Rocky Mountain Mineral Law Foundation

Mineral Law Newsletter

Published by the Rocky Mountain Mineral Law Foundation www.rmmlf.org

Volume XXXII, Number 2, 2015

Federal — Mining

Michael R. McCarthy
— Reporter —

BLM's Use of the Six-Year Average Commodity Price Was Reasonable for Determining Mining Claim Validity

In *Freeman v. U.S. Department of the Interior*, No. 1:12-cv-01094, 2015 WL 1213657 (D.D.C. Mar. 17, 2015), the plaintiff sued the U.S. Department of Interior (DOI) challenging the Interior Board of Land Appeals' (IBLA) affirmance of the Bureau of Land Management's (BLM) mine claim validity determination that the plaintiff had not established the discovery of a valuable mineral deposit. *See United States v. Freeman*, 179 IBLA 341, GFS(MIN) 16(2010). The dispute stemmed from the plaintiff's ownership of 161 placer and association placer claims for nickel in the Siskiyou National Forest in southern Oregon. *Freeman*, 2015 WL 1213657, at *3. The plaintiff applied for a mineral patent on 151 of the claims in September 1992, before Congress imposed the patent moratorium effective October 1, 1994, but the moratorium prevented the BLM's review and processing of the plaintiff's patent application. *Id.* The plaintiff then filed a plan of operations with the U.S. Forest Service (Forest Service) in 2000,

continued on page 2

Federal — Oil & Gas

Constance L. Rogers
— Reporter —

The BLM's Final Hydraulic Fracturing Rules

On March 20, 2015, the Bureau of Land Management (BLM) issued its final rule for hydraulic fracturing on federal and tribal lands, and on March 26, 2015, the final rule and the BLM's responses to public comments were published in the *Federal Register*. *See* Hydraulic Fracturing on Federal and Indian Lands, 80 Fed. Reg. 16,128 (Mar. 26, 2015) (to be codified at 43 C.F.R. pt. 3160) (effective June 24, 2015).

The stated intent of the rule is to ensure the integrity of hydraulically fractured wells, protect water quality, and provide the public with information on fracturing fluid constituents. *Id.* at 16,128. The BLM received more than 1.5 million public comments in the rulemaking process. *Id.*

The Western Energy Alliance and the Independent Petroleum Association of America have challenged the rule in the U.S. District Court for the District of Wyoming, arguing that the rule is duplicative and will create an unnecessary regulatory burden. *See* Petition for Review of Final Agency Action, *Indep. Petroleum*

continued on page 3

Environmental Issues

Randy Dann
— Reporter —

Ninth Circuit Addresses Effect of Private Party Settlements in CERCLA Contribution Actions

On April 2, 2015, the U.S. Court of Appeals for the Ninth Circuit held, among other things, that (1) in allocating liability to a nonsettling defendant in a Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 U.S.C. §§ 9601–9675, contribution action, a district court has discretion to determine the most equitable method of accounting for settlements between private parties; and (2) a party can seek contribution under 42 U.S.C. § 9613(f)(1) only for settlement costs that were necessary response costs consistent with the national contingency plan (NCP). *See AmeriPride Servs. Inc. v. Tex. E. Overseas Inc.*, 782 F.3d 474 (9th Cir. 2015).

The case arose out of contamination of the soil and groundwater in an industrial area in Sacramento, California. Valley Industrial Services, Inc. (VIS) operated an industrial dry cleaning and laundry business at the site and released perchloroethylene (PCE) into the environment during its operations. VIS eventually merged into Texas Eastern Overseas, Inc. (TEO), which assumed VIS's liabilities. VIS was a wholly-owned subsidiary of Petrolane, Inc. during part of the time VIS operated the site. In 1983, Petrolane sold the site, ultimately to AmeriPride Services Inc. (AmeriPride). During AmeriPride's ownership of the site, there were additional releases of PCE. "The contamination at the . . . site migrated onto a neighboring property owned by Huhtamaki Foodservices, Inc. (Huhtamaki), and contaminated groundwater wells owned by California-American Water Company (Cal-Am).

continued on page 6

FEDERAL — MINING

continued from page 1

which the Forest Service eventually denied, prompting the plaintiff to file a takings lawsuit with the U.S. Court of Federal Claims. *Id.* Because the takings lawsuit "turns on whether [the plaintiff] possesses a compensable property right against the United States," the court of claims stayed the case and remanded to the DOI for a determination of the validity of the plaintiff's placer claims. *Id.* The BLM commenced its validity determination, and the administrative law judge (ALJ) ruled "that the plaintiff had 'failed to establish . . . a discovery of a valuable mineral deposit.'" *Id.* at *1. The IBLA affirmed the ALJ's decision. *Id.*

The plaintiff then sued the DOI, BLM, and IBLA under the Administrative Procedure Act alleging that the validity determination of the plaintiff's placer claims was arbitrary and capricious. *See id.* at *1 & n.2. Specifically, the plaintiff challenged the determination that the plaintiff had not made a discovery of a valid mineral deposit. *Id.* at *4.

To satisfy the validity requirement, "the discovered deposits must be of such a character that a person of ordinary prudence would be justified in the further expenditure of his labor and means, with a reasonable prospect of success, in developing a valuable mine." *Id.* at *6 (quoting *United States v. Coleman*, 390 U.S. 599, 602 (1968)). Procedurally, in claim validity contest proceedings the BLM has the initial burden before the ALJ of presenting a prima facie case that a claim is invalid, after which the burden shifts to the claimant to establish by a preponderance of the evidence that the claim is valid. *Id.* at *3. Using its Mineral Commodity Price Policy (MCP), the BLM applied a six-year average for the price of nickel when determining the value of the mineral deposit at two different points in time, October 1994 (the date of the patent moratorium) and October 2000 (the date of the Forest Service's denial of the plaintiff's plan of operations). *Id.* at *7. The six-year average consisted of 36 months of average data on each side of the two points in time being analyzed, with futures prices used for the forward 36 months. *Id.* "In other words, the MCP looks both backwards and forwards to estimate a reasonable nickel price." *Id.*

The issue was critical because the MCP price for October 1994 was $3 per pound, and for October 2000, it was $2.93 per pound. At the time of the contest proceedings before the ALJ, the nickel price was $21 per pound. *Id.* After taking testimony and other evidence, the ALJ held that the plaintiff had not submitted evidence justifying the use of a price higher than the MCP. *Id.* at *8. The IBLA affirmed, finding that the evidence did not support a price over $4 per pound. *Id.* The court affirmed the IBLA, holding that "the application of the MCP in this case does not conflict with the prudent-person standard." *Id.* "Thus, the IBLA did not substitute the MCP in place of the prudent-person standard, but instead determined that the expected price of nickel resulting from the MCP was consistent with the price a prudent person would use in evaluating whether to proceed with the development of a claim." *Id.*

The *Mineral Law Newsletter* is compiled by Professors John S. Lowe and Mark S. Squillace, and edited jointly with the Rocky Mountain Mineral Law Foundation. The Foundation distributes the *Newsletter* electronically on a complimentary basis to Foundation members and on a paid circulation basis, four issues per year (print version on request); 2015 price—$96.00 per year.

FEDERAL — OIL & GAS

continued from page 1

Ass'n of Am. v. Jewell, No. 2:15-cv-00041 (D. Wyo. Mar. 20, 2015), 2015 WL 1293028. The State of Wyoming has also challenged the rule, arguing that it exceeds the BLM's jurisdiction and conflicts with the Safe Drinking Water Act of 1974, 42 U.S.C. §§ 300f to 300j-25, which gives jurisdiction over underground injection wells to the U.S. Environmental Protection Agency (EPA). *See* Petition for Review of Final Agency Action, *Wyoming v. U.S. Dep't of the Interior*, No. 2:15-cv-00043 (D. Wyo. Mar. 26, 2015), 2015 WL 1360202. The State of North Dakota and the State of Colorado were granted intervention status in Wyoming's lawsuit on April 22, 2015.

While industry and the states have criticized the rule as being unnecessary and duplicative, environmental groups have criticized the rule for not going far enough. The rule is likely to continue to draw criticism from all sides as it is implemented.

The significant requirements imposed by the rule include submitting additional well information in an application for permit to drill (APD) or sundry notice, prescribing casing and cementing standards, monitoring of annulus pressure during hydraulic fracturing operations, managing recovery fluids in above-ground storage tanks, and disclosing drilling fluids in FracFocus.

New Information Requirements for APDs

In addition to what the ADP process already requires, under the new rule operators must submit a variety of information, including the wellbore geology, depths of usable water, estimated volume of fluid, estimated direction and length of fractures, and location of other wells and fracture zones in the surrounding area. The rule also requires an estimate of the vertical distance between the fracture zone and the nearest usable water zone. *See* 43 C.F.R. § 3162.3-3(d) (effective June 24, 2015).

Casing and Cementing Standards

Casing and cementing programs must also satisfy certain performance standards, including cement return and pressure testing for surface casing, cement evaluation logs for intermediate and production casing, remediation plans, and cement evaluation logs for surface casing that does not meet specified performance standards. The casing and cement program must provide for cementing operation monitoring, mechanical integrity testing, and certification prior to hydraulic fracturing. If the cementing is found to be inadequate, the operator must notify the BLM within 24 hours and submit a remedial action plan for approval. After remediation is complete, the operator must verify that the remediation was successful by submitting a cement evaluation log or other approved method to the BLM at least 72 hours before hydraulic fracturing commences. *Id.* § 3162.3-3(e).

Monitoring Annulus Pressure During Hydraulic Fracturing

The rule requires operators to continuously monitor and record the annulus pressure at the bradenhead during hydraulic fracturing. If pressures increase by more than 500 pounds per square inch, the operator must stop fracturing operations and determine the reasons for the increase. The operator must then perform any required remedial action and a mechanical integrity test prior to recommencing operations. *Id.* § 3162.3-3(g).

Managing Recovery Fluids in Above-Ground Storage Tanks

The rule also requires operators to store all flowback and produced water in rigid enclosed, covered, or netted and screened above-ground tanks. Lined pits will be permitted only in limited circumstances where the use of a tank is infeasible for environmental, public health, or safety reasons, and a number of other conditions are met. The above-ground tanks generally may be vented, unless existing state or federal regulations otherwise require vapor recovery or closed loop systems. The tanks must not exceed a 500-barrel capacity, unless otherwise approved by the BLM in advance. *Id.* § 3162.3-3(h).

Disclosing Chemicals Used in Hydraulic Fracturing Through FracFocus

The rule requires operators to disclose the chemicals used during the hydraulic fracturing process within 30 days after the process ends. Chemical disclosures are permitted through the FracFocus website, which currently has information on more than 94,000 wells. A number of states already require operators to use FracFocus for chemical disclosure purposes. *Id.* § 3162.3-3(i). Operators and other owners of confidential information may seek trade secret protection for certain chemicals by submitting an affidavit to the BLM. *Id.* § 3162.3-3(j).

Variance Process

The rule permits operators, states, or tribes to seek variances, which may be granted, in the BLM's sole discretion, "if the BLM determines that the proposed alternative meets or exceeds the objectives of the regulation for which the variance is being requested." *Id.* § 3162.3-3(k)(3). The authority to approve a variance lies with the authorized officer for an individual variance and the BLM State Director for state and tribal variances. *Id.*

Reporter's Note: David Neslin and Josh Neely of Davis Graham & Stubbs LLP assisted in preparing this summary of the BLM's hydraulic fracturing rule.

BLM Oil and Gas Leasing Rules—Advance Notice of Proposed Rulemaking

On April 21, 2015, the BLM published an advance notice of proposed rulemaking (ANPR), stating its intent to initiate a dialogue about potential changes to the onshore oil and gas regulations governing royalties, rentals, assessments, and bonding. *See* Oil and Gas Leasing; Royalty on Production, Rental Pay-

EDITOR'S NOTE ON UNPUBLISHED OPINIONS: This *Newsletter* sometimes contains reports on unpublished court opinions that we think may be of interest to our readers. Readers are cautioned that many jurisdictions prohibit the citation of unpublished opinions. Readers are advised to consult the rules of all pertinent jurisdictions regarding this matter.

ments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments, 80 Fed. Reg. 22,148 (Apr. 21, 2015) (comments due by June 5, 2015).

The ANPR contemplates several significant changes, including adjusting the fixed 12.5% royalty rate on competitively bid federal onshore leases, increasing annual rental payments, setting minimum acceptable bids for competitive leases, and requiring minimum bond amounts for reclamation and restoration following either well abandonment or cessation of operations. BLM also is exploring whether it should eliminate the current cap on civil penalties for regulatory violations.

Royalty Rates

BLM's existing regulations prescribe a fixed 12.5% royalty for all oil and gas leases. 43 C.F.R. § 3103.3-1(a)(1). The ANPR considers amending the regulations to give the Secretary of the Interior "the flexibility to adjust royalty rates in response to changes in the oil and gas market." 80 Fed. Reg. at 22,148. The ANPR states that this new approach would further the BLM goal of "ensur[ing] that the American people receive a fair return on the oil and gas resources extracted from BLM-managed lands." *Id.* Any rate adjustment would likely apply only to new competitively issued leases issued after a final rule has been promulgated. *Id.*

In the ANPR, the BLM seeks comments on, among other things, whether: (1) the existing royalty rates provide the public with a fair return; (2) the BLM should employ a sliding-scale rate, a fixed rate, or some other rate structure; (3) the BLM should impose different rates based on region, state, formation, resource type, lease sale, or other category—or have a national rate; and (4) the Secretary of the Interior should have authority to amend the royalty rate on a lease-by-lease basis. *Id.* at 22,154–55. Additionally, if the Secretary is allowed to amend the royalty rate on a lease-by-lease basis, the ANPR seeks comments on whether the rate should be set on a lease-sale basis or whether there should be a national rate schedule that will be periodically updated on either a fixed schedule (such as annually) or when circumstance warrant (such as a price trigger). *Id.* at 22,155.

Annual Rental Payments

The ANPR also seeks comments on increasing the minimum annual rental payments, which have not been changed since 1987. The ANPR seeks comments regarding taking inflation and other market factors into account in setting rental rates, and possibly escalating the rental payments over time. *Id.*

Minimum Acceptable Bid

In the ANPR, the BLM states that "most parcels sell for well in excess of the current minimum acceptable bid." *Id.* at 22,153. The ANPR discloses that section 17 of the Mineral Leasing Act of 1920 (MLA), 30 U.S.C. § 226, authorizes the Secretary to increase the minimum acceptable bid in order to "enhance financial returns to the United States." 80 Fed. Reg. at 22,153.

Bonding

The MLA requires financial assurances prior to commencing lease operations "to ensure the complete and timely reclamation of the lease tract, and the restoration of any lands or surface waters adversely affected by lease operations . . . ." 30 U.S.C. § 226(g). The ANPR notes that the bond amounts have not been increased since 1960. 80 Fed. Reg. at 22,154. The BLM is considering amending the current bonding requirements because the requirements "do not reflect inflation and likely do not cover the costs associated with the reclamation and restoration of any individual oil and gas operation." *Id.*

Civil Penalties

The ANPR indicates that the BLM is also considering changes to civil penalty assessments for various regulatory violations, including entirely eliminating civil penalty caps or increasing them. *Id.*

RENTALS DUE ON OFFSHORE LEASES SUBJECT TO LEASE CANCELLATION

In *Energy Resources Technology GOM, Inc.*, 185 IBLA 180, GFS(OCS) 263(2015), Energy Resources Technology GOM, Inc. (Energy Resources) appealed an order to pay from the Director of the Office of Natural Resources Revenue (ONRR) unpaid rentals of $918,720 on 11 Outer Continental Shelf (OCS) leases. By regulation, the leases had a primary term of eight years, and the regulations "stipulated that, '[f]or leases issued with an initial term of 8 years, you must begin an exploratory well within the first 5 years of the term to avoid lease cancellation.'" 185 IBLA at 181 (alteration in original) (quoting 30 C.F.R. § 256.37(a)(3) (2005) (currently at 30 C.F.R. § 556.37(a)(2))). After the fifth lease year, ONRR's predecessor delayed issuing courtesy notices for rentals due for several of the rental years. *Id.* After issuing invoices for some of those years, ONRR rescinded them to consider if requiring rentals was the correct action. *Id.*

In the interim, Energy Resources relinquished the leases. Energy Resources also responded to one of the demands for payment, "arguing that each lease automatically terminated by its own terms on the sixth anniversary when no exploratory wells had been completed and no rent had been tendered." *Id.* at 182. The U.S. Department of the Interior disagreed, deciding that "an 8-year lease does not terminate automatically by operation of law if it is not drilled within the first 5 years, but remains in its primary term, accruing rental obligations, until cancelled by the Department or relinquished by the lessee." *Id.* Finding differences between the Mineral Leasing Act of 1920 (which provides for automatic lease termination of onshore leases for failure to pay rent, see 30 U.S.C. § 188) and the Outer Continental Shelf Leasing Act (OCSLA) (which does not provide for automatic lease termination of offshore leases for failure to pay rent), the IBLA found that "the Department must affirmatively act to cancel a lease for failure to comply with lease provisions, including the obligation to pay rent." *Id.* at 184 (citing 43 U.S.C. § 1334(c); 30 C.F.R. § 556.77). The IBLA found that the language in OCSLA regarding lease cancellation required affirmative action by the Department to cancel the leases. *Id.*

The IBLA also found persuasive the following language from leasing guidelines issued in 2001:

> If you decide not to drill an 8-year lease within the first 5 years, you have forfeited the right to drill in the remaining three years of the lease. However, the lease continues in primary term and you are responsible for payment of the 6th, 7th, and 8th year rental fees. To avoid these additional rental fees, the lease must be

relinquished prior to the expiration of the 5th year, or future lease anniversary dates.

Id. at 183 (emphasis omitted) (quoting Minerals Mgmt. Serv., U.S. Dep't of the Interior, "Outer Continental Shelf—Oil and Gas Leasing Procedures Guidelines," at 50 (OCS Report MMS 2001-076 Oct. 2001)).

DOT Issues Final Oil Train Rules, Enhancing Technical and Operational Standards

On May 1, 2015, the U.S. Department of Transportation (DOT) announced a final rule regulating transportation of flammable liquids by rail. *See* Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains, 80 Fed. Reg. 26,644 (May 8, 2015) (to be codified at 49 C.F.R. pts. 171–174, 179) (effective July 7, 2015). The final rule, developed by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and Federal Railroad Administration (FRA), adopts requirements intended to reduce the impacts and probability of accidents from train transportation of flammable liquids. *Id.*

Given the constraints on current pipeline capacity, and the length of time now needed to secure authorization for new pipelines, railroads are increasingly used to transport oil and gas produced from new areas, especially Canadian oil fields and the Bakken formation. A series of well-publicized derailments that resulted in casualties and significant fire damage has heightened public scrutiny of transporting petroleum products via rail. In response, PHSMA and FRA developed the new rule.

The "oil train" rule applies to "high-hazard flammable trains" (HHFT), which are defined as "a single train transporting 20 or more loaded tank cars of a Class 3 flammable liquid in a continuous block or a single train carrying 35 or more loaded tank cars of a Class 3 flammable liquid throughout the train." 49 C.F.R. § 171.8 (effective July 7, 2015). Some portions of the rule apply to "high-hazard flammable unit trains" (HHFUT), defined as "a single train transporting 70 or more loaded tank cars containing Class 3 flammable liquid." *Id.*

The rule establishes: (1) an enhanced tank car standard and a retrofitting schedule for older tank cars carrying crude oil and ethanol; (2) a new braking standard; (3) new operational protocols, such as routing requirements, speed restrictions, and information for local government agencies; and (4) new sampling and testing requirements to better classify energy products placed into transport. *See* 80 Fed. Reg. at 26,746–50.

Braking Systems

The new braking standard requires HHFTs traveling at greater than 30 mph to have in place a functioning two-way end-of-train device or a distributive power braking system. 49 C.F.R. § 174.310(a)(3)(i). By January 1, 2021, any HHFUT traveling at greater than 30 mph is required to have an electronically controlled pneumatic (ECP) braking system. *Id.* § 174.310(a)(3)(ii); 9 C.F.R. § 179.102-10.

New Tank Car Standards

New tank cars designed for use in an HHFT, and constructed after October 1, 2015, are required to meet enhanced DOT Specification 117 design or performance criteria. 49 C.F.R. § 174.310(a)(4). Existing tank cars used in an HHFT must be retrofitted in accordance with the DOT-prescribed retrofit design or performance standard, which must be completed based on a prescribed retrofit schedule. *Id.* § 174.310(a)(5).

Reduced Operating Speeds

The new rule establishes a maximum operating speed limit of 50 mph for all HHFTs in all areas. *Id.* § 174.310(a)(2). In addition, any HHFTs that contain any tank cars not meeting the enhanced tank car standards have a 40-mph speed restriction in high-threat urban areas, as defined in the Transportation Security Administration's regulations. *Id.* (citing 49 C.F.R. § 1580.3).

Sampling and Testing for Classification of Unrefined Petroleum-Based Products

The new rule also requires a sampling and testing program for all unrefined petroleum-based products, such as crude oil. Railroads must certify that such programs are in place, document the testing and sampling program outcomes, and make information available to DOT personnel. *Id.* § 173.41.

Rail Routing—Risk Assessment and Information

Under the new rule, railroads transporting HHFTs will be required to perform a routing analysis that considers prescribed safety and security factors and to select a route based on the results. *Id.* § 172.820.

The rule also requires railroads to notify certain state, local, and tribal officials, and to respond to inquiries from such officials' state and/or regional fusion centers, and requires that state, local, and tribal officials who contact a railroad to discuss routing decisions are provided appropriate contact information for the railroad in order to request information related to the routing of hazardous materials through their jurisdictions. *Id.* § 172.820(g).

Legal Challenges

The new rule has been challenged by industry groups, local governments, and environmental organizations. On May 11, 2015, the American Petroleum Institute (API) filed a petition in the U.S. Court of Appeals for the D.C. Circuit, saying that while API and its members support better tank cars, companies need more time to upgrade their fleets. The petition also asks the court to set aside the new braking rules for being unproven and costly. *See* Petition for Review, *Am. Petroleum Inst. v. United States*, No. 15-1131 (D.C. Cir. May 11, 2015).

On May 13, 2015, the Village of Barrington and the City of Aurora, Illinois, jointly petitioned the U.S. Court of Appeals for the Seventh Circuit challenging certain exemptions under the rule for shorter trains and claiming that the phase-out schedules for certain tank cars are unreasonably long. *See Vill. of Barrington v. U.S. Dep't of Transp.*, No. 15-2040 (7th Cir. filed May 13, 2015).

Finally, on May 14, 2015, a coalition of environmental groups, including the Center for Biological Diversity, ForestEthics, Sierra Club, Waterkeeper Alliance, Washington Environmental Council, Friends of the Columbia Gorge, and Spokane Riverkeeper petitioned the U.S. Court of Appeals for the Ninth Circuit, claiming that the compliance time frames are too long and the new tank standards are too weak, and seeking lower speed limits and more public disclosure about the routing of trains carrying flammable materials. *See Sierra Club v. Sec'y of Transp.*, No. 15-71461 (9th Cir. filed May 14, 2015).

Environmental Issues

continued from page 1

Chromalloy American Corporation, which owned property in the vicinity of the . . . site, also released hazardous substances that contributed to the contamination [at the site].” *Id.* at 480–81. AmeriPride has been conducting cleanup activities at the site. *Id.* at 481.

In January 2000, AmeriPride filed a complaint in district court against VIS, Petrolane, TEO, and Chromalloy seeking to recover its response costs at the site under CERCLA. *Id.* (citing 42 U.S.C. §§ 9607(a), 9613). AmeriPride ultimately entered into settlement agreements with Chromalloy and Petrolane. AmeriPride also entered into settlement agreements with Cal-Am and Huhtamaki to resolve separate lawsuits brought by those entities. The district court approved AmeriPride’s settlement agreements in July 2007, adopting section 6 of the Uniform Comparative Fault Act (UCFA) to determine how the settlements will impact nonsettling parties. *Id.*

The litigation between AmeriPride and TEO, however, continued. As part of that litigation, the district court ruled that TEO was liable to AmeriPride for response costs under 42 U.S.C. § 9607(a). *AmeriPride Servs.*, 782 F.3d at 482. The district court’s next task was to determine the effect of AmeriPride’s previous settlements in determining the amount of response costs for which TEO was liable. Related to this, “TEO moved the court for an order reasserting its previous ruling that the UCFA proportionate share approach would apply to determine the effect of AmeriPride’s settlements with Chromalloy and Petrolane.” *Id.* The district court denied this motion, indicating that “it would use equitable factors to allocate response costs between AmeriPride and TEO, but that the liability of the settling parties ‘is measured by the settlement that the court found fair and reasonable,’” meaning that the court “would reduce AmeriPride’s claims against TEO only by the dollar value of Chromalloy’s and Petrolane’s settlements.” *Id.*

TEO also filed a motion in limine asking that the district court enter “an order requiring AmeriPride to prove that its settlements with Huhtamaki and Cal-Am were for necessary costs of response incurred consistent with the NCP.” *Id.* The district court denied TEO’s motion, finding that “because the response action at the . . . site was NCP compliant, it did not need to make an individual determination regarding whether the settlement with Cal-Am and Huhtamaki met that criterion.” *Id.* The district court ultimately entered its judgment against TEO, apportioning dollar amounts for response costs. *Id.* TEO appealed that judgment to the Ninth Circuit. Primarily at issue for the Ninth Circuit were the district court’s determinations on TEO’s motions discussed above.

The first issue for the Ninth Circuit was whether the district court applied the wrong method in determining the effect of AmeriPride’s previous settlements with Huhtamaki and Cal-Am. When a statute, such as CERCLA, does not provide an approach for addressing settlements with less than all jointly and severally liable tortfeasors, courts generally look to either the UCFA or the Uniform Contribution Among Tortfeasors Act (UCATA). *Id.* at 483.

> The UFCA, which takes the proportionate share approach, provides that when an injured party settles with one of multiple tortfeasors, the settlement does not discharge the nonsettling tortfeasors but reduces the injured party’s claims against them by the amount of the settling tortfeasor’s proportionate share of the damages. Courts adopting [this] approach must therefore “determine the responsibility of all firms that have settled, as well as those still involved in the litigation.” The nonsettling tortfeasors will be responsible only for their proportionate share of the costs, even if the settling tortfeasor settles for less than its fair share of the injury. Under this approach, an injured party who settles for too little may not receive full recovery.

Id. at 483–84 (footnotes omitted) (citations omitted) (quoting *Am. Cyanamid Co. v. Capuano*, 381 F.3d 6, 20 (1st Cir. 2004)).

