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# Texas Journal of Oil, Gas, and Energy Law

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We would be remiss if we did not acknowledge the contributions made by the many individuals who made this journal a reality. Allegra Young, Assistant Dean of Communications, and Paul Goldman, Publications Business Manager, have worked together from the start to make this project happen. They fielded our daily questions, advised us on how to deal with the drama that accompanies starting a journal, and tirelessly supported us in every imaginable way. They encouraged our belief that this could be done and made sure we took each step necessary to create a journal that would survive long after the inaugural Editorial Board and staff graduated. And, perhaps most importantly, Allegra convinced Dean Bill Powers to approve our creation.

Our faculty sponsors, Professors Ernest Smith, John Dzienkowski, and David Spence, each contributed in a variety of ways. They wrote for the Journal, presented at the symposium, weeded-out unsuitable submissions, guided Victoria in the preparation of her note, and most importantly, each lent us his name. Such generosity was frankly essential and greatly appreciated by a journal attempting to get off the ground and gain respectability.

Our advisory board, Jo Ann Biggs, Commissioner Victor Carrillo, Mike Godfrey, and J.J. McAnelly, was created over the course of a year. While there was not always a clear idea of exactly what role each would play, we knew we needed all of the help we could get in ascertaining the best way to create a journal that appealed to a variety of constituencies. We never expected the ongoing generosity of time and resources that each advisor dedicated to the Journal. We are sincerely thankful for it.

Last, it would have been nice if we had found a pot of gold sitting in our office the day we were given the key. We had no such luck. But, more impressively, we discovered more companies and law firms than we had ever imagined who supported the idea of creating the first student-edited legal journal regarding energy. In fact, several donated funds before the Journal was officially created, and without those early donations, the administration would not have as eagerly lent its support. Such generosity also provided that our first issue be widely available—unique for a beginning journal. It also allowed us to host a world class symposium that included over eight hours of CLE credit at no charge. Furthermore, we were able to host a banquet awarding the first Ernest Smith Award to Frank Douglass for his lifetime contributions to the field. So, while we did not find a pot of gold, we did find real people who provided more financial support than we had ever anticipated.
To enter the rare book archive on the sixth floor of the Tarlton Law Library at the University of Texas School of Law, you must knock, a librarian unlocks a sizable dead bolt, and all ink pens must be put away. Sitting on a shelf, deep in the archive where only librarians may go, there is a small blank envelope. Inside the envelope is an eight page document that is so brittle that it must be read on a special reading stand for delicate documents. If it is not the first, it is one of the earliest model oil and gas contracts. The contract, simply titled *A Model Oil and Gas Contract*, was written by George C. Butte, a professor teaching in the Law Department at the University of Texas and published in the *University of Texas Bulletin*, April 23, 1919. The forward to the model contract is particularly illustrative:

Thousands of farmers in Texas have given oil and gas “leases” on their farms during the past year, and many more are now negotiating such contracts. In almost every case, the contract is a printed or other form prepared by the oil companies, or by their attorneys, acting in the interest of the oil companies. Farmers, as a rule, are inexperienced in the oil business and unacquainted with the legal construction of the contracts they are asked to sign.

The Law Department of the University of Texas is offering courses on the subject of oil and gas law. Under the direction of the professor in charge of these courses, a special form of oil and gas contract has been studied out, having three ends always in view: (1) perfect legality; (2) clearness of meaning; (3) fairness to both landowner and oil operator. Believing that the people of Texas—especially the Texas farmers—who are interested in the possibility of finding oil, will appreciate seeing a contract of the sort described, it is herewith submitted.

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1. There is also a large red sign in all capital letters that warns in the case of a fire, all of the oxygen will be sucked out of the room, and it would be wise to leave in such an event.
We feature this particular document because it serves to illustrate several of the underlying justifications for why this journal was started: (1) oil and gas law has long been of central importance to the state of Texas; (2) it still is; and (3) it has been of particular importance to the University of Texas School of Law for an extended period of time.

Despite the long history of oil and gas law being taught in law schools, before the publication of this journal, a student-edited legal journal focused entirely on energy issues did not exist anywhere in the country—not even in Texas. We started this Journal because of a perceived need, and even more importantly, a demand among the students for scholarly focus on oil and gas. With the blessing of the Publications Department, Professor Ernest Smith, and Dean Bill Powers, the Journal was created in the summer of 2005. It has taken a little less than a year to build and train a staff; solicit, acquire, and edit submissions; raise the money to pay the publication bill; and put on a symposium that will be the basis of the second issue. It is our hope that you will find the material interesting, useful, well-written, and perfectly edited.

THE MATERIAL

We decided early in the process that the Journal should and would appeal to academics as well as practitioners, and also serve as an opportunity for student publication. Therefore, we passed a set of bylaws stating every effort would be made by the Editorial Board to include in each issue at least one article from a legal scholar, a practicing attorney, and a current student. In the future, we plan to expand this range to also include an article written by an energy policymaker.

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3. According to the course catalogs in the archive, 1914 was the first year oil and gas was taught at the University of Texas.
4. This assertion is not meant in any way as a slight toward the ENERGY LAW JOURNAL and the students at the University of Tulsa College of Law who work on that journal. It is our understanding that the editorial content is selected or supervised by an editorial committee made up of practicing attorneys and academics in partnership with the Energy Bar Association. The content in the TEXAS JOURNAL OF OIL, GAS, AND ENERGY LAW is chosen exclusively by the student Editorial Board.
5. Ultimately, sixty-three students were members during the first year.
6. The printing, binding, and shipping cost approximately $10,000 per issue.
7. We welcome you to let us know of errors by emailing editors@tjogel.org.
Here is our first publication. It is now possible to look at what the future has in store. These are the Journal’s goals: (1) serve as a training ground for a new generation of energy attorneys; (2) publish articles that contribute to the field; (3) push for the expansion of what is considered “energy law;” (4) bring a new level of interaction between those currently involved in the field and members of the *Texas Journal of Oil, Gas, and Energy Law*; and (5) publish books that are valuable to both beginners and experts in the field.8

In order to meet our goals, we will need continued support from a number of sources. We hope that authors will find Journal publication to be a particularly attractive option—given the dedication and quality of the students editing and the size and diversity of the Journal’s readership. We hope that readers engaged in various aspects of the energy legal field will find the Journal content worthy of subscription and will be eager to attend the symposiums. It is our hope that some of you consider donating to the establishment of permanent scholarships for future student editors—as the educational opportunities afforded to student editors is beneficial to us all. Finally, we hope that the Journal is successful for generations to come.

THE EDITORIAL BOARD

April 10, 2006

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8. This may or may not be in the near future. Ultimately, we expect to find or develop material that suits our ambition. We believe that the structure of the organization and the resources available through the law school positions us to best serve and respond to the changing needs of a niche market—one that has been underserved by large traditional publishers.
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INTERPRETING OIL AND GAS INSTRUMENTS

DAVID E. PIERCE*

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* Professor of Law, Washburn University School of Law.
I. Introduction

Most oil and gas disputes are over the “meaning” of a contract or conveyance. Ostensibly, the court’s goal when deciding a “meaning” dispute is to ascertain the intent of the parties. The process by which intent is ascertained frequently determines the meaning of the instrument. Manipulating process can manipulate meaning. This is not a new phenomenon, it has been the case since the parol evidence rule and the doctrine of merger became part of the common law. The important question in the jurisprudential scheme of things is, “When should process override meaning?” For example, courts uniformly determine that process should override intent when the evidence of intent concerns conflicting terms revealed by negotiations leading up to an integrated unambiguous contract. This is more commonly known as the parol evidence rule.

The public interest issue in all process versus intent analyses is deciding when to sacrifice freedom of contract—the free will of the parties—in favor of a frequently ill-defined competing policy. When the instrument to be interpreted is characterized as a “conveyance,” the competing policy is often the ability to look at a recorded document, apply a rule of interpretation, and make a reasonable prediction about ownership. However, in most cases this is expressed as a benefit of the outcome instead of the driving force for selecting a process.

This article evaluates Texas jurisprudence governing the process by

1. When the transaction is a gift, the focus will be solely on the intent of the grantor, whether a donor, settlor of a trust, or testator of a will. When the transaction is not a gift, the focus will be on the intent of all parties to the transaction: buyer, seller, grantor, and grantee. For example, the Restatement (Third) of Property notes that some conveyances are not donative but instead are made pursuant to contract. Restatement (Third) of Property: Donative Transfers § 10.1 cmt. e (2003) (“Although these [contractual transfers] are not donative transfers, and although the transferor is not a donor, various rules stated in this Division, such as the rules regarding the use of extrinsic evidence and the use of constructional preferences in resolving ambiguities, can help determine the meaning and effect of contractual transfers of this type.”).

2. This has been aptly noted in Professor Kramer’s revealing and influential work on canons of construction used to interpret mineral deeds and oil and gas leases. Bruce M. Kramer, The Sisyphean Task of Interpreting Mineral Deeds and Leases: An Encyclopedia of Canons of Construction, 24 Tex. Tech. L. Rev. 1, 6 (1993) (“There may be an inverse relationship between the liberality of a court’s acceptance of extrinsic or parol evidence and a court’s use of canons of construction in cases involving the interpretation of a written instrument.”).

3. The doctrine of merger serves the same function in property law that the parol evidence rule serves in contract law. The issue in each case is whether a writing was intended by the parties to be their final statement regarding a transaction. See GXG, Inc. v. Texacal Oil & Gas, 977 S.W.2d 403, 415-16 (Tex. App.—Corpus Christi 1998, pet. denied) (discussing the doctrine of merger and its relationship to the parol evidence rule).

which courts purport to ascertain the intent of parties to an instrument. The false analytical tool of “ambiguity” is examined as one of the many tautological platitudes that masquerade as analysis in the interpretive process. The use of surrounding circumstances evidence, as it relates to the historical context of the transaction in which the instrument was created, is examined as a frequently overlooked, but potentially determinative, adjunct to any interpretive process that seeks the intent of the parties at the time the conveyance or contract was created. The goal of this article is to demonstrate why parties and the courts should move beyond the tautological platitudes traditionally used to evaluate interpretive issues.

Any useful analysis of jurisprudence governing instrument interpretation must account for underlying public policy. Therefore, we will begin, and end, our study by analyzing the competing policies of instrument interpretation.

II. THE COMPETING POLICIES OF INSTRUMENT INTERPRETATION:
FREE WILL V. PREDICTABILITY

A. The Parties’ Free Will to Contract and Convey

The most explicit and frequently articulated public policy impacting instrument interpretation is the desire to give effect to the free will of the parties to an instrument by recognizing and protecting “freedom of contract.” In the property law context we can call this “freedom of conveyance,” recognizing that the legal effect of most instruments, whether “oil and gas” or otherwise, is the product of contract and property law. The oil and gas “lease” is the best example. Although the instrument constitutes a “conveyance” of the oil and gas, and associated easements to develop the oil and gas, it is also a “contract” which imposes many continuing obligations on the parties to the lease.5

“Freedom of contract” and “freedom of conveyance” describe the basic policy of a free society which allows the parties to an instrument to impose, and in turn, consent to whatever terms they may objectively construct for themselves. The exceptions to this freedom concern situations where free will has not in fact been allowed to operate. These include instances of misrepresentation, mistake, duress, undue influence, unconscionability, and lack of capacity.6 The other exceptions concern

5. Professor Sullivan notes in his treatise that the oil and gas lease is “a conveyance replete with contractual provisions indicative of an executory bilateral contract” and therefore, “[t]he oil and gas lease partakes of both a contract and a conveyance.” ROBERT E. SULLIVAN, HANDBOOK OF OIL AND GAS LAW § 21, at 69, § 22, at 70 (1955).
6. Professor Farnsworth addresses these issues in his treatise as matters of “behavior” and “status.” E. ALLAN FARNSWORTH, CONTRACTS 217 (4th ed. 2004) (Chapter 4 “Policing the
the exercise of free will which conflicts with a recognized public policy.\textsuperscript{7} For example, in the contract law context the resulting agreement may authorize an activity, such as a restraint of trade, that creates unacceptable public impacts that transcend the parties to the agreement.\textsuperscript{8} In the property law context the best examples of public policy limitations on free will are the rule against perpetuities and the rule prohibiting unreasonable restraints on alienation.\textsuperscript{9}

Promotion of the parties’ free will is often tied to interpretation. To give effect to the parties’ free will, it is necessary for the court to ascertain their “will.” The linkage between free will and interpretation is often made shortly after the court declares the contract or conveyance “unambiguous.” Once this is done, the court that just decided the language in the instrument was perfectly clear (unambiguous) simply gives effect to the language chosen by the parties. This purportedly gives effect to the intent of the parties and, in turn, to their free will. Rejecting a contrary interpretation becomes a matter of protecting freedom of contract. For example, the court in \textit{Wood Motor Co. v. Nebel},\textsuperscript{10} interprets a termination clause in a franchise agreement by first noting, “We can discover no ambiguity whatever in the language . . . .”\textsuperscript{11} The court rejects the other party’s interpretation stating, “Under our view, to support that [other party’s] theory would be to make a contract for the parties and deny to them the valuable right to contract for themselves.”\textsuperscript{12} Of course, this process will accurately reflect the parties’ free will only to the extent the judge’s perceptions of what is “unambiguous” and what the language in the instrument “means” coincide with those of the parties.

This makes ascertainment of the parties’ intent to a contract or conveyance a matter of public policy. The court articulates these principles in \textit{Wood Motor} as follows:

Long ago Sir George Jessel wrote: “. . . if there is one thing which
more than another public policy requires it is that men of full age and competent understanding shall have the utmost liberty of contracting, and that their contracts when entered into freely and voluntarily shall be held sacred and shall be enforced by Courts of justice. Therefore, you have this paramount public policy to consider—that you are not lightly to interfere with this freedom of contract.” Printing and Numerical Registering Co. v. Sampson, 19 L.R., Equity, 462, 465.13

Early Texas cases elevate freedom of contract to a natural law principle: “The citizen has the liberty of contract as a natural right which is beyond the power of the government to take from him.”14

B. The Title Examiner’s Quest for Predictability

The competing policy is the desire for predictability that can be obtained by adopting bright-line objective rules of interpretation. This policy is typically mentioned when the interpretation problem can be classified as a “title” issue. For example, in J. Hiram Moore, Ltd. v. Greer,15 the court held a deed ambiguous which purported to convey an interest in a described tract of land followed by a general grant of “all of grantors [sic] royalty and overriding royalty interest in all oil, gas and other minerals in the above named county . . . .”16 Usually the ambiguous or unambiguous “analysis”17 primarily impacts the types of evidence that can be considered to define the terms of the conveyance and its meaning. In this case, however, it has a much larger impact on substantive property law principles.18

By declaring the conveyance “ambiguous” the meaning of the

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13. Id.
15. 172 S.W.3d 609 (Tex. 2005).
16. Id. at 615. The court was influenced by the grantor’s lack of any ownership in the described tract: “The deed in effect states Greer conveys nothing, and that she conveys everything. We cannot construe this deed as a matter of law.” Id. at 614.
17. Addressing whether something is ambiguous is often more “conclusion” than “analysis.” As in Greer the process consists of a justice looking at the language and concluding it is “ambiguous,” as four justices concluded, Greer, 172 S.W.3d at 614, or it is “unambiguous,” as the two dissenting justices concluded, id. at 616 (Owen, J. and Medina, J., dissenting), or that “hard cases make bad law,” as concurring Justice Hecht observed, id. at 614 (Hecht, J., concurring).
18. This case would not have attracted much attention had the trial court been able to avoid severing the interpretation issue from the rescission and reformation claims. If the trial court had found a defect in the bargaining process (justifying rescission), or a mistake in the statement of their resulting bargain (justifying reformation), the impact of the case would have been limited to its unique facts. Normally this is also the impact of declaring an instrument “ambiguous” because you can seldom predict, from one case to another, the extrinsic evidence that will be available to resolve the ambiguity. The difference in this case is that similar general conveyance language had already been given a particular meaning, in prior cases, after being declared “unambiguous.” Those holdings then became the basis for title examiners making predictions regarding the impact of similar “unambiguous” language in other conveyances.
conveyance becomes an issue of fact for a jury to decide. 19 This means that the general granting language, covering any interest the grantor owns in Wharton County, Texas, may be limited by the interpretive process. As noted by the dissent, prior cases gave effect to such general grants.20 As noted by the amici title examiners, they relied upon these prior cases when passing on titles containing general granting language.21 These are actually two separate issues. The first issue is the determination of whether doubtful cases should be resolved against finding an ambiguity so the title issue can be resolved as an issue of law. The second issue, which is not the focus of this article, is when should courts be willing to alter an interpretive rule that has been legitimately and properly relied upon by the practicing bar to advise their clients and plan their affairs.22 This second rule goes to the “stability” of titles once established by an analysis of the applicable rules. Although the two are interrelated – because stability aids predictability – predictability is an issue that influences the sort of “rule” that is selected in the first instance.

C. The Practical Impact of the Competing Policies

Maximizing a predictability policy requires that an instrument be declared “completely integrated” and “unambiguous”23 so it can be interpreted by applying an established set of interpretive rules to the language contained within the instrument. Consideration of any evidence other than the words of the instrument would thwart predictability. Uniform outcomes become the goal as opposed to any real attempt to ascertain the intent of the parties.

The basic problem with the competing policies of predictability and free will is that one can only be maximized at the expense of the other. When pressed to select among these competing policies, courts opt for a policy favoring the free will of the parties. This is perhaps best illustrated by the Texas Supreme Court’s rejection of its mechanical, rule-oriented approach to “interpretation” in Alford v. Krum in favor of a more holistic, less “predictable” approach in Luckel v. White.24 It is also

19. The court in Greer holds, “Given the deed’s ambiguity, the trial court erred in granting summary judgment. A jury should therefore hear evidence and determine the parties’ intent.” Greer, 172 S.W.3d at 614. This assumes, however, there will be additional extrinsic evidence to consider which the parties dispute.

20. “Our jurisprudence has given effect to geographic grants for more than 100 years.” Id. at 618 (Owen, J., dissenting).

21. “[Amici] tell us that the failure to give effect to the plain meaning of the deed before us will lead to severe adverse consequences including the failure of previously certain titles and security interests and a proliferation of litigation that can only be resolved by a trial to determine the meaning of ‘ambiguous’ instruments.” Id.

22. This is where I would apply a principle I routinely share with my property students: “The only thing worse than a bad rule of property is one that changes.”

23. Even when it may, in fact, be “ambiguous.”

24. Alford v. Krum, 671 S.W.2d 870 (Tex. 1984), overruled by Luckel v. White, 819 S.W.2d
illustrated by the Texas Supreme Court’s rejection of the San Antonio Court of Appeals’ more mechanical, rule-oriented “two-grant” approach in Concord Oil Co. v. Pennzoil.25 The court of appeals was adamant that its two-grant approach be applied to promote “[t]he public interest in certainty in land titles . . . .”26 This was a predictability policy the court of appeals found to be “overriding and paramount.”27 The Texas Supreme Court did not agree and reversed; a plurality of the court rejected the two-grant analysis, and the court instead promoted a free will policy built around “a unifying principle: the entire document must be examined to glean the parties’ intent.”28

When urged by amici title examiners in Concord to adopt “firm” or “bright-line” rules to resolve interpretive issues, the Texas Supreme Court rejected their invitation:

Bright-line tests that focus only on the predominance of one clause over another or that strictly construe each provision in a conveyance as a separate, independent grant, or that choose the larger of conflicting fractions are arbitrary. They will not always give effect to what the conveyance provides as a whole. The principles set out in Luckel and the approach taken in Garrett are designed to give effect to the intent of the parties as actually expressed within the four corners of the conveyance and to harmonize provisions that appear to conflict.29

The only acknowledged compromise between predictability and free will has been the rule that the search for intent is a search for the “objective” intent of the parties as opposed to their “subjective” intent.30 This too was acknowledged by the court in Concord: “the intent of the

459 (Tex. 1991). These cases are discussed fully in subsequent sections of this article.


26. Id. at 195.

27. Id.

28. Concord, 966 S.W.2d at 454.

29. Id. at 460-61.

30. Professor Farnsworth notes, “[i]f the parties attached different meanings to that language, the court’s task is the more complex one of applying a standard of reasonableness to determine which party’s intention is to be carried out at the expense of the other’s.” E. ALLAN FARNSWORTH, CONTRACTS § 7.9, at 452 (4th ed. 2004). Therefore, the goal will be to offer whatever evidence is available and relevant to establish the “standard of reasonableness” that should be used to define what will become the objective intent of the parties. This assumes there is no fault-based reason to give effect to an “innocent” party’s subjective intent that was known by the other party, or which, under the facts, the other party should have known. Id. at 449 (“a party that makes a contract knowing of a misunderstanding is sufficiently at fault to justify that party’s being subjected to the other party’s understanding.”); see also RESTATEMENT (SECOND) OF CONTRACTS § 201(2) (1981) (stating that terms in an agreement should be interpreted in accordance with the meaning attached by a party if that party had no reason to know of a different meaning and the other party knew or should have known the first party attached a different meaning to the terms).
parties must be determined from what they expressed in the instrument, read as a whole, and that the actual, subjective intent of the parties will not always be given effect even if we were able to discern that subjective intent.” As the following sections will demonstrate, perhaps the best guide for ascertaining the parties’ intent to an instrument is the consideration of all relevant evidence which assists in defining the objective intent of the parties. This would reflect the proper balance struck between the predictability and free will policies and eliminate the temptation to further tip the scales through artificial “ambiguity” determinations designed to exclude relevant evidence of objective intent.

III. FROM ALFORD V. KRAM TO CONCORD OIL V. PENNZOIL

A. Alford v. Kram: The Price of Predictability

If predictability were the main concern of courts and the practicing bar, then Alford v. Kram would still be good law. In Alford, a 1929 mineral deed granted a “one-half of one-eighth interest in and to all the oil, gas and other minerals . . .” This “granting clause” was followed by a “present lease” clause noting the conveyance “covers and includes 1/16 of all the oil royalty and gas rental or royalty due to be paid under the terms of said lease.” This was followed by a “future lease” clause which acknowledged the grantor and grantee would each own “a one-half interest in all oil, gas and other minerals in and upon said land, together with one-half interest in all future rents.” The interpretive dispute concerned whether the grantee received a one-sixteenth mineral interest (“one-half of one-eighth”) or a one-half mineral interest. The court held, “We must resolve the conflict and lack of clarity in favor of the clear and unambiguous language of the granting clause and hold that the deed

31. Concord, 966 S.W.2d at 454.
32. In a survey conducted by the Oil, Gas and Mineral Law Section of the Texas Bar, Alford v. Kram was identified as one of the “most regrettable” oil and gas law decisions of the Texas Supreme Court. Robert Bledsoe & John Scott, The Ten Most Regrettable Oil and Gas Decisions Ever Issued by the Texas Supreme Court—and the “Winner”—Based on a Survey, EIGHTEENTH ANNUAL ADVANCED OIL, GAS AND MINERAL LAW COURSE, STATE BAR OF TEXAS (1990).
33. 671 S.W.2d 870 (Tex. 1984), overruled by Luckel v. White, 819 S.W.2d 459 (Tex. 1991).
34. In a recent developments article presented in 1995, where I reported on the court of appeals opinion in Concord, I commented on the “predictability” issue as follows:

Members of the Texas oil and gas bar should be careful what they wish for—their wish might come true! The author predicts that in the years to come Texas oil and gas attorneys, at least those who examine titles, may actually long for the days of Alford v. Kram.

35. Alford, 671 S.W.2d at 871.
36. Id. at 871.
37. Id.
conveyed only a perpetual one-sixteenth mineral interest to Mang [grantee]."  

The court arrived at this conclusion by applying the following interpretive rule:

In cases involving the construction of mineral deeds, the “controlling language” and the “key expression of intent” is to be found in the granting clause, as it defines the nature of the permanent mineral estate conveyed. It logically follows that when there is an irreconcilable conflict between clauses of a deed, the granting clause prevails over all other provisions.

The Alford rule promotes predictability by ignoring language in other parts of the deed that appear to conflict with the terms of the granting clause. This means the practicing bar, seeking title certainty, could resolve the thousands of mineral deed interpretive problems by simply ignoring language in the present lease and future lease clauses of the deed. The three dissenting justices in Alford objected to the majority’s failure to give effect to all the language in the deed, and thereby give effect to what they felt was the obvious intent of the parties to the deed. The majority held the present and future lease clauses must be ignored because otherwise they muddle “the clear and unambiguous language of the granting clause.”

This allows the court to apply the Alford rule as a matter of law to the “unambiguous” deed. Without the Alford rule, the deed contains a future lease clause which “as a whole, is unclear . . . .” Because it conflicts with the granting clause, a judge might be inclined to declare the conveyance “ambiguous” to allow the court to conduct a wider search of the facts for the parties’ meaning. However, this result is avoided by declaring the present and future lease clauses “repugnant” to the granting clause and then, in effect, striking them out of the deed. Once they are eliminated from the analysis, we are left with “the clear

38. *Id.* at 874.
39. *Id.* at 872 (citations omitted).
40. The dissenting justices, like the majority, thought the conveyance was unambiguous: “There is no ambiguity in the deed that grants a one-sixteenth mineral estate so long as there is an outstanding lease and a one-half mineral estate upon the lease’s termination.” *Id.* at 875 (Pope, C.J., dissenting). They avoid ambiguity by applying a two-grant analysis with the first grant apparently being a defeasible interest “so long as there is an outstanding lease” and then a new interest vesting, through the future lease clause, once the lease terminated. If this analysis was accepted, and the future lease clause was not held to be a present conveyance of the lessor’s possibility of reverter, the interest would violate the rule against perpetuities. See generally Peveto v. Starkey, 645 S.W.2d 770 (Tex. 1982) (holding a deed granting a non-participating royalty, to take effect when production ceased in paying quantities, created a springing executory interest that was not certain to vest within the limits of the rule). However, in Luckel v. White, 819 S.W.2d 459, 464 (Tex. 1991), the court suggests: “Since the deed makes a present conveyance [in the future lease clause] of the possibility of reverter, there is no violation of the rule against perpetuities.”
42. *Id.* at 873-74.
and unambiguous language of the granting clause . . . .”43 This allows the court to remove conflicting language from the express terms of the deed before it considers whether it is ambiguous.

All of this should have pleased even the most hard core title examiner looking for predictability in the recorded document. The court applied a rule to ensure the document remained “unambiguous” and then used the same rule to assign a generic meaning to the language in the document. Apparently even title examiners flinched at a rule that would so readily discount the objective expressions of the parties found within the four corners of their deed.

B. Luckel v. White: Alford, and Predictability, Take a Hit

The court in Luckel v. White refused to apply the Alford analysis to a conveyance with present and future lease language that could be construed as repugnant to the granting, habendum, and warranty clauses.44 Instead, four justices of the court stated, “We reverse the court of appeals, overrule Alford v. Krum, and hold that the so-called ‘future lease’ clause was effective to convey a one-fourth interest in all royalties as to future leases.”45 Four dissenting justices believed the issue was proper “harmonization” of the conveyance which would avoid an Alford “repugnant to the grant” showdown.46 What we ended up with were eight justices looking at the same “unambiguous” deed47 with four concluding it meant “x” and four concluding it meant “y.” The deciding vote of concurring Justice Mauzy reflected a concern that the court should give effect to the free will of the parties. Ultimately, Justice Mauzy joined in overruling Alford because the holding limited consideration of all language in the deed. Because Justice Mauzy also concluded that the unambiguous document meant “x,” when his opinion is joined with that of the plurality, we learn that this document has always clearly and unambiguously meant “x,” not “y.” Alford is dead. Harmony, or at least harmonization, prevails.

43. Id. at 874.
44. Luckel v. White, 819 S.W.2d 459, 464 (Tex. 1991) (“Upon further consideration, we have concluded that the majority in Alford incorrectly failed to harmonize the provisions under the four corners rule and then erred in applying the ‘repugnant to the grant’ rule in disregard of the future lease clause.”).
45. Id. at 461.
46. Id. at 466 (Phillips, C.J., dissenting).
47. The plurality opinion notes, “There is no contention that the deed is ambiguous.” Id. at 461. The dissenting opinion notes, “Rather than interpreting the future-lease clause as an additional grant, I would give effect to the clear and unambiguous language of the granting, habendum, and warranty clauses, all of which express the intent to grant a permanent 1/32nd interest.” Id. at 466.
C. Concord Oil v. Pennzoil: Is Alford Looking Good Yet?

The Texas Supreme Court’s opinion in *Concord Oil Co. v. Pennzoil Exploration and Production Co.*[^48] is another 4-1-4 decision interpreting language in a deed that was determined to be an “unambiguous” conveyance. The deed granted “an undivided one-ninety sixth (1/96) interest in and to all the oil, gas and other minerals in and under, and that may be produced from” described land.[^49] A subsequent portion of the deed provided the following:

> While the estate hereby conveyed does not depend upon the validity thereof, neither shall it be affected by the termination thereof, this conveyance is made subject to the terms of any valid subsisting oil, gas and/or mineral lease or mineral lease or leases on above described land or any part thereof, but covers and includes one-twelfth (1/12) of all rentals and royalty of every kind and character that may be payable by the terms of such lease or leases insofar as the same pertain to the above described land, or any part thereof.[^50]

The issue was whether the reference to a one-twelfth “of all rental and royalty” indicated something more than a one ninety-sixth mineral interest was intended by the parties.

The trial court and court of appeals applied a “two-grant” analysis and concluded a one ninety-sixth mineral interest (grant #1) was conveyed along with a right to one-twelfth of the rental and royalty (grant #2), giving literal effect to all the language as separate conveyances.[^51] The supreme court, in a 4-1-4 split, rejected a two-grant analysis and instead sought to harmonize the varying fractions by concluding the parties intended one ninety-sixth to really mean one-twelfth.[^52] As discussed in the section that follows, apparently the only thing that everyone agreed upon in the *Alford* and *Concord* cases was that the conveyances at issue were not ambiguous.

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[^48]: 966 S.W.2d 451 (Tex. 1998).
[^49]: Id. at 453.
[^50]: Id. at 451.
[^51]: Concord Oil Co. v. Pennzoil Exploration & Prod. Co., 878 S.W.2d 191, 196 (Tex. App. 1994), rev’d, 966 S.W.2d 451 (Tex. 1998) (“We hold that the deed conveyed only a 1/96 mineral interest, in addition to the 1/12 interest in the existing lease which expired when the lease terminated.”). The court of appeals was particularly influenced by the absence of a “future lease” clause that would typically contain language supporting a right to one-twelfth of the production in the future. This would have provided further evidence of intent regarding the quantity of mineral interest the parties intended and would have aligned the conveyance with several prior holdings of the Texas Supreme Court. Id. at 195 (“The case before us is entirely different because the 1937 Crosby-Southland deed does not contain a future-lease clause.”).
[^52]: *Concord*, 966 S.W.2d at 459.
IV. TAUTOLOGICAL PLATITUDES V. REASONED ANALYSIS

A. The Artificial Role of an “Ambiguity Analysis”

Is it not odd that under the current state of the law in Texas the only time there is any real attempt to give effect to the intent of the parties is when their instruments are so poorly drafted as to be deemed “ambiguous”? Does this mean the better drafted instruments are not worthy of a court’s efforts to ascertain the intent of the parties? Apparently the better drafted instruments merely serve the function of triggering the court’s conclusion they are “unambiguous” so they can be processed through whatever the current 4-1-4 split in the court says they “mean.” Oil and gas lawyers who are truly concerned that their documents will be “interpreted” instead of “processed” will begin each document with the following recitation: “THE PARTIES INTEND THIS INSTRUMENT TO BE AMBIGUOUS.”

The problem with the current jurisprudence in Texas is the instrument merely provides the background for the current litigants to argue for a judicial pronouncement of its meaning as a matter of law. The goal of each party is to “win” the interpretive “process” war instead of seeking to interpret the instrument. With each party arguing the instrument is “unambiguous” so they can engage in their “matter-of-law” battles, the language of the instrument merely becomes a side-show for triggering the interpretive tautological platitude they hope will ultimately be applied to support their position. The process actually prevents reasoned analysis of what the court always says is the goal: ascertaining the intent of the parties. Although the use of this matter-of-law interpretive charade is demanded by the practicing bar, argued for by litigants, and pronounced by justices (plurality, concurring, and dissenting alike), it has consistently eluded the title certainty which they all purport to seek.

B. A Functional Alternative: All Relevant Evidence Regarding Objective Intent

Perhaps it is time to do something that may seem, at least facially, radical: eliminate “ambiguity” from the analysis, and the process, altogether. Eliminating the ambiguity analysis, however, is not as radical as it seems because it has never been an “analysis” but rather a convenient “conclusion.” The process would still apply the parol evidence rule and merger doctrines, and the inquiry would be, as it has always been, whether the parties intended the words in the instrument to be all the words they wanted to use to express their agreement. This is the first step of the analysis. There is no need for any sort of ambiguity analysis;
we simply ascertain whether the words used were intended by the parties to be the extent of their agreement.53

If we conclude the parties intended the instrument to contain all the terms of their agreement, we proceed to step two to consider all relevant evidence as to what those terms mean. At this stage the parol evidence rule or doctrine of merger will exclude evidence that seeks to contradict the integrated or merged instrument and, if it is deemed to be a completely integrated or merged instrument, the rule or doctrine will limit evidence that seeks to supplement the instrument. Beyond these limitations, however, any relevant evidence, in any acceptable form, should be considered by the court in seeking to ascertain the intent of the parties. This may not promote predictability, but it will at least provide an honest attempt to promote the policy of free will.

Arguably considering all relevant evidence would promote title certainty as much as the current shifting “matter-of-law” approach to these issues. The title examiner could at least read the instrument, ascertain the objective circumstances surrounding the transaction, and make an educated judgment call on how imprecise language is likely to be interpreted. The examiner would not have to anticipate the latest theory, argument, or twist a majority of the court will find convincing to change interpretive issues as a matter of law. The predictability may be less when we seek to interpret the instrument, but the risk associated with the law would be much less, as long as the guiding principle is “consideration of all relevant evidence that assists in ascertaining the intent of the parties.”

To adopt such an approach the court need not engage in a search for the parties’ subjective intent, except in situations where there is objective evidence that one party was aware of the other party’s subjective intent.54 In the vast majority of cases, the only evidence that will be available to the parties will be objective in nature. Often the original parties to the transactions will not be available; they have long since passed on and all that will be available is the objective historical record of events. Often, the evidence available in these cases will not be disputed; the only issue is the interpretive conclusion that should be drawn from the undisputed evidence.55 This should allow courts to “interpret” many instruments as a

53. These are integration and merger issues. Although not addressed in the case, the deed at issue in J. Hiram Moore, Ltd. v. Greer, 172 S.W.3d 609 (Tex. 2005) was, at most, a partial integration (merger) of the parties’ agreement because it expressly contemplates going outside of the written document to identify what is being conveyed. This means the terms of all other documents that confer on grantor a “royalty and overriding royalty interest in all oil, gas and other minerals” would have to be examined to identify the subject matter of the instrument being interpreted. Id. at 612.
54. See supra notes 30-31.
55. For example, in Concord a “fact” not contained within the four corners of the deed was
matter of law since the issue is not whether a fact exists, but rather the conclusion that should be drawn from the fact, considering its relation to all other undisputed facts. If only one reasonable conclusion can be drawn from the undisputed facts, the issue is a matter of law for the court.56

One of the basic problems with the existing analysis is it assumes one piece of evidence will be outcome-determinative. Presumably this is done to support a rule-oriented approach to defining rights in instruments. The true process is usually one of considering the weight of all the evidence. Some evidence will support one conclusion; other evidence may support a different conclusion.57 It is a matter of judgment. The section that follows addresses the types of relevant extrinsic evidence that will often be useful in ascertaining the objective intent of the parties to an instrument.

V. ASCERTAINING THE INTENT OF THE PARTIES

Once the terms of the instrument have been identified applying the parol evidence rule or the doctrine of merger, the next task is to ascertain what the parties meant when they used those terms. Although this process of ascertaining meaning has been influenced heavily by the “ambiguity analysis,” most jurisdictions, including Texas, recognize a role for objective, independently verifiable evidence of the “surrounding circumstances” that may have influenced the parties at the time the instrument was created.

that on the day before the conveyance the grantor had been conveyed a one-twelfth mineral interest. Concord, 966 S.W.2d at 453. Although the “meaning” of this fact was disputed by the parties, the fact itself was not disputed. 56. The Restatement (Second) of Contracts provides the following:

A question of interpretation of an integrated agreement is to be determined by the trier of fact if it depends on the credibility of extrinsic evidence or on a choice among reasonable inferences to be drawn from extrinsic evidence. Otherwise a question of interpretation of an integrated agreement is to be determined as a question of law.

RESTATEMENT (SECOND) OF CONTRACTS § 212(2) (1981). Comment e. expands on the black-letter provisions:

Even though an agreement is not integrated, or even though the meaning of an integrated agreement depends on extrinsic evidence, a question of interpretation is not left to the trier of fact where the evidence is so clear that no reasonable person would determine the issue in any way but one. But if the issue depends on evidence outside the writing, and the possible inferences are conflicting, the choice is for the trier of fact.

Id. at cmt. e.

57. These problems arise even though there is no dispute concerning the validity or relevancy of the evidence. Party A interprets facts 1, 2, and 3 to mean “x.” Party B interprets the same exact facts 1, 2, and 3 to mean “y.” The judge is called upon to evaluate the same facts and determine that they mean “x,” “y,” or perhaps “z.” The judge must weigh the evidence to arrive at a reasonable conclusion. This is different from having the judge merely select a rule of law that best coincides with the facts to declare what the parties meant.
A. “Surrounding Circumstances” Evidence

Surrounding circumstances evidence consists of any relevant fact existing at the time the parties entered into their instrument that may assist in ascertaining what the parties intended the instrument to mean. It is “extrinsic” evidence because its existence is not acknowledged within the four corners of the instrument being interpreted.58

1. The Concord Deed

Although courts infrequently discuss the role of surrounding circumstances evidence, it is frequently used by the courts in their interpretive processes. For example, nowhere in any of the opinions in the Concord case59 do the courts focus on their use of extrinsic surrounding circumstances evidence to interpret the deed at issue. However, in each opinion, where the court is purporting to interpret an unambiguous deed, references are made to critical facts nowhere to be found in the deed.

In the court of appeals’ opinion it relies on the following surrounding circumstances to support its conclusions:

(1) The day before the August 5, 1937 grant the grantor had been granted a 1/12 mineral interest in the land.60

(2) At the time the deed was executed, the minerals were subject to an existing oil and gas lease.61

(3) In response to Caruthers v. Leonard, lawyers conveying mineral interests that were subject to an existing oil and gas lease developed the three-grant deed which included a granting clause, a present lease clause, and a future lease clause.62

(4) Caruthers was reversed in 1943 by Harris v. Currie;63 thus, it was still good law in 1937 when the conveyance was made.

(5) The deed does not contain what industry custom and usage would label a “future lease” clause.64

60. Id. at 192. (“All parties trace their title to A.B. Crosby, who received a ½ mineral interest from Emilia T. de la Garza on August 4, 1937. The following day, August 5, Crosby executed a deed to Southland . . . .”).
61. Id. (“At issue in this oil and gas case is the size of a mineral interest conveyed by a 1937 deed executed while the grantor’s interest was subject to a producing lease.”).
62. Id. at 193.
63. Id.
64. Id. at 195 (“The case before us is entirely different because the 1937 Crosby-Southland deed does not contain a future-lease clause.”).
(6) The “two-grant” doctrine was in existence at the time the deed was executed.  

None of these matters were identified in the deed at issue. Is there any doubt that a court would consider in some fashion this sort of independently verifiable information in the chain of title on the date the conveyance was made? Must courts ignore the grantor’s source of title or the existence of an oil and gas lease when interpreting the language within the four corners of the deed at issue?

Also note that the existence, meaning, and status of the Caruthers case, and the two-grant doctrine, are not being argued as legal principles but rather are presented as matters of fact. The parties are not presenting these as legal conclusions but rather as facts the court should consider to interpret the deed. Therefore, it would be appropriate to receive expert testimony regarding the status of the “law” at the time of the conveyance because it is being presented merely to establish that such law existed as opposed to seeking to apply the law to a set of facts. This could also be done through an appropriate request for judicial notice.  

The court also recognizes the industry “usage” that developed in response to the Caruthers case: the development and use of a special form of conveyance containing a granting clause, present lease clause, and a future lease clause. Quoting the scholarship of Professor Laura Burney, the court notes: “Thus, the three-grant deed came into vogue, not to provide parties with a mode for making separate conveyances in one deed, but to insure that a single grant of a fractional mineral interest included a proportionate interest in benefits under existing and future leases.” The court relied upon this analysis to distinguish the deed at

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65. Id. (“[T]he two-grant doctrine . . . has been part of Texas law for at least half a century.”).

66. When relying upon historical context to interpret an instrument, the necessary information should always be established as a matter of fact as opposed to being left to argument. For example, assume you have a case concerning the interpretation of a 1942 conveyance and the status of Caruthers v. Leonard, as of 1942, is important to your theory. You do not want to leave these matters to mere argument. Instead, you want to establish, as a matter of fact, what the “law” was in 1942, including whether Caruthers had in fact been overruled 15 years earlier in Hager v. Stakes, or would not be overruled until December 15, 1943 in Harris v. Currie. Although these topics are proper for the use of expert testimony, in many instances a more efficient, and in some ways more effective, technique will be to establish the necessary historical context through judicial notice. See generally Olin Guy Wellborn III, Judicial Notice Under Article II of the Texas Rules of Evidence, 19 ST. MARY'S L. J. 1 (1987).

67. The term “usage” is used to describe what is often referred to as “custom and usage” or “custom and practice.” David E. Pierce, Defining the Role of Industry Custom and Usage in Oil & Gas Litigation, 57 SMU L. REV. 387, 389-90 (2004).

issue noting that “the 1937 Crosby-Southland deed does not contain a future-lease clause.”

Like the court of appeals, the Texas Supreme Court also relied heavily on surrounding circumstances. The court makes the following observations:

The deed was executed on August 5. The day before, the grantor Crosby had acquired an undivided 1/12 interest in the minerals under a deed identical to the Concord deed in all respects but one: the fraction in the granting clause. The granting clause in the deed to Crosby contained the fraction “one-twelfth (1/12)” rather than 1/96.

The parties have stipulated that at the time each of these deeds was executed, an oil and gas lease that provided for a one-eighth royalty was outstanding. That lease expired before any of the parties to this case entered into leases covering Survey Sixty-four.

The court also notes the possible influence of Tipps v. Bodine on the approach taken by the grantor in structuring its deed:

The decision in Tipps, which helped to foster this so-called “estate misconception,” went so far as to say that the use of differing fractions was the proper method of conveyance when a mineral lease was outstanding at the time of the grant. . . . The Tipps court thus blessed the use of “1/16” in the granting clause and “1/2” in subsequent clauses when the grantor owned the possibility of reverter in the entire mineral estate and wished to convey 1/2 of that interest at a time when the property was subject to a mineral lease providing for a 1/8 royalty. Tipps was decided in 1936, and the Concord deed was executed in 1937. Under the rationale of Tipps, it would have been appropriate for Crosby to have inserted “1/96” in the granting clause and “1/12” in other provisions of the Concord deed if he intended to convey a 1/12 interest in the minerals.

The court concludes it is “mindful of extant circumstances at the time the Concord and other deeds were executed.” Although the court does not view this evidence as determinative, it is “helpful and instructive . . . .” This would appear to be the appropriate role of surrounding circumstances evidence: the express language of the document is obviously critical and where we begin while surrounding circumstances

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69. Id. at 195. The court’s implicit reasoning was that since the deed at issue did not contain a future lease clause, then cases addressing the “three-grant deed” problem noted by Professor Burney should not apply. This set the stage for the court’s focus on the “two-grant doctrine” it ultimately uses to interpret the deed.
70. Concord, 966 S.W.2d at 453.
72. Concord, 966 S.W.2d at 460 (citation omitted).
73. Id.
74. Id.
evidence will often be “helpful and instructive” in determining what the parties meant when they used the express language.

The *Concord* case is particularly instructive concerning the importance of surrounding circumstances evidence. The very outcome of the *Concord* case turned on a single surrounding circumstance which was the deciding factor for Justice Enoch who cast the deciding vote with the plurality as the concurring justice in the 4-1-4 split. The critical fact was that the grantor only owned a one twelfth mineral interest at the time it conveyed the interest in dispute. If the two-grant theory of the dissenting justices is applied,75 this would result in an over-conveyance which Justice Enoch believed would be an unreasonable interpretation.76 Nothing within the four corners of the deed being interpreted revealed what the grantor owned at the time the conveyance was made. Therefore, this information was clearly “extrinsic” to the deed and could only become part of the mix of information as a relevant “surrounding circumstance” at the time the deed at issue was granted. As a result, the *Concord* case is an example of how extrinsic evidence proved to be the deciding factor in determining the meaning of an unambiguous deed.

2. *Sun Oil Co. v. Madeley* and Surrounding Circumstances

The Texas Supreme Court, in *Sun Oil Co. v. Madeley*,77 addresses a common state of affairs: “Although Sun and lessors cannot agree on the interpretation of the lease, they do agree that the lease is unambiguous.

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75. This is the approach Justice Enoch supported prior to the rehearing, and the approach he would support but for the fact it could have resulted in an over-conveyance at the time it was made. *Id.* at 463-64 (Enoch, J., concurring).

76. Justice Enoch reasoned as follows:

We cannot give the Crosby deed the reading that the dissent believes is correct—
that the deed makes two conveyances—because that reading is unreasonable. Assuming that the deed makes two conveyances, we would have the granting clause conveying a 1/96 mineral interest. But we would also have the “subject to” clause simultaneously conveying an additional 1/12 (or 8/96) interest in rentals and royalties under the then-current lease. This reading produces an over-grant.

