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The opening section of this paper briefly reviews the rule of capture and some of the problems arising from it. The second section discusses conservation statutes designed to address some of those problems. The second section put a particular emphasis on state pooling and spacing statutes, noting the numerous similarities between the various jurisdictions' statutes, but also noting the significant differences, such the statutes' treatment of mineral interest owners who choose not to participate in the cost of a well. The third section examines state regulation of federal lands, including the circumstances in which state laws purporting to regulate federal lands are preempted. Finally, the fourth section reports on trends in selected states with respect to the application of spacing and pooling rules in shale plays.

**I. Introduction - The Rule of Capture and Problems Arising From It**

In the United States, the owner of land in fee simple absolute typically has the exclusive right to conduct ***oil*** and gas exploration and production activities on and below his land.[[1]](#footnote-2)1 This follows from the common law's "*ad ceolum*" doctrine, which provides that the owner of land owns not just the surface, but the entire airspace above it and the entire subsurface below it.[[2]](#footnote-3)2 The doctrine's name comes from the Latin phrase "*cujus est solum ejus est usque ad coelum et ad inferos*," which has been translated as "for whoever owns the soil, it is theirs up to Heaven and down to Hell."[[3]](#footnote-4)3

But unlike the soil itself, which is solid and typically remains in place beneath a particular tract of land, ***oil*** and natural gas generally exist in a fluid state - either liquid or gas - and can move in response to differences in pressure. This can make production of those substances easier because they will flow to a well from the surrounding subsurface, but such "drainage" of ***oil*** or gas from the surrounding subsurface can also lead to disputes between neighbors. For example, suppose that Black, the owner of Blackacre, drills a well on his land, near the border with Whiteacre, a tract owned by his neighbor, White. Black's well begins producing ***oil*** at a substantial rate, with much of the ***oil*** likely being drained from beneath Whiteacre. Is Black entitled to operate the well and keep all the proceeds, or is White entitled to some type of relief - perhaps either an injunction to prohibit Black from operating the well or a judgment requiring Black to share the proceeds with White?

Courts began facing this issue in the late 1800s.[[4]](#footnote-5)4 Across the United States, courts resolved such disputes by adopting what became known as the "rule of capture."[[5]](#footnote-6)5 The rule of capture provides that the owner of land acquires title to all of the ***oil*** and gas produced from a well drilled on his land, even if the well causes drainage of ***oil*** and gas from beneath a neighbor's land, and that the neighbor is not entitled to compensation for such drainage.[[6]](#footnote-7)6 Courts justified the rule of capture of three grounds: (1) it was impossible to determine how much ***oil*** or gas drained from beneath a neighbor's land; (2) it would interfere with private property rights and development for a court to prohibit a landowner from drilling a well where he chose on his land; and (3) the neighbor had a self-help remedy - he could drill his own offset wells to "protect his lines."[[7]](#footnote-8)7

The rule of capture might have been the most practical rule that courts could develop on their own, but it also created certain problems. It created incentives for neighboring landowners to produce ***oil*** and gas as quickly as they could, before the neighbor did so. This often promoted individuals to drill more wells than were need to efficiently drain an area.[[8]](#footnote-9)8 This led to economic waste in the form of excessive spending on drilling. Further, too rapid a rate of production can result in inefficient use of the reservoir energy that can help transport ***oil*** up to the surface.[[9]](#footnote-10)9 The inefficient use of such energy could result in less ***oil*** being produced from a field than could be produced if the reservoir energy was more efficiently used. Thus, more ***oil*** might be left in the ground, a form of physical waste. Finally, although a landowner always has the self-help remedy drilling his own well, some people might question the fairness of the rule of capture.[[10]](#footnote-11)10

**II. State Conservation Statutes and Single Well Pooling**

Starting in the early 1900s, states and the federal government began taking steps to avoid wasteful use of a wide variety of natural resources. The enactment of conservation statutes and regulations directed toward avoiding waste of ***oil*** and natural gas resources started to become common by the 1930s and 1940s.[[11]](#footnote-12)11 Common types of regulation included creation of allowables (maximum allowable rates of production from wells) and "spacing" rules that placed limitations on well density. The spacing rules included minimum distances between a well and the nearest property line, minimum distances between wells, and in some cases, a maximum number of wells in a specified area (for example, no more than one well for a given number of acres).

But the spacing rules could create a problem. Suppose, for example, that a spacing rule prohibited drilling a well any closer than 330 feet from the nearest property line. Strict enforcement of such a rule would prohibit drilling altogether on small tracts. That could be unfair to the owner of small tracts. Further, given that the right to explore for and develop minerals is a property right, strict enforcement of such spacing rules could result in a taking of private property that might be unconstitutional in the absence of some compensation.[[12]](#footnote-13)12 One response to this problem is "pooling." In pooling, two or more separately-owned tracts are figuratively "combined" for the purposes of creating an area large enough to obtain a well permit under applicable spacing regulations.[[13]](#footnote-14)13

**A. Drilling and Spacing Units**

Numerous states have statutes that authorize conservation agencies to issue orders creating drilling or spacing units - areas of land where the only well or wells allowed will be those authorized by the agency.[[14]](#footnote-15)14 The statutes typically provide that the agency may create drilling or spacing units that will apply with respect to a common source of supply,[[15]](#footnote-16)15 after notice and a hearing,[[16]](#footnote-17)16 if the agency determines that such a unit is necessary to prevent waste,[[17]](#footnote-18)17 avoid the drilling of unnecessary wells,[[18]](#footnote-19)18 and protect correlative rights[[19]](#footnote-20)19 (correlative rights are the rights of owners in a common pool to have the opportunity to produce their fair share of ***oil*** or gas from the pool[[20]](#footnote-21)20 The statutes often state that either that a drilling unit should be the maximum size that can be efficiently drained by one well,[[21]](#footnote-22)21 or that a drilling unit must be no smaller than that size.[[22]](#footnote-23)22

**B. Statutory Pooling**

The language of statutes authorizing state conservation agencies to issue orders pooling interests and creating drilling units varies from state to state, but there are several features that are common.[[23]](#footnote-24)23 The language of pooling statutes typically suggest that the statutes apply only if two or more separately-owned tracts or separately-owned mineral interests exist within a drilling unit.[[24]](#footnote-25)24 This makes sense because, unless there are separately-owned interests, there is no need for a pooling of interests.

Pooling statutes typically state that:

in the absence of voluntary pooling, the conservation agency can pool interests[[25]](#footnote-26)25

an application for statutory pooling must be made by someone with an interest in the drilling unit[[26]](#footnote-27)26

notice must be given and a public hearing must be held prior to the conservation agency issuing a pooling order[[27]](#footnote-28)27

pooling orders must be on terms that are just and reasonable[[28]](#footnote-29)28

pooling orders must allow each owner of a tract or interest in the drilling unit the opportunity to recover or receive, without unnecessary expense, his just and reasonable share of production from the common pool[[29]](#footnote-30)29

operations incident to the drilling of a well are deemed to be operations on each separately owned tract in the unit[[30]](#footnote-31)30

the share of production allocated to each tract in the drilling unit will be deemed as having been produced from that tract.[[31]](#footnote-32)31

**C. Allocation of Production Under Pooling Statutes**

The regulator has authority to allocate production to the various tracts within the pooled unit. Often, allocation will be on a surface acreage basis - that is, each tract will be allocated a fraction of production that is equal to that tract's fraction of the total acreage in the unit.[[32]](#footnote-33)32 If, however, an allocation of production on a surface acreage basis will not yield a fair allocation, the regulator typically has authority to allocate production on some other basis.[[33]](#footnote-34)33 If production is not allocated on a surface acreage basis, it may be allocated on the basis of the estimated reserves in place beneath each tract[[34]](#footnote-35)34 Of course, the net proceeds actually paid to each tract generally will be less than the gross proceeds allocated to that tract because a portion of costs also will be allocated to each tract.

**D. Sharing of Costs and Consequences of Failure to Participate in Costs of Drilling**

Drilling wells carries economic risk - often wells are either dry holes or wells that produce ***oil*** and gas, but not enough to recover the costs of drilling. The owner of mineral interests in a pooled unit should not be forced to participate in that risk. This leads to a question - if a particular owner chooses not to participate in that risk, what share (if any) of the proceeds from a productive well should the non-participating owner receive? One possibility is a rule that an owner who refuses to participate in a well would be forever precluded from receiving a share of production or any other compensation. But arguably that is unfair because even the owners who do not participate in the well have "contributed" something to the pooled unit, namely their acreage, and states have not chosen to adopt such a rule.

On the other hand, it would be grossly unfair for a person who owned 10% of the acreage in a unit to receive 10% of gross production, free of costs, if he refused to participate in the well. Thus, at most, the nonparticipating owner in such circumstances should receive 10% of proceeds, net of drilling, completion, and operating costs. Arguably, however, payment of 10% of net proceeds would over-compensate the nonparticipating owner because he took no risk. Perhaps that nonparticipating owner should receive less than 10% of net proceeds, so that some additional compensation can be given as a reward to the owners who participated in the well, thereby incurring economic risk and making the drilling of the well possible. States typically take one of three approaches to the question of how nonparticipating owners should be compensated. The three basic approaches are the: (1) risk-fee; (2) surrender of working interest; and (3) free ride.[[35]](#footnote-36)35

**1. Risk-Fee Approach**

The most common approach taken by states is to utilize a risk-fee, which is sometimes called a "risk charge" or a "risk-penalty."[[36]](#footnote-37)36 Under this approach, state law authorizes the regulator or the operator to give the non-operators who own exploration and production rights within the compulsory pooling unit an opportunity to participate in the costs of drilling and completing the well. If a non-operator fails to participate, that non-operator's interest is treated as a "carried interest." That is, the parties who are participating in costs will "carry" the non-participating party's share of drilling costs, and the non-participating party will not be liable for any costs of drilling in the event that the well is a dry hole or fails to fully pay for itself.

Of course, if the well is productive, the operator may recover the non-participating party's share of drilling, completion, and operating costs from that party's share of production. But in addition, the operator may recover a risk-fee from the non-participating party's share of production. The risk-fee compensates the operator for the risk it took, but which the non-operator chose not to take. The risk-fee typically will be some multiple of drilling and completion costs or specified types of drilling and completion costs.

States that follow the risk-fee approach include Alabama,[[37]](#footnote-38)37 Colorado,[[38]](#footnote-39)38 Louisiana,[[39]](#footnote-40)39 Michigan,[[40]](#footnote-41)40 Mississippi,[[41]](#footnote-42)41 Montana,[[42]](#footnote-43)42 Nebraska,[[43]](#footnote-44)43 Nevada,[[44]](#footnote-45)44 New Mexico,[[45]](#footnote-46)45 New York,[[46]](#footnote-47)46 North Dakota,[[47]](#footnote-48)47 Ohio,[[48]](#footnote-49)48 Texas,[[49]](#footnote-50)49 Utah,[[50]](#footnote-51)50 and Wyoming.[[51]](#footnote-52)51

In some states that use the risk-fee approach, the amount of the risk-fee multiple - for example, is it 50%, 100%, or 200%, 300% etc. - is set by statute.[[52]](#footnote-53)52 In other states, the regulator is given the authority to set the risk-fee multiple.[[53]](#footnote-54)53 Because the operator will be allowed to recover its reasonable costs associated with the well,[[54]](#footnote-55)54 plus the risk-fee multiple of certain types of costs, it is important to define what types of costs are subject to the risk fee. Some state statutes give somewhat detailed definitions, while others are more general.[[55]](#footnote-56)55 The regulator typically will have authority to resolve disputes regarding whether costs are reasonable or subject to the risk-fee,[[56]](#footnote-57)56 though parties will have a right to seek judicial review of the regulator's decision.

**2. Surrender of working interest Approach**

Some states, such as Oklahoma, use a "surrender of working interest" approach. Under this approach, each owner of a working interest is given the option to participate in drilling costs. An owner that fails to participate is deemed to have surrendered his working interest to the operator in return for compensation, such as a bonus, royalty, or both.[[57]](#footnote-58)57 Effectively, this approach brings about an assignment of the non-participating lessee's lease rights or a lease of the unleased owner's interest. The amount of compensation to be paid for the surrender of a working interest is determined by the Oklahoma Corporation Commission. The Commission may, as an alternative, allow the non-participating working interest owner the option of paying a risk-fee,[[58]](#footnote-59)58 though the Commission is not required to offer that option.[[59]](#footnote-60)59 Oklahoma statutes do not expressly grant the Corporation Commission the authority to utilize the surrender-of-working-interest approach. Oklahoma's statute requires the Corporation Commission to allocate costs on a fair basis. The Corporation Commission developed the surrender-of-working-interest approach by way of its orders, and the Commission's use of the approach has been upheld by the Oklahoma Supreme Court.[[60]](#footnote-61)60

Several states have adopted the same general approach by statute, including Arkansas,[[61]](#footnote-62)61 Idaho,[[62]](#footnote-63)62 Illinois,[[63]](#footnote-64)63 Kentucky,[[64]](#footnote-65)64 Pennsylvania,[[65]](#footnote-66)65 South Dakota,[[66]](#footnote-67)66 and West Virginia.[[67]](#footnote-68)67 Those statutes give the working interest owner the option to participate, surrender its working interest in return for compensation, or to be carried and pay a risk fee out of its share of production.