“The UCATA pro tanto approach provides that when an injured party settles with one of two or more tortfeasors for the same injury, the settlement does not discharge the nonsettling tortfeasors but reduces the injured party’s claims against them by the dollar value of the settlement.” *Id.* at 484. Under this approach, “[i]f the settling tortfeasor settles for less than its proportionate share of the injury, the nonsettling torfeasors will end up paying more than their proportionate share.” *Id.* This approach obviously encourages early settlement, but also has the potential for unfair or collusive settlements. *Id.*

Despite previously adopting the UCFA approach in July 2007, the district court concluded at the motion in limine hearing that it would not determine the proportionate share of the damages attributable to the settling defendants, Chromalloy and Petrolane, but would instead reduce the amount of AmeriPride’s claim by the dollar amount paid by Chromalloy and Petrolane. *Id.* In effect, the district court utilized the UCATA approach. TEO argued that CERCLA requires courts to apply the UCFA proportionate share approach. *Id.*

The Ninth Circuit found, consistent with the First Circuit, that CERCLA does not mandate application of the UCATA or UCFA approach, but instead that “a district court has discretion under § 9613(f)(1) to determine the most equitable method of accounting for settlements between private parties in a contribution action.” *Id.* at 487. However, although courts have discretion in allocating response costs, the Ninth Circuit found that “they must exercise this discretion in a manner consistent with § 9613(f)(1) and the purposes of CERCLA.” *Id.* at 488. The Ninth Circuit held that the district court abused its discretion by refusing to assess the settling parties’ equitable share of fault, consistent with the UCFA proportionate share approach, which the district court had adopted in a previous ruling. At trial, the district court effectively applied the UCATA pro tanto approach, which was not consistent with its previous ruling. *Id.* at 488–89. Indeed, the Ninth Circuit stated that “once a district court selects a method in a final order approving a settlement agreement, failing to follow that approach may produce a result that is inequitable and inconsistent with CERCLA’s goals.” *Id.* at 488. Accordingly, the Ninth Circuit remanded to the district court for further proceedings. *Id.* at 489.

The Ninth Circuit next addressed TEO’s arguments that “the district court erred by failing to determine whether AmeriPride’s settlements with Huhtamaki and Cal-Am were solely for 'response costs' that were incurred consistent with the NCP . . . ." *Id.* Based on its consideration of the relationship between the CERCLA provisions for cost recovery and contribution actions—i.e., section 9607(a) and section 9613(f)(1)—the Ninth Circuit found that "if a party who was liable under § 9607(a) entered into a settlement agreement to discharge its CERCLA liability to a third party, it can seek contribution under § 9613(f)(1) only for the settlement costs that were for necessary response costs incurred consistent with the NCP." *Id.* at 490. According to the court:

> [A]llowing a party to recover settlement money in a contribution action under § 9613(f)(1) without first requiring the party to prove that the settlement reimbursed the recipient for necessary response costs incurred consistent with the NCP could produce incongruous results. For instance, AmeriPride could successfully defend a § 9607(a) action brought by Huhtamaki or Cal-Am by proving that Huhtamaki and Cal-Am's response costs did not comply with the NCP, settle with Huhtamaki and Cal-Am for liability under state law, and then seek contribution under § 9613(f)(1) against TEO for the settlement monies it paid. Accordingly, the district court erred in failing to determine the extent to which the amounts paid by AmeriPride to Cal-Am and Huhtamaki were consistent with the NCP[, and remanded accordingly].

Id. (citation omitted).

FEDERAL ENERGY REGULATORY COMMISSION

SHEILA SLOCUM HOLLIS
DENNIS J. HOUGH
— REPORTERS —

CEQ ISSUES DRAFT GREENHOUSE GAS GUIDANCE

Energy companies and project developers face a multitude of authorization and permitting requirements on both the state and federal agency levels. For proposed natural gas pipeline or liquefied natural gas (LNG) terminal projects, one of those is the environmental review performed by the Federal Energy Regulatory Commission (FERC) pursuant to its obligations under the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. §§ 4321–4347. Under NEPA, and the corresponding NEPA regulations issued by the Council on Environmental Quality (CEQ), 40 C.F.R. pts. 1500–1508, and the respective reviewing agencies, federal agencies are required to consider the environmental impacts of proposed federal actions, i.e., proposed activities and projects that require federal approval or authorization to carry out, before making a final decision on such action. While the environmental review (NEPA review) conducted by FERC could be described as comprehensive in its analysis and discussion of impacts to the air, land, waterbodies, vegetation, and animal and human populations, some view FERC as not going far enough to capture all related environmental impacts.

In response to environmental advocates' concerns that federal agency NEPA reviews, such as those performed by FERC for natural gas pipeline or LNG projects, are not conducted using the appropriate rigor or scope of analysis with respect to greenhouse gas (GHG) emissions and climate change, the CEQ, on December 18, 2014, issued revised draft guidance concerning how federal agencies should consider GHG emissions and climate change in their NEPA reviews. *See* CEQ, "Revised Draft Guidance for Federal Departments and Agencies on Consideration of GHG Emissions and the Effects of Climate Change in NEPA Reviews" (Dec. 2014) (Revised Draft Guidance), https://www.whitehouse.gov/sites/default/files/docs/nepa_revised_draft_ghg_guidance_searchable.pdf. *See also* 79 Fed. Reg. 77,802 (Dec. 24, 2014). Although the draft guidance has been made available for public comment, it is not a rulemaking and does not constitute new NEPA regulations. Nevertheless, the two main principles conveyed by the draft guidance are that an agency's NEPA review should consider "(1) the potential effects of a proposed action on climate change as indicated by its GHG emissions; and (2) the implications of climate change for the environmental effects of a proposed action." Revised Draft Guidance, at 3.

With respect to the first principle, the draft guidance explains that agencies should use projected GHG emissions amounts (including amounts of carbon sequestration and storage) when assessing the proposed action's effect on climate change. *Id.* at 8. The CEQ explains that, in its view, proposed actions lead to incremental, or project-by-project, climate change impacts, which have not been afforded the appropriate level of attention and analysis in prior NEPA reviews. *Id.* at 9. The CEQ advises that agencies should perform a degree or level of analysis of the proposed action's GHG emissions and their effect on climate change that is proportional to the quantity of those emissions. *Id.* The draft guidance also sets forth a quantitative analysis baseline whereby proposed actions with annual emissions greater than or equal to 25,000 metric tons of CO_2-equivalent would need to include a detailed quantitative emissions analysis in the NEPA review. *Id.* at 18.

What could be considered one of the more significant aspects of the draft guidance involves the temporal and spatial proximity or relationship between the proposed action and the environmental impact. While both direct and indirect climate change effects of the proposed action must be accounted for, the CEQ also recommends an examination of certain "connected" actions, and other activities that have a reasonably close causal relationship to the proposed action. *Id.* at 11. Under this recommendation, a NEPA review should consider emissions from activities occurring prior to or "upstream" of the proposed action, as well as follow-on or "downstream" activities. In addition, the standard consideration of direct, indirect, and cumulative effects, as directed by the CEQ regulations, must be conducted and included in the NEPA review. *Id.* In the case of a proposed open pit mining project, NEPA review would require an analysis of land clearing, access road construction, transportation of the mined resource, resource refining and processing, and use of the resource. *Id.* at 12. Furthermore, NEPA analyses may include a review of the applicable environmental laws and regulations, including emissions targets, specific to the proposed action to give context and a frame of reference to the impacts discussed therein. *Id.* at 14.

In regard to the second principle, the agency performing the NEPA review should analyze the effects that climate change may have on the environmental impacts of a proposed action. The draft guidelines recommend that agencies examine and compare the current state of the environment to the condition of the environment post-action, using a time frame concurrent with the project's anticipated lifespan. *Id.* at 21. Such analysis would involve and focus on environmental impacts that are affected by both the proposed action and the effects of climate change. Examples provided in the draft guidelines include an analysis of the construction, operation, and maintenance of projects located near coastlines or in locations vulnerable to the effects of sea level rise or storm surge, or projects dependent on the availability of inland water supplies. *See id.* at 24–25.

The draft guidance has received mixed reviews, with industry advocates opposing and environmental proponents praising it. It is, however, unclear what will be adopted as final guidance, or what the actual effect will be given that these guidelines will not be incorporated with the CEQ's regulations. Agencies performing the environmental reviews would have to use their past experience with NEPA when employing new guidelines, and even then the methods and analyses will likely vary on a case-by-case basis. Importantly, consideration of GHG emissions impacts is not a matter limited to this draft guidance. At present there is one case pending in the U.S. Court of Appeals for the D.C. Circuit that has the potential to determine to what extent under NEPA agencies are required to consider the impacts of natural gas production—which would include air emissions impacts—even if that production is not part of the proposed project. *See Sierra Club v. FERC*, No. 14-1275 (D.C. Cir. filed Dec. 10, 2014).

CALIFORNIA— OIL & GAS

KEVIN L. SHAW
LANDER BRANDT
— REPORTERS —

DOGGR ISSUES EMERGENCY REGULATIONS REGARDING CERTAIN INJECTION WELLS

The focus in California on hydraulic fracturing and injection practices generally led to the discovery that the State permitted disposal and enhanced recovery well injection into aquifers that had not been certified as appropriate for fluid injection under the federal Safe Drinking Water Act (SDWA), 42 U.S.C. §§ 300f to 300j-26. While there is a certain bureaucratic history as to how this situation arose, commencing with an audit in 2010, federal and state agencies are unable to state with certainty that underground sources of drinking water are being protected from contamination.

Accordingly, as part of an agreed plan with the U.S. Environmental Protection Agency (EPA) to address the uncertainty, California's Division of Oil, Gas & Geothermal Resources (DOGGR), which administers the underground injection control (UIC) program under the SDWA, adopted emergency regulations that became effective on April 20, 2015. *See* DOGGR, "Aquifer Exemption Compliance Schedule Regulations—Final Text of Emergency Regulations" (Apr. 20, 2015) (to be codified at Cal. Code Regs. tit. 14, §§ 1760.1, 1779.1). The DOGGR notice recites that as many as 2,500 wells may have been involved. *See* DOGGR, "Aquifer Exemption Compliance Schedule Regulations—Notice of Proposed Emergency Rulemaking Action" (Apr. 2, 2015) (Emergency Rulemaking Notice). For each implicated well, the operator has the option either to cease injection or to obtain an exemption. Aquifer exemptions are required to be proposed by DOGGR and approved pursuant to the federal regulations at 40 C.F.R. § 144.7. *See* Cal. Code Regs. tit. 14, § 1760.1(a)(2). DOGGR describes its implementation scheme as follows:

- October 15, 2015—shut-in deadline for wells injecting into aquifers in non-hydrocarbon-producing zones where the groundwater has less than 3,000 mg/L of total dissolved solids (TDS), unless an aquifer exemption is obtained;
- December 31, 2016—shut-in deadline for wells injecting into 11 specific aquifers historically treated as exempt by the EPA, unless the EPA takes further action to affirm exemption of the pertinent aquifer(s) before that deadline; and
- February 15, 2017—shut-in deadline for wells injecting into aquifers in non-hydrocarbon-producing zones where the groundwater has between 3,000 and 10,000 mg/L TDS, unless an aquifer exemption is obtained.
- February 15, 2017—shut-in deadline for wells injecting into aquifers in hydrocarbon-producing zones where the groundwater has less than 10,000 TDS, unless an aquifer exemption is obtained.

Cal. Code Regs. tit. 14, § 1779.1(a)–(b).

DOGGR stated that it believes that many of the affected aquifers will qualify for exemption. *See* Emergency Rulemaking Notice, at 4. DOGGR also is expected to propose new permanent regulations as well as part of a more comprehensive overhaul of the injection regulation system.

LESSOR'S DUTY TO SUPPORT THE LESSEE

Grayson Service, Inc. v. Crimson Resource Management Corp., No. 1:14-cv-01125, 2015 WL 1345806 (E.D. Cal. Mar. 23, 2015) is a follow-on case to an earlier state court proceeding. Grayson Service, Inc. (Grayson) was the successor in interest to the lessee, and Crimson Resource Management Corp. (Crimson) was the successor in interest to the mineral owner/lessor under a 1936 oil and gas lease. The various working interest owners apparently operated the property for many years, which included utilization of a water supply well drilled on the leased premises. *Id.* at *1. The relevant part of the leased land included a 250-acre tract.

In 2012, the Kern County Water Bank Authority (KWBA) claimed that it had "paramount title" to the lands and demanded that Grayson cease operations and vacate a 23-acre portion of the premises. *Id.* at *3. KWBA based its claim on a showing that it had chain of title to the surface estate of the land extending back to sovereignty. Apparently Crimson acquiesced to KWBA's use of other portions of the land as well. *Id.* at *4. KWBA brought an action in state court to seeking to have Grayson "vacate the parcel, remove all buildings, and cease all oil production, and quitclaim all rights to use the surface to KWBA." *Id.* at *3. KWBA prevailed at trial as to the 23-acre parcel. KWBA then entered that portion of the leased lands and drilled a number of water extraction wells. Subsidence occurred, damaging Grayson's wells and causing Grayson to vacate the remaining portion of the lands. *Id.* at *4.

Grayson then brought this action in federal court claiming that Crimson breached a number of lease provisions by "allowing" KWBA to install water wells, which caused damage to Grayson. However, on a motion to dismiss, the federal court rejected Grayson's lease-based arguments. Finding that the lessor never warranted title to the property, the court found that Crimson did not violate the covenant of quiet enjoyment or the implied covenants of good faith or fair dealing. *See id.* at *8–11.

Grayson also claimed, but without citing details, that Crimson's predecessors in interest conspired with KWBA to create KWBA's claim of paramount title. The federal court did not discuss the merits of this claim in the motion to dismiss because Grayson did not present sufficient facts to make the claim facially plausible. *Id.* at *8. The court appeared to cut off the argument entirely, stating that "[d]efendants, as transferees of the rights under the assignment of the lease, are not liable for any breach of the contract by their predecessors." *Id.*

Even though the state court did not adjudicate title to the balance of the leased lands outside of the 23 acres, the federal court concluded that nothing supported a contrary conclusion on the remaining portion of the 250 acres. *Id.* at *9. As such, the court dismissed the entire case, without leave to amend.

The federal court opinion says only that KWBA established superior rights to the surface of the 23-acre parcel. There was no discussion about whether rights to the mineral estate had been adjudicated. While not stated, it may be that Grayson retained a valid lease on the minerals, but due to the subsidence and interference from KWBA, the surface owner had simply made it impossible or impractical to continue to produce those minerals.

Therefore, even if the lessor conspires against the lessee and frustrates the lessee's ability to utilize the leased lands, as was the case in *Grayson*, the lessee may not have any recourse against the lessor in the absence of a violation of the express terms of the lease.

BANKRUPTCY COURT EMPHASIZES PARTIES' INTENT, STATE LAW IN CHARACTERIZING OVERRIDING ROYALTY INTERESTS

In *In re Delta Petroleum Corp.*, No. 11-14006, 2015 WL 1577990 (Bankr. D. Del. Apr. 2, 2015), the bankruptcy court considered competing motions for summary judgment as to whether certain overriding royalty interests (ORRI) constituted (1) mere contractual rights to payment that were discharged by the confirmed chapter 11 reorganization plan; or (2) real property interests that were not part of the estate in bankruptcy and, thus, survived the trustee's challenge. The court's ruling emphasized the importance of state law characterization of ORRIs, the parties' intent as expressed in the documents, and state law recording and notice rules.

Background

In 1994, an affiliate of defendant BWAB Limited Liability Company (BWAB) acquired from Union Pacific Resources Corporation an option to purchase a large number of properties, including certain federal oil and gas leases at Point Arguello, offshore Santa Barbara County, California (Properties). *Id.* at *1. BWAB assigned its option to purchase to Whiting Petroleum Corporation (Whiting). Whiting exercised the option in December 1994, acquired the Properties, and assigned to BWAB "an overriding royalty consisting of an undivided Three and One-Half Percent (3.5%) interest in Whiting's Net Revenue Interest from the Subject Properties" (1994 ORRI). *Id.* at *2. This assignment was recorded in the official records of Santa Barbara County and filed with the Minerals Management Service (MMS), Pacific OCS Region. *Id.*

In 1999, Delta Petroleum Corporation (Delta) sought to acquire Whiting's interest in the Properties, but could not obtain the required consents from other working interest owners. *Id.* at *2–3. In a transaction designed to circumvent the consent requirement, Whiting and Delta agreed that "Whiting would convey to Delta a derivative product which would provide the economic equivalent of conveying title to the Properties." *Id.* at *3. To implement this arrangement, Whiting executed an assignment of its net operating interest (1999 NOI) to debtor Delta. However, Delta did not record the assignment, "due to Whiting's concern that the other working interest owners would consider such an action as a conveyance of legal title in violation of its agreements with them." *Id.* Later in 1999, Delta entered into ORRI assignments with BWAB, granting an ORRI of 3%, and with Aleron Larson, Jr., granting an ORRI of 1% (collectively, 1999 ORRIs), neither of which were recorded in the county real property records, nor filed with the MMS. *Id.* at *3–4.

On December 16, 2011, Delta and some of its affiliates filed for chapter 11 bankruptcy relief. On August 16, 2012, the court confirmed the debtors' reorganization plan. Neither BWAB nor Larson filed claims, and apparently both continued to receive payments under their respective ORRIs until September 2012. *Id.* Following confirmation of the reorganization plan, Delta Petroleum General Recovery Trust and one of the reorganized debtors sought to recover post-petition payments to BWAB and Larson.

The Court's Analysis

The court recognized that California law classifies ORRIs as interests in real property. *Id.* at *8. The 1994 ORRI conveyance provided that it was to be governed by Colorado law. *Id.* at *7. The court cites both Colorado and California law with respect to the classification of the ORRI as an interest in real property. *Id.* at *8. The court also notes that under section 4 of the Outer Continental Shelf Lands Act, 43 U.S.C. § 1333(a)(2)(A), the law of the adjacent state—California in this case—controls as to various issues involving the classification of these federal lease interests. *See Delta*, 2015 WL 1577990, at *13 n.23. In its analysis of the 1994 ORRI, the court reasoned that the assignment established the parties' intent to grant BWAB a fractional interest in the revenue from sale of the hydrocarbons attributable to Whiting's working interest. *Id.* at *9. The court also agreed with a previous California opinion, which did not recognize a distinction between an interest granted in net revenue interest and one granted in land or hydrocarbons. *Id.* (citing *Schiffman v. Richfield Oil Co. of Cal.*, 64 P.2d 1081 (Cal. 1937)). As such, the court held that the 1994 ORRI should be characterized as an interest in real property. *Id.* Consequently, the 1994 ORRI was not a part of the estate in bankruptcy and the holder of the ORRI was not obliged to file a proof of claim.

For comparison purposes, the bankruptcy court in a case also involving offshore federal leases, but applying Louisiana law, found that the analysis of the intent of the parties necessarily went beyond the four corners of the document. *See In re ATP Oil & Gas Corp.*, No. 12-36187, 2014 WL 61408 (Bankr. S.D. Tex. Jan. 6, 2014); *In re ATP Oil & Gas Corp.*, 497 B.R. 238 (Bankr. S.D. Tex. 2013). That court held that under the Louisiana Supreme Court's decision in *Howard Trucking Co. v. Stassi*, 485 So. 2d 915 (La. 1986), the proper characterization of the transactions depended on the true commercial nature of the transaction, notwithstanding the explicit language of the transaction documents. The court concluded that "the best evidence of the parties' intent [as to characterization] is what the parties agreed to do," i.e., the "economic substance of the transactions," not the description of the transaction set out in the transaction documents. 497 B.R. at 244–45 (emphasis omitted). It is not clear from the opinion in the *Delta* case whether these sorts of arguments were raised and argued.

Regarding the 1999 ORRIs, the plaintiffs argued that the 1999 NOI was not a real property interest and, consequently, the 1999 ORRIs could not be real property interests either. *Delta*, 2015 WL 1577990, at *10. The court found that there was an issue of fact as to whether the parties intended the 1999 NOI to be a real property interest or a contractual right to payment. *Id.* at *12. Because an assignee's rights are derivative of the assignor's rights, the court engaged in a two-part analysis of the ORRI grant. First, the court examined the situation assuming that the 1999 ORRIs were real property interests. If the 1999 ORRIs were real property interests under California law, then under California's recording statutes, holders must record the conveyances of their interests in the county real property records to provide constructive notice to subsequent purchasers or mortgagees. *Id.* at *13 (citing Cal. Civ. Code §§ 1213, 1214). As the assignments of the 1999 ORRIs were not recorded, and there were no other facts constituting inquiry notice, the trustee in bankruptcy, who stands in the position of a bona fide purchaser for value and without notice, would be able to avoid the priority status of the unrecorded 1999 ORRIs pursuant to Bankruptcy Code § 544(a)(3). *Delta*, 2015 WL 1577990, at *15.

In the alternative, the court assumed that the 1999 ORRIs were not real property interests and concluded that they were prepetition contracts providing for payments to BWAB and Larson. *Id.* at *15–16. The court reasoned that, although there were no breaches prior to the effective date of the reorganization plan, the contractual rights to payment were claims within the definition of Bankruptcy Code § 101(5). *Id.* at *16. As such, to the extent that the 1999 ORRIs were contractual rights to payment, they were "claims" subject to the discharge provisions of the reorganization plan. *Id.* Because BWAB and Larson did not file claims in the bankruptcy proceeding, they lost their rights.

Although holders of the 1999 ORRI lost on summary judgment, on a related question about whether they were entitled to certain post-petition payments, the court noted that the parties would be given an opportunity to brief the question of whether the 1999 ORRIs were "production payments" or "term overriding royalty interests" pursuant to section 541 of the Bankruptcy Code. *Id.* at *17.

Conclusion

The court's ruling has several important reminders for holders of ORRIs. Most importantly, the conveyance or reservation of an ORRI must comply with applicable state law concerning the nature of the interest conveyed. This analysis should examine (1) how ORRIs are typically characterized (real property interests or contractual rights to payment); (2) whether the express language of the conveyance and the underlying agreements clearly expresses the intent of the parties regarding the interest conveyed; and (3) if the ORRI is an interest in real property, whether the state's recording statute requires recording of the instrument in order to create constructive notice that would prevent the trustee in bankruptcy from asserting its status as a bona fide purchaser without notice, thereby avoiding the ORRI.

COLORADO — OIL & GAS

SHERYL L. HOWE
— REPORTER —

COURT OF APPEALS AFFIRMS DAMAGES AWARD FOR DEDUCTIONS FROM ROYALTY PAYMENTS

In *Patterson v. BP America Production Co.*, 2015 COA 28, 2015 WL 1090004, the Colorado Court of Appeals affirmed the district court's entry of judgment for the plaintiffs based on a jury verdict. This case was filed in 2003 as a class action regarding gas produced in Adams and Weld Counties and deductions that BP America Production Company (BP), formerly known as Amoco Production Company, made from royalty payments. The case has previously been appealed twice. *See Patterson v. BP Am. Prod. Co.*, 159 P.3d 634 (Colo. App. 2006), *rev'd*, 185 P.3d 811 (Colo. 2008) (en banc) (reported in Vol. XXIII, No. 3 (2006) and Vol. XXV, No. 3 (2008) of this *Newsletter*); *Patterson v. BP Am. Prod. Co.*, 240 P.3d 456 (Colo. App. 2010), *aff'd*, 263 P.3d 103 (Colo. 2011) (en banc) (reported in Vol. XXVII, No. 2 (2010) and Vol. XXIX, No. 1 (2012) of this *Newsletter*). On the most recent, second, remand, there was a jury trial with the result that the jury awarded the plaintiffs (Royalty Owners) $7,941,809.23 in damages and the court added $32,273,817.00 in statutory prejudgment interest, bringing the total judgment to $40,215,626.23. *See* 2015 COA 28, ¶¶ 16, 17. BP and the Royalty Owners appealed.

The interest award was based on Colo. Rev. Stat. § 5-12-102(1)(b), which provides for 8% prejudgment interest. The plaintiffs had requested prejudgment interest at a rate greater than 8% under Colo. Rev. Stat. § 5-12-102(1)(a), which provides that "interest shall be an amount which fully recognizes the gain or benefit realized by the person withholding such money or property." 2015 COA 28, ¶ 21 (quoting Colo. Rev. Stat. § 5-12-102(1)(a)). The district court had granted BP's motion on this issue and dismissed, before trial, the claim for interest at a higher rate. "During the applicable period, BP did not maintain royalties, or the deductions withheld from royalties, in separate bank accounts. Instead, these funds were consistently placed in BP's master bank account and commingled with revenues from BP's other oil and gas operations throughout the United States." *Id.* ¶ 26. The Royalty Owners' experts analyzed records regarding the annualized percentage return on capital costs for BP's Colorado oil and gas operations. *Id.* ¶ 28. However, the experts did not trace the specific withheld funds to the Colorado operations and there was no evidence regarding BP's rate of return on its operations throughout the United States or BP's annual gain on its master bank account. *Id.* The court found the Royalty Owners did not "provide any causal link between the dollars withheld and an actual gain or benefit realized by BP on those dollars." *Id.* ¶ 31. Thus, the court found there was no genuine issue of any material fact and that the district court properly granted BP's Colo. R. Civ. P. 56(h) motion on this issue. *Id.* ¶ 34.

BP also argued that the district court erred in denying its request for a directed verdict and for judgment notwithstanding the verdict (JNOV) for two reasons: "(1) Royalty Owners could not prove their fraudulent concealment and equitable tolling claims for all class members; and (2) the evidence demonstrated that Royalty Owners' gas was undisputedly marketable at the well and therefore the post-production deductions from Royalty Owners' royalties were proper." *Id.* ¶ 35. The court of appeals rejected these arguments.

The fraudulent concealment issue pertained to equitable tolling of Colorado's six-year statute of limitations. *Id.* ¶ 38 (citing Colo. Rev. Stat. § 13-80-103.5(1)(a)). BP had deposed several members of the class, including several Royalty Owners involved with the gas industry. Two of the Royalty Owners used the netback methodology themselves. Another Royalty Owner testified that the division and transfer orders provided notice that BP might start deducting post-production costs. *Id.* ¶ 42. The Royalty Owners had signed oil and gas division and transfer orders that included the following language:

> Settlements for gas shall be based on the net proceeds at the wells after deducting a fair and reasonable charge for compressing and making it merchantable and transporting if the gas is sold off the property. Where gas is sold subject to regulation by the Federal Power Commission [FPC] or other governmental authority, the price applicable to such sale approved by order of such authority shall be used to determine the net proceeds at the wells.

Id. ¶ 3 (alteration in original).

> When most Royalty Owners signed the lease agreements and division and transfer orders, gas prices were federally regulated, and Royalty Owners were paid at the maximum lawful price, or the price stipulated by the lease agreements. In the 1980s, the process of deregulating the natural gas market began, and BP gradually changed how Royalty Owners' royalties were calculated. BP began to employ a netback methodology to calculate royalty payments, whereby BP deducted from Royalty Owners' royalty checks a proportionate share of the post-production costs incurred to make the gas marketable, including transportation, processing, and refinement costs.