At the time of Crosby’s deeds to his grantee, Southland, a mineral lease covered the property. The lessee held title to the mineral estate subject to the possibility that title would revert to Crosby and the other lessors in the future. Crosby, therefore, owned the possibility of a 1/12 mineral interest. Crosby’s reverter interest included the right to royalties under the then-current lease, as do all reverter interests in the absence of language to the contrary. . . . Therefore, the Crosby deed’s granting clause transferred to Southland 1/96 of Crosby’s reverter interest, carrying with it a corresponding 1/96 share of the royalties due under the then-current lease. . . . If the “subject to” clause were a separate conveyance, it would transfer to Southland an additional 8/96 interest in the royalties due under the then-current lease. Under the dissent’s construction, the granting clause and the “subject to” clause would convey 1/96 plus 8/96 for a total of 9/96 interest in the royalties, a larger interest than Crosby owned. This construction is not reasonable.

*Id.* at 464.

77. 626 S.W.2d 726 (Tex. 1981).
We also consider the lease unambiguous. The ultimate issue was whether an oil and gas lease reserved to the lessor, in addition to its royalty and a share of net profits from “oil” production, a share of net profits from “gas” production. The interpretive issue was whether the trial court improperly considered evidence of the “surrounding circumstances” to interpret the unambiguous oil and gas lease. The court appears to have clearly held that surrounding circumstances evidence can be considered “to determine whether or not the contract is ambiguous.”

The role of surrounding circumstances evidence in interpreting the document once it is found to be unambiguous is not as explicitly addressed. The court discusses this issue noting the following:

Lessors state the proper rule. Evidence of surrounding circumstances may be consulted. If, in the light of surrounding circumstances, the language appears to be capable of only a single meaning, the court can then confine itself to the writing. Consideration of the facts and circumstances surrounding the execution of a contract, however, is simply an aid in the construction of the contract’s language. There are limits. For example, when interpreting an integrated writing, the parol evidence rule circumscribes the use of extrinsic evidence.

The court’s statement footnotes section 230 of the Restatement (First) of Contracts:

The standard of interpretation of an integration, except where it produces an ambiguous result, or is excluded by a rule of law establishing a definite meaning, is the meaning that would be attached to the integration by a reasonably intelligent person acquainted with all operative usages and knowing all the circumstances prior to and contemporaneous with the making of the integration, other than oral statements by the parties of what they intended it to mean.

This is perhaps the best statement of the law as it in fact operates in most jurisdictions today. It rejects a search for the subjective intent of the parties (“statements by the parties of what they intended it to mean”) in favor of objective intent (“the meaning that would be attached to the integration by a reasonably intelligent person”) as defined by the express terms of the instrument plus objective evidence of the context in which the instrument was created (“with all operative usages and knowing all

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78. Id. at 727.
79. Id.
80. Id. at 731.
81. Id. (footnote omitted).
82. RESTATEMENT (FIRST) OF CONTRACTS § 230 (1932).
the circumstances prior to an contemporaneous with the making of the integration”). This is consistent with the court’s observation that “[i]n the usual case, the instrument alone will be deemed to express the intention of the parties for it is objective, not subjective, intent that controls.”

Section 230 of the Restatement acknowledges that various objective forms of evidence of surrounding circumstances are merely part of the objective intent of the parties as expressed in the instrument being interpreted.

This interpretation is further supported by the court’s quotation from Williston on Contracts where Professor Williston states the following:

[T]here must always be an association between words and external objects, and no matter how definite a contract may appear on its face, “words must be translated into things and facts.” Thus . . . the contract in any event had to be appraised in view of the surrounding circumstances known to the parties at the time of its execution and these reasonably could be looked to without violating the parol evidence rule even though the contract were not deemed ambiguous.

3. The American Law Institute and Surrounding Circumstances Evidence

The American Law Institute, in its restatement projects, has consistently recognized the necessity of interpreting wills, conveyances, and contracts considering the surrounding circumstances at the time the instrument at issue was created. As noted by the court in the Sun Oil case, section 230 of the Restatement (First) of Contracts expressly requires the court to interpret the instrument from the perspective of “a reasonably intelligent person acquainted with all operative usages and knowing all the circumstances prior to and contemporaneous with the making of the” instrument. The Restatement also provides specific “Rules Aiding Application of Standards of Interpretation” and divides them into two categories: primary and secondary. The primary rules are applied first; secondary rules are resorted to only “where the meaning of words or other manifestations of intention remains doubtful after the

83. Sun Oil Co. v. Madeley, 626 S.W.2d at 731 (quoting City of Pinehurst v. Spooner Addition Water Co., 432 S.W.2d 515, 518 (Tex. 1968).
84. 4 SAMUEL WILLISTON, A TREATISE ON THE LAW OF CONTRACTS § 609 (3d ed. 1961).
85. 4 SAMUEL WILLISTON, A TREATISE ON THE LAW OF CONTRACTS § 609 (3d ed. 1961).
86. Sun Oil, 626 S.W.2d at 731 n.5.
87. RESTATEMENT (FIRST) OF CONTRACTS § 230 (1932). This section is titled, “Standard of Interpretation Where There is Integration.” Comment a. to § 230 notes that “[t]he objective viewpoint of a third person is taken. He is assumed, however, to have knowledge of all operative usages . . . as well as of other accompanying circumstances.”
88. Id. § 235.
89. Id. § 236.
primary rules stated in sections 230, 233 have been applied, with all the aid that can be derived from the rules stated in section 235.”90

The primary rules are familiar and include: giving language its ordinary meaning,91 unless the context requires that it be given a technical meaning;92 interpreting the instrument as a whole,93 and “[a]ll circumstances accompanying the transaction may be taken into consideration”94 as provided for in section 230. Comment e. to the surrounding circumstances interpretive rule states the following:

The court in interpreting words or other acts of the parties puts itself in the position which they occupied at the time the contract was made. In applying the appropriate standard of interpretation even to an agreement that on its face is free from ambiguity it is permissible to consider the situation of the parties and the accompanying circumstances at the time it was entered into—not for the purpose of modifying or enlarging or curtailing its terms, but to aid in determining the meaning to be given to the agreement.95

These same interpretive principles are carried forward into the Restatement (Second) of Contracts at section 212(1): “The interpretation of an integrated agreement is directed to the meaning of the terms of the writing or writings in the light of the circumstances, in accordance with the rules stated in this Chapter.”96 Comment b. to this section addresses the relationship between “plain meaning” and “extrinsic evidence” as follows:

It is sometimes said that extrinsic evidence cannot change the plain meaning of a writing, but meaning can almost never be plain except in a context. Accordingly, the rule stated in Subsection (1) is not limited to cases where it is determined that the language used is ambiguous. Any determination of meaning or ambiguity should only be made in the light of the relevant evidence of the situation and relations of the parties, the subject matter of the transaction, preliminary negotiations and statements made therein, usages of trade, and the course of dealing between the parties.97

The Second Restatement’s equivalent rules to the First Restatement’s

90. Id. § 236 cmt. a.
91. “The ordinary meaning of language throughout the country is given to words unless circumstances show that a different meaning is applicable.” Id. § 235(a).
92. “Technical terms and words of art are given their technical meaning unless the context or a usage is applicable indicates a different meaning.” Id. § 235(b).
93. “A writing is interpreted as a whole and all writings forming part of the same transaction may be taken into consideration subject in case of integrations to the qualifications stated in § 230.” Id. § 235(c).
94. Id. § 235(d).
95. Id. § 235 cmt. e.
97. Id. at cmt. b.
primary rules of interpretation are found in section 202(1): “Words and other conduct are interpreted in the light of all the circumstances, and if the principal purpose of the parties is ascertainable it is given great weight.”98 Often the surrounding circumstances assist in identifying the “principal purpose” of the parties.

Moving from interpretation of contracts to the interpretation of conveyances, section 242 of the Restatement (First) of Property provides that “[t]he judicially ascertained intent of a conveyor is normally determined by the language employed in his conveyance, read as an entirety and in the light of the circumstances of its formulation.”99

Comment a. describes the “rationale” for this rule as follows:

The language employed in a conveyance, read as an entirety and in the light of the circumstances of its formation, constitutes the objectively observable manifestation of the conveyor’s intent and hence is necessarily assumed to evidence his subjective intent. Thus the stress upon such language and circumstances, embodied in the rule stated in this Section, tends to attain the dominant objective of the process of construction . . . .100

The other comments to section 242 focus on specific types and uses of surrounding circumstances evidence, to include:

d. Circumstances of the instrument’s formulation–Vocabulary peculiar to the conveyor.

e. Circumstances of the instrument’s formulation–Utilization of a drafting agent.

f. Circumstances of the instrument’s formulation–Skill in use of language or of legal phraseology.

98. Id. § 202(1). In comment a. it is noted that the ability to consider surrounding circumstances does not “depend upon any determination that there is an ambiguity, but are used in determining what meanings are reasonably possible as well as in choosing among possible meanings.” Comment b. to § 202 adds the following:

In interpreting the words and conduct of the parties to a contract, a court seeks to put itself in the position they occupied at the time the contract was made. When the parties have adopted a writing as a final expression of their agreement, interpretation is directed to the meaning of that writing in the light of the circumstances. . . . The circumstances for this purpose include the entire situation, as it appeared to the parties, and in appropriate cases may include facts known to one party of which the other had reason to know.

99. RESTATEMENT (FIRST) OF PROP.: FUTURE INTERESTS § 242 (1940). Comment d. of Restatement (First) of Prop.: Future Interests § 241 notes that often conveyances will be donative and the focus will be upon the intent of the grantor, testator, or settlor. However, non-donative conveyances have a “contractual or bilateral aspect” which affects the construction of the instrument by requiring “that a conveyor is bound by the meaning which he reasonably should have anticipated that the conveyee would derive from the language employed.” RESTATEMENT (FIRST) OF PROP.: FUTURE INTERESTS § 241 cmt. d (1940).

100. RESTATEMENT (FIRST) OF PROP.: FUTURE INTERESTS § 242 cmt. a (1940).
g. Circumstances of the instrument’s formulation—Prevailing manners of expression.

h. Circumstances of the instrument’s formulation—Knowledge or belief of conveyor concerning the claimants upon his bounty.

i. Other circumstances of the instrument’s formulation.

The importance of surrounding circumstances evidence continues into the Restatement (Third) of Property which provides, at section 10.2: “In seeking to determine the donor’s intention, all relevant evidence, whether direct or circumstantial, may be considered, including the text of the donative document and relevant extrinsic evidence.” Comment d. to section 10.2 explains that “all relevant evidence” includes “[e]xtrinsic evidence of the circumstances surrounding the execution of the donative document that might bear on the donor’s intention . . . .” Similarly, the Third Restatement’s provisions on the interpretation of servitudes states, at section 4.1: “A servitude should be interpreted to give effect to the intention of the parties ascertained from the language used in the instrument, or the circumstances surrounding creation of the servitude, and to carry out the purpose for which it was created.”

Surrounding circumstances evidence has been a recognized interpretive tool, inextricably tied to the express terms of the instrument, beginning with the First Restatement of Contracts in 1932 and continuing through to the present with the most recent Third Restatement of Property. The Restatements have consistently recognized the necessity of interpreting instruments in context to place the court in the position of the parties at the time the instrument was created. One of the most important roles served by surrounding circumstances evidence is to ensure that the intent of the parties is sought by applying the proper historical context.

B. The Importance of Historical Context

Is it possible for a conveyance or contract to grant more, or less, merely because of the passage of time or subsequent changes in ownership? What principle of property law states that the grantee in a conveyance of land will end up with a fundamentally different title with the mere passage of time? What principle of contract law states that an

101. Id. § 242 cmts. d.-i.
103. Id. at cmt. d.
assignee of the contract can receive fundamentally different rights than those held by their assignor? The law presumes the basic rights of the parties to a conveyance or contract will not change as time passes and grantees or assignees come and go. Therefore, there is typically only one relevant time for determining what a contract or conveyance means: the time of its creation. For example, the meaning of a deed in 1930 should be evaluated as of 1930, not some different point in time. This fundamental principle of contract and property law is often inadvertently overlooked in the interpretive process.

1. Historical Context: The Law

Among the “surrounding circumstances” under which all parties to an instrument must operate is the “law.” If the instrument is being entered into in 1930, the relevant “law” is the existing law as of 1930, not 2006, or some other moment in time. Although the law can change with time, if the issue is the intent of the parties at the time of the conveyance or contract, the only relevant evidence for interpreting the instrument is the law at the time it was created. This rule of interpretation is actually more formalized because the courts impute knowledge of existing law to all the parties to a transaction, regardless of their knowledge in fact. All parties are presumed to know the law and the law is incorporated as part of their transaction.105

Consider the impact this analysis could have had in Alford v. Krum.106 The conclusion in Alford that triggered the court’s repugnant-to-the-grant rule arose out of the court’s finding of an “irreconcilable conflict” between the one-sixteenth mineral interest conveyed by the granting clause and the one-half mineral interest contemplated by the existing and future lease clauses.107 These conflicts were “irreconcilable” because, as the majority concludes, “it is impossible to harmonize” these “internally inconsistent expressions of intent . . . .”108 However, placing this 1929 deed in the proper historical context makes the varying fractions easily reconcilable and provides the harmonization needed to avoid triggering the repugnant-to-the-grant rule.

To identify the irreconcilable conflict the court applied post-1929 law instead of the law as it existed when the conveyance was made. Instead of trying to explain the reason for the differing fractions, the court relies

105. E.g., Winder Bros. v. Sterling, 12 S.W.2d 127, 128 (Tex. 1929) (“The laws which subsist at the time and place of the making of the contract and where it is to be performed . . . enter into and form a part of it, as if they were expressly referred to, or incorporated in its terms.”) (quoting Smith v. Elliott & Deats, 39 Tex. 201 (1873)).
106. 671 S.W.2d 870 (Tex. 1984), overruled by Luckel v. White, 819 S.W.2d 459 (Tex. 1991).
107. Id. at 872-73.
108. Id. at 872.
upon characterizations of the law in treatises which examine the law as it existed in 1984, instead of 1929. For example, the court relies upon the treatises of Professors Hemingway and Summers for the proposition that “commentators have noted that these [present lease and future lease] clauses are ‘redundant,’ ‘unnecessary,’ and useful only when the meaning of the granting clause is not clearly apparent.” But this is improperly viewing the clauses in light of the law as of 1984. If properly viewed under the law as of 1929, the present lease and future lease clauses were clearly not “redundant” nor were they “unnecessary.” Instead, they were “useful” and arguably absolutely necessary to effectively express the parties’ intent that they desired the proportionate benefits under the oil and gas lease burdening the conveyed minerals to also transfer to the grantee.

Instead of examining the commentary of Professors Hemingway and Summers circa 1984, the court should have been reviewing the commentary of A.W. Walker, Jr. circa 1929. For example, in 1928 Professor Walker wrote, “The Nature of the Property Interests Created by an Oil and Gas Lease in Texas: Part I.” In this article, Professor Walker comments on the state of the law, and industry practices in response to the law, as of 1928:

The customary method of assigning royalties is by an instrument which takes the form of a conveyance of the oil and gas subject to the existing lease. However, if no specific mention is made in such a conveyance of the delay rentals and royalties apparently nothing would pass except the possibility of reverter. . . . It is customary to provide specifically in this form of an assignment for the transfer of the royalties and delay rentals to accrue under the existing lease as well as for the ownership of these minerals in case the existing lease should terminate or be cancelled.

This explains the industry’s response to Caruthers v. Leonard which held, in 1923, that a grant of the possibility of reverter in the mineral interest, “subject to the terms” of an oil and gas lease covering the conveyed interest, did not convey any rights in delay rentals payable

109. Id. at 873.
110. There is no way the parties to this 1929 conveyance could have been aware of the case law that would follow, and the treatises that would be written on these topics in the decades to come.
112. Id.
113. Id. at 47, reprinted in SELECTED WORKS, supra note 111, at 33-34.
114. 254 S.W. 779 (Tex. Comm’n App. 1923, judgm’t adopted), overruled by Harris v. Currie, 176 S.W.2d 302 (Tex. 1943).
under the lease. This resulted in the use of deed forms which conveyed the minerals (the possibility of reverter) plus rights under any existing or future oil and gas leases.

When viewed in the proper historical context, the Alford deed does not present an irreconcilable conflict because the present and future lease clauses are not “redundant” or “unnecessary” attempts to restate what was conveyed in the granting clause. Instead they are intended to be independent and necessary grants of rights under the existing oil and gas lease in accordance with the law and resulting usages when the conveyance was made. This accurate appreciation of the surrounding circumstances should have allowed the court to more readily harmonize the deed to effectuate the intent of the parties. The holding in Alford could have been averted altogether if the court had been operating in the correct temporal context.

Similar revelations could have impacted the outcome in the Concord case. In 1995, I prepared an article for the Forty-Seventh Annual Institute on Oil and Gas Law and Taxation in which I commented on the court of appeals’ decision in Concord. The court applied a two-grant approach to the deed which granted a one ninety-sixth mineral interest plus one-twelfth of the current lease benefits. This prompted me to make the following observations:

> Since the existing lease on the property had terminated, the court did not have to deal with the difficult task of calculating the precise share of production the grantee would receive under an existing lease. For example, assume the existing lease was still in existence and provided for a one-eighth royalty. What would the grantee receive as a share of production? A strong argument could be made that the grantee should receive one-twelfth of the one-eighth royalty, under the existing lease clause, plus another one-ninety-sixth of the one-eighth royalty under the granting clause. Although courts applying the two- or multiple-grant approach may assume that only one grant would operate at a time, that is clearly not what the conveyances provide.

This observation was cited by Justice Enoch in his concurring opinion where he decided, following rehearing, to change his support for the four

115. Id. at 783.
118. Concord Oil Co. v. Pennzoil Exploration & Prod. Co., 878 S.W.2d 191, 196 (Tex App. 1994), rev’d, 966 S.W.2d 451 (Tex. 1998) (“We hold that the deed conveyed only a 1/96 mineral interest, in addition to the 1/12 interest in the existing lease which expired when the lease terminated.”).
119. Pierce, supra note 117, at 1-24 to 1-25.
dissenting justices and joined with the four plurality justices. Although he preferred the two-grant analysis of the dissent, he rejected it in this case because it would result in an over-conveyance, an interpretive result he deemed unreasonable. The over-conveyance was based upon both grants operating simultaneously which would entitle the grantee to nine ninety-sixth of production when the grantor only owned a one-twelfth (eight ninety-sixth) interest in the minerals.

However, if we view the conveyance in its proper 1937 context, then Caruthers v. Leonard was still the motivating basis for the use of a two-grant conveyancing approach. Under Caruthers, the one ninety-sixth mineral interest would not be viewed as conveying any interest in the lease benefits. This was the “law” in 1937. Therefore, the grantee’s ownership of a one ninety-sixth mineral interest would not entitle the grantee to any additional royalty under the oil and gas lease—at least that would be the result under the law as it existed in 1937. Because the parties to the conveyance are presumed to know the law, then Justice Enoch would have had no problem siding with the dissenting justices’ two-grant approach because their intent must have been to convey no additional royalty under the lease through the grant of the one ninety-sixth mineral interest. The only royalty that was conveyed was through the one-twelfth of the royalty under the existing oil and gas lease.

Although the courts were well aware of the history regarding the Caruthers problem and the form deeds used to respond to the problem, this history was being offered to support a single grant interpretation. It would seem to be at least as supportive of a two-grant analysis with the presumed belief under the circumstances (the Caruthers “law”) that the

120. Concord, 966 S.W.2d at 464 (“As Professor David Pierce has noted in looking at the court of appeals’ opinion in this case, the dissent’s two-grant conclusion makes sense only if one assumes that only one grant operates at a time.”).
121. Id. (“We cannot give the Crosby deed the reading that the dissent believes is correct—that the deed makes two conveyances—because that reading is unreasonable.”). Justice Enoch described his revelation of this two-grant problem as follows:

[T]here is one other, dispositive reason that dictates the actual judgment in this case. A point that destroys the reading the dissent attempts to give the Crosby deed. And a point the plurality merely adds to the Court’s original opinion.

Were the Crosby deed to contain two conveyances rather than one, there would be an unavoidable conflict—a conflict that was, until now, overlooked by us. Even the parties failed to focus on it until oral argument on rehearing. The conflict would arise because, were the granting clause and the “subject to” clause conveying separate estates, they would convey more than Crosby owned. We need only focus on this fact.

It is this fact alone that keeps me from joining the dissent, which is otherwise correct. There is nothing inherently wrong with a deed expressing two grants, and where expressed, such grants should be honored. However, the potential for over-grant in the Crosby deed prevents me from concluding that this deed contains two grants.

Id. at 463-64.
122. 254 S.W. at 779.
123. Id.
124. See, e.g., Concord, 966 S.W.2d at 459-60; Concord, 878 S.W.2d at 193.
A one-ninety-sixth grant would not presently convey any additional interest in the royalty—such was the effect of the law at the time the deed was granted.

Actually, two different problems are at work in this case. First, *Caruthers* is arguably more supportive of a two-grant approach. Since the rights to benefits under the existing lease would not transfer under the grant of the mineral interest, a second grant is required to transfer the lease rights. This appears to be the view of at least one scholar examining the cases at the time. When Professor Walker discussed *Caruthers* he noted it is “customary to provide . . . for the transfer of the royalties and delay rentals to accrue under the existing lease as well as for the ownership of these minerals in case the existing lease should terminate or be cancelled.” 125 He footnotes this statement with the direction to “see” several cases, including *Hoffman v. Magnolia Petroleum Co.*, 126 which is best known as the source of the *Hoffman* “two-grant doctrine.”

The second problem concerns the differing fractions. To resolve this issue the plurality addressed the proper historical context when it analyzed the significance of *Tipps v. Bodine,* 127 The court first establishes the temporal relevance of the *Tipps* case: “*Tipps* was decided in 1936, and the Concord deed was executed in 1937.” 128 The plurality’s application of *Tipps* is consistent with its holding: “Under the rationale of *Tipps*, it would have been appropriate for Crosby to have inserted “1/96” in the granting clause and “1/12” in other provisions of the Concord deed if he intended to convey a 1/12 interest in the minerals.” 129 The dissent would not have engaged in this second step, but instead would have given literal effect to the two-grants: one ninety-sixth mineral interest and one-twelfth of the benefits under the existing oil and gas lease. 130

The court of appeals, citing *Harris v. Currie,* 131 explained its two-grant approach noting the effect of the *Caruthers* decision on conveyancing practices and that *Caruthers* was not overruled until 1943. 132 However, the plurality of the Texas Supreme Court, citing *Hager v. Stakes,* 133 stated that *Caruthers* was overruled in 1927. 134 Nothing in the 1927 *Hager*
decision indicated it is in any way reversing the separate grant requirement of *Caruthers*. The issue in *Hager* was whether an in-kind oil royalty under an oil and gas lease could be taxed as real property. The only aspect of *Caruthers* that the court takes issue with is the statement that once an oil and gas lease is granted, then all the lessor has remaining is a possibility of reverter. The issue in *Hager* concerns the ownership interest of a lessor when the oil and gas lease provides for an in-kind royalty. The court in *Hager* holds the lessor—under the specific leases at issue—retained a real property interest in what was designated oil “royalty” under the leases. The court merely notes that it did not adopt the *Caruthers* opinion as its own, but did adopt it “as to the determination to be made of the cause.” Any doubt regarding the status of the *Caruthers* case, following the *Hager* decision, is dispelled by the following statement by the *Hager* court:

The Caruthers Case was rightly determined, regardless of the legal effect of the lease in reserving a mineral estate to the lessor; for Leonard was not entitled to recover any part of the rentals for which he sued, because the writing under which he claimed expressly stipulated that, if the lease under which the rentals accrued was valid, that he (Leonard) bought subject to all the terms of such lease, and the lease was valid and one of its terms provided for the payment of such rentals.

This is an express reaffirmation of the *Caruthers* holding.

Although the Texas Supreme Court, in its 1943 *Harris* decision, says it reversed *Caruthers* with its 1927 *Hager* decision, I doubt that any lawyer reading *Hager* would have come to that conclusion; at least not until the Supreme Court told them in 1943. This is a good example of a situation where the party seeking to rely upon *Caruthers* as good law in 1937 (when the conveyance was made) would need to offer expert testimony as to the surrounding legal circumstances at the time of the conveyance. *Caruthers* was not overruled by *Hager* in 1927; *Caruthers* was still the “law” in 1937 when the *Concord* conveyance was made and was not overruled until six years after the *Concord* conveyance in *Harris v. Currie*.139

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136. *Id.* at 838.
137. *Id.*
138. *Id.*
139. 176 S.W.2d 302, 306 (Tex. 1943). Commenting on the *Caruthers* case, the court stated the following:

This holding [in *Caruthers v. Leonard*] was clearly erroneous, as Leonard had every right to the surface of this land necessary to enforce and enjoy his mineral title that Caruthers had for the same purpose. In our opinion, the holding above indicated, in *Caruthers v. Leonard*, was expressly overruled by this court in *Hager v. Stakes*, 116
2. Historical Context: The Original Parties

Another important historical context concerns the original parties to the instrument being interpreted. For example, assume the original parties to the conveyance or contract were both sophisticated participants in the oil and gas industry. This could impact the interpretive process by making both parties subject to industry usages and the assumption that oil and gas terms were being used employing a technical as opposed to a common meaning. Should this situation change because the property is now owned by an unsophisticated individual as opposed to the original industry participant? Clearly the rights of the parties should not change merely because the interest has been transferred. However, this is often the effect when courts fail to consider the situation of the original parties at the time the instrument was created.

An example of this temporal party context problem is illustrated by the Colorado Supreme Court’s actions in Garman v. Conoco, Inc. The issue was whether the oil and gas lessee, Conoco, could deduct various post-production costs to calculate Garman’s overriding royalty. Conoco argued that “industry practice allows proportionate allocation of post-production costs . . . .” The court refused to consider this argument by suggesting Garman was not bound by industry customs which Conoco could only rely upon when dealing with “other oil exploration companies.” At the time the instrument creating the overriding royalty at issue was created, however, Garman’s predecessor-in-interest was one of those “other oil exploration companies.” The original party to the assignment that created the interest, Monarch Oil & Uranium Co., was Garman’s source of title. It was Monarch that reserved the 4.00% overriding royalty when it conveyed its oil and gas leases covering 10,742 acres.

Tex. 453, 294 S.W. 835. In that opinion Judge Greenwood points out that the opinion in Caruthers v. Leonard was not approved by this court, but only the judgment recommended.

Id.

140. The same issues are presented when one or more of the current parties are sophisticated industry participants but one or more of the original parties were not.

141. See generally David E. Pierce, Defining the Role of Industry Custom and Usage in Oil & Gas Litigation, 57 SMU L. REV. 387, 455-61 (knowledge and usage), 461-67 (technical terms) (2004).

142. 886 P.2d 652 (Colo. 1994).

143. Id. at 660.

144. Id. The court cited Pletchas v. Von Poppenheim, 365 P.2d 261, 263 (Colo. 1961), for the proposition that parties engaged in the same occupation are presumed to have knowledge of business usages.

145. Id.

146. Garman, 886 P.2d at 654-55 n.5.
It also appears Monarch, and not Conoco’s predecessor-in-interest (an individual), may have been the party that drafted the instrument.\textsuperscript{147}

Supreme Court proceeded to interpret the instrument and apply the law as though this were a transaction between a giant, sophisticated oil company and the little unsophisticated, indeed helpless, individual.\textsuperscript{148} In reality, at the time the deal was struck, the relationships were just the opposite: Garman’s predecessor was the oil company and Conoco’s predecessor was the individual. The court should have interpreted this instrument considering the true circumstances and the true parties at the time it was created.

3. Historical Context: The World

Counsel and courts should always be attuned to the situation of the parties at the time the instrument at issue was created. What must they have known? What would have been impossible for them to have known?\textsuperscript{149} The potential for useful, relevant evidence is limited only by the ability to place ourselves in the shoes of the original parties to the instrument. Any information that can assist in understanding how the parties viewed the world when they entered into the instrument at issue should be collected and evaluated.

It is important to remember that we are not trying to ascertain what was actually perceived or “in the minds” of the parties to the instrument. Instead, the goal is to establish what a reasonable person in the position of the parties would have perceived, known, and thought.\textsuperscript{150}

VI. CONCLUSION

Recognition of free will to enter into contracts and conveyances means little if the rights of the parties under the instruments they adopt are defined by processes which fail to seek their objective intent. As Professor Farnsworth notes in his treatise: “The principle of freedom of contract rests on the premise that it is in the public interest to accord individuals broad powers to order their affairs through legally enforceable agreements.”\textsuperscript{151} This basic freedom is realized only when courts are willing to ascertain what the parties intended by their

\textsuperscript{147} Id.


\textsuperscript{149} Because it would not occur until sometime after the instrument was created.

\textsuperscript{150} Recall that the \textit{Restatement of Contracts} expressly requires courts to interpret instruments from the perspective of “a reasonably intelligent person acquainted with all operative usages and knowing all the circumstances prior to and contemporaneous with the making of the [instrument].” \textit{RESTATEMENT (FIRST) OF CONTRACTS} § 230 (1932).

\textsuperscript{151} E. ALLAN FARNSWORTH, CONTRACTS § 5.1, at 313 (4th ed. 2004).
manifestations. Any policy based upon freedom of contract must be activated by giving effect to the intent of the parties so their free will is realized.

Texas instrument interpretation jurisprudence reveals strong support for freedom of contract as a guiding principle. Competing interests in predictability of outcome have not been elevated to the level of public policy and are frequently sacrificed to give effect to the free will of the parties to an instrument. However, the Texas Supreme Court’s use of an ambiguity analysis in its interpretive process will often prevent the Court from achieving its consistently-stated goal of ascertaining the intent of the parties. The interpretive process often adheres to a formalism that may result in predictable outcomes, but contributes nothing towards accurately identifying the likely intent of the parties.

The 4-1-4 split decisions regarding the meaning of “unambiguous” documents suggest that the “ambiguity analysis” is nothing more than a conclusory label used to ensure that interpretation remains the province of courts instead of juries. It appears that courts could eliminate the ambiguity analysis altogether without damaging the parol evidence rule, the doctrine of merger, or existing law regarding interpretation. Nor would it necessarily result in more issues for juries to resolve. The parol evidence rule and the doctrine of merger would continue to focus on whether the instrument at issue was intended to be the final and complete statement of the transaction. Instead of using an all-or-nothing ambiguity analysis, courts can simply consider, based upon the state of the parties’ agreements found within their instrument, whether it was intended as an integration or as a merger. Once this is decided, the terms of the parties’ instrument will be identified. It will be these terms that become the focus of interpretation to ascertain the intent of the parties who selected those terms.

When interpreting the terms, instead of seeking testimony as to what a party meant, the focus should be on evidence that will assist the court in determining what a reasonable person would have thought upon learning of the evidence being offered. The search is not for what a party says

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152. See supra text accompanying notes 8-14.
153. See supra text accompanying notes 24-31.
154. See supra text accompanying notes 44-52.
155. See supra text accompanying notes 53-57.
156. For example, under the existing ambiguity analysis, something is either “unambiguous” or it must be “ambiguous.” This results in many situations where an instrument is anything but “clear” but it is still legally unambiguous. E.g., Mobil Exploration and Prod. U.S., Inc. v. Dover Energy Exploration, L.L.C., 56 S.W.3d 772, 776 (Tex. App. 2001) (“At the outset, we note that conflicting interpretations of a contract and unclear and uncertain language do not necessarily mean a contract is ambiguous.”). 157. See supra text accompanying note 53.
158. This does not seem like an unreasonable limitation on the search for intent since the
they meant, but rather for what a reasonable person, placed in the situation of the parties, would have meant. This perhaps elevates objective contract theory to heights only Professor Williston or Leonard Hand would take it, but it seems to be a compromise that in fact has been made by Texas courts that have struggled with the use of extrinsic evidence to interpret unambiguous, completely integrated, instruments.\textsuperscript{159}

The mixed messages provided by case law in this area can be sorted out by acknowledging the following: (1) courts routinely consider certain types of extrinsic evidence to interpret unambiguous instruments; (2) there is a wide range of extrinsic evidence, such as testimony by the parties as to what they intended, which is rarely allowed to interpret unambiguous instruments, and evidence of the law, usages, and objective circumstances of the parties at the time the instrument was created, which are frequently allowed to interpret unambiguous instruments; and (3) courts seldom make an effort in their opinions to explain these obvious gradations of extrinsic evidence.

The proposals offered in this article can be implemented without overruling prior case law or adopting new principles. District courts presently have it within their power to implement the suggested improvements without additional appellate court direction. The legal groundwork, although a patchwork, already exists, and has existed for over a century. The primary adjustment will be the introduction of a clarity as to how the interpretive rules operate, and then to clearly articulate their application to the facts.

The ultimate jurisprudential goal is clear: to ascertain the intent of the parties to the instrument. “Intent” in this context means objective intent.\textsuperscript{160} Frequently, this objective intent can be ascertained only by taking a trip back in history and placing the court in the shoes of the parties who adopt a writing as an integration of their transaction should be aware that its objective effect will govern their rights instead of their unexpressed, subjective desires.

\textsuperscript{159} Professor Williston noted, “It is even conceivable that a contract shall be formed which is in accordance with the intention of neither party.” 1 S\textsc{AMUEL W}ILL\textsc{STON}, THE LAW OF CONTRACTS § 95, at 181 (1\textsuperscript{st} ed. 1920). Judge Hand observed in \textit{Hotchkiss v. National City Bank}:

A contract has, strictly speaking, nothing to do with the personal, or individual, intent of the parties. A contract is an obligation attached by the mere force of law to certain acts of the parties, usually words, which ordinarily accompany and represent a known intent. If, however, it were proved by twenty bishops that either party, when he used the words, intended something else than the usual meaning which the law imposes upon them, he would still be held, unless there were some mutual mistake, or something else of the sort. . . .

. . . [T]he question always remains for the court to interpret the reasonable meaning to the acts of the parties, by word or deed, and no characterization of its effect by either party thereafter, however truthful, is material.


\textsuperscript{160} See supra text accompanying notes 30-31.
parties at the time the instrument was made. Unless this is done, the court will often be allowing the rights of the parties to change with the mere passage of time, or with the substitution of the original parties.161

After considering the various decisions of the Texas courts regarding instrument interpretation, it appears the current state of the law is best captured by the portion of Restatement (First) of Contracts § 230, which instructs courts to apply “the meaning that would be attached to the integration by a reasonably intelligent person acquainted with all operative usages and knowing all the circumstances prior to and contemporaneous with the making of the integration, other than oral statements by the parties of what they intended it to mean.”162 This provides the framework for a workable, and if consistently applied, a predictable process for fulfilling the underlying goal and policy of oil and gas instrument interpretation: giving effect to the free will of the parties.

161. See supra text accompanying notes 105-139.
162. Restatement (First) of Contracts § 230 (1932).
THE COMPRESSION OF NATURAL GAS: IS IT PRODUCTION OR POST-PRODUCTION?
IS IT DEDUCTIBLE FROM ROYALTIES?
IF SO, HOW MUCH?

JEFFREY C. KING*

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I. INTRODUCTION

In almost all gas fields, compression is, or will be, a necessary operation. The rising price of natural gas has caused the cost of moving the gas from the field to the consumer to increase significantly. One important reason for the cost accretion is that the equipment used for these operations burns natural gas as fuel. The higher the price of natural gas, consequently, the higher the cost of these ancillary activities. High costs also create another phenomenon: an increase in litigation between the lessor and lessee concerning who shoulders them and whether they are reasonable.

There are many cases concerning lessor-lessee disputes over the drilling of wells and the base price upon which the lessee pays royalties. Though much has been written by commentators,¹ a less common dispute

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¹ Howard R. Williams & Charles J. Meyers, Oil and Gas Law: Manual of Terms, § 645 (2004); Scott Lansdown, The Marketable Condition Rule, 44 S. Tex. L. Rev. 667 (2003); Adam Marshall, Rogers v. Westerman Farm Co.: Burdening Lessees With an Implied Duty to Deliver Gas to a Marketable Location, 56 Okla. L. Rev. 235 (2003); Scott Lansdown,
between the parties to a lease under Texas law centers on the compression activities of the producer, and on the issue of whether or not the costs associated with those activities should be paid proportionately by the lessee and lessor. As to royalties on natural gas production, this issue is becoming more important with each passing year because these operations directly impact the value of the gas produced from a lease and might determine whether a well or wells are producing in paying quantities.2

Natural gas post-production activities include dehydration, processing, gathering, transportation, and compression. Depending upon the quality of the natural gas produced from a particular lease or field, the only guaranteed operations are gathering, transporting, and (eventually) compressing. This article will focus on compression as a post-production transportation operation and the proportionate sharing of the associated costs between working interest and royalty interest owners.3 In reviewing this paper, the reader must realize that a royalty interest is “the landowner’s share of production, free of the expenses of production.”4

2. Whether a well is producing in “paying quantities” is determined not only by the amount of production but also the ability to market the gas at a profit. Whether there is a reasonable basis for the expectation of profitable returns from the well is the test. If the quantity is sufficient to warrant the use of the gas in the market, and the income therefrom is in excess of the actual marketing cost, and operation costs, the production satisfies the term “in paying quantities.”

Clifton v. Koontz, 160 Tex. 82, 325 S.W.2d 684, 691 (1959). The question is would a reasonably prudent operator have operated the well for a profit and not merely for speculation. Id. All relevant facts are to be considered. Id.

3. Working interest is the operating interest pursuant to an oil and gas lease. A working interest owner enjoys the exclusive right to explore for and produce minerals on the land. 8 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW: MANUAL OF TERMS 1191 (2004). A royalty interest owner is entitled to a share of production if, as and when there is production, free of the costs of production. Id. at 952.

With this in mind, there are four questions to be answered concerning compression:

1. What is it?
2. Is compression production or post-production?
3. How is it affected by the marketable condition rule?
4. How much should be paid?

II. WHAT IS COMPRESSION?

Compression is merely a function of increasing the pressure in the natural gas stream in order to assist in its transportation from the field to the consumer. During the life of a natural gas well, the gas flows through the mouth of the well at a higher pressure at the beginning of its production cycle than at the end of the production cycle. It follows that during the interim, the pressure at which the gas flows from the well gradually decreases. This natural event has consequences on the movement of the gas from the well bore to the ultimate consumer.

Except on rare occasions, natural gas must be transported to the consumer through a pipeline. In order for the gas to be injected into a transmission pipeline, there are certain minimum pressure requirements. Typically, the minimum pressure requirement for transmission gas pipelines is no less than 1,000 pounds per square inch (“psi”). At the beginning of their producing lives, most natural gas wells easily meet these minimum requirements. Consequently, at the beginning of the production cycle, the natural gas usually flows through the mouth of the well bore in excess of 1,000 psi and is easily injected into the transmission pipeline through a gathering line. When the pressure from the mouth of the well bore drops below 1,000 psi, however, the gas must then be “compressed” in order for it to reach the minimum 1,000 psi requirement of the transmission lines.

Simply stated, compression is the squeezing of the natural gas stream during the transportation process. The low pressure natural gas flows at its natural pressure through the gathering and trunk lines and into a compressor station, where it is then squeezed to such a pressure that it will enter the next line in the transportation chain. If the downstream

5. There are situations in which natural gas has been trucked from a well location to a pipeline. Due to the expense involved, this method is rarely used.
6. The American Gas Association defines compression as “[t]he action on a material which decreases its volume as the pressure to which it is subjected increases.” American Gas Association, www.ag.org (follow “About Natural Gas” hyperlink; then follow “Natural Gas Glossary” hyperlink; then follow “C” hyperlink).
7. A compressor station is “[a]ny permanent combination of facilities which supplies the energy to move gas at increased pressure from fields, in transmission lines, or into storage.” American Gas Association, http://www.ag.org (follow “About Natural Gas” hyperlink; then follow “Natural Gas Glossary” hyperlink; then follow “C” hyperlink).
pressure is still insufficient, the gas stream will require an additional stage of compression in order to meet minimum pipeline standards. Depending on the age of the wells and their production cycle, some gas streams require several stages of compression in order to meet minimum pressure requirements.

III. IS COMPRESSION A PRODUCTION ACTIVITY?

Natural gas is “produced” when it is severed from the land. Most compression does not involve a “down-hole” (inside the well bore) operation that causes gas to come to the mouth of the well. In contrast, most compression occurs after the gas has moved through the mouth of the well bore to the surface of the land. If the gathering lines were disconnected from the well bore and the well was opened, the natural gas would flow from the producing formation, through the mouth of the well bore, and into the atmosphere. From that perspective, compression has nothing to do with the well’s production of natural gas or its ability to do so.

On the other hand, if the natural pressure of the gas stream is insufficient for the gas stream to enter a transmission pipeline, the gas will either not be produced, or will be produced at a lower rate. From the perspective of engineering and physics, a stream that flows at a lower rate of speed has difficulty merging into a stream flowing at a higher rate of speed, for the faster flowing stream will cause back pressure on the slower flowing stream, prohibiting or inhibiting the slower stream from combining with the components from the faster flowing stream. In other words, a log jam occurs. Without compression increasing the pressure of the natural gas stream and, in effect, breaking the log jam, the gas from the wells feeding that stream will not flow through the mouth of the well. Accordingly, some have argued that the break-up of the log jam makes compression a production, not a post-production, operation because gas is not produced until it is “severed from the land.”

Why is the distinction important? It is clear that all natural gas production costs, i.e. those associated with exploring for, developing, and bringing gas to the mouth of the well, are borne by the producer alone. Under Texas law, unless the lease contains language to the contrary, royalties are subject to their proportionate share of the costs incurred

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after production, including costs associated with compression. Under the law of Oklahoma, Kansas, Colorado and certain other states, royalties are also subject to post-production compression costs under certain circumstances to be discussed below. So, the question to be answered is, “At exactly what point is the gas severed from the land?”

There are only two reported opinions on this point, one of which has been heavily relied upon by Texas courts, including the Texas Supreme Court: Martin v. Glass. In Martin, the producer drilled two wells that produced gas under their own pressure into a nearby line. The wellhead pressure, however, was insufficient to pump the gas into the marketing pipeline and the producer had to flare the gas or shut-in the wells. To avoid this loss, the producer added compression on the lease so that the gas from the wells could be taken to market. The producer gathered the gas, compressed it, and transmitted it into the buyer’s pipeline. From the facts of the case, it is clear that without the compression added to the surface gathering lines, the wells would not have produced natural gas that could have been taken to a market.

After concluding that post-production costs could be properly deducted from the royalty share, the Court analyzed whether the compression operation was production or post-production. Recognizing that gas is produced when it is severed from the land, the Martin Court stated, “[t]he facts established that ‘production’ of gas had been obtained from two wells on the Glass-Martin lease. (There was sufficient pressure to bring the gas to the wellhead or mouth of the well.)” Since there was sufficient pressure in the well bore to bring the gas to the mouth of the well, the gas was severed. According to the Martin opinion, any

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13. 571 F. Supp. 1406 (N.D. Tex. 1983), aff’d, 736 F.2d 1524 (5th Cir. 1984) (unpublished table opinion); see also Judice, 939 S.W.2d at 136; Heritage Res., Inc., 939 S.W.2d at 122-23; Parker, 716 S.W.2d at 648.
15. Id.
16. Id.
17. Id.
18. Id. at 1411. The Court made this determination based upon the location where royalties were to be determined which, under the express terms of the lease, was at the wellhead. Id. Since value was to be based upon that location, any marketing or transportation activities downstream from the wellhead had to be paid on a pro rata basis by both the working interest and royalty interest owners because the producer was transporting the lessor’s share of the gas. Id. at 1411-12.
19. Id. at 1415 (citing Lone Star Gas Co. v. Murchinson, 353 S.W.2d 870 (Tex. Civ. App.—Dallas 1962, writ ref’d n.r.e.)).
20. Id.
compression that was designed to move the gas from the well and down
the pipeline at higher pressure was not a production operation, but was a
post-production activity.\footnote{19}

The second case to address whether compression is a production or
post-production cost is \textit{Parker v. TXO Production Corp.}\footnote{20} In \textit{Parker},
TXO had drilled two wells.\footnote{21} Both wells produced successfully for several
years.\footnote{22} Eventually, compression was added by the gas purchaser to
increase the pressure in the gas stream to better deliver the gas into the
buyer’s pipeline.\footnote{23} TXO also compressed the gas at the wellsite in order
to, as testified by the TXO engineer, “increase production from the
wells.”\footnote{24} TXO then deducted the cost of its compression from the lessor’s
royalties.\footnote{25} The facts do not reveal when the TXO wellsite compressor
was installed. Additionally, there are no facts stated in the opinion
concerning whether the reservoir had sufficient pressure to move the gas
to the mouth of the well prior to being compressed.

The \textit{Parker} court recognized that the law stated in \textit{Martin v. Glass}, i.e.
if there is sufficient pressure in the well to bring the gas to the mouth of
the well, compression to assist in delivering the gas to the buyer was a
post-production operation, was correct.\footnote{26} Nevertheless, the \textit{Parker}
court then held that \textit{Martin} was distinguishable from the facts before it.\footnote{27}
Relying upon the testimony from TXO’s engineer that the compression
was added to increase production from the wells, the court ruled that the
compression was a production cost and, thus, not deductible from the
lessee’s royalties.\footnote{28}

The \textit{Parker} case is perplexing. While it acknowledges the correctness
of \textit{Martin}, it chooses to ignore the facts upon which the \textit{Martin} case was
decided in order to reach a desired outcome. In \textit{Martin}, there would not
have been any production but for the compression.\footnote{29} Still the compression
was post-production because the gas came to the mouth of the well under
its own pressure.\footnote{30} In \textit{Parker}, compression was added to \textit{increase}
production.\footnote{31} Logically, the outcome in \textit{Parker} should have been the
same as in \textit{Martin}. The result in \textit{Parker} is illogical because all post-

\begin{itemize}
\item 21. \textit{Id.}
\item 22. 716 S.W.2d 644 (Tex. App.—Corpus Christi 1986, no writ).
\item 23. \textit{Id.} at 645.
\item 24. \textit{Id.}
\item 25. \textit{Id.}
\item 26. \textit{Id.} at 648.
\item 27. \textit{Id.}
\item 28. \textit{Id.}
\item 29. \textit{Id.}
\item 30. \textit{Id.}
\item 32. \textit{Id.} at 1415.
\item 33. \textit{Parker}, 716 S.W.2d at 645.
\end{itemize}
production activities, whether they be compression, treating, dehydrating, adding pipeline capacity or otherwise, have the result of increasing production because they prepare the gas for, or move it to, the market. Without them, little or no gas would be produced because it could not be sold.