**3. Free Ride Approach**

The final approach sometimes is called the "free ride" approach.[[68]](#footnote-69)68 This approach applies when states have not adopted some other approach by statute or regulation.[[69]](#footnote-70)69 In such circumstances, the various persons holding mineral interests within the pooled unit are treated as common law cotenants.[[70]](#footnote-71)70 None may be forced to participate in the risk of drilling, and each is entitled to its proportionate share of drilling, subject only to a deduction of that owner's proportionate share of expenses from his share of production.[[71]](#footnote-72)71 States that follow this approach include Alaska,[[72]](#footnote-73)72 Arizona,[[73]](#footnote-74)73 Indiana,[[74]](#footnote-75)74 and Missouri.[[75]](#footnote-76)75 There are other states that have failed to adopt some other approach in their statutes or regulations, but those states have little ***oil*** and gas activity and thus are less relevant in this context.[[76]](#footnote-77)76

**E. Differing Treatment of Leaseholders and Owners of Unleased Mineral Interests**

Some states give more favorable treatment to non-participating owners of unleased interests than to non-participating owners of mineral leaseholds.[[77]](#footnote-78)77 For example, in Louisiana, non-participating lessees are subject to a risk-fee, but owners of unleased interests get a free ride, subject only to his payment of his proportionate share of costs out of his share of production.[[78]](#footnote-79)78

In Colorado, non-participating owners of mineral leases are subject to a risk-fee.[[79]](#footnote-80)79 A non-participating owner of an unleased interest is treated as owning a one-eighth royalty interest and a seven-eighths working interest (that is subject to a risk fee) in the rights associated with his tract.[[80]](#footnote-81)80 Accordingly, an unleased owner will receive one-eighth of the production attributable to his tract from first production, with the other seven-eighths going to pay the proportionate share of costs and the risk fee associated with seven-eighths of his total interest. After his proportionate share of costs and risk fee has been paid, he is entitled to eight-eighths of the production attributable to his tract.[[81]](#footnote-82)81 Montana follows the same approach,[[82]](#footnote-83)82 and Utah also follows this approach, but rather than treating the unleased owner as being the owner of a one-eighth royalty interest and a seven-eighths working interest in his tract, Utah treats him as being the owner of a royalty interest equal to the weighted average royalty applicable in leased tracts contained within the unit.[[83]](#footnote-84)83

**F. Treatment of Royalty Interests and Burden of Paving Royalty Interests**

In some states, it is unclear how royalty interests will be treated because the state's statutes do not address the subject and there has been little or no litigation on the issue.[[84]](#footnote-85)84 But some state statutes do address the issue. For example, a Utah statute provides that the participating owners pay any royalty owed on the production attributable to a tract under lease to a non-participating lessee.[[85]](#footnote-86)85 Under Louisiana law, a non-participating leaseholder used to be responsible for paying to his lessor any lease royalties owed on unit production that would have been attributable to the lease tract, even though the non-participating lessee was not receiving any share of production.[[86]](#footnote-87)86 But Louisiana's risk-fee statute was amended in 2012 to provide that the operator must pay to a non-participating leaseholder an amount sufficient to pay that lessee's lease royalty obligations,[[87]](#footnote-88)87 and in certain circumstances the operator must pay enough to cover all or a portion of any overriding royalties owed by the nonparticipating leaseholder.[[88]](#footnote-89)88

**G. Changes to Unit Orders**

Conservation agencies generally have authority to revise any pooling or drilling unit orders that they previously have entered.[[89]](#footnote-90)89 A revision may involve an increase or decrease in the size of a unit, a change in the shape of the unit, a change in location of the unit well, or the authorization of one or more substitute or additional wells.[[90]](#footnote-91)90 Typically, the procedure for revising an order is the same as that for entering the initial order[[91]](#footnote-92)91 - thus, if notice and a public hearing was required for the initial order, notice and a hearing likely will be required for a revision of the order.

In some states, a proposal to revise prior pooling or drilling unit orders will be considered an impermissible collateral attack and will be barred, absent a change in circumstance or the availability of new information. In Oklahoma, for example, a series of cases holds to this rule.[[92]](#footnote-93)92 Courts in Texas[[93]](#footnote-94)93 and Mississippi[[94]](#footnote-95)94 have followed similar rules. It should be noted, however, that even in jurisdictions that require a change in circumstances or information before a unit or pooling order can be revised, do not apply this rule to orders that are more akin to a general rule-making, as opposed to an adjudication or quasi-adjudication and rights and circumstances relating to specific units and parties.[[95]](#footnote-96)95

Changes to unit boundaries will have adverse effects on some parties and therefore may be opposed. An order enlarging a unit will dilute the interests of those already within the unit.[[96]](#footnote-97)96 An order decreasing the size of the unit will eliminate or reduce some parties' participation in the unit. A reduced size may also mean that some lessees must drill additional wells if they wish to maintain leases. If evidence indicates that increased well density is appropriate, an alternative to decreasing the size of existing units is to authorize additional wells in the existing units.[[97]](#footnote-98)97 Such wells sometimes are called "infill" wells.[[98]](#footnote-99)98 In Louisiana, such wells are called "alternate unit wells.[[99]](#footnote-100)99

When additional unit wells are permitted, an issue that sometimes arises is whether parties who chose not to participate in an earlier well can participate in the additional wells. In some jurisdictions, such parties might not be entitled to participate in subsequent wells if they have declined to participate in the initial well.[[100]](#footnote-101)100

**H. Necessity of Notice and Hearing Before Entry of Pooling or Drilling Unit Order**

Before a pooling or drilling unit order is entered, the regulator must hold a hearing after notice to interested parties.[[101]](#footnote-102)101

**I. Use of Property of Unleased Interest**

Sometimes parties dispute whether a unit operator can use a tract located in the drilling unit without permission of the landowner if the operator does not have a lease of the property. In some circumstances, the operator does have that right.

*Texas* ***Oil*** *and Gas Corp. v. Rein*, 534 P.2d 1277 (Okla. 1974) concerned operations in a drilling unit that the Oklahoma Corporation Commission previously had created. The operator drilled a well at the center of the unit, but evidence showed that the well was not effectively draining ***oil*** and gas from the unit.[[102]](#footnote-103)102 The operator then applied for and obtained a permit to drill a well at a new location in the unit. The new location was on land owned by the plaintiff. His land was not under lease to the operator and the plaintiff opposed the use of his property.[[103]](#footnote-104)103

The plaintiff argued that the Corporation Commission had no authority to authorize the operator to enter his property and drill a well without his consent. The Oklahoma Supreme Court disagreed. The court noted that Oklahoma law authorizes the Corporation Commission to create units and specify the location for a unit well. The court concluded that, if an operator needed a lease or the landowner's permission to drill at the location designated by the Commission, a landowner could defeat the purpose of Oklahoma's conservation laws. Accordingly, the Corporation Commission has the authority "to pool the working interests within the spacing unit and designate an operator to drill and operate the well at the designated location."[[104]](#footnote-105)104

A subsequent case before the Oklahoma Supreme Court addressed the question whether the owner of an unleased tract has a cause of action for surface damages caused by a unit operator.[[105]](#footnote-106)105 In *Cormack v. Wil-Mc Corp.*, the defendant obtained a permit from the Corporation Commission to drill a unit well at a location on the plaintiff's property.[[106]](#footnote-107)106 The operator drilled a well at the designated location and also built a road, pits, and tank battery on the plaintiff's land. The plaintiff filed suit seeking to recover $3500 for surface damages. The trial court sustained the defendant's demurrer and dismissed the case. The plaintiff appealed.

Implying that the operator's use of the surface was reasonably necessary, the Oklahoma Supreme Court noted that, "The general rule in Oklahoma is absent a contrary provision in the mineral lease, a lessee has no liability to his lessor for surface use necessary and incident to the extraction of minerals."[[107]](#footnote-108)107 The court explained that a mineral lease contains this right by implication, absent a provision otherwise, because use of the surface generally is necessary in order for the mineral lessee to extract minerals. Thus, "the rights to the minerals would be worthless" unless the lessee also had the right to use the land as reasonably necessary to produce minerals.

Further, the parties to a lease understand or should understand this. For this reason, it is presumed that "the lessor negotiates a price for his lease that includes compensation for damages to the surface which both parties contemplate at the time."[[108]](#footnote-109)108 Or, "[i]f desired, the lessor can negotiate into the contract a provision requiring the lessee to compensate him for damages to the surface caused by ***oil*** and gas exploration."[[109]](#footnote-110)109 But if there is no lease, the landowner or mineral rights owner does not have the opportunity to do that.

Further, the court stated that an unleased tract on which a unit well is drilled bears a disproportionate share of the burdens associated with ***oil*** and gas development. The court believed that the situation in which a unit well is drilled on one of several tracts located within the unit is analogous to the situation in which the owners of adjacent tracts join in granting a community ***oil*** and gas lease and a well is drilled on one of the tracts.[[110]](#footnote-111)110 The court quoted from an ***oil*** and gas treatise which stated that, in the community lease situation, "Where the drilling and other operations are all conducted on one tract, the owner of that tract bears an undue burden for the benefit of the community lessors, unless some adjustment is made."[[111]](#footnote-112)111 Noting again that the plaintiff had not granted a lease or consented to the use of his property, the court stated that it would violate the Takings Clause of the Oklahoma Constitution "to force him to accept this 'undue burden' without just compensation."[[112]](#footnote-113)112

Courts have reached a similar result in Louisiana. In *Nunez v. Wainoco* ***Oil*** *& Gas Co.*, 488 So. 2d 955 (La. 1986), the Commissioner of Conservation created a 350-acre unit and concluded that the optimum location for a well would be in the western portion of the unit.[[113]](#footnote-114)113 The operator had secured several leases in that area, but that general area also included an unleased tract owned by the plaintiff. The plaintiff had declined to grant a lease, preferring to remain unleased, hoping to obtain 100% of the production attributable to his tract, rather than a lease royalty on that amount.[[114]](#footnote-115)114

The Commissioner granted the operator a drilling permit for a location on land belonging to the plaintiff's neighbor, near the property line, and the operator eventually drilled a well pursuant to that permit at a location about twenty feet from the property line.[[115]](#footnote-116)115 The plaintiff agreed to participate in the cost of the well, which was drilled to a depth of approximately 11,730 feet. A directional survey indicated that the well crossed into the subsurface of the plaintiff's land at a depth of about 10,000 feet, that the wellbore crossed back into the neighbor's subsurface at a deeper depth, and that finally the wellbore had crossed back into the plaintiff's subsurface at about 11,000 feet. The bottom of the well was about 4 or 5 feet into the plaintiff's subsurface.[[116]](#footnote-117)116

The plaintiff filed suit, alleging that the wellbore was trespassing onto his property. He sought an injunction ordering the operator to remove the wellbore.[[117]](#footnote-118)117 The case reached the Louisiana Supreme Court. The court acknowledged a landowner generally is considered to own everything that is beneath his land,[[118]](#footnote-119)118 and that an operator's actions that cause a well to bottom beneath someone else's land generally would constitute a subsurface trespass.[[119]](#footnote-120)119 But Louisiana's conservation laws authorize the Commissioner of Conservation to create drilling units, to pool interests contained within the unit, and to select the optimum location for a well within the unit.[[120]](#footnote-121)120 The court concluded that these statutes modify the rule of trespass and that the plaintiff had no cause of action for trespass.[[121]](#footnote-122)121 The court stated, though, that if unit operation caused a landowner "particular expense, as a result of damage to his premises, or measurable inconvenience, the landowner may be entitled to recover compensation in addition to a proportionate share of production."[[122]](#footnote-123)122

Some of the Louisiana Supreme Court's language in *Nunez* emphasized that the intrusion into the plaintiff's land occurred 10,000 feet beneath the surface, rather than at the surface. But most of the court's reasoning would apply equally to a plaintiff's complaint that an operator had intruded onto the surface of the plaintiff's land while conducting reasonably necessary mineral operations. And indeed, Nunez later asserted a trespass claim against the operator based on an alleged trespass occurring at the surface.[[123]](#footnote-124)123 Nunez alleged that the operator had located a "mud pit, ring levee, water pit, water well, machinery, pipe, board road, derrick and other equipment necessary for drilling" on his property.[[124]](#footnote-125)124 Based on the Louisiana Supreme Court's decision in the earlier *Nunez* case, the Louisiana Third Circuit concluded that the plaintiff could not maintain an action for trespass, but that he would be entitled to recover for any damages he sustained. Unfortunately for the plaintiff, the trial court concluded that he had not proven that he sustained any damages and the appellate court affirmed that ruling.[[125]](#footnote-126)125

The North Dakota Supreme Court similarly has concluded that pooling and drilling unit orders supersede traditional rules of subsurface trespass.[[126]](#footnote-127)126 In *Continental Resources, Inc. v. Farrar* ***Oil*** *Co.*, the North Dakota Industrial Commission created a 640 acre unit whose boundaries coincided with a survey section.[[127]](#footnote-128)127 The area was one in which operators were using horizontal drilling. Continental Resources held leases in the northwest and southeast quarters of the section, but Farrar ***Oil*** held leases in the northeast and southwest. The Commission granted Continental a permit to drill a well, and the company proposed drilling a horizontal well that would pass beneath both companies' leased areas. Farrar took the position that Continental would commit a subsurface trespass it any well that it drilled crossed into the subsurface of land that it had under lease.[[128]](#footnote-129)128

Continental filed an action seeking a declaratory judgment that it would not commit a subsurface trespass if it drilled the proposed well. The trial court agreed and entered judgment for Continental. Farrar appealed, but the North Dakota Supreme Court affirmed. Citing and *Texas* ***Oil***, the court stated that the Commission's pooling order superseded the traditional rules of trespass and that, "[t]o hold otherwise ... would frustrate the purposes of the North Dakota Resource Act and would make an Industrial Commission's forced pooling order ineffectual."[[129]](#footnote-130)129

**III. BLM's Supervision of Federal Lands, State Regulation of those Lands, and Preemption**[[130]](#footnote-131)130

The "Property Clause" is contained in Article IV, Section 3, clause 2 of the United States Constitution. It states: "The Congress shall have Power to dispose of and make all needful Rules and Regulations respecting the Territory or other Property belonging to the United States; and nothing in this Constitution shall be so construed as to Prejudice any Claims of the United States, or of any particular State." The United States Supreme Court has stated that this clause gives *Congress* unlimited authority to regulate federal lands, but that the Constitution does not exempt federal lands from state regulation. Thus, to determine whether a particular state regulation of federal lands is enforceable, a traditional preemption analysis must be employed.[[131]](#footnote-132)131

State law can be preempted in one of three main ways. First, under "express preemption," state law is preempted if federal law expressly declares an intent to exclude or displace state law on a subject.[[132]](#footnote-133)132 Under field preemption, state law is preempted if federal law governing a field is sufficiently comprehensive to support a reasonable inference that Congress "left no room" for state regulation and intended for federal law to occupy the entire field.[[133]](#footnote-134)133 Finally, under "conflict preemption," a state law is preempted if it conflicts with federal law, so that it is impossible to comply with both federal and state law or "state law stands as an obstacle to the accomplishment of the full purpose and objectives of Congress."[[134]](#footnote-135)134

There is no United States Supreme Court jurisprudence relating specifically to the application of state pooling, spacing, or drilling unit rules to federal lands. Below, this paper examines: (1) Supreme Court jurisprudence relating to the application of other types of state laws to federal lands; and (2) lower court jurisprudence on the application of state pooling, spacing, and drilling unit rules to federal lands.