Id. ¶ 5. The royalty statements did not disclose these deductions. *Id.* ¶ 6. The court of appeals reviewed the testimony of several Royalty Owners who were gas industry participants, but concluded that "reasonable jurors could find that these class members, and the remainder of Royalty Owners, were ignorant of BP's concealed royalty deductions, relied on BP's concealment, and were unable, using reasonable diligence, to discover the concealment." *Id.* ¶ 45. Thus, the court found "the district court did not err in denying BP's motions for a directed verdict and JNOV." *Id.*

BP also argued that the Royalty Owners presented insufficient evidence to support the claim that the gas was not marketable at the well. *Id.* ¶ 46. BP argued that "the district court should have directed a verdict or granted JNOV on the issue." *Id.* The court of appeals disagreed. The court of appeals discussed prior Colorado case law regarding allocation of post-production costs and stated that "[t]he implied covenant to market obligates the lessee (BP), not the lessors (Royalty Owners), to make the gas marketable." *Id.* ¶ 47. The court quoted and analyzed testimony from BP's experts and the Royalty Owners' experts on the issue of when the gas was first marketable. For example, the court noted that the Royalty Owners' experts testified that "BP could not sell the gas 'until it's separated,'" that "there was 'no index for wellhead gas [and] no pricing for wellhead gas,'" and that "BP consistently sold its gas products after fractioning or separating out any impurities at BP's processing plants." *Id.* ¶¶ 57, 58 (alteration in original). BP's experts testified that the gas contained "'relatively low levels' of carbon dioxide and 'negligible' hydrogen sulfide," and that "there [was] and continues to be an active commercial market for raw gas at the wellhead." *Id.* ¶¶ 59, 60 (alteration in original). There was evidence that some sales occurred at the wellhead, but viewing the evidence in the light most favorable to the Royalty Owners (because this was a challenge for failure to grant directed verdict or JNOV) the court found that "a reasonable person could believe Royalty Owners' evidence and determine, for the purpose of calculating royalties, that the wellhead was not the first market for gas extracted from the wells . . . ." *Id.* ¶ 64.

BP also argued that "the district court erred in declining to instruct the jury that '[i]f a person signs a contract without reading it, that person is barred from claiming he or she is not bound by what it says.'" *Id.* ¶ 66 (alteration in original). This related to the ignorance requirement under the fraudulent concealment claim to toll the statute of limitations. *Id.* ¶ 69. The court found that:

> The crux of the contractual issue was not whether Royalty Owners signed or read the contracts, or even whether they were bound by the contractual language. Rather, the issue was whether the contracts and the additional evidence presented at trial adequately informed Royalty Owners of BP's intent to deduct post-production costs from their checks.

Id. ¶ 72. Because BP's proposed instruction "did not accurately address the controversy," the court of appeals held that the district court's refusal was reasonable. *Id.* ¶ 73.

BP's final argument was that the district court erred in denying BP's motion to decertify the class. *Id.* ¶ 76. BP's argument pertained to the class members who were familiar with the netback calculation method or who confirmed that the division orders provided notice that BP was going to deduct the costs of making gas marketable from the royalties. *Id.* ¶ 82. The court of appeals rejected BP's arguments that "(1) fraudulent concealment is inappropriate for class-wide resolution; (2) the court ignored the vast differences between class members' claims of ignorance, reliance, and diligence; and (3) the court committed legal error when it ignored evidence of Royalty Owners' constructive knowledge of, and subsequent ability to discover, the royalty deductions." *Id.* ¶ 85.

Regarding BP's first argument, the court of appeals adopted the Colorado Supreme Court's prior conclusion that "fraudulent concealment is appropriate for class-wide resolution." *Id.* ¶ 86 (citing *BP Am. Prod. Co. v. Patterson*, 263 P.3d 103, 112–13 (Colo. 2011) (en banc)). As to BP's second argument, the court of appeals found that the district court had reviewed BP's arguments and the evidence and found that the differences among class members did not defeat the class-wide inferences of ignorance, reliance, and due diligence. *Id.* ¶ 87. Finally, regarding BP's third argument, the court of appeals noted that the district court found that "[n]one of the deposition testimony . . . establishe[d] that any of the corporate class members had *actual knowledge* that [BP] was deducting costs prior to making royalty payments," and that the "Royalty Owners had no reason to suspect that anything was being concealed from them and therefore no duty to inquire into the deductions." *Id.* ¶ 88 (second alteration in original). As a result, the court of appeals affirmed the district court's decision denying BP's motion to decertify the class. *Id.* ¶ 89.

KANSAS — OIL & GAS

DAVID E. PIERCE
— REPORTER —

KANSAS SUPREME COURT SLAYS ZOMBIE DEFEASIBLE TERM MINERAL INTEREST

In *Netahla v. Netahla*, 346 P.3d 1079 (Kan. 2015), *rev'g* 307 P.3d 269 (Kan. Ct. App. 2014), the Kansas Supreme Court reversed a decision of the Kansas Court of Appeals that would have breathed new, and surprising, life back into an otherwise terminated defeasible term mineral interest. See Vol. XXX, No. 4 (2013) of this *Newsletter* for a report on the court of appeals decision. The facts can be summarized as follows: *O*, owner of land in fee, enters into an oil and gas lease with *X*. Seven months later, while the lease is still in effect, *O* conveys to *A* an undivided one-half mineral interest in the land for 15 years and so long thereafter as oil or gas is produced from the land. 346 P.3d at 1080–81. The deed creating the interest states: "Said land being now under an oil and gas lease executed in favor of, as appears of record, it is understood and agreed that this sale *is made subject to the terms of said lease*, but covers and includes one-half of all the oil royalty, and gas rental or royalty due and to be paid under the terms of said lease." *Id.* at 1080. A producing gas well was completed on the land but was declared shut-in by the lessee with no gas being produced from June 1, 1985, to 2003. The primary term on *A*'s defeasible term mineral interest terminated on June 1, 1985. *Id.* at 1081.

Prior Kansas law provides that if the defeasible term mineral interest does not contain a shut-in royalty clause, and the only well capable of producing on the land is not being produced or otherwise developed or operated, the defeasible term mineral interest terminates. *Id.* at 1082 (citing *Dewell v. Fed. Land Bank of Wichita*, 380 P.2d 379, 383 (Kan. 1963). However, in *Dewell* each mineral owner entered into a separate lease after the interest was granted; each lease contained a shut-in royalty clause. In *Netahla* the original grantor entered into the lease containing the shut-in royalty clause. *Id.* at 1082–83. The court of appeals held that including the "subject to" language in the subsequent mineral deed expressly incorporated the lease terms, including the shut-in royalty clause, into the mineral deed. *Id.* at 1081. The supreme court rejected that argument and chose to follow two Texas Court of Appeals cases interpreting identical language under similar facts that held the "subject to" language was used only to alert the grantee that its interest was burdened by a prior lease. *Id.* at 1083 (citing *Kokernot v. Caldwell*, 231 S.W.2d 528 (Tex. Civ. App. 1950); *Investors Royalty Co. v. Childrens Hospital Med. Ctr.*, 364 S.W.2d 779 (Tex. Civ. App. 1963)).

The Kansas Supreme Court reaffirms the *Dewell* rule that "absent a provision in a mineral deed stating otherwise, the payment of shut-in royalties pursuant to a lease is not the equivalent of actual production or development." *Id.* at 1085. Although it is possible for a grantor to confer on a grantee the benefits of savings clauses in an existing or future lease, the court holds that common "subject to" language does not have that effect.

LOUISIANA — OIL & GAS

ADAM B. ZUCKERMAN
STEPHANIE N. MURPHY
— REPORTERS —

LOUISIANA THIRD CIRCUIT DETERMINES THAT A LIEU WARRANT ISSUED PRIOR TO 1921 CONVEYS MINERALS

In *Midstates Petroleum, LLC v. State Mineral & Energy Board of State*, 2014-1168 (La. App. 3d Cir. 4/15/15); 2015 WL 1650549, the Louisiana Third Circuit Court of Appeals affirmed that a lieu warrant issued prior to 1921 is a contractual obligation owed by the State of Louisiana to convey land with minerals that cannot later be altered or impaired by constitutional amendment. In 1858, the State sold a piece of land, including both the surface and the minerals, to John Laidlaw. *Id.* at *1. After later determining that the State did not own just title to that land, it issued a lieu warrant in 1888 to Laidlaw that would allow him to obtain suitable land comparable to that previously sold. *Id.* In 1943, Laidlaw's heirs applied for and obtained a patent to satisfy the rights acquired under the 1888 lieu warrant. *Id.* Laidlaw's heirs, in 2011, claiming ownership of the undivided interest in the minerals of the property, granted an oil, gas, and mineral lease. *Id.* The State also claimed to have ownership of the minerals, however, asserting that the Louisiana Constitution passed in 1921 imposed a mineral reservation on any and all property subsequently sold by the State, including the 1943 patent. *Id.*

The district court held that the Laidlaw heirs owned the minerals because the State obligated itself to transfer a tract of land with minerals in 1888, via a lieu warrant, which pre-dated the passage of the 1921 mineral sale prohibition. *Id.* at *2. The court of appeals agreed. In reaching its conclusion, the court relied heavily on the Louisiana Supreme Court decision of *State ex rel. Hyams' Heirs v. Grace*, 1 So. 2d 683 (La. 1941), which held that a lieu warrant is a contract between the State and the holder that cannot later be impaired because it would be a violation of the Contracts Clause of the United States and Louisiana Constitutions. *Midstates*, 2015 WL 1650549, at *5. The court dismissed the State's argument that *Justiss Oil Co. v. Louisiana State Mineral Board*, 45,212 (La. App. 2d Cir. 4/14/10); 34 So. 3d 507, was applicable, stating that this decision was "simply incorrect and in direct contravention of the [*Hyams* decision]." *Midstates*, 2015 WL 1650549, at *7. Accordingly, the State cannot invoke section 2, article 4 of the 1921 Louisiana Constitution to prohibit the conveyance of minerals in a patent applied for and issued after 1921 to satisfy a lieu warrant applied for and issued prior to 1921.

Fifth Circuit Interprets Daywork Oil and Gas Drilling Contract

In *Zenergy, Inc. v. Performance Drilling Co.*, No. 14-60152, 2015 WL 1187739 (5th Cir. Mar. 17, 2015), the U.S. Court of Appeals for the Fifth Circuit held that the oil and gas operator, not the drilling contractor, bore all of the risk for a deviated wellbore under an International Association of Drilling Contractors form onshore daywork drilling contract (Contract). Here, Zenergy, Inc. (Zenergy) hired Performance Drilling Co., LLC (Performance) to drill a vertical oil well with a bottomhole depth of 11,800 feet in Calcasieu Parish, Louisiana. *Id.* at *1. Under the Contract, Performance was to provide a conventional drift indicator to measure the deviation of the wellbore. Per Zenergy's instructions, Performance conducted deviation surveys every 1,000 feet. After several weeks of drilling with minimal deviation, a survey at 9,504 feet reported a deviation of seven degrees. Zenergy called in a third-party contractor to review the survey. After the third-party contractor mistakenly reviewed data from a different survey (showing only two degrees of deviation), Zenergy instructed Performance to resume drilling. Subsequently, the surveys continued to report deviations of two degrees or less until a depth of 11,060 feet. After a third-party contractor came out to "log" the well, it was reported that it was severely deviated by approximately 20 degrees. *Id.* "Zenergy paid Performance for only the days during which the wellbore was deviated by less than five degrees." *Id.* at *2. Suit was filed under various Louisiana laws, including breach of contract. After a six-day jury trial, the jury returned a verdict that Performance was not liable. Zenergy appealed. *Id.*

The Fifth Circuit first discussed that a daywork contract generally provides that "the operator pays the contractor a fixed price per day to drill the well and assumes all of the risks of the drilling operation except for those expressly assigned to the contractor." *Id.* at *3. "At the other end of the spectrum is the turnkey contract, in which the operator pays the contractor a fixed price for drilling the well to a specific depth or formation and the contractor assumes considerably more risk due to his general control over the drilling operation." *Id.* "The hallmark of each type of contract is the amount of control the operator has over the drilling operation." *Id.* The court highlighted that "under a daywork contract the contractor has less control over the drilling operation than under a turnkey contract, [and] the contractor assumes only 'specified risks, while the general risk of delay and the risk of liabilities not assumed by the contractor are on the operator.'" *Id.* (quoting Owen L. Anderson, "The Anatomy of an Oil and Gas Drilling Contract," 25 *Tulsa L.J.* 359, 375 (1990)).

Although Zenergy argued that Performance breached the Contract, the court held that none of the provisions of the Contract dictated the allocation of the risk of a deviated wellbore. *Id.* The court determined that Performance's requirement to "furnish equipment, labor, and perform services . . . for a specified sum per day under the direction, supervision and control of [Zenergy]" pursuant to the Contract was not a guarantee of the final product of those services. *Id.* at *4 (alteration in original). To hold differently, the court opined, "would subvert the plain language of the Contract and the intent of the parties," which would not comport with the requirements of La. Civ. Code Ann. arts. 2054 and 2045. *Zenergy*, 2015 WL 1187739, at *4.

Louisiana Third Circuit Addresses Defense and Indemnity Agreements Between Oil and Gas Co-Defendants

In *Carmichael v. Bass Partnership*, 2014-1134 (La. App. 3 Cir. 3/11/15); 2015 WL 1035976, the Louisiana Third Circuit Court of Appeals found that a working interest owner was not entitled to defense or indemnity from another working interest owner for liability relating to remediation of the property. Here, the landowners sued several working interest owners, including the operator, alleging that their property had been damaged by exploration and production activities associated with the Hebert No. 1 Well and the Hebert No. 1 Saltwater Disposal Well in the Leleux Field, Acadia Parish. *Id.* at *1. The plaintiffs subsequently settled their lawsuit; however, claims remained between two co-defendants, Bass Partnership (Bass) and Continental Land & Fur Company (Continental), based on reciprocal defense and indemnity claims. These claims were based on letter agreements dated January 18, 2000, in which Continental agreed to assign its working interest to Bass. *Id.* Continental maintained that Bass should pay defense expenses because Bass agreed to defend and indemnify Continental for liability arising out of plugging, abandoning, and location restoration of the Carmichaels' property after assignment to Bass. *Id.* at *3. Bass, on the other hand, asserted that Continental owed Bass a share of defense costs and the settlement because liability for damages arose during the time Continental owned a working interest lease. *Id.* In response, Continental argued that its obligation to indemnify Bass was limited under the letter agreement to liability arising out of "ownership" or "title" and not operations. *Id.*

The letter agreement required Continental to defend and indemnify Bass for "liability of whatsoever kind arising out of or incident to the ownership of [Continental] of the Properties prior to the Effective date." *Id.* at *5. Extrinsic evidence produced at trial revealed that most of the contamination of the property occurred prior to the effective date. *Id.* at *6. Continental, aware of this damage, paid Bass at that time for remediation costs in exchange for relief of any obligation to restore the property. *Id.* The court found that the intent of the letter agreement was that Bass was obligated to defend and indemnify Continental for any cost relating to plugging, abandoning, and remediation of the property as defined by the letter agreement. *Id.* at *7. The court found that this included all liability relating to naturally occurring radioactive material and chloride contamination whether or not caused by operations before or after the date of the letter agreement. *Id.*

Louisiana Third Circuit Decides Subsequent Purchaser Rule Is Applicable to Mineral Leases

The plaintiffs in *Bundrick v. Anadarko Petroleum Corp.*, 2014-993 (La. App. 3 Cir. 3/4/15); 159 So. 3d 1137, owned interests in property allegedly contaminated from past oil and gas activities. "[T]he plaintiffs acquired the immovable property after the expiration of the mineral leases at issue and they did so without obtaining an assignment of their predecessor-in-interest's rights to proceed against the responsible parties for contamination to the land." *Id.* at 1140. The issue presented was whether the subsequent purchaser doctrine prohibited plaintiffs' recovery against the former mineral lessees. *Id.* at 1141.

The Third Circuit held that it did because there was no clear assignment or subrogation of the rights belonging to the owner of the property when the damage was inflicted. *Id.* at 1143. The court found that the Louisiana Supreme Court's instruction in *Global Marketing Solutions, LLC v. Blue Mill Farms, Inc.*, 2013-2132 (La. App. 1 Cir. 9/19/14); 153 So. 3d 1209, to consider its ruling in *Eagle Pipe & Supply, Inc. v. Amerada Hess Corp.*, 2010-2267 (La. 10/25/11); 79 So. 3d 246, is "a recognition that the subsequent purchaser rule applies in matters involving mineral leases." *Bundrick*, 159 So. 3d at 1143. The court further rejected the argument that the plaintiffs had a cause of action for remediation "pursuant to Article 11 of the Louisiana Mineral Code, because mineral rights are real rights . . . [that] pass with the property to a subsequent purchaser without the need for specific assignment or subrogation." *Id.* The court found that while "mineral rights are real rights, that status is reserved to the mineral lessee and not the mineral lessor." *Id.*

Oil and Gas Companies Have No Specific Duty Under Louisiana Law to Protect Members of the Public from the Results of Coastal Erosion

In *Board of Commissioners of Southeast Louisiana Flood Protection Authority-East v. Tennessee Gas Pipeline Co.*, No. 13-5410, 2015 WL 631348 (E.D. La. Feb. 13, 2015), the U.S. District Court for the Eastern District of Louisiana determined that oil and gas companies do not owe a specific duty to the state flood control authority or the public for operations that allegedly caused coastal erosion. The Board of Commissioners of the Southeast Louisiana Flood Protection Authority-East, individually and on behalf of three local levee districts, brought suit against 88 oil and gas companies operating in the "Buffer Zone." *Id.* at *1. Plaintiff alleged that Defendants' oil and gas operations "led to coastal erosion in the Buffer Zone, making south Louisiana more vulnerable to severe weather and flooding." *Id.* Defendants filed a motion to dismiss on the basis that Plaintiff could not state a viable claim against them. *Id.*

The court noted that Louisiana courts employ a duty-risk analysis, pursuant to La. Civ. Code Ann. art. 2315, which requires a plaintiff to show five elements, including that the defendant's substandard conduct was a legal cause of the plaintiff's injuries. 2015 WL 631348, at *9. Thus, the court was tasked with determining "whether a statute or rule of law imposes a duty on Defendants, for the benefit of Plaintiff, to prevent the loss of coastal lands in the Buffer Zone, mitigate storm surge risk and/or prevent the attendant increased flood protection costs incurred by Plaintiff." *Id.* at *10.

At the outset, the court noted that it "has already opined that oil and gas companies do not have a duty under Louisiana law to protect members of the public from the results of coastal erosion allegedly caused by [pipeline] operators that were physically and proximately remote from plaintiffs or their property." *Id.* (alteration in original) (internal quotation marks omitted). Thus, "[s]ince the general duty articulated by Article 2315 is insufficient to satisfy Plaintiff's burden under the duty-risk analysis, Plaintiff turns to the Rivers and Harbors Act, the Clean Water Act, and the Coastal Zone Management Act to establish the requisite standard of care." *Id.* The relevant inquiry, the court opined, was "whether the enunciated rule or principle of law extends to or is intended to protect this plaintiff from this type of harm arising in this manner." *Id.* (emphasis omitted) (quoting *Roberts v. Benoit*, 605 So. 2d 1032, 1044–45 (La. 1991)).

The court concluded that these statutes do not impose a duty on Defendants to protect Plaintiff from the harm alleged because even where "Plaintiff may derive some benefit from Defendants' compliance with those statutes, Plaintiff is not an intended beneficiary under any of them." *Id.* at *12. In reaching this conclusion, the court disregarded Plaintiff's argument that there is a duty under state law when applying these statutes, because the plaintiff here was not an intended beneficiary under any of those statutes. *Id.* at *13. The court held:

> It is not enough for Plaintiff to assert that it is a beneficiary of the federal statutes at issue. Rather, . . . Plaintiff must demonstrate as a matter of law that Defendants owe a specific duty to protect Plaintiff from the results of coastal erosion allegedly caused by Defendants' oil and gas activities in the Buffer Zone. Plaintiff has not and cannot make that showing under [these statutes]. Accordingly, the Court is compelled to conclude that Plaintiff has not stated a viable claim for negligence.

Id. at *14 (footnote omitted). The court also found that Plaintiff failed to state a claim for (1) strict liability, (2) interference with natural servitude of drainage, (3) nuisance, and (4) breach of contract, ultimately dismissing all of Plaintiff's claims against the oil and gas defendants. *See id.* at *14–22.

Mississippi — Oil & Gas

W. Eric West
— Reporter —

Oil and Gas Board Adopts Policies and Rules in Response to Tuscaloosa Marine Shale Operations, but with Statewide Application

In Vol. XXXI, No. 4 (2014) of this *Newsletter* the report stated that the substantial development in the Tuscaloosa Marine Shale (TMS) formation in southwest Mississippi had created a number of issues for the Mississippi State Oil and Gas Board (MSOGB), which administers these operations. The MSOGB has responded in several different ways.

On January 21, 2015, the MSOGB adopted four separate policy statements as follows:

(1) Policy Relating to Factors to Be Considered in Resolving the Issue of Competing Dockets;

(2) Policy Relating to Completeness of Drilling Permit Applications;

(3) Policy Relating to Drilling Unit Descriptions; and

(4) Policy Regarding 100% or "Simple" Integration Dockets Under Miss. Code Ann. § 53-3-7(1) (1972).

These policies, interestingly, are not limited to TMS wells and units but apply to all wells and units in the state.

On the MSOGB's own motion, it filed a petition for the January 21, 2015, meeting of the MSOGB to amend and revise Statewide Rule 61 (Firewalls) to prescribe new standards governing the construction and operation of dikes or firewalls surrounding oil tanks and saltwater tanks. *See* Docket No. 3-2015-D. This change would most affect TMS wells due to their high flow rates. This petition has not been heard and was continued at the April 15, 2015, meeting. *See* Order No. 217-2015.

At its April 15, 2015, meeting, the MSOGB amended Statewide Rule 6 (Well Signage—Identification of Well and Restrictions to Access), which provides for warning and information signage for oil and gas wells, tanks, and compressor stations, to also require warning and information signage for oil, gas, and saltwater flow lines. Effective July 15, 2015, such signs shall be placed along the flow lines not more than 500 feet apart. *See* Docket No. 92-2015-D; Order No. 234-2015. This minor change is not TMS related.

NEVADA — MINING

THOMAS P. ERWIN
— REPORTER —

RULE AGAINST PERPETUITIES DOES NOT APPLY TO ROYALTY PROVISION IN MINING CONTRACT

In *Bullion Monarch Mining, Inc. v. Barrick Goldstrike Mines, Inc.*, 345 P.3d 1040 (Nev. 2015), *answering certified questions from* 686 F.3d 1041 (9th Cir. 2012), the Nevada Supreme Court accepted certified questions from the U.S. Court of Appeals for the Ninth Circuit. The following questions were certified: (1) whether, under Nevada law, the rule against perpetuities applies to an area-of-interest provision in a commercial mining agreement; and (2) if the rule against perpetuities does apply, whether reformation of the agreement is available under Nev. Rev. Stat. § 111.1039(2). 345 P.3d at 1040. *See* Vol. XXX, No. 2 (2013) of this *Newsletter*.

On March 26, 2015, the Nevada Supreme Court held that the rule against perpetuities does not apply to area-of-interest royalty provisions in commercial mining contracts. 345 P.3d at 1044. Because the rule does not apply, the supreme court found no need to address the second certified question. *Id.*

The case arose from an agreement entered in 1979 pursuant to which Bullion Monarch Mining, Inc. (Bullion Monarch) reserved a 1% net smelter returns royalty on certain mining claims in Nevada's Carlin Trend. The royalty instrument provided that the royalty would apply to properties acquired in the area of interest defined in the royalty instrument. During the 1990s, Barrick Goldstrike Mines, Inc. (Barrick) acquired an interest in the properties subject to the royalty.

In 2009, Bullion Monarch sued Barrick in the U.S. District Court for the District of Nevada claiming that the royalty applied to other properties that Barrick owned in the area of interest. These properties were not described in the instrument by which Bullion Monarch reserved the royalty. Among the defenses Barrick asserted was that the area-of-interest royalty provision violated the rule against perpetuities and was void.

On February 7, 2011, the district court entered summary judgment in favor of Barrick, holding that a royalty imposed on lands acquired subject to an area-of-interest provision is a nonvested interest subject to a 21-year perpetuities period. *See Bullion Monarch Mining, Inc. v. Barrick Goldstrike Mines, Inc.*, No. 3:09-cv-00612, 2011 WL 484295 (D. Nev. Feb. 7, 2011). The court held that "[w]hen the parties to a transaction are corporations and no measuring lives are specified in the agreements," the perpetuities period is 21 years, and that a contractual term greater than 21 years is void because the contingent event of acquisition of a property within the area of interest could occur at any time following 21 years, thus violating the rule against perpetuities. *Id.* at *8. The court also held that Nevada's rule against perpetuities reformation statute does not apply to nondonative commercial transactions. *Id.* at *8–9 (citing Nev. Rev. Stat. § 111.1039(2)). The court concluded that an area-of-interest clause in a contract between two corporations would be *void ab initio* if the area-of-interest provision applied to property interests after 21 years. *Id.* at *9.

Bullion Monarch appealed to the Ninth Circuit. On June 13, 2012, the Ninth Circuit entered its order certifying the questions to the Nevada Supreme Court. The supreme court found that the rule against perpetuities was developed to promote public policy by ensuring that property remained alienable. Noting that the Nevada legislature exempted commercial, nondonative transfers from the statutory rule against perpetuities, the court concluded that applying the rule to area-of-interest royalty agreements does not further public policy and makes little sense in the world of commercial transactions. 345 P.3d at 1044. It held that as a matter of public policy the rule against perpetuities should not apply to nondonative transfers. *Id.* (citing Nev. Rev. Stat. § 111.1037).

On April 24, 2015, the Ninth Circuit reversed the summary judgment in favor of Barrick and remanded the matter for further proceedings in the district court. *See Bullion Monarch Mining, Inc. v. Barrick Goldstrike Mines, Inc.*, No. 11-15479, 2015 WL 1873142 (9th Cir. Apr. 24, 2015).

NEW MEXICO — MINING

STUART R. BUTZIER
— REPORTER —

COURT OF APPEALS UPHOLDS NEW MEXICO'S COPPER MINE RULE

On April 8, 2015, a unanimous three-judge New Mexico Court of Appeals panel affirmed the New Mexico Water Quality Control Commission's (WQCC) recently enacted regulations pertaining to ground water protection and supplemental permitting requirements for copper mine facilities (Copper Mine Rule), N.M. Code R. § 20.6.7. *See Gila Res. Info. Project v. WQCC*, Nos. 33,237, 33,238, 33,245, 2015 WL 1587396 (N.M. Ct. App. Apr. 8, 2015). As reported in Vol. XXX, No. 4 (2013) of this *Newsletter*, the Copper Mine Rule is a set of regulations comprising detailed technical requirements for the protection of ground water keyed to specific types of copper mining units, including open pits, waste rock piles, leach stockpiles, processing facilities, tailings impoundments, tanks, pipelines, etc. The rule also includes detailed mine closure requirements. The copper mine-specific requirements arose from a legislative mandate in 2009 amendments to the New Mexico Water Quality Act (WQA), N.M. Stat. Ann. §§ 74-6-1 to -17, and were developed and proposed in a rulemaking petition by the New Mexico Environment Department (NMED) after it had convened and received input from a technical advisory working group and stakeholder committee that met regularly for several months leading up to NMED's rulemaking petition. *See Gila*, 2015 WL 1587396, ¶¶ 3–5.

