

The Self-Enforcing Provisions of Oil and Gas Unit Operating Agreements: Theory and Evidence

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This article extends the existing theory and empirical investigation of unitization contracts. It highlights the importance of incentive-compatibility and self-enforcement and the bargaining problems faced in achieving viable, long-term contracts. We argue that only if the parties to a unitization contract have unit production shares that are the same as their cost shares will the contract be incentive compatible. Using a database of 60 unit operating agreements, we measure the industry's actual behavior against the principles of production from a common pool. Our survey of units that have only one production phase and that are relatively homogeneous reveals that such equal sharing rules are always found and they appear to encourage the parties to behave optimally. In more complex units with multiple production phases and/or separate concentrations of oil and gas (gas caps) we find deviations from the theoretical ideal. In the case of multiphase units, we find equal cost and production shares within phases, but not across phases. A preset trigger for shifting from one production phase to the next helps to maintain optimal behavior. For gas cap units, however, we generally do not find the equal sharing rule. Conflicts and rent dissipation follow as illustrated by the case of the Prudhoe Bay Unit. The article describes the desirable contract rules for avoiding moral hazard. It also shows how the effects of those rules can be replicated in difficult situations.

1. Introduction

This article extends the existing theory and empirical investigation of unitization contracts. It highlights the importance of incentive-compatibility and

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self-enforcement and the bargaining problems faced in achieving viable, long-term contracts. *Essential* contract elements are identified and the conditions that promote their inclusion in unit agreements are described. Less complete and effective arrangements are introduced and linked to specific geological and market conditions that complicate bargaining. Hypotheses are derived about when complete unit contracts will be observed and about the rent-dissipating behavior that will occur when alternative arrangements are adopted. The empirical investigation makes use of the largest dataset of unitization contracts compiled to date—60 unit contracts in the United States and Canada.

We argue that if the parties to a unitization contract have unit production shares that are the same as their cost shares, the contract will be incentive compatible. This follows because the allocation formula makes each party a claimant to the unit's net profits and as such, motivates them to support a production plan that maximizes unit profits. Our survey of units that have only one production phase and that are relatively homogeneous (no clustering of oil and gas in separate parts of the reservoir) reveals that such equal sharing rules are always found and they appear to encourage the parties to behave optimally. The contracts are simple and do not require detailed provisions to address potentially serious moral hazard problems, and conflicts over production and investment are minimized. The unit operator develops the field and administers the contract. In more complex units with multiple production phases and/or separate concentrations of oil and gas (gas cap) we argue that the equal sharing rule still is necessary for effective unitization. Negotiating conditions, however, are more complicated and these affect the ability of the parties to reach agreement on the required allocation formula. In multiphase units, we find equal cost and production shares within each phase, but not across phases. We show that this condition can still lead to optimal behavior among the parties if there is a preset trigger for shifting from one production phase to the next. For gas cap units, however, we generally do not find the equal sharing rule. Although the parties have incentives to draft incentive-compatible contracts, they may not be able to do so. Conflicts and rent dissipation follow as illustrated by the case of the Prudhoe Bay Unit.

Our contribution is useful because it describes the desirable contract rules for avoiding moral hazard. It also shows how the effects of those rules can be replicated in difficult situations through the use of a trigger. Finally, the analysis reveals the cases where complete unitization contracts are unlikely to be written.

Unitization contracts have been of interest to scholars in transaction cost economics, political economy, and the law for some time. Unitization is the most straightforward solution to a serious common-pool problem in oil and gas production. Under the common-law rule of capture, private property rights to hydrocarbons are assigned only upon extraction. Production rights are granted to firms through leases from those who hold the mineral rights, often landowners. Each of the producing firms has an incentive to maximize the economic value of its leases rather than that of the hydrocarbon reservoir as a whole. As firms compete for migratory oil and gas they dissipate reservoir rents with

excessive capital, too rapid production, and lost total recovery.¹ With a complete unitization agreement among the producers, however, a single firm is designated as the unit operator to develop the entire reservoir.² The other firms share in the unit profits according to negotiated formulas. The gains from agreement can be huge both from savings in capital costs and from increases in overall production that can be from two to five times unregulated output.³

With so much at stake, oil firms are motivated to reach agreement to form complete units. Yet despite this motivation, complete unitization is much more limited than neoclassical theory would predict (Bain, 1947:29). For instance, Libecap and Wiggins (1985) report that as late as 1975, only 38% of Oklahoma production and 20% of Texas production came from reservoir-wide units. Achieving consensus on a unit contract is difficult with agreements often completed only after years of negotiation, when many of the efficiency losses have already occurred. And, as we show even when unitization agreements are reached, not all are complete, leaving the potential for various forms of competition among owners that dissipate rents.⁴

To be successful, a unit agreement must align the incentives of the oil-producing firms over the life of the contract to maximize the economic value of the reservoir without repeated recontracting.⁵ Unit contracts involve a number of difficult issues that have to be addressed by negotiators. Because remaining production often lasts 20 years or more, unit agreements must be long term and must be responsive to considerable uncertainty over future market and geological conditions. They must allocate unit production and costs among the many firms that otherwise would be producing from the reservoir.⁶ In addition, they must authorize investments that may be made later to expand reservoir production and distribute the ensuing costs among the individual parties.

Unit contracts generally involve two documents. One is the unit agreement that is between the firms (lessees) that plan to unitize the reservoir and the

1. There is a considerable literature on the common-pool problem in oil and gas production and efforts to counter it. See, for example, McDonald (1971), Libecap and Wiggins (1984), Weaver (1986), Smith (1987), Lueck and Schenewerk (1996), and Libecap (1998).

2. Units generally apply to common reservoirs of hydrocarbons. An oil and gas "field" may have multiple, separate reservoirs from different geologic formations. Typically, separate reservoirs have separate units because there is no common-pool problem across them.

3. *Oil Weekly* (April 13, 1942; May 3, 1943). The *Oil and Gas Journal* (December 7, 1964) predicted that unitization would raise oil recovery by 130 million barrels on the Fairway field. The increase is valued at over \$200 million using prices compiled by Manthy (1978:111). See also, McDonald (1971:24–25, 237). The benefits of unitization are emphasized in unit documents. For example, see Anshutz East, Wyoming Unit Agreement, December 1982, on file with the authors.

4. Wiggins and Libecap (1985), Smith (1987), and Lueck and Schenewerk (1996) examine some of the bargaining issues faced by unit negotiators.