**A. United States Supreme Court Jurisprudence Regarding the Application of State Laws to Federal Lands**

Supreme Court jurisprudence includes both cases in which the court found that state or local efforts to regulate federal lands was preempted and cases in the Court found that there was no preemption.

**1. *Kleppe* - An example of preemption**

Several United States Supreme Court cases deal with the authority of states to apply their regulations on federal land. *Kleppe v. New Mexico*, 96 S. Ct. 2285 (1976) was a dispute involving wild burros. In 1971, Congress enacted the Wild Free-roaming Horses and Burros Act to protect "all unbranded and unclaimed horses and burros on public lands of the United States" from "capture, branding, harassment, or death."[[135]](#footnote-136)135 A few years later, a rancher who possessed a permit to graze his cattle on federal land, discovered that a number of wild burros were present near a well where he watered his cattle.[[136]](#footnote-137)136 The rancher complained to the New Mexico Livestock Board. The Livestock Board, consistent with its past practices, captured about 19 wild burros from the area and sold them at public auction.[[137]](#footnote-138)137

The Bureau of Land Management demanded that the Livestock Board recover the burros and return them to public lands. The Livestock Board field suit in federal court, seeking a declaratory judgment that the Act was unconstitutional.[[138]](#footnote-139)138 The Livestock Board argued that the Property Clause grants Congress the power to enact legislation to protect public lands, but that the Congress' power under the Property Clause does not authorize federal legislation to protect wild animals who happen to live on federal land and that Congress' other powers do not authorize legislation to protect wild animals that do not affect interstate commerce. The lower court ruled in favor of the Livestock Board, and the case went to the United States Supreme Court.

The Court rejected the Livestock Board's argument that the Property Clause only authorizes federal legislation to protect federal lands. The Court stated that the Congress' authority to regulate public lands under the Property Clause is "without limits."[[139]](#footnote-140)139 The Court went on to state that the Property Clause does not preclude the application of state laws on federal lands, but that whenever state laws conflict with federal laws, a preemption analysis based on the Supremacy Clause commands that federal law must prevail.[[140]](#footnote-141)140 Here, the regulations and practices of the Livestock Board directly conflicted with the federal statute's restriction on the "capture" of wild, unbranded and unclaimed burros on federal lands. Accordingly, the Court reversed the lower court's judgment in favor of the Livestock Board.[[141]](#footnote-142)141

Local regulation was also held to be preempted in *Ventura County v. Gulf* ***Oil*** *Corp*., 601 F.2d 1080 (9th Cir. 1979), *aff'd*, 100 S. Ct. 1593 (1980). In that case, the Bureau of Land Management granted a lease in 1974 covering 120 acres of land within the Los Padres National Forest in Ventura County, California for ***oil*** and gas exploration and development.[[142]](#footnote-143)142 The Department of Interior issued a drilling permit to Gulf, which had received an assignment of the lease. The U.S. Forest Service also gave its permission to drill, and California state regulators gave their approval. Gulf commenced drilling in 1976 and completed a productive well.[[143]](#footnote-144)143

Throughout this period, the leased property was zoned "Open Space" by Ventura County. The County's zoning ordinances prohibited ***oil*** and gas drilling within an Open Space zone unless the operator obtained a permit from the Ventura County Planning Commission. The requirements for obtaining such a permit included 11 mandatory conditions and the Planning Board had discretion to impose whatever additional conditions it chose.[[144]](#footnote-145)144

About a week after Gulf commenced drilling operations, the County informed Gulf that it must obtain a permit if it wished to continue drilling. After Gulf indicated that it did not intend to comply, the County brought suit in state court.[[145]](#footnote-146)145 Gulf removed the case to federal court, and the district court dismissed the County's suit.[[146]](#footnote-147)146 The County then appealed.

The Ninth Circuit affirmed, finding that the zoning ordinance was preempted.[[147]](#footnote-148)147 The appellate court noted that several paragraphs of the federal lease imposed requirements for environmental protection. Further, the lease required Gulf to abide by several conditions imposed by the Forest Service to combat environmental hazards. The lessee was required to obtain permits from the Department of Interior and the Forest Service. Moreover, the Department of Interior and the Forest Service each imposed various conditions designed to protect the environment when they approved Gulf's drilling permits.[[148]](#footnote-149)148 Finally, extensive regulations by the Department of Interior and the Forest Service also governed Gulf's drilling.[[149]](#footnote-150)149

The appellate court concluded that Ventura County's local regulation conflicted with this extensive body of federal regulation and control. The court focused on the fact that Ventura's regulation would essentially give it veto authority over development on federal lands. The court stated:

Despite this extensive federal scheme reflecting concern for the local environment as well as development of the nation's resources, Ventura demands a right of final approval. Ventura seeks to prohibit further activity by Gulf until it secures an Open Space Use Permit which may be issued on whatever conditions Ventura determines appropriate, or which may never be issued at all. The federal Government has authorized a specific use of federal lands, and Ventura cannot prohibit that use, either temporarily or permanently, in an attempt to substitute its judgment for that of Congress.[[150]](#footnote-151)150

The court stated that local concerns would not be ignored - they would be addressed through the NEPA process - and that the court was simply "rejecting a local veto power."[[151]](#footnote-152)151 The United States Supreme Court affirmed the decision in a one-word opinion that simply stated "Affirmed."[[152]](#footnote-153)152

**2. *Granite Rock* - An example of no-preemption**

*California Coastal Commission v. Granite Rock Co*., 107 S. Ct. 1419 (1987) presented the question whether federal law preempted the California Coastal Commission's requirement that a company obtain a permit from the Commission before conducting certain mining claims in a national forest. Under federal law, if a person finds a valuable mineral deposit on federal land, and he takes certain steps to "perfect" his claim, he may obtain "the exclusive right of possession and enjoyment of all the surface included within the lines of their locations."[[153]](#footnote-154)153

A company named "Granite Rock" obtained mining claims on federal land on and around Mount Pico Blanco in the Los Padres National Forest. From 1959 to 1980, Granite Rock removed small amounts of limestone from the area for analysis. In 1980, pursuant to federal regulations, Granite Rock submitted a five-year plan to the Forest Service for removal of limestone in commercial quantities.[[154]](#footnote-155)154 The plan contained details regarding the location, size, and appearance of the proposed mining operations. The Forest Service prepared an Environmental Assessment that recommended modifications to the plan. Granite Rock made the recommended modifications to the plan and the Forest Service approved the modified plan.[[155]](#footnote-156)155 Granite Rock then began mining.[[156]](#footnote-157)156

Under the California Coastal Act, any person conducting mining operations in the state's "coastal zone" must obtain a permit from the California Coastal Commission.[[157]](#footnote-158)157 Further, California's coastal zone included the area where Granite Rock's mining operations were located. Accordingly, in 1983, the Coastal Commission demanded that Granite Rock apply to the Commission for a permit to conduct mining operations.[[158]](#footnote-159)158 Instead of doing that, Granite Rock filed suit in federal court, seeking a declaration that the state-law permit requirement was preempted by federal law. The district court ruled in favor of the Commission and dismissed Granite Rock's suit, but the United States Ninth Circuit reversed and ruled in Granite Rock's favor. The Ninth Circuit stated that California had some authority to apply its environmental laws to federal lands, but that a state-law permitting requirement would undermine the Forest Service's own permitting system.[[159]](#footnote-160)159

The Supreme Court granted certiorari and considered the case. The Court reviewed certain well-established law: the Constitution's Property Clause gives the Congress "unlimited" authority to regulate federal lands, but does not prohibit State's from enforcing their regulations on federal land; accordingly, States generally may enforce their laws on federal lands, but State laws will be subject to a traditional preemption analysis and may be rendered unenforceable by preemption.[[160]](#footnote-161)160

The Court then undertook a preemption analysis. The Court concluded that federal law did not demonstrate an intent to occupy the entire field of regulation with respect to federal lands. Thus, there was not field preemption. Further, the record did not show that it would be impossible to comply with both federal and state law. Because Granite Rock had filed suit before seeking a permit, the record did not reflect what, if any conditions, the California Coastal Commission might impose. On the face of state law, however, there was no indication that it would be impossible to comply with both. The Court suggested that state-law would be preempted if it gave a state agency veto authority over mining on federal lands, but the Coastal Commission asserted that it was not seeking to preclude drilling. Accordingly, there did not seem to be conflict preemption.

Finally, the Court reasoned that certain federal statutes would preempt the enforcement of state land use planning regulations on federal land. The Court acknowledged that often there will be overlap between environmental laws and land use regulations, but that the two types of laws also can be distinguished and that the California laws at issue were environmental laws. Accordingly, the state-law requirement that Granite Rock obtain a permit from the Coastal Commission was not preempted.

There is some tension between *Ventura County* and *Granite Rock* cases. Perhaps the cases can be reconciled on the basis that federal law contains more indications that it intends to accommodate state regulation of coastal zones than indications that it intends to accommodate the application of local zoning to ***oil*** and gas activities occurring on federal land. Or perhaps the Coastal Commission's express statements that it did not intend to block mining operations is a basis for distinction. Another possibility, suggested by a prominent treatise, is that perhaps *Ventura County* was implicitly overruled.[[161]](#footnote-162)161

**B. Jurisprudence Regarding the Application of State Pooling, Spacing, and Drilling Units to Federal Lands**

Two of the leading cases on the effect of state pooling, spacing, and drilling-unit orders are *Texas* ***Oil*** *and Gas Corp. v. Phillips Petroleum Co*., 277 F. Supp. 366 (W.D. Okla. 1967) and *Kirkpatrick* ***Oil*** *& Gas Co. v. United States*, 675 F.2d 1122 (10th Cir. 1982). In *Texas* ***Oil*** *& Gas*, the plaintiff owned ***oil*** and gas leases covering federal land in Oklahoma.[[162]](#footnote-163)162 The Oklahoma Corporation Commission entered an order force pooling mineral interests in a particular formation beneath an area of land that included the plaintiff's leasehold. Later, the plaintiff declined to participate in the costs of drilling a well drilled by Phillips Petroleum, the company that had initiated the forced pooling proceeding. Under Oklahoma law, the plaintiff's failure to participate in the costs of drilling resulted in its working interest being transferred to Phillips Petroleum, in return for compensation provided by law.[[163]](#footnote-164)163

The plaintiff filed suit, seeing a ruling that it still owned its working interest and that Oklahoma's pooling order did not apply because federal law has exclusive effect with respect to federal land.[[164]](#footnote-165)164 The district court noted that the Property Clause of the United States Constitution gives Congress the authority to make laws governing federal land, and is sufficiently broad to allow federal law to preempt state law, but the Property Clause itself does not vest the federal government with exclusive authority to regulate federal lands.[[165]](#footnote-166)165 Accordingly, it is necessary to look to federal statutes or regulations to determine whether the federal government has assumed exclusive authority to regulate federal lands.

The court examined the Federal Mineral Leasing Act. The Act does not expressly preempt state law. Further, Section 187 of the Act provides that any rules promulgated by the Department for the prevention of waste must not conflict with state law.[[166]](#footnote-167)166 Further, Section 189 states that the Act should not be construed as affecting authority held by states or local government. The court concluded that these provisions demonstrate Congress did not intend to give the federal government exclusive authority to regulate.

The court concluded, however, that the Mineral Leasing Act contained at least two "limited controls." First, a federal mineral lessee cannot transfer its lease interest without consent of the federal government. Second, any pooling or communitization agreement involving federal and non-federal land must be approved by the federal government.[[167]](#footnote-168)167

In *Texas* ***Oil*** *& Gas*, the state agency's order had implemented forced pooling, and state law had the effect of transferring the plaintiff's federal lease interest. But the "limited controls" contained in the Mineral Leasing Act did not prevent the forced pooling order or the transfer of lease interest from being given effect because undisputed evidence showed that the federal government had consented to the pooling order and the transfer of the plaintiff's mineral interest. Effectively, the court held that, if the federal government consents to a state's forced pooling order, the order and accompanying state rules should be given effect. This decision was upheld by the United States Tenth Circuit in a *per curiam* opinion.[[168]](#footnote-169)168

This left a question. If a state pooling, spacing, or unitization order involves federal land, what is the effect of that order if the federal government has not given its consent. That issue was addressed in *Kirkpatrick* ***Oil*** *& Gas Co. v. United States*. In that case, a company obtained a lease of federal land in Oklahoma by assignment. At the end of the lease's primary term, the company was not producing ***oil*** or gas in paying quantities, and it had not drilled a well, but the lease tract was within a drilling and spacing unit created by the Oklahoma Corporation Commission, and a unit well was producing in paying quantities. Several months later, the federal government notified the company that its lease had terminated because of the absence of production.

The company appealed that determination to the Interior Board of Land Appeals ("IBLA"), asserting that the unit production had maintained the company's lease. The federal government argued that the unit production had no effect on maintenance of the federal lease because the federal government had not approved the unit. The IBLA upheld the determination that the lease had terminated.

The company then filed an action in federal district court, seeking a declaration that its lease was still in effect. The company pointed to Sections 187 and 189 of the Mineral Leasing Act, asserting that those sections indicated that Congress intended federal mineral leases to be subject to state pooling and communitization. The court disagreed, concluding that Section 187 primarily dealt with other issues and that Section 189 merely preserved whatever state and local authority existed. Section 189 did not grant authority to states and did not answer the question whether states can pool or communitize federal lands without federal consent.

The court examined Section 226(j), which expressly provides that the federal government must approve any pooling or communitization "agreement" involving federal lands. The company argued that the requirement for federal consent applied only to an agreement to pool or create a drilling unit, not to a state agency's order for pooling, spacing, or a drilling unit. The court disagreed. It stated that the legislative history shed no light on whether the requirement for federal consent applied both to agreements and state orders implementing pooling, spacing, or drilling units, but that allowing the federal government to be bound by a state's forced pooling order without federal consent would be inconsistent with the rest of Section 226(j).[[169]](#footnote-170)169 Accordingly, the court held that the state forced pooling order had no effect with respects to the federal lands without the federal government's consent. For that reason, the company's lease had terminated.

