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PETROLEUM CONSERVATION

AND THE

ECONOMICS OF OIL FIELD REGULATION

Michael J. Scott
Assistant Professor of Economics
University of Alaska
Anchorage, Alaska

Institute of Social, Economic and Government Research
Anchorage, Fairbanks, and Juneau

To be presented at the Western Economic Association
Fifty-first Annual Meeting, San Francisco, California
June 24-27, 1976

May 1976

*The author gratefully acknowledges the comments and helpful criticisms of the following individuals, not necessarily in order of their importance: Yoram Barzel, James Crutchfield, Gardner Brown, Robert Stokes, C. Bert Dudley, W. Michael McHugh, Josef Scwalbe, Terry W. Johnson, Ben Yu, James B. Klein, Richard Hartman, Stephen L. McDonald, and O. Scott Goldsmith. All errors and omissions are, of course, the author's responsibility.

PETROLEUM CONSERVATION REGULATION AND THE ECONOMICS OF OIL FIELD ORGANIZATION

1. Introduction

The history of the common property resources has been extensively utilized by the natural resource economics literature to demonstrate the necessity for the state to step in and force the users of the resource to recognize the costs they impose on one another through use of direct regulation, use taxes, or some form of consolidated management. Examples of the latter include commission management of a fishery and unit management of oil pools. The usual rationale for state action is that it is too difficult and costly for the potential users of a given resource to agree on a method to manage the resource in the joint best interests of all concerned; therefore, the state "ought" to regulate.[1]

This approach overlooks the fact that any management scheme has costs associated with it, including those schemes run by the state. Therefore, having demonstrated (for example) that the operating costs of an oil reservoir could be reduced, if instead of multiple lease owners operating the reservoir under Rule of Capture, the same reservoir were organized into a single ownership unit, the advocate also ought to be required to show that the state regulation

proposed can minimize the costs of reaching this solution. Typically, the state gives no choice in whether its regulation is to be applied to a resource. An interesting exception is in the area of oil field conservation regulations, where the ownership interests have both influenced the form the regulations would take, and the regulations' case-by-case application. The voluntary response of the industry to economic conditions in the establishment of regulations, and the case-by-case response to their application permits the testing of some propositions about how the state can in general minimize enforcement costs, and when the state can reduce transactions costs by regulation.

The next section discusses a simple model of petroleum reservoir management based on the individual well owner.[2] This model assumes a generalized reservoir with two well owners, but can be modified to show the difference of depletion drive from frontal-drive reservoirs, and for more than two individual owners. The third section considers two types of voluntary management schemes to reduce production costs--a minimum spacing regulation achieved by bargaining, and a unitization regulation requiring unanimous consent of the well owners to a plan for single management production. The factors leading to higher or lower transactions costs in each case are specified, and predictions are made concerning the effect of key variables on both spacing regulations and the voluntary and compulsory unitization process.

These predictions are tested statistically in the fourth section, and the last section concerns some implications for common property resources management.

2. A Theory of Petroleum Reservoir Management with Bargaining Costs

Consider two well operators[3] in a given oil pool who produce oil in such a manner that they increase each other's operating cost and reduce the future stock of recoverable oil. In the case of actual oil fields whose drive mechanism is gas dissolved in oil (dissolved gas or depletion drive), it is said by engineers that ultimate oil recovery is not influenced by the number of wells drilled, so production only lowers the future stock by the amount produced.[4] The extra term in the constraints shown below would apply to a drive mechanism like water drive or gas cap drive, where the rate of production does influence ultimate recovery.[5] The general objective function of each wealth-maximizing well owner can be written

$$(1)\quad \max_{\{x_i(t)\}t=0} \int^{T} \{P_t \cdot x_{it} - C^i(x_{1t}, x_{2t}, X_t) + \lambda(t)[-\dot{X}_t - x_{1t} - x_{2t} - X_t k(x_{1t}, x_{2t})]\}e^{-\rho t}$$

where: $\frac{\partial Ci}{\partial x_{jt}} \geq 0$, $\frac{\partial^2 C^i}{\partial x_{it}\partial x_{jt}} \geq 0$, $\frac{\partial C^i_X}{\partial x_{jt}} \geq 0$, $k_{x_{it}} \geq 0$; i,j = 1,2

and: P_t = Price of oil at time t

x_{it} = Production of oil by owner i at time t

$C^i(\ )$ = Operating costs for individual i, a function of the rate of production and the remaining stock of oil

$\lambda(t)$ = Costate variable, defined as the marginal unit value of the remaining stock, a function of time.

X_t = The remaining stock of ultimately producible oil at time t

$k(\ )$ = A production sweep efficiency variable which adjusts ultimate production downward if production from each well is not coordinated to maximize ultimate physical recovery.

ρ = Implicit discount rate

T = Some future time horizon

The relevant first order conditions for the solution of the Hamiltonian equivalent to equation (1) are (omitting the t subscripts):

$$(2)\quad \frac{\partial H^i}{\partial x_i} = P - C^i_{x_i} - \lambda[1 + Xk_{x_i}(x_1, x_2)] = 0 \qquad ,i=1,2$$

$$(3)\quad -\frac{\partial H}{\partial X} = \frac{d}{dt}(\lambda e^{-\rho t}) \rightarrow C^i_x = \dot{\lambda} - \lambda[k(x_1,x_2) + \rho] \qquad ,i-1,2$$

$$(4)\quad \dot{X} = - x_1 - x_2 - Xk(x_1,x_2)$$

The equation (2) condition for a maximum states that for each individual, his rate of production during each period equates the price of oil to his marginal operating cost, plus his marginal user cost; i.e. his influence on future recoverable oil times its marginal value as reserves. The second condition, which comes out of the mathematics of applying the Pontryagin Maximum Principle, can be interpreted to say that along the wealth-maximizing path of production, the influence of a change in ultimately recoverable oil on current production costs must equal the marginal time change in value of each unit of reserves (change in "inventory" value), adjusted for the fact that additions to recoverable reserves are future potential production, and will be discounted by the sum of their rates of physical waste and time cost. The equation (4) condition is, of course, just the constraint mentioned above. The canonical equations have been omitted.

Note that, for either individual, his wealth-maximizing current rate of production and cost structure depend not only upon his own actions, but those of his neighbor as well. Unless individual 1 knows the complete future series of actions by individual 2, he would be unable to attach any value much above zero to the value of reserves, since it is not certain that he would ever receive a share. In such a case, $\lambda = 0$, and each individual would produce oil at such a rate that price equalled marginal operating cost, user cost being

completely ignored except as the reduction in ultimately recoverable oil eventually increases operating costs parametrically for the individual well owner. Furthermore, each well owner would have to take his neighbor's actions which directly increase his own operating costs as parametric, and reduce these costs by private action. This is the familiar case of Rule of Capture, with each producer ignoring the influence of his own production on ultimate recovery, and with each producer trying to minimize the effect of his neighbor's production on his own future operating costs. The traditional methods of minimizing these effects have been to locate one's well as close to the lease boundary as possible to maximize "exclusive" production territory, and to produce one's oil quickly and store it above ground. It is possible to buy out one's neighbor to reduce his influence on one's own operating costs, and there is evidence that this was also done.[6]

Another reasonable solution to the operators' problem may have occurred to the reader. Suppose it were possible to limit the effect one's neighbors had on the total rate of recovery (hence, ultimate production), and on his direct costs of operation. The most obvious solution to the economist with benefit of hindsite is to put the entire pool under single management, so that the two wells could be operated jointly to maximize wealth for the combined operation. A second-best solution is to limit the influence of each well on ultimate recovery by explicit rules limiting the rate of production and

number of wells, and to reduce the number of wells and the influence of each producing well on its neighbors' effectiveness by regulating well spacing. This in effect fixes the schedule of x_i's for each producer so that there is a chance for the group of well owners to maximize wealth, given the regulatory constraint. This second solution is second-best because it will nearly always be necessary for regulatory convenience to specify uniform spacing and production, while field conditions are not always uniform. For example, in a frontal drive reservoir, which moves oil to the wells by the "sweep" action of an expanding gas cap or water table, the interests (and desired operating rules) of those operators behind the advancing gas or water "front" are different from those operators whose wells are benefiting from the sweep action.