5. Williamson (1975:30, 65–94) discusses incentive issues in contract enforcement.

6. Unit operating agreements typically allocate volumes of produced substances, as opposed to revenue, among the parties to the contract. A fixed allocation of unit revenues would require the joint marketing of output, which may raise antitrust issues that companies would be anxious to avoid.

property or royalty owners (lessors). This document describes the terms for the formation of the unit.⁷ The other document is the unit operating agreement, which is the more detailed contract among the working interest owners (WIOs) for forming and operating the unit. It includes the designation of the location and limits of the reservoir or formation to be unitized and the procedures to expand the unit as necessary; a definition of key terms such as development wells, injection wells, and test wells; the identity of the unit operator and procedures for removal of the unit operator; start date of the agreement; and identity of the working interests, including their holdings (leases) on the reservoir.

Unit operating agreements have additional provisions that define the operating relationships among the working interests. These provisions include governance mechanisms such as voting rules, notification requirements, grievance and arbitration procedures, unit operator reporting and accounting practices, and establishment of a supervisory committee; compensation for private capital equipment (typically, wells, pipelines, and possibly injection plants) taken over by the unit; and the sharing formula by which produced substances, capital, and operating costs are distributed among the working interests. Achieving agreement on the sharing formula is very contentious, often requiring intense negotiations with many votes taken by the working interests on various cost and production sharing options. Indeed, arriving at a consensus on shares is the most difficult issue faced in unit negotiations. Discord among the negotiators can delay unitization for years or lead to an incomplete agreement. Uncertainty and asymmetric information among the parties about unobservable lease characteristics hinder agreement on individual lease values and corresponding unit shares.

Unit operating agreements also define the phases of production as primary (when natural, subsurface pressures flush oil to the surface) and secondary (when various injection procedures are used). Based on engineering reports agreed to at the time the unit is established, the negotiating parties have some sense of how the various leases will fare in each phase of production, and different sharing or ownership percentages may be defined for each phase. General physical benchmarks are specified, such as a particular gas:oil ratio or production level. As we show, these benchmarks typically are not controversial and they play a very important role in maintaining incentive compatibility within the unit.⁸

Finally, unit operating agreements describe the mechanism by which parties are added or dropped from the unit. If the unit agreement is written during exploration or early development (when the full extent and nature of the subsurface formation are unknown) parties may be mistakenly included or excluded from the unit. Hence unit operating agreements include provisions for drilling test wells to confirm hydrocarbon deposits and justification for participation

7. For example, see the Model Form of Unit Agreement provided by the American Petroleum Institute, 3rd ed., January 1970.

8. There may be multiple secondary phases, and the type of injection—water, natural gas, carbon dioxide—depends on the nature of the reservoir.

in the unit. With these adjustments, the new (or remaining) parties participate in production and costs according to the sharing formula.⁹ These provisions define the working structure of the unit, and they are spelled out *ex ante*.¹⁰

Unit operating agreements contain both specific benchmarks and general terms. Certain contingencies are laid out, primarily the sharing formula under different production phases, and mechanisms for adding or subtracting membership. But day-to-day operation of the unit is left unspecified in the contract, with the unit operator bound only to a “best efforts” standard of performance, a standard that would be costly to monitor without self-enforcing provisions. It is not possible *ex ante* to define strict performance criteria for the unit operator because far too much remains unknown at the time the contract is written, particularly about future reservoir geological dynamics, market conditions, and production technology. Under those circumstances, it is desirable to provide the unit operator with considerable latitude in reservoir development.

Of importance, many potential long-term contracting problems are not addressed explicitly in unit operating agreements. For example, procedures to address potential extortion by some parties of the value of fixed, capital assets (nonmovable wells, injection plants, and pipelines) typically are not described. This is a potential problem. Hypothetically, any working interest could engage in opportunism and extort the unit for the value of those assets by threatening to withdraw from the agreement or otherwise hinder unit operation unless certain extortion demands were met.¹¹ Also absent are discussions of how to deal with threats by some strategically located parties to withdraw from the unit. Because of the nature of hydrocarbon deposits and changes in their flow with unit production, certain lease owners can be essential for viable unit operation because of their position on the formation. Theoretically, a small number of strategically positioned parties could force a renegotiation of the unit once it was put into place and became profitable.

These conditions could lead to opportunistic behavior and a breakdown in the unit’s operation. But in practice, extortion of the value of fixed assets and strategic behavior to force a renegotiation of the unit agreement are uncommon. We argue that the profit-sharing formula specified in the unit operating agreement reduces the incentive of the parties to engage in these actions. If the sharing formula has the characteristics described below and if it applies to all communicating hydrocarbon deposits, then each party becomes a residual claimant to the profits from effective operation of the *entire* unit. Under these circumstances, the working interests would not want to hold up needed invest-

9. Exxon, for example, has recently applied as operator of the Point Thomson Unit in Alaska for the state’s permission to add one of its adjacent leases to the unit, thereby raising its working interest while proportionately decreasing the interests of other owners. See *Petroleum News Alaska* (September 28, 1998:3).

10. See the Model Unit Operating Agreement for Statutory Unitization provided by the American Petroleum Institute, 1st ed., March 1974.

11. The problem of asset specificity arises because significant investments will be made in the unit that have value or most value only under an operational unit. Hence those parties who make the investment are vulnerable to holdups by the other parties to capture some of the rents.

ment or delay new production practices (such as drilling injection wells) in order to force a renegotiation of the contract. Such actions would not only reduce unit profits, but would invite similar strategic behavior by other parties, eroding the basis for any long-term cooperation to maximize the value of the unit. As such, the profit-sharing formula provides for self-enforcing cooperative behavior among the working interests and expands what Klein (1996) refers to as the “self-enforcing range” of the contract.¹² Accordingly, although reaching agreement on the sharing formula involves long and costly negotiations, once established the formula reduces ex post enforcement costs.

Our argument proceeds as follows: In the next section we summarize the common-pool problem in hydrocarbon reservoirs and then show how unitization with a profit-sharing formula having *specific* characteristics solves the problem. Section 3 examines two empirically important issues that complicate agreement on the unit sharing formula—very skewed holdings of oil and gas and multiple production phases. Section 4 presents empirical evidence. Section 5 summarizes the results and provides generalizations for understanding the functioning of oil and gas unit agreements.