Based upon the reliance on Martin by the court in Parker, one can conclude that if the testimony had been that the TXO wells had sufficient pressure to bring the gas to the mouth of the well and compression was added to increase line pressure, which resulted in more production from the wells, the result in both cases would have been the same. Unfortunately, such was not the testimony and it appears that the cases are irreconcilable. Having said that, the ruling in Martin is the more logical and reliable of the two cases. This conclusion is bolstered by the fact that the Texas Supreme Court has cited to, and relied upon, Martin, rather than Parker, in no less than two loadstar cases concerning the proper payment of royalties after taking into consideration deductions for post-production costs—Heritage Resources, Inc. v. NationsBank[34] and Judice v. Mewbourne Oil Co.[35]

In summary, in Texas, if the well will produce under its own pressure, compression is a post-production operation. Such is the law, even though it adds the benefit of increasing production from the well because it removes the log jam described above. As a post-production activity, under Texas law the lessor’s share of the reasonable cost of compression is properly deductible from his or her royalties.[36] Under the law of Oklahoma, Colorado, and Kansas, however, more analysis is required under the marketable condition rule.

IV. IS COMPRESSION AFFECTED BY THE “MARKETABLE CONDITION RULE”? 

One question the reader may ask is whether or not compressing gas is “marketing” when it deals more with transportation. The answer to this question depends upon the breadth of the word “marketing.” A broad definition of marketing is the sale of production and the steps necessary to complete the transaction. By using this wide view, compression is clearly a marketing function, as would be all other activities until the gas reached the burner of the ultimate consumer. A more limited definition would be that marketing is the preparation of the gas by eliminating impurities and the negotiation of a sales contract. This more constrained

34. 939 S.W.2d 118, 122-23 (Tex. 1996).
35. 939 S.W.2d 133, 136 (Tex. 1996).
36. Heritage Res., Inc., 939 S.W.2d at 122.
view eliminates the transportation of gas from the field to the consumer and all related endeavors, including compression, from marketing.

Why is the distinction important? Under Texas law, it is of no importance. Unless there is lease language to the contrary, royalty owners must pay their proportionate share of all post-production costs. Under the law of other states, though, such costs are not deductible from royalties until the producer has prepared the gas for market, i.e., has placed it in a marketable condition. After creating a marketable product, expenses for treating, compressing or transporting the gas are properly deductible. Due to its proximity to the state of Texas, this article will focus upon Oklahoma to illustrate this view.

In a somewhat controversial decision, the Oklahoma Supreme Court held in *Mittlestaedt v. Santa Fe Minerals, Inc.*, that a producer has a duty to provide a marketable product available to market at the wellhead or on the leased premises. Oklahoma believes that such a duty is part of either the lessee’s production obligations, or its duty to market production after severance. In which area of oil and gas jurisprudence this obligation falls under Oklahoma law is unclear. What is clear, though, is that in Oklahoma compressing low pressure gas on the leased premises for injection into a higher pressure pipeline is a part of the producer’s duty to provide a marketable product. As such, the costs associated with compression until the product is marketable are not shared by royalty owners. After the gas is “marketable,” compression that occurs off of the leased premises may be deductible from royalties if the lessee can show that the compression enhanced the value of an already marketable product and increased royalties. The analytical rules set forth in *Mittlestaedt* are also used in Kansas and Colorado.

Unlike Texas law, the Oklahoma view creates uncertainty and is fertile ground for litigation. Whether a post-production charge for compression against a royalty owner is allowable is an individual case by case analysis. That means a court must review several facts. Where did the compression occur – on the leased premises or off? If the compression was on the lease, it is not deductible. If the compression occurs off of the

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37. *Id.*
40. *Id.* at 1208.
42. *Mittlestaedt*, 954 P.2d at 1209.
43. *Id.* at 1210.
leased premises, the court must then determine whether gas was in a “marketable” condition prior its compression. If so, did the compression change the constituents of the gas?46 Additionally, if all of the above is true, did the compression enhance the value of the gas?47 The problem with the complicated Oklahoma marketable condition rule is that it ignores certain key realities.

The first reality is that all natural gas is a marketable product at the well. Regardless of its condition or pressure status, all natural gas has a value at the wellhead and may be sold at the wellhead. For many years, natural gas was sold at the well to pipeline companies. The pipeline companies would gather the gas, treat it, process it, compress it and transport it.48 Typically, the purchase price paid by these companies was a set price minus the cost for these activities. Royalties were then paid based upon the actual amount received from the pipeline company. Though pipeline companies are no longer wellhead buyers of gas,49 there are third party purchasers of natural gas at the wellhead. Non-producing middle market companies and pure marketing companies purchase wellhead volumes and then perform these services. Additionally, some producers, or their affiliates, also purchase wellhead gas from third parties.50 The price paid by these buyers will be a market price minus the cost for these services. The point is that all natural gas is marketable regardless of its condition. To require a producer to conduct operations to place the gas in the condition the court deems marketable is a questionable use of judicial power.

The second reality is that the marketable condition rule seems to ignore the clear language the parties chose to use in their lease as to where and how royalties are to be valued. Under the marketable condition rule, regardless of all other language used by the parties in their agreement, the lease must specify that deductions for compression and other post-production activities may be made by the lessee.51 Oklahoma believes that the implied covenant to market requires the producer to create a marketable product, and that the implied covenant trumps, or modifies, the express language in the lease.52

46. Id. at 1210.
47. Id.
48. Hardwick & Hayes, supra note 1, § 11.02.
49. Pipeline companies ceased such activities primarily in response to FERC orders 380 and 436. See generally Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1149 (D.C. Cir. 1985); Associated Gas Distributors v. FERC, 824 F.2d 981, 994 (D.C. Cir. 1987).
52. Wood, 854 P.2d at 882-83.
The question that should be asked is whether the parties had already agreed to post-production deductions based upon the clear and unambiguous language they agreed upon. Most oil and gas leases place the point of royalty determination at the “mouth of the well” or at the “wellhead.” Based upon the custom and usage in the industry, which Oklahoma recognizes is used in interpreting contracts, the terms “mouth of the well” and “wellhead” have distinct and clear meanings. The “mouth of the well” or “wellhead” is the location where the gas exits the earth. Consequently, by placing the point of valuation at that location, the parties have established the type of commodity for which royalties shall be paid – raw natural gas in its natural state. As a result, any post-production activity, including compression, enhances the value of the gas and the lessor should share in this expense.

Furthermore, many leases, if not most, set a clear and objective methodology for the determination of the value to be paid to the lessor. The most commonly used valuation method is “market value of the gas.” The term “market value” is an express clause that has a clear and unambiguous meaning. It means the value a willing buyer will pay to a willing seller when neither is obligated to buy or sell. Consequently, many leases require that royalties be based upon the market value of the gas at the wellhead. Again, the agreed upon language sets a location, which is prior to any post-production operations, and a method of valuation, i.e., what a willing buyer would pay to a willing seller for natural gas in the existing conditions as it exits the wellhead. When a court supplements this clear and unambiguous language with a covenant to render the gas in a marketable condition, it is changing the intent of the parties, which is improper.

The third reality is that the working interest owner bears most of the cost and risk anyway. The marketable condition rule is based upon mistrust when there is no need for it. As stated in Mittelstaedt, the rationale for the marketable condition rule is that “nonworking interest owners (royalty owners) have no input into the cost-bearing decisions. These owners have no input on the marketing decisions. If costs were imposed on royalty owners they would be ‘sharing the burdens of working interest owners without the attendant rights.’”

Since royalty owners have no input, they should not be burdened with the cost regardless of the lease language. This reasoning ignores one very

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53. Mittelstaedt, 954 P.2d at 1208.
55. Howell, 112 P.3d at 1159.
56. HECI Exploration v. Neel, 982 S.W.2d 881, 888 (Tex. 1998).
57. Mittelstaedt, 954 P.2d at 1207 (citations omitted).
important point concerning an oil and gas lease: the largest share of the costs associated with post-production operations is suffered by the lessee or producer. The royalty share is normally less than twenty percent. It comes to reason that the working interest share of eighty percent will be motivated to keep the costs as low as possible. Additionally, the royalty owner already has a check on the amount of costs to be charged. As will be discussed below, only “reasonable” costs may be allocated to the royalty owner. It follows, then, that the royalty owner does have input into the cost-making decision.

In summation, if a producer is operating wells in Oklahoma, Colorado, Kansas, or other states, he will have to contend with the marketable condition rule. Despite the fact that the lease language controls the intent of the parties, these states have read a different intent into the oil and gas lease. One factor these courts did not consider, however, is that by not allowing a deduction for compression, some wells may not be produced at all, depending upon the price of natural gas. Moreover, Oklahoma could have—and should have—excluded compression and transportation from the marketable condition rule. Neither operation has anything to do with making the gas marketable by eliminating impurities from the stream. Such a separation in the definition of marketing is more logical than lumping all of these operations under the rule and forcing the fact intensive inquiry described above.

V. IF THE COST OF COMPRESSION IS DEDUCTIBLE, HOW MUCH IS ALLOWABLE?

There is not an opinion, at least in Texas, that answers this question as a matter of law. The only guidance available from the judiciary is that the cost must be “reasonable.” The question of reasonableness is more hotly debated when it is the producer, as opposed to a third party, that is providing the compression services. Lessors believe that the producer’s reasonable costs are limited to the actual costs of operating the compressors and nothing more. Producers feel that operational costs are one of many factors.

58. Id. at 1209.
59. In Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970), the Oklahoma Supreme Court held that off-lease transportation was deductible from the royalty share based upon the language used in the lease concerning where and royalties were to be determined. Id. at 398-99. In Wood, the court was asked to expand this rule to transportation, and specifically compression, that was on the leased premises. Wood v. TXO Prod. Corp., 854 P.2d 880, 881 (Okla. 1992). The court limited its ruling in Johnson to off the leased premises operations based on the marketable condition rule without providing a rational basis for the distinction except to imply that the distance to the market was a deciding factor. Wood, 854 P.2d at 882.
60. Le Cuno Oil Co. v. Smith, 306 S.W.2d 190, 195 (Tex. Civ. App.—Texarkana 1957, writ ref’d n.r.e.).
An important question that all concerned persons should ask is what is the universe of costs associated with compression? A non-inclusive list of costs are:

1. Cost of the compressor;
2. Cost of installation and hook-up;
3. Cost of parts and maintenance;
4. Human hours associated with maintenance and operation; and
5. Fuel.61

Some of these broad categories may be classified as capital costs by the producer. Royalty owners assert that capital costs should never be forced upon the royalty share. According to the lessor’s perspective, the physical compressors are assets of the producers. They questioned why they should be burdened with the repayment of its share of this expense, when he does not own the asset, nor receives the tax benefit of depreciating that asset over time. From the working interest perspective, capital costs are real and necessary expenses for the addition of compression to a gas stream and, as such, are proportionately deductible from the royalty share. Additionally, lessees believe that they should be entitled to a reasonable return on their capital investment and should be allowed to charge a profit to the royalty owner.

The issue is whether the cost charged to the royalty share was “reasonable.” The question of “reasonableness” must be resolved by a fact finder on a case by case basis.62 There is no magic formula to cure this dispute. Some guidance, however, is available.

Since the legal question over deductibility centers around the language in the royalty clause in the lease, the standard concerning the amount of allowable costs should also be found in the royalty clause of the lease. There are generally two types of royalty clauses, market value and proceeds of sale. Market value is measured by comparable sales of like kind and quantity of gas.63 Under a proceeds clause, royalties should be paid based upon the best price reasonably obtainable.64 Though similar, these two terms are not the same when it concerns the base value upon which royalties should be paid.65 It is suggested here that the amount of

61. The author is aware that this list is very broad and that there may be many additional items to add or to delete. It is not intended to be limited to the enumerated items but is for illustrative purposes only.
63. See Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 372-74 (Tex. 2001) (stating that two measures of royalties due are market value and amount realized); *see also Heritage Res., Inc.*, 939 S.W.2d at 122.
65. Yzaguirre, 53 S.W.3d at 372-74.
deductions should be upon the same standard as set forth in the lease: either market value or the best price reasonably obtainable. In this area, though, the terms may be a distinction without a difference.

A good measure for the reasonableness of post-production deductions, regardless of the language in the royalty clause, is the amount paid by other producers for the same service in the same or similar field. If the producer, or one of its affiliates, is supplying the compression, the court and jury should review the prices charged by independent third party compression companies. Although not dispositive, if the producer’s charge is within the band between the highest and lowest prices charged by independent third parties, it is within the range of reasonableness. If the producer was not providing the compression, the price charged by the third party is the one that would be levied against the royalty share. If the two prices are similar, then there is no difference suffered by the lessor.

Likewise, if the producer or one of its affiliates is providing compression services to other producers, the prices agreed upon in those transactions are evidence of reasonableness. The non-affiliated producer is motivated to negotiate the best price it can for compression services since it bears the largest portion of this expense. Since it is so motivated, the non-affiliated producer will not normally agree to a price that is above the market range for this service. While this argument is persuasive, another factor to consider is the availability of competitive compression services in the field. If the competition is limited or non-existent, the lessee may have to further justify its charge by explaining how it determined the price and that the price is in accordance with industry standards. Another response from the lessee, and a check against it being unreasonable, is that if its price was too high, the non-affiliated producer would provide its own compression services if it could do so at a cheaper price.

Does the above discussion also mean that if a third party is providing the compression services that the question of reasonableness is answered as a matter of law? The answer is “no.” If the basis for royalty payments is “market value,” the third party charges must be equal to or less than the range of comparable charges in the field. As for royalties based upon the proceeds from the sale of production, the producer needs to seek and obtain the lowest third party compression charge reasonably available in the field for like services. The rationale for this position is that under the implied covenant to reasonably market, which applies to proceeds royalty clauses but not to market value clauses, the lessee must pay royalties

based upon the highest price reasonably obtainable. In order to achieve that goal, the lessee should also be seeking the lowest deductible costs reasonably obtainable considering the services to be provided.

The answer to the question of how much can be deducted from the royalty share has to be determined on a case by case basis. The relevant factors to consider include the lease, the availability of compression facilities in the area, the amount of gas to be compressed and many others. As stated above, since compressors use natural gas as fuel, the amount of the deductions for this service can be very expensive and hotly contested.

VI. CONCLUSION

At the beginning of this article, the author asked the reader to keep in mind that a royalty interest is “the landowner’s share of production, free of the expenses of production.”67 The entire analysis concerning post-production costs and who bears the expense is dependent upon when production is complete and the nature of the interest owned by the royalty owner after severance. When production is complete is a matter of reviewing the oil and gas lease, which is a contract and is construed as such.68 The intent of the parties to an agreement should be determined from the language they placed in their agreement. Once the parties have agreed upon the location of valuation of the lessor’s compensation, all marketing, transportation and sales activities by the producer from that point on include the landowner’s “share of production.” As a result, all expenses from the point of valuation until sale should rightly be shared proportionately by the lessee and the royalty owner.

68. See id. at 121 (explaining contractual construction rules used to interpret oil and gas lease); Hitzelberger v. Samedan Oil Corp., 948 S.W.2d 497, 503 (Tex. App.—Waco 1997, pet. ref’d) (“oil and gas lease is a contract and must be interpreted as a contract”).
REMEDIES FOR DEFRAUDED PURCHASERS OF OIL AND GAS INTERESTS UNDER THE SECURITIES LAWS

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I. INTRODUCTION

It is often surprising to most people, including attorneys, when they learn that many oil and gas interests are securities. After all, the term “securities” typically conjures up visions of stocks and bonds issued by large corporations and traded on Wall Street. So, it seems counterintuitive to include oil and gas interests in the same category as stocks and bonds. But the reality of the matter is that many oil and gas interests do fall within the statutory definition of a security.

As noted by Oliver Wendell Holmes, “[t]he life of the law has not been logic: it has been experience.”¹ In other words, the law does not always make a lot of sense unless viewed in the context of its historical development. There is no question about it: on its face, the grouping of oil and gas interests into the same category as stocks and bonds is somewhat illogical. However, when the United States Congress and many state legislatures enacted securities laws in the early twentieth century, fraud in oil and gas transactions was rampant. Consequently, these legislative bodies included the term “oil and gas interests,” or some variation thereof, in the statutory definition of a security to give defrauded investors in oil and gas interests an additional legal remedy. Therein lies the explanation of how such dissimilar instruments were grouped together under the rubric of securities.

This article provides the practitioner with a working knowledge of when an oil and gas interest is considered a security under federal law, Texas law, or both.² Then it examines the private rights of actions available to defrauded investors under federal and Texas law. Particular

². Many people are unaware of the applicability of the federal and state securities laws to oil and gas interests or simply choose to ignore the laws. See George Lee Flint, Jr., Annual Survey of Texas Law Article: Securities Regulation, 57 SMU L. Rev. 1207, 1217-18 (2004). Flint noted the following:

The Board had numerous enforcement actions against issuers who did not register their securities. . . . A considerable portion dealt with sale of oil and gas interests, where some operators either are unaware of the securities laws aspects of oil and gas interests, or felt that the penalty, usually refunding the investment of the complaining purchaser, was not a sufficient deterrent warranting registration.

Id.; John Burritt McArthur, Coming of Age: Initiating the Oilfield Into Performance Disclosure, 50 SMU L. Rev. 663, 736 (1997) (“Though securities requirements should apply to many oil and gas investments, they often are ignored.”); Peter W. Goodwin, What Sellers of Producing Oil & Gas Properties Should Know about Federal Laws, HOUS. LAW., Sept.-Oct. 1990, at 46, 46 (“[S]ales of producing properties that are sales of securities may be more common than many lawyers suspect.”); Julian M. Meer noted the following:

It frequently comes as a shock to many people in the oil and gas business to be informed that as a general rule, in both the federal and state securities laws, oil and gas property interests are included within the broad definition of the term “security,” and that a transfer of an oil and gas interest for value involves the sale of a security.

attention is given to the significant differences between the Texas Securities Act (TSA) and the federal securities laws. The article concludes by identifying which law typically provides the most relief to defrauded investors.

II. DEFINITION OF A SECURITY

Under both federal and Texas law, the definition of a security includes oil and gas interests. However, the term “security” under the TSA includes many oil and gas interests that the federal definition of the term security excludes. Consequently, the TSA oftentimes regulates transactions in oil and gas interests that the federal securities laws do not. The definitions of a security under federal law and Texas law are examined in turn below.

A. Oil and Gas Interests Covered by the Federal Securities Laws

Oil and gas interests may be classified as securities under either one of two analyses under the federal securities laws.\(^3\) An oil and gas interest may be considered a security under the portion of the federal securities acts that expressly defines a security to include certain oil, gas, or other mineral interests. Alternatively, an oil and gas interest may be considered a security under the portion of the securities act that includes “investment contracts” as securities.

1. Fractional Undivided Interest in Oil and Gas Rights

The Securities Act of 1933 defines a security to include any “fractional undivided interest in oil, gas, or other mineral rights.”\(^4\) The Securities Exchange Act of 1934 defines a security to include any “participation in... any oil, gas, or other mineral royalty or lease.”\(^5\) Although these two definitions differ slightly in which oil and gas interests qualify as a security, courts have interpreted them in harmony to mean virtually the same thing.\(^6\) Courts have done this by ignoring the 1934 Act’s definition of a security and using the 1933 Act’s definition of a security as the exclusive basis for deciding which oil and gas interests are securities.\(^7\)

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6. Landreth Timber Co. v. Landreth, 471 U.S. 681, 686 n. 1 (1985) (“We have repeatedly ruled that the definitions of “security” in § 3(a)(10) of the 1934 Act and § 2(1) of the 1933 Act are virtually identical and will be treated as such in our decisions dealing with the scope of the term.”); Adena Exploration, Inc. v. Sylvan, 860 F.2d 1242, 1244 n. 4 (5th Cir. 1988).
7. Goodwin, supra note 2, at 46 (“If the definitions of ‘security’ in the 1933 and 1934 Acts are to be treated the same, which specific reference to oil and gas interests is controlling? The 10th Circuit has held that the 1933 Act’s reference to oil and gas interests is controlling.”).
Consequently, an oil and gas interest may be a security under either act if it is a fractional undivided interest in oil, gas, or other mineral rights. But not all fractional undivided interests in oil, gas, or other mineral rights are securities. Fractional undivided interests in oil, gas, or other mineral rights are only considered securities if they were created by the seller splitting an interest into several fractional undivided interests. And even then, the fractional undivided interests are securities only for the purpose of the first transaction after they were created. A fractional undivided interest is not considered a security when the purchaser of the fractional undivided interest subsequently sells his entire ownership in the fractional undivided interest. Courts reached this conclusion by reading the definition of a security under the federal securities laws in conjunction with the definition of an issuer under the federal securities laws. In the context of selling interests in oil, gas, or other mineral rights, the definition of an issuer under federal law has been explicitly limited to owners of fractional undivided interests in oil, gas, or other mineral rights who create fractional interests to be sold.

In SEC v. Joiner, the U.S. Supreme Court explained why Congress limited its inclusion of oil and gas interests in the definition of a security to just fractional undivided interests:

Oil and gas rights posed a difficult problem to the legislative draftsman. Such rights were notorious subjects of speculation and fraud, but leases and assignments were also indispensable instruments of legitimate oil exploration and production. To include leases and assignments by name might easily burden the oil industry by controls that were designed only for the traffic in securities. This was avoided by including specifically only that form of splitting up of mineral interests which had been most utilized for speculative purposes.

As discussed below, the Texas legislature was less concerned with overburdening the oil industry than protecting investors. Consequently,

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8. Adena Exploration, 860 F.2d at 1252-53; Nor-Tex Agencies, 482 F.2d at 1097-98.
9. SEC v. C.M. Joiner Leasing Corp., 320 U.S. 344, 352 (1943); Woodward v. Wright, 266 F.2d 108, 112 (10th Cir. 1959); Adena Exploration, 860 F.2d at 1246 (“What Joiner left to implication Judge Murrah made explicit in his influential opinion in Woodward v. Wright, 266 F.2d 108 (10th Cir. 1959), a landmark securities case which remains frequently cited today.”).
10. Adena Exploration, 860 F.2d at 1245 n.5 (“Where the owner of a fractional undivided working interest surrenders his entire interest whole, there is no sale of a ‘fractional undivided interest’ under the Act.”); Lynn v. Caraway, 252 F. Supp. 858, 861-862 (W.D. La. 1966), aff’d per curiam, 379 F.2d 943 (5th Cir. 1967), cert. denied, 393 U.S. 951 (1968).
12. Securities Act of 1933 § 2(a)(4), 15 U.S.C. § 77b(a)(4) (2006) (“[T]he term ‘issuer’ means the owner of any such right or of any interest in such right (whether whole or fractional) who creates fractional interests therein for the purpose of public offerings.”)
13. C.M. Joiner Leasing, 320 U.S. at 352.
the definition of security under Texas law includes a large number of oil and gas interests that the federal definition excludes.

2. An Oil and Gas Interest that is an Investment Contract

Pursuant to the United States Supreme Court’s analyses in *Landreth*\(^ {14} \) and then in *Reves*,\(^ {15} \) courts should first determine whether the oil and gas interest is a fractional undivided interest in oil, gas, or other mineral rights. If the oil and gas interest at issue does not fall with this phrase, then the court may determine whether it is considered an “investment contract” and therefore a security under the federal securities laws.\(^ {16} \)

The Securities Act of 1933 and the Securities Exchange Act of 1934 each define a security to include an “investment contract.” The United States Supreme Court has defined an “investment contract” to mean a contract, transaction or scheme that “involves [1] an investment of money in [2] a common enterprise [3] with profits to come solely from the efforts of others.”\(^ {17} \) This three-pronged analysis is a general catchall that qualifies many investments in business arrangements as securities. Oftentimes an oil and gas interest will qualify as an investment contract, and hence a security under federal securities law, where the purchaser of the oil and gas interest will “look entirely to the efforts of other persons to make their investment a profitable venture.”\(^ {18} \)

B. Oil and Gas Interests Covered by the Texas Securities Act

The methodology under Texas law to determine if an oil and gas interest is a security is somewhat similar to that under federal law. An oil and gas interest may fall within the phrase in the TSA definition of a security that specifically identifies certain oil and gas interests as securities. Alternatively, the oil and gas interest may be covered as a security under the portion of the TSA that includes “investment contracts” as securities. The distinction, however, is that the TSA definition of a security explicitly includes many oil and gas interests that are excluded from the federal definition of a security.\(^ {19} \)

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18. *San Francisco-Oklahoma Petroleum Exploration Corp. v. Carston Oil Co.*, 765 F.2d 962, 966 (10th Cir. 1985) (quoting *Woodward v. Wright*, 266 F.2d 108, 112 (10th Cir. 1959)).
19. The court in *Darwin*, stated the following:
In defining the term “security” the Federal Act refers to “fractional undivided interest in oil, gas, or other mineral rights.” The Texas Act, Sec. 2(a) does not so limit the
1. Whole, Fractional, Segregated or Undivided Interests in Oil and Gas Rights

The TSA reads in relevant part that a security includes any “certificate or any instrument representing any interest in or under an oil, gas or mining lease, fee or title.”20 This definition is notably more far-reaching than the federal definition of a security.21 After all, the federal definition of a security only includes fractional undivided interests in oil, gas, or other mineral rights.

As explained above, the definition of a security under federal law is read in conjunction with the definition of an issuer to exclude many oil and gas interests from the scope of the federal securities laws.22 However, because the TSA does not have such a restrictive definition of an issuer, the definition of a security under Texas law has not been similarly constricted. Under the TSA, an issuer is defined broadly to include “every company or person who proposes to issue, has issued, or shall hereafter issue any security.”23 In contrast, federal securities law limits the definition of an issuer, in the context of oil and gas interests, to owners of fractional undivided interests in oil, gas, or other mineral rights who create fractional interests to be sold.24 Due to the different definitions of an issuer under federal and state law, most fractional undivided interests are considered securities under the TSA, regardless of whether the seller created it by splitting an interest into several fractional undivided interests.

In fact, when read in conjunction with another provision of the TSA, it is apparent that the Texas legislature intended the definition of a security to include a wide variety of oil and gas interests besides fractional undivided interests. The TSA provides that “interests in and under oil, gas or mining leases, fees or titles, or contracts relating thereto . . . whether whole, fractional, segregated or undivided in any single oil, gas or mineral lease, fee or title, or contract relating thereto” may be exempt from registration under the TSA under certain circumstances.25 By implication, the TSA definition of a security includes “interests in and under oil, gas or mining leases, fees or titles, or contracts relating

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21. See generally Meer, supra note 2, at 238.
thereto . . . whether whole, fractional, segregated or undivided in any single oil, gas or mineral lease, fee or title, or contract relating thereto. 26

In Kadane v. Clark, the Texas Supreme Court explained why the legislature included oil and gas interests in the definition of a security under state law and intimated that the TSA should cover a broad array of oil and gas interests.

The history relating to the sale of securities in this State is well known. The development of the oil industry emphasized the necessity of regulating sales of securities issued on oil leases and other instruments relating to the oil business. An enormous number of worthless securities were sold to the public, and nothing was realized on many of these investments by the buyers. There was no restraint upon such sales nor upon those who made them. The public was notoriously imposed upon, and oftentimes people were defrauded out of their life’s savings. There was a public demand for protection against such sales. The legislature sought to cope with the situation by enacting the Securities Act. 27

Although the variety of oil and gas interests included within the TSA definition of a security is broad, there are limitations. For instance, the original lease created by a landowner who grants an oil and gas lease to the first lessee is not a security under the TSA. 28 (But any subsequent trading of the oil and gas lease after its creation is regulated as a security under the TSA. 29) And, a license to simply test the ground for the existence of oil or gas is not considered a security under the TSA either. 30

2. An Oil and Gas Interest that is an Investment Contract

Of course an oil and gas interest may qualify as a security under the TSA under the portion of the definition of a security that includes an “investment contract” as a security. Texas courts follow federal court interpretations in applying the investment contract analysis, so analysis of

26. As explained in more detail below, even though a security may be exempt from registration under the TSA, it is still subject to the antifraud provision of the TSA. See infra Part II.C.

27. Kadane v. Clark, 143 S.W.2d 197, 199 (Tex. 1940). Although the Texas legislature has amended the TSA several times since Kadane, the TSA definition of a security as it relates to oil and gas interests has remained the same since then.


29. Meer, supra note 2, at 238.

what is an investment contract under Texas law is generally the same as under federal law.31

III. CHOOSING BETWEEN CLAIMS UNDER THE FEDERAL SECURITIES LAWS AND THE TEXAS SECURITIES ACT

The purchaser of an oil and gas interest may have a remedy under the securities laws if he (1) purchases an oil and gas interest that should have been registered under the securities laws but was not, or (2) is the victim of a misrepresentation or omission. The federal and Texas claims available to address the first type of injury are actually quite similar, so they are discussed only briefly in this article. On the other hand, if the investor is a victim of either a misrepresentation or an omission, a claim under the TSA is generally far superior to those under the federal laws. Nonetheless, each of these federal securities claims bear examination because in certain instances the TSA is preempted by the federal securities laws.

A. Sale of an Unregistered Security

The mantra for securities lawyers is that there are only three types of securities: (1) registered, (2) exempt, or (3) or illegal. To elaborate, after identifying an instrument as a security, it must be registered pursuant to the securities laws—unless it is exempt from registration. If a security is not exempt from registration, the purchaser of such a security can seek rescission of the sales transaction under either state or federal law.32

Under both federal and state law, the statutory claim to seek rescission of an unregistered security is relatively straightforward. In general, the aggrieved investor simply has to prove that the investment was a security, was not registered, and was not exempt from registration.33 Proof of scienter and reliance is unnecessary.34 Because the elements for proving a rescission claim under federal and Texas law are so similar, neither has a significant advantage over the other. The most significant differences are that, as explained above, many more oil and gas interests fall within the TSA definition of a security than under the federal definition of a

31. Sparks v. Baxter, 854 F.2d 110, 113-14 (5th Cir. 1988) (“In Searsy v. Commercial Trading Corp., 560 S.W.2d 637 (Tex.1977), Texas adopted the elements of an investment contract which the Supreme Court had announced for such a contract under the federal securities legislation.”); see also TEX. REV. CIV. STAT. ANN. art. 581-10-1, §A (Vernon 2005) (The Texas Securities Act “may be construed and implemented to effectuate its general purpose to maximize coordination with federal and other states’ law and administration . . . .”).
33. Swenson v. Engelstad, 626 F.2d 421, 424 (5th Cir. 1980).
34. Id. (“The Securities Act of 1933 imposes strict liability on offerors and sellers of unregistered securities. Recovery may be had under § 12(1) ‘regardless of whether (the purchaser) can show any degree of fault, negligent or intentional, on the seller’s part.’”)

security and the statute of limitations for the Texas claim is longer than under the federal claim.35

B. Federal Securities Claims to Recover for Misrepresentations and Omissions

Statutory claims for fraud under the federal securities laws are much more popular than those under state securities laws. The popularity of the federal securities claims is probably due in part to widespread coverage that those claims are given in law review articles and treaties. When confronted with securities fraud, the claims most often asserted are those under Section 10(b) of the Securities Exchange Act of 1934 and Sections 11 and 12(a)(2) of the Securities Act of 1933.

1. Rule 10b-5 Claim

Since 1946, courts have recognized a private right of action under Section 10(b) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder (the “Rule 10b-5 claim”).36 The Rule 10b-5 claim is regarded as the general antifraud claim under the federal securities laws.37 Unlike claims under Section 11 or Section 12(a)(2) of the Securities Act of 1933, the Rule 10b-5 claim addresses all claims of fraud in the sale or purchase of securities. As explained below, claims under Section 11 and Section 12(a)(2) are only available if the fraud took place in the context of a public offering. The Rule 10b-5 claim may be asserted to recover for fraud that regardless of whether it takes place in the context of a public offering, private placement, or secondary transaction.38

Although the Rule 10b-5 claim is generally applicable to redress fraud in the sale or purchase of a security, it does have significant shortcomings. For instance, the Rule 10b-5 claim requires proof of scienter and reliance,39 making it significantly more difficult to prove. And since 1975,

35. The statute of limitations for a claim under Section 12(a)(1) of the Securities Act of 1933, 15 U.S.C. 77l(a)(1) is “one year after the violation upon which it is based” and in no event “more than three years after the security was bona fide offered to the public.” 15 U.S.C. § 77m (2006). The statute of limitations for a claim under the TASA is generally no “more than three years after discovery of the untruth or omission, or after discovery should have been made by the exercise of reasonable diligence; or . . . more than five years after the sale . . . .” TEX. REV. CIV. STAT. ANN. art. 581-33, § H(2) (Vernon 2005).
39. Dura Pharm., Inc. v. Broudo, 125 S.Ct. 1627, 1631 (2005); Unger v. Amedisys Inc. 401 F.3d 316, 322 n.2 (5th Cir. 2005).
the U.S. Supreme Court has taken every opportunity it has had to make the Rule 10b-5 claim less attractive for aggrieved investors to assert. As a result, it is a far less useful claim than it used to be.

Fortunately for investors in Texas, the general antifraud claim under the TSA has not been watered down like the Rule 10b-5 claim and is often a very attractive alternative. But because claims under the TSA may be preempted by claims under the federal securities acts, an aggrieved investor may have to fall back on the Rule 10b-5 claim under certain limited circumstances.

2. Section 11 and Section 12(a)(2) claims

Claims under Section 11 and Section 12(a)(2) of the Securities Act of 1933 are much easier to prove than a Rule 10b-5 claim because neither of these two claims requires proof of scienter. In addition, proof of reliance is never required to prove a Section 12(a)(2) claim and is only occasionally required to prove a Section 11 claim. But claims under Section 11 and Section 12(a)(2) have their own drawbacks.

A Section 11 claim only provides a remedy if the misrepresentation or omission was made in a registration statement. Therefore, Section 11 only protects investors “who purchased their stock during the relevant public offerings” and “aftermarket purchasers as long as the stock is traceable back to the relevant public offering.” Section 11 does not provide a remedy to investors that purchased securities issued through a private offering.

Section 12(a)(2) only provides a remedy if the misrepresentation or omission was made in, or orally about, a prospectus. The Fifth Circuit

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41. See infra notes 76-78 and accompanying text.


44. In re Enron Corp., No. MDL1446, 2003 WL 23305555, at *6 (S.D. Tex. Dec. 11, 2003) (footnote omitted) ("[U]nder § 11 the plaintiff generally does not have to establish scienter, causation (materiality) or reliance." 15 U.S.C. § 77k(a) provides "a statutory exception to the usual rule that reliance is not required for a § 11 claim . . . .").

45. Rosenzweig v. Azurix Corp., 332 F.3d 854, 873 (5th Cir. 2003) ("[Section] 11 only applies to public registered offerings.").

46. Krim, 402 F.3d at 492.

has held that Section 12(a)(2) only applies in the context of a public offering. Consequently, the protections of Section 12(a)(2) do not extend to defrauded investors who purchased a security through a private offering, a secondary market offering, or in the aftermarket.

Section 11 and Section 12(a)(2) each contain a statutory defense granting defendants the right to raise the affirmative defense of loss causation. For years, Section 11 provided that loss causation may be raised as an affirmative defense. In 1995, Congress amended the Securities Act of 1933 to provide that a defendant may assert the affirmative defense of loss causation to a claim under Section 12(a)(2). The “loss causation affirmative defense allows a defendant to avoid liability if the depreciation in the value of the security did not result from any nondisclosure or false statement made in the prospectus or registration statement.”

As explained below, the aggrieved investor would probably prefer to bring a claim under the general antifraud provisions of the TSA instead of under either Section 11 and Section 12(a)(2) unless it is preempted. That way the aggrieved investor would be able to avoid dealing with all of the above described obstacles that others asserting a claim under either Section 11 and Section 12(a)(2) must address.

C. The Texas Securities Act’s General Antifraud Claim

Fortunately for defrauded investors in Texas, they usually have the option of asserting a claim under the TSA that is far superior to any of those that could be brought under the federal securities laws. The general antifraud claim under the TSA is just as easy, in fact easier, to prove than

\[\text{Gustafson} \text{ to hold that the term ‘oral communication’ in Section 12(a)(2) is a ‘communication that relates to a public written communication, such as a prospectus.’} \]

\[\text{48. Lewis v. Fresne, 252 F.3d at 357 (“Section 12 of the 1933 Act does not apply to private transactions.”); In re Enron Corp., 310 F. Supp. 2d at 860 (“Section 12 applies only to public offerings and not to private transactions.”); Shanahan v. Vallat, No. 03 Civ. 3496 (MBM), 2004 U.S. Dist. LEXIS 25523, at *20 (S.D.N.Y. Dec. 14, 2004) (“Several courts have held that Gustafson excludes ‘purchasers in private or secondary market offerings’ from bringing claims under section 12(2).”); First Union Disc. Brokerage Servs., Inc. v. Milos, 997 F.2d 835, 843-44 (11th Cir. 1993) (“Section 12(2) of the 1933 Act does not apply to aftermarket transactions.”) \]

\[\text{49. Lewis, 252 F.3d at 357 (“Section 12 of the 1933 Act does not apply to private transactions.”); In re Enron Corp., 310 F. Supp. 2d at 860 (“Section 12 applies only to public offerings and not to private transactions.”); Shanahan v. Vallat, No. 03 Civ. 3496 (MBM), 2004 U.S. Dist. LEXIS 25523, at *20 (S.D.N.Y. Dec. 14, 2004) (“Several courts have held that Gustafson excludes ‘purchasers in private or secondary market offerings’ from bringing claims under section 12(2).”); First Union Disc. Brokerage Servs., Inc. v. Milos, 997 F.2d 835, 843-44 (11th Cir. 1993) (“Section 12(2) of the 1933 Act does not apply to aftermarket transactions.”) \]

\[\text{50. Securities Act of 1933 § 11(e), 15 U.S.C. § 77k(e) (2006); In re Worlds of Wonder Sec. Litig., 35 F.3d 1407, 1421-22 (9th Cir. 1994).} \]


\[\text{53. See infra notes 76-78 and accompanying text.} \]
a claim under either Section 11 or Section 12(a)(2). But unlike a claim under Section 11 or Section 12(a)(2), the TSA claim is not constrained to redressing fraudulent registration statements or misrepresentations or omissions made in, or orally about, a prospectus. Instead, the general antifraud claim under the TSA applies to all sales and purchases of securities, just as the Rule 10b-5 claim does. But the TSA claim is much easier to prove and generally provides a better remedy than a Rule 10b-5 claim.

As noted by the Texas Supreme Court, the TSA “considered as a whole, is something less than a model of lucidity in legislative drafting.” That much is apparent when reviewing the civil liability provision of the TSA which reads in part:

A person who offers or sells a security (whether or not the security or transaction is exempt under [the Texas Securities Act]) by means of an untrue statement of a material fact or an omission to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they are made, not misleading, is liable to the person buying the security from him . . . 

But the complexity of this provision belies the ease of proving a TSA claim. For starters, the claim does not require proof of either scienter or reliance, both of which are elements of a Rule 10b-5 claim. In fact, the TSA imposes strict liability upon violators.

As if these attributes were not attractive enough, many defenses that can be raised against claims under the federal securities laws cannot be raised against a TSA claim. This is significant because common law defenses such as ratification, waiver, estoppel, and failure to mitigate are often formidable obstacles to establishing a Rule 10b-5 claim.

The only defenses to a TSA claim are those provided for in the statute itself and the defense of joint adventurers. In Duperier v. Texas State
Bank, the court expressly held that a defendant could not raise ratification, comparative fault, loss causation, or mitigation as affirmative defenses to a TSA claim. Although the court did not expressly hold that a defendant could not raise any common law defenses, the court implied as much in its opinion. For instance, the court held that comparative fault could not be raised as a defense “[b]ecause the statute provides no other defenses, and a comparative fault defense would abrogate the effect of the statute.” In sum, it appears that the Duperier court would not recognize any defense other than the two “absolute defenses” available under the TSA.

The TSA expressly provides that “a person is not liable if he sustains the burden of proof that either (a) the buyer knew of the untruth or omission or (b) he (the offeror or seller) did not know, and in the exercise of reasonable care could not have known, of the untruth or omission.” These two statutory defenses mirror those that all of the above described federal claims are subject to anyway, so they do not make the TSA claim any less advantageous.

Damages under the TSA are quite generous. As noted by one court, the federal statute upon which the TSA damage provision was modeled, “permits windfall recoveries.” The aggrieved investor pursuing a claim under the TSA is entitled to rescission if the investor still holds the securities. But if the aggrieved investor already sold the securities in

“A joint venture is a defense to any cause of action arising under the Texas Securities Act.”).

61. 28 S.W.3d 740 (Tex. App.—Corpus Christi 2000).
62. Id. at 753-754.
63. Id. at 753.
64. Id.
65. TEX. REV. CIV. STAT. ANN. art. 581-33, § A(2) (Vernon 2005).
66. A defendant may avoid liability under Section 11 if “it is proved that . . . [the buyer] knew of such untruth or omission.” 15 U.S.C. § 77k(a) (2006). “Section 12(2) of the 1933 Act explicitly provides that liability shall not lie for the failure to disclose a material fact in a prospectus where ‘the purchaser . . . know[s] of such untruth or omission.’” Jensen v. Kimble, 1 F.3d 1073, 1079 n.10 (10th Cir. 1993) (citing 15 U.S.C. § 77(2)). An offeror may avoid liability under Section 11 and Section 12(2) if he can “demonstrate that he did not know, and could not reasonably have been expected to know, of the untruth or omission.” SEC v. Sw. Coal & Energy Co., 624 F.2d 1312, 1318-19 (5th Cir. 1980). If the plaintiff knew of the untruth or omission, the plaintiff cannot prove that he reasonably relied upon the untruth or omission, a required element in a Rule 10b-5 claim. If the defendant did not know of the untruth or omission, the element of scienter required under a Rule 10b-5 claim cannot be proved.
68. In construing the TSA, the court in Texas Capital Securities, Inc. v. Sandefur held that “a plaintiff who still owns the securities in question is only entitled to rescission. Rescission is intended to restore plaintiffs to their original position. A finding of actual damages is not
dispute, he is entitled to damages equal to his out-of-pocket loss. Consequently, if the securities in dispute declined in value after their sale, the aggrieved investor’s recovery is unaffected. The aggrieved investor is entitled to the return of the purchase price, plus pre-judgment interest, costs, attorney’s fees, and possibly exemplary damages. The seller who violated the TSA bears the risk that the securities may decline in value after the sale, not the aggrieved investor.

Secondary liability is available and often sought under the TSA. The TSA allows a defrauded investor to pursue an aiding and abetting claim—a claim that the U.S. Supreme Court extinguished under the Rule 10b-5 claim in 1994. In Central Bank of Denver, N.A. v. First Interstate Bank of Denver, N.A., the Supreme Court held that a private plaintiff could not assert a private cause of action under Rule 10b-5 against aids and abettors. Fortunately for Texas investors, the TSA explicitly allows defrauded investors to seek recovery from those who aid and abet a securities violation.

For investors in oil and gas interests, perhaps the greatest advantage of the TSA claim over the Rule 10b-5 claim is that a greater variety of oil and gas interests are actionable under the TSA than under any of the federal securities claims. As explained above, the TSA defines the term security in a much more expansive fashion than the federal securities laws define the same term. Consequently, defrauded purchasers may be able
to assert a claim under the TSA when a claim under the federal securities laws is not available.

Despite the above described advantages to a claim under the TSA, there are limited instances when the claim will not be available. Perceiving a need for federal securities laws to preempt certain class actions brought under state law, Congress passed the Securities Litigation Uniform Standards Act of 1998 ("SLUSA"). SLUSA provides that the federal securities claims preempt state law claims in class actions involving "covered securities." Covered securities are defined in such a way that they generally only include publicly traded securities. Fortunately for oil and gas investors in Texas, the circumstances under which their access to the remedies under the TSA is barred are relatively limited.

IV. CONCLUSION

As explained above, there are substantial differences between the definition of a security under federal law and the definition of a security under Texas law. In sum, the definition of a security under Texas law includes many oil and gas interests that are excluded as securities under the federal securities laws. As a consequence, the purchaser of an oil and gas interest may have a claim under the TSA but not under the federal securities laws. Even if the oil and gas interest qualifies as a security under both the federal securities laws and the TSA, an aggrieved investor would probably prefer to file a TSA claim over a federal securities claim because of the relative ease in proving a corresponding claim under the TSA.

Figure 1 shows the Gulf of Venezuela. Map of Gulf of Venezuela [Golfo de Venezuela] (gulf), Venezuela, Microsoft® MapPoint®, http://encarta.msn.com © 1993-2004 Microsoft Corp. All rights reserved.
NOTE & COMMENT

THE COLOMBIA-VENEZUELA MARITIME BOUNDARY CASE: PROPOSAL FOR A JOINT DEVELOPMENT ZONE IN THE GULF OF VENEZUELA

VICTORIA VANBUREN *

Colombia and Venezuela both assert sovereign rights over two offshore areas with petroleum potential. In 1941, the countries ratified a demarcation treaty to settle a lengthy disagreement over their land boundary on the Guajira Peninsula. This treaty, however, did not provide for delimitation of marine and submarine spaces in the Gulf of Venezuela.

Over time, Colombia and Venezuela’s interests on the Gulf have shaped their policy decisions on whether to participate in the 1958 Geneva Convention on the Continental Shelf and the 1982 United Nations Convention on the Law of the Sea. As a result, no provision on continental shelf delimitation in either treaty is binding upon both nations. Colombia and Venezuela also do not recognize as compulsory the jurisdiction of the International Court of Justice. Consequently, international law does not provide an adequate legal framework and mechanism to resolve this dispute. Nevertheless, the current economic-political environment suggests that a diplomatic compromise between the two states might be possible.

This Note proposes a joint development regime, in which the parties agree to explore and develop oil and gas reserves without giving up sovereignty claims in the disputed areas.