However, whether unit management is adopted or field rules are adopted in the absence of unit management, it is never an obvious or easy process to determine what the field rules ought to be. As the establishment of field rules actually works under either unit management or by state regulation in the absence of a unit agreement, it is necessary for the well owners to produce information for open hearings on the oil reservoir's physical characteristics which will "justify" the field rules they propose. This would undoubtedly be true whether the well owners had a voluntary self-policing association or whether the state fulfilled the function as arbiter, since

enforcement costs are reduced for any set of rules if they are self-enforcing; i.e., if those persons "ruled" regard the rules as justified by fact ("fair"). Given this information requirement, some resources will be devoted to bargaining to reduce enforcement costs. If the persons ruled by common agreement among themselves bore the enforcement costs, they would bargain for "fair rules" to reduce these costs. If the state bears the enforcement costs, it requires a similar investment to reduce the enforcement costs.

3. Processes and Costs of Oil Field Organization

In Texas, the state chosen to test some of these hypotheses, the bargaining process to develop field rules takes place in a forum called an MER hearing, where all interested parties can present evidence on any proposed set of field operating rules to the Texas Railroad Commission, which may issue them as a state regulation. As explained above, two key variables are the spacing of wells and the rate of production of wells. The use of the Railroad Commission as an arbiter and enforcer of the spacing decision would be cheaper to the well owners as long as the number, spacing, and production of wells is the same as in the case where private agreement determined

the outcome. The following heuristic argument suggests that with an open hearing process, as long as the state selects a recommendation which represents a consensus of the well owners, the spacing would be the same. Since the same argument could be used for number of wells or rate of production, these also would be the same under either bargaining or regulation.

Figure I is a hypothetical case where two parties to a collective agreement must agree to limit spacing in an oil field, curves BAC and GFH are the individual marginal value in exchange (marginal benefit) curves, while ΣMB is their vertical sum. All curves are drawn on the assumption that the other party chooses the same density of drilling, and production rates are constant. Also, suppose that the curves are drawn so that operating costs are netted out. If each party could be assured that the other would not drill on a greater or less density than he, each would prefer a common drilling density which maximizes his net total benefits. One party would thus prefer OA wells/160 acres, while the other wants OF. Past OA, the first party would be willing to spend up to the amount of decrease in his total net product to prevent adoption of the denser drilling scheme; e.g., at OF he is willing to spend AFL to get OA wells/160 acres spacing rules. The second party in the example, on the other hand, is willing to pay up to AKF to get from OA to OF. Densities greater than OF will not be selected for bargaining since both parties lose wealth. However, in order to capture

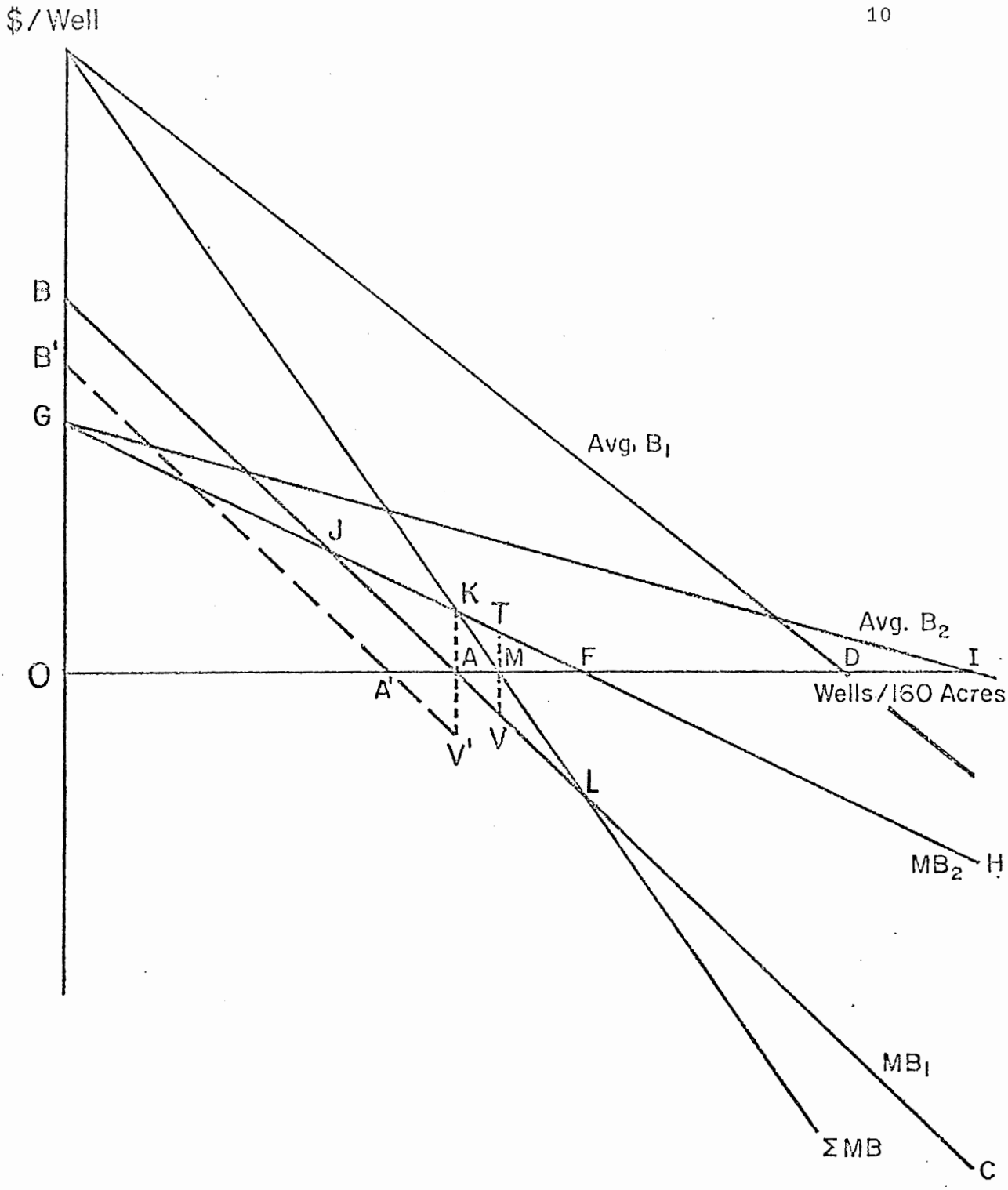

Figure 1. The Spacing Decision

imperfectly specified ownership rights, both parties might competitively drill up their properties to greater densities, e.g., OD or OI,[7] where average net value product equals zero.

The uniform spacing which will maximize the value of the whole reservoir is OM, where the vertical sum of marginal net benefits goes to zero. At this point, the marginal value of denser spacing to the second party just equals the marginal cost to the first party (TM=VM). Between OM and OF, the first party is willing to spend more resources to argue for lesser densities than the second is, to argue for greater density of development. On the other hand, between OA and OM, the second party (who gains from denser spacing anywhere up to OF) is willing to spend more for denser spacing than the first party (who loses by denser spacing) is willing to spend to prevent it. Thus, there is a tendency to settle on a common maximum density of OM wells per acre.

It may be argued that the damaged party could maximize benefits by allowing the other to drill at density OM or OF, while he himself drills at only OA, thus avoiding a loss of AMV. This is not the case, however, since these marginal net benefit curves are drawn on the assumption of uniform spacing. If the second party drills his land with more wells per acre, cross drainage will likely take place, causing curve BAC to shift toward the origin. Consequently, he will drill at lower density only if the loss due to the inward shift of

BAC results in a smaller total loss than AMV. This is unlikely because when curve BAC shifts inward (to B'A'B'), point A no longer results in zero marginal loss. It will in turn have a total cost such as A'V'A associated with it.

Using Figure 1 as a model, it should become apparent why several things occur. Notice that uniform spacing is the general rule agreed upon in this model, even though an efficient single owner operation of this reservoir might have unequal spacing. Further, one should expect "dissimilar" characteristics of different parts of the reservoir could result in more difficulty for individual owners in identifying their MB_i (and higher costs of agreement), and that large numbers of bargainers could (but not inevitably) make agreements difficult to reach.