2. The Common Pool in Oil and Gas Reservoirs and Necessary Provisions for Complete Unit Contracts

2.1 The Common-Pool Problem

Competitive extraction from common-pool oil and gas reservoirs generates potentially large efficiency losses, and unitized operations can provide a remedy.¹³ The particular form of the unitization agreement, however, determines whether that remedy will be effective. The common-pool problem arises when multiple firms extract from a reservoir where the underlying resources are in communication via interrelated pressure gradients and resource migration. Under these conditions, extraction by one firm affects the volume and cost of production elsewhere within the reservoir.¹⁴

Absent any type of cooperative effort, the outcome of competitive extraction is well known. Each firm determines the number of wells it will drill and sets output from each well so as to maximize its private profits, ignoring the cost and production externalities it inflicts on other producers. It raises overall costs by releasing natural gas or other substances during production, thereby reducing the underground pressures that push oil to the surface. As pressures fall, pumping and injection of other propellants become necessary. Further, the firm’s

12. As described by Klein and Murphy (1997:417), “the self-enforcing range measures the extent to which market conditions can change, thereby altering the gains to one or the other party from nonperformance, without precipitating nonperformance.”

13. The common-pool problem would be circumvented if landowners agreed to coordinate production. In cases where surface ownership is large enough to cover all or nearly all of an entire reservoir, unitized production is routine. Where surface holdings are more fragmented, the problem increases. For discussion, see Libecap and Wiggins (1984).

14. For general discussion of the common-pool problem using fisheries to illustrate the issues, see Gordon (1954) and Cheung (1970). Smith (1987) focuses on the problems of oil production from a common pool.

production encourages migration of oil from elsewhere in the reservoir, allowing it to extract its neighbor's oil. Since all firms recognize these conditions, they have incentive to competitively drill and drain the reservoir. Accordingly, at any point in time, individual production decisions are made to enhance the value of firm leases rather than to maximize the economic value of the overall reservoir.

2.2 Characteristics of Complete Unit Contracts

To avoid the loss associated with competitive extraction, the lease owners may attempt to reach consensus on a more optimal production plan to avoid rent dissipation. There are, however, several possible forms that unitized operations might take, and not all are equally effective. Under unitization the unit operator will drill wells and produce oil and natural gas from the reservoir. The associated costs and production are allocated among the lease owners according to a prearranged sharing rule. Negotiating an agreement on the unit-sharing rule, however, can be particularly difficult. But successfully addressing the common-pool problem requires more than agreement on a sharing formula. The allocation formula must take a *particular* form in order to align incentives and ensure that the unit production plan maximizes the economic value of the reservoir.

For each lease owner a *single* equity share or participation factor must be adopted that applies equally to both costs and production throughout the reservoir. If each member's share of production is matched by his share of expenditures over the life of the reservoir, then all parties will be residual claimants to the *net* economic profits from *unit-wide* production. Each party will be motivated by individual incentives to pursue a common plan of efficient development.¹⁵ Only if this condition is met can we say that the reservoir has been *completely* unitized and that the common-pool problem has been remedied.

If shares are assigned in this manner during unit negotiations, maximization of the value of the reservoir (economic efficiency) becomes a common goal at the outset. Alternatively, if there is a wedge between the cost and production shares assigned to any party, then the consensus will fail and conflicts emerge. For example, if the sharing formula does not uniformly allocate each type of cost in the same proportion as production, certain owners will advocate actions that would skew development in the direction of those expenditures (e.g., injection wells) in which they carry a relatively light load—even if that is inconsistent with maximizing the overall value of the unit. Dissension, violation of the unit agreement, and rent dissipation are likely results.

To resolve such disputes, some parties (typically those with the largest leases and the most to lose) may devise side payments that restore consensus and allow

15. Operating firms typically lease the mineral rights from surface landowners, and they often have multiple sectors. For discussion of the proportionate allocation of production and costs, see Plan of Unitization, East Binger (Marchand) Unit, Caddo County, Oklahoma, Article 17. See also, Article 11.1 of the American Petroleum Institute, Model Forms for Voluntary and Statutory Unit Operating Agreements, 4th and 2nd eds., respectively, June 1, 1993.

development to proceed. Although side payments may balance interests at one particular point in time and persuade all parties to support a common course of development, they do not assure incentive compatibility over the remaining life of the unit. New disputes and conflicts will emerge (and the need for additional side payments will ultimately arise) if cost and production shares are not made equal. Interests can easily fall out of balance as soon as circumstances (expected prices, costs, or production possibilities) change, which they inevitably do. Further, efficiency losses inflicted on the unit from disagreement and nonoptimal production practices may be irreversible due to resulting changes in reservoir dynamics. Accordingly, ex post efforts to align interests via side payments are not apt to be as effective as the ex ante proportionate assignment of costs and production to each party.

Of importance, aligning incentives through a profit-sharing formula reduces the information necessary for implementing a unit agreement. The contract can be left relatively simple because new information will be incorporated and plans adapted by consensus over the life of the unit in a manner that maximizes its value and the returns to the parties. For example, new information about the configuration, extent, and communication of reservoirs is revealed through production. This knowledge may require extension or contraction of the unit with the corresponding addition or subtraction of interests from the unit. When parties are added or deleted, the relative position of the incumbent interests is maintained as outlined in the initial profit-sharing formula. Renegotiation of the formula is not required. Similarly, the allocation formula is robust against unexpected changes in oil prices, costs, or recovery methods. The incentives of the working interest owners remain aligned (without side payments or recontracting) even as these features of the project are unpredictably altered.

Because each party will favor a production plan that maximizes the economic value of the unit, execution can safely be left in the charge of a single unit operator without detailed performance provisions or enforcement guidelines defined at the initiation of the contract.¹⁶ Any firm with a lease interest in the reservoir and the technical competence to develop it would provide incentive-compatible management. Beyond this, reliance on a single unit operator reduces the transaction and coordination costs that would arise if there were multiple unit operators and as such, further enhances the overall net value of the reservoir.