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I. INTRODUCTION

The twentieth century rightly deserves the title “the century of oil.” Yet for all its conflict and complexity, there has often been a “oneness” to the story of oil, a contemporary feel even to events that happened long ago and, simultaneously, profound echoes of the past in recent events. At one and the same time, this is a story of individual people, of powerful economic forces, of technological change, of political struggles, of international conflict and, indeed, of epic change.1

Colombia2 and Venezuela3 were under Spanish rule for three hundred years before achieving independence early in the nineteenth century.4 Since that time, the neighboring nations have struggled to delineate their jurisdictional boundaries. Successive boundary negotiations that began in 1833 concluded with a final demarcation treaty in 1941.5 The treaty settled the land frontier between the countries but was silent regarding marine and submarine spaces.6

2. The official name of Colombia is the “Republic of Colombia” (República de Colombia in Spanish) [hereinafter Colombia]. Colombia is located on the northwestern coast of South America, bordered by the waters of the Caribbean to the north and Panama, which divides the two bodies of water, on the northwest, Venezuela and Brazil on the east and Peru and Ecuador on the south. Colombia has a total area of 1,138,910 square kilometers, slightly less than three times the size of Montana, and an estimated population of forty-three million. U.S. CENT. INTELLIGENCE AGENCY, THE WORLD FACTBOOK-COLOMBIA, http://www.cia.gov/cia/publications/factbook/geos/co.html (last visited March 17, 2006) [hereinafter FACTBOOK-COLOMBIA].
3. The official name of Venezuela is the “Bolivarian Republic of Venezuela” (República Bolivariana de Venezuela in Spanish) [hereinafter Venezuela]. Venezuela is located on the northern coast of South America. It is bordered by the Caribbean Sea and the Atlantic Ocean to the north, Guyana to the East, Brazil to the South, and Colombia to the southwest and west. Venezuela occupies a total of 912,050 square kilometers, slightly more than twice the size of California, with approximately 25.4 million residents. U.S. CENT. INTELLIGENCE AGENCY, THE WORLD FACTBOOK-VENEZUELA, http://www.cia.gov/cia/publications/factbook/geos/ve.html (last visited March 17, 2006) [hereinafter FACTBOOK-VENEZUELA].
5. AYALA, supra note 4, at 80.
Negotiations concerning the maritime boundary in the northwest part of the Gulf of Venezuela continued throughout the twentieth century without reaching a mutually satisfactory agreement. Presently, two offshore areas are subject to controversy: continental shelf delimitation of the Gulf of Venezuela south of Castilletes and marine rights pertaining to Los Monjes, a small group of islands located at the entrance to the Gulf.

This Note concludes that international law fails to provide an adequate legal framework and binding mechanism to resolve the Colombia-Venezuela maritime boundary case. A joint development zone, however, presents a feasible compromise and would permit the nations to share exploration and exploitation of seabed resources without relinquishing their respective claims in the Gulf of Venezuela.

Part II of this Note reviews the historical origins of the maritime boundary dispute in the Gulf of Venezuela. Part III discusses the international law principles concerning the Colombia-Venezuela case. Part IV presents the positions adopted by Colombia and Venezuela through the statements of their delegations or leading authorities in the field and briefly examines their case under international law. Part V considers the contemporary relations between Colombia and Venezuela and discusses the countries’ current need for oil. Part VI presents the framework for a proposed joint development zone. Finally, the appendix contains maps showing several possible delimitations of the Gulf of Venezuela.

II. BACKGROUND AND HISTORY OF THE DISPUTE

A. La Gran Colombia and Uti Possidetis Juris of 1810

Colombia and Venezuela were once colonies of Spain. After achieving independence from the Spanish empire in 1810, revolutionary hero Simon Bolivar formed a new nation called “Gran Colombia,” consisting of present-day Venezuela, Panama, Colombia, and Ecuador. Some diplomatic attempts to settle the dispute include the following: the interchanged visits of Perez and Arrieta in 1965 and 1966, respectively; the meeting of the Mining and Petroleum Ministers in Bogotá in 1967; the Colombian Ministry of Exterior visit to Caracas in 1968; the Sochagota agreement to continue negotiations in 1969; the Rome Negotiations in 1970-1973; the 1973-1975 Negotiations; the Proposal of President Alfonso Lopez Michelsen in 1975; the Caraballeda Hypothesis in 1979; the 1980-1985 Negotiations; and in 1987, Colombia demanded that Venezuela comply with the Treaty of 1939. See MARCO GERARDO MONROY CABRA, DELIMITACIÓN TERRESTRE Y MARÍTIMA ENTRE COLOMBIA Y VENEZUELA (TERRESTRIAL AND MARITIME DELIMITATION BETWEEN COLOMBIA AND VENEZUELA) 81-93 (1989).

8. Anastasia Strati, Potential Areas for Joint Development, in JOINT DEVELOPMENT OF OFFSHORE OIL AND GAS VOL. II 118 (1990); see also FACTBOOK-VENEZUELA, supra note 3 (citing the boundary dispute between Columbia and Venezuela).

9. Juan Pablo Lupi & Leonard Vivas, Politic and Prospect in Latin America: (Mis) Understanding Chavez and Venezuela in Times of Revolution, 29 FLETCHER F. WORLD AFF. 81,
Colombia proved to be politically unsustainable and in 1829, Venezuela separated from Gran Colombia to become an independent nation.10

Following the dissolution of Gran Colombia, the emerging republics of Colombia and Venezuela incorporated into their Constitutions the doctrine of uti possidetis juris of 1810.11 This principle states that a country gaining independence from colonial rule inherits the original borders of the previous state.12 Thus, upon severance from Gran Colombia, Venezuela’s territorial limits should have remained the same as under Spanish administration.13 But the exact location of the borders during colonial times was difficult to ascertain, and this issue became central to the land boundary controversy.14 As a result, the application of the principle of uti possidetis juris of 1810 to set the boundary lines between Colombia and Venezuela has been a prolonged, complicated affair.

B. Michelena-Pombo Treaty of 1833

In 1833, Colombia and Venezuela negotiated the Michelena-Pombo Treaty, the first international document that attempted to establish the boundary lines between the two countries.15 Santos Michelena, the boundary negotiator for Venezuela, argued that the former province of

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94 (2005). In 1810, the various Latin American provinces proclaimed independence from Spanish domination. AYALA, supra note 4, at 62.
10. Nelson, supra note 6, at 177; see also Lupi & Vivas, supra note 9, at 94 (discussing the political instability of Gran Columbia).
11. MONROY, supra note 7, at 28-29. The Venezuelan Constitution of 1830 established the formula that would be expressed in subsequent constitutions. The territory of Venezuela is comprised of everything that was denominated Capitania General de Venezuela. PABLO OJER, EL GOLFO DE VENEZUELA: UNA SÍNTESIS HISTÓRICA [THE GULF OF VENEZUELA: A HISTORICAL SYNTHESIS] 14 (1983).
12. OJER, supra note 11, at 21-22. The origin of the concept of uti possidetis is traced back to Roman jurists. Id. Generally, uti possidetis was used in disputes involving real property. Id. The courts applied the formula “uti possidetis ita possidetatis” (translates to: “as you possess, so you may possess”) to determine who would keep the property while the case was pending in court. Id. Apparently, it was Simon Bolivar who adopted this principle, formalized by the Colombian Secretary of Foreign Affairs in 1823. Id. Notwithstanding their similar name, the differences between its Roman predecessor and the Latin American version are significant. Id. While the Roman uti possidetis was provisional and referred to occupation or possession of the disputed property, the Bolivarian adaptation took into account only the legal title, even if it was not confirmed by actual possession and the duration of the title was permanent. Id. Invoking the principle of uti possidetis juris of 1810, New Spain was transformed into Mexico and Virreinato del Perú became the Republic of Perú. JOSÉ MANUEL BRICEÑO MONZILLO, VENEZUELA Y SUS FRONTERAS CON COLOMBIA [VENEZUELA AND ITS BORDERS WITH COLOMBIA] 42 (1986).
13. BRICENO, supra note 12, at 35.
14. In Latin America, the doctrine of uti possidetis juris was conceived to avoid boundary conflicts, affirm the emerging countries’ sovereignty, guarantee reciprocity, and negate the possibility of establishing colonies in America. SALCEDO, supra note 4, at 283.
15. KALDONE G. NWEIHED, LA DELIMITACIÓN MARÍTIMA AL NOROESTE DEL GOLFO DE VENEZUELA [MARITIME DELIMITATION AT THE NORTHWEST OF THE GULF OF VENEZUELA] 22 (1975). The objectives of the negotiations were to define the borders between the two republics and to resolve the recognition, sharing, and payment of Gran Colombia’s debt acquired between 1819-1830. BRICENO, supra note 12, at 53.
Venezuela had historically extended along the Atlantic coast to Cabo de la Vela, which would mean that Venezuela was the only occupant of the Guajira Peninsula. However, Michelena realized that Colombia had expanded its presence on the peninsula, and insisting on Cabo de la Vela as the boundary would not solve the dispute. Eventually, the diplomats agreed on drawing a line beginning at Cabo Chichibacoa, as the point at which the northern part of the Colombia-Venezuela boundary would begin.

Despite Colombia’s ratification of the Michelena-Pombo Treaty in 1834, the Venezuelan legislature, after numerous heated debates, formally rejected the treaty in 1840. Venezuelan Congressmen argued that their country would lose sixty-two miles of coastline (measuring from Cabo de la Vela to Cabo Chichibacoa), together with its corresponding land. If ratified by Venezuela, this agreement would have granted Colombia roughly two-thirds of the Guajira Peninsula but no land with coastline on the Gulf.

C. Spanish Arbitral Award of 1891

In 1881, the countries agreed to submit the entire boundary dispute to the arbitration of King Alfonso XII of Spain. The rationale was that Spain, former owner of the disputed territories, would have access to ancient, accurate title documents. However, Venezuelan scholars have long questioned the impartiality of the Spanish forum for political and religious reasons. It was in Venezuela where the independence movement from Spain began, and Venezuela was known to have a more liberal population than Colombia, one which would inevitably conflict with characteristic Spanish Catholic morals. This context would translate into a more favorable treatment for Colombia’s territorial claims.

16. N. Weihed, supra note 15, at 22-23. Venezuela supported this claim with several historical documents; one dated 1528, in which Spanish King Carlos V stated that the limit of the Venezuelan province was Cabo de Vela and another by geographer Francisco Jose Calderas dated 1808. Briceño, supra note 12, at 56; see also Alegato de Venezuela en su Controversia Sobre Límites con Colombia, Venezuela [Venezuela’s Claim in Its Controversy over Territorial Boundaries with Colombia] Ministerio de Relaciones Exteriores de Venezuela [Venezuela’s Ministry of Foreign Affairs] 114 (1979) (stating that the title granted to Carlos V provided that the province of Venezuela began at Cabo de la Vela).
17. N. Weihed, supra note 15, at 22-23.
18. Briceño, supra note 12, at 54.
19. Id. at 57.
20. Id.
21. Id. at 55.
25. Id.
In 1885, the Spanish king died unexpectedly without resolving the Colombia-Venezuela dispute and the decision was left to the regent Queen Maria Cristina. Finally, in 1891 the Queen handed down the award. This award accepted the arguments made by the Colombian lawyers and purported to follow the principle of *uti possidetis juris* of 1810.

The text of the Spanish Arbitral Award designated the starting demarcation on the Atlantic coast at “Los Mogotes also known as Los Frailes.” After decades of studies and expeditions, neither Colombia nor Venezuela found the exact location of that mark. Thus, the demarcation commission used Castilletes as a reference, a spot located at Latitude 11° 51’ North.

The resolution to set the land boundary at Castilletes contradicts the text of the award. The award’s preamble describes the territories in dispute as being north of the twelfth parallel, rather than south, where Castilletes is located. Some commentators have also suggested that “Los Mogotes also known as Los Frailes,” refers to Los Monjes Islands, located at Latitude 12° 30’ North, which would agree with the language in the preamble.

In addition to the vagueness of the Spanish Arbitral Award, other factors contributed to the difficulty of implementing the resolution. The lack of geographical knowledge of those times, the uninhabitability of the areas, and the large size of the territory to be demarcated (2,200 sq km) were all obstacles to the correct demarcation. Although confusing, the Spanish Award resulted in Venezuela losing a considerable part of the Guajira Peninsula.

**D. Swiss Arbitral Award of 1922**

After the hundred-year anniversary of independence from Spain, difficulties over the execution of the Spanish Award persisted. In particular, the nations disputed whether the award could be carried out

27. *Venezuela accepted the Spanish Arbitral Award within the context of domestic political turmoil: a brief civil government by Raimundo Andueza Palacios, a controversy regarding the constitutional amendment to extend the presidential term, and Crespo’s legal revolution. Id. at 27-28.*
28. *Monroy, supra* note 7, at 44.
31. *Id. at* 62-63.
32. *Id.*
33. *Id. at* 63.
34. *Id. at* 62.
35. *Before 1900, Venezuela enjoyed sovereignty over 80% of the Guajira Peninsula and Colombia had no coastline on the Gulf. Now, conversely, Venezuela has 20% of the land surface at La Guajira. Id. at 65.*
partially as Colombia maintained, or whether it had to be carried out as a whole as Venezuela contended. The parties agreed to arbitrate again, now through a Swiss commission. In 1922, the Swiss panel affirmed the execution of the Spanish Arbitral Award in the piecemeal fashion that Colombia advocated. Consequently, each country had a right to occupy the territories that were partially adjudicated by the Spanish Award, even the areas where the demarcation was not completed.

**E. Santos-Lopez Contreras Treaty of 1941**

In 1941, Colombia and Venezuela signed the Treaty on the Demarcation of Borders and Navigation of Common Rivers. Under the administration of Eduardo Santos in Colombia and General Eleazar Lopez in Venezuela, this treaty represented the closing of the long land boundary negotiations that began with the Michelena-Pombo Treaty of 1833. The 1941 treaty recognized as definitive and irrevocable the demarcation work done according to the Swiss experts and declared the end of the differences concerning the countries’ territorial limits.

The treaty of 1941 was ratified by both Colombia and Venezuela. The Colombian Congress eagerly ratified the treaty the same year. Although it was hardly a popular treaty in Caracas, the Venezuelan Congress approved the new treaty after a heated debate. Many wondered why the Venezuelan government leaders accepted such a disadvantageous arrangement. One congressman defended his position by declaring that the people of Venezuela wanted to know where their nation began and where it ended.

In summary, the arbitral awards of the Spanish Queen in 1891 and the Swiss panel in 1922, coupled with the Santos-Lopez Contreras Treaty of 1941, brought Colombia closer to the Gulf of Venezuela by granting her a small coastline on the Gulf, a marine space that had been traditionally

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36. Nelson, supra note 6, at 177. Because the demarcation commissions could not find the point at the coast (Los Mogotes also known as Los Frailes), Colombia advocated demarcation on the rest of the Guajira Peninsula, where the Spanish arbitral award was unambiguous. Briceño, supra note 12, at 67. On the other hand, Venezuela did not recognize Colombian occupation even on the areas clearly identified by the award. Id.
40. Monroy, supra note 7, at 51.
41. Id. at 68.
42. Briceño, supra note 12, at 68-69. After signing the Treaty of 1941, Venezuela began claiming sovereignty over Los Monjes Islands. Presumably, these islands were not mentioned in the text of the Spanish Arbitral Award of 1891. Holguín, supra note 23, at 28.
43. Monroy, supra note 7, at 52.
44. Briceño, supra note 12, at 73.
45. Id.
Venezuelan.46 Because there was no reference to respective maritime rights in the Gulf, the delimitation of marine and submarine areas between the two states later became an issue. This omission coincided with a growing number of coastal nations extending their jurisdiction seaward and with developments in principles of international law concerning maritime boundary delimitation.

III. INTERNATIONAL LAW: THE LAW OF THE SEA

A nation’s claims of sovereign rights over ocean and seabed spaces are influenced by maritime territorial jurisdiction concepts in international law. To understand the basis on which Colombia and Venezuela justify their legal arguments, a review of international law is helpful. This section describes developments in the Law of the Sea and case law from international tribunals relevant to the Colombia-Venezuela case.

Historically, the territorial sea47 was deemed to extend only three miles from the coastal state baseline.48 States active in marine trade supported this limit in order to maintain the “freedom of the seas.”49 Since the middle of the twentieth century, most countries have claimed a twelve-mile limit and many countries, including most South American countries, have asserted rights to a 200-mile territorial sea.50 In addition, the issue of territorial sea limits became confused by jurisdictional claims for such diverse purposes as fisheries, customs, and immigration controls.51 The three-mile rule has been recently discarded as a rule of general application to be superseded by contending jurisdictional claims.52

Although international law generally dictates that the oceans beyond the territorial sea are free for shipping, fishing, and transportation by peoples of all nations, traditional international law was silent about the right to extract minerals from the sea.53 As techniques for deep sea mining and drilling developed in the twentieth century, the issue became

47. The territorial sea of a coastal state is a maritime belt around its coastline or territorial waters and is treated as an indivisible part of its domain. MALCOLM N. SHAW, INTERNATIONAL LAW 490-91 (5th ed. 2003).
48. ERNEST E. SMITH ET AL., INTERNATIONAL PETROLEUM TRANSACTIONS 216 (2d ed. 2000). Originally, the “cannon-shot” rule defined the effective limit of control over the sea exercised from the land and it was the range of shore-based artillery. At the turn of the nineteenth century, this was transmuted into the three-mile rule. SHAW, supra note 47, at 505.
49. For example, the United States, Japan, the United Kingdom, and the Netherlands supported this limit. SMITH ET AL., supra note 48, at 216.
50. Id.
51. SHAW, supra note 47, at 490-91.
52. Id.
53. SMITH ET AL., supra note 48, at 216.
increasingly salient.\textsuperscript{54} This led to the creation of the continental shelf as a legal concept.\textsuperscript{55}

Four events are particularly responsible for shaping the modern doctrine of the continental shelf: the Truman Proclamation on the Continental Shelf of 1945, the 1958 Geneva Convention on the Continental Shelf, the \textit{North Sea Continental Shelf} cases of 1969, and the 1982 United Nations Convention on the Law of the Sea.

\textit{A. The Truman Proclamation on the Continental Shelf of 1945}

Even before World War II, pressure from the oil industry began building in the United States to extend American jurisdiction seaward to provide the stable legal climate necessary for the development of offshore petroleum.\textsuperscript{56} Consequently, in 1945 the U.S. government proclaimed that it regarded the “natural resources of the subsoil and seabed of the continental shelf beneath the high seas but contiguous to the coasts of the United States as appertaining to the United States subject to its jurisdiction and control.”\textsuperscript{57}

The proclamation by President Truman constituted a unilateral claim of ownership by the United States federal government of all portions of the continental shelf adjacent to the United States.\textsuperscript{58} However, this proclamation did not define what was meant by “continental shelf” or what its outer limits were.\textsuperscript{59} Many countries quickly followed the lead of

\textsuperscript{54} \textit{Id.}

\textsuperscript{55} Geologically, the continental shelf is defined as follows:

[T]he seaward portion of the extension of the continental landmass which begins with the upland coastal plain and extends seaward until a marked increase in slope occurs . . . \[t\]he term has come generally to refer only to that submerged portion. The average water depth at the break in slope was traditionally considered to be 200 meters although in fact this average depth is approximately . . . 130-140 meters . . . . The width of the continental shelf also varies substantially, ranging from virtually zero breadth off the western coast of South America to 800 miles or more beneath the Bering Sea, averaging approximately 40 miles in width worldwide. In the United States, shelf width varies from as little as one mile off portions of California, to 100-150 miles off the Gulf coast, to over 200 miles off New England . . . .

\textsuperscript{56} DAVID B. KETO, LAW AND OFFSHORE OIL DEVELOPMENT: THE NORTH SEA EXPERIENCE 64-65 (1978).

\textsuperscript{57} SMITH ET AL., supra note 48, at 216 (citing Proclamation No. 2667, 10 Fed. Reg. 12303 (Sept. 27, 1945)).

\textsuperscript{58} \textit{Id.}

\textsuperscript{59} The White House press release that accompanied the proclamation noted, however, that generally submerged land, which is contiguous to the continent, and which is covered by no more than 100 fathoms (600 feet) of water is considered the continental shelf. KETO, supra note 56, at 65.
the United States and claimed their adjacent continental shelves, but because they were based on geology, the claims were disparate in extent.60 These claims resulted in vigorous protests by many countries, leading to the 1958 Geneva Convention on the Continental Shelf.61

B. The 1958 Geneva Convention on the Continental Shelf

The 1958 Geneva Convention on the Continental Shelf (“Continental Shelf Convention”) defined the continental shelf in terms of its exploitability rather than upon the geological definition.62 According to Article 1, the term “continental shelf” refers

(a) to the seabed and subsoil of the submarine areas adjacent to the coast but outside the area of the territorial sea, to a depth of 200 metres or, beyond that limit, to where the depth of the superjacent waters admits of the exploitation of the natural resources of the said areas; (b) to the seabed and subsoil of similar submarine areas adjacent to the coasts of islands.

This provision caused problems because rapidly developing technology gave nations the ability to extract resources from a much greater depth than 200 meters, meaning that the outer limits of the shelf were very unclear.64

Article 6 established the means to be used in delimiting continental shelf areas. Section 1 uses the principle of equidistance in the delimitation of continental shelves that are adjacent to the territories of two or more states whose coasts are opposite each other. The section provides that “[i]n the absence of agreement, and unless another boundary line is justified by special circumstances, the boundary is the median line, every point of which is equidistant from the nearest points of the baselines from which the breadth of the territorial sea of each state is measured.”65 Section 2 established the same procedure for continental shelf areas shared by adjacent coastlines.66
The participant nations signed the Continental Shelf Convention on April 29, 1958 and it later entered into force on June 10, 1964. A study of the ratifications of the 1958 Geneva Conventions does not, however, provide a complete picture of the conventions’ impact on the international legal system, as many states not ratifying the 1958 conventions nevertheless implemented their provisions.

C. The North Sea Continental Shelf Cases of 1969

The equidistance provision of the Continental Shelf Convention came under strong attack in the North Sea Continental Shelf cases. These cases, heard before the International Court of Justice (“ICJ”), reviewed the problems facing adjacent states where a concave coastline creates difficulties for the delimitation of a joint continental shelf.

The ICJ held, inter alia, that the use of the equidistance method of delimitation was not obligatory as between the parties and the principles enumerated in Article 6 of the Continental Shelf Convention did not constitute customary international law. The Court held that the relevant rule was as follows:

[D]elimitation is to be effected by agreement in accordance with equitable principles, and taking account of all the relevant circumstances, in such a way as to leave as much as possible to each Party all those parts of the continental shelf that constitute a natural prolongation of its land territory into and under the sea, without encroachment on the natural prolongation of the land territory of the others.

Commentators have criticized international maritime boundary case law for its indeterminacy:

International law does not require that maritime boundaries be delimited in accordance with a particular method; rather it requires that they be delimited in accordance with equitable principles taking into account all of the relevant circumstances. The equitable

67. Id.
70. Although Denmark and the Netherlands were parties to the Continental Shelf Convention, the Federal Republic of Germany was not a party. Id.
71. Id.
principles are indeterminate and the relevant circumstances are theoretically unlimited.\textsuperscript{72}

Configuration of the relevant respective coastlines, length of relevant coastlines, existence of islands, security considerations, and the prior conduct of the parties may all be pertinent factors in the particular circumstances of the case.\textsuperscript{73}


Pressures from a wide range of states and international organizations led to the 1982 United Nations Convention on the Law of the Sea (“UNCLOS”).\textsuperscript{74} UNCLOS formally went into effect in 1994, and by 2006, 149 countries had ratified it.\textsuperscript{75} By defining the concepts of territorial sea, contiguous zone, continental shelf, and exclusive economic zone (“EEZ”), UNCLOS has brought some degree of uniformity to the seaward extent of coastal nations’ jurisdictional claims.\textsuperscript{76}

UNCLOS set a twelve-mile territorial sea limit. Under UNCLOS Article 3, all states have the right to establish the breadth of the territorial sea up to a limit not exceeding twelve nautical miles from the baselines.\textsuperscript{77} By 1994, over 120 coastal states had established a twelve-mile territorial sea.\textsuperscript{78}

Article 33 provides that a state can also establish a “contiguous zone” extending up to twenty-four nautical miles from its shore, in which it can enforce its customs, fiscal, immigration, and health laws.\textsuperscript{79} The contiguous zone under the 1958 Convention on the Territorial Sea was limited to a maximum of twelve miles from the baselines.\textsuperscript{80} Under that Convention, if a country had already claimed a twelve-mile territorial sea, the question


\textsuperscript{73} \textit{SHAW}, supra note 47, at 540. Between the 1958 Convention and the signing of UNCLOS in 1982, the ICJ decided two other important cases in addition to the \textit{North Sea Continental Shelf} cases: the \textit{Anglo-French} case and the \textit{Tunisia-Libya} case. The concept of equidistance is crucial to these cases; the major issue is whether equidistance should be a mandatory requirement of equitable delimitation or merely a tool to assist the courts or the parties in delimitating the area in dispute. James H. Rodgers, \textit{The Continental Shelf of Ireland: the Law and Politics of Delimitation}, 3 UCLA J. Int’l L. & For. Aff. 129, 142 (1998).

\textsuperscript{74} “Many Third World states wished to develop the exclusive economic zone (EEZ) idea to prevent technologically advanced states from being able to extract minerals” from within other countries’ EEZ. Western states wanted to protect their freedom of passage through international straits. \textit{SHAW}, supra note 47, at 492.


\textsuperscript{76} \textit{SMITH ET AL.}, supra note 48, at 217.


\textsuperscript{78} \textit{SMITH ET AL.}, supra note 48, at 221.

\textsuperscript{79} UNCLOS, supra note 77, art. 33.

\textsuperscript{80} \textit{SHAW}, supra note 47, at 516.
of claiming a contiguous zone would not arise. Recently however, under
the new twenty-four mile limit, the concept of contiguous zones has
acquired relevance, and in 1997 more than fifty states had claimed a
contiguous zone.

UNCLOS departed from the “exploitability” definition of the
continental shelf; instead, Article 76(1) declares the following:

The continental shelf of a coastal state comprises the seabed and
subsoil of the submarine areas that extend beyond its territorial sea
throughout the natural prolongation of its land territory to the outer
dge of the continental margin, or to a distance of 200 nautical miles
from the baselines from which the breadth of the territorial sea is
measured where the outer edge of the continental margin does not
extend up to that distance.

Where the continental margin actually extends beyond 200 miles,
geographical factors are taken into account in establishing the limit,
which shall not exceed 350 miles from the baselines. This complex
formulation has caused difficulty. In an attempt to provide a mechanism
to resolve these problems, UNCLOS established a Commission on the
Limits of the Continental Shelf, consisting of twenty-one experts elected
by the nations party to UNCLOS.

UNCLOS grants a 200-nautical mile EEZ to coastal states. Article 55
defines the EEZ as “an area beyond and adjacent to the territorial sea,
subject to the specific legal regime established [in UNCLOS].” The
EEZ “shall not extend beyond 200 nautical miles from the baselines from
which the breadth of the territorial sea is measured.” In addition,
Article 56 grants the coastal state within the EEZ

sovereign rights for the purpose of exploring and exploiting,
conserving and managing the natural resources . . . of the waters
superjacent to the seabed and of the seabed and its subsoil, and with
regard to other activities for the economic exploitation and
exploration of the zone, such as the production of energy from the
water, currents and winds.

81. Id.
83. UNCLOS, supra note 77, art. 76(1) (emphasis added).
84. Id. art. 76.
85. SHAW, supra note 47, at 524.
86. UNCLOS, supra note 77, art. 55.
87. Id.
88. Id. art. 56.
In the past two decades, approximately 115 states have proclaimed 200-mile EEZs and “no state appears to have claimed an EEZ of different width.”

In contrast to the Continental Shelf Convention, UNCLOS fails to provide specific guidelines for delimiting maritime boundaries. The only guidance UNCLOS provides is that boundary disputes involving the continental shelf or EEZ shall be resolved “by agreement on the basis of international law, as referred to in Article 38 of the Statute of the International Court of Justice, in order to achieve an equitable solution.”

Even after the signing of UNCLOS, the 1958 Continental Shelf Convention might still bind some nations. The 1958 Continental Shelf Convention is still in effect if countries have ratified it and not acceded to the 1982 UNCLOS. All states are prima facie bound by the accepted customary rules of international law, while only the parties to the Conventions will be bound by the new rules contained therein. Since one must envisage some states not adhering to the 1982 Convention, the 1958 rules will continue to be of importance.

IV. THE GULF OF VENEZUELA AND LOS MONJES ISLANDS

A. Colombia and Venezuela’s Perspectives on the Gulf of Venezuela

The Gulf of Venezuela (the “Gulf”) is an inlet of the Caribbean Sea extending seventy-five miles north to south and reaching a maximum east to west width of 150 miles. It is bounded by the Guajira Peninsula on the west, by the Paraguana Peninsula on the east, and is connected with Lake Maracaibo to the south. The Gulf has a total surface area of 27,000 square kilometers, and its shoreline is almost entirely within Venezuela (94%). Its average depth is from twenty to thirty meters, and it reaches a maximum depth of fifty meters.

89. SHAW, supra note 47, at 520.
91. SHAW, supra note 47, at 493.
92. Id.
93. Colombia’s maritime claims are the following: 1) territorial sea: 12 nautical miles; 2) exclusive economic zone: 200 nautical miles; and 3) continental shelf: 200-mile depth or to the depth of exploitation. FACTBOOK-COLOMBIA, supra note 2. Venezuela’s maritime claims are the following: 1) territorial sea: 12 nautical miles; 2) contiguous zone: 15 nautical miles; exclusive economic zone: 200 nautical miles; and 3) continental shelf: 200-mile depth or to the depth of exploitation. FACTBOOK-VENEZUELA, supra note 3.
94. BRICENO, supra note 12, at 99.
95. Id.
96. NWEIHED, supra note 15, at 43.
The Gulf is of prime strategic economic importance to Venezuela. Navigation rights on the Gulf are crucial to minimize oil transportation costs. The Gulf is the only route connecting Lake Maracaibo with the Caribbean Sea and world oil markets.\textsuperscript{97} Maracaibo is significant because it holds one of the four major Venezuelan oil fields,\textsuperscript{98} and Maracaibo is closer to the Texas Port of Galveston than Galveston is to Baltimore.\textsuperscript{99} If Colombia was to have sovereign rights on the Gulf and proceeded unilaterally to exploitation of its oil reserves, it would obstruct the shipping lanes of Venezuelan oil tankers leaving Maracaibo.

Colombia has maintained that the method of delimiting the marine and submarine areas in the Gulf should be the median line proposed in 1951 by Whitmore Boggs, geographer for the United States Department of State.\textsuperscript{100} This line would divide the Gulf in half between the opposite peninsulas of Guajira and Paraguana, then apply the equidistant principle between the adjacent states, starting at Castilletes.\textsuperscript{101} Colombia supports the equidistant claim by citing Article 6 of the Continental Shelf Convention.\textsuperscript{102} Venezuela counters that the equidistant principle is not the obligatory method of delimitation by referring to the ICJ decision on the North Sea Continental Shelf cases.\textsuperscript{103}

Venezuela insists that the Gulf is a perfectly identifiable case of a “historic bay,” a well-established principle of customary international law.\textsuperscript{104} Thus, it advocates delimitation north of Castilletes, because the Gulf waters south of Castilletes are traditionally and historically a Venezuelan interior sea.\textsuperscript{105} Colombia opposes this argument, stating that the Gulf is not exclusively Venezuelan, by asserting the geographic reality that Colombia has a small coastline on the Gulf.\textsuperscript{106} Colombia further claims that, with the exception of the twelve-mile territorial sea measured from the baselines, the Gulf is open and part of international waters.\textsuperscript{107}

A leading Venezuelan scholar suggests that the maritime boundary between Colombia and Venezuela should follow the same trajectory as

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\textsuperscript{97} BRICENO, supra note 12, at 97.
\textsuperscript{98} The other sedimentary basins are Falcon, Apure, and Oriental. Venezuela is home to the Western Hemisphere’s largest conventional oil reserves at 77.8 billion barrels, as of January 2004. ENERGY INFO. ADMIN., COUNTRY ANALYSIS BRIEFS: VENEZUELA (Sept. 2005), http://www.eia.doe.gov/cabs/Venezuela/pdf.pdf.
\textsuperscript{99} BRICENO, supra note 12, at 98.
\textsuperscript{100} CARPIO, supra note 46, at 34-35.
\textsuperscript{101} AYALA, supra note 4, at 103.
\textsuperscript{102} Id.
\textsuperscript{103} Id. at 110.
\textsuperscript{104} BRICENO, supra note 12, at 98-99. Waters in historic bays are treated as internal waters, supported by general acquiescence rather than any principle of international law. SHAW, supra note 47, at 499.
\textsuperscript{105} AYALA, supra note 4, at 109.
\textsuperscript{106} Id. at 107.
\textsuperscript{107} Id.
the existing land boundary. Under this approach, the delimitation of the Gulf boundary would start at Castilletes and continue into the ocean in a northeasterly direction. This theory of delimitation would, in effect, confer most of the Gulf to Venezuela and no Gulf waters south of Castilletes to Colombia.

B. Colombia and Venezuela’s Perspectives on Los Monjes Islands

Los Monjes are a group of small islands located at the northwest entrance to the Gulf of Venezuela. Several rock islets integrate the archipelago: “Monjes del Norte,” “Monje del Este,” and “Monjes del Sur.” At 39.96 kilometers east of the Guajira Peninsula and 78.33 kilometers west of the Paraguana Peninsula, Los Monjes are closer to present-day Colombian territory than to Venezuela. Although at one time Colombia claimed ownership over Los Monjes, they are now under Venezuela’s sovereignty, jurisdiction, and control.

The disagreement over Los Monjes is with respect to their territorial sea and continental shelf rights. The overlapping of territorial sea claims occurs because the distance between the closest island of Los Monjes and Colombian territory at La Guajira is only nineteen miles, while the territorial sea claimed by each country is twelve miles. In other words, adding the territorial sea of Colombia and Venezuela will result in twenty-four miles; consequently, five miles in the middle would be claimed by both nations.

Los Monjes, nineteen miles offshore from Colombia, are within the Colombian 200-mile continental shelf claim. Venezuela suggests establishing a median line between the Colombian territory at La Guajira Peninsula and Los Monjes, conceding Los Monjes their own continental

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109. The archipelago is located at Latitude 12° 30’ North and Longitude 70° 55’ West. BRICEÑO, supra note 12, at 89.
110. Id. at 63-64.
111. MONROY, supra note 7, at 57.
112. The conflict over the sovereignty of Los Monjes began in June 1951 with the publication of the Colombian magazine Territorios Nacionales which stated that Los Monjes were Colombian territory. HOLGUÍN, supra note 23, at 28. In response, Venezuela insisted on its ownership over the archipelago. Id. at 28-29. In November 1952, Colombian Chancellor Juan Uribe Holguín sent Venezuelan Ambassador Juan Gerónimo Pietri a diplomatic note, DM-543, which recognized Venezuela’s sovereignty over Los Monjes. Id. at 29-30. Nevertheless, some authors questioned the constitutionality of this procedure since the Colombian Congress did not approve note DM-543 as required by the Colombian Constitution. Id.
113. CARPIO, supra note 46, at 62.
114. Id. at 63-64.
115. AYALA, supra note 4, at 86.
116. FACTBOOK-COLOMBIA, supra note 2.
Venezuela relies on the Geneva Conventions, which grant territorial sea and continental shelf rights to islands.118 Colombia, to the contrary, refuses to recognize the rights of Los Monjes to either a territorial sea or a continental shelf. Colombian jurists argue that an “island” is a considerable extension of inhabited or habitable land.119 Because humans cannot inhabit Los Monjes, the argument goes, Los Monjes are not “islands” within the meaning of the Continental Shelf Convention.120 Consequently, Los Monjes should not benefit from maritime rights.121

C. Colombia and Venezuela’s Case Under International Law

Under international law, the outcome of the Colombia-Venezuela maritime boundary dispute is uncertain.122 It appears that no treaty article on continental shelf delimitation is binding concurrently upon Colombia and Venezuela. Although both nations ratified the 1958 Continental Shelf Convention,123 Venezuela made a reservation to Article 6, which relates to the means to be used in delimiting continental shelf areas.124 The Venezuelan delegate mentioned that among the reasons for this reservation was the existence of “special circumstances” in the Gulf of Venezuela.125 Venezuela’s purpose in rejecting this provision was to
exclude the principle of equidistance as the mandatory method of delimitation.126

Additionally, UNCLOS is not binding upon either Colombia or Venezuela. Colombia, a country that voted favorably to pass its text, has not ratified it and Venezuela is not a signatory party to UNCLOS.127 Colombia and Venezuela have therefore approached their maritime boundary delimitation negotiations from different legal bases and are not likely to agree on the international law standard that applies to this case.

The principles of customary international law relating to maritime delimitation advanced by the ICJ should apply to the international community, including Venezuela and Colombia. But there is no common understanding of customary maritime delimitation law. Judge Gilbert Guillaume, President of the ICJ, has concluded that following the North Sea Continental Shelf, Tunisia-Libya, and Gulf of Maine cases, the law of maritime delimitation was far from clear. He declared, “At this stage, case law and treaty law had become so unpredictable that there was extensive debate within the doctrine on whether there still existed a law of delimitations or whether, in the name of equity, we were not ending up with arbitrary solutions.”128 However, “[s]ensitive to these criticisms, in subsequent years the Court proceeded to develop its case law in the direction of greater certainty.”129 Furthermore, there is no doctrine of stare decisis in international adjudication.130 Each case is treated individually, adding to the uncertainty of the outcome of the Colombia-Venezuela dispute.

It is possible for treaty law to become customary law. Scholars have identified two different ways in which customary law evolves out of a general multilateral conference. The first way is when rejected conference proposals are later successfully asserted by their advocates in the face of weak resistance.131 Second, custom may also evolve when a consensus is reached at the negotiating conference and the agreeing parties put the provisions into practice before the treaty is ratified.132 Thus, it is likely that some UNCLOS articles might become binding upon

126. Id.
129. Id.
131. The 1958 Geneva Conference allowed for the evolution of customary law in this manner when it fixed the outer but not the inner limits of contiguous zone. Howard, supra note 68, at 333.
132. Id.
non-parties (like Venezuela and Colombia) as the ICJ recognizes them as
customary principles of international law.133

However, the ICJ is not a mandatory dispute settlement forum to
resolve the Colombia-Venezuela maritime delimitation case. Generally,
mainline jurisdiction by the ICJ over states is voluntary, unless the state
has agreed to compulsory jurisdiction.134 Colombia recognized as
compulsory the jurisdiction of the ICJ in 1937,135 but it terminated this
recognition in 2001.136 On the other hand, Venezuela has never agreed to
compulsory jurisdiction of the ICJ.137

V. THE POLITICS OF OIL: THE CASE FOR A COLOMBIA-VENEZUELA
JOINT DEVELOPMENT ZONE

The dispute between Colombia and Venezuela over the determination
of maritime boundaries continues despite the various negotiations
undertaken; no common approach or mutually acceptable compromise
has been reached.138 Moderates in both nations have often suggested that
joint exploitation of the disputed territory would be the most feasible and
practicable solution.139 In the past, these suggestions have not gained
momentum. The current climate may be more conducive to increased
cooperation. Economic and political factors relating to the importance of
oil for the two nations have changed.

A. Contemporary Relations Between Colombia and Venezuela

The relations between controversial Venezuelan President Hugo
Chavez140 and his Colombian counterpart Alvaro Uribe141 have been

133. Because of widespread state practice, several UNCLOS provisions now clearly have the
effect of customary international law. For example, the twelve-mile nautical mile territorial sea
set out in Article 3 and the concept articulated in Article 76 that every state is entitled to a
continental shelf of at least 200 nautical miles regardless of geology. SMITH ET AL., supra
note 48, at 222.
134. SHAFTAIL ROSENNE, ROSENNE’S THE WORLD COURT: WHAT IS IT AND HOW IT
any general rule of present-day international law imposes on states the obligation to refer their
legal disputes to the Court. Id. Once consent has been given, the decision of the Court is final
and binding and without appeal. Id. The states parties to the litigation are obliged to comply
with the decision. Id.
135. International Court of Justice, Declarations Recognizing as Compulsory the Jurisdiction
[hereinafter Declarations].
136. Charter of the United Nations and Statute of the International Court of Justice art. 4
137. See Declarations, supra note 135 (listing the countries that have accepted the
jurisdiction of the ICJ as compulsory—Venezuela not included).
138. See supra text accompanying note 7.
139. Strati, supra note 8, at 118.
140. President Chavez took office in February 1999. Jay G. Martin, Venezuela as an
Opportunity for Investment in the Petroleum Industry, 20 ENERGY L.J. 325, 338 (1999). In the
same year, under Chavez's directive, the Constitution was rewritten by a newly elected
tense but cooperative. Uribe and Chavez planned for tighter oil collaboration during a meeting in Venezuela in July 2004. The political leaders agreed to build a natural gas pipeline that would eventually serve the California and Asia markets at an estimated cost of $200 million. Analysts have commented that this pipeline investment “make[s] business sense.”

In 2004, however, the long disagreement over the territories in the Gulf of Venezuela resurfaced. The Colombian newspaper El Espectador asserted on September 14, 2004 that Venezuela was preparing to license for exploration seven oil blocks in the disputed area of the Gulf. The reserves of these blocks account for ten billion barrels of oil, according to the newspaper. The Colombian government requested from Venezuela additional information about the licenses. In response, the Minister of Communications of Venezuela stated that the rumors regarding oil exploration licenses granted by Venezuela were mere “speculations.”

The Colombia-Venezuela relationship suffered considerable strain during the spring of 2005. A dispute arose over the arrest of a member of the Revolutionary Armed Forces of Colombia, Colombia’s main guerrilla group, who was allegedly seized in Venezuela. Consequently, Venezuela recalled its Colombian ambassador and Venezuela’s Foreign Constituent Assembly. Id. at 339. Despite Chavez’s claims that the changes were in the pursuit of democracy, opponents viewed the move as a strategy for the establishment of an ultimate dictatorship. Id. The new Constitution lengthened the presidential term from five to six years, permitting immediate re-election for incumbents. Lupi & Vivas, supra note 9, at 82-83. It also granted the Venezuelan military the right to vote and the ability to intervene in political affairs. Lupi & Vivas, supra note 9, at 82-83. Chavez may be better known because of his troubled relations with the United States. On September 16, 2005, during a televised interview, Chavez claimed that he possessed “evidence of a United States plan to invade Venezuela.” Interview by Ted Koppel with Venezuelan President Hugo Chavez, News Anchor, ABC News, in New York, N.Y. (Sept. 16, 2005) (transcript available for purchase at http://www.transcripts.tv/nightline.cfm).

141. Colombian President Alvaro Uribe is known as a conservative leader who maintains close ties with the United States. Guillermo Martinez, A Tense Peace, SUN-SENTINEL (Fort Lauderdale, Fla.), Jan. 13, 2005, at 25A.
143. In an effort locate foreign buyers, Venezuela has engaged in continued discussions with China about the possibility of exporting oil and gas to meet China’s growing industrialization needs. Juan Forero, Venezuela Pushes to Lead Regional Oil Economy, N.Y. TIMES, Aug. 13, 2004, at W1.
144. Id.
145. El Espectador, supra note 142.
146. Id.
147. Patricia Vasquez, Colombia Presents Problem for Venezuela’s Latest Upstream Bidding Round, OIL DAILY (Wash., D.C.), Sept. 17, 2004. Coincidentally, it was claimed back in 1968 that ECOPETROL, the Colombian state-owned petroleum company, granted a concession to an American company south of Castilletes, in the heart of the Gulf of Venezuela. But the Venezuelan government intervened in this contract. Briceno, supra note 12, at 78-79.
148. El Espectador, supra note 142.
Minister froze a number of oil projects with Colombia, including a new oil pipeline and expansion plans for existing refineries and production of petrochemicals.150

During the next month, however, Colombia and Venezuela resumed negotiations on the pipeline project.151 Industry analysts suggest that despite recent tensions, Venezuela is unwilling to suspend the oil pipeline project indefinitely.152 Commentators believe that this was the most serious diplomatic discord between the two countries in many years despite Chavez’s assertion that the hostilities were exaggerated.153

B. Colombia and Venezuela’s Need for Oil

Because any workable joint development scheme requires a high degree of cooperation, reasonably good relations would appear to be a prerequisite for a joint agreement between Colombia and Venezuela. Nevertheless, the example of the Japan-South Korea joint development zone demonstrates that the need for oil may override political considerations.154

Both Venezuela and Colombia are important oil producers. Venezuela is among the top ten crude oil producers in the world and has been categorized as one of the top oil suppliers to the United States in recent years.155 According to the Energy Information Administration, Venezuela’s petroleum industry constitutes “more than three-quarters of total Venezuelan export revenues, about half of total government revenues, and about one-third of GDP.”156 In order to maintain a solvent government and to preserve Chavez’s popularity through the funding of social programs, it is imperative that Chavez continues to pursue profitable oil undertakings.157

In contrast, energy analysts warn that if no significant new oil reserves are discovered in the near future, Colombia will become a net importer of petroleum by 2009.158 Colombia, the third largest Latin American exporter of oil, has consistently been one of the United States’ top ten

150. Id.
152. Kerr, Venezuela Suspends, supra note 149.
153. Kerr, Colombia, supra note 151.
154. From the beginning, the Japan-South Korea joint development agreement was a highly sensitive political issue. However, this agreement was instigated by the oil world crisis in 1973. Strati, supra note 8, at 121.
155. ENERGY INFO. ADMIN., supra note 98.
156. Id.
suppliers. Oil exportation provides a third of Colombia’s revenue, making it its number one exporting commodity. However, foreign investors and oil companies, citing unfavorable contract terms and deteriorating civil unrest, have abandoned Colombia, causing oil exploration and development to stifle—Oil production in Colombia has decreased from 830,000 barrels per day in 1999 to 535,000 barrels per day in 2004.