The court's opinion arose from consolidated appeals of the Copper Mine Rule that had been brought by New Mexico's Attorney General (AG) and certain non-governmental organizations and individual parties (collectively, NGOs) who were dissatisfied with the outcome of the rule after the lengthy stakeholder and public hearing proceedings leading to its adoption. The appellants made a combination of arguments relating to whether the rule violates the WQA and whether various aspects of the rule were supported by substantial evidence. The court rejected the arguments of the AG and NGOs and affirmed the WQCC's Copper Mine Rule. *Id.* ¶ 2. In rejecting the argument that the Copper Mine Rule violates the WQA, the court framed its detailed rationale by pointing out, among other things, that the WQCC rulemaking proceeding was one approach that the court had previously acknowledged could be employed to flesh out requirements under the WQA. *Id.* ¶ 15 (citing *Phelps Dodge Tyrone, Inc. v. WQCC*, 2006-NMCA-115, ¶ 35, 140 N.M. 464, 143 P.3d 502). The court also noted that an agency's regulations "are presumptively valid and will be upheld if [they are] reasonably consistent with the authorizing statutes." *Id.* ¶ 20 (alteration in original) (quoting *N.M. Mining Ass'n v. WQCC*, 2007-NMCA-010, ¶ 11, 141 N.M. 41, 150 P.3d 991).

In the context of rejecting the appellants' several substantial evidence arguments, the court considered assertions that the Copper Mine Rule "allow[s] widespread ground water pollution in excess of [the state's ground water quality standards] under an entire mine facility up to 'distant' monitor wells or even to the property boundary." *Id.* ¶ 33. The court found those arguments to be unfounded or otherwise exaggerated because, among other things, the Copper Mine Rule requires NMED approval of the number and placement of monitoring wells, which the rule specifically requires must be put "as close as practicable around the perimeter and downgradient of *each* mining unit . . . ." *Id.* ¶ 35 (emphasis added) (citing N.M. Code R. § 20.6.7.28 (A), (B)). The court further pointed out that if interested parties hypothetically objected to monitoring well locations proposed by a permittee in the context of particular copper mine permit proceedings, they would have opportunities to make their opinions known during the public participation processes associated with those permitting proceedings. *Id.* (citing N.M. Stat. Ann. § 74-6-5(G)).

After the court of appeals rendered its opinion affirming the Copper Mine Rule, the AG and NGOs filed three separate petitions for writ of certiorari seeking to further appeal to the New Mexico Supreme Court. As of the date of this writing, neither the WQCC nor the intervenor-appellees, which include three affiliated copper mining companies operating in New Mexico and NMED, have responded to the petitions, and no discretionary ruling on the petitions is expected until after any responses are filed.

Editor's Note: The reporter was one of the counsel of record for the intervening mining companies in the *Gila* case, as well as in the *Phelps Dodge* case mentioned in this report.

SANTA FE COUNTY'S INTERIM MINING MORATORIUM UPHELD FOR NOW

A state district court judge in Santa Fe on April 20, 2015, upheld a year-long moratorium on sand and gravel blasting extraction activity within Santa Fe County that became effective on September 16, 2014. *See Buena Vista Estates, Inc. & Rockology, Inc. v. Bd. of Cnty. Comm'rs of Santa Fe Cnty.*, No. D-101-CV-2014-02281 (N.M. Dist. Ct. Mar. 20, 2015). Santa Fe County's Board of County Commissioners (Board) imposed the moratorium after the party challenging it, Rockology, Inc. (Rockology), had applied for approval of a proposed blasting extraction operation, had completed a public hearing process, and was awaiting a decision by the same Board. *Id.* at 1. The court held that the moratorium—which the court found was entered to allow time for adopting new requirements for "developments of countywide impact" including mining—was "a reasonable measure designed to temporarily halt development while the [County] considered comprehensive zoning changes and was therefore a valid stopgap or interim measure." *Id.* at 10 (alteration in original) (quoting *119 Dev. Assocs. v. Vill. of Irvington*, 566 N.Y.S.2d 954, 955 (App. Div. 1991)).

According to the court, the Board's moratorium was a constitutionally permissible exercise of the County's police power under established law. *Id.* at 11 (citing *Brazos Land, Inc. v Bd. of Cnty. Comm'rs of Rio Arriba Cnty.*, 1993-NMCA-013, ¶¶ 27–30, 115 N.M. 168, 848 P.2d 1095). Rockology argued that the moratorium was a quasi-judicial decision targeted specifically to prevent its controversial extraction operation on Santa Fe County's high-profile La Bajada Hill. The court, however, cited authority for the proposition that although opposition to a specific proposed activity may have been the impetus for the County's action, where the action reflects a policy to be applied in the future more broadly than to a single property, Rockology's argument lacked merit. *Id.* at 13 (citing *KOB-TV, L.L.C. v. City of Albuquerque*, 2005-NMCA-049, ¶ 25, 137 N.M. 388, 111 P.3d 708). The court therefore did "not take issue with the County's ability to enact a moratorium." *Id.*

Moreover, the court held that Rockology's claim based on the avoidance of a decision on its application was not ripe since the County's moratorium was not a "final decision," and instead was merely an "interim" moratorium. *Id.* at 8. The court did, however, note that the County had "used the moratorium to hold in abeyance a pending application," and found that the appellants "certainly have a right to receive [a decision] at some point." *Id.* at 13. Although the court found the moratorium to be lawful "[a]t this stage," the court also granted leave to amend to Rockology, an apparent invitation to raise its right to a decision again should the County fail to take final action on Rockology's application or extend the moratorium for some period that might be unlawful. *Id.* Perhaps as a signal that the court would view the interim moratorium to be unlawful if it were extended, instead of dismissing the case, the court took the opportunity to summon the parties to a scheduling conference on November 16, 2015, one month to the day after the year-long moratorium is due to expire. *Id.* at 14.

Ohio — Oil & Gas / Mining

J. Richard Emens
Sean Jacobs
Craig J. Wilson
— Reporters —

Dormant Mineral Act Update

We continue to await guidance from the Ohio Supreme Court on Ohio's Dormant Mineral Act (DMA), Ohio Rev. Code § 5301.56. The Ohio Supreme Court has accepted two additional cases for review, adding to the growing number of DMA cases sitting before Ohio's highest court. *See Eisenbarth v. Reusser*, 2014-Ohio-3792, 18 N.E.3d 477 (7th Dist.), *appeal granted*, 141 Ohio St. 3d 1488, 2015-Ohio-842, 26 N.E.3d 823 (table); *Dahlgren v. Brown Farm Props. L.L.C.*, 2014-Ohio-4001, 19 N.E.3d 926 (7th Dist.), *appeal granted*, 141 Ohio St. 3d 1487, 2015-Ohio-842, 26 N.E.3d 823 (table). Given the number of DMA cases and issues accepted by the Ohio Supreme Court, many lower courts in Ohio have stayed their DMA cases.

Failure to Develop Deep Formations Underlying Shallow Wells Does Not Cause Lease to Terminate as to Deep Formations

The Fourth District Court of Appeals in *Marshall v. Beekay Co.*, 2015-Ohio-238, 27 N.E.3d 1 (7th Dist.), upheld the trial court's decision that the leases at issue were in full force and effect as to all formations despite the lack of development in deep formations. The appellants, Gary D. and Cora A. Marshall (Landowners), own 99 acres collectively subject to two oil and gas leases signed prior to 1905. *Id.* ¶ 3. In 1960, the appellees, Beekay Company et al. (Beekay), assigned shallow rights under the leases but reserved the deep rights unto themselves. *Id.* ¶ 4. The shallow rights are currently owned by Sandbar Oil and Gas Co. (Sandbar), which was operating 15 shallow wells on the Landowners' acreage that had been continuously producing in paying quantities. *Id.*

In 2013, the Landowners filed a complaint claiming that Beekay violated implied covenants by failing to reasonably explore and develop from the formations reserved in 1960 and that the oil and gas leases should be terminated as to the deep formations. *Id.* ¶ 5. The trial court granted summary judgment in favor of Sandbar, holding that it has continuously produced from the shallow formations (Landowners do not dispute that the leases are valid and in force and effect as to the shallow formations). *Id.* ¶ 6. The trial court also granted summary judgment in favor of Beekay, holding that Sandbar's continuous production kept the leases in full force and effect as to all formations. *Id.*

On appeal the Landowners argued that when Beekay assigned away the shallow rights, it divided the mineral interest and created an obligation on the part of Beekay to reasonably develop the deep rights, and that Beekay cannot rely on shallow production by Sandbar to keep the deep rights in effect. *Id.* ¶ 13. The Seventh District Court of Appeals rejected this argument. *Id.* ¶ 14. The court found that the 1960 assignment of shallow rights did not create a separate obligation for Beekay to reasonably develop the deep rights. *Id.* ¶ 18. The court instead held that the leases covered all formations and that Beekay's rights were protected by Sandbar's continuous production from the shallow formations, which satisfied the obligation to reasonably develop the leases. *Id.* ¶ 21. The court found that "there was no duty to further develop as long as gas and oil were being found in paying quantities." *Id.* ¶ 23.

Ohio Supreme Court Limits Local Government's Power to Regulate Oil and Gas Activity

The Ohio Supreme Court in *State ex rel. Morrison v. Beck Energy Corp.*, No. 2013-0465, 2015-Ohio-485, 2015 WL 687475, held that state law preempted the City of Munroe Falls' (City) rights to enforce oil and gas ordinances. In 2011, Beck Energy Corporation (Beck) obtained a permit from the Ohio Department of Natural Resources (ODNR) through Ohio Rev. Code ch. 1509 to drill an oil and gas well on property within the corporate limits of the City. 2015-Ohio-485, ¶¶ 2–3. Chapter 1509 gives ODNR "'sole and exclusive authority to regulate the permitting, location, and spacing of oil and gas wells and production operations' within Ohio (excepting certain activities regulated by federal laws)." *Id.* ¶ 4 (quoting Ohio Rev. Code § 1509.02). After Beck began drilling under its state-issued permit, the City issued a stop-work order and filed a complaint seeking injunctive relief because Beck was violating five Munroe Falls Codified Ordinances. *Id.* ¶ 7. The City alleged that Beck violated an ordinance prohibiting construction or excavation without a "zoning certificate" and four ordinances relating to oil and gas drilling. *Id.* ¶¶ 8–9. Violations of such ordinances are first-degree misdemeanors. *Id.* ¶ 10.

The trial court rejected Beck's argument that the City's ordinances conflicted with the statewide regulatory scheme set forth in chapter 1509 and granted the City's request for a permanent injunction. *Id.* ¶ 11. The Ninth District Court of Appeals reversed the trial court decision, holding that section 1509.02 preempted the City's right to enforce the five ordinances. *Id.* ¶ 12.

"The court of appeals rejected the [C]ity's argument that the Home Rule Amendment [to the Ohio Constitution] allowed it to impose its own permit requirements on oil and gas drilling operations." *Id.*

The Ohio Supreme Court stated that while the Home Rule Amendment to the Ohio Constitution "gives municipalities the 'broadest possible powers of self-government in connection with all matters which are strictly local . . . ,'" *id.* ¶ 14 (quoting *State ex rel. Hackley v. Edmonds*, 80 N.E.2d 769, 773 (Ohio 1948)), it does not "allow municipalities to exercise their police powers in a manner that 'conflict[s] with general laws,'" *id.* ¶ 15 (alteration in original) (quoting Ohio Const. art. XVIII, § 3). The court then set forth a three-prong analysis stating that "a municipal ordinance must yield to a state statute if (1) the ordinance is an exercise of the police power, rather than of local self-government, (2) the statute is a general law, and (3) the ordinance is in conflict with the statute." *Id.*

In going through the three-prong analysis, the court first found that the City's ordinances constituted an exercise of police power as such ordinances "do not regulate the form and structure of local government," which the City did not dispute. *Id.* ¶ 18. Second, the court found that section 1509.02 is a general law because it meets the following four conditions: (1) it is part of a statewide and comprehensive legislative enactment; (2) it applies to all parts of the state alike and operates uniformly throughout the state; (3) it sets forth police, sanitary, or similar regulations; and (4) it prescribes a rule of conduct upon citizens generally. *See id.* ¶¶ 19–23. The court rejected the City's argument that section 1509.02 does not apply to all parts of the state alike because only the eastern part of Ohio has economically viable quantities of oil and gas. *Id.* ¶ 20. Lastly, the court found that the City's ordinances were in conflict with section 1509.02 because they prohibit what section 1509.02 allows (state-licensed oil and gas production within Munroe Falls) and because section 1509.02 provides ODNR the sole and exclusive authority to regulate oil and gas wells and production operations. *See id.* ¶¶ 24–32.

The City made a number of policy arguments for why local governments and the State should work together to regulate oil and gas activity, with the State controlling well construction and operations and municipalities designating which land within their borders should be available for those activities. *Id.* ¶ 33. The court deferred to the general assembly on this question and made it clear that the court's decision was concerned with the five ordinances at issue, not whether the law should generally allow municipalities to have concurrent regulatory authority. *Id.*

This decision is a victory for Ohio operators. However, by explicitly limiting its holding to the five ordinances and leaving open the possibility that other ordinances could coexist with the general assembly's comprehensive scheme, the court does not close the door on this issue.

SEVENTH DISTRICT COURT OF APPEALS REAFFIRMS DECISION IN *HUPP*

In *Belmont Hills Country Club v. Beck Energy Corp.*, 7th Dist. Belmont No. 13BE18, 2015-Ohio-1322, 2015 WL 1592999, and *Bentley v. Beck Energy Corp.*, 7th Dist. Belmont Nos. 13BE33, 13BE34, 2015-Ohio-1375, 2015 WL 1593126, the Seventh District Court of Appeals reaffirmed its prior decision in *Hupp v. Beck Energy Corp.*, 2014-Ohio-4255, 20 N.E.3d 732 (7th Dist.), *appeal granted*, 141 Ohio St. 3d 1454, 2015-Ohio-239, 23 N.E.3d 1196 (table), which overturned one of the most significant trial court decisions during the recent Ohio Utica/Point Pleasant Shale play. *See* Vol. XXXI, No. 4 (2014) of this *Newsletter*. In these cases the Seventh District Court of Appeals held that the leases at issue were not perpetual and that they contained an express waiver of the implied covenant of reasonable development. These cases involve three appeals that arose out of two trial court judgment entries. *Belmont Hills*, 2015-Ohio-1322, ¶ 1; *Bentley*, 2015-Ohio-1375, ¶ 1. As the issues presented in the appeals were identical, they were heard together, with two of the appeals being consolidated in one opinion (*Bentley*) and the other appeal being addressed in a separate opinion (*Belmont Hills*).

The facts in the cases are similar and involve one or more oil and gas leases entered into between 2009 and 2011 with appellant Beck Energy Corporation (Beck), some of which were later assigned to appellant Petroleum Development Corporation. *Belmont Hills*, 2015-Ohio-1322, ¶ 4; *Bentley*, 2015-Ohio-1375, ¶¶ 4–6. All of the leases at issue contained two-tier habendum clauses (with a primary term of definite duration followed by a conditional secondary term) and a delay-rental clause. *Belmont Hills*, 2015-Ohio-1322, ¶¶ 4–7; *Bentley*, 2015-Ohio-1375, ¶¶ 7–9. The trial court granted motions for summary judgment in favor of the appellee in *Belmont Hills* (the Belmont Hills Country Club) and the appellees in *Bentley* (the Bentley family, the Menoski family, the Chambers family, the Kuba family, and the Busby family) holding that: (1) the leases contained an implied covenant to reasonably develop; (2) the leases were perpetual; (3) the leases seriously offended public policy and were *void ab initio*; and (4) the leases lacked mutuality and consideration. The trial court found that although the leases contained an implied covenant to reasonably develop, Beck had not violated such covenant. *Belmont Hills*, 2015-Ohio-1322, ¶ 9; *Bentley*, 2015-Ohio-1375, ¶ 11.

In reversing the decisions of the trial court granting summary judgment in favor of the appellees, the Seventh District Court of Appeals first looked at whether the leases contained an implied covenant to reasonably develop. The court followed its decision in *Hupp* and overturned the trial court's findings holding that the implied covenant to reasonably develop had been waived because the leases contained language expressly negating implied covenants and the leases included a delay rental clause that negated any implied covenant to reasonably develop. *Belmont Hills*, 2015-Ohio-1322, ¶¶ 16–21; *Bentley*, 2015-Ohio-1375, ¶¶ 19–24. The court next overturned the trial court's findings that the leases at issue were perpetual. Again following its decision in *Hupp*, the court held that a habendum clause containing a conditional secondary term following a primary term of definite duration did not render a lease perpetual nor could the lessees hold the leases in perpetuity by making nominal payments under the delay rental provisions. *Belmont Hills*, 2015-Ohio-1322, ¶¶ 22–31; *Bentley*, 2015-Ohio-1375, ¶¶ 25–34. The court found that because the leases were not perpetual they also did not violate public policy. *Belmont Hills*, 2015-Ohio-1322, ¶¶ 32–35; *Bentley*, 2015-Ohio-1375, ¶¶ 35–38. Finally, the court found that the leases were not illusory or void for lack of consideration because they place clear obligations on the lessee (drill a well within six months of the lease or pay a delay rental each year of the primary term until a well has been drilled) and do not give the appellants an unlimited right to determine the nature and extent of their performance. *Belmont Hills*, 2015-Ohio-1322, ¶¶ 36–43; *Bentley*, 2015-Ohio-1375, ¶¶ 39–46.

Pipeline Property Quick-Take

On December 2, 2014, Texas Eastern Transmission, LP's (Texas Eastern) Ohio Pipeline Energy Network (OPEN) pipeline project was approved by the Federal Energy Regulatory Commission (FERC). *See* Order Issuing Certificate, *In re Tex. E. Transmission, LP*, 149 FERC ¶ 61,198 (2014). As part of this approval, Texas Eastern acquired the right of federal eminent domain pursuant to section 7 of the Natural Gas Act, 15 U.S.C. § 717f. At the end of December, Texas Eastern filed suit in the U.S. District Court for the Southern District of Ohio against approximately 56 landowners who had not settled with Texas Eastern on pipeline easement terms and conditions. *See Tex. E. Transmission, LP v. 3.2 Acres Permanent Easement*, No. 2:14-cv-02650 (S.D. Ohio filed Dec. 16, 2014).

On January 12, 2015, the court issued an opinion and order granting Texas Eastern a temporary restraining order and preliminary injunction granting immediate possession of those landowner property interests that have not settled with Texas Eastern, also known as the right of "quick-take." *See Tex. E. Transmission, LP v. 3.2 Acres Permanent Easement*, No. 2:14-cv-02650, 2015 WL 152680 (S.D. Ohio Jan. 12, 2015). Quick-take means that Texas Eastern obtained the right to enter the properties of those landowners that had not granted an easement and install the pipeline without acquiring an easement.

Editor's Note: The reporters' law firm was involved in the *Texas Eastern* matter.

Oklahoma — Oil & Gas

James C.T. Hardwick
— Reporter —

Preferential Right to Purchase Barred by Laches

In *J.D. Kirk, LLC v. Cimarex Energy Co.*, No. 14-6122, 2015 WL 1346216 (10th Cir. Mar. 26, 2015), the U.S. Court of Appeals for the Tenth Circuit affirmed a district court holding that the doctrine of laches barred the enforcement of a preferential right to purchase. In 1991, David Kirk and J.D. Kirk, LLC (collectively, Kirk) became party to a joint operating agreement (JOA) that contained a preferential right to purchase provision. *Id.* at *1. Another party to the JOA transferred an interest covered by the JOA to a third party in 1997. That interest was eventually transferred to Cimarex Energy Company (Cimarex). *Id.* at *2. The interest was force-pooled in 2008, and a well was completed on the pooled unit in June 2009. In 2008, Kirk discovered that companies not party to the JOA had somehow acquired interests covered by the JOA's preferential right to purchase. In November 2009, Kirk became aware of Cimarex's ownership of the interest. *Id.* at *3. In 2011, Kirk filed suit against Cimarex seeking specific performance of the JOA's preferential right to purchase. *Id.* at *4. The district court granted Cimarex's motion for summary judgment based on laches. *Id.* at *5.

The Tenth Circuit first held that only prejudice, as opposed to irreparable harm, was required to establish laches. *Id.* at *8. Then, noting that laches must be rigorously applied in suits involving oil properties and other speculative ventures, the court held that Kirk's claim was barred. *Id.* at *9. The court determined that Kirk's 16-month wait to file suit was too long, especially given that it previously had notice that other companies who were not parties to the JOA had somehow acquired interests. Upon receiving that notice, Kirk should have investigated further and, having failed to do so, the court found that Kirk had slept on its rights, which were then barred by laches. *Id.* at *11.

Court Declines to Find that Ownership in Oil and Gas Company Was Abandoned

In *Unit Petroleum Co. v. Veitch*, No. 4:14-cv-00105, 2015 WL 84830 (N.D. Okla. Jan. 7, 2015), the court held that the Uniform Unclaimed Property Act, Okla. Stat. tit. 60, §§ 651–688, applies to the stock of oil and gas companies. Unit Petroleum Company (Unit) filed an interpleader action because there was a dispute as to who owned Petrohunter Energy, Inc. (Petrohunter), an interest holder in a well operated by Unit. Petrohunter was initially owned by KT Capital Corp. (KT), which in turn was owned by Steven Simonyi-Gindele. William A. Vietch claimed that KT and Simonyi-Gindele abandoned their ownership of Petrohunter and unilaterally declared that he now owned it. 2015 WL 84830, at *3.

The court noted that there is little or no case law concerning common-law abandonment of property in Oklahoma. *Id.* at *5. It reasoned that Oklahoma's adoption of the Uniform Unclaimed Property Act likely accounted for the absence of common-law authority. The court held that Vietch could not claim ownership in Petrohunter based upon common-law abandonment, but instead would have to comply with the Uniform Unclaimed Property Act's statutory procedures. *Id.* at *7. Those procedures include sending written notice to the apparent owner, filing a report with the state treasurer, and making a claim with the treasurer. *Id.* at *6. As Vietch had not complied with those procedures, he could not claim ownership. Additionally, the court found that Oklahoma law required Vietch to disclose the full value of the mineral interest to Simonyi-Gindele and KT when he had previously attempted to purchase the interests. *Id.* at *8. The court ultimately concluded that KT owned Petrohunter because it had not abandoned its interest. *Id.* at *9.

PACIFIC NORTHWEST — OIL & GAS

CARLIN A. YAMACHIKA
BRIAN E. HAMILTON
— REPORTERS —

OREGON COURT OF APPEALS BROADLY INTERPRETS MINERAL RESERVATION TO INCLUDE COMMON ROCK

Copeland Sand & Gravel, Inc. v. Estate of Dillard, 341 P.3d 187 (Or. Ct. App. 2014), *aff'd on reh'g*, 346 P.3d 526 (Or. Ct. App. 2015) (per curiam), involved the interpretation of a mineral reservation in a warranty deed. The deed reserved "all minerals in, under and upon the premises." The question before the court was whether the reservation included common rock such as basalt. 341 P.3d at 189. The Oregon Court of Appeals construed the reservation in favor of the reservation holder, Richard Skidmore, rejecting landowner Copeland Sand and Gravel, Inc.'s (Copeland) assertion that a mineral reservation does not include rock used for construction material as a matter of law.

In 1954, defendant Richard Skidmore's predecessor-in-interest executed a warranty deed to a lumber company for 120 acres of land subject to the aforementioned reservation. *Id.* at 189. The lumber company's successor-in-interest, Copeland, subsequently sought to use rock from the land as gravel for construction purposes. *Id.* Copeland filed an action for quiet title and declaratory relief. *Id.* Both parties sought summary judgment, each arguing that the reservation was unambiguous in support of their respective positions. *Id.* The trial court concluded that the mineral reservation did not include rock used for construction purposes, and granted declaratory relief in Copeland's favor. *Id.* On appeal, the court applied a three-step analysis to determine the meaning of the mineral reservation: (1) whether the text of the reservation is unambiguous; (2) whether any extrinsic evidence is available to resolve any ambiguity; and (3) whether maxims of construction point to a particular result. *Id.* (citing *Yogman v. Parrott*, 937 P.2d 1019 (Or. 1997) (en banc)).

As to whether the mineral reservation was ambiguous, Copeland argued that a reservation of mineral rights only includes minerals that have intrinsic value, not sand, gravel, and rock that might have an incidental use as a construction material. *Id.* Copeland relied on the holding in *Whittle v. Wolff*, 437 P.2d 114, 115, 118 (Or. 1968), that a reservation of "all subsurface rights, except water" did not include the right to sand and gravel. *Copeland*, 341 P.3d at 189. In *Whittle*, however, the nature of the particular land in question meant that a reservation that included rock used for construction would have resulted in the complete destruction of the surface in order to mine such rock. *Id.* at 190 (citing *Whittle*, 341 P.2d at 117). The court therefore concluded that *Whittle* did not apply a general rule to follow in every case. *Id.* Rather, the holding in *Whittle* only concerned the particular deed before the Oregon Supreme Court, and thus Copeland's reliance on the holding was misplaced. *Id.* In rejecting Copeland's interpretation, the court held that a mineral reservation does not exclude rock used for construction as a matter of law. *Id.*

The court also rejected Skidmore's attempt to apply the broad dictionary definition of "mineral" to include "basalt" and "rock." *Id.* Such a dictionary definition was not applicable because it would be broad almost to the point of being meaningless. *Id.* (noting that the dictionary definition would "encompass everything that is neither animal nor vegetable"). Nor did the court accept the definition of "mineral" found in Or. Rev. Stat. § 516.010(4), as there was no indication that the parties intended for the term as used in the deed to bear the meaning provided by the statute. *Copeland*, 341 P.3d at 190–91. The court instead concluded that either party's proffered interpretation was reasonable, and thus the term "mineral" as used in the reservation was ambiguous. *Id.* at 191.

In the absence of any extrinsic evidence of the parties' intent, the court finally relied on maxims of construction. *Id.* (citing *Yogman*, 937 P.2d at 1021). Specifically, the court applied the maxim that "[w]hen there is ambiguity in a deed, the general rule is to construe it against the grantor." *Id.* (quoting *Verzeano v. Carpenter*, 815 P.2d 1275, 1278 (Or. Ct. App. 1991)). In this case, the grantor was Copeland's predecessor-in-interest, while the grantee was Skidmore's predecessor-in-interest who reserved the mineral rights. *Id.* The court concluded therefore that the reservation should be construed in Skidmore's favor to include common rock. *Id.* at 192. *See also id.* (noting that Or. Rev. Stat. § 42.260 also directs that ambiguous provisions should be construed in favor of "the party in whose favor the provision was made").