In practice, the unit operator is usually the largest lease owner on the reservoir. This firm has the most at stake in unitization, thus minimizing any incentive for opportunistic behavior that would harm other interests. If discovered, this deception could lead to the breakdown of the unit. Supervision of the unit operator also is formally addressed in the unit operating agreement with requirements for a governing board and votes on production and investment decisions. The

16. There may be differences in opinion regarding geological conditions or technical capabilities that affect the production plan. The single-equity provision, however, means that such differences will not arise due to strategic behavior.

governing board is composed of the other interests, and voting weight is defined by the profit-sharing formula, again granting those with the greatest stake in the unit the greatest role to play in production and investment decisions. Supermajority voting rules are described, with the requirements increasing with the significance of the issue at hand.¹⁷

3. Geologic/Information Problems and Alternative Unit Agreements

Despite the attractive attributes of a complete unit contract, not all unit agreements are written with these provisions. Disagreements during unit negotiations can impede acceptance of a sharing formula that aligns the incentives of the parties. An alternative, less effective contract can be the result. The negotiation of unit shares is burdened by uncertainty regarding the volume and value of the assets (leases) that each party brings to the unit. We are not concerned here with the possibility that negotiations may simply fail, leading to the alternative of competitive extraction. The potential for contractual failure has been examined elsewhere (Libecap and Wiggins, 1985). Rather, we consider the impact of certain provisions that lease owners commonly adopt in practice to avoid contractual failure, but which subsequently alter the fundamental structure of the unit in ways that can threaten its effectiveness.

Negotiating over unit shares amounts fundamentally to the trading of disparate assets among the working interest owners. Because the reservoir has distinct physical properties that are not uniformly distributed, the respective leases generally reflect assets that differ very much in kind as well as quantity. Some lease owners may have mostly gas beneath their leases, while others have mostly oil. In order to completely unitize the reservoir, the two sides have to adopt (at least implicitly) agreed terms of trade by which an interest in gas is exchanged for a compensating interest in oil. Similarly, certain parties may hold leases that provide natural sites for production wells (e.g., high on the formation) during primary production, while others may hold leases that are better candidates for water or gas injection (e.g., low on the formation) during secondary production. Again, it will be necessary for the parties to adopt terms of trade based on the lease locations and the potential for enhanced recovery efforts to supplement the natural reservoir drive.

Through repeated negotiations, WIOs typically are capable of translating differences in quantity of resources into ownership shares in the unit. However, here we argue that differences in kind are more problematic. The basis for placing relative values on the oil and gas assets may not be obvious to the bargaining parties. Gas ownership presents a particular problem. The valuation of gas in the reservoir depends on whether it is assumed to be marketed, as opposed to being reinjected in support of enhanced oil recovery efforts. Due to limited transportability in some cases, the existence of any external market for the gas may be doubtful, especially in remote locations. To the extent that

17. For example, see Article 4.4 of the Anschutz Ranch East Unit Operating Agreement on file with the authors.

the imputed value of gas is speculative, WIOs may find it difficult to adopt any definite terms of trade of oil for gas and be unable to agree on any particular distribution of equity in the unit as a whole.

The difference in kind between gas and oil is not simply imagined. The volatility of short-term gas price movements exceeds that of oil, at least as reflected in futures market trading of the last several years. Indeed, in recent years natural gas has exhibited the highest volatility of any commodity traded on organized U.S. futures exchanges (Fitzgerald and Pokalsky, 1995:196). Not only are gas values more volatile, they do not always tend to parallel movements in the value of oil. For example, the correlation between the real wellhead values of gas and oil produced in the United States during the past 2 years (monthly values) is only 38%.

Over the longer time spans relevant to the units included in our database (which date between 1938 and 1992) there were other disparities between oil and gas prices. One was a lack of pipeline technology of the type needed to move large volumes of remote natural gas to major markets. This condition meant that many natural gas markets were local, whereas oil markets were national and international. Another was the effect of the Federal Power Commission's distortive regime of price controls that held natural gas prices below market value throughout most of the 1950s through the 1970s. Consequently, gas markets developed differently, as MacAvoy (1983:78–120) has noted, from most other raw-material and fuel markets. Until fairly recently, natural gas tended to be accumulated as an unwelcome by-product in the search for oil and was sold at prices not much more than gathering costs.

Differences in valuing the contribution of leases during secondary versus primary recovery operations may pose similar difficulties for the working interest owners. The value of leases that are strategically important to secondary recovery efforts depends very much on the presumed effectiveness of enhanced recovery techniques. The performance of those techniques can vary significantly from reservoir to reservoir and can be substantiated only through actual testing. The relevant tests cannot be performed until the reservoir has been developed and depleted—several years perhaps after the unit has been in operation. Consequently, lease owners who hold a relatively large interest in primary production may be unwilling during equity negotiations to trade a portion of that asset away if the compensation is to take the form of an expanded interest in secondary recovery.

In sum, lack of information and differences in expectations may undermine the working interest owners' ability to trade in assets that are different in kind or quantity and are highly uncertain in value. Such circumstances would impede the ability of the interests to write complete unit contracts. They are most likely to occur when there are very skewed holdings of oil and gas or when production involves both primary and secondary recovery.

In response, the working interest owners may elect to partition the unit in a way that isolates differences among tracts and permits them to be negotiated separately. The simplest example of this occurs when a reservoir is spatially partitioned into separate gas cap and oil rim participating areas (PAs), based on

the preponderance of oil or gas in various parts of the reservoir.¹⁸ Individual sharing formulas are then negotiated for each PA.

Under these arrangements, each working interest owner is assigned a distinct share in the operations of the participating area rather than the unit as a whole. The party whose lease overlies a relatively large share of the oil, for example, is assigned a relatively large share of equity in the oil rim PA, and perhaps little or none of the equity in the gas cap PA. Alternatively, a reservoir may be partitioned across time, as when production efforts are divided into primary and secondary recovery phases, with each working interest owner accepting distinct interests in reservoir operations during each of the two phases. Both types of partition (dual PA and multiphase recovery) are quite common in the industry because they reduce the costs of reaching initial agreement on the unit. But they may weaken the ability of the unit operating agreement to align incentives and hence maximize the economic value of the reservoir.

When the reservoir is partitioned along any dimension, a boundary is created that may incite competition for resources and for value. The existence of such partitions may render the unit incomplete and hence create conflicts of interest that must be managed by the lease owners in order to avoid inefficient, competitive development. We now turn to the two most common forms of partitioning—dual PA (gas cap and oil rim) units and multiphase units—to identify where the problems are most severe.

3.1 Dual Participating Areas: Gas Cap versus Oil Rim

Often a reservoir will hold a large accumulation of oil with a distinct pocket of associated gas positioned at the very top of the formation. If individual lease holdings are distributed unevenly across the boundaries of such a reservoir, certain lease owners may have a disproportionately large share of the gas concentrated beneath their leases, while other owners hold leases that are predominantly associated with oil. If the parties are unable to reach agreement on the relative values of these two resources, they may choose to partition the unit into dual participating areas. In this case, each member accepts an equity interest in the oil rim production that is distinct from his interest in the gas cap production. All produced substances and costs are first allocated between the two participating areas and then assigned to individual lease owners on the basis of equity shares within the respective PAs. The problematic aspect is that, when considering a lease owner's combined stake in the unit as a whole, production and cost shares for any one member will not necessarily coincide.