C. Joint Scheme Precedents in Venezuela and Colombia

Venezuela and Colombia have established joint schemes with other countries. Even though it is customary to regard President Truman’s 1945 Proclamation as the first clear assertion of the idea that a continental shelf belongs to a coastal state, Venezuela and the United Kingdom, on behalf of Trinidad, concluded a treaty in 1942 delimiting the continental shelf. In 2002, Venezuela and Trinidad & Tobago began negotiations to unitize the natural gas fields within their settled boundaries. Similarly, Colombia signed a joint development treaty with Jamaica in 1993.

D. The Case for a Joint Development Zone

The longstanding Colombia-Venezuela dispute is not clearly resolved by existing international law. The countries have approached the maritime boundary delimitation from different legal perspectives and Venezuela, because of its history of losing territory to Colombia, is unlikely to agree to submit the claim to arbitration by the ICJ.

However, recent developments indicate the potential for compromise. The political significance of oil for both nations has risen, given the importance of oil revenues to Chavez’s popularity and Colombia’s growing need for oil. The stagnation of oil exploration in Colombia and

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159. Id.
160. Id.
161. Id.
Chavez’s aspirations to build oil and gas pipelines through Colombian territory, coupled with the prospect of larger financial rewards due to prominently higher oil and gas prices, make a bilateral agreement more desirable. In addition, the nations have experience with joint development schemes. A workable solution for the parties would be to establish a joint development zone in order to proceed toward development of the petroleum resources in the disputed areas.

VI. FRAMEWORK FOR JOINT DEVELOPMENT ZONES

A joint development zone can be defined as “an agreement between two States to develop so as to share jointly in agreed proportions by inter-State cooperation and national measures the offshore oil and gas in a designated zone of the seabed and subsoil of the continental shelf . . . .” 165 The fundamental provisions of a joint development agreement are geographical scope, management structure, allocation of proceeds, preservation of rights, duration and termination, type of contract, governing law, and dispute resolution.

A. Geographical Scope

The geographical scope of a joint development zone can vary. Generally, geographical areas are defined in accordance with geographical and geological factors, or geographical coordinates. 166 Some other approaches include dividing the zone by a provisional line into sub-zones or establishing a joint regime for a disputed island. 167 In the event of a border dispute, the area of the joint development zone is commonly defined by the area of “overlapping claims” of the parties. 168

B. Management Structure

The British Institute of International and Comparative Law has identified three basic models of joint development agreements. 169 The first model is a two-state joint venture structure, which mandates compulsory joint ventures between the states or their nationals. 170 Under

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165. Hazel Fox et al., Joint Development of Offshore Oil and Gas 45 (1989).
167. Id. at 173 (discussing the 1974 Japan-South Korea Agreement which divided the joint development zone into nine sub zones and the joint regime established by Iran and Sharjah on the island of Abu Musa).
169. Fox et al., supra note 165, at 115
170. Id.
this model, “each state selects its own concessionaires or licensees and those selected jointly develop the area using something akin to an international joint operating agreement.”

The 1974 Japan-South Korea Agreement best exemplifies this model. However, this agreement is likely to complicate the management of the zone because of the existence of two licensing and taxing authorities as well as a joint commission. Additionally, complications may arise due to the presence of oil and gas reservoirs crossing the boundaries of the sub-zones.

Within the Colombia-Venezuela context, the two-state joint venture structure looks promising. Colombia may feel the most comfortable employing this agreement because the 1993 Colombia-Jamaica Treaty follows this model. The most difficult issue would be whether division of administration on the basis of blocks or on the basis of a line is acceptable to both Colombia and Venezuela.

Another model consists of a joint authority structure with licensing and regulatory powers. The joint authority manages the development of the zone on behalf of the two states. The 1979 Memorandum of Understanding between Malaysia and Thailand is an example, though problems have been encountered with its implementation. Recent agreements employing this model are the 1989 Australia-Indonesia Agreement over Area A of the Timor Gap Zone and the 2001 Nigeria-Sao Tome and Principe (Nigeria-STP) Treaty.

The joint authority model is the most complicated and requires an elevated degree of collaboration compared to the other two models. However, despite the additional administrative burdens, the joint authority structure has recently become a popular choice. The proceeds

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171. Derman & Kupolokun, supra note 163, at 27.
173. FOX ET AL., supra note 165, at 147.
174. Id.
175. See Ong, supra note 164, at 790 (explaining how the Colombia-Jamaica Treaty establishes a joint development zone).
176. FOX ET AL., supra note 165, at 115.
177. Id.
178. Willheim, supra note 172, at 833-34 (explaining how the Malaysia-Thailand joint authority has unresolved problems on fundamental issues such as choice of law for civil disputes).
179. Ong, supra note 164, at 791-92. The Timor Gap Zone Treaty established a Ministerial Council and Joint Authority to regulate petroleum exploration and exploitation in Area A of the zone of cooperation. Id.
180. Lerer, supra note 168, at 5. Under the Nigeria-STP Treaty, a Council of Ministers was established to act as a joint authority regulatory body. Id.
181. Ong, supra note 164, at 791.
182. Derman & Kupolokun, supra note 163, at 27.
would be divided based upon what the joint agreement provides, which is unrelated to the geography of the area. Consequently, the joint authority structure model provides more certainty with respect to revenue sharing, as opposed to the Japan-South Korea sub-zone agreement.

As applied to Colombia-Venezuela, the joint authority structure might not be a successful approach. President Chavez, nicknamed “El Comandante” (the Commander), is not likely to agree to a management structure in which he cedes control to a strong joint authority. In addition, the practicability of harmonizing the laws of both countries depends largely on the similarities of their domestic laws. Agreement on the supranational laws that will govern the joint development zone might take a long time.

The third model is a single-state structure, in which one state administers and oversees development of petroleum reserves for the benefit of both states with the other state’s role restricted to revenue sharing and monitoring. The 1969 Abu Dhabi-Qatar Agreement and the 1989 agreement in principle between Australia and Indonesia with respect to the areas B and C of the Timor Gap are examples of this model.

Early joint development agreements followed this model, but this approach has become less popular in recent years, even when it is the simplest option available. The main issue is the apparent loss of autonomy by the state whose sovereign rights are administered by the other state. The administration of the zone by only one state casts doubt on the strength of the non-managing state’s sovereignty claims.

A single-state structure is highly advisable for Colombia-Venezuela because of its simplicity, but Colombia is not likely to agree on this model. Venezuela, as the larger oil producer, will presumably have a more advanced petroleum infrastructure than Colombia and could manage the zone more efficiently. However, the issue would be whether Colombia, as the non-managing state, is willing to trust Venezuela to pass on its agreed share of the profits. The length of the dispute, coupled with the recent significant incidents between the countries, suggests that Colombia is not likely to accept such an arrangement, even if Venezuela

183. See FOX ET AL., supra note 165, at 147 (discussing splits based upon equity interests opposed to physical area allotments).
184. Id.
185. Id. at 115.
186. Id. In the 1989 Australia-Indonesia Timor Gap Treaty, each country manages the zone bordering their nation and pays 10% of the revenues derived from that zone to the other country. Ong, supra note 164, at 789.
187. FOX ET AL., supra note 165, at 149.
promised transparency in accounting for the revenues from oil and gas production.

C. Allocation of Proceeds

Another issue to be decided is how the financial shares will be allocated. In the original Timor Gap Agreement between Australia and Indonesia, “there was a 50/50 allocation in one area and 90/10 and 10/90 allocation in the other two areas.”188 In the case of Nigeria-STP, Nigeria takes a 60% share against STP’s 40% share.189

D. Preservation of Rights

Most of the existing joint development zones have been devised to deal with the question of boundaries or competing claims of sovereignty and jurisdiction. Generally, governments entering into a joint development agreement reserve their sovereign rights over areas of overlapping claims.190 This reservation makes these joint agreements preferable from a political point of view because the negotiated terms are temporary.191 Such temporary agreements are encouraged by Article 83 of UNCLOS.192

E. Duration and Termination

The countries must also decide on the duration of the agreement, as well as the reasons and procedures for terminating the agreement. The duration should be long enough to allow for exploration and exploitation of petroleum resources.193 The 2001 Nigeria-STP Treaty has a duration of forty-five years with an option to renew after thirty years.194 The Japan-

188. Derman & Kupolokun, supra note 163, at 27.
189. Id.
190. Lerer, supra note 168, at 2.
191. Id.
192. Article 83(3) states that pending agreement on delimitation of the continental shelf, “the states concerned, in a spirit of understanding and cooperation, shall make every effort to enter into provisional arrangements of a practical nature and, during this transitional period, not to jeopardize or hamper the reaching of the final agreement. Such arrangements shall be without prejudice to the final delimitation.” UNCLOS, supra note 77, art. 83(3). Furthermore, Professor Lagoni argues that the meaning of the phrase “shall make every effort” to enter into provisional agreements is, in fact, an obligation to negotiate such measures in good faith. Rainer Lagoni, Interim Measures Pending Maritime Delimitation Agreements, 78 A.I.L. 345, 354-55 (1984). An example of a “without prejudice” clause appears in the 2001 Nigeria-STP joint development agreement:

Nothing contained in this Treaty shall be interpreted as a renunciation of any right or claim relating to the whole or any part of the Zone by either State Party or as recognition of the other State Party’s position with regard to any right or claim to the zone or any part thereof.

Derman & Kupolokun, supra note 163, at 27-28.
193. Lerer, supra note 168, at 7 (suggesting a duration between thirty and forty years).
194. Constantine Oguntbiyi & Richard Shoylekov, More on the New Gulf, AFRICAN REVIEW
South Korea Agreement will continue for fifty years, but if exploitation of the natural resources is no longer feasible, the parties may terminate the agreement by mutual consent. The Saudi Arabia-Kuwait Agreement does not have a defined duration and may be terminated by either country.

\[ F. \text{ Type of Contract Within the Joint Development Zone} \]

The joint development agreement will generally specify the contract used to facilitate exploration, development, and production. Most often, concessions or production sharing contracts will be adopted, although the contract could also take the form of a service contract. The 2001 Nigeria-STP joint authority administers a system that combines licenses with production sharing contracts.

\[ G. \text{ Governing Law} \]

The Vienna Convention on the Law of Treaties is the controlling authority for joint development agreements because those agreements effectively constitute treaties between the participating nations. This is significant because it may be necessary for the nations to incorporate the terms of the joint development agreements into the countries’ domestic laws. In addition to the petroleum regime, the parties also need to agree on the governing laws that will apply to the zone—fiscal laws, customs regulations, labor and employment laws, health and safety laws, environmental regulations, and criminal laws, among others.

\[ H. \text{ Dispute Resolution} \]

Many joint development agreements include provisions for the settlement of disputes. For example, the Austria-Czechoslovakia Agreement establishes a mixed technical commission, the decisions of which are binding unless a party objects within a month. The Kuwait-Saudi Arabia Agreement provides for dispute resolution by the Arab League and the ICJ. The France-Spain joint zone limits the dispute

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196. Id.


200. Id.

201. Id. at 28.


203. Id.
resolution methods to consultations between the parties and negotiation or arbitration.204

In sum, a joint development agreement is not an obligatory rule of law, but a process predicated upon the willingness of nations to voluntarily enter into temporary arrangements for economic and political reasons.205 There is a growing trend of countries negotiating voluntary settlements with each other.206 This trend is likely to continue because joint development agreements are useful tools to reduce the likelihood of avoidable conflicts between nations.207

VII. CONCLUSION

Simon Bolivar conceived the doctrine of *uti possidetis juris* of 1810 as a way to avoid border disputes between the emerging nations from Spanish colonization. However, what appeared as a simple principle took Colombia and Venezuela over a hundred years to implement. Even then, when the 1941 treaty established the land boundaries on the Guajira Peninsula, it did not provide for maritime rights. Consequently, the controversy shifted from the demarcation of the land frontier to the delimitation of ocean and seabed spaces. At that time, technological advances created the possibility of exploitation of offshore oil reserves and many nations extended their jurisdictions seaward.

International law and tribunals have not been able to resolve the Colombia-Venezuela maritime boundary case. The claimant countries assert legal and historical arguments in support of their positions, but do not agree on the underlying principles for resolving this dispute. This case is an example of the double dichotomy characteristic of conventional international law.208 An internal dichotomy exists because the central provisions of the 1958 Continental Shelf Convention, which was adhered to by all parties to the treaty are at odds with Venezuela’s reservation of Article 6 on Continental Shelf Delimitation. The broader, external dichotomy is between customary international law and treaty law. Even thought Colombia and Venezuela did not ratify UNCLOS, the countries may still be bound by some of its provisions, because those principles have become part of customary international law. Furthermore, Venezuela’s reluctance to accept compulsory jurisdiction by the ICJ and Colombia’s withdrawal of consent in 2001 make it unlikely that both nations will agree to submit the dispute for international arbitration.

204. *Id.*
205. *Id.* supra note 8, at 120.
Thus far, bilateral negotiations to resolve sovereign rights in the Gulf of Venezuela have borne little fruit. However, the current political leaders for both states have made oil a national priority. Oil-rich Venezuela’s need to construct oil and gas pipelines through Colombia and Colombia’s imminent need for oil suggest increasing interdependence. Thus, cooperation and a greater normalization of their relations are needed. Moreover, the rumors of Venezuela licensing for oil exploration in the Gulf indicate that the time is ripe to begin negotiations for a joint development zone to avoid a military conflict in the region.

A joint development agreement would accommodate the parties’ political and economic interests. Any boundary negotiation with Venezuela is delicate because it takes place against a historical background in which Venezuela lost most of the Guajira Peninsula to Colombia’s sovereignty. No political leaders want to tell their citizens that they lost territory to a neighboring country. However, a joint development regime does not grant title to the disputed areas, but merely provides a framework to explore and exploit the seabed resources. In conclusion, a joint development agreement places business and economics paramount to politics—the need to share petroleum reserves takes priority over the need to delimit maritime boundaries.
RECENT DEVELOPMENTS IN TEXAS, UNITED STATES, AND INTERNATIONAL ENERGY LAW

EDITED BY VICTORIA VANBUREN*

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Sapte.
I. INTRODUCTION

The Recent Developments in Texas, United States, and International Energy Law section consists of selected cases and brief discussions of legislation and regulations related to energy law.\(^1\) Part II begins the section with a foreword by Professor Ernest E. Smith. Part III focuses on developments in Texas energy law. This Part includes an article on Texas electric markets and electricity regulation and an update on legislative and regulatory developments in Texas oil and gas law. Part III also includes case summaries in Texas oil and gas law. In Part IV, this section explores developments in United States energy law. This Part includes an article on New Source Review under the Clean Air Act, a discussion of the oil and gas policy provisions in the 2005 Energy Policy Act, and case summaries in United States oil and gas law. Part V concludes with international developments in energy law. This Part presents changes in petroleum laws in Iraq, Saudi Arabia, Kazakhstan, Algeria, Nigeria, Bolivia, Brazil, Paraguay, Uruguay, and Argentina.

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1. The content of the Recent Developments section is provided for general information purposes only. The TEXAS JOURNAL OF OIL, GAS, AND ENERGY LAW is not responsible for the accuracy or completeness of the case summaries provided in this section. The short articles may serve as a useful beginning point in the legal research process, but are not a substitute for primary research of the laws of the jurisdiction in discussion.
II. FOREWORD

BY PROFESSOR ERNEST E. SMITH

In most instances, the energy-law developments set out below represent a continuation of existing trends, regardless of whether viewed from a global, national or state perspective. Several are especially noteworthy.

Internationally, it is clear that membership in the World Trade Organization (“W.T.O.”) is still a coveted prize. Saudi Arabia now joins a long list of other countries that, after years of negotiation, have acquired membership in the W.T.O. and, like many other members, old and new, have encountered opposition to certain pricing practices. In this instance it is the sale of natural gas liquids, which, when sold domestically, have been priced at a thirty percent discount below the international market price. Some W.T.O. members have viewed this practice as a de facto subsidy to the Saudi petrochemical industry, which has experienced phenomenal growth within the last few years. In Latin America, sovereign ownership of hydrocarbons and development of hydrocarbon reserves by a state oil company continue to be staple subjects of nationalistic fervor, as they have been since Mexico’s 1938 expropriation of the oil industry. In 2004, Bolivia’s electorate voted in favor of state ownership of all oil and gas at the wellhead and in favor of reincorporating the state oil company Yacimientos Petrolíferos Fiscales Bolivianos. Implementing legislation was enacted in 2005.

In the United States, controversies over the Clean Air Act and new source review continued unabated; while Congress made another stab at addressing the energy crisis and developing a coherent, comprehensive approach to energy by enacting the Energy Policy Act of 2005. The resulting statute, which is neatly summarized in the following material, makes only incremental changes with respect to oil and gas exploration and production. These changes include simplifying the process for

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permitting oil and gas operations on federal lands and exempting some operations from the requirements of the National Environmental Policy Act of 1969. The siting of liquefied natural gas facilities has also been expedited by provisions making clear that the Federal Energy Regulatory Commission has exclusive authority over siting and provisions setting up a clearer process for locating pipelines and natural gas storage facilities. Hydraulic fracturing received support through provisions stipulating that fluids injected for this purpose were not subject to Environmental Protection Agency regulations governing subsurface disposal. On the other hand, pro-development advocates were once more unsuccessful in opening the Arctic National Wildlife Refuge to exploration and production.

On the state level, courts in Kansas and Oklahoma continue to wrestle with disputes over calculation of royalties; and in Wyoming, where rights to coalbed methane gas (“CBM”) are of paramount importance, the Wyoming Supreme Court has once more been required to determine the parties’ rights under deeds executed decades earlier, when such gas was a dangerous nuisance rather than a valuable mineral. Its approach in *Mullinnix LLC v. HKB Royalty Trust* was similar to that taken in earlier cases, such as *McGee v. Caballo Coal Co.*, and *Newman v. RAG Wyoming Land Co.* In those cases the Wyoming court looked to industry usage and also made a detailed analysis of deed language to determine the parties’ intent. In *McGee*, for example, the court was faced with determining ownership of CBM under a deed in which the grantor had conveyed “all coal and all other minerals . . . contained in or associated with coal and which may be mined and produced with coal which Grantor owns or holds in said lands” and reserved “oil, gas and other minerals.” In ruling that CBM was not included within the grant, the court pointed to the language referring to the production of minerals “with coal” and to the fact that such gas has never been produced along with coal. In *Mullinnix*, the grantor had simply reserved “oil rights.” Rejecting the argument advanced by the grantors (or their successors) that the term referred to all mineral rights, the court looked to the specific language of the deed and to trade usage in concluding that the reservation did not include gas.

Disputes between surface owners and lessees or pipelines companies were once more the principal source of oil- and-gas related

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7. *Id.*
9. 53 P.3d 540 (Wyo. 2002); see also Jacqueline L. Weaver, *Onshore Oil and Gas Case Update: 2003* [2003] 54 Oil & Gas Inst. (MB) 3-1, 3-27.
litigation in Texas. Insofar as thesurface owners have sought damages, they have been largely unsuccessful both in this year’s cases and in the immediately preceding years. If the claim was based on the defendant’s negligence or on nuisance, as in Denman v. SND Operating, L.L.C.,\textsuperscript{10} Mieth v. Ranchquest, Inc.,\textsuperscript{11} Primrose Operating Co. v. Senn,\textsuperscript{12} Cook v. Exxon Corp.,\textsuperscript{13} Exxon Corp. v. Tyra,\textsuperscript{14} OXY USA, Inc. v. Cook,\textsuperscript{15} Denman v. Citgo Pipeline Co.,\textsuperscript{16} Senn v. Texaco, Inc.,\textsuperscript{17} and Exxon Corp. v. Pluff,\textsuperscript{18} the plaintiffs either lacked standing because the injury to the land occurred before they bought the land; or, if the injury occurred after they bought the land, they had standing to sue, but lost because they failed to meet their burden of proving their land’s diminution of value as a result of new oil spills. If the plaintiffs’ claim was based on an express contractual clause, either the clause was not broad enough to include the injury in question, as in Fenner v. Samson Resources Co.,\textsuperscript{19} and Exxon Corp. v. Pluff\textsuperscript{20}; the claim was denied on procedural ground, as in OXY USA, Inc. v. Cook\textsuperscript{21}; or the plaintiff could not establish causation, as in Duke Energy Field Services, L.P. v. Meyer.\textsuperscript{22}

Landowners have had more success under the accommodation doctrine, which requires a company to accommodate a surface owner’s existing use if such accommodation is reasonable within industry standards.\textsuperscript{23} Texas Genco, LP v. Valence Operating Co.\textsuperscript{24} is notable for its conclusion that a portion of a landfill that would not be used by an electric generating company for lignite-ash disposal for at least seven years was nonetheless an existing use. The court pointed out that other portions of the landfill were currently being used and drilling at the site selected by the oil and gas lessee would require configuration of the entire landfill. The court in Trenolone v. Cook Exploration Co.\textsuperscript{25} reversed a summary judgment for an oil and gas company on the ground that there was a fact question as to whether the company, as owner of the dominant

\textsuperscript{10} No. 06-04-00061-CV, 2005 WL 2316177 (Tex. App.—Texarkana Sept. 23, 2005).
\textsuperscript{11} 177 S.W.3d 296 (Tex. App.—Houston [1st Dist.] 2005).
\textsuperscript{12} 161 S.W.3d 258 (Tex. App.—Eastland 2005).
\textsuperscript{13} 145 S.W.3d 776 (Tex. App.—Texarkana 2004).
\textsuperscript{14} 127 S.W.3d 12 (Tex. App.—Tyler 2003).
\textsuperscript{15} 127 S.W.3d 16 (Tex. App.—Tyler 2003).
\textsuperscript{16} 123 S.W.3d 728 (Tex. App.—Texarkana 2003).
\textsuperscript{17} 55 S.W.3d 222 (Tex. App.—Eastland 2001, pet. denied).
\textsuperscript{18} 94 S.W.3d 22 (Tex. App.—Tyler 2002, pet. denied).
\textsuperscript{19} No. 01-03-00049-CV, 2005 WL 2123043 (Tex. App.—Houston [1st Dist] Aug. 31, 2005).
\textsuperscript{20} 94 S.W.3d 22.
\textsuperscript{22} See Getty Oil Co. v. Jones, 470 S.W.2d 616 (Tex. 1971); ERNEST E. SMITH & JACQUELINE LANG WEAVER, TEXAS LAW OF OIL AND GAS § 2.1(B)(2)(a) (1998 ed. and 2005 update).
\textsuperscript{23} No. 10-04-00365-CV, 2006 WL 133555 (Tex. App.—Waco Jan. 18, 2006).
\textsuperscript{24} 166 S.W.3d 495 (Tex. App.—Texarkana 2005).
estate, was barred by the accommodation doctrine from using an abandoned pipeline running beneath plaintiffs’ houses.

The continuation of existing trends is paralleled by the persistence of unresolved problems. Oil companies contemplating investment in newly emerged or emerging oil-rich nations still encounter legal uncertainties that raise serious questions about the security of such investments. The proposed Iraqi constitution is emblematic of this problem. Its provisions imply both federal control and regional control over the country’s oil resources. As Nabil A. Issa points out below, the Kurd region of Iraq is notable for its relative stability and known oil resources, and prices of oil are at an historic high; nonetheless, in the face of the constitutional ambiguity, large foreign oil companies have been largely unwilling to rely on the Kurdistan Regional Government’s representation that it has the right to award concessions or other development rights. Somewhat similar uncertainties have been endemic to the petroleum regime of the Russian Republic since the dissolution of the Soviet Union; and they become even more serious when coupled with the prospect of unfavorable legislative changes. In Iraq national legislation may adversely affect the rights of any company that has received a concession from the Kurd’s regional government. In Kazakhstan, a recent amendment to the country’s subsurface law creates a pre-emptive right in the state to acquire an interest in existing subsurface use agreements. Such legislation has an obvious negative effect on the value of existing investments in Kazakhstan’s petroleum sector and a potential chilling effect on new investment.

In Texas, as of this writing, the petition for supreme court review of Mission Resources, Inc. v. Garza Energy Trust26 was still pending, and with it the continued uncertainty over whether cracks, fluids and “proppant” that cross lease lines as a result of hydraulic fracturing constitute an actionable subsurface trespass. The obvious problem from the standpoint of the industry is that almost any frac job may result in subsurface fissures that extend beyond the boundaries of a lease, and the potential liability, as exemplified in Mission Resources, may easily run into the millions. In a much different area of oil and gas law, a new problem has arisen: Distinguishing between a Mother Hubbard clause and a “catch-all” clause that makes a general reference to all of the grantor’s mineral interests in a specified defined geographic area, such as a county or survey. Both types of clauses are widely used as a way of avoiding detailed tract descriptions or new and expensive surveys, but each has been assumed to have a quite different effect. Until quite recently, most Texas oil and gas attorneys have probably felt reasonably

confident that they could distinguish between the two types of clauses and state how they were construed. That confidence has been shaken by *J. Hiram Moore, Ltd. v. Greer.*

Not all readers will agree that the developments mentioned in this brief foreword are the most important or noteworthy; but all will certainly benefit by perusing the articles and briefs set out below.

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27. 172 S.W.3d 609 (Tex. 2005).
III. RECENT DEVELOPMENTS IN TEXAS ENERGY LAW

A. Texas Electric Markets and Electricity Regulation

JAMES BARKLEY* AND PAUL PFEFFER**

The Texas electric market is entering its fifth year of deregulation.28 In the Electric Reliability Council of Texas (“ERCOT”) region, which covers the majority of Texas electric ratepayers, the price of electricity for most customers has been deregulated since January 2002.29 The only remaining price regulation applies to residential and small commercial customers who have remained with the retail suppliers affiliated with their former integrated electric utilities, and customers within municipalities and electric cooperatives that have opted out of deregulation. Beginning in January 2007, prices will be fully deregulated for all residential and small commercial customers outside the opt-out areas.30 In the non-ERCOT areas of the state, the markets continue to move toward the same kind of ERCOT deregulated structure.31

Retail Competition

As in any robust market, the ability to choose providers is essential to competition. The Public Utility Commission of Texas (“Commission”) continues to focus its efforts on educating electric customers, particularly residential customers, regarding their ability to switch retail electric providers. While approximately three-fourths of industrial and small commercial customer load has switched away from their affiliated providers (i.e., the providers spun off from the integrated utility originally serving the customer), only about one-third of residential customer load

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29. Id. § 39.102(a) (“Each retail customer in this state, except retail customers of electric cooperatives and municipally owned utilities that have not opted for customer choice, shall have customer choice on and after January 1, 2002.”).
30. Id. § 39.202(a).
has done so.\footnote{Paul Hudson, Pub. Util. Comm’n of Texas, Electricity—A State Summary, House Regulated Indus. Comm., November 14, 2005, at 8 (2005), available at http://www.puc.state.tx.us/about/commissioners/hudson/present/pp/RegIndCom111405.pdf.} Residential customers have been slow to switch despite the fact that there are generally ten to twelve service providers available.\footnote{Id.} The Commission has maintained a wealth of information on its website to ensure that residential customers understand their service options and the potential savings associated with switching away from the regulated prices of their affiliated providers.\footnote{See, e.g., Pub. Util. Comm’n of Texas, Your Choice, http://www.powertochoose.org/yourchoice/default.asp (last visited Mar. 12, 2005).} However, because many residential customers do not have internet access, the Commission continues its efforts to reach customers through a number of additional means, including bill inserts and publications in newspapers and other media outlets.\footnote{See, e.g., Matt Stiles & Mike Snyder, White Targets Energy Costs for Residents; $1 Million Drive Will Provide Data on Local Providers, Hous. Chron. Feb. 9, 2006, at B1.}

Hand in hand with this customer education is the need to ensure that a significant number of retail electric providers continue to operate in the Texas deregulated market in order to foster competition and lower prices. When the retail market opened in 2002, there were more retail electric providers offering service than there are today, particularly for residential customers. Pacific Gas and Electric (“PG&E”) and Shell Energy chose to exit the Texas retail market within a few months of the market opening, and some smaller providers have since left.\footnote{Press Release, Electric Reliability Council of Texas, Shell Energy Withdraws From Ohio and Texas Electric Power Markets (Sept. 4, 2001) (on file with author), available at http://www.ercot.com/news/press_releases/2001/pr20010904.html; Press Release, PG&E Corp., Spencer Station Generating to Shut Down (Nov. 5, 2002) (on file with author), available at http://www.pgecorp.com/news/press_releases/Release_Archive2002/021105-1press_release.shtml.} More troubling is the financial condition of some of the providers that stayed. New Power Company, an Enron subsidiary, and Texas Commercial Energy (“TCE”) declared bankruptcy in June 2002 and March 2003 respectively.\footnote{In re New Power Co., 313 B.R. 496 (Bankr. N.D. Ga. 2002); In re Texas Commercial Energy, LLC (Bankr. S.D. Tex. 2003) (No. 03-20366-C-11); see also Sudeep Reddy, Plano, Texas-Based Electricity Provider Files for Bankruptcy Protection, Dallas Morning News, Mar. 7, 2003.} Other retail providers have complained of financial difficulties associated with their retail electric service businesses.\footnote{See e.g., In re AmPro Energy, No. 32242, 2006 WL 64590 (Tex. P.U.C. Jan. 10, 2006) (proceeding on AmPro Energy LP’s petition to cease operations as a retail electric provider).} For customers, the loss of their chosen provider usually results in higher rates, particularly in the case of retail electric provider bankruptcies. Indirectly, the reduction in competition as providers leave or fail may also hurt customers.
The Commission has acted proactively, with the cooperation of affected providers, to minimize the financial effects of the customer switches following bankruptcy. For example, the Commission conducted extensive proceedings in coordination with the bankruptcy court to approve plans in which New Power’s customers were switched to providers with lower rates than the provider of last resort, the default option upon retail provider failure, and that TCE’s customer switches complied with the Commission’s rules. Absent express Commission approval to the contrary, abandoned retail customers are served by the provider of last resort, which charges a fairly high rate for service.

Certain retail providers have attempted to reach the same results as New Power and TCE, that is, switching customers to providers other than the provider of last resort, without the formalities of a bankruptcy court Commission proceeding. Several customers have challenged the right of providers to increase their rates as part of such transfers. Whether these retail providers will be permitted to make such transfers and escape fixed-price commitments remains to be seen, as the complaints that the customers have raised are still pending.

Renewable Energy

The Commission is also implementing the state’s new renewable energy goals, which were passed by the Texas Legislature, effective September 1, 2005, as Senate Bill 20. The new goals call for the state’s target renewable generation capacity to double between 2009 and 2015. The 2009 target (2,880 megawatts) was set as part of the original deregulation legislation in 1999, but the Commission noted in March 2005 that the original goal was likely to be met early—primarily due to the large increase in wind generation projects spurred by federal tax incentives that were to end on December 31, 2005. The new goals (5,880

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41. See id; Petition of Consumer Groups, Control No. 25838 (Tex. P.U.C. May 2, 2002), available at http://interchange.puc.state.tx.us/WebView/Interchange/Documents/25838_1_346781.ZIP.
43. Id. § 3.
megawatts by 2015) set interim targets as well, and call for 500 megawatts of the new generation to be from sources other than wind energy.\footnote{Tex. S.B. 20 § 3.}

In addition to the capacity targets, the legislature also recognized, and proposed specific provisions to address, some of the recent problems associated with wind generation projects.\footnote{Id. § 2.} Generally, wind power generators can be installed and connected to the electric grid much faster than any necessary transmission expansions can be constructed. This situation resulted in severe curtailment of wind generation in the McCamey, Texas, area beginning in 2001.\footnote{See generally ERCOT, CURRENT PROTOCOLS, § 7.8 (Nov. 30, 2005), available at http://www.ercot.com/mktrules/protocols/current/07-120105.doc; see also Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas, Project No. 26376 (Tex. P.U.C. 2005), http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp (follow “Login” hyperlink; then search “Control Number” for “26376”; then follow “Search Now” hyperlink).}

Senate Bill 20 streamlined many of the time consuming aspects of the certification process for new transmission lines supporting renewable energy projects, and required the Commission to find that such facilities are used and useful, prudent and includable in rate base for the utilities installing them, without the need for any factual findings on those matters.\footnote{See TEX. UTIL. CODE ANN. § 36.053(d) (Vernon 2004).} The Commission is currently in the rulemaking process of implementing all of the requirements of Senate Bill 20.\footnote{Rulemaking Relating to Renewable Energy Amendments, Project No. 31852 (Tex. P.U.C. 2005), http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp (follow “Login” hyperlink; then search “Control Number” for “31852”; then follow “Search Now” hyperlink).}

Nodal Market

The biggest market issue on the horizon is the switch from the current zonal market system to a nodal pricing system. ERCOT currently has five market zones, and each zone has a single energy-clearing price for the entire zone.\footnote{ERCOT, \textit{supra} note 47, § 7.3.} Any transmission congestion between the zones is monitored and addressed through the auction of “transmission congestion rights,” which allow parties to transport across the zones.\footnote{Id.}

Other than local congestion management within certain limited areas of the five zones, market participants are not required to designate receipt and delivery points for their electric energy transaction beyond the zonal level (i.e., delivery from the Houston Zone to the Houston Zone, or from the Houston Zone to the North Zone).\footnote{ERCOT, \textit{supra} note 47, § 7.3.} However, local
congestion has increased in recent years, and it is the opinion of ERCOT and the Commission that this zonal system does not provide sufficient price transparency to allow parties to react to different price points and efficiently mitigate local congestion.53

Beginning in 2009,54 the market will switch to a locational marginal pricing structure, also known as nodal pricing, which is similar to the structure used in the northeastern PJM market. Rather than relying on five large zones, each major supply or load source will comprise an individual node.55 Market participants will submit bids for energy delivered at various nodes.56 ERCOT will use that information and the known constraints of the grid, to deploy generation sources in a manner that minimizes the energy price given the physical constraints.57 This will generate a transmission value for every node-to-node path on the system, calculated by the energy price difference between nodes, and will allow for better allocation of transmission costs and better planning for transmission expansions.58

One consequence of the new system is that the prices actually received for electricity will be the nodal prices, which may not match the prices in bilateral electricity supply contracts. Parties to bilateral contracts will have to consider this possible disparity and set up a process to account for the differences and keep the parties whole. A mechanism commonly used is a contract for differences, by which the parties allocate the risk of differences between the nodal prices and their contract price. ERCOT and the Commission are in the process of developing all of the rules and protocols that this change to nodal pricing will require.59

57. Id.
58. Id.
59. Id.; Control No. 31600, supra note 55; Control No. 31540, supra note 55.
B. Selected Recent Oil and Gas Legislation and Regulation

HOLLY VANDROVEC *

This article discusses only a select few of the many new laws that emerged from the 79th Legislature that will affect the oil & gas industry, as well as some resulting regulations. The chart at the end of the article provides a brief description of other bills passed during the 79th Session that will also impact the industry.

House Bill 380 Well-Specific Plugging Insurance

Texas requires operators to properly plug and abandon oil and gas wells to minimize damage to the environment. To help ensure that resources are available at the time a well is required to be plugged, Texas requires operators to provide financial security to the Railroad Commission of Texas (“Commission”). Operators who are required to provide financial security under § 91.103 of the Natural Resources Code now have the option of acquiring a well-specific plugging insurance policy for any one or more wells to meet that requirement. House Bill 380 creates this option and excludes wells and well depths covered by such a policy from calculations of the amount required by the rules for a bond, letter of credit, or cash deposit.

The new well-plugging statute and effectuating rule, § 3.78(g) of Title 16 of the Texas Administrative Code, requires that the insurance policy: (1) be approved by the Texas Department of Insurance, (2) name the State of Texas as the owner and contingent beneficiary of the policy, (3) name a primary beneficiary who agrees to plug the specified well bore, (4) be fully prepaid and unable to be cancelled or surrendered, (5) provide that the policy continues in effect until the specified well bore has been plugged, and (6) provide that benefits will be paid when, but not before, the specified well bore has been plugged in accordance with Commission rules in effect at the time of plugging. Further, the benefits of the policy must amount to at least $2 for each foot of well depth for

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61. TEX. NAT. RES. CODE ANN. § 89.011 (Vernon 1978).
62. Id. § 91.103.
63. TEX. NAT. RES. CODE ANN. § 91.104(c) (Vernon Supp. 2005).
64. Id. §§ 91.1041(c)-(d), 91.1042(c)-(d); see also 16 TEX. ADMIN. CODE § 3.78(g) (Vernon 2005).
“land” wells, or as specifically provided by the Commission for “bay” wells or offshore wells.66

In addition to implementing the provisions of House Bill 380, the amendments to § 3.78(g) close a loophole in the regulatory program that previously allowed an operator without financial security to obtain a permit to drill, recomplete, or reenter a well and produce for up to one year without filing financial security.67 Because the deadline for filing financial security was set at the time of filing an initial organization report or upon yearly renewal, it was possible that if the operator abandoned the well before renewing the organization report, no financial security would exist to cover the well.68 Under the amended rule, operators must submit the required financial security not only under the same conditions as the previous rule, but also “as a condition of the issuance of a permit to drill, recomplete or reenter” a well.69 Therefore, financial security must now be filed before the operator commences drilling.

House Bill 2161 – Orphaned Wells, Tax Incentives, and Pipeline Safety70

House Bill 2161 creates the Orphaned Well Reduction Program, which offers incentives to those willing to “adopt” or plug orphaned wells. An orphaned well is a well for which the Commission has issued a permit, for which production, injection, or disposal activity has not been reported to the Commission for the preceding year, and the operator’s Commission-approved organization report of which has lapsed.71 If an operator is considering assuming regulatory responsibility for an orphaned well, the operator must file a form with the Commission giving notice of intent to conduct a surface inspection of the well.72 After the Commission accepts the notification, the operator must give written notice to the surface owner at least three days before the date of inspection.73 The potential operator may then inspect the well visually and conduct nonevasive testing such as determining the well pressure.74 If the operator desires to operate the well, the operator may file a second form with the

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68. Id.
69. Id.
71. TEX. NAT. RES. CODE ANN. § 89.047(a)(3) (Vernon Supp. 2005).
72. Id. § 89.047(b).
73. Id. § 89.047(d).
74. Id. § 89.047(c).
Commission and will be assigned the right to operate the well upon proof of a possessory right in the mineral estate.\textsuperscript{75}

The incentives for adopting an orphaned well are: (1) partial reimbursement for reactivating the well, (2) a nontransferable severance tax exemption from oil or gas produced from the reactivated well, and (3) exemption from oil-field cleanup regulatory fees for all future production from the well.\textsuperscript{76} In order to be entitled to a payment for partial reimbursement for reactivating a well under the program, the operator must have been designated as the operator of the orphaned well during the two-year period from January 1, 2006 through December 31, 2007.\textsuperscript{77} Awards are processed on a first-come first-served basis and the aggregate of total reimbursements is capped at $500,000 per fiscal year.\textsuperscript{78}

In addition to the “adoption” of wells by operators, a surface owner may wish to protect its surface estate by plugging an orphaned well located on its property. In exchange for entering into a contract with a Commission-approved well plugger who plugs the well in accordance with the statute, the surface owner may apply for a partial reimbursement for the costs incurred.\textsuperscript{79} The partial reimbursement is equal to the lesser of fifty-percent of the cost to plug the well or fifty-percent of the average cost incurred by the Commission to plug similar wells in the area over the previous two years.\textsuperscript{80}

The bill also seeks to encourage production from marginal wells\textsuperscript{81} and to encourage the use of enhanced recovery equipment\textsuperscript{82} through tax incentives prescribed by amendments to several sections of the Tax Code.

Pipeline safety provisions were also included in House Bill 2161. Section 117.012 of the Natural Resources Code and § 121.201 of the Utilities Code were amended to allow the Commission to adopt safety standards to prevent damage to pipeline facilities resulting from the movement of earth by a person.\textsuperscript{83} Certain activities are specifically excluded from any standards promulgated, such as mining, and the statute allows others to be excluded by the rules as well.\textsuperscript{84} Such rules may not become effective, however, until September 1, 2007.\textsuperscript{85}

\textsuperscript{75} Id. § 89.047(f).
\textsuperscript{76} Id. § 89.047(b)(3).
\textsuperscript{77} Id. § 89.047(h).
\textsuperscript{78} Id. § 89.047(j).
\textsuperscript{79} Id. § 89.048(b)-(d).
\textsuperscript{80} Id. § 89.048(d).
\textsuperscript{81} TEX. TAX CODE ANN. § 201.059 (Vernon Supp. 2005).
\textsuperscript{82} Id. § 201.061.
\textsuperscript{83} TEX. NAT. RES. CODE ANN. § 117.012(p) (Vernon Supp. 2005); TEX. UTIL. CODE ANN. § 121.201(b) (Vernon Supp. 2005).
\textsuperscript{84} TEX. NAT. RES. CODE ANN. § 117.012(o) (Vernon Supp. 2005); TEX. UTIL. CODE ANN. § 121.201(e) (Vernon Supp. 2005).
\textsuperscript{85} TEX. NAT. RES. CODE ANN. § 117.012(p) (Vernon Supp. 2005); TEX. UTIL. CODE ANN. § 121.201(f) (Vernon Supp. 2005).
Senate Bill 1130 – Requirement that Pipeline Operators Report Contamination

Senate Bill 1130 applies to “common carriers,” owners, and operators of pipelines under the Texas Natural Resources Code. The new legislation requires these entities (hereinafter generally referred to as “operators”) to make a contamination report to the Commission and to the affected landowner within twenty-four hours of detecting petroleum-based contamination in proximity of the pipeline. A contamination report may be made by telephone, fax, or e-mail and must include the global positioning satellite (“GPS”) coordinates of the location of the contamination.

The contamination need only be reported if it is present on the surface of water, if it affects at least five linear yards of soil, or if the affected soil extends beyond the face of the excavation in which the contamination is observed or detected. In addition, it appears that contamination need only be reported if detected “in the process of placing, repairing, replacing, or maintaining” a pipeline. If strictly construed, the literal reading of the statute may result in failure to report in cases where the operator gains knowledge of contamination unconnected to placement, replacement, repair or maintenance of a pipeline.

In response to the contamination report, the Commission must collect a soil sample from the contaminated area within three business days after receiving the report. The benefit to the operator of filing the contamination report is that the operator is then released from all liability for the contamination or the cleanup of the contamination covered by the report unless the contamination is “caused by” the operator. Although this section makes it clear that an operator is not liable for contamination emanating from another operator’s pipeline within an easement, it does not clarify what causation is required for the operator to be liable. For instance, if the operator’s pipeline is clearly the source of the contamination but it has been damaged by a third party, it is not clear whether the Commission will find that the contamination is “caused by” the operator simply because it was released from the operator’s pipeline.

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87. TEX. NAT. RES. CODE ANN. § 81.056(a)(1) and (b) (Vernon Supp. 2005).
88. TEX. NAT. RES. CODE ANN. § 81.056(c) (Vernon Supp. 2005).
89. Id.
90. TEX. NAT. RES. CODE ANN. § 81.056(b) (Vernon Supp. 2005).
91. Id.
92. TEX. NAT. RES. CODE ANN. § 81.056(d) (Vernon Supp. 2005).
93. Id. § 81.056(e).
Senate Bill 7 (2nd Called Session) – Limitations on the Use of Eminent Domain

Following the controversial U.S. Supreme Court decision in *Kelo v. City of New London*, where the proposed use of private property by a city for a private development project was deemed a “public use,” Texas became one of many states to respond with legislation limiting the use of eminent domain to condemn private property. Senate Bill 7 added Chapter 2206 to the Government Code which prohibits the use of eminent domain if it (i) confers a private benefit on a particular private party through the use of the property, (ii) is for public use that is merely a pretext to confer a private benefit on a particular private party, or (iii) is for economic development purposes (unless as specifically provided in the statute).

Taken alone, these limitations could have stalled further development of certain aspects of the oil and gas industry such as transportation of product via new pipelines. However, the bill contains eleven exceptions, several of which directly address the industry. The exceptions include the provision of utility services, the operations of a common carrier or an energy transporter, powers of gas or electric utilities as specified by Utilities Code Chapter 181, and underground storage operations.

In addition to the limitations and those exceptions noted above, the bill provides that nongovernmental entities authorized to condemn property through the use of eminent domain, such as common carrier pipeline operators, shall be subject to the Public Information Act in the same manner as a governmental body with respect to that information collected, assembled, or maintained by the entity related to the taking of private property through the use of eminent domain.

Finally, Senate Bill 7 creates an interim committee to study issues related to the use of the power of eminent domain, including the issue of what constitutes adequate compensation for property condemned. The interim committee is charged with the task of preparing a report, which must be filed with the Lieutenant Governor and Speaker of the House of Representatives by December 1, 2006.

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96. TEX. GOV’T CODE ANN. § 2206.001(b) (Vernon Supp. 2005).
97. *Id.* § 2206.001(c)(5).
98. *Id.* § 2206.001(c)(7).
99. *Id.* § 2206.001(c)(8).
100. *Id.* § 2206.001(c)(9).
101. *Id.* § 552.0037.
## Additional Oil & Gas Legislation from the 79th Legislature

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C. Texas Oil and Gas Case Summaries

SUMMARIES COMPILED BY STAFF MEMBERS OF
THE TEXAS JOURNAL OF OIL, GAS, AND ENERGY LAW

QUESTION PRESENTED: WHETHER THE SALE BY QUITCLAIM DEED OF
AN EXPIRED OIL AND GAS LEASE, WITHOUT AN EXPRESS
REPRESENTATION BY THE SELLER WITH REGARD OF THE VALIDITY OF
THE LEASE, IS A MISREPRESENTATION UNDER THE TEXAS SECURITIES
ACT.


Geodyne Energy Income Production Partnership I-E (“Geodyne”) secured a number of oil and gas interests by special warranty deed. This acquisition included a ten percent interest in a lease located in the Gulf of Mexico, for which the State of Texas was the lessor. The primary term of the lease expired, but the lease remained in effect while oil and gas were produced in paying quantities. Production slipped below this threshold. Not long after, Geodyne put a number of its energy interests up for auction—including its ten percent interest in the Gulf of Mexico lease. The Newton Corporation (“Newton”) bought that interest for $300. Almost three months later, the Texas General Land Office, which administered the lease on behalf of the state, informed Newton, through the lease operator, that the lease had expired and the well needed to be plugged. Newton subsequently brought suit against Geodyne for violation of the Texas Securities Act (“TSA”).

