others	California	499	5843	79	
Russell	Glorieta	Texas	800	6100	22	
Salt Fork	Southeast Skinner	Oklahoma	1840	5000	10	
San Ardo	Lombardi	California	4400	2122	167	
Santa Fe Springs	Main Area Others	California	1480	5411	1275	
Santa Maria Valley	Main	California	4660	4711	129	
Sartwell	Third Bradford	Pennsylvania	1330	1200	8	
Sho-Vel Tum	Pennsylvanian-Deese	Oklahoma	3100	2400	42	
Smackover	Old	Arkansas	29500	2000	33	
Soso	Bailey	Mississippi	2760	12051	13	

Field	Reservoir	Location	Reservoir Size (Acres)	Reservoir Depth (Feet)	Residual Oil (MBBLS/Ac)	Off-Shore Water Depth (Feet)
Sour Lake	Frio	Texas	2700	4400	49	
South Mountain	Sespe Main	California	3090	5319	116	
Spraberry Trend	Spraberry	Texas	500000	8511	15	
Steamboat-Butte	Tensleep	Wyoming	1595	6980	111	
Stroud	Prue	Oklahoma	9600	2900	9	
Tom O'Connor	Catahoula-Frio-Miocene	Texas	15000	5800	16	
Torrance	Main	California	4338	3737	122	
TXL	Tubb	Texas	16400	6158	16	
Vacuum	Grayburg-San Andres	New Mexico	18800	4400	40	
Ventura	C Block	California	3380	6643	307	
Ventura	D-5, D-6 North	California	3380	11222	157	
Ventura	D-7, D-8	California	3380	12010	336	
Ward Estates North	Yates-Seven Rivers	Texas	35000	3000	25	
Walnut Bend	Winger	Texas	2972	5488	6	
Welch	San Andres	Texas	28000	4900	10	
West Bay	Medium	Louisiana	10240	9000	17	
West Ranch	41-A	Texas	4487	5750	17	
Wichita Co. Regular	0'-2100'	Texas	50000	1700	29	
Wilmington	Ford	California	6895	5000	206	
Wilmington	Lower Terminal	California	4000	4000	299	
Wilmington	Tar	California	6895	2500	114	
Wilmington	Upper Terminal	California	6895	3000	187	
Yellow Creek	Eutaw	Mississippi	3560	5078	25	

Field	Reservoir	Location	Reservoir Size[a] (Acres)	Reservoir Depth (Feet)	Residual Oil[a] (MBBLS/Ac)	Off-Shore Water Depth (Feet)
Off-Shore						
Bay Marchand 002	3600'D	Louisiana	--	3823	--	100
Bay Marchand 002	8300'EE	Louisiana	--	12087	--	100
Bay Marchand Block 2	BM4800 RD-VU	Louisiana	--	4800	--	100
Eugene Island 126	2B(1) RF-A	Louisiana	--	9414	--	100
Eugene Island 276	U-RA-SU 1W	Louisiana	--	11287	--	100
Eugene Island 330	Seg. A	Louisiana	--	4500	--	300
Eugene Island 330	FB	Louisiana	--	7250	--	300
Grand Isle Block 43	G-1	Louisiana	--	8950	--	100
Grand Isle Block 43	R-6	Louisiana	--	12400	--	100
Main Pass 41	A	Louisiana	--	6950	--	100
Main Pass 144	7500	Louisiana	--	7200	--	300
Main Pass 306	44/45	Louisiana	--	6500	--	300
Main Pass 306	29	Louisiana	--	6300	--	300
Main Pass Block 69	RB-SU	Louisiana	--	7400	--	100
Ship Shoal 207	RB	Louisiana	--	10975	--	100
Ship Shoal 208	FB-3	Louisiana	--	9700	--	100
South Marsh Island 73	B-65-G	Louisiana	--	5750	--	100
South Pass 27	RASU	Louisiana	--	8750	--	100
South Pass 65	RB	Louisiana	--	7200	--	300

Field	Reservoir	Location	Reservoir Size[a] (Acres)	Reservoir Depth (Feet)	Residual Oil[a] (MBBLS/Ac)	Off-Shore Water Depth (Feet)
South Pass Block 27	RA-SU	Louisiana	--	7850	--	100
South Pass Block 24	U2-RA-SU	Louisiana	--	9530	--	100
Timbalier Bay Block 21	BRD	Louisiana	--	10961	--	100
W. Delta Block 30	IF.Res. C-2	Louisiana	--	7409	--	100
W. Delta Block 30	7150' Res E	Louisiana	--	7550	--	100
W. Delta 73	RA	Louisiana	--	8294	--	100

[a]This information, for certain off-shore reservoirs, is proprietary and can not be listed. Therefore, the information for all reservoirs was deleted.

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