Efficient unit-wide production requires that each member's share of the oil rim be the same as that member's share of the gas cap. Whenever a single reservoir is partitioned geographically into multiple participating areas, any

18. Partitions within units also may be made to segregate highly permeable sections of a reservoir (where the underlying resources will be easier to recover in primary recovery) from sections that have low permeability but are useful for secondary recovery.

deviation in equity shares across the partition will create conflict. For example, members holding greater shares in the oil rim than in the gas cap would favor actions that promote oil recovery at the expense of gas. This could, for example, include opportunistic support for projects to reinject produced gas into the reservoir, as opposed to sending it to market. It could also include opposition to projects, like construction of gas treatment plants, designed to extract natural gas liquids to be mixed with oil for pipeline shipment. Similarly, gas owners could promote excessive natural gas production and early sales that would impair pressure maintenance in the reservoir and reduce the recovery of oil.

3.2 Multiphase Units: Primary versus Secondary Production

In the case of multiphase units, the reservoir partition corresponds to the transition between primary and secondary recovery efforts. A consensus on efficient extraction from the multiphase unit requires that each owner hold a uniform share across phases. Otherwise an owner who holds a relatively large interest in primary recovery would favor shifting a greater proportion of extractive effort into the primary phase—perhaps by obstructing efforts to initiate the transition to secondary recovery methods. Conversely, those members holding relatively large interests in secondary recovery would favor a shortening of the primary phase, or perhaps a less intensive primary recovery effort (e.g., wider well spacing).

In practice, each member's share typically differs across phases, depending on how each lease is expected to perform initially during primary and secondary production. Due to variations in geological conditions within the reservoir, the performance of any lease can vary significantly across phases.

Different allocations across phases raise the question of whether the members employ some alternative contract arrangements to mitigate the potential efficiency losses that would result from discord. The key provision in this regard appears to be an objective predetermination of the events that will trigger the transition from primary to secondary recovery. When a unit is originally formed, members agree that secondary recovery will be initiated when reservoir production or alternatively, the gas:oil ratio, reaches a certain level, signifying a critical level of exhaustion of the original oil resource. Gas production tends to rise, relative to oil, as the reservoir is depleted. The total production or gas:oil ratio triggers are objective and based upon mutually agreed engineering assessments. Moreover, the nature of the trigger tends to *automatically defeat* any subsequent efforts to opportunistically manipulate recovery efforts in either phase.

For example, the incentive of an owner with a relatively large share of secondary production to minimize primary production is tempered because such action would, under the agreed transition criterion, only extend the primary recovery period. As primary production is reduced, the anticipated rise in the gas:oil ratio is delayed, and this condition postpones the transition to secondary recovery. Thus reliance on this type of fixed transition rule can be understood as a contractual device designed to restore (approximately) the incentive com-

patibility that would otherwise be destroyed by creation of the partition.¹⁹ If the partition did not exist, there would be no need or value in precommitting to a fixed transition rule. Through this contractual mechanism, the lease owners can align incentives for cooperative behavior through the productive life of the reservoir. Notice, however, that it is still imperative even with the trigger that within each recovery phase each member holds a single equity share. If not, disputes would persist regarding the optimal plan for recovery within the phase.

4. Empirical Analysis

4.1 Evidence from 60 Unit Operating Agreements

Our examination of the structure of unit operating agreements suggests that the following key features would tend to be observed in practice:

- a) A complete unit operating agreement will have a profit-sharing formula that assigns costs and production in an equal manner for each of the parties to the agreement.
- b) The partitioning of a unit between production phases (multiphase) and between oil rim and gas cap (dual PAs) potentially results in incomplete contracts. Proportionate cost and production shares for the unit as a whole are less likely to be observed in these units than in single-phase, single-PA units.
- c) Dual-PA units will have different individual cost and production shares for the unit as a whole, and hence be incomplete.
- d) If multiphase units have individual cost and production shares that are equal at any point in time, the use of a fixed transition rule from phase to phase will allow the unit contract to be complete.
- e) Complete units will have routine production histories with little or no evidence of discord and rent dissipation.
- f) Incomplete units will have discord among the operating interests and rent dissipation will be observed. Such behavior will be most pronounced for dual-PA units.

The empirical investigation begins with an examination of 60 unit operating agreements from oil and gas reservoirs in Alaska, Alberta, Illinois, Louisiana, Oklahoma, New Mexico, Texas, and Wyoming. Unit operating agreements often are placed on file with the state regulatory agency, such as with the Oklahoma Corporation Commission. Other files were made available to us from company records. These operating agreements include many important reservoirs in the United States and Canada, and the reservoirs represented ranges from strictly oil or gas to both oil and gas and from relatively simple geological formations to more complex ones. Moreover, there is considerable variation in the number of parties involved in the units, from two working interests in the Cole Creek, Wyoming, unit to 113 working interest owners in the Empire Abo,

19. We are grateful to the anonymous referee who suggested this interpretation.

New Mexico, unit.²⁰ The unit operating agreements span a wide time range, including the July 3, 1934, Fourbear, Wyoming, unit and more recent units, such as the May 1, 1992, Rocky Ford Upper Mannville F Pool Oil unit, Alberta. Hence we believe that the empirical record from this diverse sample of operating agreements is reflective of the general pattern of unitization contracting.

Other studies indicate that regulatory environments across states, including that of the federal government, affect the incidence of unit agreements. Further, the size of company holdings and whether or not companies are repeat contractors across many reservoirs influences their willingness to agree to unitization (Libecap and Wiggins, 1985; Wiggins and Libecap, 1985). Our examination focuses on a different question. Once parties write a unitization contract, will that contract have the characteristics necessary to successfully align incentives, and how do geological/informational issues affect the parties' ability to write such contracts?

Table 1 summarizes key aspects of the unit operating agreements: whether and how each reservoir has been partitioned, whether members' cost and production shares are equalized at each point in time, and whether (in the case of multiphase units) a trigger was adopted *ex ante* to balance and control the transition from primary to secondary recovery. As shown in the table, 78% (47 of 60) of the unit operating agreements include the provisions that we have identified as being essential for incentive compatibility in a unitization agreement. This finding underscores the importance of aligning the interests of the parties behind a production plan that maximizes the value of the reservoir over the life of the contract. At the same time, 22% of the sample do not have the characteristics required to ensure incentive compatibility throughout the life of the unit. We now turn to a closer examination of the individual units to see if the potential bargaining problems associated with formation of the various types of units help explain the observed contracting patterns.