Accordingly, the court reversed the trial court's order granting Copeland's motion for summary judgment and remanded to the trial court to issue a declaration in conformity with its decision. *Id.*

PENNSYLVANIA — MINING

JOSEPH K. REINHART
SEAN M. MCGOVERN
ABIGAIL F. JONES
— REPORTERS —

UPDATE ON PENNSYLVANIA LEGISLATURE'S OVERSIGHT OF CLEAN POWER PLAN IMPLEMENTATION

Pennsylvania lawmakers are considering a resolution that would establish a joint committee to prepare a report on implementation of the U.S. Environmental Protection Agency's (EPA) proposed regulation of carbon dioxide emissions from existing power plants. *See* House Resolution No. 259 (H. Res. 259), 2015 Gen. Assemb., Reg. Sess. (Pa. 2015). Last year, the Pennsylvania Greenhouse Gas Regulation Implementation Act (GHG Act), 71 Pa. Cons. Stat. §§ 1362.1–.4, granted the Pennsylvania legislature the opportunity to approve or disapprove the Commonwealth's plan to comply with the EPA's "Clean Power Plan" rule. *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014). *See also* Vol. XXXI, No. 4 (2014) of this *Newsletter*. The GHG Act, which was supported by the Pennsylvania Coal Alliance, addressed the process that will be used by the Pennsylvania Department of Environmental Protection (PADEP) to develop a compliance plan, and also required that PADEP's compliance plan be submitted to the General

Assembly for review and approval. The GHG Act has been used as a model for other states looking to give their legislatures a role in the process of developing a compliance plan.

H. Res. 259 would create the Joint Select Committee on the Implementation of the Environmental Protection Agency's Greenhouse Gas Regulation (Committee). The Committee would investigate and make recommendations about the Commonwealth's approach to compliance with the EPA's rules. H. Res. 259 would require the Committee to hold public hearings and accept written testimony as part of the investigation process.

Pennsylvania has also been selected by the National Governors Association as one of four states to participate in a "policy academy" intended to provide technical assistance and expert advice related to implementation strategies for the EPA's proposed rules. *See* News Release, Nat'l Governors Ass'n, "States Prepare for Future Federal Greenhouse Gas Rule" (Mar. 19, 2015). The participating states will receive advice from private sector, academic, and government experts on the economic and environmental effects of different implementation strategies. *Id.*

New Administration in Pennsylvania Identifies Key Appointees

Earlier this year, Pennsylvania inaugurated Governor Tom Wolf. In recent months Governor Wolf has made appointments to positions in his administration that influence mining and energy regulation in the commonwealth. John Quigley was appointed Acting Secretary of PADEP. He has previously been Secretary of the Department of Conservation and Natural Resources (DCNR) and held a position with Citizens for Pennsylvania's Future (PennFuture), an environmental nonprofit group. Cindy Dunn was appointed Acting Secretary of DCNR. She has worked at DCNR in various positions under both Democratic and Republican governors, and, most recently, was President and CEO of PennFuture. These two acting secretaries will face confirmation hearings in the Pennsylvania Senate. Notably, both the Governor's Chief of Staff, Kathleen McGinty, and his Secretary of Planning and Policy, John Hanger, were former secretaries of PADEP. John Hanger was also formerly affiliated with PennFuture.

Pennsylvania — Oil & Gas

Kevin M. Gormly
— Reporter —

Supreme Court Denies Equitable Tolling of Oil and Gas Lease

On February 17, 2015, the Supreme Court of Pennsylvania held that the primary term of an oil and gas lease was not equitably tolled where the lessor had pursued an unsuccessful declaratory judgment suit challenging the validity of the lease. *See Harrison v. Cabot Oil & Gas Corp.*, 110 A.3d 178 (Pa. 2015).

In 2007, Cabot Oil & Gas Corporation (Cabot), the lessee, entered into an oil and gas lease with Wayne Harrison, the lessor, for the exclusive right to explore for oil and gas resources. *Id.* at 179. In February 2010, approximately halfway through the five-year primary term of the lease, Harrison and his wife filed a declaratory judgment action against Cabot in the U.S. District Court for the Middle District of Pennsylvania. *Id.* In response, Cabot filed a counterclaim seeking a declaratory judgment that the primary term of the lease would be equitably tolled while the suit was pending and extended for an equivalent period of time, if Harrison's suit failed. *Id.* at 179–80.

On Cabot's motion for summary judgment on Harrison's claim, the district court awarded judgment in Cabot's favor on the underlying lawsuit. *Id.* at 181. However, on Cabot's counterclaim, the court concluded that "the law of [the] Commonwealth does not provide for equitable extensions of oil and gas leases under the circumstances." *Id. See also Harrison v. Cabot Oil & Gas Corp.*, 887 F. Supp. 2d 588, 596–98 (M.D. Pa. 2012). Accordingly, Cabot filed an appeal to the U.S. Court of Appeals for the Third Circuit contending that, if presented with this issue, the Pennsylvania Supreme Court would recognize the general rule adopted by almost every other jurisdiction that a lessee is entitled to an equitable extension of the lease term where the lessor's claim repudiating the lease is denied. *Harrison*, 110 A.3d at 181. Additionally, Cabot filed a motion requesting certification to the Supreme Court of Pennsylvania. *Id.*

The Supreme Court of Pennsylvania accepted certification from the Third Circuit to consider: "When an oil and gas lessor files an unsuccessful lawsuit to invalidate a lease, is the lessee entitled to an equitable extension of the primary lease term equal to the length of time the lawsuit was pending?" *Harrison v. Cabot Oil & Gas Corp.*, 96 A.3d 988, 989 (Pa. 2014) (mem.).

Presented with this issue of first impression in Pennsylvania courts and of significant public importance given the recent boom of oil and gas leases throughout Pennsylvania, the court refused to recognize the "mainstream approach of other jurisdictions which have treated a meritless lease challenge as a repudiation and applied equitable remedial principles." *Harrison*, 110 A.3d at 182. Instead, the court found that "[u]nder Pennsylvania law, anticipatory repudiation or breach requires an 'absolute and unequivocal refusal to perform or a distinct and positive statement of an inability to do so.'" *Id.* at 184 (quoting *2401 Pa. Ave. Corp. v. Fed'n of Jewish Agencies of Greater Phila.*, 489 A.2d 733, 736 (Pa. 1985)). Moreover, in the Commonwealth, a filing of a declaratory judgment action contesting the validity of an agreement is not an unequivocal refusal to perform. *Id.* at 184–85. Therefore, the court refused to "adopt a special approach to repudiation pertaining to oil-and-gas leases, as a substantial number [of] other jurisdictions would appear to have done." *Id.* at 185.

Despite the above findings, the court did not foreclose the availability of equitable relief where there is an actual affirmative repudiation of the oil and gas lease—beyond the mere pursuit of a challenge to the validity of the lease. *Id.* at 186. Further, the court recognized that companies could negotiate express tolling provisions in the lease agreements. *Id.*

Superior Court Reaffirms General Rule that Coalbed Methane Gas Is Conveyed Through Coal Ownership

On appeal to the Superior Court of Pennsylvania, owners of oil and gas rights in a 790-acre tract of land in Gilmore Township, Greene County (collectively, the Kennedys) challenged multiple orders and a judgment entry disposing of their claims of quiet title to coalbed methane gas (CBM) in the Pittsburgh seam; claims of quiet title to CBM in the Rider seam; and claims for trespass, conversion, unjust enrichment, and replevin. *See Kennedy v. Consol Energy Inc.*, No. 514 WDA 2014, 2015 WL 1813997, at *1 (Pa. Super. Ct. Apr. 22, 2015). The Kennedys appealed, and the superior court affirmed each of the trial court's respective holdings.

In a deed dated January 14, 1932, the predecessors in title to the Kennedys conveyed the property, but excepted and reserved the rights to the coal in the Pittsburgh and River veins and all of the oil and gas underlying the property. *Id.* In 1961, the Kennedys' predecessors conveyed their interests to all of the coal in the Pittsburgh and River veins to Consol Energy Inc. (Consol), being "the same interest in said tract of coal and mining rights which was reserved . . . in deed . . . dated January 14, 1932." *Id.* at *2. In 2005, Consol began degasification prior to the mining of the coal in the Pittsburgh vein. *Id.*

The process of degasification is undertaken to prevent explosions by removing CBM—a highly combustible gas that is present in the coal itself. *Id.* Relatively recently, CBM has become commercially marketable and, therefore, extremely valuable. *Id.* Thus, in 2007, the Kennedys filed a multi-claim complaint seeking ownership of the CBM under the subject property. *Id.* Specifically, the Kennedys contended that the reservations in the 1932 and 1961 deeds for "all of oil and gas in place" included CBM in the Pittsburgh and River veins. *Id.* at *4. On appeal, the Kennedys presented three questions for review: (1) whether the trial court misapplied *U.S. Steel Corp. v. Hoge*, 468 A.2d 1380 (Pa. 1983), regarding ownership of CBM by the coal owner; (2) if the trial court erred in entering summary judgment based on its own determination of the facts, when there were substantial questions of fact in the record; and (3) whether the trial court misconstrued the 1961 deed by finding that it conveyed the Pittsburgh Rider seam in addition to the "Pittsburgh or River vein." 2015 WL 1813997, at *3.

While the superior court emphatically denied that *Hoge* established a per se rule that the owner of the coal is also the owner of the CBM, it held that *Hoge* did create "the general rule that, when a coal severance deed is silent as to ownership of the [CBM], or does not expressly reserve [CBM] from the coal conveyance or specifically define [CBM] as a gas, the [CBM] contained in the coal belongs to the owner of the coal." *Id.* at *5. In addition, the superior court noted that "[i]n interpreting deeds, the principle *expressio unius est exclusio alterius* applies, meaning the express mention of one thing excludes all others." *Id.* at *6. With the express language of the 1932 and 1961 deeds not including CBM, but clearly reserving the right to drill for natural gas, the superior court affirmed that the grantor did not intend to retain any right in the CBM. *Id.* Thus, the 1961 deed merely reserved natural gas, and the CBM had been conveyed to Consol with the coal. *Id.*

Moreover, the superior court also found that the express language in the 1961 deed, which conveyed a right-of-way to access the coal in the Pittsburgh or River vein, was legally dispositive of the Kennedys' trespass claim. *Id.* at *8. As the deed conveyed an easement to Consol for "free, uninterrupted use and enjoyment of right of way into and under" the property, Consol was privileged to enter adjacent strata. *Id.* Thus, Consol's privilege to enter the adjacent strata in order to ventilate the CBM negated the Kennedys' trespass claim. The superior court also found that "[t]he fact that the degasification operation is a profitable enterprise does not exceed or run afoul of the right of way." *Id.*

Although there was evidence on the record that some the Kennedys' gas could have migrated to Consol's wells, the superior court found that summary judgment was nonetheless appropriate on the conversion claim. *Id.* at *9–11. Simply, the Kennedys could not provide evidence to support their damages for the allegedly converted gas. *Id.* at *11. The Kennedys attempted to support their conversion claim by asserting that the trial court should have applied the "confusion of goods doctrine," under which the property of two or more parties becomes commingled to the point where each party's respective items cannot be determined. *Id.* at *9–10. However, since the record lacked evidence of the fraudulent intermingling of gas, the superior court affirmed that the Kennedys failed to establish the element of an ascertainable loss. *Id.* at *11.

Finally, the superior court held that the Kennedys' quiet title claim over the Rider seam's CBM failed because there was no proof that the Rider seam actually existed under the property. *Id.* While the Kennedys' contention that the conveyance in the 1961 deed of the Pittsburgh coal seam to Consol did not include the Rider seam, the superior court found that the Rider seam was nonetheless separate and distinct from the roof coal zone of the Pittsburgh seam. *Id.* at *12. Therefore, evidence of the roof coal zone of the Pittsburgh seam under the property could not support evidence of the existence of the Rider seam. *Id.*

Third Circuit Rebuffs Use of Federal Bankruptcy Law to Reject Unexpired Oil and Gas Lease

In a non-binding precedential opinion, on March 18, 2015, the U.S. Court of Appeals for the Third Circuit affirmed the U.S. Bankruptcy and District Court for the Western District of Pennsylvania's denial of Mustafa Tayfur's attempt to reject an unexpired oil and gas lease pursuant to 11 U.S.C. § 365. *See In re Tayfur*, 599 F. App'x 44 (3d Cir. Mar. 18, 2015). Additionally, the Third Circuit affirmed that Tayfur's lease was not "at-will" under Commonwealth law, nor did the lease or assignment of the lease violate the statute of frauds. *See generally id.*

On December 28, 2005, Tayfur, who owned approximately 107 acres in Butler County, Pennsylvania, executed a lease with Central Appalachian Petroleum (CAP) granting oil and gas extraction rights with a primary term of 10 years. *Id.* at 45. The lease could be extended through either continued annual payments under the lease or the commencement of extraction. CAP assigned the lease to East Resources, Inc. (East) on July 14, 2006, and SWEPI L.P. (SWEPI) took over the lease, as East's successor-by-merger. *Id.*

Tayfur voluntarily filed a petition for bankruptcy under Chapter 13 of the U.S. Bankruptcy Code on November 14, 2011, and communicated with the bankruptcy court that he planned to fund his bankruptcy through payments received under his oil and gas lease. *Id.* However, as SWEPI had yet to begin extraction as of 2013, "Tayfur filed a motion to reject his lease with SWEPI pursuant to 11 U.S.C. §§ 365(a) and (d)(2), which permit a trustee to reject unexpired leases of the debtor where doing so would benefit the bankruptcy estate." *Id.* at 45–46. After the bankruptcy and district courts denied his motion, Tayfur appealed the decision to the Third Circuit. *Id.* at 46.

On appeal, the Third Circuit affirmed that rejecting the lease with SWEPI would not benefit the Tayfur estate.

> Under 11 U.S.C. § 365(h)(1)(A)(ii), where the trustee rejects an unexpired lease, but that lease's term has already commenced:
>
> > "the lessee may retain its rights under such lease (including . . . *possession* . . .) that are in or appurtenant to the real property for the balance of the term of such lease and for any renewal or extension . . . ."

Id. at 50 (quoting 11 U.S.C. § 365(h)(1)(A)(ii)). Thus, "[u]nder this provision, SWEPI would continue to have possessory rights [under the lease] at least until the end of the primary lease term," and possibly could continue to retain possessory interests under an extension of the lease. *Id.* In addition, the Third Circuit would not overturn the bankruptcy court's factual findings that rejection of the lease would not be in the best interests of Tayfur's estate. *Id.* at 51.

With regard to Tayfur's arguments under the Commonwealth law, the Third Circuit found them equally unappealing. First, the Third Circuit reaffirmed that an oil and gas lease is not controlled by Pennsylvania's Landlord and Tenant Act of 1951, and therefore, Tayfur's argument that the lease is terminable at will was without merit. *Id.* at 48. Second, CAP's failure to sign the lease did not cause the lease to expire, because "the signature requirement of Pennsylvania's general statute of frauds applies only to . . . the lessor," and here, Tayfur signed the lease. *Id.* Finally, the lease assignment from CAP to East was equally valid, as the "general principle of oil and gas law [is] that a lessee is free to assign its interest, absent an express clause stating otherwise," and the lease between Tayfur and CAP did not contain such an express clause. *Id.* at 49.

Governor Wolf Signs Executive Order Banning New Oil and Gas Leases on State Park and Forest Lands

On January 29, 2015, recently elected Governor Tom Wolf signed an executive order that bans new oil and gas leases of state park and state forest land. *See* Exec. Order No. 2015-03, "Leasing of State Forest and State Park Land for Oil and Gas Development" (Jan. 29, 2015) (Order No. 2015-03). Governor Wolf's executive order also supersedes and rescinds former Governor Tom Corbett's Executive Order 2014-03, which allowed companies to extract oil and gas beneath state park and state forest land from wells drilled on adjacent properties. *See* Exec. Order No. 2014-03, "Leasing of State Forest and State Park Land for Oil and Gas Development" (May 23, 2014). His executive order specifically recognized the Environmental Rights Amendment to the Pennsylvania Constitution, Pa. Const. art. I, § 27, as well as the Department of Conservation and Natural Resources' (DCNR) duties pursuant to the Conservation and Natural Resources Act, 71 Pa. Cons. Stat. §§ 1340.101–.1103. Under these guiding principles, the executive order denies any additional leasing of state park or forest lands owned and/or managed by the DCNR for oil and gas development.

Nonetheless, the executive order seems to impliedly comply with and recognize the commonwealth court's ruling that the DCNR, not the Governor, has the exclusive authority to make and execute leases for extraction of oil and gas on state lands. *See* Order No. 2015-03 ("subject to future advice and recommendations made by the DCNR"). *See also Pa. Envtl. Def. Found. v. Commonwealth*, 108 A.3d 140 (Pa. Commw. Ct. 2015); Vol. XXXII, No. 1 (2015) of this *Newsletter*. This executive order also does not affect oil and gas leases already in effect.

This executive order followed through on one of Governor Wolf's campaign pledges involving the oil and gas industry. Governor Wolf also pledged to seek legislative approval for a 5% extraction tax on natural gas.

Texas — Oil & Gas

William B. Burford
— Reporter —

Distinction Between Temporary and Permanent Injury to Real Property Clarified

The Texas Supreme Court took the opportunity in *Gilbert Wheeler, Inc. v. Enbridge Pipelines (East Texas) L.P.*, 449 S.W.3d 474 (Tex. 2014), to clarify several aspects of the law governing the proper measurement of damages for injury to real property, claims for which are a consistent source of employment for oil and gas litigators.

Gilbert Wheeler, Inc. (Wheeler) owned a heavily wooded 153-acre tract of land in Shelby County, Texas, that it used as a family retreat and called "the Mountain." Enbridge Pipelines, L.P. (Enbridge) sought an easement for a pipeline across Wheeler's tract, and the parties negotiated a right-of-way agreement requiring Enbridge to install its pipeline by boring underneath the ground in order to preserve the trees on the property. Enbridge neglected to inform its contractors, though, and instead of boring underground, they cut down a swath of trees, bulldozed the ground, and channelized a stream. Wheeler sued Enbridge for both breach of contract and trespass and obtained jury awards of $300,000 on its breach of contract claim as the reasonable cost to restore the property and $288,000 on the trespass claim for the intrinsic value of the destroyed trees. Wheeler elected to recover the damages awarded for breach of contract, and Enbridge appealed. The court of appeals reversed the trial court's judgment on the basis that Wheeler had failed to secure a finding whether the injury was temporary or permanent. *Id.* at 476–77.

The court of appeals had agreed with Enbridge that the question of whether the injury to the Mountain should be regarded as permanent or temporary was crucial to the measure of damages, if any, to which Wheeler was entitled. According to long-established law, the supreme court explained, "[i]f land is temporarily but not permanently injured by the negligence or wrongful act of another, the owner [is] entitled to recover the amount necessary to repair the injury . . . ." *Id.* at 478 (first alteration in original) (quoting *Trinity & S. Ry. Co. v. Schofield*, 10 S.W. 575, 576 (Tex. 1889)). On the other hand, "the true measure of damages in case of permanent injury to the soil is the difference between the value of the land immediately before the injury and its value immediately after." *Id.* (quoting *Ft. Worth & D.C. Ry. Co. v. Hogsett*, 4 S.W.365, 366 (Tex. 1887)). Wheeler argued that this distinction has no place when damages stem from breach of contract rather than tort: "restoration costs [would] give [Wheeler] the benefit of its bargain under the right-of-way agreement and thus [were] the proper measure of damages regardless of whether the injury to the Mountain [were] characterized as temporary or permanent." *Id.* at 479.

Wheeler's appeal, the supreme court said, raised broad concerns about the temporary-versus-permanent distinction, and the court addressed them in turn. The distinction between temporary and permanent injury, it first held, "is not limited in [its application] to causes of action that sound in tort rather than contract," as Wheeler argued. *Id.* "[T]he injury in question under either cause of action is the same," it pointed out, and the court saw "no reason to compensate a party differently because the wrongful conduct that caused the identical injury stem[med] from breaching a contract rather than committing a tort." *Id.* The temporary-versus-permanent distinction therefore underlay "the determination of the proper measure of damages for both the trespass and breach-of-contract claims at issue." *Id.* at 479–80.

The court then, for the sake of clarity in the law, went on to formulate the definitions of permanent and temporary injury to real property. According to the court's new definition,

> [a]n injury to real property is considered permanent if (a) it cannot be repaired, fixed, or restored, *or* (b) even though the injury can be repaired, fixed, or restored, it is substantially certain that the injury will repeatedly, continually, and regularly recur, such that future injury can be reasonably evaluated. Conversely, an injury to real property is considered temporary if (a) it can be repaired, fixed, or restored, *and* (b) any anticipated recurrence would be only occasional, irregular, intermittent, and not reasonably predictable, such that future injury could not be estimated with reasonable certainty.

Id. at 480. "[W]hether an injury is temporary or permanent," the court held, "is a question of law for the court to decide," although "the facts that underlie the temporary-versus-permanent distinction must be resolved by the jury upon proper request." *Id.* at 481.

The general rules are applied with some flexibility, the court went on, and it noted two exceptions that were important in this case. First, "[i]n cases involving temporary injury, Texas courts have recognized the so-called economic feasibility exception to the general rule that the cost to restore is the proper measure of damages." *Id.* "[W]hen the cost of required repairs or restoration exceeds the diminution in the property's market value to such a disproportionately high degree that the repairs are no longer economically feasible," a temporary injury is deemed permanent so that the landowner will not be excessively compensated. *Id.* Also, the court confirmed, there is an exception to the rule that the measure of damages for permanent injury is diminution of the land's value when the injury involves the destruction of trees. When a landowner can show that the destruction of trees on real property resulted in no diminishment, or essentially nominal diminishment, in the property's market value, the landowner may recover the intrinsic (aesthetic and utilitarian) value of the trees. *Id.* at 483.

Because the question of whether the injury to the land was temporary or permanent was a question of law, the court held, Wheeler was not required to submit a jury question on that issue, and the court of appeals had erred in holding that Wheeler had waived its entitlement to damages on that basis. *Id.* at 484. "[A]pplying the definitions [the court] supplied in this opinion," the court further held that "the injury to the Mountain [was] deemed permanent as a matter of law" under the economic-feasibility exception inasmuch as the evidence presented by both sides showed that the cost of restoration would be vastly disproportionate to the diminution in the property's value. *Id.* But because "a landowner may recover for the intrinsic value of the trees on his property [if] the diminution in the fair market value of the land is essentially nominal," as it was here, Wheeler could pursue his claim under the intrinsic value exception. *Id.* at 485. The court remanded the case to the court of appeals to address issues it had not reached. *Id.* at 486.

Failure of Executive to Obtain Market Royalty Rate May Have Breached Duty to Nonparticipating Royalty Owner, but Agreeable Lessee Is Not Responsible

KCM Financial LLC v. Bradshaw, No. 13-0199, 58 Tex. Sup. Ct. J. 437, 2015 WL 1029652 (Tex. Mar. 6, 2015), represents the Texas Supreme Court's latest effort to define the duty the owner of the executive right, i.e., the right to execute oil and gas leases, owes to a royalty owner whose interest is subject to that right. "Although the parameters of the duty are imprecise," the court averred, "at bottom, the executive is prohibited from engaging in acts of self-dealing that unfairly diminish the value of the non-executive interest." *Id.* at *1.

Betty Lou Bradshaw held a non-participating royalty interest in 1,773 acres of the Mitchell Ranch in Hood County, Texas. The 1960 deed reserving the interest to Bradshaw's parents described the interest as one-half of any future royalty and mandated that any royalty be not less than one-eighth. *Id.* at *2. Steadfast Financial LLC (Steadfast), which became KCM Financial LLC during the pendency of the appeal, held the right to execute oil and gas leases binding on Bradshaw's one-half of the royalty and on Steadfast's remaining one-half. In April 2006 Steadfast sold the surface of the land to Range Resources Corp. and executed an oil and gas lease to Range Production I, L.P., evidently an affiliate of Range Resources Corp. (collectively, Range). *Id.* at *4. Steadfast reserved a one-eighth royalty in the lease and received a bonus payment, not shared by Bradshaw, of $7,505 per acre. *Id.* at *5. In January 2007 Bradshaw sued Steadfast, alleging that it had breached its duty to her by obtaining an exorbitant bonus payment at the expense of a higher royalty in a trade-off that diminished the value of her interest. She also sued Range, asserting that Range had conspired with Steadfast and aided and abetted its breach. *Id.* The supreme court affirmed the court of appeals' reversal of the trial court's summary judgment for

Steadfast, but it reversed the court of appeals and reinstated the trial court's summary judgment for Range.