The TSA imposes liability on “[a] person who offers or sells a security. . .by means of an untrue statement of material fact or an omission to state a material fact.” Newton alleged that Geodyne represented that it was selling a ten percent interest in a valid lease. The court held that no misrepresentation had occurred, because Newton received a ten percent interest in the lease. The court maintained that while the lease had expired before the auction, the rights and duties of the interest owners had not. The deal may have worked out unprofitably for Newton—resulting in a ten percent interest in plugging cost rather than profit.
than an equivalent interest in profit—but it was a ten percent interest, nonetheless. Therefore, Geodyne made no misrepresentation.

In addition, the court said that the language of the parties’ Assignment and Bill of Sale indicated, as a matter of law, that the interest was conveyed by quitclaim deed. As a general rule, “the presumption of law is that [the purchaser] acts upon his own judgment and knowledge of title, and he will not be heard to complain that he has not acquired perfect title.” The court held that the terms of the auction precluded any claim that the Geodyne represented the validity of the lease. Furthermore, the court pointed to Newton’s own admission that it had known the property was not producing the paying quantities necessary to sustain the lease when Newton purchased its interest.

Further, the court said that construing the TSA to outlaw quitclaim deeds, as Newton impliedly suggested, would have profound policy implications with which the court was not comfortable.

QUESTION PRESENTED: WHETHER UNDER THE AAPL FORM 610-1977 THE OPERATOR IS CONTRACTUALLY BOUND TO WAIT THIRTY DAYS AFTER THE WORKING INTEREST OWNER’S RECEIPT OF NOTICE BEFORE COMMENCING PROPOSED OPERATIONS AND WHETHER THE NON-CONSENT PENALTY IS UNENFORCEABLE.

Valence Operating Co. v. Dorsett, 164 S.W.3d 656 (Tex. 2005).

In this case, the Texas Supreme Court interpreted notice provisions in a common oil and gas operating contract—the 1977 American Association of Petroleum Landmen Form 610 Model Form Operating Agreement (Model Form Agreement). Dorsett, the owner of an interest in several oil wells, brought a suit against Valence Operating Company (“Valence”), the operator, for breach of contract. Dorsett alleged that Valence breached the Model Form Agreement by commencing work before the thirty-day notice period expired and by enforcing a non-consent penalty against Dorsett.

Under the Model Form Agreement, a party wishing to drill a well must give the other parties written notice of the proposed operations. Parties have thirty days after the receipt of notice to elect to participate in the well. Parties who do not elect to participate are assed non-consent penalties.

The court maintained that the thirty-day notice period merely set a deadline for Dorsett to decide whether to participate in any proposed operations. It did not restrict Valence’s ability to start work. The court found that the only time constraint imposed on Valence was a separate
clause requiring it to begin work within sixty days of the expiration of the notice period.

Regarding the issue of the non-consent penalty, the court pointed out that Dorsett was notified of every proposed subsequent operation and did not consent to any of these operations within the thirty-day period. According to the terms of the agreement, this made Dorsett a non-consenting party. Dorsett contended that the portion of the agreement pertaining to non-consenting penalties was an unenforceable liquidated damages provision. The court disagreed because liquidated damages provisions fix the amount of damages to be paid in advance; the non-consent provision did not fix damages. Therefore, the non-consent provision did not impose liquidated damages but was a means by which the consenting parties could recover their investments and receive specified returns for future operations.

The court concluded that “[consenting parties] undertake a financial risk that the non-consenting parties do not. Here, the non-consenting party [was] not being punished for breaching the contract; she simply agreed not to participate in a return on investments she did not make.” The court further argued that the non-consent penalty could not be a liquidated damages clause because damages were not tied to a breach of contractual obligations.

**Question Presented:** Whether salt dome storage caverns may be appraised and taxed separately from the surface land above them.


Coastal Liquids Partners, L.P. (“Coastal”) had leased two salt dome storage caverns from the Texas Brine Corporation. The caverns were used to store liquid hydrocarbons. From 1996 to 1999, Coastal had been taxed nearly $2 million in property taxes on the two caverns. Coastal challenged the Matagorda County Appraisal District’s (“District”) valuation of these taxes on several grounds.

Coastal argued that the storage caverns may be taxed only as “land” and as a part of the surface property to which they are attached, not separately. The court rejected this argument. The court stated that it had been long-established that some features of real property can be taxed separately despite the fact that they are all part of the same surface tract. The court distinguished the present case from *Gifford-Hill & Co. v. Wise*
County Appraisal District,\textsuperscript{102} in which the Texas Supreme Court held that, under some circumstances, subsurface limestone cannot be appraised separately from the land above it.

The court’s concern in \textit{Gifford-Hill} was protecting unsuspecting farmers and ranchers from increased taxes and facilitating the constitutional goal of open land presentation. However, where the caverns had been in active commercial use, distinct from the uses occurring on the land’s surface, the court found that these concerns where no longer relevant. The court noted that, although the constitution requires taxation to be equal and uniform, different circumstances may warrant different appraisal methods.

Coastal also claimed that the District’s listing of the storage caverns as both “improvements” and “other” in the appraisal records for previous tax years created a presumption of double taxation. This argument was rejected. The Property Tax Code (“Code”) requires that property be described with sufficient certainty to identify it. Incorrect categorization was not a problem because the records gave Coastal notice of what property was included in each tax account. Moreover, the court said that it would not be incorrect for the purposes of the Code to categorize the caverns as “improvements” because the caverns were man-made structures used as a storage facility. Therefore, the court held that the caverns could be appraised separately from the surface above them.

\textbf{QUESTION PRESENTED: WHETHER, UNDER A LEASE ALLOWING POOLING BY RECORDING A DESIGNATION OF POOLED UNIT, SUCH A DESIGNATION CAN MAKE THE POOLING RETROACTIVELY EFFECTIVE FROM THE DATE OF FIRST PRODUCTION.}

\textit{Tittizer v. Union Gas Corp.}, 171 S.W.3d 857 (Tex. 2005).

Union Gas Corporation (“Union Gas”) entered into multiple oil and gas leases with members of the Gisler family (“Gislers”) and several adjoining landowners. The leases contained pooling clauses that allowed Union Gas to pool acreage owned by the various lessors for production of natural gas and entitled each lessor to receive a pro rata share of royalty fees from production anywhere in the unit.

Union Gas completed the Watts-Gisler No. 1 Well as part of a pooled unit and the well began production on March 27, 2000. Union Gas did not file a Designation of Pooled Unit (“Designation”) until August 7, 2000. The Designation included language that purported to make the pooled

\textsuperscript{102} 827 S.W.2d 811 (Tex. 1991).
unit effective retroactively from the date of first production on March 27, 2000.

The Gislers filed a breach of contract claim against Union Gas to defeat the retroactive effect of the Designation and sought one-hundred-percent of the royalties for the well from the production date until the date of filing for the Designation.

Union Gas sought a declaration defining the rights of the parties concerning the royalty payments and joined the neighboring landowners, including Tittizer, as third-party defendants. Union Gas also sought a declaration that the effective date of the pooling would be the date of first production for all royalty owners.

Tittizer counterclaimed against Union Gas seeking a declaration that the effective date of the pooled unit under her lease was the date of first production. Tittizer also sought to recover her share of royalties accruing from the date of first production to the date of judgment.

The Gislers prevailed at trial on their claim for one-hundred-percent of the royalties from the Watts-Gisler No. 1 Well and were awarded $1.3 million. The trial court also awarded Tittizer her pro rata share of royalties from March 27, 2000 through April 30, 2001, the date of judgment in her favor, plus attorney's fees.

On appeal, Union Gas argued that it had been wrongfully ordered to pay double royalties for production between March 27, 2000 and August 7, 2000. The Supreme Court held that Tittizer was not entitled to royalties for production between March 27, 2000 and August 7, 2000 because the lease clearly stated that pooling commenced on the record date of the Designation. Under the terms of the lease, Union Gas could pool by filing for the designation at any time, but Union Gas could not retroactively pool to a date prior to the filing. The lease specifically stated, “Lessee shall exercise said option as to each desired unit by executing an instrument identifying such unit and filing it for record in the public office in which this lease is recorded.”

**QUESTION PRESENTED: WHETHER A ROYALTY DEED THAT INCLUDES AN ERRONEOUS SPECIFIC GRANT, DESCRIBING ONLY INTERESTS NOT OWNED BY THE SELLER, AND A GENERAL GRANT OF ALL OF THE SELLER’S INTERESTS IN THE COUNTY IS AMBIGUOUS.**

*J. Hiram Moore, Ltd. v. Greer*, 172 S.W.3d 609 (Tex. 2005).

Mary Greer (“Greer”) held title to the surface and minerals of a twenty-acre tract in Wharton County. In May 1997, Greer leased the minerals in her tract to J. Charles Holliman for development. The
following September, Greer executed a royalty deed to Steger Energy Corporation. J. Hiram Moore, Ltd. ("Moore") later acquired the interest from Steger Energy. In December 1998, Kaiser-Francis Oil Co., successor to the working interest in Greer’s tract previously conveyed to Holliman, completed a well and began producing oil. Moore claimed all royalties with respect to Greer’s interests. Greer disputed the claim.

The Texas Supreme Court held that the royalty deed was ambiguous, therefore, a jury should hear evidence and determine the parties’ intent. The court concluded that the deed’s specific description either did not describe any royalty interest belonging to Greer or incorrectly described Greer’s royalty interest. The general description, however, conveyed:

[A]ll of grantors royalty and overriding royalty interest in all oil, gas and other minerals in the above named county or counties, whether actually or properly described herein or not, and all of said lands are covered and included herein as fully, in all respects, as if the same had been actually and properly described herein.

Reasoning that the deed conveyed both everything and nothing, the Court held that the contract was ambiguous and could not be construed as a matter of law. The Texas Supreme Court declined to follow the reasoning of the court of appeals, which based its decision on cases holding that a general description cannot convey a “substantial” property interest.

QUESTION PRESENTED: WHETHER PUC’S RULE THAT A LEGALLY ENFORCEABLE OBLIGATION ARISES ONLY WHEN A QUALIFIED FACILITY CAN DELIVER POWER WITHIN 90 DAYS IS INCONSISTENT WITH PURPA.


In early 1996, Power Resource Group, Inc. ("PRG"), a developer of power projects, entered into negotiations with Texas New Mexico Power Company ("TNMP") to supply power to TNMP. On September 20, 1996, the project was certified as a qualifying facility ("QF") and PRG undertook various preparations in furtherance of the project. On February 13, 1998, PRG made a final written commitment, which PRG claimed gave rise to a legally enforceable obligation ("LEO"). TNMP subsequently refused to execute an agreement with PRG and the plant was never built.

PRG petitioned the Public Utility Commission of Texas ("PUC") to compel TNMP to purchase energy. PUC found that TNMP had no obligation because its rules implementing the Public Utility Regulatory
Policies Act of 1978 ("PURPA") establish a legally enforceable obligation only if the facility was within ninety days of delivering power. The federal rule, 18 C.F.R. § 292.304(d), promulgated by the Federal Energy Regulatory Commission ("FERC"), allows QFs to provide energy to utilities either by contract or pursuant to a LEO.

PRG alleged that PUC’s rule (Tex. P.U.C. Subst. R. 25.242(f)(1)(B)) is inconsistent with PURPA and FERC regulations. The Fifth Circuit reviewed PUC’s implementation with deference because the state had broad authority to implement PURPA.

The court found that PRG failed to show that PURPA and the FERC regulations required that all QFs be able to create a LEO at any time. The court said that states “must provide for legally enforceable obligations [LEOs] as distinct from contractual obligations,” but it is up to each state and their regulatory agencies to “determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under state law.” Although other states may allow QFs to form LEOs at any time, this does not compel Texas to be equally generous. The court held that in codifying Texas Substantive Rule 25.242(f)(1)(B), “the PUC acted within its discretion and properly implemented FERC’s regulations regarding when a LEO is created.”

**QUESTION PRESENTED:** WHETHER HYDRAULIC FRACTURE STIMULATION TREATMENT OF A WELL ON AN ADJACENT LEASE CONSTITUTES SUBSURFACE TRESPASS AND WHETHER PUNITIVE DAMAGES ARE INAPPROPRIATE OR EXCESSIVE.


The Garza family ("Garzas") owned an undivided interest in a tract of land and leased the minerals to Coastal Oil and Gas Corporation ("Coastal"). Coastal owned an adjacent tract of land outright. Coastal used hydraulic fracturing ("fracing") to increase production of a well on the adjacent tract. This fracing crossed the lease line and drained oil and gas from the Garzas’ land.

The court held that fracing can be the basis of a claim for subsurface trespass, based on the Texas Supreme Court’s holding in *Gregg v. Delhi-Taylor, Co.* In *Gregg,* the Texas Supreme Court said that a plaintiff’s allegations that fracing a well near the property line was subsurface

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103. 162 S.W.2d 411 (Tex. 1961).
trespass were “sufficient to raise an issue of whether there is a trespass.” The court declined to follow GeoViking, Inc. v. Tex-Lee Operating Co., which relied on the rule of capture to conclude that fracing was not a subsurface trespass.

The court found that there was sufficient evidence for the jury to find Coastal guilty of bad faith pooling. When pooling, the lessee is not required to subordinate its own interests entirely to those of the lessor, but the lessee must take into account the interests of both itself and the lessor. The court held that evidence tending to prove that Coastal did not adequately consider the financial interests of the Garzas when pooling was sufficient to lead to the finding of bad faith pooling.

The court found there was sufficient evidence to establish Coastal’s specific intent to cause substantial injury to the Garzas, showing that they acted with malice. This evidence included, *inter alia*, that Coastal possessed a greater interest in the adjacent track, that they intended for the fracing to drain oil and gas from the Garza’s tract, and that Coastal did not drill protection wells until the oil and gas were gone and the Garzas had filed suit. From the same evidence, the court held that there was more than a scintilla of evidence to prove that Coastal’s intent in fracing was to deprive the Garzas of their property. This evidence supported the jury’s conclusion that Coastal committed felony theft. The finding of felony theft removed the statutory cap on punitive damages.

Coastal claimed that punitive damages were inappropriate because the jury had not awarded tort damages. The court found that the contract damages for bad faith pooling and tort damages for trespass overlapped, and that the jury had awarded damages for both claims. Therefore, punitive damages were appropriate. Coastal also claimed that the punitive damages—nearly twenty times the amount of actual damages—violated its right to due process under the United States Constitution. The court found the behavior of Coastal “highly reprehensible” and held that the damages were not grossly excessive and did not violate the Fourteenth Amendment.

104. 817 S.W.2d 357 (Tex. App.—Texarkana 1991).
QUESTION PRESENTED: WHETHER THE TEXAS NATURAL RESOURCES CODE PROVIDES FOR A PRIVATE CAUSE OF ACTION FOR VIOLATION OF STATUTORY REQUIREMENTS.


NOTICE: THIS OPINION HAS NOT BEEN RELEASED FOR PUBLICATION IN THE PERMANENT LAW REPORTS. UNTIL RELEASED, IT IS SUBJECT TO REVISION OR WITHDRAWAL.

Emerald Oil & Gas, L.C. (“Emerald”) brought suit against Exxon Corp. and Exxon Texas, Inc. (“Exxon”) for wrongful conduct in plugging and abandoning certain oil and gas wells. Emerald obtained the mineral leases on the wells after Exxon abandoned the field. Emerald alleged that Exxon intentionally sabotaged the wells and misrepresented the status of the wells in public filings with the Railroad Commission of Texas (“Commission”).

Several of Emerald’s causes of action were based on the Texas Natural Resources Code (“Code”) governing the duty of an operator (§ 89.011), prohibiting waste in the production, storage, or transportation of oil and gas (§ 85.045), and providing a suit for damages (§ 85.321).

The court held that § 85.321 provided a basis for Emerald’s causes of action against Exxon for violation of the Code. This section provides a right of action for a party whose interest in production was damaged by another party’s violation of applicable law. The court found that the existence of a private right of action is consistent with legislative intent and Texas State Constitution Article 16, § 59. The court rejected Exxon’s argument that the ability of the Commission to enforce the Code precludes a private right of action; Section 85.322 of the Code specifically states that an action by the Commission will not preclude a private right of action.

The court rejected Exxon’s argument that recognition of a duty to Emerald would “inflict an undue burden on mineral lessees” in favor of future lessees. A lessee is only required to satisfy the state conservation laws for operators, which do not impose an undue burden in favor of future lessees. Furthermore, § 85.321 provides a defense for lessees who act as “a reasonably prudent operator would act under the same or similar facts and circumstances.” Finally, § 85.045 of the statute also limits liability for “damages that may occur as a result of acts done or omitted
to be done by them or each of them in a good faith effort to carry out this chapter.”

The court rejected Exxon’s argument that it owed no duty to Emerald because Emerald had no rights to the oil field at the time the alleged sabotage took place. The court found nothing in the language or purpose of the legislation to suggest that the Legislature intended to limit the remedy to only injured parties possessing rights at the time of the violation. Thus, the statute is applicable to Emerald, who may bring a cause of action against Exxon.

The appellate court found that Emerald’s pleadings set forth sufficient facts, which if proven true, gave rise to causes of action against Exxon, and thus reversed the summary judgment previously granted by the trial court and remanded the case for further proceedings.

**QUESTION PRESENTED:** WHETHER AN ACTION FOR TERMINATION OF AN OIL AND GAS LEASE DUE TO LACK OF PRODUCTION REQUIRES EVIDENCE OF PROFITABILITY WHEN THERE IS A COMPLETE CESSATION OF PRODUCTION FOR SEVERAL MONTHS.


On April 26, 1999, Reeter acquired part of a surface estate subject to three mineral leases. The records from the Railroad Commission of Texas showed that there was no production from the leases between February 1998 and December 1998 and during the months of February, March, and April of 1999. In 2002, Reeter filed suit against the operators of said leases (collectively, “Brown”), alleging that the leases had all expired prior to her acquisition of the property due to lack of production. Reeter filed a motion for partial summary judgment seeking to terminate the three leases.

By their terms, the leases would remain in effect for three years and as long thereafter as oil, gas, or other minerals were produced from the land. “Production” in these clauses has been construed to mean “production in paying quantities.” To establish that a lease terminated due to “cessation of production in paying quantities,” the lessor must prove: (1) that the lease failed to yield a profit over a reasonable period of time, and (2) that a reasonably prudent operator would not have continued to operate the well in the manner in which it was being operated for the purpose of making a profit and not merely for speculation.

Brown asserted that because Reeter’s evidence did not address the profitability of production from the lease, that the evidence was deficient for summary judgment. The court disagreed, distinguishing between
claims alleging “total cessation of production” and claims involving a “cessation of production in paying quantities.” When there has been a total cessation of production, the two-prong analysis of production in paying quantities is inapplicable. Because Reeter alleged a total cessation of production, she did not need to address the profitability of production from the lease.

**QUESTION PRESENTED:** WHETHER AN OIL COMPANY BREACHED THE MAINTENANCE-OF-INTEREST PROVISION IN A JOA BY ASSIGNING ITS INTEREST IN A PORTION OF THE UNIT.


ExxonMobil Corporation (“Exxon”) and Valence Operating Company (“Valence”) were parties to a joint operating agreement (“JOA”), which included the following maintenance-of-interest (“MOI”) provision:

E. Maintenance of Interest: Notwithstanding any other provisions to the contrary, no party shall sell, encumber, transfer or make other disposition of its interest in the leases embraced within the Contract Area and in wells, equipment and production unless such disposition covers either:

- the entire interest of the party in all leases and equipment and production; or
- an equal undivided interest in all leases and equipment and production in the Contract Area. (strikeouts in original)

Several wells were drilled on the property covered by the JOA. The wells passed through the shallower Cotton Valley Sand formation, into the deeper Cotton Valley Lime formation. The drilling revealed that there were “proven behind-pipe reserves” in the Cotton Valley Sand formation. Exxon entered into a farmout agreement assigning its entire interest in these behind-pipe reserves to a third party.

A JOA is interpreted under the principles of contract law, which seek to determine the true intentions of the parties as expressed in the writing. In light of the surrounding circumstances, the court found that the MOI was unambiguous and that the intent of the provision was to prevent the partition of the undivided interests in the lease. The strikeouts merely reflected the parties’ recognition that their interests were not uniform, Exxon owning 81.8 percent and Valence owning only 18.2 percent of the lease.
Exxon argued that it did not breach the JOA because the MOI only forbid transferring a partial interest in the lease and the equipment and production. Exxon asserted that it assigned its interest in the lease only and not in the equipment in production; therefore, the MOI did not apply. From the plain language of the farmout agreement, the court found that Exxon assigned its entire “interest in land” in the behind-pipe reserves. The assigned interest included Exxon’s interests in equipment and production appertaining to the behind-pipe reserves. Therefore, Exxon breached the MOI’s requirement that transfers be either of a party’s entire interest or of an undivided interest.

Without the farmout agreement, Exxon would have had the same interest as Valence in producing from both formations by the most economical means. Valence presented evidence that the most economical means would be using the existing wellbores. The court concluded that the additional costs of drilling new wells to access the behind-pipe reserves were consequential damages arising from the farmout agreement.

The JOA required a party wishing to drill to give notice to the other parties. If the other party did not consent, they were assessed penalties in the form of withheld royalties. The court found that the requirement to consent could only be triggered by notice in compliance with the JOA requirements and not notice from a stranger to the agreement. Therefore, non-consent penalties should not have been assessed against Valence for failing to consent to drilling proposals by Exxon’s assignees.
IV. RECENT DEVELOPMENTS IN UNITED STATES ENERGY LAW

A. New Source Review Under the Clean Air Act: Background and Recent Cases

DAVID B. SPENCE *

Clean Air Act Permitting and the Energy Industry

Coal-fired power plants and oil refineries in the United States face extensive regulation under the Clean Air Act. Coal combustion produces an impressive list of harmful air pollutants, including: (1) particulate matter (fine dust), which is a source of respiratory problems, heart and lung disease, and haze, and which can contain mercury ("Hg"), a toxic metal that can enter the food chain through deposition of combustion particulates into waterways; sulfur dioxide ("SO2"), which mixes with moisture in the upper atmosphere to form sulfuric acid, which falls as acid rain, damaging vegetation and changing the pH of aquatic environments; nitrogen oxides ("NOx"), which are a precursor to both acid rain and ground-level ozone ("smog"), a source of respiratory problems in some humans; and carbon dioxide ("CO2"), which is the earth’s most plentiful greenhouse gas and is widely believed to be hastening global warming. Oil refineries also emit SO2, NOx and

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110. While there remains a healthy debate about the effects of global warming and the proper regulatory response, if any, there is something approaching consensus in the scientific
particulates and CO2, as well as volatile organic chemicals (such as benzene) and other toxic substances.

The Clean Air Act regulates emissions of particulates, SO2, and NOx through national ambient air quality standards ("NAAQS") established by the United States Environmental Protection Agency ("EPA") and permitting requirements. The EPA is in the process of regulating emissions of mercury from coal-combustion, but there are no plans by the Bush Administration to regulate carbon dioxide emissions in the United States. The Clean Air Act requires new stationary sources of pollution, like oil refineries and power plants, to secure a permit from state regulators before emitting conventional pollutants, like SO2, particulates and NOx. The permit must contain emissions limitations for these pollutants that reflect the level of pollution control that is achievable given currently available technology, meaning that the emissions limits must be relatively more stringent than levels of pollution control achieved by most other similar sources. These technology-based standards vary depending upon whether the new source is located

community about the conclusion that human activity is hastening the rate of warming, in part through coal combustion. For a useful summary of the science of global warming, see the Intergovernmental Panel on Climate Change, Climate Change 2001: The Scientific Basis, at http://www.grida.no/climate/ipcc_tar/wg1/index.htm, particularly Chapter 4, at http://www.grida.no/climate/ipcc_tar/wg1/127.htm.

111. See, e.g., Section 109 of the Clean Air Act, which obligates the EPA to establish NAAQS for sulfur dioxide and nitrogen oxides. 42 U.S.C. § 7409(a) (requiring NAAQS for all pollutants “for which air quality criteria have been issued prior to” December 31, 1970, a group that included sulfur dioxide); 42 U.S.C. § 7409(c), added in 1977 (requiring NAAQS for nitrogen oxides).

112. 42 U.S.C. § 7409 (2006). NAAQS represent the maximum concentrations of these conventional pollutants in the outdoor air that the EPA has determined will protect public health with an “adequate margin of safety.” Id. at § 7409(b)(1). Nitrogen oxides are covered indirectly by this regime, in that the NAAQS for ground-level ozone triggers regulation of NOx emissions through the Clean Air Act permit system.

113. Coal-fired power plants represent 40 % of mercury emissions in the United States. U.S. Envtl. Protection Agency, Frequently Asked Questions, Mercury, http://www.epa.gov/mercury/faq.htm (last visited Mar. 29, 2006). The Bush Administration has proposed mercury emissions regulations, but those regulations have been challenged in court and are not yet effective. CO2 is the most common of several greenhouse gases—gases that tend to trap heat from the sun in the atmosphere—that are thought to contribute to global warming. U.S. Envtl. Protection Agency, Global Warming-Emissions: Individual, http://yosemite.epa.gov/oar/globalwarming.nsf/content/emissionsindividual.html (last visited Mar. 28, 2006). Coal-fired power plants are the source of more than 80 % of CO2 emissions in the United States. The EPA has not proposed to regulate CO2 emissions under the Clean Air Act, and the Bush Administration has concluded that the Act does not permit such regulation. Id.


116. These so-called “technology based standards” differ depending upon whether the plant is located in an attainment or nonattainment area for the pollutant in question. In attainment areas, the emissions limitation must reflect the “best available control technology.” § 7475(a)(4). In nonattainment areas, the limitation must reflect the “lowest achievable emissions rate.” § 7503(a)(2).
in an area that is in attainment with NAAQS; if so, the standard is one that is designed to prevent significant deterioration of the air, and is called a “PSD permit;” if not, a different standard applies.

However, it is up to the state permit writer to determine the precise emissions limitations that reflect the applicable technology-based standard at any given point in time, subject to the requirement that the limitation not be less than certain backstop levels contained in “new source performance standards” (“NSPS”) established by EPA for certain source categories. Thus, as new permits are issued, old permits expire and are renewed, pollution control technology grows more efficient and effective, and the statutory technology-based standard—the level of pollution control that is available, achievable, and better than the industry norm—grows more stringent over time.

This Clean Air Act permitting regime has resulted in significant reductions in pollution levels and in emissions of conventional pollutants like SO2, particulates, and NOx. Even without controlling for economic and population growth, emissions of SO2 in 2003 were just over half of what they were in 1970, while particulate emissions in 2003 were approximately one tenth of their 1970 levels. Reductions in NOx emissions were much more gradual, but only because steep reductions in stationary source emissions of NOx were offset by increases in emissions from automobiles. As a consequence of Clean Air Act regulation, more and more air quality control regions in the United States have come into “attainment” with the NAAQS for particulates, ozone, and SO2, while ground levels of these pollutants have declined steadily.

117. That is, what is “best available” or “lowest achievable” changes over time. Permit writers have access to information about emissions limits contained in permits issued to similar facilities, and may use that information as well as other information about pollution control technology to reach a determination about the level of emission control that meets the statutory standard in question.
118. These backstop limitations are found in EPA’s “new source performance standards,” which are minimum emissions limitations for new sources within particular industrial categories. Section 111 of the Act directs EPA to issue these standards, § 7411(f).
120. These data are based on particles of ten microns in size, also known as “PM10.” The EPA’s particulate matter NAAQS dates back to the 1970s. The agency promulgated a fine particle standard covering particles 2.5 microns in size (“PM2.5”), in the 1990s. The EPA does not have historical emissions data for PM2.5. See id.
121. Emissions of particulates have declined from 12.2 million tons per year in 1970 to 2.3 million tons per year in 2003. Id.
122. Emissions of nitrogen oxides have declined from 26.9 million tons per year in 1970 to 20.5 million tons per year in 2003. Id.
124. The Clean Air Act classifies all air quality control regions as either “attainment” or “non-attainment” areas for each conventional pollutant, depending upon whether the region is
However, despite this progress, critics contend that coal combustion and oil refineries continue to do harm by emitting pollution that slips through the cracks of the Clean Air Act regulatory regime. One of the largest cracks, critics say, is the Act’s exemption for old plants. In particular, coal-fired power plants continue to produce sixty-five percent of the SO2 emissions in the United States and twenty-seven percent of NOx emissions. Since the Act’s tough permitting provisions applied only to “new” sources of air pollution, plants that were in existence at the time the permitting requirements took effect—“grandfathered” plants—fall outside the scope of the Act’s coverage and continue to pollute at essentially unregulated rates long after the passage of the Act.

meeting the federal standard. § 7407(a)(1)(A).

125. As of this writing, a mere thirteen counties in the United States are “nonattainment” for (i.e., out of compliance with) the sulfur dioxide standard, while fifty-seven counties (mostly in the West) are nonattainment for particulate matter and more than 400 counties are nonattainment for the ozone standard. This represents considerable improvement since the 1970s and 80s, particularly with respect to sulfur dioxide and particulates. For attainment rates, see U.S. Env’t Protection Agency, Nonattainment Areas Map—Criteria Air Pollutants, http://www.epa.gov/air/data/nonat.html?us~USA~United%20States (last visited Mar. 28, 2006).

126. Long-term transport of SO2 (and to a lesser extent, NOx) in the upper atmosphere has remained a problem and concern over the effects of acid rain continued to grow after the passage of the Clean Air Act, prompting the creation of the “acid rain program” through amendments to the Act in 1990. The acid rain program imposed a graduated reduction of emissions of acid rain precursors from coal-fired power plants of more than 50%, through a tradable permit program under which plants may buy and sell SO2 and NOx emissions rights. The program is found at Title IV of the Act, 42 U.S.C.§ 7651 (2000) et seq. Acid rain allowances—each representing the right to emit one ton of sulfur dioxide in a calendar year—are bought and sold on several public commodities exchanges.

For a description of the program, including a description of market activity in the allowance market, see U.S. Env’t Protection Agency, Acid Rain Program, http://www.epa.gov/airmarkets/arp/ (last visited Mar. 28, 2006).


“Modifications” and New Source Review

The language of the Clean Air Act authorizes EPA to apply new source review to any plant that had been “modified”—that is, any plant that has undergone a “physical change” resulting in an increase in emissions. This statutory language seems to impose stricter new source permitting standards on those older sources whose emissions increased as a result of any physical change, including repair or maintenance work. However, in 1978, EPA promulgated a rule defining the term “physical change” to exclude “routine maintenance, repair and replacement,” apparently signaling its intention to exempt mere repairs from new source review, even if those repairs increase emissions. Nevertheless, EPA did bring a few enforcement actions against plant owners during the decade and a half following the 1978 regulation, contending that work on these plants had gone beyond “routine maintenance, repair and replacement” (“RMRR”), triggering new source review.

These cases also presented courts with the question of how to determine whether emissions “increase” after the physical change is made. Should EPA compare actual emissions before and after the work, or should it look at the plant’s potential to emit pollutants before and after the work? Should it focus on total emissions or emissions per unit of energy produced?

These early new source review cases produced some minimal guidance on the question of the scope of the “maintenance, repair and replacement” exemption. In Alabama Power v. Costle, the D.C. Circuit concluded that the statute’s new source review provisions ought not to exempt old plants from new source standards indefinitely and the Seventh Circuit in Wisconsin Electric Power Co. v. Reilly (“WEPCO”) held that any physical change in the plant increases emissions, regardless of the nature of the work. These early decisions also pushed EPA to compare actual past emissions to projected actual future emissions when

131. See Clean Air Act § 111(a), defining a “new source” (to which new source permitting standards apply) to include sources which have been constructed or “modified.” 42 U.S.C. § 7411(a)(2) (2000).
132. See Clean Air Act § 111(b)(4), defining modification to include: “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” 42 U.S.C. § 7411(a)(4) (2006).
133. 40 C.F.R. § 60.14(e).
134. 636 F.2d 323 (D.C. Cir. 1979).
135. Id. at 400 (“the provisions concerning modifications indicate that this is not to constitute a perpetual immunity from all standards under the [new source review] program”).
136. 893 F.2d 901 (7th Cir. 1990).
137. Id. at 909 (“any physical change means precisely that”).
deciding whether an emissions increase has occurred under the Act, rather than comparing actual past emissions with potential future emissions.

With the advent of competition in the electric industry in the 1990s came fears that without a guaranteed return on their investments, the electric industry would rely less on cleaner, more expensive sources of power and more on older, dirtier coal-fired power plants. The Clinton-era EPA seemed to embrace this view that restructuring of the electricity industry posed a danger of increased emissions from coal-fired power plants, and stepped up its efforts to bring those plants within the ambit of the Act’s stricter permitting provisions through the process known as “new source review.” The Clinton Administration initiated judicial enforcement actions against approximately thirty coal-fired power plants, and took administrative action against the Tennessee Valley Authority with respect to nine additional coal-fired plants. Most of these cases were still pending by the time the Bush Administration took power in early 2001.

138. The EPA sometimes made this determination by comparing the pre-change actual emissions (which could be far below the plant’s potential emissions) with the post-change potential emissions (which could be far greater than the plant’s actual emissions). The Wisconsin Electric court disapproved of the EPA’s application of the “potential to emit” test: [T]he EPA’s analysis here seems circular: in order to demonstrate that the Port Washington like-kind replacement project constitutes a modification, the EPA applies the potential to emit concept (to show an increase in emissions). And in order to apply the potential to emit concept to like-kind replacement, the EPA assumes that the plant is a “modified” unit. Id. at 917


140. This concern is reflected in the EPA’s dispute with FERC over the latter’s analysis of the environmental impacts of restructuring in the Environmental Impact Statement accompanying the FERC’s restructuring rule, Order 888. This disagreement was referred to the Council on Environmental Quality in May of 1996, which reported that it was able to resolve the disagreements through negotiation. See COUNCIL ON ENVIRONMENTAL QUALITY, ANNUAL REPORT, PART I, THE NATIONAL ENVIRONMENTAL POLICY ACT 16 (1996), available at http://ceq.ch.doc.gov/reports/1996/part1.pdf; see generally Michael Kantro, Shall it Be Said that My Dusk Was in Truth My Dawn?, 25 WM. & MARY ENVTL. L. & POL’Y REV. 533 (2000) (providing a summary and analysis of the EPA-FERC dispute on the air pollution effects of restructuring).


142. One of the judicial enforcement actions was settled, with the defendant agreeing to make a variety of pollution control upgrades. See United States v. Tampa Elec. Co., No. 99-2524, CIV-T-23F (M.D. Fla., filed Nov. 3, 1999). With respect to the other judicial enforcement actions, the Bush Justice Department concluded that continuing these actions was “consistent with the Clean Air Act and its regulations.” U.S. JUSTICE DEPT OFFICE OF LEGAL POLICY, NEW SOURCE REVIEW: AN ANALYSIS OF THE CONSISTENCY OF ENFORCEMENT ACTIONS WITH THE CLEAN AIR ACT AND IMPLEMENTING REGULATIONS 5 (2002), available at http://www.usdoj.gov/olp/nsreport.pdf.
After the transition, the Bush Administration’s National Task Force on National Energy Policy (“NEP”)\(^ {143}\) concluded that aggressive application of new source review to old coal-fired power plants was confusing and unwieldy and could jeopardize energy security. The Bush Administration finally replaced the Clinton Administration’s new source review policy with a new, less aggressive policy in 2002. The new policy permits plant owners to perform more physical plant changes without triggering new source review.

The new rule, *inter alia*, (1) authorizes plant owners to use “plant-wide applicability limits” (“PALs”) that permit plant owners to lump together regulated pollutants when determining whether an emissions increase has occurred and to avoid new source review for increases in emissions that remained below certain specified levels, (2) exempts from new source review RMRR work that represents capital spending of less than twenty percent of plant value, and (3) authorizes plant owners to calculate emissions effects using a baseline of pre-work emissions based upon any two years within a specified pre-work range.\(^ {144}\)

Oddly, despite the 2002 rule changes, the Justice Department continued to prosecute most of the pending Clinton-era new source review enforcement actions,\(^ {145}\) and even filed a few additional suits.\(^ {146}\) But until 2005, only a few of these Clinton-era enforcement actions reached the decision stage. In 2002, one federal district court held that plant owners must make a determination of whether a modification has occurred (and, therefore, must project the effect of work on emissions levels) before the work begins.\(^ {147}\)

In 2003, another federal district court concluded that under the RMRR exclusion, “routine” work is defined not by the types of activities that are performed in the industry as a whole, but rather by the type of work done at individual units.\(^ {148}\) In both of these federal district court cases, the


\(^{148}\) The court stated that to focus on industry-wide norms would be in “direct conflict with the superceding and controlling language of the Clean Air Act.” *United States v. Ohio Edison Co.*, 276 F. Supp.2d 829, 855 (S.D. Ohio, 2003). The court also noted the confused nature of new
companies performing the work argued that because of changing EPA interpretations of the RMRR exemption over time, they lacked “fair notice” of the meaning of the NSR rules. Both district courts rejected those arguments. Meanwhile, several state Attorney Generals and industrial and environmental groups challenged the 2002 rule in court, and the rule was stayed pending that challenge.

Recent Developments

The last eighteen months have seen a continuation of regulatory activity at EPA on new source review and several major federal court decisions addressing the question of how to determine when a modification triggering new source review under the Clean Air Act has occurred. The Bush Administration finalized its NSR rule exempting certain work from NSR, and many aspects of the 2002 rule were affirmed on appeal by the D.C. Circuit. Meanwhile, the federal courts reached conflicting resolutions of the question of how to calculate whether work done on a plant causes an emission increase for purposes of determining whether a modification triggering new source review has occurred.

Final Rule Denying Petitions for Reconsideration of the Routine Maintenance, Repair, and Replacement Rule

On June 10, 2005, EPA finalized its RMRR exclusion exempting from NSR replacement work on plants that comprises less than twenty percent of the replacement cost of the plant. EPA had stayed the RMRR portions of the 2002 rule pending reconsideration. After rehearing, EPA affirmed that projects that meet the twenty percent threshold are exempt from major NSR if they meet the other necessary criteria in the final rule. These other criteria require that the replaced component (1) is identical or functionally equivalent, (2) does not alter the basic design

source review litigation and administration:
This case highlights an abysmal breakdown in the administrative process following the passage of the landmark Clean Air Act in 1970. For 33 years, various administrations have wrestled with and, to a great extent, have avoided a fundamental issue addressed in the Clean Air Act, that is, at what point plants built before 1970 must comply with new air pollution standards.

149. The fair notice argument is based upon the D.C. Circuit’s opinion in Gen. Elec. Co. v. EPA, 53 F.3d 1324 (D.C. Cir. 1995), a leading fair notice case. In General Electric, the court concluded that “the [agency’s] interpretation is so far from a reasonable person’s understanding of the regulations that they could not have fairly informed [the defendant] of the agency’s perspective.” Id. at 1330. Both the SIGECO and Ohio Edison courts rejected the fair notice claims. See SIGECO, 2002 WL 1629817, at *2; Ohio Edison, 276 F.Supp.2d 829, at 889.


151. Id. at 33,845.
parameters of the process unit, and (3) does not cause the process unit to exceed any emission limitation or operational limitation (that has the effect of constraining emissions) that applies to any component of the process unit and that is legally enforceable.152


In a challenge to the non-RMRR portions of the 2002 NSR rule, the D.C. Circuit in 2005 upheld most of the rule against challenges brought by states, industry, and environmental groups, citing its obligation to defer to reasonable EPA interpretations of the Clean Air Act under the Chevron rule.153 Most notably, the court upheld two key provisions of the rule: one that permits plant owners calculating emissions increases or decreases as the result of potential modifications to select as its emission “baseline” any two years among the five years154 preceding the work; and the rule’s PAL provisions, which permit plant owners to avoid NSR as long as plant-wide emissions remain below specified limits (i.e., PALs, which can be greater than pre-work baseline emissions).

Petitioners challenged these provisions as contrary to the statute’s plain meaning, noting that the statute requires NSR for work that “increases” emissions. Noting that the statute does not define “increases,” the court concluded that the EPA rule was a reasonable interpretation of the Act entitled to Chevron deference.

The court also rejected a claim by industry petitioners that “modification” must have the same regulatory meaning for NSR and NSPS because Congress used the same language in both statutory contexts. It says that the language “as used in” refer only to statutory usage, not to regulatory definitions. It does not decide if “Congress intended to require that EPA use identical regulatory definitions of modification across the NSPS and NSR programs.”


In this case the D.C. Circuit addressed the RMRR exclusion’s consistency with the Clean Air Act, an issue not considered in its 2005 decision in New York I. The RMRR rule excludes from NSR

152. Id.
154. The rule establishes a five-year range for utility owned boilers and a ten-year range for other plants.
“replacement of components with identical or functionally equivalent components that do not exceed twenty percent of the replacement value of the process unit and does not change its basic design parameters . . . .” Applying the Chevron two-step analysis, the Court quickly zeroed in on the question of whether EPA may by rule interpret the Clean Air Act’s definition of “modification”—which applies to “any physical change” that increases emissions—to exclude physical changes that fall short of this twenty percent threshold. The Court concluded that the RMRR rule fails Chevron step one, in that it contradicts the plain meaning of the statutory phrase, “any physical change.” Conceding that EPA has the power to exempt de minimus physical changes from the definition of modification, the Court concludes that the statutory language does not permit the exclusion of “physical changes that are [not] costly or major.”


Duke Energy replaced boilers and other major parts of several power plants, thereby enabling the plants to operate longer and increasing annual emissions. In calculating whether emissions had increased—hence a modification triggering NSR had occurred—EPA compared actual annual pre-work emissions to projected annual post-work emissions. Duke Energy objected, arguing that since its hourly emissions rate did not increase, an “increase” triggering NSR did not occur.

On June 15, 2005, the Fourth Circuit agreed, based in part on its conclusion that the Act required EPA to use a single, consistent definition of the term “modification” in both its new source performance standard (“NSPS”) program and its prevention of significant deterioration (“PSD”) program, the latter of which was at issue in the case.155 In its PSD program, EPA had been using actual projected annual (rather than hourly) emissions. The court declared, “[w]hen Congress mandates that two provisions of a single statutory scheme define a term identically, the agency charged with administering the statutory scheme cannot interpret these identical definitions differently.”

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155. The NSPS program establishes baseline minimum emissions control levels for new sources within particular industrial categories. Permits issued to new or modified sources must contain emissions limits at least as strict as the NSPS standards. The PSD program governs the issuance of permits to new sources in areas that are in attainment with national ambient air quality standards. PSD permits may contain emissions limits more stringent than NSPS limits, and may not contain less stringent limits.

Cinergy Corp. had made “physical changes” to some of its plants, and EPA alleged that these changes amounted to modifications triggering NSR. Cinergy disputed EPA’s conclusion, contending that EPA had improperly concluded that the work increased emissions from the plant. Following the D.C. Circuit’s reasoning in New York v. Environmental Protection Agency and rejecting the approach taken by the Fourth Circuit in United States v. Duke Energy Corp., the Federal District Court for the Southern District of Indiana held that the determination of whether an increase in emissions has occurred in the context of the NSR program should be based on an annual rather than hourly emissions rate.

The court noted that statutory reference to “modifications” used in the PSD sections of the statute did not expressly or impliedly incorporate the preexisting EPA NSPS regulations using the hourly rate calculation. EPA had no such hourly rate requirement in its NSR regulations. By adding a reference to modified facilities to the PSD section of the statute, said the court, Congress did not limit EPA’s authority to define “modification” by regulation, nor did it—expressly or impliedly—tell EPA to change its NSR regulations.


EPA alleged that Alabama Power had made modifications triggering NSR to several of its existing power plants. The Federal District Court for the Northern District of Alabama faced the same issues regarding the scope of the RMRR exclusion and measurement of emissions increases addressed by the court in Cinergy, but reached precisely the opposite conclusion, rejecting the D.C. Circuit’s analysis in New York I decision in favor of that used by the Fourth Circuit in Duke Energy.

The court concluded: (1) that the RMRR exclusion covered work that was “routine within the industry” rather than routine within the plant, and (2) that emissions increases may be calculated only on the basis of hourly rates, not annual totals. The court based this latter holding on the conclusion that Congress’ reference to plant “modifications” in the PSD section of the statute was based upon the definition of modification found in EPA’s NSPS regulations—which requires an hourly emissions test—and a conclusion that EPA cannot interpret the PSD regulations differently. Additionally, the court found that the PSD “hours of operation” exclusion did not only apply to the physical change prong of the test, but also required a change in hourly emissions.

SCOTT H. SEGAL *

There is an oft-quoted Texas expression that, “there’s nothing in the middle of the road but yellow stripes and dead armadillos.”156 To that dubious list, we might also add energy legislation, which seemingly can only emerge from the middle of the confusing and contradictory roadways of congressional politics. The most recent effort, the Energy Policy Act of 2005,157 was signed into law by President George W. Bush on August 8, 2005 at Sandia National Laboratories in New Mexico, and constitutes the first major piece of comprehensive energy legislation adopted in over twelve years.158 While reasonable minds can differ on the subject of just how comprehensive this or the last energy bill159 were, there is no doubt that the legislation at least touches on every major aspect of energy production and consumption.