Other courts have used similar reasoning. For example, *Ohmart v. Dennis*, 196 N.W.2d 181 (Neb. 1972) is a case in which the United States and its lessee successfully invoked Nebraska's compulsory pooling statute. A party that opposed the pooling order argued that the federal government and its lessee were precluded from seeking a pooling order because a district court in a prior proceeding had denied the federal lessee's first request for a pooling order.[[170]](#footnote-171)170 The Nebraska Supreme Court disagreed. It explained that the district court in the prior case had properly denied the lessee's first request for a pooling order because the federal government had not consented to that request, and federal consent is necessary in order for a pooing order involving federal land to have effect.[[171]](#footnote-172)171 But the federal government had joined in the lessee's second request for a pooling order. Thus, the second request raised a different issue than the first request and was not precluded.[[172]](#footnote-173)172

Similar concepts apply with respect to Indian lands. Mineral leases covering Indian lands generally are subject the approval of the Secretary of the Interior, who is given authority to enact regulations regarding the operation and development of such leases.[[173]](#footnote-174)173 The Secretary has promulgated a regulation which provides that State and local laws do not apply to the development of Indian lands, except that the Secretary "may in specific cases or in specific geographic areas adopt or make applicable to Indian lands all or any part of such laws."[[174]](#footnote-175)174

This rule was applied in *Samedan* ***Oil*** *Corp. v. Cotton Petroleum Corp*., 466 F. Supp. 521 (W.D. Okla. 1978). In *Samedan*, the parties disputed various matters, including whether a lease held by Sun ***Oil*** had been maintained by production from a drilling unit created by the Oklahoma Corporation Commission. The court held that the lease had not been maintained by unit production because the Department of Interior had rejected a request that it approve a proposed communitization agreement for the drilling unit that included the well.[[175]](#footnote-176)175 Thus, a state agency's pooling order had no effect when the Department of Interior had not approved it. On the hand, sometime later (after Sun's lease had terminated) a party submitted a different communitization proposal. That proposal became effective because the Secretary of Interior approved it.[[176]](#footnote-177)176

**C. Retroactivity of BLM Decision to Consent to State Pooling**

There have been some interesting cases regarding the retroactivity of a decision by BLM to consent to a state's spacing or pooling or drilling unitization order. In *Shearn v. Ward Petroleum Corp*., 808 F. Supp. 1530 (W.D. Okla. 1992), the question was whether the federal government and its lessee could benefit retroactively from the federal government's approval of a state-created unit. In *Shearn*, the following occurred:

1976 - the Oklahoma Corporation Commission establishes a spacing and drilling unit that includes some land owned by the federal government

1983 - the defendant becomes the operator of a unit well

1984 - the defendant establishes production from the unit well

1990 - the United States issued an ***oil*** and gas lease to Michael Sheam for the federal land in the unit

1991 - BLM ratifies the 1976 spacing and drilling unit.

Thus, the unit well was not on federal land, but a federal lease was located within the drilling unit, and the state had pooled interests within the unit. The operator of the well did not notify the federal government about the well or ask the federal government to decide whether it would approve or decline to approve the state-created unit. After the federal government learned of and approved the unit, the federal government took the position that its approval of the unit had retroactive effect, and the government was entitled to compensation for the production that occurred during the seven years prior to its approval of the unit.

The government asserted a claim against the operator for the entire portion of unit production attributable to the federal land between the start of production and the effective date of the federal lease, and for a lease royalty on the portion of production attributable to the federal land in the unit for the period after the lease became effective. The federal lessee also asserted a claim against the operator. The operator argued that BLM's consent to the order creating the spacing and drilling unit could not be given retroactive effect, but the court disagreed, and granted summary judgment in favor of the U.S. and its lessee.

The suit was initiated by the federal lessee, who did not name the other owners of working interests in the unit as parties. When the federal government asserted its own claims, it did not join the other working interest owners. The unit operator argued that the other owners of working interests were necessary parties, but the court rejected that argument. The court acknowledged that, if the federal government's approval of the unit was given retroactive effect, that would mean that the operator had overpaid the other working interest owners. The court stated that the operator could file suit against the other working interest owners to recover possible overpayments, but that the federal lessee and federal government would not be required to add them to the litigation in *Shearn*.

In *Kardokus v. Walsh*, 797 P.2d 322 (Okla. 1990), retroactivity became an issue in a dispute that involved only private parties. In *Kardokus*,

the Oklahoma Corporation Commission created a drilling and spacing unit that included certain Indian land

July 27, 1984 - an individual holding a lease on the Indian land begins drilling a well that is completed as a producing well on the Indian land

August 1984 - the Corporation Commission issues a pooling order

October 1, 1985 - an application is submitted to the Department of the Interior for approval of a communitization agreement covering the area within the drilling and spacing unit

March 1986 - the U.S. approves the communitization agreement, giving its approval retroactive effect to October 1, 1985, the date application was made for approval of the communitization agreement.

The dispute in this case related to an ***oil*** and gas lease covering private land that was within the unit, but which was not Indian land. Neither the lessors nor the lessees were Indians. The primary term of the private lease expired on June 27, 1984. The lessees had not established production, but they filed suit seeking a judgment that their lease was still in effect. They argued that their private lease had been maintained by drilling of the unit well and then by production from that well. The lessors asserted that the private lease had expired by its own term because the primary term ended before the Department of Interior authorized inclusion of the Indian land in the unit.

The lessees countered that, even though the Indian land could not be affected by the Oklahoma spacing and drilling unit until the Department of Interior gave its approval, a transaction between purely private parties such as the lessor and lessee were not dependent on Interior's decision. Accordingly, given Oklahoma's rule that unit production will maintain a lease within the unit, even if the unit well is not on the lease, the private lease held by the lessees has been maintained. The court rejected that argument, concluding that the well on Indian land could not be counted as a unit well until the effective date of the Department of Interior's approval of communitization.

The lessees asserted two additional arguments. First, they argued that the *force majeure* clause in the lease had maintained the lease. Specifically, they argued that state law prevented them from drilling their own well because a unit well already had been drilled on the Indian lease. The court disagreed, stating that the unit order had no effect until it was approved by the federal government. Thus, up until that time, the lessees could have applied for their own drilling permit and communitization order.[[177]](#footnote-178)177

Finally, the lessees argued that the Department of Interior's approval of the communitization should be given retroactive effect to the date the Indian lease was granted.[[178]](#footnote-179)178 The court rebuffed that argument, stating that if the lessor wished to pursue the argument, if should file an administrative appeal to challenge the portion of the Department of Interior's decision that set the effective date of the communitization agreement.[[179]](#footnote-180)179

**D. Cooperation Between BLM and State Agencies**

The Bureau of Land Management and state regulator often have a cooperative relationship. In some states, BLM and relevant state agencies have entered memoranda of understanding regarding their relationship.[[180]](#footnote-181)180

**IV. Trends in Pooling and Unitization in Shale Plays in Selected States**

**A. Colorado**[[181]](#footnote-182)181

Colorado Revised Statute 34-60-116 authorizes the Colorado ***Oil*** and Gas Conservation Commission to create drilling units and issue orders that implement pooling of interests. The statute provides that "no drilling unit shall be smaller than the maximum area that can be efficiently and economically drained by one well."[[182]](#footnote-183)182 Thus, the language of the statute does not prohibit the creation of drilling units larger than the size that can be drained efficiently by one well. Further, the statute expressly authorizes the permitting of more than one well in a drilling unit.[[183]](#footnote-184)183

Colorado is seeing extensive development of shale formations, much of it in the Niobrara Shale, which covers much of northeastern Colorado, as well as parts of Wyoming, Kansas, and Nebraska. Much of the Niobrara is located within an area designated by Colorado as the Greater Wattenberg area. Some special spacing and drilling unit rules apply there.[[184]](#footnote-185)184 For example, if a drilling and spacing unit does not already exist for a horizontal well, an operator proposing a horizontal well must designate a horizontal wellbore spacing unit that "shall be comprised of the governmental quarter-quarter sections in which the wellbore lateral penetrates the productive formation, as well as any governmental quarter-quarter sections that are located less than four hundred sixty (460) feet from the completed interval of the wellbore lateral."[[185]](#footnote-186)185 If a lateral is not oriented in an exact north-south or east-west direction, the horizontal wellbore lateral can have a staircase shape. The only spacing limitation on these wells is a 150 foot setback from other wellbores.[[186]](#footnote-187)186 Thus, horizontal wellbore units can overlap one another, and a particular tract of land can be located within multiple units.

Outside the Greater Wattenberg area, Colorado's general pooling and drilling unit provisions apply. Hundreds of 640 acres units have been created, but the more recent trend has been toward larger units. Numerous 960 and 1280 acre units have been created. Also, some event larger units - sometimes as large as 2500 acres in size have been created - in some cases, with different operators for different wells within the unit. Some landowners have expressed concern about the creation of units that large based on fears that, if the initial wells drilled in the unit do not yield good results, operators may not diligently develop the unit and leases throughout the large unit could be held by just a few wells. Operators have been able to address that concern to some extent by showing development plans that call for multiple wells to be drilled.

There also has been an issue with how to apply Colorado's risk-fee provision to non-participating parties in a multiple well unit. The risk fee provision contained in Colorado Revised Statute 34-60-116(7) has some references to "the well." Further, a regulation that addresses the procedure for forced pooling, contains references to "the well."[[187]](#footnote-188)187 Arguably, this suggests that the Colorado ***Oil*** and Gas Conservation Commission can only impose pooling, and operators can only require parties to elect to participate or not participate in drilling costs, on a well-by-well basis, one well at a time. Further, arguably there could be some inequities in requiring a party to decide to participate in a package of multiple wells drilled over a long period.

On the other hand, the Colorado statutes and rules do not expressly state that, in a multiple unit well, the election to participate or not participate will be made one well at a time, and it is not clear that such an interpretation should be inferred merely because the relevant statute and regulation contain references to "the well." Further, inequities could be created by allowing the election to participate or not participate to be made one well at a time. With such a system, there is an incentive for parties to elect not to participate on the first well in the unit, to allow others to take all the risk. Then, if that well is a success, the persons who declined to participate in the first well can elect to participate in subsequent wells, once the area has been "de-risked" by the drilling of a first successful well.

So far, this issue has been addressed by operators proposing multiple wells when they start development of a unit. Parties with mineral interests in the unit can then be required to consent to the package of proposed wells. Under this scenario, as long as the operator drills the proposed wells within two years (the period for which a drilling permit is valid), the operator can impose Colorado's risk fee in a way that prevents a party from electing not to participate in the first well, thereby allowing other parties in the unit take all the risk for that well, then electing to start participating in subsequent wells only after a first well has proven to be a success.

Another Colorado trend has been the creation of "unconventional resource" units as large as five sections in size. There is not a special statute authorizing such units. Instead, the Commission has created such units using its general authority to issue orders creating drilling units and pooling interests. For the creation of such units, the Commission generally has required the existence of a single operator, a joint operating agreement, and the consent of mineral interest owners holding at least 85% in interest.

Finally, there have been issues relating to the creation of drilling units and pooling when such units were not authorized by leases - either because the lease did not contain a pooling provision, or the lease limited pooling to a unit size smaller than the drilling units used for horizontal drilling, or because the lease's pooling provision did not authorize pooling that would dilute the lessor's interest beyond a specified amount. The existence of such pooling clauses in the lease does not prevent the Colorado ***Oil*** and Gas Conservation Commission from using its authority to create drilling units and order pooling, or prevent lessees from requesting the imposition of statutory pooling. Accordingly, operators have been able to use Colorado's statutory pooling provisions even when leases do not contain pooling provisions or contain pooling provisions that are not adequate.

**B. Louisiana**

**1. The Haynesville Shale, Alternate Unit Wells, and the Size of Units**

The Haynesville Shale is a dry gas play that stretches across a large portion of northwest Louisiana and a portion of northeast Texas. A Haynesville Shale boom began in 2008. The number of rigs operating in the Haynesville Shale has dropped significantly, in part because of low gas prices, but Office of Conservation records indicate that there were 2643 active Haynesville Shale wells as of September 21, 2014, with 2387 of those being listed as producing wells and 256 listed as pre-production wells.

After Haynesville Shale activity began, the Louisiana Office of Conservation proceeded to create about 2228 Haynesville Shale drilling units. It has been common practice in north Louisiana for many years to create units that are approximately 640 acres in size, with the boundaries of units typically corresponding to governmental survey sections. The Commissioner of Conservation followed the same practice when creating Haynesville Shale units, and that has raised some controversy.

As in other shale plays, operators use horizontal drilling and hydraulic fracturing in the Haynesville Shale. Because the shale has low permeability, there will not be much drainage of natural gas from the portion of the formation beyond the area that is hydraulically fractured. Further, the typical half-length of fractures is significantly less than half the width of a 640 acre section. Accordingly, one well will not efficiently drain a 640 acre Haynesville Shale unit. Instead, several wells - perhaps about eight - will be needed to drain the unit. Accordingly, at the request of several operators, the Commissioner has granted permits for "alternate unit wells" - that is, wells in addition to a first unit well.[[188]](#footnote-189)188

The Louisiana Office of Conservation has a long history of issuing permits for "alternate unit wells" if one well will not efficiently drain a unit, but the Commissioner's authority to issue permits for alternate unit wells was challenged recently in two noteworthy cases. In each of the cases, the plaintiffs based their challenges on the language of Louisiana Revised Statute 30:9, the statute which grants the Commissioner the power to create drilling units. That statute states, in part, "A drilling unit, as contemplated herein, means the maximum area which may be efficiently and economically drained by one well."[[189]](#footnote-190)189

The first of the two cases was *Walker v. J-W Operating Co*., 2012 WL 6677913 (La. App. 1st Cir. 2012). This case did not involve a shale play, but the case raised the question of the Commissioner's authority to issue permits for alternate unit wells. *Walker* concerned the Caspiana Field, a gas field in northwest Louisiana. In 1975, the Commissioner issued orders dividing the field into 22 units of approximately 640 acres each, based on evidence from which he conclude that a single well could efficiently drain 640 acres.[[190]](#footnote-191)190 Since then, the Caspiana Field has been significant drilled, and based on current data it is evident that one well will not efficiently drain 640 acres in that field. For that reason, the Commissioner began granting requests from operators in the mid-1990s for permits to drill alternate unit wells.