It should be apparent that the discussion of dissimilar spacing why uniform spacing is selected. If dissimilar spacing is allowed, then no party can be certain of his marginal net benefits with respect to different spacing on his own properties, since this will be dependent on others' decisions. In addition, for depletion reservoirs, uniform spacing appears to minimize cross drainage, except where plots are too small to accommodate even one well of the agreed-upon spacing.[8]

If two properties show unequal marginal net benefits at the same uniform spacing (as shown in the case of Figure 1), then the greater the disparity of marginal net benefit curves in the vicinity of the maximum total benefit spacing, the more each party will be willing to spend for other (suboptimal) spacing, and the more difficult it

will be to reach agreements. It is also apparent that if all the marginal benefit curves were exactly the same, then expenditures to get spacing other than the joint wealth-maximizing one would be equal to zero. The implication is that physically similar properties should imply low cost agreements, and relatively fewer ones imposed by political action, although this hypothesis could not be checked with the data available.

Figure 1 shows a case in which there are only two parties who must agree on spacing. This diagram could be modified to accommodate more, however, simply by placing more net marginal benefit curves on the graph and summing them vertically, as before. This vertical sum of marginal benefits and costs of spacing other than the one where $\Sigma MB = 0$ would not necessarily be greater, however, since this would depend upon both the shape of the marginal benefit curves and their number. If it were simply true that more net marginal benefit curves of the same height as curve BAC were added to the existing curves in Figure 1, ΣMB would be steeper, and one could say that the process to reach the point where $\Sigma MB = 0$ (not necessarily point M) would probably be more expensive, since the marginal willingness to pay at all nonoptimal spacings would be larger.[9] With more owners in a reservoir of fixed size, the shown marginal benefit curves would tend to rotate downward (counterclockwise), since the marginal net benefits of drilling wells to an owner of a small piece of property

are partly appropriated by his neighbors. However, nothing is suggested about ultimate spacing. Since large numbers of owners of a fixed-size reservoir inevitably results in small total benefits of drilling to each owner, and higher negotiating and enforcement costs, all will wish to minimize bargaining and enforcement costs by state regulation.

The hypothetical agreement via bargaining results in the maximum joint net benefits to the bargaining parties in the demonstration above. As long as the state follows a consensus of the well owners in setting the rules, and freely allows competitive spacing requests, it can be assured of reducing the overall costs of spacing regulation by absorbing the enforcement costs. It is not otherwise assured of having achieved a solution which maximizes net benefits to the well owners.

The bargaining process described above will result in different spacing if a different starting point for the negotiation process were selected. For example, if the process began with the field already drilled to densities of one well per acre, it would be more difficult to subsequently achieve 40 acre spacing via the MER hearing process because it would involve closing of producing wells, possible compensation of some parties for their investment, and the general reorganization of the reservoir. The state could minimize transactions costs by preventing a massive investment in wells before

field rules are adopted. This could be accomplished by either prohibiting post-discovery drilling until field rules are established, which greatly restricts the amount of available information on the field, or by restricting spacing in a given field based on past profitability experience with drilling of reservoirs at known depths. In other words, the state could approximate the eventual spacing rules by using past behavior as a guide. If the state regulatory commission is a device for minimizing the transactions costs associated with reaching wealth-maximizing spacing, one would predict:

1) The existence of rules to limit spacing in advance of MER hearings.

2) The change of these rules in response to changes in the costs of drilling (increases of which would imply fewer wells or wider spacing), and in response to the market price of oil (an increase in which would imply narrower spacing to increase the current rate of production).

3) That spacing and production requested in MER hearings to establish field rules would show a high correlation with those parameters in state pre-hearing rules.

In contrast, one would predict from the usual argument that the field rules are established to prevent physical waste (maximize physical sustained yield):

1) The existence of rules to limit spacing in advance of MER hearings, to prevent waste.

2) No necessary relationship between minimum spacing and depth, or between minimum spacing and the price of oil, since the object is physical conservation, based strictly on reservoir oil flow properties.

3) That spacing and production requested in MER hearings would bear no particular relationship to those established in pre-hearing rules, since the well owners would be trying to maximize wealth, and the state would be trying to minimize physical waste unrelated to, for example, the cost of drilling and price of oil.

Both explanations imply minimum spacing regulations. However, when the state tries to minimize transactions costs of setting up field rules, it behaves in a different way than if it tries to prevent physical waste. In particular, the transactions-cost minimizing regulator takes the value of production from the regulated resource and changes in that value and the costs of production into account, while the physical waste-preventing regulator should not. The empirical evidence in the fourth section of this paper demonstrates that the Texas Railroad Commission has, in fact, attempted to adjust its field rules to changing economic conditions in such a way that minimization of field organization costs seems a likely motive. In doing so, it has provided a method of controlling inter-individual producer effects in the absence of unit management.

Unitization

Unit management may be arrived at through negotiations or by state regulation. During the study period, 1925-1972, the state of Texas did not have a law on the books requiring unit management;

therefore, it was used as a case to show when transactions costs for establishing voluntary unit agreements are higher and when lower. The predicted results were then compared with Louisiana, which had compulsory unitization. The long time period (often several years) between discovery and voluntary unitization, even for reservoirs discovered in fairly recent times, contrasts strongly with the minimum time period required for forming a unit of only a few months, and suggests that the oil field operators are willing to absorb somewhat higher operating costs in the short run (and lower ultimate oil recovery) to reduce the transactions costs of forming unit agreements.

The demand for, and the costs of, forming new units are determined by certain physical aspects of the reservoir and the difficulty of obtaining knowledge about these aspects. Since the physical attributes of a field are only known with certainty after it is completely "drilled up," exploited, and abandoned, the participants in any unitization process necessarily start with less than complete knowledge about the amount of oil in place under the property of each interest, the ability of the producing formation to convey this oil to the well bores, and the nature of the drive mechanisms. Properly speaking, the process of organizing a production unit is primarily one of developing and agreeing upon this information. The actual negotiation process usually takes about two years, and much of that is devoted to technical (engineering and geological) committee

work, which develops information both on the reservoir and on the size share of the proceeds acceptable to each party.[10] If the process is entirely voluntary, and if competitive terms of agreement designating different relative shares are permitted in the negotiating process, then each party will develop his own information until his marginal value of additional search by field work and bargaining just equals the marginal time and resource costs of bargaining.

The information gathering process in reservoir unitization can then be viewed as one of private information search, where the reward for additional information is one's share of the additional oil obtained from the field by unit management, plus the change in this share due to bargaining times the present value of total recovery. The costs of the bargaining process are the decrease in recoverable oil, plus his expenditures on personnel and other resources which are devoted to improving the information necessary to unitize the reservoir. Therefore, an individual will want to conclude the bargaining process as soon as the marginal value of information on total reservoir size and characteristics and his share of total recoverable oil equal his marginal resource and user costs, since this is the point where the total net value of additional information is maximized for that individual. Past that point, he will attempt to shorten the bargaining process by conceding part of what he perceives to be his maximum share to the other parties, or he will

spend resources (for example, by offering to carry part of their investment risk) in order to acquire their agreement.[11] He must do this, since the only way the voluntary agreement can be reached is by mutual consent to halt the bargaining process, to set the shares as these then exist in one of the competing share contracts, and to proceed with field development on a unit basis.

Figure 2 illustrates the point with a model of a bargaining process where each party devotes a constant amount of resources per period of time to the bargaining process. The process develops information concerning the size of total production of each tract and the reservoir as a whole. The improved information also reveals the details of the drive mechanism so that all parties become increasingly aware of what share of production each party could expect in the presence of unitization. Each individual will want to bargain only as long as either the perceived present value of total production is increasing faster than his share is decreasing, or the expected share is increasing faster than present value of total product remaining to be exploited by the unit decreases.