In Table 1, 27 of the 60 cases (45%) represent simple, unpartitioned units. Of the 33 partitioned units, 19 are multiphase units and 11 are dual-PA units. In addition, three units are hybrids, being partitioned into multiple production phases and separate gas/oil participating areas. We see significant differences between these categories.

First, among the group of unpartitioned units, all 27 cases satisfy the equal shares criterion for incentive compatibility. In each of these cases, where the geological formation and development concepts were straightforward enough to allow the owners to pool and trade all assets within a single category, the theoretical prescription of equal cost and production shares throughout the unit was followed invariably.

The 19 multiphase units also satisfy the equal shares criterion during each production phase. By design, these units were structured to permit variation in the owners' shares between phases, and in all but one case the units include an

20. Cole Creek Unit Operating Agreement, January 30, 1953; Empire Abo Unit Operating Agreement, October 1, 1972.

Table 1. Unit Operating Agreement Characteristics

Unit name	Equal cost/ production share ^a	Partition type ^b	Phase trigger	Unit name	Equal cost/ production share ^a	Partition type ^b	Phase trigger
Anshutz East	✓	M	✓	Salem Flood	✓	M	✓
Benton	✓	U		Salt Creek S.	✓	U	
Big Stone Gas	✓	U		Seeligson	✓	U	
Birch Creek	✓	U		Sharon Ridge Canyon	✓	U	
Brady Deep	✓	U		S. Swan Hills	✓	M	✓
Burke Ranch	✓	M		Southwest Homer	✓	M	✓
Carpenter	✓	M	✓	Star Misner- Hunton	✓	M	✓
Collums Mud Sand	✓	M	✓	Sycamore	✓	M	✓
County Line	✓	M	✓	W. Cement Medrano	✓	U	
E. Binger	✓	U		W. Edmond	✓	U	
E. Burke Ranch	✓	M	✓	W. Elmwood	✓	M	✓
E. Salt Creek	✓	U		Wildhorse	✓	M	✓
Edson Cardium B	✓	U		Big Sand Draw	✓	U	
Empire Abo	✓	M	✓	Cole Creek	✓	U	
Fox Deese- Springer	✓	M	✓	Forebear	✓	U	
Goldsmith S. Andreas	✓	U		W. Poison Spider	✓	U	
Graham Deese	✓	M	✓	Canyon Reef	✓	U	
Grass Creek Curtis	✓	M	✓	Bumpass		M,D	✓
Green River Bend	✓	U		N. Thackerville		M,D	✓
Hartzog Draw	✓	U		Virginia Hills Belloy		D	
Joffrey D-2	✓	U		Alliso Canyon		M,D	✓
Karon	✓	D		Clive D-2		D	
Little Buffalo	✓	U		Clive D-3A		D	
Milroy	✓	M	✓	Harmattan E.		D	
Nipisi Gilwood	✓	M	✓	Harmattan Elkton		D	
N. Twining	✓	U		NAMAO Blairmore		D	
Painter Reservoir	✓	U		Rocky Ford		D	
Pembina	✓	U		Bonnie Glen		D	
Ostracod				D-3A			
Ryckman Creek	✓	U		Minnehik		D	
Sage Spring Creek	✓	U		Buck Lake Prudhoe Bay		D	

^a Equal cost/production share at any point in time.

^b U = unpartitioned, M = multiphase, D = dual PA.

ex ante trigger to balance and control the transition between phases.²¹ Of the 11 dual-PA units, however, only one case satisfies the equal shares criterion. These units represent reservoirs where the positioning of individual lease holdings was skewed enough to produce an unbalanced distribution of oil and gas among owners, and where the marketability of oil and gas resources differed so much in kind that the owners could not establish common terms of trade. Only in these conditions would we expect the difficulties in bargaining over initial shares to loom so large that the owners would adopt a contractual framework that actually jeopardizes the incentive compatibility of the agreement.²²

Finally we have the three hybrid cases that involve both spatial and temporal partitions of the unit. These units incorporate contractual features from both types: they all include ex ante triggers to balance and control the transition between primary and secondary recovery phases, but also they all involve skewed and disparate gas and oil holdings that the owners were unable to pool among themselves. These hybrid units do not have the requisite sharing requirements for incentive compatibility, and hence closely resemble the dual-PA units in our sample.²³

Why would the parties write a contract with provisions that create potential conflicts of interest? Previous research on unitization contracting has shown how difficult it is to reach agreement in general to unitize oil fields. Wiggins and Libecap (1985) showed that negotiations took from 4 to 9 years in the seven units they examined. Further, in five of those seven, only partial units were formed because not all parties could agree on the sharing formula. This general contracting problem explains why unitization overall is less common in the United States than one would expect, considering only the benefits of agreement and not the corresponding negotiating costs. The evidence presented here reveals more precisely the kinds of problems that oil and gas firms face in negotiating unit contracts.

The analytical framework suggests that negotiating parties will have greatest difficulty reaching agreement on lease values and hence unit shares when holdings of oil and gas are highly skewed. Thus we observe units partitioned

21. The Burke Ranch Unit Operating Agreement does not indicate an explicit trigger, although it may have been part of an attachment that is missing from our files.

22. Examination of the production and cost sharing rules for the Clive D-3 unit in Alberta illustrates the incentive problem found in dual-PA units. Effectively the oil interests share in the oil reserves and costs and the gas interests share in the gas reserves and costs as if these were distinct entities within the unit. But, of course, they are not. There are cost externalities from gas production for oil producers and vice versa. Under this arrangement, the parties will have to concern themselves with competing maximization problems and strategies rather than the value of the unit as a whole. Our subsequent discussion of the Prudhoe Bay unit indicates where this may lead.

23. To formally test for the statistical relationship between the frequency of observing an equal cost/production allocation rule and the frequency of observing dual-PA units, we created a 2×2 contingency table. A chi-square statistic with 1 degree of freedom was constructed with a calculated value, $\chi^2 = 54.53$. With a critical value of 6.64, we can reject the null hypothesis that observing the equal equity allocation rule and observing a dual-PA unit are independent at the 99% confidence level. This result supports our argument that dual-PA units are unlikely to have equal cost and production sharing rules. For a discussion of our approach, see Dudewicz and Mishra (1988:533).