This article will provide some description of the politics and context that produced the Energy Policy Act of 2005 (“Act”). Then, the article will provide a summary of the Act, with a particular emphasis on oil and gas issues. Last, the article will examine future challenges in energy policy-making, including the President’s recent call to action in the State of the Union address of January 31, 2006.160


In Washington, there is hardly any greater hearty perennial than energy legislation. Because energy is so inextricably tied to commerce, national security and even environmental protection, the production, distribution, and consumption of energy in all forms has long been thought of as an acceptable province of federal authority. In fact,

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“energy” and “agriculture,” alone among commodities, are represented as cabinet-level agencies.\textsuperscript{161}

It came as no surprise that this particular Administration made the promulgation of energy policy a high priority. First, both President Bush and Vice President Cheney had a strong affinity for energy issues, having both served in varying capacities in the energy industry and both hailing from energy-producing states.\textsuperscript{162} Second, the time was ripe for energy legislation.\textsuperscript{163} It has long been said that Congress will not act on matters until an emergency presents itself. In the case of energy legislation, sustained high prices in both the transportation\textsuperscript{164} and natural gas markets\textsuperscript{165} constituted one such emergency. Blackouts were another threat, and the national security implications of untrammeled reliance on foreign crude oil in the period after September 11, 2001 constituted another.\textsuperscript{166}

From virtually the beginning of the Bush Administration, senior officials of the government had planned to make energy policy a priority. In January 2001, Vice President Cheney convened a special task force to

\begin{itemize}
  \item \textsuperscript{162} Interview by Ben Greenman with Nicholas Lemann, Staff Editor, NEW YORKER (May 7, 2001), available at http://www.newyorker.com/online/content/articles/010507on_onlineonly01 ("…both men [Cheney and Bush] grew up in oil boomburms, long before they worked in the industry.").
  \item \textsuperscript{163} See, e.g., Pennsylvania Governor Edward G. Rendell, Speech to the National Press Club: An American Energy Harvest Plan: Jobs, Prosperity, Independence (Dec. 1, 2005), available at http://www.governor.state.pa.us/governor/cwp/view.asp?a=5&q=444223 ("America needs a sound forward-looking energy policy. And it needs federal leadership. The time is ripe.").
  \item \textsuperscript{164} Editorial, Fossilized Fuel Legislation, LA TIMES, Apr. 20, 2005, at B12 ("With prices at the gas pump near $3 a gallon, the Senate this year should figure out that the time is ripe for a better-designed energy bill. The public is ready to hear not just about lower gas prices but also real conservation.").
  \item \textsuperscript{165} Justin Blum, Natural Gas’s Danger Signs, WASH. POST, Oct. 7, 2005, at D1 ("Andrew N. Liveris, chief executive of Dow Chemical Co., told a hearing yesterday before the Senate Energy and Natural Resources Committee that the country is in a ‘natural gas crisis…How can I recommend investing here?’ Liveris said. U.S. natural gas prices are among the highest in the world.").
  \item \textsuperscript{166} The White House Transcript states the following:
    We’ve had some ideas, but we have not had a national energy policy. And as a result, our consumers are paying more for the price of their gasoline, electricity bills are going up. We had a massive blackout two summers ago that cost this country billions of dollars and disrupted millions of lives. And because we didn’t have a national energy strategy over time, with each passing year we are more dependent on foreign sources of oil.

White House Transcript, supra note 158, at 2; U.S. Dep’t of Energy, The Energy Bill & You, http://www.energy.gov/about/584.htm (last visited Mar. 28, 2006) ("On July 29, 2005, Congress passed the first comprehensive energy legislation in over a decade. This historic bill follows many of the principles outlined by President Bush to strengthen our nation’s electrical infrastructure, reduce our dependence on foreign oil, increase conservation and expand the use of clean renewable energy.").
develop a national energy plan pursuant to the President’s executive order. The task force contained senior White House staff, together with detailees from cabinet agencies, including the United States Department of Energy. The work of the task force yielded a comprehensive plan, many provisions of which ultimately found their way into the Act.167

The process of developing legislative proposals through executive branch leadership is hardly new. The process has been used previously in the energy context as well as in other policy areas such as medical care. In this case, critics of the process argued that private sector input converted the task force proceedings into a process regulated by the Federal Advisory Committee Act (“FACA”).168 Because the task force was not charted under FACA and did not conform to other provisions of that act, critics contended that the task force was acting in violation of the statute. After refusing to abide by a district court’s in camera discovery order, the case eventually made it to the Supreme Court, resulting in a remand and dismissal by the Court of Appeals for the District of Columbia Circuit.169 Despite this legally inauspicious beginning, Congress nevertheless dedicated itself to the task of energy legislation—a task that would take over four years to complete.

Energy legislation often reflects a variety of interests, most of which are regional in character. Whereas the Midwest may favor expanded ethanol mandates given its proximity to corn production, the coasts do not prefer such mandates given the difficulty of bringing ethanol to those markets. Sunny climates may prefer federal tax credits for solar energy production, but colder climates may be more concerned with low-income assistance for home heating. Whereas Texas and Louisiana may prefer to develop offshore oil and gas resources, California and Florida take a contrary view. In fact, calls for conceptual unity or overarching philosophy in energy legislation often simply fall on deaf ears.170

167. A comprehensive discussion of the deliberations and process of the Vice President’s energy task force can be found at U.S. GEN. Accounting Office, Energy Task Force: Process Used to Develop the National Energy Policy GAO-03-894 (2003), available at http://www.gao.gov/new.items/d03894.pdf. On January 29, 2001, President George W. Bush issued a memorandum establishing the National Energy Policy Development Group (NEPDG) within the Executive Office of the President for the purpose of developing a “national energy policy designed to help the private sector, and government at all levels, promote dependable, affordable, and environmentally sound production and distribution of energy for the future.” The President named Vice President Cheney chairman and assigned cabinet secretaries and other federal officials to serve with the Vice President. Five months later, the NEPDG issued its final report to the President. As the President directed, the NEPDG ceased to exist as of “the end of fiscal year 2001,” that is, September 30, 2001. In re Cheney, 406 F.3d 723, 729 (D.C. Cir. 2005) (en banc).


169. In re Cheney, 406 F.3d 723 at 729.

Politically, the diffuse opinions regarding energy policy among the several states can make it difficult to pass legislation through both houses of Congress. The House of Representatives, for its part, is governed by practical rules of debate that favor strong control by the chamber’s leaders. Since the House Leadership at the time—Speaker Dennis Hastert (R-IL) and Majority Leader Tom DeLay (R-TX)—were of like mind on energy policy, working majorities (however slight) were found to advance energy legislation much along the lines of the Bush Administration’s plan, with additional changes made by the House’s point person on energy, Chairman Joe Barton (R-TX) of the House Energy and Commerce Committee.

The road was considerably bumpier in the United States Senate. There are two principal reasons for this difficulty: first, Senate rules allow for forty senators to keep debate going on a given bill indefinitely, making the votes needed for energy legislation a supermajority of sixty senators; second, the regional differences regarding energy policy (as discussed above) are magnified because each region has equal representation in the Senate, regardless of the region’s population. In short, energy legislation kept dying in the Senate.

As each iteration of a new energy bill progressed, the list of controversial items kept narrowing. Whereas the House of Representatives was willing to consider proposals to allow for oil and gas exploration and development in the Arctic National Wildlife Refuge (“ANWR”), the Senate was not. Whereas the House of Representatives was willing to consider limited liability provisions for federally-mandated fuel additives like methyl tertiary butyl ether

A1 (quoting one energy lobbyist, “In the end, regional politics always tends to win out.”).


172. Author Amanda Griscom offered one view on unified House Leadership and passage of the energy bill:
For more than a month, the Republican House leadership has been planning a much-touted “energy week” centered on legislation that mimics nearly verbatim the Energy Policy Act–that same old bill that sailed through the House last fall with avid support from the White House, but was then defeated twice by filibusters in the Senate.


(“MTBE”), the Senate was not.176 Indeed, the limited proposals eventually gathered together as comprehensive legislation were in large measure a result of the Senate’s make-up and rules.

2. View from the Middle of the Road: the Energy Policy Act of 2005

The Act, eventually adopted as Public Law 109-58, was a lengthy enactment running 550 pages and eighteen titles.177 The Act covered such diverse topics as energy efficiency, renewable energy, oil and gas exploration and production, clean coal development, Indian energy, nuclear power, vehicles and fuels issues, and major reforms regarding the economic regulation of electricity.178 From ceiling fans to sugar cane, from daylight savings to microturbine power plants, the Act touched on virtually every energy topic while mastering few.179

Critics of the Act, perhaps more concerned with appropriate commentary for direct mail advertising than the facts,180 claimed that the Act was particularly generous to the oil and gas sector. Such a case is difficult to make when viewed through the lens of the actual lobbying on the bill. Indeed, the oil industry’s two most important legislative initiatives, the development of ANWR and the appropriate treatment of MTBE liability, were both left on the cutting room floor as a result of intense negotiations between the House of Representatives and the Senate in conference. Despite this result, the Act does contain some provisions that deal with oil and gas exploration and development, as well as transportation fuels and oil shale and tar sands.

176. Press Release, Nat’l Petrochemical & Refiners Ass’n, NPRA Comments on Senate Passage of Energy Bill (June 28, 2005), http://www.npradc.org/news/releases/detail.cfm?docid=1942&archive=1. NPRA President Bob Slaughter stated in part the following:

Most concerning is that the [Senate] bill does not contain a MTBE limited liability provision like the House bill.

We believe that the limited liability protection for MTBE against defective product claims is a must-do item in any comprehensive energy bill, and we will work with Congress to ensure that this provision is included in the final package.

Id.


178. See id.

179. See id.


Title III of the Act deals specifically with oil and gas issues. According to the Senate Energy and Natural Resources Committee ("ENR"), which together with the House Energy and Commerce Committee constituted the principal committees of jurisdiction for the bill, summarized the oil and gas provisions, stating that the bill:

(a). includes provisions to streamline oil and gas development on existing federal lease sites to bring the fuels to market sooner;

(b). the bill permanently authorizes the Strategic Petroleum Reserve and authorizes the DOE Secretary to fill the reserve to 1 billion barrels;

(c). calls for a Department of Interior inventory of oil and gas resources on the Outer Continental Shelf to enable the federal government to better assess the extent of these resources;

(d). facilitates the construction of needed gas infrastructure by improving and streamlining the process to permit pipeline infrastructure with the Federal Energy Regulatory Commission ("FERC") as the lead agency and with a consolidated record;

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182. Id. at 7.

183. The United States Department of Energy describes the Strategic Petroleum Reserve as the following:

[T]he largest stockpile of government-owned emergency crude oil in the world. Established in the aftermath of the 1973-74 oil embargo, the SPR provides the President with a powerful response option should a disruption in commercial oil supplies threaten the U.S. economy. It also allows the United States to meet part of its International Energy Agency obligation to maintain emergency oil stocks, and it provides a national defense fuel reserve.


184. SENATE HIGHLIGHTS, supra note 181, at 7.

185. According to the Minerals Management Service, a bureau of the United States Department of the Interior,

The Outer Continental Shelf (OCS) consists of the submerged lands, subsoil, and seabed, lying between the seaward extent of the States’ jurisdiction and the seaward extent of Federal jurisdiction. The continental shelf is the gently sloping undersea plain between a continent and the deep ocean. The United States OCS has been divided into four leasing regions. They are the Gulf of Mexico OCS Region, the Atlantic OCS Region, the Pacific OCS Region, and the Alaska OCS Region. In 1953, Congress designated the Secretary of the Interior to administer mineral exploration and development of the entire OCS through the Outer Continental Shelf Lands Act.


186. SENATE HIGHLIGHTS, supra note 181, at 7.

187. The Federal Energy Regulatory Commission is defined as the following:

[An] independent, five-member regulatory agency within the Department of Energy that regulates the transmission and sale of natural gas for resale in interstate commerce; regulates the transmission of oil by pipeline in interstate commerce; regulates the transmission and wholesale sales of electricity in interstate commerce;
(e). provides coastal impact assistance of $1 billion over four years to energy-producing states to encourage ongoing production by assisting in coastal enhancement and conservation programs;\textsuperscript{189}

(f). ensures an adequate supply of natural gas in the coming years, including clarification of FERC’s exclusive authority to site liquefied natural gas ("LNG")\textsuperscript{190} facilities.\textsuperscript{191} The bill further ensures supply by creating a clear process for siting natural gas infrastructure such as pipelines and storage.\textsuperscript{192}

The Act also contains specific provisions dealing with transportation fuels. Title XV of the Act specifically establishes “an ethanol mandate requiring fuel manufacturers to use 7.5 billion gallons of ethanol in gasoline by 2012.”\textsuperscript{193}

Other provisions of the bill, dealing, for example, with energy efficiency, corporate average fuel economy for automobiles and trucks, or even global climate change, arguably have an effect on the demand for oil and gas and their derivative products. These provisions are, however, beyond the scope of this article.

b. Intersection of Environmental Regulation and Oil and Gas Production

The Act does contain a variety of provisions designed to address environmental obstacles to oil and gas exploration and development. One of the surviving House of Representatives’ proposals was aimed at permit simplification for oil and gas projects on federal lands. The provision also licenses and inspects private, municipal, and State hydroelectric projects; oversees environmental matters related to natural gas, oil, electricity, and hydroelectric projects; administers accounting and financial reporting regulations of jurisdictional companies; and approves site choices as well as abandonment of interstate pipeline facilities.

\textsuperscript{188} Senate Highlights, supra note 181, at 7.

\textsuperscript{189} Id.

\textsuperscript{190} Liquefied Natural Gas (LNG) is defined as the following: [A] clear, colourless liquid that forms when natural gas has been cooled to -162C. It is odourless, non-toxic and non-corrosive. In its liquid form, natural gas is more efficiently stored and is economic to transport in dedicated LNG carriers overseas to receiving terminals. Indeed, converting natural gas into LNG is the only viable way to transport natural gas to places that are beyond the reach of pipeline systems. In liquid form, natural gas takes up 600 times less space than it does as a gas. It is like shrinking the volume of a beach ball to that of a ping-pong ball.

Shell Gas & Power, Liquefied Natural Gas, http://www.shell.com (follow “Gas & Power” hyperlink; then follow “Products & Services” hyperlink; then follow “Liquefied Natural Gas (LNG)” hyperlink).

\textsuperscript{191} Senate Highlights, supra note 181, at 7.

\textsuperscript{192} Id.

\textsuperscript{193} Id. at 1.
authorizes the Secretary of Interior to exempt certain operations from the National Environmental Policy Act ("NEPA"). NEPA requires the familiar environmental impact statement process with ample opportunities for public comment, litigation, and delay. The NEPA exemption applies to “individual surface disturbances” resulting from oil and gas operations of less than five acres on leases no larger than 150 acres and only when an initial site-specific analysis of environmental impact already has been completed.194

Another victory for oil and gas development came in the form of provisions dealing with hydraulic fracturing.195 Hydraulic fracturing, according to the United States Environmental Protection Agency (“EPA”), is a “technique” that “allows oil or natural gas to move more freely from the rock pores where they are trapped to a producing well that can bring the oil or gas to the surface.”196 Specifically, the technique is described as follows:

After a well is drilled into a reservoir rock that contains oil, natural gas, and water, every effort is made to maximize the production of oil and gas. One way to improve or maximize the flow of fluids to the well is to connect many pre-existing fractures and flow pathways in the reservoir rock with a larger fracture. This larger, man-made fracture starts at the well and extends out into the reservoir rock for as much as several hundred feet. The man-made or hydraulic fracture is formed when a fluid is pumped down the well at high pressures for short periods of time (hours). The high pressure fluid (usually water with some specialty high viscosity fluid additives) exceeds the rock strength and opens a fracture in the rock. A propping agent, usually sand carried by the high viscosity additives, is pumped into the fractures to keep them from closing when the pumping pressure is released. The high viscosity fluid becomes a lower viscosity fluid after a short period of time. Both the injected

195. The Act amends the Safe Drinking Water Act to read as follows:
(1) UNDERGROUND INJECTION—The term “underground injection”—
(A) means the subsurface emplacement of fluids by well injection; and
(B) excludes—
(i) the underground injection of natural gas for purposes of storage; and
(ii) the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.
water and the now low viscosity fluids travel back through the man-
made fracture to the well and up to the surface.197

The controversy surrounding hydraulic fracturing was intensified due
to a federal court decision198 that prompted EPA to begin a process to
regulate the practice. Previously, EPA had taken the position that the
fluids were not injected for purposes of disposal, but rather to improve
the geological properties of the formation. Supporters of the practice
essentially argued that environmental impacts were de minimus, that the
process was important for efficient oil and gas production, and that any
regulation must be highly site-specific rather than national and
proscriptive in nature.199 Opponents of the process, such as the mercurial
Robert F. Kennedy, Jr., contend that it can contaminate water sources
with benzene, a chemical present in certain mixtures.200 For its part, the
Act resolves the controversy in favor of the oil and gas sector by restoring
the status quo prior to the court decision.201

c. Offshore Oil and Gas Exploration and Development

Though the Outer Continental Shelf Lands Act of 1953, as amended,202
permits the exploitation of certain offshore oil and gas projects on the
OCS, it does so only “in a manner that protects the environment and
returns revenues to the federal government in the way of bonus bids,
rents, and royalties.”203 The program to develop OCS lands has been
controversial, resulting in a moratorium in all OCS areas other than
Texas, Louisiana, Alabama, and some parts of Alaska.204 The moratorium
was put in place by a 1990 Presidential Directive issued by President
George H. W. Bush and at the strong urging of California, Florida, and
certain environmental organizations.205 While the original moratorium
was to last ten years, President William J. Clinton extended it until
2012.206

197. Id.
198. Legal Envtl. Assistance Found., Inc. v. EPA, 118 F.3d 1467, 1477 (11th Cir. 1997).
203. M ARC HUMPHRIES, CONGRESSIONAL RESEARCH SERVICE ISSUE BRIEF FOR
CONGRESS, OUTER CONTINENTAL SHELF: DEBATE OVER OIL, AND GAS LEASING AND
REVENUE SHARING, CRS IB10149, at 3 (2005), available at http://cnie.org/NLE/CRSreports/
05oct/IB10149.pdf.
204. Id.
205. Id.
206. Id.
The Act does not directly address the moratorium on OCS leasing, but it does stick its toe in the water. The Act establishes a “comprehensive inventory” of oil and natural gas assets on the OCS.\textsuperscript{207} Section 357 of the Act bars the Interior Department from actual drilling in conducting the inventory, which is due in February 2006.\textsuperscript{208} Even this inventory raised substantial environmental hackles as a first step towards exploiting the OCS.\textsuperscript{209}

Beyond OCS consideration, the Act as adopted also simplifies the regulatory and permitting requirements for natural gas development on federal lands. Under § 366 of the Act, the Secretary of Interior is given ten days to notify applicants whether their permits have been rejected.\textsuperscript{210} Even development projects that are not approved at the outset may receive a deferral of up to two years to allow the applicant to perfect their submission to the Department of the Interior.\textsuperscript{211}

d. Liquefied Natural Gas

The Act mandates that the Department of Energy undertake a study on the cumulative risks and benefits of the various offshore LNG facilities “reasonably assumed to be constructed” in the Gulf of Mexico.\textsuperscript{212} This development is predicated on the further development of OCS resources. The report, mandated under § 1828 of the Act, is supposed to deal with the environmental and marine impacts of the “open-rack vaporization systems,” necessary to extract LNG.\textsuperscript{213} Title III of the Act also clarifies the FERC’s jurisdiction for siting, construction, expansion, and operation of import-export facilities located onshore or in state waters.\textsuperscript{214} The section does not provide FERC with eminent domain authority over siting LNG facilities, however.\textsuperscript{215}

While it is unclear whether the Act’s limited LNG provisions will facilitate substantial additional construction of facilities, the importance of doing so cannot be overstated. Senator Pete Domenici (R-NM), chairman of the Senate ENR Committee, observed:

\begin{itemize}
  \item \textsuperscript{208} Id.
  \item \textsuperscript{209} Press Release, U.S. Rep. Frank Pallone, Jr., Pallone, Calls OCS Inventory in Republican Energy Bill Unnecessary (Aug. 1, 2005), http://www.house.gov/apps/list/press/nj06_pallone/pr_aug_OCS.html (“The unnecessary inventory included in the Republican energy bill is not about ‘seeing what is out there,’ but about pushing for oil and gas drilling in areas currently protected by the law.”).
  \item \textsuperscript{210} § 366, 30 U.S.C. § 226(p) (2006).
  \item \textsuperscript{211} Id.
  \item \textsuperscript{212} Pub. L. No.109-58, § 1828, 119 Stat. 594, 1136.
  \item \textsuperscript{213} Id.
  \item \textsuperscript{215} Id.
\end{itemize}
We have some difficult choices ahead that require federal leadership. The Energy Information Agency tells us we must increase our importation of LNG nearly 30-fold by 2025 to meet domestic demand. The American Gas Foundation yesterday warned that natural gas prices could double in the next 15 years if we don’t increase domestic production, build LNG ports and diversify our sources of electricity.216

**e. Oil Shale and Tar Sand**

According to the U.S. Geological Survey, the United States has approximately 2 trillion barrels of crude petroleum in oil shale formations, particularly in the western part of the U.S. Beyond that, the nation also has 80 billion barrels of oil in tar sands.217 The Act creates a task force to recommend policies to facilitate oil shale and tar sands leasing, and also creates a research and development program to bring new technologies to bear on these resources.218 The Act authorizes sales of commercial shale leases when the situation warrants.219 Federal land leasing of this sort for shale and tar sands is likely to focus on Colorado, Utah, and Wyoming, with private operations to receive leases by late 2007. These projects are not exempt from the environmental impact assessment process, however.220

3. A Look to the Future: Can Unfinished Energy Business Get Out of Traffic?

The Act produced a good start for oil and gas legislation and certainly raised a number of questions for future policy makers to resolve. While beyond the scope of this article, the Act’s tax provisions221 are designed to stimulate future investment in the oil and gas sector. But despite all of its successes, the Act was open to the criticism that it stressed supply-side solutions over demand-side solutions; that is, while the Act sought to encourage the development of additional oil and gas resources, it was less

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217. See supra note 181.

218. Id.

219. Id. But see Randy Udall & Steve Andrews, Oil Shale May be Fool's Gold, DENVER POST, Dec. 18, 2005, at E1 (“Buried underground in western Colorado are a trillion tons of oil shale. For a century, men have tried and tried again to unlock this energy source. But the rocks have proved stubborn, promising much, delivering little.”).

220. See supra note 194.

enthusiastic about encouraging efficiency or conservation. This argument, however, is based more on perception than reality because the Act has substantial provisions regarding the energy efficiency of appliances222 and even some provisions on automobile efficiency.223

The Act’s final passage was in part a reaction to gasoline and natural gas prices that exceeded historical averages at the time debate on the Act intensified. Gasoline prices actually began to decline as the final conference on the energy bill got underway. By the end of August 2005, however, Hurricane Katrina made landfall, and took substantial energy assets off-line. Predictably, gasoline prices once again began a significant upward climb. The call went out immediately to revisit energy legislation, despite the fact that the ink on the Act was barely dry.224

The Act had been considered over a four-year process, allowing ample time for debate of all the major constituent issues. Only its final adoption was presaged by significant energy price concerns. Despite this pedigree, the emergence of the twin hurricanes impacting the Gulf Coast caused a serious rethinking.225 While no legislation was adopted in answer to this call—the political capital generated by the hurricanes was diverted to supplementary appropriations measures226 and oversight of the recovery227—it is instructive to observe the energy proposals that were advanced at the time. These policy options included a renewed interest in development of ANWR, increases in automobile fuel economy standards,

224. Id. at 3 (“[P]rices continued to surge, spiking at the end of August when Hurricane Katrina shut down refining operations in the Gulf of Mexico. The continuing crisis has renewed attention to some issues that were dropped or compromised in the debate over P.L. 109-58.”).
225. Id. at 6.
226. The chairman of the appropriations subcommittee with jurisdiction over hurricane response noted the following:
   Over the past month, this Congress has provided over $62 billion with little justification from the Department and the Administration. We did so because everyone agreed the need was urgent—we could not let our response to one of the largest disasters this nation has ever faced be interrupted because of lack of funding. While we acknowledge that more financial assistance will be needed, the sense of urgency has subsided. FEMA has over $40 billion on hand to respond to any eligible request for assistance for the next several weeks.
conversion of the mere OCS inventory to additional leasing, further efforts to encourage refinery construction, and, of course, the requisite call for additional authority to deal with so-called “price gouging” in the fuels market.228

Like the proverbial gift that keeps on giving, circumstances calling for rational and effective oil and gas policy remain constant, and the federal government cannot resist additional efforts to tinker with major energy proposals. On January 31, 2006, President Bush delivered his State of the Union address to the U.S. Congress.229 Arguing that the nation remains “addicted to oil,” President Bush called for an ambitious replacement of seventy-five percent of foreign oil imported from the Middle East with domestic energy sources (like ethanol and other alternatives) by the year 2025.230 While reasonable minds can differ about the possibility of reaching this outcome,231 it is hard not to admire the goal of making significant in-roads into the nation’s fossil fuel dependence.

Daniel Yergin, a noted energy consultant and author of *The Prize*, recently observed, “Every Administration since the early 1970’s has struggled with the issue of rising oil imports and the right mix of policies to deal with them.”232 While the oil and gas sector will undoubtedly find its way in light of the impacts of the Act and the pace of its implementation, the only certainty is that our democratic institutions will continue to fight over the appropriate road map.

C. United States Oil and Gas Case Summaries

JANA L. GRAUBERGER* AND ANNA T. KNOLL**

QUESTION PRESENTED: DISTINGUISHING ROYALTY OBLIGATIONS UNDER PRIVATE OIL AND GAS LEASES FROM TAXPAYER OBLIGATIONS FOR PAYMENTS RELATED TO OIL AND GAS PRODUCTION.


In this case, the Colorado Supreme Court distinguished royalty obligations under private oil and gas leases from taxpayer obligations for purposes of determining allowable deductions from tax payments related to oil and gas production. The court rejected an analogy to its decision in Rogers v. Westerman Farm Co., finding that the taxpayer was allowed to deduct processing costs on the leasehold from its tax payments, even though the same deductions may not be allowable from royalty payments under a private oil and gas lease.

Petron operates ten oil and gas wells on six leaseholds in Washington County, Colorado, each of which consists of equipment that brings unprocessed material consisting of fluids and gas to the surface at the casing head. Once at the surface, the material is processed to separate the water and gas from the oil, which is then transported to a tank battery for metering and storage until it is delivered to the purchaser. These processes increase the value of the extracted material in its unprocessed state by rendering it saleable. Petron filed tax deduction schedules using the netback method to report the wellhead selling price of its oil production. Petron did not deduct the vertical costs of extracting the material from the earth, but did deduct the horizontal costs of preparing the material for sale. Petron reduced the value of the oil at the downstream point of sale (the tank battery) by the costs incurred for gathering and processing activities that took place between the wellhead.

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233. 29 P.3d 887 (Colo. 2001).
and the battery. The county tax assessor denied all of Petron’s deductions for gathering and processing costs. The assessments were instead based on the gross lease revenues that Petron received at the outlet of the tank batteries.

The court of appeals ruled that Petron’s deductions should have been allowed, holding that the material produced at the wellhead constituted “unprocessed” material, and that Petron’s costs of breaking down that material, removing the water, and transporting the product to the tank battery were deductible “gathering” and “processing” costs. The Colorado Supreme Court affirmed.

Washington County attempted to analogize the facts of this case to Rogers as grounds for rejecting the deductibility of the costs of rendering the extracted materials saleable. Washington County based its analogy on the rejection in Rogers of the rule that gas is “produced” when it is physically severed from the earth. The court declined to accept the analogy, noting that Rogers concerned royalty obligations under private gas leases, specifically, how natural gas was to be valued for purpose of calculating royalties and the implied covenant to market between working interest owners and royalty interest owners.

The court held that the analysis of the allocation of costs incurred downstream of the physical wellhead in Rogers was not relevant to the present case, where the pertinent assessments were not of the “marketable product” but rather of the “unprocessed material.” The court further noted that in the royalty context, oil and gas leases are construed strictly against the lessee in favor of the lessor, and in the context of taxation, construction is in favor of the taxpayer.

The court concluded that the County’s determination that gathering, processing, and transportation expenses could not be deducted unless they occurred away from the leasehold property surrounding the well would result in non-uniform treatment of taxpayers in similar situations, and contradicts both the legislative intent behind the pertinent statutes and the state constitution. The court held that Washington County must allow for deduction of processing costs on the leasehold site.

**Question Presented:** Whether lessee was required to pay lessor’s share of transportation costs deducted from royalty payments under a gas purchase agreement.


This matter involved whether the lessee under two oil and gas leases was required to pay the lessor’s share of the transportation and other
expenses deducted under a gas purchase agreement between the lessee and a third-party purchaser. The Kansas Court of Appeals held that the lessee could not deduct such costs from its royalty payments under circumstances where the lessee had prevented fulfillment of a condition precedent contained in the oil and gas leases.

The oil and gas leases contained a condition precedent requiring the lessee, Key Gas, to charge transportation costs and other expenses to the leases before Key Gas became liable for these expenses. Because these costs were deducted by the gas purchaser, ONEOK, from the amount paid to Key Gas for gas purchased under their contract pursuant to its terms, they were not charged to the leases by Key Gas and the condition precedent that would trigger Key Gas's liability for the costs was never fulfilled. However, the court of appeals noted that Key Gas had control of the condition precedent and it had an implied obligation to protect the lessor, Davis, from costs that would reduce his royalty. The court determined that Key Gas made fulfillment of the condition precedent impossible when it entered into the gas purchase agreement with ONEOK and allowed ONEOK to deduct transportation costs and other expenses. It held that “Key Gas will not be allowed to use its own action which prevented the condition precedent from being fulfilled to escape liability for these costs.”

In reaching its conclusion, the court of appeals considered the parties’ intent under the leases. Key Gas had relied upon the customary trade practice of taking gas from the wellhead to the first point of sale as support for its argument that it was not liable for the deductions from Davis’ royalty payments. To rely on trade custom or usage, however, the party asserting that argument must show that the other party knew of the custom or that the knowledge of this custom is so widely known that it may be presumed that the other party knew of it.

Finding no evidence that Davis knew or should have known of the particular practice, the court excluded consideration of the customary practice from evaluation of the parties’ intent. Looking to the lease, then, for evidence of intent, the court concluded first that the parties intended that Davis “bear no cost” for transportation of gas and, second, that Key Gas would base Davis’ royalties on the payments received for oil and gas production under the leases. The court interpreted these provisions to include Key Gas’s obligation to refrain from reducing the amount of any royalty revenues Davis was entitled to receive. However, when Key Gas contracted with ONEOK, it relinquished control over transportation costs and other expenses, rendering performance of the condition precedent impossible. Consequently, the court found that Key Gas could not rely on nonperformance of a condition precedent to deny liability
under circumstances where its own action was the cause of the nonperformance.

The appellate court reversed and remanded with directions that Davis recover from Key Gas the amount charged by ONEOK for gas treatment, dehydration, compression, transportation, and water hauling, plus interest.

**QUESTION PRESENTED:** WHETHER A LESSEE OWS A DUTY TO RESTORE THE SURFACE OF LAND LEASED FOR OIL AND GAS PRODUCTION ACTIVITIES TO PRE-LEASE CONDITION.


This case involved consideration by the Louisiana Supreme Court of the lessees’ duty to restore the surface of land leased for oil and gas production activities. The court held that the lessees owed no duty to restore the surface of coastal marshland to pre-lease condition by backfilling canals, and that in the absence of an express lease provision, the Louisiana Mineral Code article that obligates a lessee to act as a reasonably prudent operator does not impose an implied duty to restore the surface to its original, pre-lease condition absent proof that the lessee exercised its rights under the lease unreasonably or excessively. The court distinguished this matter from its decision in *Corbello v. Iowa Production* on grounds that *Corbello* involved an express lease provision obligating the lessee, upon termination of the lease, to “reasonably restore the premises as nearly as possible to their present condition.”

The trial court in this case had awarded a $1.1 million fund for the restoration of marshland at the oversight of a special master. The court of appeals imposed an implied obligation to restore the surface where the lease terms did not address restoration obligations, held that an award of money damages was inappropriate and that the proper remedy was actual restoration, and declined to limit the restoration obligation to the value of the property, even though the cost of restoration far exceeded the value of the property.

The Louisiana Supreme Court resisted “the temptation . . . to thrust a great part of the solution to the problem of coastal restoration upon the oil and gas companies.” The court held that “where the mineral lease expressly grants the lessee the right to alter the surface in the manner it

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234. 850 So. 2d 686 (La. 2003).
did, and is silent regarding restoration. [Mineral Code] article 122 only imposes a duty to restore the surface to its original condition where there is evidence of unreasonable or excessive use.” Because the lease expressly granted the right to dredge canals, the lessor consented to the changes necessarily incident to dredging, and the “wear and tear” that occurred was contemplated in the lease.

The court also noted that the lessees’ evidence that they complied with regulations, and that it was industry custom not to backfill canals, demonstrated that they did not exercise their lease rights unreasonably or excessively.

**QUESTION PRESENTED**

**DETERMINING THE GROSS VALUE OF GAS FOR THE PURPOSES OF GROSS PRODUCTION AND PETROLEUM EXCISES TAXES WHERE THERE IS NO ARM’S LENGTH SALE OF GAS AT THE WELLHEAD.**


This case concerned the method for determining the gross value of gas at the wellhead, in the absence of an arm’s length sale, for the purposes of gross production and petroleum excise taxes.

Texaco produced gas that it gathered and processed with its own gathering system and processing plant. Texaco sold the residue gas, extracted liquid hydrocarbons, and drip condensates to third parties at the tailgate of the plant, as well as extracted liquid hydrocarbons and drip condensates. Texaco also gathered and processed gas purchased from other producers in the field under wellhead gas purchase contracts for a percentage of the proceeds received at the tailgate of the plant. Texaco executed a written contract with itself to purchase its gas at the wellhead at a price based on the price it paid other producers. When reporting its gas production to the Oklahoma Tax Commission (“OTC”), Texaco calculated the gross production and petroleum excise taxes based on a percentage of the proceeds it received at the tailgate of the plant. The OTC filed suit against Texaco, alleging that Texaco had “intentionally devised and implemented a scheme to calculate gross production and petroleum excise taxes on a price less than the fair market value with the intent of evading payment of the taxes. The OTC sought damages of at least $20 million in gross production and petroleum excise taxes, plus interest and penalties.

Each party moved for partial summary judgment with respect to the method for calculating the wellhead value of the gas in the absence of an arm’s-length sale. The OTC alleged that Texaco must pay taxes based on
the gross proceeds realized from the first arm’s length purchase of the
gas. Texaco claimed that it had properly paid the taxes based on
comparable sales prices for wellhead sales of gas of like kind, quality, and
character in the same field. The district court granted Texaco’s motion
for summary judgment, but certified the judgment for immediate review.
The Oklahoma Supreme Court granted OTC’s petition for writ of
certiorari, ultimately reversing and remanding the case for further
proceedings.

In Apache Gas Products Corp. v. Oklahoma Tax Commission,235 the
court had concluded that the OTC should calculate the gross production
tax on the gross proceeds realized by each producer from his individual
sales contracts. If, however, the contract does not reflect arm’s length
bargaining, then the OTC should calculate the take on the prevailing
price in the field at the time of production.

In the context of royalty payments, the court had previously
determined in the absence of an arm’s length wellhead purchase, the
royalty payments must be calculated on the prevailing market price or the
work-back method, whichever one is higher.236 The court noted that this
method falls within the statutory scheme for calculating gross production
tax, and had been effectively used by the OTC in the administrative
assessment process. In accordance with Howell, the Oklahoma Supreme
Court concluded that the gross value of gas for calculation of gross
production taxes must be determined by using the prevailing price
method or the work-back method, whichever resulted in the higher value
in the absence of an arm’s length sale.

The court further held that Texaco’s contract with itself to purchase its
own gas at the wellhead could not form the basis to establish the value of
the gas for calculating gross production taxes.

QUESTION PRESENTED: DISCUSSING WHETHER TRADE USAGE OF THE
TERM “OIL RIGHTS” IN THE 1940’S OPERATED TO RESERVE GAS RIGHTS
WITHOUT A SPECIFIC REFERENCE TO “GAS.”

Mullinnix LLC v. HKB Royalty Trust, 126 P.3d 909 (Wyo. 2006).

In this case, the Wyoming Supreme Court examined trade usage and
held that deeds executed in the 1940s reserving “oil rights” did not
reserve gas rights due to the absence of a specific reference to “gas.”

Two deeds, executed in the 1940s and conveying real property in Campbell County, Wyoming reserved “oil rights” to the respective grantors. Grantors of both deeds asserted that, according to trade usage at the time and in the place the deeds were executed, “oil rights” included both oil and gas, suggesting that the true intent of the grantors was to reserve an interest in gas, as well as in oil. With respect to the Hickman deed, the district court determined that the term “oil rights” was facially unambiguous, holding that as a matter of law any such reservation of rights did not include gas rights. The appellate court reversed and remanded with instructions to consider the circumstances surrounding the execution of the deed to determine the intent of the parties.

The Mullinnix deed also reserved “oil rights.” To secure those rights, Mullinnix, successor-in-interest to the original grantor, recorded a “Declaration of Interest” signed by the holders of the mineral rights declaring their interest to be a fractional interest in the oil, gas, and associated hydrocarbons. Mullinnix filed an action to quiet title to the mineral interests it had acquired through the transaction with the original grantor. The district court stayed its proceedings until the appellate court resolved the issue with respect to the Hickman case.

Once the Hickman case was remanded, the district court consolidated the two cases. In accordance with the appellate court’s first decision on the Hickman case, the district court evaluated the evidence relevant to whether the term “oil rights” had a particular trade usage. The court concluded that in Campbell County in the 1940s references to oil and gas were specific when used to reserve interests in mineral deeds. The court held that the grantors had reserved the oil rights, but conveyed the gas rights.

At trial, Mullinnix and Hickman had the burden of proving that use of the term “oil rights” in deeds in Campbell County in the 1940s had a particular trade usage, a burden the district court found they did not meet. Both parties attempted to show that ranchers often referred to their entire bundle of mineral rights as “oil rights” and that this meaning was what was intended to be conveyed by the deeds. The district court, however, found that because natural gas was not considered a commercial product in the region at that time, and because oil and gas were usually referred to individually and specifically in formal use, Mullinnix and Hickman had not carried their burden of proof.

Urged to reconsider the use of evidence of the surrounding circumstances in determining the meaning of a deed’s terms, the appellate court reiterated its prior holdings that “the ultimate goal of [its] interpretation of any contract, including a deed, is to discern the intention of the parties to the document.” Analysis of the plain meaning of the words at the time of execution is the first step in this process. The court
noted that this type of evaluation is not a violation of the parol evidence rule, as that rule is intended to prevent supplementation of the terms of the document; but it does not prohibit the use of extrinsic evidence of the circumstances surrounding the execution of the contract to interpret the meaning of its terms. Usage of trade is a proper factor to be considered in interpreting a contract.

Turning to the effectiveness of the Declaration of Interest recorded by Mullinnix, the appellate court agreed with the district court that the document did not affect the parties’ interests in the mineral estate. The Declaration did not convey property and did not alter then-existing ownership of the property it described. Furthermore, the owners of the mineral interests who had signed the Declaration were not precluded by the doctrines of estoppel, laches, or waiver from challenging Mullinnix’s claim to the gas estate. Finally, the evidence showed that Mullinnix did not rely on the Declaration of Interest when he acquired the mineral deed from the original grantor because as the Declaration was not signed until nearly a week after the mineral deed to Mullinnix was recorded. The court affirmed the district court’s judgment on all counts.

**QUESTION PRESENTED: WHETHER GRANTOR CONVEYED AND RESERVED A GREATER INTEREST IN A MINERAL ESTATE THAN GRANTOR OWNED.**


The Wyoming Supreme Court interpreted the validity and effect of a warranty deed conveying all interest in the surface estate and reserving a one-third interest to each of the three grantors under circumstances where one grantor had no interest in the mineral estate to reserve.

Ray Gilstrap, William Gilstrap, and Daisy Pearl Williams each received an undivided one-third interest in a 680-acre ranch with a 320-acre mineral estate pursuant to the their mother’s will. The siblings agreed to redistribute the estate, giving Ray the entire surface estate, Ray and William each received one-half of the mineral estate, and Daisy received other assets. William and Daisy later executed a warranty deed purporting to convey the entire property, both surface and minerals, to Ray, reserving to each of them a one-third interest in the mineral estate. In 2003, William and Daisy’s heirs brought an action to quiet title as to the mineral interest.

The district court found that William and Daisy’s heirs had no interest in the mineral estate. The court grounded this holding on the rule
established in *Duhig v. Peavy-Moore Lumber Co.*, 237 adopted by Wyoming in *Body v. McDonald*.238 The court concluded that because Daisy owned no interest in the mineral estate, her reservation of a one-third interest failed and was instead attributed to William. This reallocation caused William to reserve a two-thirds interest when he, in fact, only owned half. Because this reservation could not be reconciled with Daisy and William’s conveyance of the entire surface and mineral estate to Ray, under the *Duhig-Body* rule the reservation failed and Ray’s successors owned the entire mineral estate.

On appeal, neither party argued that the language of the deed was ambiguous, though both parties asserted different meanings. The appellate court reiterated its longstanding rule that interpreting an unambiguous contract concerning mineral interests entails analysis of the surrounding facts and circumstances, the relationship of the parties, the subject matter of the contract, and the apparent purpose of making the contract. The critical inquiry into deeds with express reservations is what the grantor purported to give to the grantee, and not what he intended to reserve for himself. If the grantor did not own a large enough mineral interest to satisfy both the grant and the reservation, the grant must be satisfied first as a superior obligation to the reservation.

The appellate court noted that under the plain terms of the deed, the entire 680-acre estate was conveyed to Ray, reserving to William and Daisy one-third of the mineral interests each. The district court’s addition of Daisy’s attempted reservation to William’s reservation required, in the appellate court’s view, the court to ignore the face of the deed, which clearly grants only a one-third interest to Ray. The court found no precedent for giving the grantee more than the deed granted to him. The court concluded that where the grantee is the co-tenant and owner of the outstanding interest, that interest must be subtracted from the interest warranted by the grantor. The court further held that a grantee cannot bring an action for breach of warranty where he owns the outstanding interest that the grantor is alleged to have warranted.

The court held that Ray was entitled to his one-third interest, to be satisfied out of the one-half interest owned and warranted by William. William was entitled to the remainder of the one-half interest he warranted less the one-third interest reserved, resulting in a one-sixth interest reserved. William could not retain a full one-third interest because he could not fulfill his grant of a one-third interest to Ray when he only owned a one-half interest. The risk of title failure rests on the grantor if the grant and the reservation cannot both be given effect.

237. 144 S.W.2d 878 (Tex. 1940).
V. RECENT DEVELOPMENTS IN INTERNATIONAL ENERGY LAW

A. Middle East: Petroleum Provisions of Iraq’s New Constitution and the Admission of Saudi Arabia to the WTO

NABIL A. ISSA *


Prime Minister Ibrahim Al-Jaafari’s recent comment that the “basis for dialogue will primarily be the constitution, respect for the constitution and its contents” appears innocuous on its face. 239 This affirmation of the validity of the constitution by Prime Minister Al-Jaafari, however, is largely viewed by Sunni leaders in Iraq as an attempt to deprive the Sunni population of the benefits of the country’s petroleum resources.

The draft constitution was approved in a general referendum on October 15, 2005 (“Constitution”), with little input from, and over the vociferous objections of, Iraq’s Sunnis. The Constitution, however, will not come into effect until it is published in Iraq’s Official Gazette, and after the formation of the new government elected on December 15, 2005. 240

Petroleum reserves in Iraq are concentrated largely in the Shiite-controlled southern region and in the predominantly Kurd-controlled northern region. Many Sunnis feel that certain provisions of the Constitution remove a great deal of central government control over hydrocarbon resources and place it in the hands of regional governments in an attempt to limit the Sunni population’s ability to benefit from the country’s oil revenues. In addition, the Kurdistan Regional Government is already working with foreign oil companies to explore for reserves in

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the northern region. This has infuriated non-Kurdish Iraqis and the federal government in Baghdad, who view this as a further attempt by the Kurds to monopolize control over oil revenues generated in the northern region. Thus, it is critical to review the pertinent provisions of the Constitution in light of the history and recent relevant regulations regarding the control of petroleum resources in Iraq.

History

International oil companies ("IOCs") were first granted concessions for the exploration and production of petroleum in Iraq in 1925. Since 1927, when oil was first discovered in Kirkuk, petroleum has played an important part in Iraq’s history. However, the confiscation of almost all land not held by a concession in the early 1960s, followed by the nationalization of the assets and operations of the Iraq Petroleum Company in 1972 (and all other foreign assets in 1975), has led to a relative paucity of foreign investment and technology being used to develop this important sector of the Iraqi economy. Despite the lack of foreign investment, Iraq was able to advance its oil industry on the back of higher crude oil prices during the decades of the 1960s and 1970s.

The eight-year long Iran-Iraq War severely damaged the petroleum industry’s infrastructure in Iraq. The local industry was further crippled following the invasion of Kuwait in 1990, the imposition of UN sanctions, the Gulf War in 2003, and the ongoing attacks on infrastructure in the petroleum sector by insurgents. Thus, since 1990 Iraq has seen little investment in its petroleum sector over a period when its existing infrastructure has suffered extensive damage over and above normal depreciation. Currently, the unstable security situation, lack of transparent enforcement of economic laws, the introduction of a new political process, and widespread corruption contribute to the ongoing malaise of the petroleum industry. Moreover, the IOCs appear to be avoiding much activity in Iraq until the security situation and legal regime stabilize, largely limiting their involvement to providing technical support that can be delivered from outside Iraq. Without substantial investment, it is nearly impossible for Iraq to achieve its production potential during one of the biggest booms in the history of the worldwide petroleum industry.

Kurdistan Regional Government

Iraqi Kurds have been recognized as a distinct ethnic group in Iraq since the 1920 Treaty of Sevres. The interim constitution for Iraq issued in 1958 provided that Arabs and Kurds are partners in the Iraqi state. On March 11, 1970, an agreement was reached with the Iraqi Kurdish people regarding the boundaries of the Kurdistan Region of Iraq.244 However, Saddam Hussein did not honor these agreements and carried out a campaign of ethnic cleaning and genocide culminating in the Arabization of oil-rich cities such as Kirkuk. Security Council Resolution 688 of April 5, 1991, established a safe haven for Kurds in the North of Iraq and granted the Kurds a degree of self-determination.245 The Kurds also began developing three semi-independent provinces that were sealed off from the rest of Iraq as part of a no-fly zone enforced by American and British warplanes.246 With the downfall of Saddam Hussein in April 2003, Kurdistan was relatively stable, both economically and politically, and possessed a better-developed infrastructure. Following their strong showing in the Iraqi elections held in January 2005, the Kurds were able to exert significant influence over the drafting of the Constitution.247 The Constitution reflects such influence in that it secures important political and economic rights for Kurdistan.