The three different individuals in Figure 2 perceive their future prospects somewhat differently. Mr. 1 (corresponding to MP_1) feels that he has most of the useful information he can obtain on the reservoir, and that his total benefits from bargaining will tend to fall rapidly with further bargaining. He may also feel that his share is unlikely to increase much as a result of

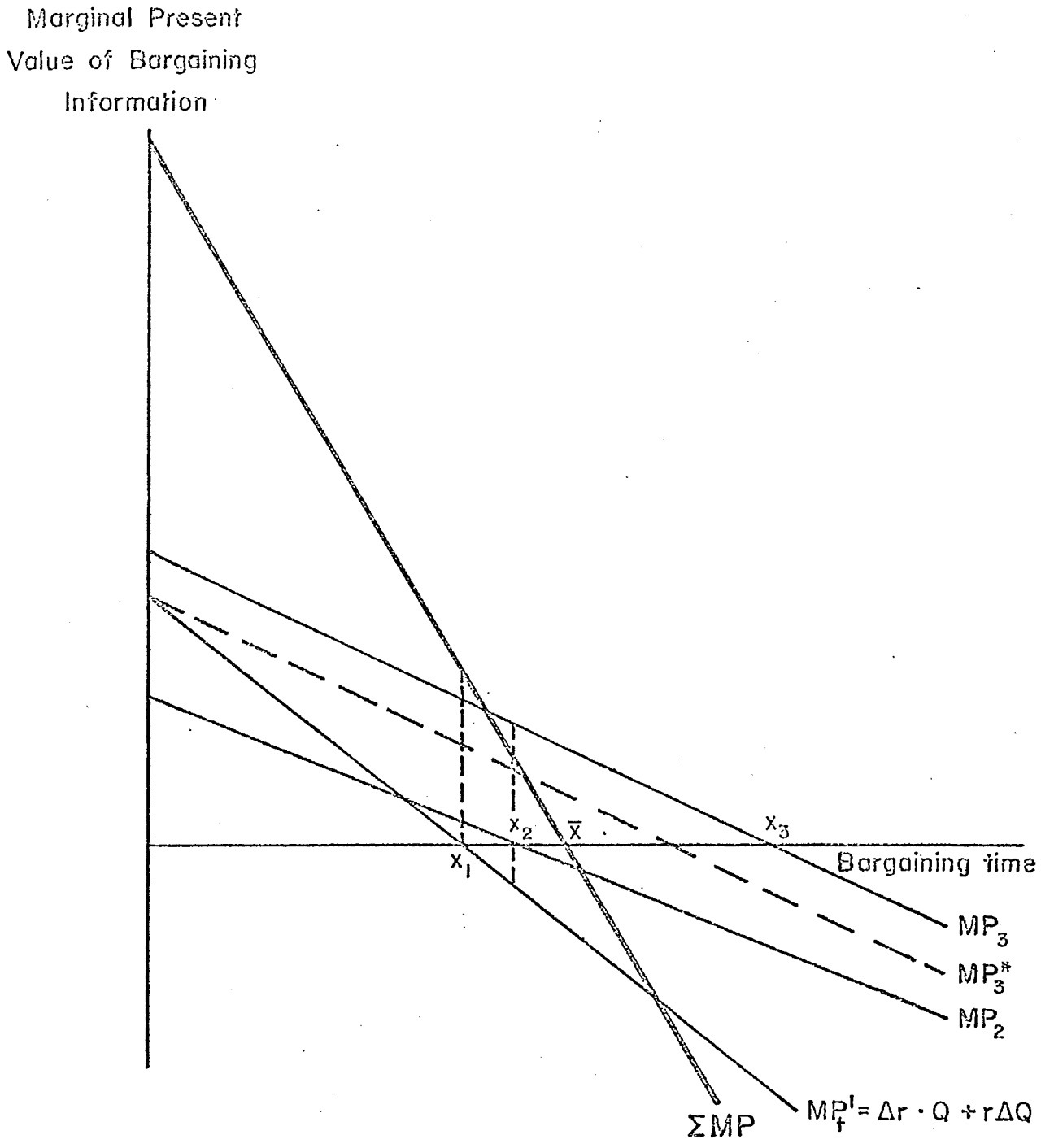

Figure 2. The Unitization Period.
Q = Present value of total incremental production due to unitization.
r = Share of the i^{th} individual under the best competing offer.

further bargaining; in fact, he may have to concede shares. Mr. 3 is an optimist. He feels production information is being advanced by the bargaining process, or that his own share is increasing, or both. Mr. 2 lies between Mr. 1 and Mr. 3 in optimism. Past x_1, Mr. 1 will be willing to concede shares to Mr. 2 and Mr. 3. Past x_2, Mr. 2 and Mr. 1 will be willing to concede shares to Mr. 3. If Mr. 3 were clever, he could extract a payment at time $\bar{x}$ equal to the vertical sum of MP_1 and MP_2 out to x_3, by threatening to bargain until x_3. He cannot actually carry out his threat, however, since the value of total product would be reduced for the reservoir as a whole (ΣMP is in the negative quadrant). Anyone extracting less from Mr. 1 and Mr. 2 would receive their votes for his proposal, and obtain a share of the proceeds equal to the difference between the combined shares of Mr. 1 and Mr. 2 under the two alternatives. Several iterations of this hypothetical competitive offer procedure guarantee $\bar{x}$ will be chosen, since this maximizes the perceived rents of the bargaining process to all individuals combined. Even if there is only one explicit offer, as long as there are no restrictions to prohibit the parties from making offers (i.e., propose different share agreements), latent or possible proposals will guarantee a number no larger than $\bar{x}$ will result.

Could the competitive process of offer and counter-offer yield a shorter bargaining period than $\bar{x}$? After all, if the relative shares

can be settled earlier, a larger present value of production could be obtained. This is like saying that if the outcome of a horse race were known in advance, the winners could be paid by the losers and there would be no need to run the race--the statement is formally true, but practically irrelevant. It is only by the process of offer and counter-offer that the information becomes known to Mr. 1 and Mr. 2 that they are losing wealth past x_1 and x_2, respectively, as bargaining goes on, and to Mr. 3 that he can get more wealth by prolonging the process. Suppose that there is a suggestion made that at point x_2, Mr. 1 transfer a share to Mr. 3 equivalent to what Mr. 3 could earn by bargaining one unit of time longer, while Mr. 2 pays nothing and receives nothing. Mr. 1 will not do this, since it costs him more than the "prematurely" reached bargain is worth, and he will not sign the agreement. At $\bar{x}$, further waiting costs Mr. 1 and Mr. 2 more, while Mr. 3 gains less by further bargaining. It will pay one of the three individuals to suggest a sharing arrangement where the combined incremental shares given up by Mr. 1 and Mr. 2 at least compensate Mr. 3 for ceasing to hold out. No one can do better, since at any other point the marginal cost to Mr. 1 and Mr. 2 combined is greater than the benefit to Mr. 3, and someone will balk. Note that this successful offer may be the same offer as previously turned down, but with the passage of time, it becomes acceptable since the costs of the same package vary with time. The competitive offer process

guarantees that if shares were freely flexible, voluntary unitization would result in the earliest possible agreement. The combined offer of the losing parties increases the costs of holding out to the remaining party, so his apparent net marginal value of holding out, given the offer of additional oil, is zero (see curve MP_3^*).

The Effects of Shift Parameters on Optimal Unitization

We now move to a consideration of the effects of various parameters on the curves shown in Figure 2. Larger total gains from unitization, all costs of bargaining being the same, would in general shift the curves to the right. Since the total dollar advantage to be gained from any bit of information about the reservoir operational characteristics is now larger, the bargaining parties will try to acquire more of them. Therefore, they will tend to bargain longer, and $\bar{x}$ will shift to the right.

A second factor which will parametrically shift the bargaining time curves is any innovation in the bargaining process which will reduce or increase the costs of bargaining per period of time. In general, if costs of bargaining fall, the amount of time and resources which each owner or operator will devote to bargaining behavior will increase. This would be true if, for example, the bargaining parties could produce oil while waiting to agree, as long as they foresaw no effect on ultimate recovery.