The plaintiffs in *Walker* are surface owners in the area covered by the Caspiana Field. Their land was burdened by a mineral servitude, which is somewhat like a mineral estate. The plaintiffs objected to the Commissioner's granting of permits for alternate unit wells because those wells resulted in a greater portion of their land being used for ***oil*** and gas activity. And of course the benefit from that activity was going to the owner of the mineral servitude, rather than the plaintiffs. The plaintiffs sought an injunction to prohibit the Commissioner from granting permits for alternate unit wells. The plaintiffs argued that the Commissioner has no authority to grant permits for alternate unit wells.

The plaintiffs asserted that, if new evidence demonstrates that one well will not efficiently drain a previously-created drilling unit, the Commissioner's only option is to decrease the size of the unit. An order prohibiting the permitting of alternate unit wells would, of course, benefit the plaintiffs in the short run because no additional wells would be drilled on their property to target the Caspiana Field unless and until the existing units were decreased in size and new units were created. Further, if new and smaller units were created, that also would benefit the plaintiffs. A key difference between a mineral servitude and a mineral estate is that a mineral servitude terminates by prescription of nonuse if the servitude ever is not used for a 10- year period. Just as large units can make it easier to hold leases by production, large units can make it easier to interrupt the running of prescription of nonuse on a mineral servitude. And, if the mineral servitude burdening the plaintiffs' land prescribed, the ownership of minerals would be reunited with surface ownership, thereby benefitting the plaintiffs.

But the court rejected the plaintiffs' argument. The court concluded that, when new evidence demonstrates that a unit cannot be efficiently drained by one well, the Commissioner has discretion either to decrease the size of the unit and create additional units (which can each have their own unit well) or issue permits for alternate unit wells for the existing unit.

The second challenge was in *Gatti v. Louisiana*, which did involve Haynesville Shale units. In that case, the plaintiffs argued that the Commissioner of Conservation has no authority under Louisiana Revised Statute 30:9 to create drilling units that are larger than can be drained by one well. Further, the plaintiffs alleged that the Commissioner knew at the time he created the Haynesville Shale units that a 640-acre Haynesville Shale unit could not be drained by one well. The plaintiffs argued that, under these circumstances, the Haynesville Shale units were absolutely null - that is, they were void retroactive to the time of their creation. The plaintiffs brought a putative class action and sought various relief. They asked for a declaration that the Commissioner had no authority to issue permits for alternate unit wells, but the plaintiffs' main goals were (1) a declaratory judgment that the Haynesville Shale units were retroactively void and (2) money damages for the plaintiffs who held mineral rights on the land where Haynesville Shale wells had actually been drilled, and whose lease royalty or other payments had been "diluted" by the fact that the payments were calculated as if the 640-acre units were valid.

The defendants - the Office of Conservation and various exploration and production companies - sought dismissal of the case based on the fact that the plaintiffs had not brought their challenge to the unit orders within 60 days of the orders - the time limit imposed by Louisiana Revised Statue 30:12 for seeking review of an order of the Commissioner. The district court dismissed on that basis. But in January 2014 the Louisiana First Circuit reversed and remanded the case, holding that the plaintiffs' challenge was not barred on the basis of untimeliness. The plaintiffs had argued that the 60-day time limit imposed by the statute does not apply if someone challenges an order of the Commissioner on the basis the order was beyond the Commissioner's authority. The First Circuit accepted that argument.

If the First Circuit's holding had been upheld, that would have been very significant. It would have meant that there would be no time limit whatsoever to challenging orders of the Commissioner, provided that a person could frame the challenge as being based on the Commissioner having exceeded his authority, as opposed to basing a challenge on the Commissioner allegedly having made an erroneous factual conclusion.

Further, if the plaintiffs had proceeded with their case and eventually obtained an order that 2228 Haynesville Shale units were retroactively void, that would have meant: (1) a large number (probably thousands) of leases that everyone thought had been held by unit production would actually have terminated; (2) a large number of mineral servitudes that everyone thought had been kept alive by unit production from a well not on the servitude tract would actually have terminated; (3) thousands of persons would have been underpaid the amount of lease royalties they were owed; (4) thousands of other lessors would have been overpaid because they received lease royalties because their land was in the unit; and (5) because horizontal laterals often pass beneath multiple tracts of land, the production would have to be allocated between those tracts for purposes of calculating lease royalties, notwithstanding the fact that it is not clear under Louisiana law how such an allocation would be made in the absence of a unit.

The prospect that orders of the Commissioner would remain subject to challenge forever, as well as the multiple problems that would have been created for industry if the plaintiffs had obtained the relief they sought, prompted the defendants to seek review from the Louisiana Supreme Court. Further, industry groups filed *amicus* briefs in support of the defendants' request for review. The Louisiana Supreme Court granted the request for review, but did not set the case for briefing and argument. Instead, in August 2014, the court reversed the appellate court's ruling and reinstated the trial court's decision. The Supreme Court did not issue an opinion or explain its reasoning in its order.

**2. Cross Unit Wells**

In Louisiana, there is a 330 feet setback from unit or lease lines, except for ***oil*** wells drilled to a depth of less than 3000 feet.[[191]](#footnote-192)191 This can result in a 660 feet area - 330 feet on each side of the unit line - from which hydrocarbons are not recovered. To address this problem, the Louisiana Office of Conservation has issued permits for cross-unit wells that can cross a unit boundary. The cross-unit wells are considered to be wells for each of the two units. The Office of Conservation has implemented a policy that production should be allocated between the two units based on the length of perforated lateral beneath each unit.

There has not yet been litigation regarding this practice, but some persons have questioned whether the Commissioner has the power to authorize allocation of production based on perforated length of lateral, as opposed to an actual measurement of production from each unit.

Also, some people have expressed concern that a cross unit well might be drilled just a short distance across the unit lines, and that a relatively short section of lateral might have the effect of holding leases throughout a unit and interrupting prescription of nonuse on mineral servitudes located in the unit. So far, this has just been a theoretical issue. In each of the units for which a cross-unit well has been authorized, there already was a producing well that was holding whatever leases are in the unit and interrupting prescription of nonuse for any servitudes in the unit. But the Louisiana legislature has created a "Cross Unit Well Study Commission," which is chaired by the Commissioner of Conservation, with representatives of both industry and landowners, to study the issue and make a recommendation for reform.

**3. The Tuscaloosa Marine Shale**

The Tuscaloosa Marine Shale is an ***oil*** play that stretches in a band across central Louisiana into southwestern Mississippi. Activity in the "TMS" is still in its early stages, but operators have requested and the Commissioner has created larger units than are typical in Louisiana. For example, 960-acre rectangular units have been created.

**C. North Dakota**[[192]](#footnote-193)192

North Dakota Century Code § 38-08-07 authorizes the North Dakota Industrial Commission to establish spacing units and § 38-08-08 authorizes the Commission to order the pooling of interests. Section 38-08-08 also authorizes the imposition of a risk penalty on parties that decline to participate in the costs of a well. North Dakota applies risk penalties on a well-by-well basis, rather than on a unit basis. Thus, a party that chooses not to participate in one well can participate in a subsequent well. As in many other states, an operator may use statutory pooling even if the lease states that the lessee may not pool without the lessor's consent.[[193]](#footnote-194)193

**D. Pennsylvania**[[194]](#footnote-195)194

Pennsylvania has a statute that authorizes the Pennsylvania Department of Environmental Protection's Office of ***Oil*** and Gas to create spacing units[[195]](#footnote-196)195 and order pooling.[[196]](#footnote-197)196 But these provisions only apply with respect to formations located deeper than the Onondaga horizon.[[197]](#footnote-198)197 The Utica Shale is deeper than the Onondaga horizon, but Marcellus Shale, which has been the focus of most shale activity in Pennsylvania, is shallower than the Onondaga. Accordingly, there has been relatively little use of statutory drilling units and statutory pooling in the development of Pennsylvania's shale resources. Instead, any pooling had to be based on consent, whether the consent took the form of pooling provisions in leases or otherwise.

In 2013, however, Pennsylvania enacted HB 259, which is codified at 58 Pennsylvania Statutes § 34.1. The statute states:

Where an operator has the right to develop multiple contiguous leases separately, the operator may develop those leases jointly by horizontal drilling unless expressly prohibited by a lease. In determining the royalty where multiple contiguous leases are developed, in the absence of an agreement by all affected royalty owners, the production shall be allocated to each lease in such proportion as the operator reasonably determines to be attributable to each lease.

This statute can has effects similar to a pooling provision. For example, in the absence of pooling, even if an operator holds leases for all of the tracts that would be penetrated by a horizontal lateral, the lack of a method to allocate the production of a horizontal well between the various lease tracts could be a hurdle. This statute attempts to remove that hurdle by authorizing the operator to allocate production "to each lease in such proportion as the operator reasonably determines to be attributable to each lease."

Further, unless the owner of the land on whose property the wellhead is located is the lessor and his lease contains an adjacent lands clause, the owner of that tract might have a basis to object to the fact that wellhead located on his property is carrying gas that is produced from and allocated to other tracts.[[198]](#footnote-199)198 Similarly, owners of other might have a basis to complain if a horizontal lateral passing beneath their land is carrying gas from that is produced from and allocated to other tracts that are located nearer the toe of the lateral than their own tract. The statute appears to remove that hurdle to horizontal drilling by providing that the "operator may develop [the] leases jointly by horizontal drilling unless expressly prohibited by a lease."

**E. Texas**

Texas has seen extensive development of shale resources in the Barnett Shale in North Texas, the Eagle Ford Shale in South Central Texas, the western portion of the Haynesville Shale in East Texas, and the Permian Basin in West Texas.[[199]](#footnote-200)199 There have been several interesting developments relevant to spacing, drilling units, and pooling.

**1. Setbacks and Assignment of Acreage for Calculation of Allowables**

In Texas, spacing generally is governed by the Texas Railroad Commission's Rule 37, which creates a setback of 467 feet from property or lease lines and 1200 feet from any well completed or drilled on the same tract.[[200]](#footnote-201)200 Rule 38 establishes the general rule regarding well densities and the amount of acreage assigned to a well for purposes of calculating an allowable.[[201]](#footnote-202)201

But Texas also has a rule that applies specifically to horizontal wells. Rule 86 generally governs spacing and allocation of acreage for purposes of calculating allowables.[[202]](#footnote-203)202 Rule 86 adopts the same setbacks as are contained in Rule 37, but specifies that all points of the horizontal wellbore must satisfy the setback distance.[[203]](#footnote-204)203 Rule 86 also specifies that the acreage assigned to a particular horizontal well for purposes of calculating an allowable will be the number of acres that would be assigned to a vertical well, plus an additional number of acres that depends on the length of the horizontal lateral.[[204]](#footnote-205)204

In addition, the Railroad Commission had adopted a number of rules for particular fields to facilitate the development of shale formations. For example, in 2005, the Railroad Commission adopted a rule that eliminated any setback distance between wells in the Barnett Shale.[[205]](#footnote-206)205 At the same time, it adopted the "take point rule," which provides that, if portions of a horizontal lateral do not contain any perforations or "take points," that portion of the lateral need not satisfy Rule 37 setbacks.[[206]](#footnote-207)206 In addition, the Commission sometimes has adopted a dual set of lease line setback rules. Recognizing that fractures typically propagate and therefore horizontal wells in shale plays typically drain from a direction perpendicular to the direction of the wellbore, the dual setback distances sometimes have been established at 467 feet from lease lines in the direction perpendicular to the wellbore, as well as a minimum of 100 feet from the toe of the lateral to any lease lines in the direction parallel to the lateral.[[207]](#footnote-208)207

**2. Statutory Pooling**

Texas has a statutory pooling law, the Mineral Interest Pooling Act,[[208]](#footnote-209)208 but it is not often used because it contains several requirements that make it cumbersome to use. There has been some renewed interest in using the Act for pooling of interests in the Barnett Shale in urban areas,[[209]](#footnote-210)209 but operators also have turned to other methods to facilitate development using horizontal wells that will pass beneath multiple tracts.

**3. Methods to Facilitate Development other than Statutory Pooling**

Parties have used voluntary pooling. In addition, parties have used production sharing agreements. A production sharing agreement is an agreement between the persons holding royalty, working interests, and other mineral interests in multiple pooled units and unpooled leases regarding how to allocate production from horizontal wells within that area.[[210]](#footnote-211)210 The Railroad Commission will consider granting permits to drill on a PSA basis if working interest and royalty interest owners holding at least 65% of the interest in each lease or pooled area to be traversed by the horizontal well agree to the PSA.