Article 112 of the Constitution provides that Iraq is made up of a “decentralized capital, regions and governorates, and local administrations.” Article 137 provides that legislation “enacted in the region of Kurdistan since 1992 shall remain in force, and decisions issued by the government of the region of Kurdistan—including court decisions and agreements—shall be considered valid unless amended or annulled pursuant to the laws of the region of Kurdistan by the competent entity in the region, provided they do not contradict with the Constitution.” Kurdistan is currently the only organized region in the federal system and has been actively touting itself as a center for foreign investment, including in its oil and gas sector.248 Due to ambiguities in the laws and the Constitution, however, investors in Kurdistan may not be as free to invest in Kurdistan as is represented by the Kurdistan Regional Government.249

244. Telephone Interview with Mohamed El Roubi, Managing Partner, I&D Iraq Law Alliance, in Baghdad, Iraq (Feb. 21, 2006).
245. Id.
247. El Roubi, supra note 244.
248. Id.
249. Id.
Oil and gas are given special prominence in the Constitution. While smaller foreign oil companies have been willing to rely on the Kurdistan Regional Government’s interpretation of the Constitution, the IOCs have decided to defer substantial investment in E&P activities insofar as the Constitution does not clearly provide for investment in unexplored blocks. In addition, the Constitution, as discussed at the outset, is not yet in effect.

Article 108 of the Constitution provides:

“[O]il and gas are under the ownership of all the people of Iraq in all regions and governorates.” (emphasis added).

Article 109 of the Constitution provides:

“[T]he federal government with the producing governorates and regional governments shall undertake the management of oil and gas extracted from current fields provided that it distributes oil and gas revenues in a fair manner in proportion to the population distribution in all parts of the country with a set allotment for a set time for the damaged regions that were unjustly deprived by the former regime and the regions that were damaged later on, and in a way that assures balanced development in different areas of the country, and this will be regulated by law. . .(and) shall together formulate the necessary strategic policies to develop the oil and gas wealth in a way that achieves the necessary strategic policies to develop the oil and gas wealth in a way that achieves the highest benefit to the Iraqi people. . .” (emphasis added).

Article 111 provides:

“[P]riority goes to the regional law in case of conflict between other powers shared between the federal government and regional governments.”

The provisions of the Constitution appear to be inconsistent, implying federal control in one provision and regional control in another. The references to special allotments of petroleum revenues to regions that were “unjustly deprived by the former regime” is largely viewed as a requirement that such monies first go to Shiite and Kurd controlled areas for a set period of time. It is also arguable, however, that the Sunnis will benefit from such revenues to the extent that the Constitution provides that such resources are owned by all the people of Iraq. A number of provisions of the Constitution, such as Article 109, utilize language such as “this will be regulated by law” implying that subsequent enabling legislation will provide the required clarity. It should also be noted that Article 137 of the Constitution provides for the establishment of a
constitutional amendment committee, which will have four months to review the Constitution and propose amendments to the parliament. These amendments, if approved, will be subject to another public referendum.

The IOCs are generally uncomfortable relying on the assurances of a regional government that it has jurisdiction to award concessions in the absence of clarity in the Constitution on the issue and the expectation that enabling legislation may affect an investment made in the interim. In addition, the IOCs are aware that production-sharing agreements (“PSAs”) awarded to the Chinese National Petroleum Corporation and Russia’s Lukoil in 1998 became meaningless in light of UN sanctions and the downfall of the Saddam Hussein regime. The only companies willing to risk such investment to avail themselves of the tremendous reserves and high oil prices have been relatively small oil companies.

Petroleum Law

Iraq needs a comprehensive petroleum law to clarify the process of awarding contracts for the exploration and development of its natural resources. This law will need to provide whether such contracts are awarded as PSAs, development and production contracts (“DPCs”), operating service agreements (“OSAs”), or on some other basis. Unfortunately, the only draft laws appear to be those concerning the downstream sector for the importation and sale of refined petroleum products rather than the upstream development of Iraq’s resources for both domestic use and export.

2. The Admission of Saudi Arabia to the WTO

On December 11, 2005, following twelve years of negotiations, the Kingdom of Saudi Arabia joined the World Trade Organization (“WTO”) just prior to the WTO meeting in Hong Kong. WTO membership will have immediate and long-term effects on foreign companies engaged in business in Saudi Arabia. As a WTO member, Saudi Arabia is required to abide by the relevant agreements covering trade in three key areas: services, goods, and intellectual property. This summary focuses on the compromise Saudi Arabia made with its trading partners.
partners in the WTO on the issue of dual pricing of gas and natural gas liquids used as feedstock. Feedstock pricing has been a critical issue in terms of Saudi Arabia's accession to the WTO. Currently, natural gas (methane and ethane) is sold to domestic consumers at $0.75 per million BTU pursuant to governmental regulation. There is no export of natural gas by Saudi Arabia. While this price is considerably less than prevailing international prices for natural gas, Saudi Arabia has persuaded the other WTO members that the high cost of liquefying natural gas for export should be considered against the cost of using such natural gas locally as feedstock. Thus, the $0.75 per million BTU price for methane and ethane has been accepted and is expected to continue in force in the Kingdom.

Certain natural gas liquids (propane, butane and natural gasoline) ("NGLs") have been subject to different prices based on whether the NGLs were sold domestically or internationally. While international NGL sales reflected prevailing market prices, domestic NGL sales were priced at a thirty percent discount against the export price received by Saudi Aramco during the preceding quarter. Some WTO members (predominantly from the E.U.) took the position that this discount for domestic purchasers effectively subsidized petrochemical producers in Saudi Arabia to the detriment of petrochemical producers located elsewhere.

Saudi Arabia noted that it had rescinded the express thirty percent discount in 2002, and that NGL domestic prices were now required to be commercially based. However, Saudi Arabia explained in the course of the accession negotiations that such commercial considerations, in Saudi Arabia's view, justified charging lower prices for domestic NGL sales than for NGL exports. Saudi Arabia listed several factors for this price discrepancy, including (i) the lack of required investment in liquefaction, storage, and terminal infrastructure, (ii) the reduced costs of marketing NGLs domestically, and (iii) the reduced volatility of selling NGLs as baseload feedstock under long-term purchase contracts with petrochemical producers compared to spot export sales to power producers with seasonal demand fluctuations.

The Report of the Working Party on the Accession of the Kingdom of Saudi Arabia to the WTO noted Saudi Arabia's commitment that domestic NGL prices would be based on "normal commercial considerations, based on the full recovery of costs and a reasonable profit" but without addressing what level of discount, if any, was appropriate in light of the cost savings and other benefits cited by Saudi Arabia. It is generally believed that WTO accession will eventually
necessitate reducing the thirty percent discount, though the amount and timing of such reduction are yet to be determined. 255

The comparative advantage petrochemical facilities have in Saudi Arabia as a result of the feedstock pricing is contributing to the current astronomical growth in this sector in Saudi Arabia.

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B. Kazakhstan: Petroleum Regime Changes

ALMAS ZHAIYLGAN* AND MARLA VALDEZ**

Kazakhstan’s Caspian Sea sector is opening to further investment following the Kashagan field discovery a few years ago. The probable reserves are reported to be greater than 50 billion barrels recoverable in the Caspian. The Development Plan for 2003-2015 for the Caspian, prepared by the government of Kazakhstan, estimates that more than $30 billion will be spent over the next twelve years. An estimated fifty-six platforms, two new ports, two new export pipelines, and other infrastructure are planned. At least twenty-three blocks containing mid-size to large prospects will be tendered at a rate of no fewer than three per year. The above estimates of investment do not include any of the onshore investment and development.

Naturally, the rules for investing and operating in Kazakhstan’s petroleum industry are changing. Since 2004, Kazakhstan has been experiencing a change in the legal regime applicable to its petroleum industry. The Tax Code has been amended several times and the latest amendments came into effect on January 1, 2006. On December 8, 2004 and October 14, 2005, substantial amendments to the Petroleum Law and Subsurface Law were made. Finally, a new Production Sharing Agreement Law (applicable to the Caspian and Aral Seas, hereinafter the “PSA Law”) came into effect on July 15, 2005. All these developments will have a substantial impact on the petroleum industry going forward. They reflect the government’s policy of increased participation of the National Oil Company, increased attention to the use and development

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of local content and “high technologies,” a change in the government’s take, and increased regulation and oversight.

Increased Participation of the National Oil Company

One of the important objectives of the new petroleum regime will be the increased participation of the National Oil Company, KazMunaiGas. This participation takes several forms. The first is the required minimum fifty percent equity participation in all new contracts, as provided in the newly adopted PSA Law and Decree No. 708 of the Government of the Republic of Kazakhstan, adopted in June 2002, which approved rules for representing state interests by the National Company in subsurface contracts with other investors (hereinafter “Decree No. 708”). The second is the regulatory oversight to be provided by an “authorized state agency,” as provided for in both the PSA Law and Decree No. 708 and discussed in more detail below. The third is the concept of a “Strategic Partner,” which was added to the Petroleum Law. The Strategic Partner is a foreign or Kazakhstan company selected by KazMunaiGas to be its partner in a contract that it obtained by direct negotiation. The company selected to be the Strategic Partner will be responsible for paying the signing bonus and exploration costs unless otherwise provided in the terms of a joint operating agreement.

State Preemptive Right

One of the most noteworthy provisions in the amendments to the Subsurface Law gives the state a priority right to purchase an interest in a subsurface use contract or in an entity having subsurface use rights that is offered for sale. The preemptive right clause was added into Article 71 of the Subsurface Law by the amendments of December 8, 2004:

[I]n order to preserve and strengthen the resource and energy base of the country’s economy, in new and previously executed contracts for subsurface use, the state shall have a priority right over any other party to the contract, or participants of a legal entity holding the subsurface right, or any other persons, to acquire the subsurface use right (or part thereof) and/or interest (shareholding) in a legal entity holding the subsurface use right being alienated, on conditions which are no worse than those offered by other buyers.

This type of legislatively imposed state preemption is rare in other jurisdictions and investors have expressed concerns that such a right may reduce the value of their investments. Despite such concerns, in October 2005, Kazakhstan adopted a number of amendments to its subsurface use legislation, which further extended the ability of the state to exercise its preemptive right. The amendments extend the preemptive right to the
alienation of shares or interests in a legal entity, which may directly or indirectly determine or exert influence on decisions made by the subsurface user, if the main activity of such legal entity is related to subsurface use in the Republic of Kazakhstan. This amendment was designed to extend the right to the sale of shares of holding companies, such as PetroKazakhstan Inc., a Canadian company listed in Toronto, New York, London, and Frankfurt, indirectly owning subsurface rights in Kazakhstan.

In order to give teeth to this provision, given the potential difficulty of enforcing such right as it relates to shares of non-Kazakhstan entities being sold outside of Kazakhstan, the Subsurface Law was also amended to give the Competent Authority the right to terminate a subsurface use contract where a transfer occurs without first offering the interest to the state pursuant to Article 71 of the Subsurface Law. The Competent Authority—currently the Ministry of Energy and Mineral Resources—is the appointed state authority that acts on behalf of Kazakhstan in the exercise of the rights associated with the conclusion and implementation of contracts.

In the Petroleum law, the amendments of October 14, 2005 require written permission of the Competent Authority for the assignment of rights and obligations under a subsurface use contract to another legal entity or individual, as well as for the alienation of a participating interest (shareholding) in a legal entity having subsurface use rights. As mentioned above, such a provision was previously in the Subsurface Law. However, the Petroleum Law now provides that the Competent Authority may refuse to issue consent for the contractual assignment of rights and obligations under provisions established by the legislature of the Republic of Kazakhstan. This requirement also now applies to transactions with affiliated entities; previously, such consent was not required where the parent company gave a guarantee.

Increased Focus on Local Content and Technology

Promotion of local content and the use and development of high technology is key to Kazakhstan’s policy for the further economic development of the country. For many years, the Petroleum and Subsurface Laws have required parties carrying out petroleum operations to use goods and equipment manufactured in Kazakhstan and to hire Kazakhstan enterprises for the performance of services, provided that they meet the requisite standards. The contractor is obligated to give preference to hiring Kazakhstan personnel to conduct training and to transfer technology. In addition, the October 2005 amendments to the Subsurface Law now require parties to agree on the salaries to be paid to Kazakhstan personnel when concluding a subsurface use contract.
In order to ensure that Kazakhstan suppliers of goods and services are given priority when considering competing bids, the amendments require that their bid price be discounted by twenty percent when comparing bids for purposes of determining the winner of a tender for the provision of goods, work, and services. The 2004 amendments to the Subsurface Law further cement the domestic requirements by providing that subsurface contracts may be suspended for violations of the obligations regarding Kazakhstan content. Finally, it should be noted that the Tax Code provides no recovery for costs incurred in violation of the domestic content requirements.

Regulation and Oversight

Currently, several entities have the right to exercise control over the activities of contractors. The activities of subsurface users are controlled by the Competent Authority, the authorized agency, and other relevant state bodies as required.

The PSA Law provides for an authorized state agency that will be a participant in the management of each PSA and will sit on the PSA’s management committee. This authorized agency may be the National Oil Company only if it has assigned its equity interest in the subject PSA. If it has not assigned its interest, a different entity will be designated as the authorized state agency. This provision effectively increases the participation of the state in PSAs both directly and through the National Oil Company. No authorized agency will be created for a PSA where the interest of the National Oil Company remains at fifty percent or more and the operator is a subsidiary of the National Oil Company. This provision was designed to ensure that the state controls a PSA through the National Oil Company and either the presence of an authorized agency or an operator controlled by the state.

The authorized agency will be appointed by the government and will have a number of regulatory functions related to PSAs. According to Decree No. 708, an “authorized body” is the National Oil Company authorized by the state to control, supervise, and regulate petroleum operations pursuant to PSAs, except for the execution of controlling and supervising functions of the state bodies. In addition, the activities of subsurface users are open for inspection by any state body—including tax, environmental, safety, etc.—that is authorized to inspect the activities of subsurface users.

Gas Flaring

Prior to August 1999, the Petroleum Law was silent as to flaring. Under environmental laws, flaring was allowed prior to 1999, within the
In 1999, the Petroleum Law was amended to generally prohibit flaring, except with a permit from the Geology Committee and the prior approval of the Agency on Environment. On December 8, 2004, the Petroleum Law was amended to allow the granting of such permits and approval only for testing of wells during exploration or for emergency situations. The prohibitions came into force immediately upon publication, giving companies that were already operating no time to adjust to the new requirements. Infrastructure for associated gas disposal cannot be built overnight; the only way to comply is to lower oil production rates. In addition, the law provided no exceptions for fields where the cost of alternatives to flaring, such as the use of associated gas, would make production uneconomic.

To address these problems, additional amendments were introduced to the Petroleum Law on October 14, 2005. These amendments provided that, for contractors performing oil operations in accordance with subsurface use contracts as of December 1, 2004, the requirement to utilize gas shall not be applied until July 1, 2006. The amendments extend the period for implementation for seventeen months, but the period required to build the necessary facilities to utilize gas ranges from three to five years. Moreover, these latest amendments do not address the period before these amendments have been made, when many companies were technically in violation. Thus, it is unclear whether the contractors will remain liable for flaring violations that occurred between December 1, 2004 and October 14, 2005. Finally, none of the amendments of 2004 and 2005 address the issue of fields where gas utilization is uneconomic.

PSA Law

Many of the provisions in the PSA Law are similar to those already provided in the Petroleum Law and Subsurface Law. However, the PSA Law states that it takes precedence over other applicable laws, including the Subsurface and Petroleum Laws, on the issues that it covers.

The PSA Law applies to the Caspian and Aral Sea areas only. The Law does not apply to onshore production sharing agreements. The PSA Law requires a minimum fifty percent participation of the National Oil Company in all PSAs.

The PSA Law limits the term of contracts to 25 years for production, 35 years for combined exploration and production, and 45 years for unique reserves (100 million tons of crude hydrocarbons or 100 billion cubic meters of gas). This provision is similar to amendments made to the Subsurface Law that increased the term for granting subsurface use rights for unique reserves to forty-five years. Twelve months prior to the expiration of a PSA, the parties can negotiate an extension if there is
production remaining. Any such extension will be subject to the laws in effect at the time it is negotiated.

The PSA Law also requires an additional agreement, which will be considered a part of the PSA, addressing the obligations to use high technologies and to develop and construct new main pipelines and other infrastructure. This additional agreement, while considered a part of the PSA, only becomes effective once a commercial discovery is made.

Tenders for each block will be established by a decision of the government of Kazakhstan and may open or closed. A commission created by the government carries out the tenders. Tender conditions (terms of a bid) must provide for the following: (i) Kazakhstan local content for performance of the petroleum operations, (ii) mandatory supply of a specified amount of hydrocarbons to domestic refineries, and (iii) proposals for development of high technologies, new processing production facilities, main and other pipelines, construction and joint use of infrastructure and other facilities. Not all Caspian Sea blocks are required to be tendered; the government may identify offshore blocks to be provided on PSA terms without holding tenders “in pursuance of international contractual and other obligations of the Republic [of Kazakhstan].”

One provision provides that there is automatic termination of the PSA if the investor’s “tax procedure” does not come into effect within one year. The meaning of this provision is unclear.

Conclusion

Kazakhstan is viewed as one of the few places where international oil companies can still replenish their reserves. The country clearly recognizes this demand and wants to ensure that it benefits fully from its enviable position of holding such vast untapped reserves. The recent amendments to the subsurface legislation and the new PSA Law reflect the state’s policy of protecting its interests and promoting the interests of its population.
C. Algeria: Recent Developments Since the Adoption of the New Hydrocarbons Law in July 2005

Cyril Vock*

In July 2005, Algeria promulgated Law No. 04-05 of April 28, 2005 (Hydrocarbons Law) that introduced a new legal regime for the activities of prospecting, exploration, production, and transportation of hydrocarbons in the country.256 A number of draft implementation decrees have been in preparation since before the finalization of the Hydrocarbons Law, but these decrees have not yet been finalized and officially published in Algeria. This article summarizes some of the provisions of the Hydrocarbons Law and the draft decrees and discusses some of the practical developments that have occurred since the Hydrocarbons Law came into force.

New Regulatory Agencies

The Hydrocarbons Law created two new administrative authorities: the Hydrocarbons Regulation Authority (“ARH”) and the National Agency for the Development of Hydrocarbons Resources (“ALNAFT”). Generally, the two new agencies are entrusted with functions and duties previously held by Sonatrach. Algeria, following the trend in the European Union, has been gradually reallocating regulatory functions to independent administrative bodies.

When the agencies were formally put in place, the Minister of Energy and Mines summarized the activities of ALNAFT as “the promotion of investments in the hydrocarbons sector, the allocation and control of

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exploration contracts and/or development, as well as the collection of oil royalties,” whereas ARH’s functions were described as “the economic regulation of natural monopolies (transportation by pipeline, storage of petroleum products) as well as monitoring compliance with regulations in areas such as health and safety, and the protection of the environment.”

Legal Status

The Hydrocarbons Law provides for a formal separation of these two agencies from the Ministry of Energy and Mining, and from Sonatrach. The agencies are legally independent and have their own judicial personality, budget, and resources. Applying notions of French law, it would seem that that these bodies are neither public administrative authorities (Etablissement Public Administratif), nor commercial or industrial ones (Etablissement Public Industriel et Commercial). Their judicial personality remains nonetheless that of a public law nature.

However, as a matter of law and of fact, it would seem that the Ministry of Energy and Mining retains a level of control over their organization.

a. Functioning

The Board of Directors

Under Article 12 of the Hydrocarbons Law, the agencies’ boards of directors, each consisting of five directors and one chairman, are appointed by presidential decree. Under the draft decrees, both boards would include one representative of the Ministry of Energy and Mining and one representative of the Ministry of Finance. In addition, ARH’s board would include a representative of the ministry in charge of the environment, and ALNAFT’s board would include one representative of the Bank of Algeria.

Currently, the division of ALNAFT in charge of awarding exploration blocks is led by M. Djilali Takherist, the former exploration director at Sonatrach. The draft decree provides that the term of office for ARH’s
directors will be three years, but does not specify the term of office for ALNAFT’s directors.

The boards of directors will meet more often in ordinary sessions for ALNAFT (four times a year) than for ARH (twice only), but extraordinary meetings may also be convened. The boards will be in charge of the organization and general running of the agencies and of the implementation of annual and multi-annual activity programs. Both boards would make decisions based on a majority vote.

The Chairmen

On November 14, 2005, the two administrative bodies were formally put in place with M. Sid Ali Bitata as chairman for ALNAFT and M. Nourredine Cherouati as chairman for ARH.261 Under the draft decree, the chairmen would be directly accountable to the minister in charge of hydrocarbons. The chairmen would be in charge of the general management and act on behalf of their agencies, submit annual and multi-annual activity programs, and have general executive functions. Again, the draft decrees are silent as to the term of office for ALNAFT’s chairman but provides for a six-year term for ARH’s chairman.

Exploration and Production Activities

a. Prequalification Criteria and Change in Control

According to the draft decree, a bidder candidate is required to submit in advance to the relevant authority (ALNAFT for exploration and production contracts and ARH for the other activities covered by the Hydrocarbons Law) all documents or information related to the “key characteristics of their qualification” and keep them up-to-date on any changes to those characteristics. The draft decree is helpful in that it lists the items that would constitute key characteristics. These items include: (i) contracts between bidders or with third parties related in particular to their management, costs or income sharing or winding up of their companies; (ii) articles of association; (iii) list and nationality of shareholders holding more than ten percent of the capital; (iv) experience and competence; and (v) any operation that may result in a change in a “determining power” to manage their companies.

Once a contractor has a contract in place that enables it to conduct petroleum activities under the Hydrocarbons Law, if measures or operations result in a change in the “key characteristics” that may lead to

a change in control in the management of the company, the contractor must, within fifteen days, inform the relevant authority. ALNAFT or ARH then has three months to notify the contractor if it considers that these changes are incompatible with its contract remaining in place, in which case the contract may be brought to an end in accordance with the Hydrocarbons Law.

b. Submission of Information

Entities willing to undertake exploration or production must first qualify by providing information to Algerian authorities and, in line with the transfer of competence from the Ministry to the new agencies, ALNAFT will be the recipient of such information.

c. Bidding Procedure

According to Article 32 of the Hydrocarbons Law, ALNAFT awards exploration and exploitation contracts after a competitive bid. Further regulations should specify the selection procedure of acreages that are to be offered. The draft decrees that have been under preparation for some time only provide limited details in this regard. Under Article 33 of the Hydrocarbons Law, ALNAFT will announce the single criterion upon which the award process will be based. ALNAFT will then organize a data room to present the acreage that will be open to competitive bidding. Potential applicants will have access to the data room where they will be able to assess the data (mostly technical) on the acreage.

A special commission, within ALNAFT, in charge of assessing the bids, will then launch the competitive bidding process 30 days after the closing of the data room. While the draft decree does envisage broad publicity, it does not seem to set forth any rules that the commission would be required to follow to make this competitive bid public. It nonetheless establishes fees, calculated per acreage, in return for access to the bid documents.

The bid documents must include the acreage identified, the type of model contract to be adopted, the single selection criterion chosen by ALNAFT, the type of guarantee to be provided by the applicant, the grounds for disqualification, the conditions for the submission of the bid (deadline, etc.), and the formalities that the applicant will need to comply with to be authorized to enter into a contract with ALNAFT and to conduct petroleum operations in Algeria. Lastly, a deposit to an Algerian bank is required to be made by each bidder to guarantee the serious nature of its offer. The draft decree does not seem to contain further details on the two-stage bidding procedure (technical and economic) indicated in Article 34 of the Hydrocarbons Law.
The relevant commission will assess a bid according to the single selected criterion. Bids will be disqualified if the offer is conditional, if it would result in an amendment or change to the model contract, or if it contains a minimum work program that would fall short of the one set out by regulations. The ALNAFT chairman, will make the award decision based on the recommendations made by the commission. The decision will be published in two national daily newspapers for three days.

**d. Relinquishment**

The draft decree relating to the delimitation of relinquishment, exploitation, and retention acreages specifies that relinquishment acreages must consist of adjoining areas. At the end of the exploration phase, ALNAFT may require the relinquishment area to include a discovery well that was not declared commercial or potentially commercial or that was not the object of a request for a retention period. This requirement would presumably include a discovery well whose development plan has not yet been approved, but the wording of the draft decree is not entirely clear.

**e. Production Acreage**

The same draft decree indicates that if a production area includes several fields, its delimitation must include the entire geographical area of the field and the limits of the deposits cannot be extended in each direction (north, south, east or west) by more than five kilometers. Such limits will be projected onto the surface to constitute the outer boundaries of the production area.

**f. Assignment**

In line with the Hydrocarbons Law, the draft decree confirms that ALNAFT would need to approve the transfer of interests by a contractor in exploration and exploitation contracts. However, a slight discrepancy is noted: under Article 31 of the Hydrocarbons Law, any transfer (even to an entity that belongs to the “contractor group”) requires the prior approval of ALNAFT, whereas the draft decree reviewed for this article seems to suggest that this requirement did not apply in the case of a transfer of an interest between members of the “contractor group.” Lastly, the draft decree does not add further details on the terms and conditions for the exercise of Sonatrach’s preemption right set out in Article 31.
D. Nigeria: Developments in Petroleum Law

STEPHEN ONGEJOSE

For a number of reasons, not the least of which is the desire to create an attractive investment environment for the more technically challenging deepwater exploration and production activity, Nigeria has different fiscal and legal regimes for petroleum exploration and production activity in the onshore and shallow offshore areas on the one hand, and the deep offshore and inland basins on the other. Onshore and shallow offshore activity is generally conducted through joint ventures with the Nigerian government-owned statutory corporation, the Nigerian National Petroleum Corporation ("NNPC"), while deep offshore and certain inland basin activity is generally conducted though production sharing contracts ("PSCs") between the international oil companies ("IOCs") and the NNPC as licensee or concession holder.

While the legal basis for joint ventures is the Petroleum Act enacted in 1969, and the subsidiary legislation and amendments thereto over the last several years, the production sharing contracts are regulated by a combination of the Petroleum Acts and the specialized Deep Offshore and Inland Basins (Production Sharing Contracts) Decree of 1999 ("Decree of 1999"), retroactively effective from 1993. One critical difference between these two regimes is the tax rate: 85 percent for onshore and shallow offshore activity based on the Petroleum Profits Tax Act and 50 percent for deep offshore based on the Decree of 1999. Under the Petroleum Acts, any person meeting certain criteria can apply for the issuance of an Oil Prospecting License ("OPL") or an Oil Mining Lease ("OML"), but for deep offshore activity, the NNPC is the license holder. In 1999 however, in order to encourage indigenous participation, the Nigerian government awarded licenses for a number of "indigenous blocks" to Nigerian companies. Consequently, at least in theory, those companies became similarly positioned as the NNPC to enter into PSCs with the IOCs. In reality though, what occurred was a situation in which the indigenous companies, in consideration of a corresponding royalty, farmed out a percentage of their interests in the concessions to the IOCs while at the same time entering into technical services agreements with them for the development of the concessions.

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Deepwater Blocks Allocations to Companies
(Back-in-Rights) Regulations 2003

As the above scenario was clearly not the intention of the government, and as a result of the litigations that followed a rash of license revocations by the government, in 2003, the government enacted the Deepwater Blocks Allocations to Companies (Back-in-Rights) Regulations 2003 ("Regulation"). This Regulation modifies all deepwater OPLs and OMLs issued prior to the commencement of the Regulation (July 5, 2003) and in which the Nigerian government, through the NNPC does not already have 100 percent interest; the Nigerian government reserves a right to participate in any OML(s) derived from any OPL. The Regulation fixes the government’s right to participate in such concessions at “five-sixths of the allottee’s interest in the oil prospecting license and oil mining lease,” on such terms as the government may determine from time to time, provided the terms governing the acquired interest are no less favorable to the government than the terms prevalent in current production sharing contracts. Where the “company” does not have a production sharing contract in place with respect to the concession and each “party” funds its interest share directly, the Nigerian government shall acquire five-sixths of the “Nigerian ownership interest” in the OML as a funding participant.

The first part of the Regulation is clear in its intent and application. The second, is much less so. “Company” may refer to the indigenous companies holding the OPL or OML; it may also refer to the NNPC. If it refers to the NNPC, then there is an obvious contradiction. That part of the Regulations would then only apply to a block in which (1) the NNPC does not currently hold 100 percent interest in the concession, (2) the NNPC does not currently have a PSC in place either with an IOC or an indigenous company, and (3) the NNPC and the other part interest holder have a joint funding arrangement.

The question would then be, to what does the “Nigerian ownership interest” refer? It surely does not refer to the NNPC interest. If it refers to the indigenous companies’ interest, then it would apply only to oil blocks in which the indigenous companies do not have a PSC, but instead, have a joint venture with another company. Therefore, the application of this provision can be avoided by those companies awarding PSCs and effectively making themselves analogous to the NNPC, defeating the apparent intention of the Regulation.

Oil Prospecting Licences (Conversion to Oil Mining Leases, etc.)
Regulations 2003

In December 2003, the Nigerian government enacted the Oil Prospecting Licences (Conversion to Oil Mining Leases, etc.)
Regulations 2003 (‘2003 Regulations’). The 2003 Regulations’ principal purpose is to amend Regulation 2(3) of the Petroleum (Drilling and Production) Regulation 1969 (‘1969 Regulations’), which provides for the grant of multiple OMLs from one OPL. The 1969 Regulations provide that “all oil mining leases derived from an oil prospecting license shall be in compact blocks or units; and, where more than one block or unit is so derived, each block or unit shall be the subject of a separate and distinct lease.” The 2003 Regulations limit the number of possible OML grants from an OPL to a maximum of two grants, and only upon satisfaction of the requirements for the grant of an OML as contained in the 1969 Regulations, as well as the additional requirements in the 2003 Regulations, namely:

(a) Satisfaction of the Minister that the “quantum of the level of productivity” and operational activity so far undertaken is sufficient to justify an additional OML,

(b) Demonstration of sufficient financial and technical ability to justify the grant of the second OML,

(c) Acceptance of the terms and conditions for the grant of the second OML, such terms and conditions including the signature bonus being:

(i) If the OPL was being developed under the terms of a PSC, then the second OML will be subject to a new PSC whose terms shall be no less favorable to the government than those applicable in the government’s model form PSC current at the time of the grant of the OML or the Regulations, whichever is later,

(ii) If the OPL was being developed under the terms of a sole risk arrangement, then the additional OML shall be developed under a joint venture arrangement that includes NNPC’s participation in accordance with the Deep Water Blocks Allocations to Companies (Back-in-Rights) Regulations 2003 and the applicable fiscal regime will be that relevant to the holder of the OML, the location of the OML and prevailing at the time of the conversion,

(iii) If the OPL was being developed under the terms of a joint venture arrangement, then the additional OML shall be developed under a joint venture arrangement that includes NNPC’s participation on such terms as may be determined by the Minister and the applicable fiscal regime will be that relevant to the holder of the OML, the location of the OML and prevailing at the time of the conversion,

(d) The payment of a signature bonus fixed by the Minister at his discretion taking into consideration,

(i) The current market value of the area of the OML,

(ii) The leaseholders current level of operational activity and expenditure prior to the application, and
(iii) The competitiveness of the signature bonus paid on the OPL.

Treaty Between the Federal Republic of Nigeria and the Democratic Republic of Sao Tome e Principe on the Joint Development of Petroleum and other Resources in Areas of the Exclusive Economic Zone of the Two States (Ratification and Enforcement) Act, 2005.

This piece of legislation is not an amendment to any current Nigerian Petroleum law but was enacted on February 25, 2005 in order to give local effect to the Treaty signed between Nigeria and Sao Tome e Principe on February 21, 2001. This ratification and local enactment of the Treaty by the two contracting states was necessary for the execution and effectiveness of production sharing contracts between the Joint Development Authority established under the Treaty and the IOCs in respect of the Joint Development Zone.

The key provisions of the law include, *inter alia*:

1. the establishment of a Joint Development Zone between the two countries,
2. the establishment of a Joint Ministerial Council,
3. the Establishment of a Joint Developmental Authority charged with the responsibility, amongst others, of entering into and managing exploration and production contracts with IOCs,
4. establishment of a legal and tax regime for exploration and production activity within the Zone,
5. establishment of a procedure for the exploitation of other resources within the Zone,
6. establishment of a procedure for the resolution of disputes between the Joint Development Authority and private interests, and between the states parties,
7. residual provisions dealing with management of current production contracts in the event of renunciation of the Treaty by either or both state parties.

This law is important to Nigeria (and Sao Tome e Principe) because it introduces a legal and tax regime for the exploitation of petroleum resources that is different from the current Nigerian regime in a territory, which for importation, exportation, and certain duty payment purposes is considered an extension of both Nigerian and Sao Tomean territory. Revenue from exploitation contracts signed pursuant to the Treaty is split sixty percent for Nigeria and forty percent for Sao Tome e Principe and represents Sao Tome e Principe’s first entry into the international oil and gas market.
Conclusion

The provisions discussed above represent only a few of the recent changes to Nigerian petroleum law. Significant changes to existing laws and regulations dealing with the handling of associated and non-associated gas have been made in the recent past, especially as the Nigerian government looks to achieve a gas flareout target of 2008. Additionally, a number of proposals for amendments to the 1969 Petroleum Acts and the Decree of 1999 are pending in the legislature and could be passed into law in the coming years, introducing significant changes to the legal and fiscal situation in Nigerian petroleum law.
E. Latin America: 2005 Developments in Hydrocarbons Law∗

MARÍA V. VARGAS∗

BOLIVIA


Law 3058 implements the National Referendum of July 18, 2004, where the people of Bolivia voted for (i) recovering for the state the ownership of all hydrocarbons at the well head, (ii) abrogating the previous hydrocarbons law – (Law 1689 of 1996), (iii) reincorporating the state oil company Yacimientos Petrolíferos Fiscales Bolivianos (“YPFB”), and (iv) exporting natural gas within a national policy that covers the national demand, promotes the industrialization of gas inside the country, and collects taxes and royalties from oil companies in an amount up to fifty percent of the value of oil and gas production. Consistent with such mandate, Law 3058 abrogated Law 1689 and established the new legal framework for the exploration, production, commercialization, transportation, refining, industrialization, distribution, and export of hydrocarbons. Its main aspects are summarized below.

Ownership of Hydrocarbons

Article 5 of Law 3058 expressly confers to the state the ownership of all hydrocarbons produced at the wellhead. Thus, all hydrocarbon reservoirs belong to the state and no contract may grant ownership rights over hydrocarbon reservoirs or hydrocarbons at the wellhead up to the fiscalization point.262

Mandatory Conversion of Risk Sharing Contracts (“RSC”)

Law 3085 provides that all existing RSCs, licenses, and concessions that were granted under Law 1689 must be converted into any of the new

∗ The statutes are seperated by country.
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262. “Wellhead” is defined as the exit point of the total current of fluids produced by a well before entering into any conditioning facilities for transportation (defined as a “Conditioning System”). “Fiscalization Point” is defined as the point where hydrocarbons are measured after going through a Conditioning System.
Types of Contracts.

Law 3058 recognizes three types of petroleum contracts: (i) Production Sharing Contracts (“PSCs”), (ii) Operating Contracts (“OCs”), and (iii) Association Contracts (“ACs”). A common principle under all three is the obligation of the contractor to deliver to the state the total amount of hydrocarbons produced according to the particular terms set forth in each contract. These contracts must be entered into with YPFB, an entity that had been privatized and which is now reincorporated and re-established by Law 3085. YPFB represents the state and exercises on its behalf all ownership rights over the hydrocarbons. In general, petroleum contracts may not exceed a total of forty years. All production thereunder must be delivered to YPFB and depending on the type of contract, the contractor will be entitled to either compensation (under an OC) or to a participation in the production (under a PSC or an AC).

PSCs. Under a PSC, the contractor with its own means and for its exclusive cost and risk carries out exploration and exploitation activities in the name and on behalf of YPFB for a share of the production at the Fiscalization Point, after deductions for royalties and taxes. Contractor recovers its development, production and abandonment investments, as well as its payments for royalties and participations, pursuant an amortization program payable in production from the field. YPFB shares the production once such amortization has been determined. YPFB and the contractor each pay the royalties, participations, and taxes in proportion to their share of production. The control and supervision of petroleum operations under each PSC corresponds to a board of directors formed by the relevant contracting parties.

OCs. In an OC, the contractor performs exploration and exploitation operations with its own means and for its exclusive cost and risk in the name and on behalf of YPFB, for a percentage of the production, in cash or in kind, which covers its total costs and profits. YPFB does not make any investment, does not assume any risk or liability, and the contractor must contribute the total capital, facilities, equipment, materials, personnel, and technology required. Operations are supervised by a Follow-Up and Control Unit formed by representatives of YPFB and the contractor. YPFB is responsible for the payment of royalties, taxes, and participations on the production.

AC’s. YPFB has the option to enter into an association with the holder of an OC after a commercial discovery. To exercise this option, YPFB must reimburse, with cash or production, a percentage of the direct
exploration costs of the producing wells as assessed by an external audit. Each AC sets forth the particular participation of production for each party. YPFB assumes all the risks and benefits of the Association in proportion to its participation. The administration and management of the AC corresponds to an Operator designated by the participants. The Operator distributes the production among the participants after payment of royalties and other state participations. The control and supervision of the operations corresponds to a Follow-up and Control an Executive Unit formed for each AC.

**Royalties.** The following royalties must be paid in U.S. dollars or equivalent local currency, or in kind, at the election of the beneficiary: (i) a *Departmental Royalty* of 11 percent of the production measured at the Fiscalization Point, payable to the Department where production originates; (ii) a *National Compensatory Royalty* of 1 percent of the national production, payable 2/3 to the Department of Bení and 1/3 to the Department of Pando, and (iii) a participation of 6 percent of the national production, payable to the General Treasury of the Nation.

**Direct Tax on Hydrocarbons.** Law 3058 creates a Direct Tax on Hydrocarbons (*Impuesto Directo a los Hidrocarburos*—“IDH”) of thirty-two percent of the total production of hydrocarbons measured at the Fiscalization Points. The aggregate amount of the royalties (eighteen percent) plus the IDH must result in a total payment for the Bolivian state of not less than fifty percent of the value of the hydrocarbon production.

**Surface Fees.** Contract areas are subject a surface fee per hectare, which amount varies depending on the zone. The surface fee must be paid per year in advance by YPFB and the contractor must reimburse to YPFB the amounts paid within thirty days from receipt of the certification of payment. The particular rules for delimitation of areas for petroleum contracts were issued pursuant to Supreme Decree No. 28366 of September 21, 2005.

**Gas Exports.** By mandate of Law 3058 YPFB must be the Aggregator or Seller for all exports of natural gas from Bolivian territory. YPFB must allocate the required export volumes among the producers according to criteria set forth in the law. YPFB will also establish the destination and sources of the production allocating the quotas of supply of natural gas among the producers according to back-to-back contracts.

**Consultation to Indigenous Communities.** Finally, Law 3058 requires that the indigenous communities be consulted prior to any hydrocarbon activity. This consultation is mandatory and its results must be respected.
BRAZIL


The ANP issued three regulations regarding open access to gas transportation infrastructure, assignment of transportation capacity, and tariffs. Regulation No. 27 develops the principle of “open access” set forth in Brazil’s Oil Law which grants shippers right of access to existing transportation facilities, or new ones to be built, upon payment of adequate compensation to its owner. Regulation No. 27 provides that Transporters must allow non-discriminatory access and connection of their facilities to other transportation facilities but excludes the application of open access rules to new transportation facilities, defined as those with less than six years of operation. Transporters and shippers must execute standard transportation agreements, which must be previously submitted to ANP. Available transportation capacity must be offered and allocated according to open season rules previously approved by the ANP. Regulation No. 28 regulates the assignment of contracted transportation capacity and provides that the holder of a firm transportation contract may assign its contracted capacity to a third party, in whole or in part, but such assignment does not release assignor from its obligations vis-à-vis the transporter unless with the express agreement of the latter. All transactions of assignment of capacity must be previously disclosed to the transporter and to the ANP and must be publicly disclosed by the transporter.

Regulation No. 29 sets forth the criteria for gas transportation tariffs. According to Regulation No. 29 tariffs may not discriminate or grant preferential treatment and must reflect the efficient costs and other variables such as distance and volume. Tariffs must be disclosed to the ANP and the public.

PARAGUAY

New Regulation of the Hydrocarbons Law - Decree 6597, November 15, 2005 (“Decree 6597”).

Decree 6597 regulates Law 779 of November 20, 1995, which sets forth the legal framework for the prospecting, exploration, and exploitation of petroleum and other hydrocarbons in Paraguay. Under Law 779,
hydrocarbons in their natural state belong to the state, which may grant prospecting permits and concessions for exploration and production.

Prospecting permits grant the holder the right to conduct surface prospecting and surveying activities in a designated area for a one-year term, extendible for one more year, and the priority to select one or more lots within such area for exploration activities. Exploration concessions have a four-year term, extendible for two more years. Under the exploration concession, the concessionaire must complete certain minimum exploration work. The concessionaire has the right to select one or more production lots to conduct production operations, converting its concession into a production concession with respect to such lots. Production concessions have a twenty-year term, extendible for up to ten more years, and the hydrocarbons produced belong to the concessionaire, subject to payment of royalties on gross production, surface fees, and taxes.

Supervision and control of hydrocarbon operations are duties of the Ministry of Public Works and Communications (Ministerio de Obras Públicas y Comunicaciones), particularly, to the Office of the Vice-minister of Mines and Energy of the MOPC (Gabinete del Viceministro de Minas y Energía del Ministerio de Obras Públicas y Comunicaciones—"GVME").

The main subjects regulated by Decree 6597 are the following: (i) procedures for review and approval of applications for Prospecting Permits and Concessions; (ii) reports and technical data to be submitted by permit and concession holders to the GVME; (iii) characteristics of the performance guaranties required from permit holders; (iv) description of the minimum work required from permit or concession holders during the prospecting period, fines for failure to complete the work program and extensions thereof; (v) procedures for entering into a concession; (vi) work program and reporting requirements during the exploration phase; (vii) procedures after a discovery, (viii) procedures, reports, and data to commence the exploitation phase; (ix) regulations of production operations; (x) training and transfer of technology obligations; and (xi) procedures for extensions to the concession term.

**URUGUAY**

Law 17.910, October 12, 2005 - (“Law 17.910”).

June 18, 2001 and thus far has forty-two signatory parties, including the U.S. which ratified it on April 15, 2003. The Convention aims for (i) obtaining and maintaining a high level of safety in the handling of spent fuel and radioactive waste by improving the national measures and international cooperation, including technical cooperation; (ii) ensuring that all stages of handling of spent fuel and radioactive waste have effective measures against radioactive risks; and (iii) preventing accidents with radioactive implications and mitigating their consequences.

ARGENTINA

Hydrocarbons Law of the Province of San Juan - Law 7620, September 8, 2005 (“Law 7620”).

The legislature of the Province of San Juan (“Province”) issued its own Hydrocarbons Law, Law 7620, exercising the authority transferred to the Argentinean provinces over the hydrocarbons located within their territories by Law 24.145 of September 24, 1992, and according to Decree 546 of 2003, which acknowledged the right of the provinces to grant exploration permits and concessions for exploitation, storage, and transportation of hydrocarbons in their jurisdictions. The Province also adopted its Model Contract for Exploration and Production and opened a bid round to award various blocks.

Under Law 7620, the authority to grant exploration permits and concessions for exploitation belongs to the Province’s Executive Power, and the monitoring of hydrocarbon activities belongs to the Direction of Energy Resources. The Province’s energy company, Energía Provincial Sociedad del Estado (“EPSE”), may carry out activities of exploration, exploitation, industrialization and commercialization of hydrocarbons, either on its own or associated with third parties. In the event of a commercial discovery, EPSE has the right to participate in the exploitation phase with a percentage that varies depending on the discoveries and previously set forth in the relevant bidding terms.

Law 7620 also establishes the following incentives to promote investment in hydrocarbons effective for a five year term: (i) 50 percent reduction of surface fees and royalties during the exploration phase, (ii)

263. Law 24.145 transferred to the provinces the ownership over the hydrocarbons located within their territories, including those located in the sea adjacent to their shores up to a distance of 12 marine miles, and reserved for the National State the reservoirs located in the territory of the Federal Capital or within its jurisdiction on the Argentine bed of the La Plata River, and those located from the exterior border of the territorial sea in the continental platform or up to a distance of 200 marine miles measured from the base lines (Law 24.145, Art. 1).

264. According to information from the Argentinean law firm Maciel, Norman & Asociados, Repsol YPF and Oil M&S were the only companies that submitted bids, both for the Jachal block, and the winner is expected to be announced by March 20, 2006.
50 percent reduction of surface fees and royalties during exploitation, and 
(iii) reductions up to 50 percent of the stamp tax applicable to acts, 
contracts, and operations related to hydrocarbons. The specific 
reductions will be set forth in the relevant bidding terms.

The Model Contract is a tax-royalty type, with an exploration phase 
during which the contractor must carry out a minimum work program, 
and a development and production phase of twenty-five years, extendible 
for up to five more years. EPSE has the option to participate in 
association with the contractor upon a commercial discovery, with a 
percentage equal to five percent plus the additional participation 
percentage offered by the contractor in its bid. If EPSE exercises this 
option, EPSE must reimburse the contractor’s direct expenses related to 
the drilling and completion of the producing wells and reserve evaluation 
expenses. The contractor must pay the Province royalties of twelve 
percent on the production during the exploitation phase. Royalties are 
determined based on the price actually obtained from the 
commercialization of the production, but the Province may request 
payment in kind. If EPSE opts to participate in the exploitation, the 
royalties are reduced in proportion to EPSE’s participation percentage.