Conversely, if the cost of bargaining is increased by innovation or government action, then agreements will be reached more quickly (though not necessarily more "equitably"--for example, one way to increase costs is to tax the production of nonunitized wells at 100 percent, something the small independent with his tenuous cash flow situation is sure not to like at all). It is entirely consistent with this parametric shift that the sometime Louisiana practice of shutting in fields to prevent "wasteful" uses of natural gas led to relatively rapid unitization of these fields.[12]

Would unitization be preferred to minimum spacing and production regulations by individual well operators? The answer is dependent upon what stage of reservoir life is discussed. The principal advantage of well-spacing regulation is that it is a simple rule of thumb requiring little knowledge about either the slope or the height of the individual marginal benefit curves. To achieve a constrained maximum value of production, it is only necessary to know approximately at what spacing ΣMB goes to zero, a fact which, as was pointed out previously, may vary from reservoir to reservoir. However, past experience will in most cases yield a reasonable rule of thumb, especially if there are similar reservoirs in the area. One spacing will certainly be easier to agree upon than the total net benefits each party could receive by competitive extraction, a number which would have to be agreed upon in the case of a simple purchase of operating

rights.[13] It would probably be easier to agree upon than even the share of net benefits to each party, as must be determined for unitization contracts, since little is known initially about the reservoir. As information improves on the physical parameters of the reservoir, it will be increasingly easier to determine the probable contribution of each tract to overall production. Moreover, the rule-of-thumb spacing may prove inappropriate, and would have to be revised. Thus, it is expected that most unitizations on depletion drive reservoirs would take place late in the life of the reservoir, while the reservoir would be initially controlled with spacing regulations.

Another point at which unitization will clearly be preferred is when an investment of major proportions, such as injection equipment for water flooding, is being considered.[14] Unless each operator is guaranteed a share of the returns from such an operation and/or compensation for having his well "flooded out" in water flood projects, for example, he will not be willing to invest money in such a project. Well spacing regulation will not ordinarily enable him to recover his investment from his neighbors; consequently, only the outright purchase of the neighbors' operating rights or income-sharing agreements such as unitization will make these projects possible.

4. EMPIRICAL TESTS

In this section of the paper, the results of empirical tests of the propositions contained in Section 3 are reported. There are three sets of these results. The first pertains to the proposition that the Texas Railroad Commission was motivated by the economics of oil extraction in setting up its minimum spacing regulations, and that since changes in requested field rules with respect to spacing were highly correlated with shifts in minimum spacing regulations and with changes in the costs and value of production, there is a strong inference that the Commission attempted to minimize field organization costs. The second set of empirical results pertains to the transactions costs of unitization, and measures these costs implicitly by the elapsed time between discovery and unitization and by the physical characteristics of a sample of successfully formed Texas units. The final set of results pertains to the correlation of the Texas results with compulsory and voluntary units in Louisiana.

a. Well Spacing in Texas

The system of regulation of oil and gas wells in Texas over the study period has been described very adequately elsewhere.[15] To summarize the factors of importance for these tests, it is enough to

know that when a new reservoir was discovered, the Texas Railroad Commission applied a statewide minimum spacing regulation which specifies the minimum distance between wells, for which exceptions may be granted through a public hearing process.[16] In addition, and this is what is important for this test, the Commission limited the maximum production per well, based upon the depth of the well and the spacing. This "top allowable" came from a table called the Texas Yardstick. Two such tables, one applying from 1947 to 1965, and one applying to all reservoirs discovered after January 1, 1965, are reproduced in Table 1a and Table 1b. Actual production in most new fields was further limited by a Market Demand Factor (MDF) which was a percentage of the top allowable (decided monthly by the Commission) that each well was actually allowed to produce, when the well's daily production was averaged over the month. Since the effect of the MDF was to limit production and stabilize oil price, increases and decreases in this variable make a reasonable rough index of changes in the implicit market price of oil (see Figure 3).

The first test of the proposition that the Railroad Commission was motivated by economic considerations in its Yardstick regulations is supplied by even a cursory examination of Tables 1a and 1b. As is pointed out above, the top allowable (and actual production) increases with increases in depth for every spacing. According to a 1947 memo supplied to the author by the Commission,[17] it was explicitly the intent of the Commission to take the cost of drilling

Table 1a

Texas 1947 Yardstick, Discovery, and Marginal Allowable Schedules

Depth Interval, Feet	Daily Allowable, Barrels				
	Yardstick[1]				
	10 Acres	20 Acres	40 Acres	Discovery Allowable	Marginal Allowable
0 - 1,000	18	28	-	20	10
1,000 - 1,500	27	37	57	40	10
1,500 - 2,000	36	46	66	40	10
2,000 - 3,000	45	55	75	60	20
3,000 - 4,000	54	64	84	80	20
4,000 - 5,000	63	73	93	100	25
5,000 - 6,000	72	82	102	120	25
6,000 - 7,000	81	91	111	140	30
7,000 - 8,000	91	101	121	160	30
8,000 - 8,500	103	113	133	180	35
8,500 - 9,000	112	122	142	180	35
9,000 - 9,500	127	137	157	200	35
9,500 - 10,000	152	162	182	200	35
10,000 - 10,500	190	210	230	210	35
10,500 - 11,000	-	225	245	225	35
11,000 - 11,500	-	255	275	255	35
11,500 - 12,000	-	290	310	290	35
12,000 - 12,500	-	330	350	330	35
12,500 - 13,000	-	375	395	375	35
13,000 - 13,500	-	425	445	425	35
13,500 - 14,000	-	480	500	480	35
14,000 - 14,500	-	540	560	540	35

[1]Yardstick allowables for other spacings are determined by adding one barrel per day for each additional acre above the spacings shown.

Table 1b

Texas 1965 Allowable Yardstick

The following schedule allowable is assigned all wells according to depth of the reservoir and proration unit size authorized by the Commission upon expiration of the discovery allowable, if discovery of the field occurred on or after January 1, 1965.

Depth	10 Acres	20 Acres	40 Acres	80 Acres	160 Acres
0 - 2,000	21	39	74	129	238
2,000 - 3,000	22	41	78	135	249
3,000 - 4,000	23	44	84	144	265
4,000 - 5,000	24	48	93	158	288
5,000 - 6,000	26	52	102	171	310
6,000 - 7,000	28	57	111	184	331
7,000 - 8,000	31	62	121	198	353
8,000 - 8,500	34	68	133	215	380
8,500 - 9,000	36	74	142	229	402
9,000 - 9,500	40	81	157	250	435
9,500 - 10,000	43	88	172	272	471
10,000 - 10,500	48	96	192	300	515
10,500 - 11,000		106	212	329	562
11,000 - 11,500		119	237	365	621
11,500 - 12,000		131	262	401	679
12,000 - 12,500		144	287	436	735
12,500 - 13,000		156	312	471	789
13,000 - 13,500		169	337	506	843
13,500 - 14,000		181	362	543	905
14,000 - 14,500		200	400	600	1,000