Table 2. Firm Shares in Oil and Gas in Dual Participating Areas, Prudhoe Bay Unit

Firm	Oil rim PA share (%)	Gas cap PA share (%)
BP	51	14
Exxon	22	42
ARCO	22	42
Small holders	5	2

into dual participating areas when firms have concentrated holdings of oil or gas. To illustrate we outline the owners' shares in the oil rim and gas cap PAs in the Prudhoe Bay unit of Alaska.

When ownership across firms is concentrated in oil or gas, formation of a complete unit will require that large volumes of oil be traded for gas among firms. It is hard to negotiate that trade if there is uncertainty about the value of gas production. Uncertainty in valuing skewed holdings in gas and oil leads to bargaining disputes in arriving on a single share formula. As a fallback, firms can more easily agree on the valuation of their holdings within more homogeneous sections of the reservoir. The result, however, is the creation of dual participating areas with distinct share formulas. Although such unit agreements are not complete, the parties may chose those contracts over the alternative of no unit agreement.

The reason that multiple phases appear not to be a serious obstacle to negotiating share formulas is that the firms are dealing primarily with differences in quantity (between primary and secondary production) not kind (oil and gas). Accordingly, there is less uncertainty involved in estimating and agreeing to the value of unit shares within each phase, especially when phases are inaugurated by a preset and uncontroversial trigger. The parties have another important incentive to agree to collective action beyond solving the common-pool problem. Absent a unit to coordinate injection and production, effective reservoir-wide secondary recovery typically is not possible, and the economic life of the reservoir will be drastically shortened.

Another contributing factor to contracting success in multiphase versus dual-PA units could be that individual share differences across phases typically are *smaller* than differences across oil and gas holdings in gas cap reservoirs. We hypothesize that when firms have similar shares across partitions it will be easier for them to reach agreement on a unit-wide profit sharing formula. The reasoning is that they will have less at stake in moving from one partition (participating area or phase) to another and hence be more flexible in unit negotiations.

To empirically examine this issue, we calculated the absolute difference in each firm's share across partitions in dual oil and gas PAs and multiphase units. We have data on individual firm shares in each phase or participating area, as relevant, for nine dual-PA units and for five multiphase units.²⁴ The mean of the

24. The nine dual-PA units are Prudhoe Bay, Virginia Hills Belloy, Namao Blairmore, Bonnie Glen, Minnehick, Harmattan-Elkton, Harmattan-East, Rocky Ford, and Clive D-3. The five multiphase units are Graham Deese, Wildhorse, Grass Creek Curtis, County Line, and Collums.

absolute share differences is 1.04 percentage points ($SD = 1.75$) for 129 firms in the five multiphase units and over three times greater at 3.41 percentage points ($SD = 9.60$) for 157 firms in the nine dual-PA units. A t -test of the difference in the means allows for rejection of the hypothesis that the means are the same.²⁵ Differences in the productive value of leases within the unit across phases are smaller than are the differences due to the geological concentration of oil and gas deposits when there are gas caps.

4.2 The Case of Prudhoe Bay

If we are correct that equal individual cost and production shares effectively align incentives, then units with those characteristics should have comparatively routine, noncontroversial production histories. Tests of this claim are difficult to perform because of the limited data available. Disputes within private unit operating agreements generally are resolved through mediation with no public record. Only the most hotly contested agreements will involve litigation and/or appeals to state regulatory agencies.

Our search of court cases involving the units included in Table 1 provides a lengthy record for the Prudhoe Bay unit (PBU) in Alaska.²⁶ Examination of regulatory records at the Texas Railroad Commission and the Oklahoma Corporation Commission provides little indication of protracted conflict among the working interests within other units in these two states. By contrast, the public records of the Alaska Oil and Gas Conservation Commission (AOGCC) clearly show that the Prudhoe Bay Unit Operating Agreement has had a history of intense and costly disputes among the working interests.

The Prudhoe Bay field was discovered in early 1968. Unit negotiations began in 1969, and the first unit agreement was not completed until 1977.²⁷ It has been revised several times since then.²⁸ One serious problem facing the negotiators was how to value the natural gas in the gas cap, where ARCO and Exxon's leases happened to be clustered. Most of the oil was located in a zone below the gas cap, in a region referred to as the oil rim where BP's leases were concentrated. Given the remote position of the field and the absence of a natural gas pipeline, it was not clear whether gas would be sold in large amounts or kept in the reservoir to maintain natural subsurface pressure to assist in oil extraction.

Since the economic value of the gas resources was highly speculative, the parties searched in vain for a formula that would allocate to each party a fixed

25. The t -statistic is -3.03 (assuming unequal variances) and the critical value is 1.97. The results are similar if Prudhoe Bay is dropped from the analysis. The mean share difference is 2.98 with a standard deviation of 9.12. The mean share difference for the dual-PA units is still about three times that of the multiphase units.

26. A useful description of the Prudhoe Bay reservoir is found in Szabo and Meyers (1993).

27. A letter of intent to unitize was signed by the principal lease owners in August 1969. Negotiations continued on and off until the final agreement was reached in April 1977.

28. At least seven significant amendments to the Prudhoe Bay Unit Operating Agreement were adopted in the 1980s and 1990s largely to address disputes over natural gas and oil valuation, investment, and production. At times, outside arbitrators, the courts, and various state regulatory agencies were used to compel these changes.

share of all hydrocarbons produced from the reservoir [Alaska Oil and Gas Conservation Commission (AOGCC), April 12, 1996:238, 289, 951–56]. After 8 years of bargaining, an agreement was reached among the lease owners that designated two separate participating areas within the reservoir: each lease owner was allocated a fixed share of oil rim production and costs and a separate and numerically *different* share of gas cap production and costs. As Table 2 shows, BP, for example, was allocated 51% of production from the oil rim but only 14% of production from the gas cap.²⁹

Under this arrangement, gas cap owners became residual claimants to gas cap profits and oil rim owners became residual claimants to oil rim profits. None of the parties was made a residual claimant to the unit-wide profits. The formation of dual, competing participating areas within the single reservoir brought conflicts of interest, opportunistic behavior, and an intense battle over how the reservoir would be developed.