The court began with an explanation of the principles governing the relationship between the executive and non-executive owners. Although the relationship has been described as fiduciary in nature, it pointed out, "the executive is not required to grant priority to the non-executive's interest." *Id.* at *7. Rather, "the executive's duty is to acquire for the non-executive every benefit that he exacts for himself." *Id.* (quotation marks omitted) (quoting *Lesley v. Veterans Land Bd. of State*, 352 S.W.3d 479, 490 (Tex. 2011)). "[E]vidence of self-dealing can be pivotal," said the court, and it has "generally observed the absence of self-dealing" when it has declined to find a breach of the duty. *Id.* at *8. "[T]he controlling inquiry," the court summed up, "is whether the executive engaged in acts of self-dealing that unfairly diminished the value of the non-executive interest." *Id.*

The determination of whether the executive has engaged in self-dealing at the non-executive's expense is a difficult one, the court recognized. "[M]yriad components of any given arrangement can affect the overall value of a mineral lease . . . . [and] [t]he interests of the executive and the non-executive may . . . be aligned in some respects but not others." *Id.* at *9. In the court's view, "the executive may discharge its duty to the non-executive without yielding entirely to the non-executive's best interests. To hold that the executive must [invariably] obtain the highest royalty available would . . . unduly impinge the executive's right to make and amend leases." *Id.* On the other hand, "the going rate for a royalty interest is not altogether immaterial." *Id.* The situation here, where the executive holds the right to obtain benefits, such as bonuses, in which the non-executive has no interest, according to the court, "presents a conundrum that requires balancing the bundle of rights that comprise the mineral estate." *Id.* at *10. The conduct alleged here, that "the executive [had] misappropriated what would have been a shared benefit (a market-rate royalty interest) and converted it to a benefit reserved only unto itself (an enhanced bonus), with the intent to diminish the value of Bradshaw's royalty interest," if proven, was to the court "the essence of self-dealing." *Id.*

The court refused to hold that the executive's duty could be satisfied merely by obtaining some royalty or the minimum required in the deed creating the non-participating royalty. "[T]he subject transaction must be viewed as a whole in determining whether the terms of a mineral lease, including the negotiated royalty, reflect the executive's required utmost good faith and fair dealing . . . ." *Id.* Because there was some summary judgment evidence that "the one-eighth royalty Steadfast negotiated was artificially low, the bonus Steadfast received was unusually high, and Steadfast intended to minimize the benefit shared with Bradshaw," Steadfast was not entitled to summary judgment. *Id.*

Turning to Bradshaw's claim against Range under civil-conspiracy and aiding-and-abetting theories, the court had no hesitation in holding it "untenable as a matter of law." *Id.* at *11. "Evidence that Range knew the [mineral] estate was burdened with Bradshaw's non-participating royalty interest, may have known about tensions between Bradshaw's and Steadfast's interests, and agreed to a one-eighth royalty and an eight-figure bonus payment" showed nothing more than a typical business transaction on mutually acceptable terms. *Id.* Were the court to validate Bradshaw's theory of derivative liability, it noted, "it would be difficult to conceive of a context in which a lessee would not owe a . . . fiduciary duty to the other side of the bargaining table," because both sides would be required to balance their interests against the non-executive's. *Id.* This would be not only contrary to the limited scope of the duty to the non-executive, the court declared, it would be nonsensical. *Id.*

The court went on to hold that Bradshaw could not support her contention that she was entitled to impose a constructive trust on Steadfast's one-half of the one-eighth lease royalty, in addition to her own one-half of one-eighth, so that Bradshaw would be paid the one-half of the allegedly available one-fourth lease royalty she claimed she should have received. The imposition of a constructive trust, the court pointed out, requires that some particular property be identified that has been wrongfully taken; "[a] constructive trust is not merely a vehicle for collecting assets as a form of damages." *Id.* at *14. The royalty payments on which Bradshaw sought a constructive trust emanated from Steadfast's royalty interest, not any interest taken from her. *Id.*

The court's essential pronouncements relative to the executive's duty are summarized early in the opinion. "[N]o bright line rule can comprehensively or completely delineate the boundaries of the executive's duty." *Id.* at *1. Instead, "the lease and the circumstances of its execution must be considered as a whole . . . ." *Id.* "[T]he executive's failure to obtain a market-rate royalty does not conclusively establish a breach of duty," but is a relevant factor. *Id.* Every case in which breach of the executive's duty is alleged must therefore depend on the facts. It probably can be said, though, that an executive who fails to negotiate the highest available royalty rate will have breached his duty to a non-participating royalty owner if he has also negotiated in the same transaction offsetting benefits unusually favorable to the lessor in which the non-executive does not share.

OFFSHORE OPERATOR HELD NOT AN ADDITIONAL INSURED FOR SUBSURFACE POLLUTION LIABILITY

The Texas Supreme Court in *In re Deepwater Horizon*, No. 13-0670, 58 Tex. Sup. Ct. J. 330, 2015 WL 674744 (Tex. Feb. 13, 2015), *answering certified question from* 728 F.3d 491 (5th Cir. 2013), answered the question, certified to it by the U.S. Court of Appeals for the Fifth Circuit, of whether BP America Production Co. and affiliates (collectively, BP), the operator, was covered as an additional insured under insurance policies carried by Transocean Offshore Deepwater Drilling, Inc. and affiliates (collectively, Transocean), the drilling contractor, for liability for subsurface oil releases stemming from the April 2010 explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico.

Under the parties' drilling contract, Transocean agreed to indemnify BP against liability for above-surface pollution, regardless of fault, and BP agreed to indemnify Transocean against all pollution risk Transocean did not assume, including that of subsurface pollution. 2015 WL 674744, at *2. The drilling contract also required Transocean to carry various types of insurance and to name BP and related entities additional insureds in each of its policies "except Workers' Compensation for liabilities assumed by [Transocean] under the terms of [the

Drilling] Contract." *Id.* at *3 (alterations in original) (emphasis omitted).

Transocean's insurance policies obligated the insurers to pay for any loss on behalf of an "Insured" for liability imposed by law or assumed by the "Insured" under an "Insured Contract." *Id.* The policies extended "Insured" status not only to Transocean but also to "[a]ny person or entity to whom the 'Insured' is obliged by oral or written 'Insured Contract' . . . to provide insurance such as afforded by [the] Policy." *Id.* (alterations in original). An "Insured Contract" was defined as "any written or oral contract or agreement entered into by the 'Insured' . . . and pertaining to business under which the 'Insured' assumes the tort liability of another party to pay for 'Bodily Injury' [or] 'Property Damage' . . . to a 'Third Party' or organization." *Id.* (alteration in original). After BP made a demand for coverage for subsurface pollution as an additional insured under Transocean's policies, the insurers sought a judicial declaration that BP was not entitled to it. *Id.* at *4. On appeal from a federal district court determination that BP was not an "Insured" under Transocean's policies, the Fifth Circuit certified the question to the Texas Supreme Court.

The court focused on the language of the insurance policies. An insured may, the court recognized, "gratuitously choose to secure more coverage for an additional insured than it is contractually required to provide," and a policy for such coverage will be enforced in favor of the additional insured. *Id.* at *6. The policies here required the insurers to afford additional-insured coverage only to one to whom the named insured is obliged by contract to provide coverage. The policies thus required the court to consult the drilling contract to determine whether Transocean was obliged to procure insurance coverage for BP as an additional insured. *Id.* at *9. Because the drilling contract required Transocean to provide insurance, according to the court's interpretation, only for liabilities assumed by Transocean, it concluded that BP was intended to be an additional insured under the insurance policies only as to those liabilities and no others. *Id.* at *11. Transocean did not assume liability for subsurface pollution and was therefore "not 'obliged' to name BP as an additional insured as to that risk." *Id.* Because there was no obligation to provide insurance for that risk, BP lacked status as an "Insured" for it. *Id.*

GAS WELL OPERATOR'S DEFAMATION SUIT ALLOWED TO PROCEED AGAINST ONE OF THREE DEFENDANTS

The Texas Supreme Court in *In re Lipsky*, No. 13-0928, 2015 WL 1870073 (Tex. Apr. 24, 2015), *denying mandamus from* 411 S.W.3d 530 (Tex. App.—Fort Worth 2013), considered the Texas Citizens Participation Act (TCPA), Tex. Civ. Prac. & Rem Code §§ 27.001–.011, in the context of a homeowner's criticism of a natural gas producer. Range Resources Corporation and Range Production Company (collectively, Range) drilled two natural gas wells near Steven and Shyla Lipsky's house in Weatherford, Texas. After complaints by the Lipskys and by Alisa Rich, their environmental consultant, the U.S. Environmental Protection Agency (EPA) issued an order blaming gas contamination in the Lipskys' water well on Range's gas wells and imposed remediation measures. Eventually the Texas Railroad Commission (RRC) determined that Range had not contaminated the Lipskys' water, and the EPA later withdrew its order without explanation. Meanwhile, the Lipskys had filed suit against Range for damages resulting from Range's alleged contamination of their well, and Range counterclaimed against the Lipskys and brought a third-party claim against Rich for defamation, business disparagement, and civil conspiracy. 2015 WL 1870073, at *1–2. The Lipskys' suit was dismissed by the trial court as an improper collateral attack on the RRC's determination, but the trial court denied the Lipskys' and Rich's motion to dismiss Range's claims. *Id.* at *2.

The Lipskys and Rich sought dismissal of Range's suit under the TCPA, the purpose of which is to "protect[] citizens from retaliatory lawsuits that seek to intimidate or silence them on matters of public concern." *Id.* at *3. The TCPA provides a special procedure for the expedited dismissal of such suits: If a defendant shows by a preponderance of evidence that the plaintiff's claim relates to the defendant's right of free speech, petition, or association, the plaintiff must, to go forward, establish a prima facie case for each essential element of its claim "by clear and specific evidence." *Id.* (quoting Tex. Civ. Prac. & Rem. Code § 27.005(c)). The court of appeals held that the trial court should have dismissed Range's claims against Shyla Lipsky and Rich, because Range could not point to specific evidence of their casting blame on Range, but it allowed Range to proceed against Steven Lipsky. The supreme court affirmed the court of appeals' decision.

On appeal to the supreme court the only question was whether Range had met its burden of establishing a prima facie case by clear and specific evidence; there was no dispute that Range's claims implicated Steven Lipsky's free-speech rights. Lipsky contended that the phrase "clear and specific evidence" elevates the evidentiary standard the plaintiff must meet, requiring direct evidence. "Range, on the other hand, argue[d] that circumstantial evidence and rational inferences may be considered by the court in determining whether clear and specific evidence exists and that the TCPA's prima-facie-case requirement does not impose a higher or unique evidentiary standard." *Id.* The phrase "clear and specific evidence," the court pointed out, is defined in neither the TCPA nor in the common law, so the words are to be given their plain and ordinary meaning. *Id.* at *6. Although the requirement of such evidence, in the court's view, indicates that a plaintiff's "general allegations that merely recite the elements of a cause of action . . . will not suffice" and that "a plaintiff must provide enough detail to show the factual basis for its claim," the TCPA "does not impose an elevated evidentiary standard or categorically reject circumstantial evidence." *Id.* at *7. Having made this determination, the court next considered whether Range had met its burden with respect to its business disparagement and defamation claims.

"To prevail on a business disparagement claim," the court observed, "a plaintiff must establish that (1) the defendant published false and disparaging information about it, (2) with malice, (3) without privilege, (4) that resulted in [economic] damages to the plaintiff." *Id.* at *8 (footnote omitted) (quoting *Forbes Inc. v. Granada Biosciences, Inc.*, 124 S.W.3d 167, 170 (Tex. 2003)). The court agreed with Lipsky that the conclusory statement in an affidavit of a Range vice president that it had "suffered direct pecuniary and economic losses" and other losses in excess of $3 million was insufficient, being "devoid of any specific facts illustrating how Lipsky's alleged remarks about Range's activities actually caused such losses." *Id.* at *9. To show a prima facie case for defamation, however, as opposed to business disparagement, Range was not required to plead and prove specific economic loss if the plaintiffs' alleged actions amounted to defamation per se, i.e., statements so obviously harmful that general damages may be presumed, such as damages for mental anguish and loss of reputation. *Id.* The gist of Lipsky's statements that were the basis of Range's complaint, that Range had contaminated the Lipskys' well and that the RRC had been unduly influenced to rule otherwise, by their nature "adversely affect the perception of Range's fitness and abilities as a natural gas producer." *Id.* at *12. Because those statements amounted to defamation per se, the court held, Range need not plead or prove actual damage. The trial court therefore had not abused its discretion in denying Lipsky's motion to dismiss. *Id.*

The court affirmed the court of appeals' order requiring dismissal of Range's claims against Shyla Lipsky and Alisa Rich. The court of appeals had, it observed, considered Range's evidence of Rich's predisposition to blame Range and other producers for contamination but had reasonably "concluded it was not clear and specific evidence that 'Rich had conspired with the Lipskys to blame Range on this occasion.'" *Id.* at *12 (quoting 411 S.W.3d at 551). Likewise, no clear and specific evidence established a prima facie case that Shyla Lipsky or Rich published any defamatory remarks against Range or conspired with Steven Lipsky to do so. *Id.* at *13.

Lost Profits from Foreign Gas Drilling Venture Held Too Speculative as Measure of Its Value, but Amounts Participants Were Willing to Spend Is Competent Evidence

The central issue in *Phillips v. Carlton Energy Group, LLC*, No. 12-0255, 2015 WL 2148951 (Tex. May 8, 2015), was whether Carlton Energy Group, LLC (Carlton), the plaintiff, had met its burden to demonstrate the amount of its damages against Gene Phillips and affiliated business entities (collectively, Phillips) that had deprived Carlton, through breach of contract and tortious interference with contract, of Carlton's interest in an oil and gas venture.

In October 2000 CBM Energy Limited (CBM) secured from the government of Bulgaria a concession to explore a large area for coalbed methane gas. *Id.* at *1. It entered into an agreement with Carlton under which Carlton was to provide up to $8 million in funding for the wells that would be required for the initial testing and development of the project in exchange for up to a 48% interest. *Id.* at *2. Carlton began efforts to attract investors for the project and eventually offered Phillips a 10% interest in exchange for $8.5 million, sufficient cash to pay for initial drilling and development, which would leave Carlton with 38%. Phillips accepted by letter agreement on August 23, 2004. *Id.* at *4.

Within a few months Phillips had met with CBM and the Bulgarian government, convinced CBM to declare Carlton in default under the CBM-Carlton agreement, and entered into a new agreement with CBM to acquire 60% of the project in exchange for $6.5 million and Phillips's agreement to carry CBM's development and operating costs. *Id.* After one well was drilled, which apparently never produced but demonstrated the existence of a large and potentially profitable reservoir, the concession terminated in 2007. Phillips lost $13 million on the project. *Id.* at *5.

Carlton sued Phillips in late 2006, alleging Phillips's breach of the August 2004 contracts and tortious interference with Carlton's contract with CBM. *Id.* At trial the jury returned a verdict for Carlton, finding that Phillips had breached the agreement with Carlton and had tortiously interfered with the Carlton-CBM contract and awarding actual damages of $66.5 million for the fair market value of Carlton's interest in the contract at the time of the breach and for tortious interference, plus $8.5 million in exemplary damages. *Id.* at *7.

After concluding that the jury's findings on the existence and breach of a contract between Phillips and Carlton and on tortious interference were supported by sufficient evidence, the court came to Phillips's principal argument, "that Carlton's evidence of the fair market value of a 38% interest in the Bulgarian project . . . [was] too speculative to support an award of damages." *Id.* at *9. The law is well-settled, the court first observed: "lost profits can be recovered only when the amount is proved with reasonable certainty." *Id.* The proof need not be perfect or exact but must be based on objective data and cannot be speculative. The court remarked that while it had "never spoken to whether this requirement of reasonable certainty of proof should apply when lost profits are not sought as damages themselves but are used to determine the market value of property for which recovery is sought, it clearly must." *Id.* at *10.

Carlton argued for its $66.5 million damage award on the basis of an expert engineer's testimony of the volume of recoverable gas the concession was believed to contain, from earlier studies by another engineer, the price obtainable for the gas, the number of wells that would be drilled, and the success rate, all of which, Carlton argued, was deeply discounted by the jury in arriving at its valuation. *Id.* at *11. Merely laying out the calculation for which Carlton argued, with its sweeping assumptions, demonstrated for the court how completely conjectural it was. It provided no basis for the projection of gas volumes nor for assessing the risks of drilling and getting the gas to market, the court pointed out, and the witness admitted he merely offered the jury a "considerable range" of values to consider. *Id.* "Nothing in the evidence," the court concluded, "support[ed] the jury's $66.5 million finding." *Id.*

But another damage calculation for which Carlton argued was based on an actual offer by a willing seller: Phillips's agreement to pay Carlton $8.5 million for a 10% interest. By simple extrapolation, this indicated to Carlton's expert that the entire prospect was worth $85 million less $3 million in drilling costs for three wells required by the concession. *Id.* The court could not hold, it said, "that the amount Phillips was willing to pay Carlton, for the very interest at issue, [was] not some evidence to support the verdict," to the extent of a 38% of $82 million valuation, although Carlton could argue on remand to the court of appeals, based on the amounts Carlton agreed to pay CBM and that others had expressed willingness to pay for specified interests, that "the jury's verdict was against the great weight and preponderance of the evidence . . . ." *Id.* at *11.

Property Description in Foreclosure Assignment Held Not Limited to Well's Proration Unit

Imprecision in conveyancing and carelessness in title assurance are both constant sources of disputes. *Victory Energy Corp. v. Oz Gas Corp.*, No. 08-12-00248-CV, 2014 WL 8045237 (Tex. App.—El Paso Sept. 17, 2014, pet. denied), presents extreme examples of how.

In 1974 Gary Garlitz acquired an oil and gas lease for his company, Chesapeake Bay Gas Gathering Co. (Chesapeake Gas Gathering), on, among other land, a quarter-section of land on his wife's family's ranch in Crockett County, Texas, SE¼ of Section 155, Block O, GH&SA Ry. Co. Survey. The lease was extended beyond its two-year primary term by production from several wells, including the Argee Oil Co. No. 1-155, which was assigned an 80-acre proration unit under RRC rules consisting of land mostly in E½SE¼ of Section 155. A well was also drilled in W½SE¼ of Section 155, the Crockett 1-155, but it was evidently not producing during the period of the occurrences that led to the suit. *Id.* at *1–2.

In 1986 Chesapeake Gas Gathering executed a deed of trust granting a mortgage lien on its oil and gas leasehold in SE¼ of Section 155. Chesapeake eventually defaulted in the payment of the indebtedness the deed of trust secured, and the lien was foreclosed at a trustee's sale in 1998. *Id.* at *2–3. The trustee acting under the deed of trust's power of sale executed a trustee's deed to Oz Gas Corp. (Oz Gas), the purchaser, conveying "the property more particularly described on Exhibit 'A' attached hereto . . . ." *Id.* at *3. Exhibit "A" described, as part of "Parcel 3," the SE¼ of Section 155. All of the Exhibit "A" property descriptions were preceded by a clause the court called an "introductory proviso":

> The following oil and gas leases are limited in area to the Railroad Commission of Texas proration units surrounding the oil and/or gas wells referenced below and are subject to depth restrictions and the other provisions of these leases.

Id. at *4. After the land description of SE¼ of Section 155 (and two other tracts) was a description of the 1974 oil and gas lease by lessor, lessee, date, and recording data, followed by a description of wells, in tabular form, including the well in E½SE¼ Section 155:

Wells	Working Interest	Net Revenue Interest
Argee Oil Company #1-155 and #1-166	75%	.5791670

See id. at *3.

Oz Gas continued to operate the Argee No. 1-155 Well in E½SE¼ of Section 155 from 1998 until the time of suit. Meanwhile, Garlitz conducted at least some preliminary work on the old Crockett well in W½SE¼ of Section 155, without Oz Gas's knowledge, it maintained, beginning in 1999. In 2007 Garlitz, claiming to be acting on behalf of the mineral owners, executed an oil and gas lease on W½SE¼ of Section 155 to Universal Energy Resources, Inc. (Universal), which proceeded to drill two wells at a cost of about $6 million. Victory Energy Corp. (Victory), HCP Investments, L.L.C. (HCP), and SmartGas, L.L.C. (SmartGas) acquired the wells from Universal and became defendants in Oz Gas's trespass to try title suit in which it sought to establish its oil and gas leasehold title to W½SE¼ of Section 155. *Id.* at *4–5. The trial court granted Oz's motion for summary judgment on the basis that the 1998 trustee's deed included all of SE¼ Section 155 and found that Victory, HCP, and SmartGas were bad-faith trespassers and thus not entitled to recover their drilling costs out of revenue from the wells' production. *Id.* at *6. The court of appeals affirmed.

The court recognized that the central issue was whether the "introductory proviso" limited the trustee's deed's operation to the 80-acre proration unit assigned to the Argee No. 1-155 Well. The court agreed with Oz that it did not. Reading the "general, vague" wording of the proviso as limiting the conveyance to only wells and their surrounding proration units would render the inclusion of the full quarter-section description essentially meaningless, in the court's view. *Id.* at *9. "[T]he more natural reading *and the only tenable reading* of the Trustee's Deed," the court declared, was that the quarter-section descriptions in Exhibit "A" operated as conveyances of the grantor's rights in those tracts as well as any rights the grantor had in wells explicitly listed and their proration units. *Id.* at *10 (emphasis added). Casting about for an explanation for what the limiting proviso might mean if not construed as "merely boilerplate" and meaningless, as Oz Gas contended, the court found that the proviso served to clarify that (1) the working interest in operative wells was limited in area to the proration units surrounding the referenced wells, and (2) the overall interest in the described tracts and in the wells being conveyed was no larger than that conveyed in the original 1974 lease. *Id.* According to this analysis, the court went on, the conveyance was limited to 75% of the working interest in the proration unit for the Argee No. 1-155 Well but was unlimited and conveyed 100% in the rest of SE¼ Section 155. *Id.* at *11.

Turning to the question of whether the trespass committed in drilling the wells in W½SE¼ Section 155 was in bad faith, the court held that the trial court was justified in finding that the defendants "did not have an honest and reasonable belief in the superiority of their title." *Id.* at *14. That they had relied on a 20-year-old title opinion without having it updated or searching the records themselves was practically dispositive.

Pipeline Company Held Not Entitled to Summary Judgment on Common Carrier Status

In *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas, LLC*, No. 09-14-00176-CV, 2015 WL 575179 (Tex. App.—Beaumont Feb. 12, 2015, no pet. h.), the court of appeals reversed a summary judgment granted by the trial court to Denbury Green Pipeline-Texas, LLC (Denbury Green), a pipeline company seeking to establish its right, by eminent domain, to lay a carbon dioxide pipeline across Texas Rice Land Partners, Ltd.'s (Texas Rice) farm and ranch property.

Denbury Green was formed, according to testimony of its officers, to construct, own, and operate the "Green Line," a pipeline for the transportation of carbon dioxide from the Texas-Louisiana border along the Gulf Coast to the Oyster Bayou Unit in Chambers County, Texas, and the West Hastings Unit in Brazoria and Galveston Counties. An affiliate of Denbury Green's, Denbury Onshore, LLC (Denbury Onshore), operated the Jackson Dome Unit in Mississippi, a major source of the carbon dioxide to be transported, and it also owned interests in the Oyster Bayou and West Hastings Units, including a large majority of the working interest in the West Hastings Unit, which it also operated. *Id.* at *1–2. When Texas Rice refused to allow Denbury Green access to survey the route of its pipeline, Denbury Green sought and obtained a summary judgment enjoining interference with its right of entry on the basis that Denbury Green was a common carrier with the right of eminent domain. *Id.* at *3. That judgment was reversed in *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas, LLC*, 363 S.W.3d 192 (Tex. 2012), in which the supreme court held that Denbury Green must establish itself to be a common carrier by more than just a cursory filing with the RRC holding itself out as one. On remand the trial court again granted summary judgment to Denbury Green, and this appeal resulted.

To exercise the right of eminent domain, the court of appeals observed, Denbury Green was required to meet the statutory definition of a common carrier. 2015 WL 575179, at *3 (citing Tex. Nat. Res. Code Ann. § 111.002 (a common carrier "owns, operates, or manages . . . pipelines for the transportation of carbon dioxide or hydrogen . . . for the public for hire")). Further, for a person intending to build a pipeline to qualify as a common carrier, a reasonable probability must exist that the pipeline will at some point after construction serve the public by transporting gas for third-party customers. *Id.* Thus, central to the court's inquiry, it remarked, was "Denbury Green's intent at the time of its plan to construct the Green Line." *Id.*

Denbury Green pointed to arrangements it had made with two third-party generators after the pipeline had been completed to transport their carbon dioxide as proof of its intention to provide services to the public. Further, its officers asserted, it had always intended its Green Line to be available to other carbon dioxide owners and had intentionally placed the line near potential shippers. *Id.* at *4. The transportation contracts Denbury Green obtained after the pipeline was built did not, in the court's view, necessarily speak to its intent at the time of its plan to construct the line, and Denbury Green's subjective beliefs about who might use the line "[did] not demonstrate, as a matter of law, a reasonable probability that, at the time Denbury Green intended to build the Green Line, the pipeline's purpose was to serve the public." *Id.*

Given evidence that (1) Denbury Onshore owned a controlling interest in both the West Hastings Unit and the Jackson Dome Unit; (2) only a very small percentage of non-operator working interest owners ratified Denbury Green's transportation agreements; and (3) the other interest owners did not take title to or possession of the carbon dioxide transported to the Texas units, reasonable jurors could differ on whether Denbury Green's contracts with its own affiliate, Denbury Onshore, and with the post-construction shippers were sufficient to establish its intent to serve the public, the court concluded. *Id.* at *5. The evidence therefore raised a fact issue regarding whether Denbury Green's taking served a substantial public interest. Since reasonable minds could differ on whether, at the time Denbury Green intended to build the Green Line, a reasonable probability existed that the Green Line would serve the public, summary judgment was improper. *Id.*

LEASE PROVISION FOR EXPIRATION AS TO UNDRILLED DEPTHS HELD AVOIDED BY POOLING AGREEMENT

The court in *Albert v. Dunlap Exploration, Inc.*, No. 11-12-00064-CV, 2015 WL 730119 (Tex. App.—Eastland Feb. 12, 2015, pet. filed), considered an oil and gas lease covering a 251.5-acre tract in Palo Pinto County, Texas, that contained in an addendum a provision for partial termination:

> 22. This lease shall expire at the end of the primary term hereof or any extension thereof by reason of operations being conducted at the end of the primary term hereof . . . as to all depths below the deepest depth drilled theretofore established in a well located on lands covered by this lease.

Id. at *1 (emphasis omitted). During the lease's primary term the lessors and lessee joined in executing a "Declaration of Pooled Unit" in which they agreed to pool the 251.5 acres covered by the lease with another 70.5-acre lease as to substances produced from gas wells on the land, "as to all depths covered by said leases." *Id.* Three gas wells were drilled in the pooled unit during the primary term of the lease, two of them on the 251.5-acre tract it covered, the deepest one being the BPE No. 2 well drilled to a true vertical depth of 4,135 feet and a measured depth of 4,261 feet.

David Albert and ABX Oil & Gas, Inc. (ABX) acquired the leases dedicated to the pooled unit in 2001. In 2003 they entered into a farmout agreement with Dunlap Exploration, Inc. (Dunlap) under which Dunlap drilled four wells. Albert and ABX assigned Dunlap their leasehold on 160 acres as a result of the farmout agreement, retaining the other 162 acres. In 2007 and 2008 ABX drilled two wells on the 251.5-acre tract, the BPE No. 6, completed to produce between 4,172 feet and 4,176 feet, and the BPE No. 1D, completed to produce between 4,164 feet and 4,167 feet. Dunlap sued Albert and ABX, alleging that the BPE No. 1D had been drilled on land that had been assigned to Dunlap and that the BPE No. 6 had been drilled too close to Dunlap's acreage in violation of RRC spacing rules. As part of the settlement of the lawsuit, Dunlap assigned ABX its leasehold rights with respect to production from the BPE No. 1D wellbore in excess of a 40% working interest, and ABX and Albert assigned Dunlap a 40% working interest in its leasehold rights with respect to production from the BPE No. 6 wellbore. *Id.* at *2. After the settlement, however, Albert and ABX asserted that Dunlap had no interest in the depths from which the No. 1D and No. 6 wells were producing, because the lease had expired as to those depths at the end of its primary term. Albert and ABX instead now owned the entire working interest in those "deep rights," they contended, notwithstanding the settlement agreement and assignments, under a lease they obtained from the mineral owner after the settlement. Dunlap again sued and obtained a summary judgment declaring that the lease no longer contained a depth limitation and upholding Dunlap's working interest in the BPE No. 1 and No. 6 wells. *Id.* at *3. The court of appeals affirmed.

The court agreed with Dunlap that the pooling agreement had modified the depth limitation in the lease because it provided that production from the pooled unit held the land covered by the leases as to all depths. The lessors had agreed to the modification by their execution of the pooling agreement, the court held, rejecting Albert's and ABX's argument that nothing in the pooling agreement expressly purported to modify the partial termination provision of the lease. *Id.* at *6.