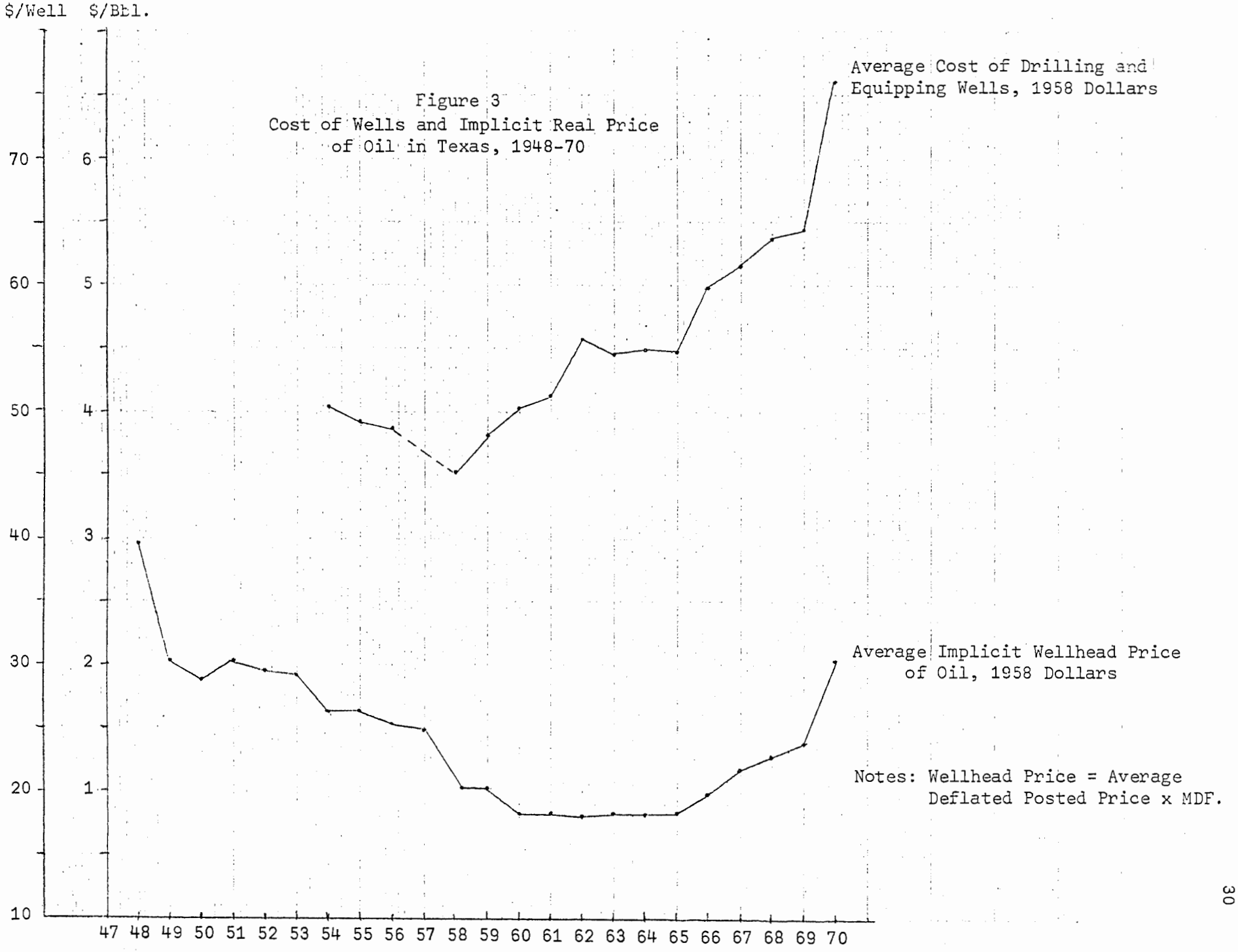

Figure 3
Cost of Wells and Implicit Real Price of Oil in Texas, 1948-70

Notes: Wellhead Price = Average Deflated Posted Price x MDF.

Sources: Texas Railroad Commission; API, IPAA, MCOGA, Joint Association Survey.

and operating wells at various depths into account. When the schedule was changed in 1964 after an extended period of declining implicit real oil prices (Figure 3), an important source of information at the public hearings was a series of computer runs by an industry advisory group which analyzed the costs and profitability of oil wells in Texas by depth and spacing for field conditions in 1963.[18] The conclusion of the industry advisory committee was that incentives for narrow spacing should be reduced, while they should be increased for wider spacing. This was done, as can be seen by comparing Table 1a and 1b.

As the incentives to space the fields wider were increased by the change in the Yardstick schedule, the actual spacing and top allowables requested by the participants in MER hearings also changed. Taking the depth of the discovered formation into account, along with a limited number of physical characteristics of the reservoir which would imply higher oil recovery, the change in regulations (captured by a dummy variable) was significantly associated with a shift to wider (and less costly) spacing. The results of four regressions are shown in Table 2.[19]

Even though the double-logrithm regression equations were run on a slightly different data set, the same basic results appear to hold. The change in regulations (SPX) had a positive impact on the field spacing requests. In addition, the more costly the field to

Table 2

THE IMPACT OF CHANGE IN TEXAS' YARDSTICK, 1964

(constant not reported)

Dependent Variable	Explanatory Variable, Coefficient, and t-Ratio						d.f.	$\bar{R}^2$	F
	SPX	DEPTH	PERMEAB	POROSITY	THICKNES	H20PCENT			
(1) SPACEREQ	22.6643	0.0078	-0.0019	-0.4097	-0.0780	-0.0437	221	.2055	2.20
	(3.1859)	(6.000)	(-1.8695)	(-0.8695)	(-0.7967)	(-0.3099)			
(2) SPACEREQ	22.2499	0.0079	-0.0653	--	--	--	224	.2119	--
	(3.2280)	(6.58)	(4.5034)						
	SPX	DEPTHL	PEMEABL	POROSITL	THICKNSL	H20PCNTL			
(3) SPACERQL	0.4987	0.1225	-0.0472	-0.0526	(-0.0343)	(-0.0290)	272	.1953	1.13
	(5.9653)	(5.0412)	(-2.4082)	(-1.0626)	(-1.1510)	(-1.1027)			
(4) SPACERQL	0.4871	0.1260	(-0.0553)	--	--	--	275	.1942	--
	(5.8616)	(5.2282)	(3.500)						

Definitions (Note: Variables ending in L are the natural log version)

SPACEREQ = Spacing requested at MER hearings, in acres/well equivalent.

SPX = Dummy variables signifying whether 1947 Yardstick, or temporary field rules corresponding to the 1965 Yardstick applied. 1947 = 0.

DEPTH = Average subsurface depth to top of reservoir "pay" zone (feet).

PERMEAB = Average horizontal permeability of producing formation (millidarcies).

POROSITY = Average porosity of producing formation (percent of volume).

THICKNES = Average net effective pay thickness (feet).

H20PCENT = Connate water content (percent of pore space).

develop (as shown by DEPTH), the wider was the spacing requested. Finally, the more "valuable" the reservoir per acre (as would be measured by an increase in each remaining variable except H2OPCENT), the narrower was the spacing requested at the MER hearings. This is, of course, consistent with an outward shift in the curves in Figure 1. The equations indicate significant variables for a student-t one-tail test with a .95 confidence level ($t.05 = 1.645$). The F ratio on the right indicates that at .95 confidence level, the indicated equation cannot be distinguished from the equation beneath it ($F_{.05} = 3.87$).

That the transactions costs of developing new fields were actually reduced by the change in regulations is suggested from the following argument and test. Remember that the incentives for narrowly-spaced wells were reduced, and those for widely-spaced wells increased in the Yardstick schedule. If initial negotiation costs of organizing on wide spacing were reduced by providing additional incentives to drill on wide spacing before the field rules were set, the cost savings should make it possible to drill deeper prospective reservoirs. To separate the effect of improved technology, which might have made deep wells possible on all spacings, the new fields were separated into the categories for which incentives were reduced (0-39 acre spacing), unchanged (40-73 acres), and increased (80 acres and over). The results were only conclusive on narrow spacing, but

in that case, a definite and statistically significant effect showed that removal of incentives for narrow spacing made it possible to develop only shallower fields. For the unchanged and improved incentives fields as a group, the effect on depth was positive (Table 3),[20] although virtually unchanged when differences in field quality were taken into account (Table 4). The fact that depth for wider spacing was unchanged when adjusted for field quality, is in itself a strong result when compared to the results for narrow spacing.

b. Unitization Costs

The question of when bargaining costs for development of field-wide management units are larger, and when they are smaller was addressed in the third section of this paper. In that section, the following hypotheses were proposed:

1. The greater the value of unitizing the field, the more resources and time the well owners would be willing to spend to produce an outcome favorable to themselves. Given a long and costly unitization period, this implies that such increases in the value of unitization would permit larger fields to be unitized, by offsetting higher unitization costs.