In addition, some operators, notably Devon, have used "allocation wells." An allocation well is a well drilled without a production sharing agreement. Devon was the first company to obtain a permit from the Railroad Commission for an allocation well.[[211]](#footnote-212)211 Allocation wells have been used where an operator has the working interest in all tracts that the horizontal lateral will traverse. The Railroad Commission has granted permits to drill, but it also has issued a caution. The Commission has indicated that an operator's holding the working interest in all tracts to be traversed was sufficient to justify the granting of a permit to drill, but that the Commission was not taking a position on whether Devon's method of allocating production between tracts was appropriate. Further, the Commission took no positon on whether an operator having the working interest in each tract was sufficient, in the absence of pooling or a production sharing agreement, to give the operator sufficient contract or property rights to drill and operate a well that crossed multiple tracts.[[212]](#footnote-213)212

**4. Allocation of Lease Royalty From Horizontal Well's Production After Lease Tract is Subdivided**

In *Springer Ranch, Ltd. v. Jones*, 421 S.W.3d 273 (Tex. App. 2013), a horizontal well was located on a lease tract. The lease tract had been subdivided after the lease was granted, and the horizontal lateral traversed two of the sub-tracts. Under Texas law, as in most states, the rule of non-apportionment provides that when a lease tract is subdivided, any lease royalties on production from the lease are not apportioned between the owners of the sub-tract on which the well is located. Instead, the owner of the land on which the well is located is entitled to the entire lease royalty that is owed on production from the well, in the absence of agreement to the contrary.[[213]](#footnote-214)213 In *Springer Ranch*, the owners of sub-tracts into which the lease tract had been divided had entered an agreement, but the agreement was similar to the rule of non-apportionment. The parties had agreed that all lease royalties from any well would be paid entirely to the owner of the "surface estate on which such well or wells are situated."[[214]](#footnote-215)214

The parties' main dispute was how to apply that rule in the context of a horizontal well that traversed two tracts. The owner of the tract on which the wellhead was located argued that he should receive the entire lease royalty. The court rejected that argument, concluding that the well was "on" both of the tracts. Because the well was on both tracts, the court concluded that it would be necessary to allocate the production between the two tracts. One party argued that the most appropriate way to allocate production was to look at the total length of the lateral between the first perforation in the lateral and the last perforation, and to allocate to each tract a share of production corresponding to the portion of that perforated length beneath that tract.[[215]](#footnote-216)215 The court agreed with that method of allocation and entered judgment on that basis.[[216]](#footnote-217)216

**F. Wyoming**

Most drilling units created in Wyoming are 640-acre units, but the Wyoming ***Oil*** and Gas Conservation Commission also has approved drilling larger drilling units, including 1280-acre units, to accommodate the drilling of horizontal wells with longer laterals.[[217]](#footnote-218)217

**V. Conclusion**

The rule of capture may be the most practical way to resolve drainage disputes between neighbors in the absence of conservation regulations. But the rule of capture creates incentives that can lead to economic and physical waste, and it does not necessarily protect correlative rights. Accordingly, most states have responded with conservation statutes and regulations that include provisions for the creation of drilling and spacing units, and for statutory pooling. Most state statutes granting agencies the authority to create drilling units and order pooling have several similarities.

One of the most significant differences between state pooling statutes is how they treat mineral interest owners who elect not to participate in the costs of the well. There are three basic approaches. The first is the risk-fee method. In it, the non-participating owner is treated as a carried interest who is liable for his share of costs, but only out of production. He also is responsible for a risk-fee that is paid out of his share of production. The risk-fee is some multiple (which varies by state) of certain categories of drilling and completion costs. A second approach is the surrender-of-working-interest approach, in which the non-participating owner is required to surrender his working interest to the operator in return for compensation. Finally, a third approach is to given non-participating owners a "free ride," meaning that they need not pay any costs on a dry hole, that their responsibility for costs of drilling and completing a productive well is paid out of production only, with no liability for a risk fee.

Although the United States Constitution's Property Clause has been interpreted as giving Congress unlimited authority over federal lands, it does not make regulation of federal lands a subject that only can be regulated by Congress. With respect to attempts to apply state spacing and pooling regulations on federal lands, this has been interpreted as meaning that state pooling and spacing regulations can apply if the federal government consents to them. Otherwise, the rules have no effect on federal lands.

Because many state statues dealing with drilling units and pooling were drafted prior to the extensive use of horizontal drilling and hydraulic fracturing, some traditional regulatory practices regulating to well spacing, pooling, and the size and shape of drilling units were not well suited to current exploration, production, and development practices. This has led some regulatory agencies to adopt new regulatory practices.