Moreover, the lessors had executed a ratification of the lease in 2001, when Albert and ABX had acquired it, with an amendment setting forth the amount of acreage allowed to be included in a proration unit for any well drilled on the lease. A schedule contained in the amendment included depth ranges from the surface down to depths below 5,500 feet, and the instrument stated that the amendatory provisions would supersede anything to the contrary in the lease. The ratification's reference to the drilling of wells in excess of 5,500 feet negated the lease clause calling for termination as to depths deeper than those drilled, in the court's view. *Id.* at *6–7.

The court finally upheld the trial court's determination that Albert and ABX were estopped by their earlier conduct from taking the position that the lease had expired. They had drilled the No. 1D and No. 6 wells, the court pointed out, presumably in reliance on the pooling agreement and the ratification, presumably had taken and sold production from them, and had expressly included the wells in the settlement agreement with Dunlap. As a matter of law they were estopped from repudiating their authority to have drilled the wells to their productive depths, notwithstanding an express representation in the settlement agreement that ABX and Albert did not own a leasehold interest below the deepest depth of any well drilled during the lease's primary term. *Id.* at *8.

Jury Instruction Improperly Limited Period of Time Under Consideration for Paying Production Analysis

In *BP America Production Co. v. Laddex, Ltd.*, No. 07-13-00392-CV, 2015 WL 691212 (Tex. App.—Amarillo Feb. 17, 2015, pet. filed), the court of appeals reversed the judgment of the trial court, based on a jury verdict, declaring BP America Production Company's (BP) oil and gas lease on a tract in Roberts County, Texas, terminated upon cessation of production in paying quantities and Laddex, Ltd.'s (Laddex) new lease from the mineral owners effective.

The "Arrington lease" held by BP had been executed in 1971 for a term of five years and as long thereafter as oil or gas was being produced. A single well was drilled on the land, and it produced steadily until August 2005. Production diminished significantly from then until November 2006, when the well resumed production in quantities comparable to those before the 2005 slowdown. In 2007 Laddex acquired a "top lease" that would vest in possession on termination of the Arrington lease, and it filed suit seeking termination of the Arrington lease on the basis that production in paying quantities had ceased. The jury returned a verdict that the well had failed to produce in paying quantities and that a prudent operator would not have continued to operate it, and the trial court entered judgment declaring the Arrington lease terminated. *Id.* at *1.

The court first addressed the trial court's denial of BP's motion to dismiss the suit because Laddex lacked standing. Laddex's top lease, BP argued, violated the rule against perpetuities and was void because the lessee's interest would not vest until the Arrington lease terminated, which might occur after the period allowed by the rule. *Id.* at *2. The court disagreed. The lease expressly stated that it vested in Laddex "any and all remainder and reversionary interest" upon expiration of any prior lease. *Id.* at *3. "[T]he conveyance in the Laddex lease [was] not made contingent upon any happening" and was "without any condition other than that inherent in the possibility of reverter." *Id.* The only right that was not presently vested was the right of possession, the court declared, so that the lease did not violate the rule against perpetuities. *Id.*

The court upheld, however, BP's challenge to the question in the jury charge, "From August 1, 2005 to October 31, 2006, did the Mahler D-2 Well fail to produce in paying quantities?" *Id.* at *4. "The controlling issue that the trial court was required to submit to the jury was whether the lease failed to produce in paying quantities over a reasonable period of time," the court observed. *Id.* The 15-month period that the jury charge identified as the relevant period limited the jury's consideration to a period of time that was not reasonable in assessing the lease's true profitability, since it included only the period of diminished production. *Id.* Certainly, in the court's view, evidence that the lease had returned to profitable production was material to the question of what time period was reasonable under the circumstances. *Id.* Consequently, the court reversed the trial court's decision and remanded the case for a new trial. *Id.* at *5.

Mother's Claim of Breach of Fiduciary Duty Against Sons Who Purchased Her Minerals Held Barred by Limitations

A number of Texas cases have recently dealt with the statute of limitations as a bar to a suit for reformation of a deed, either to add or expunge a mineral reservation allegedly omitted or included by mistake. Somewhat similarly, *Moczygemba v. Moczygemba*, No. 04-14-00110-CV, 2015 WL 704405 (Tex. App.—San Antonio Feb. 18, 2015, no pet. h.), decided whether limitations barred a mother's suit against her sons for breach of a fiduciary duty to her by failing to exclude the minerals when they bought her 400 acres of land in Wilson and Karnes Counties, Texas.

Mary Moczygemba had nine children. Two of them, Tommy and Harry, helped her with farm and ranch business. In 2000, when she was 74 years old, Mary sold 200 acres to Tommy and 200 acres to Harry, each for $40,000, Mary's asking price. Deeds were prepared and executed without any mineral reservation. *Id.* at *1. According to the testimony of both Mary and Tommy, the reservation of minerals never occurred to either of them at the time, although there had been oil and gas leases executed over the years. Nevertheless, the sale, and especially the conveyance of Mary's minerals to Tommy and Harry, evidently resulted in a great deal of family dissension. Mary's eldest son, Edwin, she testified, did not speak to her for 12 years. *Id.* at *2.

On October 12, 2012, Mary sued Tommy and Harry for breach of an "informal" fiduciary duty to her, by inducing her to execute the deeds in 2000 when she did not understand their impact on mineral ownership and by not explaining in complete detail that she would be giving up her mineral interest. *Id.* The trial court granted Tommy's and Harry's motion for summary judgment on the basis of the four-year statute of limitations applicable to claims for breach of fiduciary duty, and the court of appeals affirmed.

On appeal Mary argued that the discovery rule applied so that limitations did not begin to run until she learned of Tommy's and Harry's alleged breach, less than four years before she sued. *Id.* at *3. Tommy and Harry countered that "the discovery rule [did] not apply because (1) Mary's injury, the allegedly wrongful transfer of the mineral interests, was not inherently undiscoverable, and was in fact easily discoverable [by reading] the deeds; and (2) the evidence of her injury [was] not objectively verifiable." *Id.* at *4. The court agreed with Tommy and Harry that there was no objectively verifiable evidence of Mary's injury. While the deeds themselves were evidence of the transfer of Mary's mineral interests, the court explained, "they [were] not evidence that the mineral interests were *wrongfully* transferred" so that Mary had suffered an actual injury. *Id.* at *5. No objectively verifiable evidence pointed to any wrongful intent on the part of Tommy and Harry; Mary herself admitted there had been no discussion of minerals at all because she had never thought about it. *Id.* at *6.

RAILROAD COMMISSION ORDER BASED ON PRESUMED LEASE EXPIRATION UPHELD ON REHEARING

The court in *Roland Oil Co. v. Railroad Commission of Texas*, No. 03-12-00247-CV, 2015 WL 870232 (Tex. App.—Austin Feb. 27, 2015, no pet. h.) (mem. op.), affirmed a district court order affirming the RRC's decision to deny Roland Oil Company (Roland), the operator of the Charlotte Field Unit in Atascosa County, Texas, an extension of time to complete the required testing and plugging of wells in the unit. After having reached the opposite conclusion in its initial opinion issued on August 29, 2014, on rehearing the court held that the RRC had been reasonable in concluding that Roland did not have a good faith claim to a continuing right to operate the wells because its leases had expired.

When Roland applied in early 2005 for an extension of time to complete required testing on certain inactive wells in the unit, the RRC determined that Roland had been delinquent in failing to perform the testing for years and not only denied Roland's request but issued a "severance" order effectively barring it from producing any well until the work was done. *Id.* at *2. Roland performed repairs necessary for the testing, but there was no production from the unit from May 2005 until August 2006, after the RRC lifted its severance order. A mineral owner by then had, in June 2006, notified the RRC of his contention that Roland's lease had lapsed because of the cessation of production. *Id.* The RRC thereupon concluded that Roland lacked a good-faith claim to a right to operate the unit, a prerequisite to any extension of time to plug inactive wells, and cancelled Roland's plugging extension. The district court upheld the RRC's order. *Id.* at *3.

Roland maintained that the unit agreement's force majeure clause excused the cessation of production that otherwise would have terminated its lease. The clause suspended Roland's obligations under the agreement and perpetuated unit leases while operations were prevented "by any rule, regulation, or order of a governmental agency; . . . or by any other cause or causes beyond reasonable control of the party." *Id.* at *5 (emphasis omitted). Because the RRC's order of severance required it to stop production, Roland contended, its lease remained effective. The court agreed with the RRC that the force majeure clause did not apply because it was within Roland's reasonable control to stay current on required testing, which would have avoided the severance order. *Id.* at *4. It rejected Roland's interpretation that the force majeure clause did not require the cause to be beyond Roland's control, pointing out that the clause's use of the word "other" before "causes beyond reasonable control" made it clear that it intended that any stated force majeure event would not excuse performance unless beyond the obligated party's control. *Id.* at *6.

Roland also argued that its right to operate the unit wells had been perpetuated by the unit agreement, which had a term extending as long as unit operations were conducted without a cessation of more than 90 consecutive days, unit operations being defined as "all operations conducted . . . for or on account of the development and operation of the Unitized Formation for the production of Unitized Substances." *Id.* at *7 (footnote omitted). The court of appeals disagreed. Evidence supported the RRC's finding that all work Roland performed during the gap in production was limited to inactive wells, and that work was not done in an effort to cause the wells to produce but in preparation for their plugging. The RRC was therefore reasonable in concluding that those acts did not fall within the definition of unit operations. *Id.* at *8.

DEED'S EXCEPTION OF MINERALS ERRONEOUSLY CALLED "HERETOFORE RESERVED" LEFT EXCEPTED MINERALS IN GRANTORS

The court in *Griswold v. EOG Resources, Inc.*, No. 02-14-00200-CV, 2015 WL 1020716 (Tex. App.—Fort Worth Mar. 5, 2015, no pet. h.), affirmed summary judgment for EOG Resources, Inc. (EOG) against its oil and gas lessors, Danny and Rhonda Griswold. The Griswolds claimed ownership of the entire mineral estate of a 31.25-acre tract in Montague County, Texas, and had complained that EOG wrongly refused to pay them royalty on more than 50%.

The Griswolds were the successors to the interest of the grantees under a 1993 deed that had conveyed the land and included the following provision:

> LESS, SAVE AND EXCEPT an undivided 1/2 of all oil, gas and other minerals found in, under and that may be produced from the above described tract of land heretofore reserved by predecessors in title.

Id. at *2 (alteration omitted). The grantors in fact had owned 100% of the minerals in the tract at the time of the deed; none had been theretofore reserved by predecessors in title except an interest that had become merged with the grantors' title years earlier. The Griswolds argued that the deed, by referring to an interest "heretofore reserved by predecessors in title," had attempted to except something that did not exist, so that the exception was a nullity. EOG countered, and the court agreed, that the fact that the reason stated for the exception was erroneous, false, or mistaken did not defeat the expressed intention to exclude a 1/2 mineral interest from the estate conveyed. *Id.* at *3.

The Griswolds were correct in drawing a general distinction between a reservation and an exception, the court noted. *Id.* An exception has the same effect as a reservation, though, when the interest excepted is not outstanding in another. Following *Pich v. Lankford*, 302 S.W.2d 645 (Tex. 1957), which had construed deeds with very similar exception language in the same context, the court explained that the "heretofore reserved" phrase "was but a recital purporting to state why the exception was made." 2015 WL 1020716, at *4. Its falsity did not, as the Griswolds maintained, negate the entire save-and-except clause. Because the excepted interest did not pass to the grantees, or to the Griswolds as successors to the grantees' interest, and was not outstanding at the time of the deed, the legal effect of the exception was to leave the excepted 1/2 mineral interest in the grantors. EOG was obligated to the Griswolds only for royalty on their 1/2 interest, not the whole. *Id.*

Oil and Gas Lessee Not Liable to Lessors' Cotenants for Bonus Money

Aycock v. Vantage Fort Worth Energy, LLC, No. 11-13-00338-CV, 2015 WL 1322003 (Tex. App.—Eastland Mar. 20, 2015, no pet. h.) (mem. op.), affirmed the trial court's summary judgment for Vantage Fort Worth Energy, LLC (Vantage), the lessee of a 2008 oil and gas lease from Fitzhugh H. Pannill Jr. and others on a 1,409-acre tract of land in Erath County, Texas, against the Aycocks, owners of undivided mineral interests not owned by the lessors in the leased tract.

Vantage paid Pannill a bonus of $750 per acre for Pannill's undivided interest in the land, consisting of about 526 net mineral acres. After learning of the lease in late 2010, the Aycocks mailed a letter to Vantage, to which Vantage never responded, asking to meet with Vantage about the lease. Contending that their letter had effectively ratified the lease and thus entitled them to a share of all benefits accruing to the lessors under it, the Aycocks sued Vantage for their alleged portion of the bonus money paid Pannill. *Id.* at *1.

Even assuming, without deciding, that Pannill had purported to lease the Aycocks' interests and that the Aycocks had ratified the lease by their letter, the court held, Vantage was not liable to the Aycocks for any bonus payment. *Id.* at *2–3. Although "a nonconsenting [mineral] cotenant, after ratifying a lease, may recover any profits already paid to a lessor cotenant," Vantage was not the lessor cotenant and had received no money, the court pointed out. *Id.* at *3. The unpaid mineral cotenants therefore could recover no bonus money from Vantage. *Id.*

Purchaser of Oil and Gas Property Held to Have Assumed Seller's Obligation to Indemnify Prior Owner

The court in *ConocoPhillips Co. v. Noble Energy, Inc.*, No. 14-13-00884-CV, 2015 WL 1456444 (Tex. App.—Houston [14th Dist.] Mar. 26, 2015, no pet. h.), reversing the trial court's summary judgment for Noble Energy, Inc. (Noble), rendered judgment that Noble was contractually obligated to indemnify ConocoPhillips Company (ConocoPhillips) against environmental claims involving the Johnson Bayou Field in Cameron Parish, Louisiana, which ConocoPhillips had settled for $63 million.

Phillips Petroleum Company (Phillips), a predecessor of ConocoPhillips, had been the operator of the property and in 1994 had entered into an exchange agreement with Alma Energy Corp. (Alma). In agreeing to acquire the Johnson Bayou property, Alma agreed to indemnify Phillips against claims arising out of waste materials or hazardous substances on the property, including those resulting from Phillips's actions prior to the exchange to Alma. *Id.* at *1. Alma filed for chapter 11 bankruptcy in 1999 and during the bankruptcy proceeding sold its assets to East River Energy, L.L.C. (East River) pursuant to an asset purchase and sale agreement (PSA) dated May 3, 2000. *Id.* at *2. In the PSA East River, which became Elysium Energy, L.L.C. (Elysium) and eventually, through a series of mergers, Noble, agreed to assume the seller's "obligations under any executory contracts or unexpired oil and gas leases expressly assumed hereunder." *Id.*

When ConocoPhillips, among other current and former owners and operators of the property, was sued by the State of Louisiana and the Cameron Parish School Board for environmental damage and contamination in 2010, it sought defense and indemnity against the claims from Noble. *Id.* at *3. Noble refused the demand on the basis that its predecessor had assumed only certain liabilities in the bankruptcy sale along with Alma's assets, not including the indemnity obligation under the 1994 exchange agreement, so that there was no privity of contract between Nobel and ConocoPhillips. The trial court agreed with Nobel. *Id.* at *4.

The court of appeals acknowledged that, as Nobel contended, the assignee of a party's rights under a contract "is not obligated to perform the assignor's obligations unless it expressly assumes them." *Id.* at *8. The assignment by Alma to Elysium, the Noble predecessor, of all of Alma's rights and interests in contracts associated with the Alma assets did not, as ConocoPhillips argued, conclusively establish the transfer of both Alma's rights and its obligations. *Id.* at *9. Elysium had, however, agreed to perform Alma's obligations under any executory contract expressly assumed. Because the Exchange Agreement in which Alma had agreed to indemnify ConocoPhillips was an executory contract within the meaning of the federal bankruptcy laws, since a breach by either party of its indemnification obligation would have been a material one, Nobel, as Elysium's successor, was contractually obligated for the indemnification. *Id.* at *14–15.

Insurance Policy Held Not to Provide Coverage Beyond Limits to Restore Well to Production

The court in *Prime Natural Resources, Inc. v. Certain Underwriters at Lloyd's, London*, No. 01-11-00995-CV, 2015 WL 1457534 (Tex. App.—Houston [1st Dist.] Mar. 26, 2015, no pet. h.) (mem. op.), affirmed summary judgment for the insurer of an offshore well in which Prime Natural Resources, Inc. (Prime) owned an interest, damaged by Hurricane Rita in 2005.

Prime claimed its policy provided coverage for its 50% share of all costs necessary to restore the well and its associated platform to its pre-storm condition, some $17 million, including $4 million for debris removal and for rebuilding the well's platform. *Id.* at *1. The insurer countered that it had paid Prime the policy limits of $900,000 for the replacement cost value of the platform, $225,000 for the cost of debris removal, and $2,880,866 for pipeline damage and redrill operations, all of which were specific coverages and limits of the policy. *Id.* at *2. The court agreed, rejecting Prime's arguments that certain policy provisions applied to extend the coverage beyond the limits the insurer asserted. Coverage for redrilling and restoration of the *well* included operations in the hole itself but not to rebuild the platform; "salvage" operations covered in the policy did not include platform debris removal; and the policy's coverage of costs of preventing a blowout or out-of-control well could not be stretched to include the cost of removing debris and rebuilding the platform. *Id.* at *9.

UTAH — MINING

M. BENJAMIN MACHLIS
— REPORTER —

UTAH LEGISLATURE PASSES BILLS AFFECTING AIR QUALITY AND ENVIRONMENTAL PERMIT APPEALS

During the 2015 legislative session, Utah lawmakers passed several bills amending the laws governing the Utah Department of Environmental Quality (DEQ). Of particular interest to the oil, gas, and mining industries are House Bill 226 (HB 226), 2015 Utah Laws ch. 80 (amending Utah Code Ann. § 19-2-106) (effective May 12, 2015), which removed the statutory prohibition on the ability of DEQ's Air Quality Board (AQB) to promulgate air quality regulations that are more stringent than federal requirements, and Senate Bill 282 (SB 282), 2015 Utah Laws ch. 379 (amending Utah Code Ann. § 19-1-301.5) (effective May 12, 2015), which amended the procedures for administrative appeals of DEQ permitting decisions.

<u>Air Quality Board Granted Authority to Enact Regulations More Stringent than the Corresponding Federal Regulations</u>

Utah Code Ann. § 19-2-106 previously provided that "no rule which the [AQB] makes for the purpose of administering a program under the federal Clean Air Act may be more stringent than the corresponding federal regulations which address the same circumstances," unless the AQB "makes a written finding after public comment and hearing and based on evidence in the record, that the corresponding federal regulations are not adequate to protect public health and the environment of the state." Utah Code Ann. § 19-2-106(1), (2) (2014). The statute also required the finding to "be accompanied by an opinion referring to and evaluating the public health and environmental information and studies contained in the record which form the basis for the [AQB's] conclusion." *Id.* § 19-2-106(2).

HB 226 amends section 19-2-106 by deleting the prohibition on more stringent regulations and providing that the AQB "may make rules for the purpose of administering a program under the federal Clean Air Act different than the corresponding federal regulations which address the same circumstances." HB 226 § 1 (to be codified at Utah Code Ann. § 19-2-106(1)(a)). *See* 2015 Utah Laws ch. 80. However, regulations that differ from the corresponding federal requirement are only allowed if the AQB: (1) holds a public comment period and a public hearing; and (2) "finds that the different rule will provide reasonable added protections to public health or the environment of the state or a particular region of the state." HB 226 § 1 (to be codified at Utah Code Ann. § 19-2-106(1)(a)(i), (ii)). The findings that a different rule is warranted must be in writing and must be "based on evidence, studies, or other information contained in the record that relates to the state of Utah and type of source involved." *Id.* (to be codified at Utah Code Ann. § 19-2-106(2)). The amendment also requires the AQB to "consider the differences between an industry that continuously produces emissions and an industry that episodically produces emissions, and make rules that reflect those differences." *Id.* (to be codified at Utah Code Ann. § 19-2-106(1)(b)).

This amendment represents a compromise between the previous language and the proposal in Senate Bill 87, which never made it out of the Senate and would have removed any restrictions on the AQB's ability to promulgate more stringent regulations by repealing section 19-2-106 in its entirety. The changes are designed to allow regulators some flexibility to implement regulatory requirements directly tailored to Utah's unique air quality challenges.

<u>Changes to Permit Review Adjudicative Proceedings</u>

The legislature also passed SB 282, which revises the procedures under which administrative appeals of environmental permitting decisions are reviewed by administrative law judges (ALJ) for all of the divisions of DEQ. *See* Utah Code Ann. § 19-1-301.5. The bill: (1) provides minimum standards for the content of a petition to review a permitting decision; (2) clarifies that in a proceeding challenging a permit order or financial assurance determination, the permittee is a party to such proceeding regardless of who filed the appeal; (3) sets page limits for briefing; (4) sets time frames in which the ALJ must render a decision on dispositive motions or the merits; and (5) changes the standard of review for such appeals from requiring that determinations be upheld so long as they were "supported by substantial evidence taken from the record as a whole" to requiring that determinations be upheld so long as they are "not clearly erroneous based on the petitioner's marshaling of the evidence." SB 282 § 2 (to be codified at Utah Code Ann. § 19-1-301.5). The amendments are designed to streamline the adjudicatory process, and DEQ will have to undertake rulemaking to bring its procedural rules into line with the requirements of SB 282.

UTAH — OIL & GAS

ANDREW J. LEMIEUX
— REPORTER —

UTAH SUPREME COURT HOLDS THAT FEDERAL, STATE, AND TRIBAL INTERESTS MAY BE EXCLUDED WHEN CALCULATING THE SEVERANCE TAX RATE ON OIL AND GAS

In *Anadarko Petroleum Corp. v. Utah State Tax Comm'n*, 2015 UT 25, 345 P.3d 648, the Utah Supreme Court was called upon to determine whether an oil and gas operator properly excluded federal, state, and tribal interests when calculating its severance tax rate.

Utah Code Ann. § 59-5-102 requires the owner of an interest in oil or gas produced from Utah wells to pay severance tax on the oil or gas produced and saved, sold, or transported from the field where the oil or gas is produced. The applicable tax rate is based on the fair market value of the oil or gas. *See id.* § 59-5-103.1. Federal, state, and tribal interests are exempt from the severance tax. *Id.* § 59-5-102(1)(b). At issue in *Anadarko* was whether such interests, exempt from the severance tax itself, are to be included when determining the fair market value of produced oil or gas for purposes of the severance tax rate calculation.

In Utah, the severance tax rate is determined by applying a statutory formula. First, the taxpayer calculates "the fair market value of the interest in oil or gas according to a sale in an 'arm's-length contract' or by 'comparison to other sales of oil or gas.'" *Anadarko*, 2015 UT 25, ¶ 4 (quoting Utah Code Ann. § 59-5-103.1(1)(a)). Next, deductions for processing and certain transportation costs "are subtracted from that amount to yield the net taxable value." *Id.* (citing Utah Code Ann. § 59-5-103.1(1)(b)). Then, "the [Utah State Tax Commission (Commission)] divides the taxable value by the amount of oil or gas produced." *Id.* For natural gas, "the Commission calculates the percentage of the unit price up to $1.50 and then the percentage above $1.50." *Id.* The percentage of the unit price that is less than or equal to $1.50 is taxed at a rate of 3%, and the percentage above $1.50 is taxed at a 5% tax rate. *Id.* (citing Utah Code Ann. § 59-5-102(2)(b)). Similarly, the severance tax rate for oil is 3% up to and including the first $13 per barrel, and 5% for values greater than or equal to $13.01 per barrel. *See* Utah Code Ann. § 59-5-102(2)(a).

In this case, Anadarko Petroleum Corporation (Anadarko) operated oil and gas wells in Carbon and Uintah Counties from 2008 to 2011. *Anadarko*, 2015 UT 25, ¶ 2. Applying the statutory formula for determining its severance tax rate on the produced oil and gas, Anadarko deducted federal, state, and tribal royalty interests from the net taxable value when calculating the per unit price of oil and gas. *Id.* ¶ 6. Before the Commission, the Auditing Division of the Commission disagreed with Anadarko's exclusions, contending that "the unit price should be calculated 'based on the prices at which the gas was sold, prior to the point when the producer paid the exempt royalties.'" *Id.*

Based on its interpretation of section 59-5-103.1, the Commission agreed with the Auditing Division, finding that "the exempt entities' interests—the interests of federal and state governments, and Indian tribes—are not subject to the severance tax but must be included in the calculation of value under [sections 59-5-102 and 59-5-103.1]." *Id.* ¶ 7. The Commission also "concluded that '[t]axable value is established prior to being allocated between the two tax rates' and that the Auditing Division's methodology did not increase Anadarko's taxable value." *Id.* (alteration in original). Because the exempt royalty interests were not enumerated in the deduction provisions of section 59-5-103.1(1)(b), the Commission concluded that the severance tax statute "does not permit the deduction of such interests." *Id.* ¶ 14.

The Utah Supreme Court disagreed with the Commission, finding that "the plain meaning and structure of the severance tax statute categorically excludes federal, state, and Indian tribe interests from the unit price calculation." *Id.* ¶ 10. The court noted that

> the Commission's reading of the severance tax statute [as disallowing deductions for federal, state, or tribal royalty interests when calculating the value of production] is plausible if section 59-5-103.1 is read in isolation. But when read in harmony with section 59-5-102(1)(b), . . . the plain language and structure of the statute categorically excludes federal and Indian tribe interests from the value calculation set forth in section 59-5-103.1.

Id. ¶ 12. The court reasoned that because "subsection 102(1)(a)—the provision that imposes the severance tax and sets forth how the rate is to be calculated under section 103.1—is, by its own terms, '[s]ubject to Subsection [102](1)(b),'" and because section 102(1)(b) "specifically excludes exempt interests from consideration under the entire section . . . . no provision in section 59-5-102 applies to" federal, state, or tribal interests. *Id.* ¶ 14 (alterations in original). The court stated that "[t]his excludes the interests of these entities not just from the imposition of a severance tax, but from any consideration in calculating the 'value' of an interest under section 59-5-102(1)(a) as determined by section 59-5-103.1." *Id.* Thus, Anadarko was "permitted to deduct these interests in calculating the unit price used to determine its tax rate." *Id.*

In dissent, Associate Chief Justice Nehring stated that section 59-5-102 "very clearly does not tax the exempted interests, but it says nothing of deducting those interests for the purposes of calculating fair market value." *Id.* ¶ 26. Nehring cited the specific deductions provided in section 59-5-103.1 and the absence of a deduction in section 59-5-103.1 for exempt royalty interests. *Id.* He concluded that section 59-5-103.1 is unambiguous and does not allow for the deduction of exempt royalty interests when calculating the value of production. *Id.* ¶ 28. In response, the majority noted that "[i]f, as we hold today, section 59-5-102(1)(b) excludes exempted royalty interests altogether from both the imposition of the severance tax *and* the value calculation it references in section 59-5-103.1, including an additional deduction for such interests in section 59-5-103.1 would have been entirely superfluous." *Id.* ¶ 16. The court further explained that the tax exempt interests were not "deductions," but rather exclusions from the tax base. *Id.* ¶ 17. Thus, the court noted that "the Legislature's failure to include a specific deduction for exempt royalty interests in section 103.1 does not tell us anything about whether it intended to allow taxpayers to deduct them in the severance-tax-rate calculation." *Id.*

As a result of *Anadarko*, a greater percentage of the oil and gas produced by lessees who pay federal, state, or tribal royalties in Utah will be taxed at the lower 3% rate rather than the higher 5% rate, which will likely result in significant tax savings.