2. The greater the number of well owners (working interests) and landowners (royalty interests), the more costly should be the negotiating process, but the less the impact on the total bargaining process each interest will have. Therefore, the greater will be the time and

Table 3

THE EFFECT OF CHANGES IN TEXAS
TOP ALLOWABLES ON SPACING AND DEPTH

	0-79 Ac./Well	80-320 Ac./Well	Row Total
0-7000 ft.	Cell Frequency: Actual: 60 Expected: 100.372	Cell Frequency: Actual 57 Expected: 28.359	117 128.731
7001 - 14000 ft	Cell Frequency: Actual: 3 Expected: 18.714	Cell Frequency: Actual: 66 Expected: 37.994	69 56.708
Column Total	Actual: 63 Expected: 119.086	123 66.353	186

Chi-Square test value:

$$\Sigma \frac{(\text{Actual Frequency} - \text{Expected Frequency})^2}{\text{Expected Frequency}} \cong 78.94$$

Chi-Square critical value (confidence level = .95) = 3.841 (d.f. = 1)

Table 4

EFFECT OF CHANGES IN TEXAS TOP ALLOWABLES ON DEPTH

		Explanatory Variable and t-Ratio						
Dependent Variable	Spacing	SPX	PERMEAB	POROSITY	THICKNES	H20PCENT	d.f.	$\bar{R}^2$
DEPTH	80 and over	11.23 (0.03)	1.05 (2.23)	-82.29 (-2.91)	10.89 (2.18)	-4.41 (0.24)	113	.134
DEPTH	40-79	-133.89 (0.29)	0.25 (.78)	67.51 (2.27)	18.27 (2.22)	-10.77 (0.52)	91	.064
DEPTH	20-39	-1219.66 (1.98)	0.67 (2.09)	17.69 (0.53)	9.86 (0.79)	-45.80 (24.02)	36	.251

other resources which will have to be devoted by each owner to unitization, and the greater will have to be the size of the field to make the effort worthwhile.

3. The greater the well drilling cost of field development, the more costly it is to have "unnecessary" wells drilled, and the more resources which would be devoted to unitization. Greater development costs per well would therefore be associated with larger projects, since the greater unitized management cost savings at greater depths would permit the larger expenditure of time and other resources necessary to unitize larger areas.

The results of four regressions on a sample[21] of Texas voluntary units drawn from the field files of the Texas Railroad Commission are shown in Table 5.

As can be seen by reference to Table 5, the expected results could only be partially confirmed. In all cases, the additional recovery expected did lead to greater expenditures of time, and did imply that larger projects were possible. As an additional hypothesis, one can predict that the increased price of oil over the last three years has increased the size of units formed because of the greater value to the participants of forming field-wide units. Greater resources will be devoted to unitization, which should shorten the time required to form all units, but those providing the greatest gains will still take the longest, as indicated in Table 5.

Table 5

DETERMINANTS OF TEXAS UNITIZATION COSTS

(constant not shown)

Dependent Variable	Explanatory Variable and t-Ratio					
	ADDOIL	WI	RI	DEPTH	d.f.	$\bar{R}^2$
PROJACR	0.098 (4.861)	75.051 (4.654)	4.534 (1.386)	0.174 (4.948)	87	.685
TMONTH	0.004 (3.419)	0.183 (0.221)	-0.037 (-0.221)	0.008×10^{-2} (0.045)	87	.120
	ADDWOIL	ADDROIL	--	DEPTH		
PROJACR	1.241 (3.451)	-0.050 (-0.055)		0.203 (3.648)	88	.203
TMONTH	0.036 (3.074)	0.016 (0.568)		0.003×10^{-1} (.167)	88	.083

Definitions

ADDOIL = Additional ultimate recovery of hydrocarbons expected as a result of unit project proposed (Bbls. equivalent).

WI = No. of working interests in the project area (No. of individuals).

RI = No. of royalty interests in the project area (No. of individuals).

PROJACR = Acreage encompassed by the proposed unit eventually adopted (acres).

TMONTH = Total number of months elapsed between the discovery date and date the unit agreement was effective.

DEPTH = Average subsurface depth to top of reservoir (feet).

ADDWOIL = Additional ultimate recovery per working interest.

ADDROIL = Additional ultimate recovery per royalty interest.

Greater numbers of working interests and royalty interests increase the costs per period of time of forming units, thus making only relatively large units worthwhile for unitization, and implying greater time periods required. The first effect tends to be confirmed by the table, but not the second. The fit is so poor on the TMONTH regressions that very little can be said about the effects of the explanatory variables WI and RI. It is possible, however, that a direct measure of the resources costs devoted to unitization might yield the expected positive relationship between WI and RI and the resources required to develop a fieldwide unit.

As an aside, I might add that unit agreements in the state of Alaska contain a clause which probably prevents much of the disagreement I found in reading through unitization hearings records in Texas. The standard unit agreement for state-owned lands in Alaska contains a clause which says that, in the absence of agreement about the amount of oil in place under each party's properties, the parties shall appoint a named consulting firm as the arbiter, or should that not be satisfactory, one named by the senior Federal district judge. This, combined with the usually small number of working interests and the threat of unitization by state regulation, makes voluntary unit agreements relatively easy to reach. The industry has taken more than the usual amount of trouble with respect to the Prudhoe Bay Field, however.[22]

The increased costs of nonoptimal development as measured by greater DEPTH imply that the gains of unitization would be larger for any given level of additional recovery; hence, that larger amounts of resources would be devoted to unitization, including time required, and that greater DEPTH would also be associated with larger PROJACR, making these increased costs worthwhile. The effect on TMONTH is of the correct sign, but not distinguishable from zero. However, the effect on PROJACR is both of the expected sign and statistically significant in either formulation.

c. Compulsory Unitization

Does compulsory unitization reduce the transactions costs of unit agreements? To test this proposition, data was collected on a sample of Louisiana unitized pressure maintenance and secondary recovery projects, and the results on the size of project are presented in Table 6. It appears that compulsory unitization is resorted to more frequently for large fields, where both the value of unitization and the costs of unitization are likely to be larger. Secondly, it is applied far more frequently in water injection projects than in gas injection projects. Water injection includes much of secondary recovery in the U.S., while gas injection is more frequently a pressure maintenance (gas reinjection) operation during primary production. In general, water injection is also more expensive to undertake because of water treatment and disposal

requirements. Finally, waterflood and primary production water drive operations cannot be undertaken efficiently in the absence of unit management. Thus, the well owners would be more likely to spend greater amounts on unitization for water injection both because unitization makes it possible and because of the greater cost. They can, therefore, get the greatest gains out of compulsory unitization on these projects, and as Table 6 shows, this is when compulsory unitization is most frequently used.

Table 6

SIZE CHARACTERISTICS OF LOUISIANA
VOLUNTARY AND COMPULSORY UNITS

(Pressure Maintenance and Secondary Recovery)

Type of Project and Acres in Project	Number of Reservoirs:		Percentage of Reservoirs in Acreage Class:	
Gas Injection:[1]	Voluntary	Compulsory	Voluntary	Compulsory
0-39	421	88	82.7	17.3
40-99	43	25	63.2	36.8
100-499	16	41	28.1	71.9
500-999	1	21	4.5	95.5
1000-1999	1	36	2.7	97.3
2000-4999	1	25	3.8	96.2
over 5000	0	9	0.0	100.0
Acres Unknown	8	0	100.0	0.0
Total	491	245	66.7	33.3
Water Injection:				
0-39	16	30	34.8	65.2
40-99	8	33	19.5	80.5
100-499	11	120	8.4	91.6
500-999	2	49	3.9	96.1
1000-1999	2	35	5.4	94.6
2000-4999	0	18	0.0	100.0
over 5000	0	7	0.0	100.0
Acres Unknown	0	0	---	---
Total	39	292	11.8	88.2

[1]Only a small proportion of gas injection projects are explicitly gas cap type drive.

SOURCE: Louisiana Department of Conservation, Secondary Recovery and Pressure Maintenance Operations in Louisiana, 1972, Report.

5. Conclusion

At the outset, I discussed the general rationale for state regulation of common property resources. It has been shown that in the case of oil fields, the owners of the mineral rights have been able to agree to practice unit management, both in the absence and the presence of statutory or compulsory unitization. The states have been responsive to changes in the profitability of oil extraction, and have adjusted regulations to reduce transactions costs of reaching wealth-maximizing cooperative agreements. Even where compulsory unitization has existed, as in Louisiana and Alaska, the states have shown restraint in its use, applying it generally in those cases where unitization is most valuable, and the costs of organizing the greatest. What are the implications for other common-property resources?