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1. 1Atlantic Richfield Co. v. Tomlinson, 859 P.2d 1088, 1094 (Okl. 1993); California Minerals v. County of ***Kern***, 62 Cal. Rptr. 3d 1, 6 (Cal. Ct. App. 2007); La. Rev. Stat. 31:6. An exception to the general rule is that, in most states, ownership of mineral rights can be severed from the ownership of land. This can occur if a landowner sells the mineral rights or if the landowner sells surface rights and retains mineral rights for himself. Doing either of these things creates separate estates - a mineral estate and a surface estate. Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW § 301; Teel v. Chesapeake Appalachia, LLC, 906 F. Supp. 2d 519, 522 (N.D. W.Va. 2012). The general rule in the United States that landowners own the mineral rights relating to their land is not the global norm. In most other countries, the national government owns the right to produce minerals. John S. Lowe, ***OIL*** AND GAS IN A NUTSHELL 8 (5th edition 2009). [↑](#footnote-ref-2)
2. 2Thrasher v. City of Atlanta, 173 S.E. 817, 825 (Ga. 1934). [↑](#footnote-ref-3)
3. 3Alyce Gaines Johnson Special Trust v. El Paso E & P Co., L.P., 773 F.Supp.2d 640, 645 (W.D. La. 2011). The doctrine has been stated by Lord Coke and by William Blackstone, and is repeated in Kent's Commentaries. *See* 1 Coke, Institutes (19th ed. 1832) ch. 1, § 1(4a); 2 Blackstone, Commentaries (Lewis ed. 1902) p. 18; 3 Kent, Commentaries (Gould ed. 1896) p. 621.Some scholars have questioned the wisdom of a strict adherence to this doctrine with respect to the subsurface. *See, e.g.*, Keith B. Hall, *Hydraulic Fracturing: If Fractures Cross Property Lines is there an Actionable Subsurface Trespass?*, 54 Nat. Res. J. 301 (Fall 2014); Owen L. Anderson, *Lord Coke, the Restatement, and Modern Subsurface Trespass Law*, 6 Tex. J. ***Oil*** Gas & Energy L. 203 (2010-2011); David E. Pierce, *Minimizing the Environmental Impact of* ***Oil*** *and Gas Development by Maximizing Production Conservation*, 85 N.D. L. Rev. 759, 771-72 (2009). [↑](#footnote-ref-4)
4. 4Kelly v. Ohio, 49 N.E. 399 (Ohio 1897); Barnard v. Monongahela Natural Gas Co., 65 A. 801 (Pa. 1907). [↑](#footnote-ref-5)
5. 5*See, e.g.*, Patrick H. Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW § 204.4; Terence Daintith, FINDERS KEEPERS? HOW THE LAW OF CAPTURE SHAPED THE WORLD ***OIL*** INDUSTRY 7 (RFF Press 2010) [↑](#footnote-ref-6)
6. 6Several sources provide excellent, comprehensive treatment of the Rule of Capture. *See, e.g.*, Bruce M. Kramer and Owen L. Anderson, *The Rule of Capture - An* ***Oil*** *and Gas Perspective*, 35 Envtl. L. 899 (2005); Terence Daintith, *Finders Keepers? How the Law of Capture Shaped the World* ***Oil*** *Industry* (RFF Press 2010). For an interesting discussion of a suggested change from a traditional rule of capture analysis, see David E. Pierce, *Carol Rose Comes to the* ***Oil*** *Patch: Modem Property Analysis Applied to Modern Reservoir Problems*, 19 Penn St. Envtl. L. Rev. [↑](#footnote-ref-7)
7. 7Kelly v. Ohio, 49 N.E. 399 (Ohio 1897); Barnard v. Monongahela Natural Gas Co., 65 A. 801 (Pa. 1907). [↑](#footnote-ref-8)
8. 8Gadeco, LLC v. Industrial Com'n of State, 812 N.W.2d 405, 407 (N.D. 2012); Nunez v. Wainoco ***Oil*** & Gas Co., 488 So.2d 955, 960 (La. 1986) (rule of capture encouraged indiscriminate drilling). [↑](#footnote-ref-9)
9. 9Nunez v. Wainoco ***Oil*** & Gas Co., 488 So.2d 955, 960 (La. 1986) (referring to possible waste of reservoir energy and diminished ultimate recovery). [↑](#footnote-ref-10)
10. 10*Cf. Nunez*, 488 So.2d at 960 (noting that one goal of conservation regulation can be "to insure a fair and reasonable participation, by the surface owners in the common pool within the producing area"). [↑](#footnote-ref-11)
11. 11There are multiple articles discussing the history of conservation statutes. One is: Leslie Moses, *The Constitutional, Legislative and Judicial Growth of* ***Oil*** *and Gas Conservation Statutes*, 13 Miss. L.J. 353 (1941). [↑](#footnote-ref-12)
12. 12*See* U.S. Const. amend. V. [↑](#footnote-ref-13)
13. 13Patrick H. Martin and Bruce M Kramer, MANUAL OF ***OIL*** AND GAS TERMS at 272 (14th edition 2009). [↑](#footnote-ref-14)
14. 14Colo. Rev. Stat. §34-60-116(3); Wyo. Stat. § 30-5-109(c)(1). Often, "drilling unit" is contemplated to be the maximum area that can be drained by one well. *See, e.g.*, La. Rev. Stat. 30:9(C); Patrick H. Martin and Bruce M Kramer, MANUAL OF ***OIL*** AND GAS TERMS at 726 (definition of "drilling unit") and 918 (definition of "spacing unit") (14th edition 2009). [↑](#footnote-ref-15)
15. 15La. Rev. Stat. 30:9(B); N.M. Stat. § 70-2-17(B) (proration units); N.D. Cent. Code § 38-08-07(1); Okla. Stat. 52 § 87.1(a); Utah Code § 40-6-6(1); Wyo. Stat. § 30-5-109(a). [↑](#footnote-ref-16)
16. 16Colo. Rev. Stat. §34-60-116(1); Mont. Code 82-11-201; Okla. Stat. 52 § 87.1(a); Wyo. Stat. § 30-5-109(a). [↑](#footnote-ref-17)
17. 17Colo. Rev. Stat. §34-60-116(1); La. Rev. Stat. 30:9(B); Mont. Code 82-11-201; N.M. Stat. § 70-2-17(B) (proration units); N.D. Cent. Code § 38-08-07(1); Okla. Stat. 52 § 87.1(a); Wyo. Stat. § 30-5-109(a). [↑](#footnote-ref-18)
18. 18Colo. Rev. Stat. §34-60-116(1); La. Rev. Stat. 30:9(B); Mont. Code 82-11-201; N.M. Stat. § 70-2-17(B) (proration units); N.D. Cent. Code § 38-08-07(1). [↑](#footnote-ref-19)
19. 19Colo. Rev. Stat. §34-60-116(1); Mont. Code 82-11-201; N.D. Cent. Code § 38-08-07(1); Okla. Stat. 52 § 87.1(a); Wyo. Stat. § 30-5-109(a). [↑](#footnote-ref-20)
20. 20Eugene Kuntz, *Correlative Rights in* ***Oil*** *and Gas*, 30 Miss. L.J. 1, 2 (1958); Halbouty v. Railroad Commission, 357 S.W.2d 364, 374 (Tex. 1962) ("It is an obvious result that if in a common reservoir one tract owner is allowed to produce many times more gas than underlies his tract he is denying to some other landowner in the reservoir a fair chance to produce the gas underlying his land."); Elliff v. Texon Drilling Co., 210 S.W.2d 558, 562-3 (Tex. 1948); Higgins ***Oil*** & Fuel Co., Inc. v. Guaranty ***Oil*** Co., 82 So. 206, 212 (La. 1919) ("The rights of the several owners of the gas filed are coequal; one owner cannot exercise his own right so as to preclude his neighbor from exercising his, or so as to interfere with the neighbor."); La. Rev. Stat. 31:10 and cmt. [↑](#footnote-ref-21)
21. 21La. Rev. Stat. 30:9(B); N.M. Stat. § 70-2-17(B) (proration units). [↑](#footnote-ref-22)
22. 2222 Colo. Rev. Stat. §34-60-116(3); Utah Code § 40-6-6; Wyo. Stat. § 30-5-109(b). [↑](#footnote-ref-23)
23. 23Parties can enter voluntary pooling arrangements, but this paper focuses on state conservation laws. Thus, this paper generally will not discuss voluntary pooling. [↑](#footnote-ref-24)
24. 24*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(a); N.M. Stat. § 70-2-17(C); N.D. Cent. Code § 38-08-08(1); 52 Okla. Stat. § 87.1(e); Tex. Nat. Res. Code § 102.011; Utah Code § 40-6-6.5(1); Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-25)
25. 25*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A)(1); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(b); N.D. Cent. Code § 38-08-08(1); N.M. Stat. § 70-2-17(C); Tex. Nat. Res. Code § 102.011; Utah Code § 40-6-6.5(2)(a); Wyo. Stat. § 30-5-109(1). [↑](#footnote-ref-26)
26. 26*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); Mont. Code 82-1 1-202(1)(b); N.D. Cent. Code § 38-08-08(1); Tex. Nat. Res. Code § 102.012; Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-27)
27. 27*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A)(1)(a); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(b) (after hearing, though not expressly referring to notice); N.D. Cent. Code § 38-08-08(1); N.M. Stat. § 70-2-17(C); 52 Okla. Stat. § 87.1(e); Tex. Nat. Res. Code § 102.016; Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-28)
28. 28*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A)(1)(a); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(b); N.M. Stat. § 70-2-17(C); N.D. Cent. Code § 38-08-08(1); 52 Okla. Stat. § 87.1(e); Tex. Nat. Res. Code § 102.017; Utah Code § 40-6-6.5(2)(b); Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-29)
29. 29*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A)(1)(a); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(b); N.D. Cent. Code § 38-08-08(1); N.M. Stat. § 70-2-17(C); 52 Okla. Stat. § 87.1(e); Tex. Nat. Res. Code § 102.017 (stating that pooling order must give each owner a chance to produce his fair share, but not referring to "without unnecessary expense). [↑](#footnote-ref-30)
30. 30*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); Mont. Code 82-l1-202(1)(b); N.D. Cent. Code § 38-08-08(1); N.M. Stat. § 70-2-17(C); Tex. Nat. Res. Code § 102.053; Utah Code § 40-6-6.5(3)(a); Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-31)
31. 31*See, e.g.*, Colo. Rev. Stat. § 34-60-116(6); La. Rev. Stat. 30:10(A)(1)(b); Miss. Code § 53-3-7(a)(a); Mont. Code 82-1 1-202(1)(b); N.D. Cent. Code § 38-08-08(1); N.M. Stat. § 70-2-17(C); 52 Okla. Stat. § 87.1(e); Tex. Nat. Res. Code § 102.053; Utah Code § 40-6-6.5(3)(b); Wyo. Stat. § 30-5-109(f). [↑](#footnote-ref-32)
32. 32*See, e.g.*, Anschutz Corporation v. Wyoming ***Oil*** and Gas Conservation Commission, 923 P.2d 751, 757 (Wyo. 1996) ("surface acreage is perhaps the most frequently employed basis for allocating pooled production"); Tex. Nat. Res. Code Ann. §102.051(a); Panhandle Eastern Pipe Line Co. v. Corporation Commission, 285 P.2d 847, 854 (Okla. 1955); Traverse ***Oil*** Co. v. Chairman of Natural Resources Comm'n, 396 N.W.2d 498, 500 (Mich. App. 1986). [↑](#footnote-ref-33)
33. 33Anschutz Corp., 923 P.2d at 755-7; Tex. Nat. Res. Code Ann. § 102.051(b). [↑](#footnote-ref-34)
34. 34See Anschutz Corporation v. Wyoming ***Oil*** and Gas Conservation Commission, 923 P.2d 751, 757 (Wyo. 1996) (discussing possibility of allocating production based on reserves); [↑](#footnote-ref-35)
35. 35For an excellent overview of these approaches, see Patrick Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW (abridged version, 4th edition) § 944. [↑](#footnote-ref-36)
36. 36A prominent treatise uses "nonconsent penalty" and also "risk penalty." Patrick Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW at § 944 (using "nonconsent penalty") and § 973 n.3.1 (using "risk penalty"); Louisiana's relevant statute refers to a "risk charge." La. Rev. Stat. 30:10(A)(2)(b)(i). EOG Resources, Inc. v. Chesapeake Energy Corp., 605 F.3d 260, 263 (5th Cir. 2010) (using "risk fee"). [↑](#footnote-ref-37)
37. 37Ala. Code § 9-17-13. [↑](#footnote-ref-38)
38. 38Colo. Rev. Stat. § 34-60-116(7). [↑](#footnote-ref-39)
39. 39La. Rev. Stat. 30:10(A). [↑](#footnote-ref-40)
40. 40Mich. Comp. Laws Ann. 324.61513(4); Mich. Admin. Code R. 324.1206(4). [↑](#footnote-ref-41)
41. 41Miss. Code Ann. § 53-3-7(2)(g). [↑](#footnote-ref-42)
42. 42Mont. Code Ann. § 82-11-202, [↑](#footnote-ref-43)
43. 43Neb. Rev. Stat. § 57-900(2). [↑](#footnote-ref-44)
44. 44Nev. R.S. 522.060(4). [↑](#footnote-ref-45)
45. 45N.M. Stat. Ann. § 70-2-17(C). [↑](#footnote-ref-46)
46. 46N.Y. Env. Cons. Law § 23-0901(3). [↑](#footnote-ref-47)
47. 47N.D. Cent. Code § 38-08-08(3). [↑](#footnote-ref-48)
48. 48Ohio Rev. Code Ann. § 1509.27. [↑](#footnote-ref-49)
49. 49Tex. Nat. Res. Code Ann. §§ 102.013 and 102.052 [↑](#footnote-ref-50)
50. 50Utah Code Ann. § 40-6-6(6). [↑](#footnote-ref-51)
51. 51Wyo. Stat. § 30-5-109(g). [↑](#footnote-ref-52)
52. 52La. Rev. Stat. 30:10(A)(2)(b)(i) (setting 200% penalty for unit wells, substitute unit wells, and cross unit wells, but 100% penalty for alternate unit wells); Nev. R.S. 522.060(4) (setting 300% fee). [↑](#footnote-ref-53)
53. 53N.M. Stat. Ann. § 70-2-17(C) (giving regulator authority to set risk fee, but setting cap of 200%); Mich. Admin. Code R. 324.1206(4). [↑](#footnote-ref-54)
54. 54Virtually all pooling statutes expressly limit the operator to charging *actual* costs that are *reasonable*. Colo. Rev. Stat. § 34-60-116(7); La. Rev. Stat. 30:10(A)(2)(b)(i); N.M. Stat. Ann. § 70-2-17(C). This may include a reasonable charge for supervision. See, e.g., Colo. Rev. Stat. § 34-60-116(7); La. Rev. Stat. 30:10(A)(2)(b)(i); Nev. R.S. 522.060(4); N.M. Stat. Ann. § 70-2-17(C). [↑](#footnote-ref-55)
55. 55For example, the Mississippi statute has significant detail, whereas the Nevada statute has considerably less. Miss. Code Ann. § 53-3-7(2)(g); Nev. R.S. 522.060(4). [↑](#footnote-ref-56)
56. 56*See, e.g.*, Colo. Rev. Stat. § 34-60-116(7)(a); La. Rev. Stat. 30:10(f); N.M. Stat. Ann. § 70-2-17(C); Nev. R.S. 522.060(4); Tex. Nat. Res. Code Ann. § 102.052(b); Wyo. Stat. § 30-5-109(g). [↑](#footnote-ref-57)
57. 57Wakefield v. State of Oklahoma, 306 P.2d 305, 308 (Okla. 1957); Anderson v. Corporation Commission, 327 P.2d 699, 700-1 (Okla. 1957). [↑](#footnote-ref-58)
58. 58Patrick Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW at §§ 944, 972. [↑](#footnote-ref-59)
59. 59Wakefield v. State of Oklahoma, 306 P.2d 305, 308-9 (Okla. 1957) [↑](#footnote-ref-60)
60. 60Anderson v. Corporation Commission, 327 P.2d 699, 700-1 (Okla. 1957). [↑](#footnote-ref-61)
61. 61Ark. Code Ann. § 15-72-304(b)(4). [↑](#footnote-ref-62)
62. 62Idaho Code § 47-322(c). [↑](#footnote-ref-63)
63. 63111. Comp. Stat. Ann. 725/22.2(f) [↑](#footnote-ref-64)
64. 64Ky. Rev. Stat. Ann. 353.640 (3). [↑](#footnote-ref-65)
65. 6558 Pa. Stat. § 408(c). [↑](#footnote-ref-66)
66. 66S.D. Codified Laws 45-9-33. [↑](#footnote-ref-67)
67. 67W. Va. Code, § 22C-9-7(b)(5). [↑](#footnote-ref-68)
68. 68*See, e.g.*, Patrick Martin and Bruce M. Kramer, WILLIAMS & MEYERS ***OIL*** AND GAS LAW (abridged version, 4th edition) § 944; *see also* Patrick H. Martin, "Unleased and Unjoined Owners - Forced Pooling and Co-Tenancy Issues" § 18.03[3], Proceedings of the Rocky Mountain Mineral Law Fifty-Sixth Annual Institute (2010). [↑](#footnote-ref-69)
69. 69Patrick H. Martin, "Unleased and Unjoined Owners - Forced Pooling and Co-Tenancy Issues" § 18.03[3], Proceedings of the Rocky Mountain Mineral Law Fifty-Sixth Annual Institute (2010). [↑](#footnote-ref-70)
70. 70*Id.* [↑](#footnote-ref-71)
71. 71*Id.* [↑](#footnote-ref-72)
72. 72*Id.; see also* Alaska Stat. Ann. § 31.05.100 (providing that non-participating lessee is responsible for reimbursing operator for non-participant's share of costs, but that reimbursement is required only out of production). [↑](#footnote-ref-73)
73. 73Ariz. Stat. Ann. § 27-505(A). [↑](#footnote-ref-74)
74. 74Ind. Code 14-37-9-3. [↑](#footnote-ref-75)
75. 75Vernon Ann. Missouri Stat. 259.110. [↑](#footnote-ref-76)
76. 76Patrick H. Martin, "Unleased and Unjoined Owners - Forced Pooling and Co-Tenancy Issues" § 18.03[3], Proceedings of the Rocky Mountain Mineral Law Fifty-Sixth Annual Institute (2010). [↑](#footnote-ref-77)
77. 77*Id.* [↑](#footnote-ref-78)
78. 78La. Rev. Stat. 30:10(A). [↑](#footnote-ref-79)
79. 79Colo. Rev. Stat. § 34-60-116(7)(b). [↑](#footnote-ref-80)
80. 80Colo. Rev. Stat. § 34-60-116(7)(c). [↑](#footnote-ref-81)
81. 81*Id.* [↑](#footnote-ref-82)
82. 82Mont. Code Ann. § 82-1 l-202(2)(c). [↑](#footnote-ref-83)
83. 83Utah Code Ann. § 40-6-6.5(6). [↑](#footnote-ref-84)
84. 84Patrick H. Martin, "Unleased and Unjoined Owners - Forced Pooling and Co-Tenancy Issues" § 18.03[5], Proceedings of the Rocky Mountain Mineral Law Fifty-Sixth Annual Institute (2010). [↑](#footnote-ref-85)
85. 85Utah Code Ann. § 40-6-6.5(5). [↑](#footnote-ref-86)
86. 86Gulf Explorer, LLC v. Clayton Williams Energy, Inc., 964 So. 2d 1042 (La. App. 1st Cir. 2007). [↑](#footnote-ref-87)
87. 87La. Rev. Stat. 30:10(A)(2)(b)(ii)(aa) [↑](#footnote-ref-88)
88. 88La. Rev. Stat. 30:10(A)(2)(b)(ii). [↑](#footnote-ref-89)