At the heart of the conflicts has been the inevitable competition between gas and oil lease owners. From the outset, the lease owners have been aware that the sale and removal of gas from the reservoir would impair ultimate recovery of oil because of the consequent loss of reservoir pressure. That cost falls disproportionately on BP (as majority owner of the oil rim). On the other hand, any gas reinjection program designed to maintain reservoir pressure or otherwise enhance the recovery of oil has the potential to divert marketable gas that could perhaps be sold elsewhere, and this burden falls disproportionately on ARCO and Exxon. These two companies have favored processing the gas that was produced in association with oil to extract as much natural gas liquids (NGL) as could be blended with oil for shipment and sale down the Trans-Alaska Pipeline. BP has favored processing the gas to produce miscible injectant (MI), which could be reinjected into the reservoir to enhance the recovery of remaining oil [AOGCC Conservation Order No. 360 (Prudhoe Bay Oil Field, Prudhoe Oil Pool), August 9, 1995 (revised November 3, 1995), paragraphs 73–74 (hereafter referred to as “AOGCC Order 360”)].

The ensuing competition among the respective firms illustrates the costs incurred when interests are not aligned. For example, on February 9, 1995, ARCO (acting as operator of facilities in the eastern region of the reservoir) unilaterally increased the production of NGLs for shipment down the pipeline. To offset ARCO’s initiative, BP (acting as operator of facilities in the western region of the reservoir) unilaterally restricted the volume of NGLs that it blended with the stream of crude oil entering the pipeline, thereby leaving the total shipment of NGLs from the Prudhoe Bay unit unchanged. In retaliation, ARCO then increased its own blending of NGLs into the crude oil stream, but BP again took offsetting action. In addition, BP filed a claim in the Alaska Superior Court that would permit the company to take its share of reservoir production

29. Costs assigned to each participating area were allocated among owners on the same basis as production.

in kind, thereby preventing ARCO from using that oil as a vehicle for increased blending of NGLs. BP also filed a request with the Alaska Public Utilities Commission for permission to construct a new pipeline within the reservoir to segregate and convey its share of the oil for shipment off the unit, prior to any further blending of NGLs. The pipeline was not necessary to develop the unit, only to protect BP's interests (AOGCC Order 360, 1995, paragraphs 135–136).

It is obvious that none of these actions was designed to increase the economic value of the PBU as a whole; indeed, these actions by the various parties in their own private interest have served to dissipate the rents of the unit. It was not the depletion of reserves that set Prudhoe crude oil production into decline in 1988. Rather the turning point in the life of the reservoir was caused by lack of agreement on who would pay for facilities to handle the growing fraction of gas that was produced in association with oil as the reservoir matured (see Szabo and Myers, 1993:4).

Although the parties have disagreed publicly about the ultimate cost of the contested plan to sell rather than reinject the produced NGL, the potential impact is apparently significant. By BP's estimate, maximum reinjection of the gas would boost ultimate recovery of liquid hydrocarbons by some 150–200 million barrels. In BP's view, ARCO's proposal to divert a portion of the injected gas for sale as NGL would decrease ultimate recovery by 60–80 million barrels (AOGCC Order 360, 1995, paragraphs 59 and 62). To put these numbers in perspective, consider that any single oil reservoir with as much as 100 million barrels of recoverable reserves is considered a "giant" relative to the size distribution of all U.S. oil and gas reservoirs (see Nehring, 1981:13–15).

5. Concluding Remarks

In this article we have extended the theory and empirical analysis of unitization agreements that address common-pool losses in oil and gas production. We have isolated the key elements of the unit operating agreement that are necessary to align incentives among the working interests in order to maximize the economic value of the reservoir. We also identified the geological/informational conditions that could impede agreement on complete unit contracts and lead instead to the writing of different contracts where production and investment incentives would differ among firms. Such differences would lead potentially to conflicts and behavior that dissipated reservoir rents. Evidence from 60 unit operating agreements has been used to examine implications of the theoretical framework. In addition, the case study of the Prudhoe Bay unit illustrates the discord and waste that occurs when the interests of the parties are not aligned.

The analysis highlights the importance of achieving incentive compatibility in drafting unit contracts and the corresponding self-enforcement of cooperative group behavior such contracts can bring. Agreeing on a profit-sharing formula that binds the interests of the parties over the long term, however, is not always possible. This condition appears to be particularly evident when holdings on the reservoir are heterogeneous with respect to kind—when some parties

own primarily oil and others primarily gas. Disagreement on the terms of exchange of gas for oil typically result in the partitioning of the reservoir into distinct and competing participating areas with separate production and cost allocation formulas. In effect, the parties become separate groups of share holders in segments of the same oil and gas reservoir. The potential for wasteful competition is clear.

Firms write unit contracts with dual PAs when there are very skewed holdings of oil and gas within a reservoir and when agreement on a single participating area and profit-sharing formula is not forthcoming. State regulatory agencies are then faced with a trade-off: endorsing a unit agreement with a dual PA in order to facilitate earlier, albeit incomplete, cooperative development of the reservoir or forcing the parties to continue to negotiate until a complete unit agreement can be written. Hence regulatory agencies must weigh the costs of conflicting incentives and associated rent dissipation with dual-PA units against the costs of delaying the formation of a unit until a complete, incentive-compatible agreement can be written. This latter case might mean delaying reservoir development and production. The outcome of balancing these costs likely will vary from case to case. Nevertheless, this article has made clear for the first time the contracting problems and costs that are linked to dual-PA units. This information can be of use in the regulatory process.

Our analysis has also shown that, by contrast, multiphase units do not typically have the same incentive problems found in dual-PA units. When production is partitioned across primary and secondary recovery periods, with different sharing formulas during each period, unit operating agreements still have profit-sharing arrangements for the whole unit during each period. The transition from one phase to the next is managed through the use of a preset contractual trigger, and there is little apparent effort by the owners to opportunistically maneuver across phases. In effect, the parties are shareholders in the entire reservoir during each phase, although their shares may differ by small amounts from one phase to another.

The theory and analysis presented here provides new insights into the process of unitization and the writing of oil and gas contracts. We are not arguing that cooperative agreements for other empirical settings, such as crop share contracts, have the same profit-sharing characteristics we have described here.³⁰ In particular, the geological/informational aspects responsible for the partitioning units in our sample may be unique to the oil and gas context. Rather, our examination of oil and gas unitization contracts illustrates the important role that the *content* of contracts can make in aligning incentives *ex ante* to reduce enforcement costs and promote wealth maximizing behavior *ex post*. Further, the analysis of unitization contracting points out the dangers of partitioning heterogeneous parties into more homogeneous subgroups during contract negotiation. Although,

30. Allen and Lueck (1993), for example, examine the conditions under which profit or output sharing is optimal in crop share contracts.

such clustering may facilitate agreement within the subgroup, the agreed-to provisions may not be incentive compatible for the entire group. Hence, the overall contract will be incomplete and faced with compliance problems.

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