The implications seem to be as follows: First, where unit management is not possible to achieve, the state ought to regulate in such a way that the users of the resource have maximum input into the process, and that the result would be as much as possible like that which would be reached by mutual consent. Thus, nationwide pollution abatement standards are, it seems to me, an excellent way to maximize enforcement costs. Secondly, regulatory agencies should

concentrate their efforts where agreement by resource users is least likely, rather than attempting to build up an enforcement record with easy cases. The hard cases are also where the participants would tend to look most to government to help, so on both counts the government could save enforcement costs. Finally, maximum attention ought to be given to the value of output and the cost of production from common property resources. The users will be paying attention to these factors, so the state is only deluding themselves if they regulate based on physical parameters only. This is a mistake the oil producing states have never made.

There are some implications for specific resources. For example, most fisheries are operated on rule of capture notions, modified by quotas, which are equivalent to top allowable schedules, or by restrictions on production techniques, which are equivalent to minimum spacing regulations and restrictions upon the gas-oil ratio. As is actually the case, the theory in this study suggests that fishermen subjected to gear restrictions would try to maximize with respect to uncontrolled margins of pulling power of boats, storage facilities on board, fish-finding techniques, etc. This study's results, when generalized, suggest that quota incentives could be built into gear restrictions. For example, a larger <u>total</u> quota could be allowed for fishermen agreeing to take the quota over many months rather than just a few, and <u>smaller</u> quotas on the other

end. This might help reverse the trend of overcapitalization in fishing, without direct resort to buy-back provisions or single firm management. The quotas could be scaled down as fishing extended over more and more months with smaller equipment. These incentives could also be made multi-dimensional--in gear, boat, fishing time, fishing area, etc. Another generalization occurs in ground water, which is also currently exploited under law of capture methods. An alternative to the state charging for water withdrawal privileges, which may be politically odious, is to resort to minimum spacing rules on allowable pumping wells, together with allowable rates of withdrawal, rights which could be subdivided and sold to newcomers. Depth might or might not enter as a factor in the allocation system; however, spacing incentives which reduced <u>total</u> withdrawals, while increasing permitted withdrawals per well, are possible.

These are just a few generalizations. Probably a great many others are possible, but they are beyond the scope of this paper and the current interest of its author. In general, the state can reduce the costs of exploiting common property resources without resorting to unit management. However, even where unit management is required, the state as enforcement agency can reduce its enforcement costs by wise selection of the cases it handles and the regulations it selects.

FOOTNOTES

1. See, for petroleum, Wallace Lovejoy and Paul T. Homan, Economic Aspects of Oil Conservation Regulation (Baltimore: Johns Hopkins Press for Resources for the Future, 1967); Stephen L. McDonald, Petroleum Conservation in the United States (Baltimore: Johns Hopkins Press for Resources for the Future, 1971); Vernon L. Smith, "The Economics of Production from Natural Resource Industries," American Economic Review 58(3): 409-431, June 1968; Morris Adelman, "Efficiency of Resource Use in Crude Petroleum," Southern Economic Journal 31: 101-122, October, 1964.

2. "Well owner" will be used interchangeably in this paper with "working interest" to signify those individuals having ownership rights to oil in a given reservoir, plus the right to change the rate of production. "Royalty interests" will be used to denote persons having partial ownership rights to produced oil (usually a fixed percentage), but who have no say in the rate of production or other matters of operation.

3. Two well owners are used for simplicity. In reality, there may be numerous working interests. One of the sample units in the fourth section had 192 separate working interests, and the East Texas Field had many more. However, the model presented here is general.

4. See, for example, Frank W. Cole, Reservoir Engineering Manual 2 edn. (Houston, Gulf Publishing Co., 1969), p. 97.

5. Cole, p. 111 and pp. 123-130.

6. The American Petroleum Institute History of Petroleum Engineering records that some interests in the William Phillips No. 2 well in the Oil Creek, Pennsylvania field bought a neighboring well in 1862 which was causing water flooding for $500,000 and plugged the well. There are numerous other examples, but this is one of the earliest.

7. OD and OI are the distances where the all-or-nothing "demand" curves cross the horizontal axis. At these points, the marginal rents available to the respective parties equal zero, and no more wells would be drilled even in a competitive drilling case.

8. Actually, each well owner would want wider spacing set for producers other than himself, since this would shift his marginal benefit curve outward. However, it would be an enormously expensive bargaining process to decide spacings of individual properties on a lease-by-lease basis. Hence, the spacing tends to be equal even in physically heterogenous reservoirs.

9. Those familiar with the theory of public goods and externalities may argue that there is a free-rider problem implicit in this "willingness to pay" formulation. However, unless expenditures for exploration, lawyers, political contributions are actually made, some parties will find themselves worse off than they would be at some other spacing, and they will try to influence the bargaining process in that direction. Since there is some slippage in the process of influencing political bodies, little can be said about final spacing in individual reservoirs; the only predictions possible are on the direction of effects--e.g., when marginal values generally rise at all spacings, denser spacings would be requested.

10. The conclusion is that relative shares are the usual bone of contention primarily since the reading of a sample of 124 field files of the Texas Railroad Commission revealed no cases where objections to a specific unit were ever other than on the grounds of relative shares. All parties raising "technical" questions about the boundaries of the field, whether the proposed project would work, methods of computing reserves, etc., did so in a context which clearly showed they had compensation in mind. This was true whether they were in the unit (explicitly, relative shares), or neighbors to the unit (requesting protection from unit activities such as water flooding). The Oil and Gas Journal reported on September 28, 1968, that of 700 plus (voluntary) recovery units formed in Texas up to that time, "equity has been argued at some stage in the formation or approval of virtually every one of them." See "Major Unitization Fuss Rocking Texas," Oil and Gas Journal, 66(39)98-99, September 28, 1968.

11. Since he always has the option of continuing the bargaining search, the most he will be willing to concede is the cost of that additional bargaining necessary to maintain the wealth already acquired. Regardless of whether he offers

to "buy off" the parties continuing to bargain, or whether he invests the funds in the bargaining process to increase the costs (reduce the benefits) of the other party's continued search, the maximum offered will be the same. Since marginal benefits of search to the party who wishes to continue search cannot be less than those when he is opposed by an active bargaining party, he will not be bought off for less.

12. In general, attempts to improve the efficiency of the bargaining process (increase the cost of holding out) will increase the speed with which agreements are concluded. Innovations increasing the costs of holding out will shorten the search periods for units already under negotiation, and will result in a larger number of units formed.

13. Under competitive extraction, the parties are not constrained to select equal spacing, so there is no way to determine one's own potential net benefits from operating, rather than selling out. Consequently, it is difficult to determine the appropriate sale price.

14. These type of operations depend upon the monitoring and coordinating of an advancing fluid front, which is best done by central management. It often requires converting some producing wells to injecting wells, and different production rates in different parts of a reservoir.

15. See, for example, McDonald or Lovejoy and Homan, op. cit., note 1, above.

16. Rule 37, Railroad Commission of Texas.

17. Memo: "In re: Ammended Formula for Arriving at Allowables on Wells After the Expiration of a New Field Discovery." Dated July 21, 1947. This memo was written by Mr. Jack K. Baumel, Chief Engineer, Oil and Gas Division, to the Texas Railroad Commissioners.

18. The Industry Advisory Committee report can be found in the Texas Railroad Commission Statewide Hearing file, "Railroad Commission of Texas Pertaining to Revision of Allowable Yardstick used to Determine Producing Rates for Oil Fields in Texas," July 16, 1964.

19. The data for these regressions came from MER Hearing Summaries [Annual] (Austin, Texas: Texas State House Reporter).

20. Expected numbers were generated by multiplying the proportion of fields in each cell of Table 3 that were developed under the 1947 Yardstick, times the total number of fields developed under the 1965 Yardstick. The total of expected proportions does not add up to 186 due to rounding errors.

21. The sample was compiled by selecting a list of projects from an advance listing of unitized oilfield conservation projects for 1974, prepared for a 1974 Interstate Oil Compact Commission publication. Since it was expected the fields still in primary (flush) recovery would be less likely to be unitized and more susceptible to organization costs, a subsample was prepared of only those fields listing pressure maintenance as a factor in the type of fluid injection as a proxy for primary recovery projects. This set was too large, so a random subsample was selected, yielding 124 fields. Missing data further trimmed the sample size.

22. This is consistent with greater bargaining costs being associated with greater field value. In addition, the case of Prudhoe Bay is different because of the long period required to construct the Trans-Alaska Oil Pipeline.