89. 89A thorough treatment of this subject is provided elsewhere. *See, e.g.*, Bruce M. Kramer and Patrick H. Martin, THE LAW OF POOLING AND UNITIZATION, Chapter 14. [↑](#footnote-ref-90)
90. 90*Id.* at § 14.02. [↑](#footnote-ref-91)
91. 91*Id.* [↑](#footnote-ref-92)
92. 92A leading case is Wood ***Oil*** Co. v. Corporation Commission, 239 P.2d 1021 (Okla. 1950). Several other cases come to the same result. *See, e.g.* Chaparral Energy, L.L.C. v. C.E. Harmon ***Oil***, Inc., 149 P.3d 1070 (Okla. 2006); Harding & Shelton, Inc. v. Sundown Energy, Inc., 130 P.3d 776 (2006). [↑](#footnote-ref-93)
93. 93*See, e.g.*, Railroad Commission v. Aluminum Company of America, 380 S.W.2d 599 (Tex. 1964). The Texas Supreme Court also relied in part on the fact that parties had acted in reliance on the order. *Id.* Also, a court in New Mexico held that the conservation agency would need to make findings that justified a change in an earlier order. *See* Continental ***Oil*** Co. v. ***Oil*** Conservation Commission, 373 P.2d 809 (N.M. 1962). [↑](#footnote-ref-94)
94. 94*See, e.g.*, Barnwell, Inc. v. Sun ***Oil*** Co., 162 So. 2d 635 (Miss. 1964). [↑](#footnote-ref-95)
95. 95*See, e.g.*, State ***Oil*** & Gas Board v. Mississippi Mineral and Royalty Owners Assoc., 258 So. 2d 767 (Miss. 1971) (concerning changes in statewide spacing rules); *see also* Bruce M. Kramer and Patrick H. Martin, THE LAW OF POOLING AND UNITIZATION, § 14.01. [↑](#footnote-ref-96)
96. 96*Id.* at 14.02[2]. [↑](#footnote-ref-97)
97. 97Id. at 14.02[3]; *see also* Winter v. Corp. Comm., 60 P.2d 145 (Okla. 1983); Okla. Stat. 52 § 87.1(d). [↑](#footnote-ref-98)
98. 98Amoco Production Co. v. Thunderhead Investments, Inc., 235 F. Supp. 2d 1163, 116-7 (D. Colo. 2002); Southwest Kansas Royalty Owners Assoc, v. Corporation Commission, 769 P.2d 1, 4 (Kan. 1989) (referring to "infill drilling). [↑](#footnote-ref-99)
99. 99Walker v. J-W Operating Co., 2012 WL 6677913 (La. App. 1st Cir. 2012). Under Louisiana terminology, an "alternate unit well" is an additional unit well. This should be distinguished from a "substitute unit well," which replaces a prior unit well. [↑](#footnote-ref-100)
100. 100*See, e.g.*, Amoco Production Co. v. Corporation Commission, 751 P.2d 203, 208 (Okla. 1988). [↑](#footnote-ref-101)
101. 101*See, e.g.*, Ark. Code Ann. § 15-72-304(a) (hearing for "integration" orders); Colo. Rev. Stat. § 34-60-116 (hearings before order for drilling unit or pooling); Idaho Code § 47-321(b) (hearing for spacing unit); La. Rev. Stat. 30:10(A)(1)(a) (hearing for pooling order); Tex. Nat. Res. Code Ann. §§ 102.016 (hearing before pooling order); Wyo. Stat. § 30-5-109(a) (hearing for drilling unit). [↑](#footnote-ref-102)
102. 102Texas ***Oil*** and Gas Corp. v. Rein, 534 P.2d 1277, 1278 (Okla. 1974). [↑](#footnote-ref-103)
103. 103*Id.* [↑](#footnote-ref-104)
104. 104Id. at 1279. [↑](#footnote-ref-105)
105. 105Cormack v. Wil-Mc Corp., 661 P.2d 525 (Okla. 1983). [↑](#footnote-ref-106)
106. 106*Id.* at 526. [↑](#footnote-ref-107)
107. 107*Id.* [↑](#footnote-ref-108)
108. 108*Id.* at 526. [↑](#footnote-ref-109)
109. 109*Id.* [↑](#footnote-ref-110)
110. 110*Id.* at 526. [↑](#footnote-ref-111)
111. 111*Id.* (quoting from Summers treatise). [↑](#footnote-ref-112)
112. 112*Id.* [↑](#footnote-ref-113)
113. 113Nunez v. Wainoco ***Oil*** & Gas Co., 488 So. 2d 955. 956 (La. 1986) [↑](#footnote-ref-114)
114. 114*Id.* at 956 [↑](#footnote-ref-115)
115. 115*Id.* at 957. [↑](#footnote-ref-116)
116. 116*Id.* at 957. [↑](#footnote-ref-117)
117. 117*Id.* at 958. [↑](#footnote-ref-118)
118. 118*Id.* at 962; *see also* La. Civ. Code art. 490. [↑](#footnote-ref-119)
119. 119*Nunez*, 488 So. 2d at 958. [↑](#footnote-ref-120)
120. 120*Id.* at 963. [↑](#footnote-ref-121)
121. 121*Id.* at 963-4. The court cited with apparent approval the Oklahoma Supreme Court's decision in Texas ***Oil*** and Gas Corp. v. Rein, 534 P.2d 1277 (Okla. 1975) [↑](#footnote-ref-122)
122. 122*Id.* at 964 n.29 (citing Cormack v. Wil-Mc Corp., 661 P.2d 525 (Okla. 1983)). [↑](#footnote-ref-123)
123. 123Nunez v. Wainoco ***Oil*** and Gas Co., 606 So. 2d 1320 (La. App. 3rd Cir. 1982). [↑](#footnote-ref-124)
124. 124*Id.* at 1323. [↑](#footnote-ref-125)
125. 125*Id.* at 1327. [↑](#footnote-ref-126)
126. 126Continental Resources, Inc. v. Farrar ***Oil*** Co., 559 N.W.2d 841, 844 (N.D. 1997). [↑](#footnote-ref-127)
127. 127*Id.* at 843. [↑](#footnote-ref-128)
128. 128*Id.* at 844. [↑](#footnote-ref-129)
129. 129*Id.* at 846. [↑](#footnote-ref-130)
130. 130An excellent treatment of this subject is contained in the multi-volume pooling and unitization treatise authored by Bruce Kramer and Pat Martin. *See* Bruce M. Kramer and Patrick H. Martin, 1 THE LAW OF POOLING AND UNITIZATION, Chapter 16 "Federal Lands" (3rd edition 2013). This topic also has been covered at past Rocky Mountain Mineral Law Foundation events. *See, e.g.*, Owen L. Anderson, *State Conservation Regulation -- Single Well Spacing and Pooling -- Vis-À-Vis Federal and Indian Lands*, Ch. 2 of Special Institute on Federal Onshore ***Oil*** and Gas Pooling and Unitization (2006). [↑](#footnote-ref-131)
131. 131107 S. Ct. at 1425. The doctrine of preemption is based on the "Supremacy Clause" of the United States Constitution, which is found at article VI, cl. 2 of the United States Constitution. It states: "This Constitution, and the Laws of the United States which shall be made in Pursuance thereof; and all Treaties made, or which shall be made, under the Authority of the United States, shall be the supreme Law of the Land; and the Judges in every State shall be bound thereby, any Thing in the Constitution or Laws of any State to the Contrary notwithstanding." [↑](#footnote-ref-132)
132. 132*Hillsborough County v. Automated Medical Laboratories, Inc*., 105 S. Ct. 2371, 2375 (1985); *Farnia v. Nokia, Inc*., 627 F.3d 97, 115 (3rd Cir. 2010). [↑](#footnote-ref-133)
133. 133*California Coastal Comm'n*, 107 S. Ct. at 1425; *Hillsborough County*, 105 S. Ct. at 2375 (1985); *Farnia*, 627 F.3d at 115. The Supreme Court has stated, "Pre-emption of a whole field also will be inferred where the field is one in which 'the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject.'" *Hillsborough County*, 105 S. Ct. at 2375. [↑](#footnote-ref-134)
134. 134*California Coastal Comm'n*, 107 S. Ct. at 1425; *Hillsborough County*, 105 S. Ct. at 2375); *Farnia*, 627 F.3d at 115. [↑](#footnote-ref-135)
135. 135Kleppe v. New Mexico, 96 S. Ct. 2285, 2288 (1976). [↑](#footnote-ref-136)
136. 136*Id*. at 2288-9. [↑](#footnote-ref-137)
137. 137*Id*. at 2289. [↑](#footnote-ref-138)
138. 138*Id*. [↑](#footnote-ref-139)
139. 139*Id*. at 2291. [↑](#footnote-ref-140)
140. 140*Id*. at 2293-4. [↑](#footnote-ref-141)
141. 141*Id*. at 2295. [↑](#footnote-ref-142)
142. 142Ventura County v. Gulf ***Oil*** Corp., 601 F.2d 1080, 1082 (9th Cir. 1979), *aff'd*, 100 S. Ct. 1593 (1980). [↑](#footnote-ref-143)
143. 143*Id*. at 1082. [↑](#footnote-ref-144)
144. 144*Id*. at 1082. [↑](#footnote-ref-145)
145. 145*Id*. [↑](#footnote-ref-146)
146. 146*Id* [↑](#footnote-ref-147)
147. 147*Id*. at 1083-4. [↑](#footnote-ref-148)
148. 148*Id*. at 1084. [↑](#footnote-ref-149)
149. 149*Id* [↑](#footnote-ref-150)
150. 150*Id*. at 1084. [↑](#footnote-ref-151)
151. 151*Id*. at 1086. [↑](#footnote-ref-152)
152. 152Ventura County v. Gulf ***Oil*** Corp., 100 S. Ct. 1593 (1080). [↑](#footnote-ref-153)
153. 153California Coastal Commission v. Granite Rock Co., 107 S. Ct. 1419, 1422 (1987) (citing 30 U.S.C. § 26). [↑](#footnote-ref-154)
154. 154*Id*. at 1422. [↑](#footnote-ref-155)
155. 155*Id*. at 1422-3. [↑](#footnote-ref-156)
156. 156*Id*. at 1423. [↑](#footnote-ref-157)
157. 157*Id*. at 1423. [↑](#footnote-ref-158)
158. 158*Id*. [↑](#footnote-ref-159)
159. 159*Id*. at 1423. [↑](#footnote-ref-160)
160. 160*Id*. at 1425. [↑](#footnote-ref-161)
161. 161*See* Bruce M. Kramer and Patrick H. Martin, 1 THE LAW OF POOLING AND UNITIZATION, § 16.05[1] (3rd edition 2013). The Wyoming Supreme Court distinguished *Ventura County* in *Gulf* ***Oil*** *Corp. v. Wyoming* ***Oil*** *& Gas Conservation Comm'n*, 693 P.2d 227 (Wyo. 1985), holding that federal statutes did not preempt the state agency's imposition of additional requirements on Gulf's request for a permit to drill. [↑](#footnote-ref-162)
162. 162277 F. Supp. at 367. [↑](#footnote-ref-163)
163. 163*Id*. at 367 & n.1. [↑](#footnote-ref-164)
164. 164*Id*. at 368. [↑](#footnote-ref-165)
165. 165*Id*. [↑](#footnote-ref-166)
166. 166*Id*. at 369. [↑](#footnote-ref-167)
167. 167*Id*. The requirement for federal approval of lease assignments is found in 30 U.S.C. § 187. The requirement for federal approval of such pooling or communitization agreements is contained in 30 U.S.C. § 2260. [↑](#footnote-ref-168)
168. 168Texas ***Oil*** and Gas Corp. v. Phillips Petroleum Co., 406 F.2d 1303 (10th Cir. 1969). [↑](#footnote-ref-169)
169. 169675 F.2d at 1125. [↑](#footnote-ref-170)
170. 170196 N.W.2d at 183. Because the federal government had acquired the land at issue from a private owner, the federal lease was governed by the Mineral Leasing Act for Acquired Lands. *Id., see also* 30 U.S.C. § 351-360. [↑](#footnote-ref-171)
171. 171196 N.W.2d at 185. [↑](#footnote-ref-172)
172. 172*Id*. at 185. [↑](#footnote-ref-173)
173. 17325 U.S.C. § 396. [↑](#footnote-ref-174)
174. 17425 C.F.R. § 1.4. [↑](#footnote-ref-175)
175. 175466 F. Supp. at 526. [↑](#footnote-ref-176)
176. 176*Id*. [↑](#footnote-ref-177)
177. 177797 P.2d at 325-6. [↑](#footnote-ref-178)
178. 178*Id*. at 325. [↑](#footnote-ref-179)
179. 179*Id*. at 326. [↑](#footnote-ref-180)
180. 180*See* Owen L. Anderson, "State Conservation Regulation - Single Well Spacing and Pooling - Vis-à-vis Federal and Indian Lands," *Federal Onshore* ***Oil*** *and Gas Pooling and Unitization*, Paper 2 at pp. 20-2 (Rocky Mt. Min. L. Fdn. 2006). [↑](#footnote-ref-181)
181. 181The author thanks to Sam Niebrugge and Greg Nibert, Jr. of Davis Graham & Stubbs. During a telephone call with the author, they provided important insights regarding trends in Colorado. Any errors, however, are exclusively the responsibility of the author. Another valuable source of information regarding trends in Colorado is: Jamie L. Jost, and Joseph M. Evers, "Pooling and Unitization Methods Across Shale Basins (or Lack Thereof): Niobrara," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8B (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-182)
182. 182Colo. Rev. Stat. 34-60-116(2). [↑](#footnote-ref-183)
183. 183Colo. Rev. Stat. 34-60-116(4). [↑](#footnote-ref-184)
184. 184*See* 2 Colo. Code Regs. 404-1:318A. [↑](#footnote-ref-185)
185. 185*See* 2 Colo. Code Regs. 404-1:318A(a)(4)(D). [↑](#footnote-ref-186)
186. 186This restriction is contained in See 2 Colo. Code Regs. 404-1:318A(n). [↑](#footnote-ref-187)
187. 1872 Colo. Code Regs. 404-1:530. [↑](#footnote-ref-188)
188. 188The assertions stated in the paragraph above are adopted from the allegations of the plaintiffs in the *Gatti* case that is discussed below. [↑](#footnote-ref-189)
189. 189La. Rev. Stat. 30:9(B). [↑](#footnote-ref-190)
190. 190*Id*. at \*1. [↑](#footnote-ref-191)
191. 191La. Admin. Code tit. 43, part XIX, § 1905. [↑](#footnote-ref-192)
192. 192North Dakota pooling and drilling unit issues were discussed earlier this year at a Rocky Mountain Mineral Law Foundation Special Institute. *See* Amy L. De Kok, "Pooling and Unitization Methods Across Shale Basins; Overview of Pooling and Unitization in North Dakota,' Development Issues In Major Shale Plays: What's on the Horizon?, Paper 8D (Rocky Mt. Min, L Fdn. 2014). [↑](#footnote-ref-193)
193. 193Egeland v. Continental Resources, Inc., 616 N.W.2d 861 (N.D. 2000), [↑](#footnote-ref-194)
194. 194Pooling and drilling unit issues in Pennsylvania were addressed earlier this year at a Rocky Mountain Mineral Law Foundation Special Institute in Pittsburgh. *See* Benjamin M. Sullivan, "Pooling and Unitization in the Marcellus and Utica Plays In Ohio, Pennsylvania, and West Virginia," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8A (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-195)
195. 19558 P.S. § 407. The statute, which was enacted in 1961, states that the Pennsylvania ***Oil*** and Gas Conservation Commission has authority to create drilling units. *Id.; see also* 58 P.S. § 402 (defining "Commission" as meaning the Pennsylvania ***Oil*** and Gas Conservation Commission). [↑](#footnote-ref-196)
196. 19658 P.S. § 408. The statute refers to "integration of interests," rather than "pooling of interests." *Id*. [↑](#footnote-ref-197)
197. 19758 P.S. § 403(b)(1). [↑](#footnote-ref-198)
198. 198Again, this assumes the absence of pooling. [↑](#footnote-ref-199)
199. 199Issues relating to shale development were discussed at a recent Rocky Mountain Mineral Law Foundation Special Institute. *See* John Hicks, "Pooling and Unitization Methods Across Shale Basins: Texas (Eagle Ford and Barnett)," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8C (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-200)
200. 200Tex. Admin. Code tit. 16, § 3.37(a)(1). [↑](#footnote-ref-201)
201. 201Tex. Admin. Code tit. 16, § 3.38. [↑](#footnote-ref-202)
202. 202Tex. Admin. Code tit. 16, § 3.86. [↑](#footnote-ref-203)
203. 203Tex. Admin. Code tit. 16, § 3.86(b). [↑](#footnote-ref-204)
204. 204Tex. Admin. Code tit. 16, § 3.86(d). [↑](#footnote-ref-205)
205. 205*See* John Hicks, "Pooling and Unitization Methods Across Shale Basins: Texas (Eagle Ford and Barnett)," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8C, p. 10 (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-206)
206. 206*Id*. at 10-11. [↑](#footnote-ref-207)
207. 207*Id*. at 13. [↑](#footnote-ref-208)
208. 208Tex. Natural Resources Code §§ 102.001 *et seq*. [↑](#footnote-ref-209)
209. 209*See* John Hicks, "Pooling and Unitization Methods Across Shale Basins: Texas (Eagle Ford and Barnett)," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8C, p. 10 at pp. 26-34 (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-210)
210. 210*See id*. at 10; *see also* H. Martin Gibson, *Modifying* ***Oil*** *& Gas Documents for Horizontal Drilling*, 19 Tex. Wesleyan L. Rev. 77,113 (Fall 2012). [↑](#footnote-ref-211)
211. 211*See* John Hicks, "Pooling and Unitization Methods Across Shale Basins: Texas (Eagle Ford and Barnett)," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8C at p. 36 (Rocky Mt. Min. L. Fdn. 2014); Robert C. Grable, "Royalty Payments and Other Current Issues from Horizontal Wells," *Horizontal* ***Oil*** *& Gas Development*, Paper 13A at pp. 13-21 (Rocky Mt. Min. L. Fdn. 2012). [↑](#footnote-ref-212)
212. 212*See* John Hicks, "Pooling and Unitization Methods Across Shale Basins: Texas (Eagle Ford and Barnett)," *Development Issues in Major Shale Plays: What's on the Horizon?*, Paper 8C at p. 36 (Rocky Mt. Min. L. Fdn. 2014); Robert C. Grable, "Royalty Payments and Other Current Issues from Horizontal Wells," *Horizontal* ***Oil*** *& Gas Development*, Paper 13A at pp. 13-21 (Rocky Mt. Min. L. Fdn. 2012). [↑](#footnote-ref-213)
213. 213Garza v. De Montalvo, 217 S.W.2d 988, 993 (Tex. 1949). [↑](#footnote-ref-214)
214. 214*Springer Ranch*, 421 S.W.3d at 277. [↑](#footnote-ref-215)
215. 215*Id*. at 285-6. [↑](#footnote-ref-216)
216. 216*Id*. at 286, 289. [↑](#footnote-ref-217)
217. 217Trends in Wyoming were discussed at a Rocky Mountain Mineral Law Foundation Special Institute in May 2014. *See* Jamie L. Jost and Joseph M. Evers, "Pooling and Unitization Methods Across Shale Basins (or Lack Thereof): Niobrara," Development Issues in Major Shale Plays: What's on the Horizon?, Paper 8B (Rocky Mt. Min. L. Fdn. 2014). [↑](#footnote-ref-218)