Editor's Note: The reporter's law firm serves as counsel for Anadarko Petroleum Corporation and Kerr-McGee Oil & Gas Onshore, L.P.

Utah Board of Oil, Gas and Mining May Now Authorize the Drilling of More Than One Well When Establishing Drilling Units

The Utah legislature recently amended the drilling unit statute to provide for the drilling of more than one well when a drilling unit is established under certain circumstances. *See* Senate Bill 188, 2015 Utah Laws ch. 44 (amending Utah Code Ann. § 40-6-6). Effective May 12, 2015, the Utah Board of Oil, Gas and Mining (Board):

> (6) . . . may establish a drilling unit and concurrently authorize the drilling of more than one well in a drilling unit if the board finds that:

> (a) engineering or geologic characteristics justify the drilling of more than one well in that drilling unit; and
>
> (b) the drilling of more than one well in the drilling unit will not result in waste.

Utah Code Ann. § 40-6-6(6). This legislation is a precursor for anticipated regulations from the Board relating to horizontal wells in Utah.

Utah Simplifies the Process for Permitting Directional Wells Located Outside Required Setbacks

The Utah Division of Oil, Gas and Mining (DOGM) recently amended its regulations governing directional drilling to simplify the process for operators to obtain permits to drill directional wells with surface locations outside the setbacks required by Utah Admin. Code r. 649-3-2 or applicable orders of the Utah Board of Oil, Gas and Mining (Board), as long as the wells will not be perforated or completed outside the required setbacks. *See* Utah Admin. Code r. 649-3-3(1), -11(1.2).

Previously, an operator seeking an exception location for a directional well whose surface location was outside the required setbacks had to obtain

> [w]ritten consent from all owners within a 460 foot radius of the proposed well location when such exception is to the requirements of [Utah Admin. Code r. 649-3-2], or . . . all owners of directly or diagonally offsetting drilling units when such exception is to an order of the board establishing oil or gas well drilling units

regardless of where the well would be perforated or completed. *Id.* r. 649-3-3(1.2)–(1.3).

Under the amended regulations, as long as "the point of penetration of the targeted productive zone(s) and bottom hole location" are located within the required setbacks, DOGM may approve an application for permit to drill a directional well "without notice and hearing conditioned upon the operator filing a certification included with the application that it will not perforate and complete the well in any other zone(s) outside of said tolerances without complying with the requirements of [Utah Admin. Code r. 649-3-11(1.1)]." *Id.* r. 649-3-11(1.2). *See also id.* r. 649-3-3(1) (outlining the requirements for obtaining exception location approval, including the required consents, subject to the provisions of Utah Admin. Code r. 649-3-11(1.2)). Thus, operators who will not be perforating and completing a directional well outside the required setbacks do not need to obtain the written consent of the owners of the oil and gas outside the setbacks or exception location approval after notice and a hearing before the Board, insofar as the wellbore is located outside the required setbacks. *See id.* r. 649-3-11(1.2). *See also id.* r. 649-3-3(3).

By eliminating the requirement to obtain the oil and gas owners' consent or an exception location from the Board under these circumstances, the amended regulations will reduce the time and money required for operators to obtain drilling permits for such wells, especially in situations where a Board hearing would have been necessary.

High Cost Infrastructure Tax Credit Available for Certain Projects in Utah

In an effort to encourage high cost infrastructure projects in Utah, the legislature has created income tax credits for entities undertaking such projects under certain circumstances. *See* Senate Bill 216, 2015 Utah Laws ch. 356 (amending Utah Code Ann. § 63M-4-401; enacting Utah Code Ann. §§ 59-7-618, 59-10-1033, 63M-4-601 to -605). The new legislation is effective May 12, 2015, but the tax credits apply to taxable years beginning on or after January 1, 2016.

Under the new law, industrial, mining, manufacturing, and agriculture entities that construct infrastructure related to energy delivery, railroads, roads, and water supply or removal projects may be able to claim a tax credit of up to 30% of the income and sales taxes generated by the project. *See* Utah Code Ann. §§ 63M-4-602(3), (4), -603(4)(b). The credit may be claimed for up to 20 years or until 50% of the infrastructure construction costs are recouped. *Id.* § 63M-4-603(4)(a). To result in a credit, the project must expand or create new industrial, mining, manufacturing, or agriculture activity in Utah or involve a new investment of $50 million or more in an existing industrial, mining, manufacturing, or agriculture project. *Id.* § 63M-4-602(3). The infrastructure component of the project must also exceed $10 million or 10% of the total cost of the project. *Id.*

In the eleventh hour of the legislative session, the legislature made the tax credit applicable to "fuel standard compliance projects," defined as projects that are "designed to retrofit a fuel refinery in order to make the refinery capable of producing fuel that complies with the United States Environmental Protection Agency's Tier 3 gasoline sulfur standard described in 40 C.F.R. Sec. 79.54." Utah Code Ann. § 63M-4-602(2). The credit for such projects may be claimed for 20 years or until 30% (rather than the 50% provided for other high cost infrastructure projects) of the infrastructure construction costs are recouped. *Id.* § 63M-4-603(4). The credit is limited to 30% of the income and sales taxes generated by the project and is set by the Utah Energy Infrastructure Authority Board (Board). *Id.* In setting the credit amount, the Board must take into account the likelihood that the project would be completed without a tax credit and the estimated completion date of the project. *Id.*

Before claiming the tax credit, a claimant must enter into an agreement with and obtain a certificate from the Governor's Office of Energy Development regarding the credit. *Id.* §§ 63M-4-603(1), (3), -604(6). The issuance of a certificate is also subject to the approval of the Board, which will evaluate the benefit of the project to the State of Utah according to certain criteria set forth in the statute. *Id.* § 63M-4-603(2).

West Virginia — Oil & Gas

Andrew S. Graham
— Reporter —

Statutory Pooling Bill Fails on Final Night of Legislative Session

On March 14, 2015, the final day of the 2015 regular session of the West Virginia legislature, the West Virginia House of Delegates defeated House Bill 2688, which would have created a statutory pooling system for horizontal wells producing from formations above the Onondaga formation, including Marcellus Shale wells. The vote was 49-49, with two members not voting. The House vote came after the West Virginia Senate had approved the bill on a vote of 24–10 earlier that day. The House had initially passed the bill on March 4 by a vote of 60–40. Ten members who had voted for passage of the bill on March 4 switched their votes on March 14 and voted against it. The second House vote arose because the Senate had made minor changes to the bill that required the consent of the House of Delegates. With the defeat of the bill, producers developing the Marcellus Shale still must rely on West Virginia's limited common law of pooling for the joint development of leases. A similar bill is expected to be introduced in the 2016 regular session of the West Virginia legislature.

West Virginia does not have an over-arching statutory pooling system. Instead, there is a hodgepodge of pooling rules that only cover certain limited development situations. As a result, statutory pooling is not available for most oil and gas development in the state. West Virginia has three different pooling statutes: (1) one for gas wells producing from formations located above the Onondaga formation, but the statute only comes into play when a coal owner objects to the well's location during the permitting process, W. Va. Code §§ 22C-8-1 to -19; (2) one for oil and gas wells producing from formations located below the Onondaga formation, along with wells used in connection with secondary recovery operations for oil, regardless of depth, *id.* §§ 22C-9-1 to -16; and (3) one for coalbed methane wells, *id.* §§ 22-21-1 to -29. For horizontal wells drilled into the Marcellus Shale, which has been the focus of so much of the more-recent oil and gas exploration and production in West Virginia, no statutory pooling is available unless there are coal owner objections to the location of the well. *Id.* § 22C-8-7.

Wyoming — Mining

Andrew A. Irvine
— Reporter —

Wyoming Moves to Take Over Regulation of Uranium Mining from Nuclear Regulatory Commission

Governor Matt Mead signed legislation in February that authorizes the Governor, through the Wyoming Department of Environmental Quality (WDEQ), to begin negotiations with the U.S. Nuclear Regulatory Commission (NRC) to enter into an agreement for Wyoming to assume regulatory authority over uranium mining within the state. *See* House Bill 27, 2015 Wyo. Sess. Laws ch. 60 (to be codified at Wyo. Stat. Ann. § 35-11-2001) (effective Feb. 27, 2015). Currently in Wyoming, the NRC regulates source materials from uranium mining and milling and the wastes associated with those activities.

An agreement with the NRC would include the components necessary for the State to administer a program to regulate such source materials. *Id.* The WDEQ has been designated as the lead agency to develop that program, which must be as stringent as federal law. *Id.* Governor Mead indicated that the new law is "good for Wyoming and our economy" and represents "the first step in cutting the bureaucracy in the licensing process and gives the state the power to regulate uranium mining." Office of Governor Mead, "Governor Mead Signs Legislation Giving Wyoming Authority Over Uranium Permitting" (Feb. 28, 2015).

Wyoming Creates Minerals to Value Added Products Program

The Wyoming Legislature created a new program called the "Wyoming Minerals to Value Added Products Program" that is administered by the Wyoming Business Council (WBC) and intended to aid the economic development of the state. *See* House Bill 53, 2015 Wyo. Sess. Laws ch. 56 (to be codified at Wyo. Stat. Ann. §§ 9-20-101 to -104) (effective July 1, 2015). The program provides for the State to enter into contracts to provide up to 20% of the feedstock minerals at a set price to a facility that converts minerals to a higher value product. *Id.* (to be codified at Wyo. Stat. Ann. § 9-20-102(d)). No single contract shall exceed $50 million under the program. *Id.*

Under the program, contracts must, among other provisions: have an anticipated beneficial impact on the state; provide adequate consideration for the State to enter the contract; and not create debt for the state beyond the current year's taxes. *Id.* (to be codified at Wyo. Stat. Ann. § 9-20-103(c)(i)). Facilities interested in participating in the program must submit a proposal to the Governor, and after a recommendation from the Governor, facilities must then submit an application to the WBC. *Id.* (to be codified at Wyo. Stat. Ann. § 9-20-102(b)). The WBC then determines whether to recommend, based on the terms of the contract and other factors, whether the State Loan and Investment Board should approve the contract. *Id.* (to be codified at Wyo. Stat. Ann. § 9-20-102(c)).

Task Force to Study How to Simplify Taxes on Minerals

In February, the Wyoming legislature passed a law that created a task force on mineral taxes consisting of four legislative members and six appointed members. *See* Senate File 42, 2015 Wyo. Sess. Laws ch. 73. "The task force shall study and make recommendations for a fair, viable and simplified system of valuation and taxation for minerals." *Id.* § 1(c). The task force is directed to "[d]evelop a fair, understandable valuation and taxation system which is as simple as possible to comply with and administer," and to "[c]onsider whether proposed changes to the mineral severance tax and the mineral gross product tax can be made revenue neutral to the state, local government and industry."

Id. § 1(c)(iii)–(iv). The task force will meet over the next two years and is required to submit a final report that includes its final recommendation and any proposed legislation to the legislature for the 2017 session. *Id.* § 1(d).

Wyoming Infrastructure Authority May Issue Bonds for Coal Ports

The Wyoming legislature enacted a law to allow the Wyoming Infrastructure Authority (Authority) to issue up to $1 billion in bonds to finance infrastructure projects located outside the state. *See* Senate File 24, 2015 Wyo. Sess. Laws ch. 181 (amending Wyo. Stat. Ann. §§ 37-5-305(a), -403(a)). The Authority is a state agency that works to promote the development of Wyoming's economy through improvements to the state's electric and energy transmission infrastructure and by encouraging consumption of Wyoming energy. Previously, the law required projects funded by the Authority to be located, at least in part, within Wyoming. *See* Wyo. Stat. Ann. § 37-5-403(a) (2014). The new law removes that requirement and replaces it with a requirement that a bond may be issued if the project improves energy transmission infrastructure and facilitates the consumption of Wyoming energy. *See* 2015 Wyo. Sess. Laws ch. 181 (amending Wyo. Stat. Ann. § 37-5-403(a)). The primary beneficiaries of the new law are likely to be coal ports in northwestern Wyoming that could serve to export Wyoming coal overseas. *See* Ben Neary, "Wyoming Legislature Approves Bill to Authorize $1 Billion in Bonds for Coal Ports," *Assoc. Press* (Mar. 9, 2015).

Wyoming Joins Interstate Mining Compact Commission

Pursuant to a law passed in February, Wyoming adopted the Interstate Mining Compact (Compact) and becomes a full member of the Interstate Mining Compact Commission (IMCC). *See* Senate File 34, 2015 Wyo. Sess. Laws ch. 42 (to be codified at Wyo. Stat. Ann. §§ 30-4-103 to -108) (effective Feb. 25, 2015). According to its website, the IMCC is a "multi-state governmental agency/organization that represents the natural resource and related environmental protection interests of its member states." IMCC, "Welcome," http://www.imcc.isa.us/index.html. Prior to the new law, Wyoming was an associate member of the IMCC. To become a full member, Wyoming adopted the Compact, which spells out the powers and functions of the IMCC. The IMCC's powers are of a "study, recommendatory or consultative nature," and do not include regulatory powers. IMCC, "What We Do," http://www.imcc.isa.us/Do.htm. "The [IMCC] provides a forum for interstate action and communication on [natural resources and environmental] issues of concern to the member states." *Id.* The move to join the IMCC as a full member provides Wyoming a greater voice on the IMCC with regard to mining and other issues relevant to the state. *See* Mark Wilcox, "Wyoming Joins Mining Compact to Get Voice," *Wyo. Bus. Report* (Feb. 26, 2015).

Wyoming — Oil & Gas

William N. Heiss
— Reporter —

Wyoming Supreme Court Interprets Net Profits Contract, Finds Wyoming Royalty Payment Act Allows Recovery of Attorneys' Fees for Post Judgment Actions and Finds Segregation of Attorneys' Fees Is Not Required When Case Involves More Than Claims Under That Act

Ultra Resources, Inc. v. Hartman (*Ultra I*), 2010 WY 36, 226 P.3d 889, involved a suit for a declaratory judgment recognizing a net profits interest (NPI) owned by the plaintiffs burdening the working interests of the defendants in the Pinedale Anticline gas field. In that case the Wyoming Supreme Court recognized the existence of the NPI. The plaintiffs were awarded a money judgment for amounts due on the NPI through December 2006 and also awarded $3.9 million in attorneys' fees under the Wyoming Royalty Payment Act (WRPA), Wyo. Stat. Ann. §§ 30-5-301 to -305. *See* Vol. XXVII, No. 2 (2010) of this *Newsletter*.

In 2010 the plaintiffs filed a motion with the district court to enforce that judgment, claiming that the defendants were not accounting to the plaintiffs properly under the contract creating the NPI. Giving little weight to the defendants' argument that the court lacked jurisdiction to consider the matters raised in the plaintiffs' motion, the court held that it had jurisdiction and issued a number of orders on the merits of the motion. *See Ultra Res., Inc. v. Hartman* (*Ultra II*), 2015 WY 40, ¶ 5, 226 P.3d 889.

In the appeal to the Wyoming Supreme Court,

> [t]he primary order at issue . . . pertain[ed] to the defendants' attempts to charge pre-2007 expenses to calculate the NPI starting January 1, 2007. The district court ruled that the NPI had been fully calculated through December 31, 2006 at trial, and the [contract creating the NPI] required expenses to be charged to the NPI in the month following the date the expenses were invoiced. Consequently, the district court refused to allow the defendants to charge expenses invoiced prior to January 1, 2007, when calculating the 2007 NPI. The district court also concluded the plaintiffs were the prevailing parties in the enforcement proceeding pursuant to the [WRPA] . . . and [consequently] the operating defendants were required to pay the plaintiffs' attorney fees.

Id. ¶ 6.

On appeal, the Wyoming Supreme Court first stated that courts have the inherent authority to interpret and clarify their declaratory judgments, to enforce their own judgments, and to grant supplemental declaratory relief. *Id.* ¶¶ 10, 11, 30.

Much of the decision concerned "the district court's interpretation of its judgment from the 2007 trial and the defendants' ongoing . . . accounting responsibilities [for the NPI], particularly the timing of expense reporting." *Id.* ¶ 31. The supreme court generally upheld the trial court and held that the trial court "properly concluded that all expenses deductible from the NPI calculation for 2006 should have been included in the defendants' trial evidence." *Id.* ¶ 45. The defendants could not include in post-2006 NPI accounting any expenses incurred prior to 2007.

The contract establishing the NPI provided: "Within one (1) month after the close of each calendar month, Operator shall furnish to [the plaintiffs] a statement of costs and expenses incurred and charges made and all receipts and credits received during such calendar month." *Id.* ¶ 49. The court held that "[u]nder this provision and others in the contract, the proper time for charging an expense to the NPI is when it is 'incurred' by the operator." *Id.*

"The defendants argued, however, that a cost is incurred for . . . purposes [of calculating the NPI] when it was billed to the joint interest partners in a [joint interest bill (JIB)] or, in other words, 'jibbed.'" *Id.* ¶ 50. The supreme court did not buy this argument and upheld the trial court's finding that

> the contracting parties were familiar with the JIB process but did not expressly incorporate that accounting time into the NPI terms. Instead, the original parties adopted a reporting deadline based upon when the operator incurs an expense, i.e., when an expense is invoiced, thereby making the recipient liable for the amount due.

Id. ¶ 56.

While the two supreme court cases over this controversy primarily involved the applicability and interpretation of the provision in the document creating the NPI, the cases do have holdings of interest to practitioners under the WRPA. "The district court ruled the WRPA applied to the post-judgment proceedings, the plaintiffs were the prevailing parties, and they were entitled to an award of reasonable attorney fees and costs." *Id.* ¶ 78.

The defendants claimed that "even if the plaintiffs were entitled to an attorney fees award, the district court erred by allowing the plaintiffs' entire request." *Id.* ¶ 73. The defendants claimed that "the district court abused its discretion by failing to require the plaintiffs to segregate their fees between the WRPA claims they prevailed upon and other claims." *Id.* ¶ 74.

> Given [that] the post-judgment issues focused on the defendants' responsibilities under the WRPA, the [NPI] and the judgment based upon the act and the contract, the district court's refusal to require segregation of fees between WRPA and non-WRPA claims in the post-judgment proceedings was [found by the supreme court to be] consistent with [its] decision in *Ultra I*.

Id. ¶ 81.

WOGCC Amends Drilling Location Rules

The Wyoming Oil and Gas Conservation Commission (WOGCC) recently amended its rules concerning well locations. The new rules require, among other things, that wells, pits, wellheads, pumping units, tanks and treaters be located no closer than 350 feet from any water supply. WOGCC Rule 3, § 22(b). Another amendment provides that no wells or production facilities be located closer than 500 feet from an occupied structure. WOGCC Rule 3, § 47(a). Variances to these limitations can be granted by the Supervisor in certain circumstances and for good cause.

Canada — Oil & Gas

Vivek T.A. Warrier
Alastair MacKinnon
— Reporters —

Operator Granted Summary Judgment Against Producer for Disputed Invoice Amounts

Overview

In *SemCAMS ULC v. Blaze Energy Ltd.*, 2015 ABQB 218, a gas facility operator was granted summary judgment for its unpaid invoices, even though the non-paying producer disputed the amounts owing and claimed various set-offs. This decision confirms the "pay first, dispute later" structure of many oil and gas industry agreements, and will likely impact other Alberta natural gas producers and facility operators to the extent they are subject to similar contracts.

Background

Under five separate contracts (Agreements), SemCAMS ULC (SemCAMS), as operator, provided gas transportation, gas processing, and facility operation services for Blaze Energy Ltd. (Blaze), a natural gas producer. All five agreements required the operator to invoice the producer monthly for services rendered. The invoices were based upon the operator's estimated costs and estimated production volume for the month. All invoices were payable within 30 days of receipt. The Agreements further provided for a "13th month adjustment," whereby the invoiced amounts were adjusted to reflect actual costs and throughput for the preceding year. All of the Agreements also contained audit provisions, which allowed for further adjustments based upon audit results. *See id.* paras. 1–16.

The Agreements all required the producer to pay invoices as they were rendered, even if the amount was disputed. "Some of the Agreements expressly state[d] that the 'Producer shall not be allowed to withhold payment of any portion of the bill presented by the Operator, due to a protest or question relating to such bill.'" *Id.* para. 13. Others stated the operator could sue for unpaid invoices "as if the obligation to pay such amount and the interest thereon were liquidated demands due and payable on the relevant date such amounts were due to be paid, without any right or resort of such Producer to set-off or counterclaim." *Id.*

Between July 2012 and April 2013, SemCAMS rendered 11 invoices to Blaze, totaling $6,900,081.29. *Id.* para. 9. The 13th month adjustment for 2012 resulted in a credit to Blaze of $761,662.36, leaving a net amount owing of $6,138,419.03 (Invoiced Amount). *Id.* para. 10. Blaze refused to pay the Invoiced Amount, alleging accounting errors and overcharges, and claiming various set-offs. When its demand for payment went unheeded, SemCAMS exercised an operator's lien on Blaze's share of residue gas, and recovered $998,105.56. *Id.* para. 12. Notwithstanding this partial recovery, SemCAMS applied to the court for summary judgment for the full Invoiced Amount. Blaze responded by filing a counterclaim, asserting the alleged errors, overcharges, and set-offs.

Reasoning

The issue before the court was whether SemCAMS was entitled to summary judgment for the Invoiced Amount, subject to future adjustments as provided for in the Agreements, or whether a trial was required to determine the ultimate amount owing between the parties, after considering the alleged errors, overcharges, and set-offs claimed by Blaze. *Id.* para. 17. The court approached the issue as a question of contractual interpretation, to determine the intention of the parties in the event of an invoice dispute.

SemCAMS argued that it was entitled to summary judgment based on the wording of the Agreements. In particular, it emphasized that the contractual provisions contemplated payment of invoices within 30 days, that there were built-in adjustment mechanisms, and that the Agreements provided that Blaze was required to pay disputed invoices and/or SemCAMS was entitled to sue for unpaid invoices without any right of counter-claim or set-off for Blaze. *Id.* para. 18. Therefore, SemCAMS argued that even if Blaze later proved further adjustments were warranted, it was nevertheless entitled to immediate judgment for the Invoiced Amounts. *Id.*

Blaze disputed the literal interpretation of the Agreements advocated by SemCAMS. Rather, Blaze argued that it would be commercially absurd if it were contractually obligated to pay any invoice rendered by the operator, regardless of the amount claimed or how obviously flawed it might be. *Id.* para. 40. Furthermore, Blaze argued that after correcting the accounting errors and overcharges, and assessing the applicable set-offs, SemCAMS actually owed money to Blaze. *Id.* para. 22. Therefore, summary judgment was inappropriate, and a trial was required to determine the ultimate amount owing between the parties, and which party owed it.

Applying the modern approach to summary judgment, the court determined that SemCAMS' entitlement to immediate payment of the Invoiced Amounts did not genuinely require a full trial. The total amount of the invoices was not disputed, just whether Blaze would ultimately have to pay the full amount. The court held that the operator's entitlement to immediate payment of its invoices was a separate issue from the producer's right to subsequently audit and dispute charges. *Id.* para. 47.

After reviewing the relevant portions of the Agreements, the court was satisfied that the intent of the parties was that the monthly invoices would be immediately due and payable within 30 days, despite any dispute over the amount invoiced. The Agreements were clear that the producer was not entitled to withhold payment and that the operator was entitled to sue for payment if it did. The producer's recourse was to the audit provisions of the Agreements, not holding back payments that were contractually due. *Id.*

The court rejected Blaze's submission that such an arrangement was commercially absurd. Rather, the court found it to be a reasonable allocation of risk. The Agreements could have provided that disputed amounts could be withheld, but in this case the parties elected a different arrangement. The court inferred this was because the operator needed reliable cash flow to fulfill its ongoing obligations. *Id.* para. 48. Furthermore, there was no evidence the invoices were rendered in bad faith; had there been evidence of fraud or malfeasance, the court noted, the result might have been different. *Id.* para. 50.

In the result, the court granted summary judgment for the Invoiced Amount, less the funds recovered by SemCAMS through its operator's lien and an agreed set-off. Contractual interest was also awarded. The judgment, however, was subject to the important caveat that Blaze was still entitled to pursue its counterclaim and establish any adjustments that might be warranted under the Agreements. *Id.* para. 51.

Significance

This case demonstrates that the court is attuned to the "pay first, dispute later" structure of many commercial agreements and it is prepared to give effect to such contractual intent. It provides guidance for how the court will interpret similarly worded contracts and it suggests how alternative risk allocations might be achieved through different contractual provisions. Perhaps most importantly, this case signals that producers subject to similarly worded contracts may not validly delay payment by requesting an audit of the operator's invoices.

61st ANNUAL INSTITUTE
July 16–18, 2015

Join us in Anchorage for our 61st Annual Institute. Among the northernmost cities on Earth, Anchorage features dozens of parks and 122 miles of paved bike paths, all with a backdrop of the salmon-rich waters of Cook Inlet and the 5,000-foot-plus peaks of Chugach State Park. Warmed by a maritime climate and a summer sun that doesn't set until 11:00 pm, visitors can spend the day fishing Ship Creek downtown, hiking the nearby mountains, photographing glaciers, visiting museums and theaters, dining at fine restaurants, and enjoying a city with one of the highest concentrations of microbreweries per capita in the country. Dozens of wilderness adventures are within a quick drive from downtown, and a short plane ride opens up endless adventures.

The Annual Institute opens with the General Session on Thursday morning. That afternoon and for the remainder of the conference, attendees can choose among the Mining, Oil & Gas, Water, Public Lands, Environmental, International, and Landman's Sections. See https://www.rmmlf.org/confrnce/AI61news.pdf for details.

Upcoming Programs

61st Annual Rocky Mountain Mineral Law Institute
July 16–18, 2015 ● Anchorage, Alaska

Mining Agreements: Contracting for Goods and Services
September 22–25, 2015 ● Vancouver, British Columbia

International Oil & Gas Law, Contracts & Negotiations: Part 1
October 5–9, 2015 ● Houston, Texas

International Oil & Gas Law, Contracts & Negotiations: Part 2
October 12–16, 2015 ● Houston, Texas

Federal Oil & Gas Law Leasing Short Course
October 19–22, 2015 ● Westminster, Colorado

Oil & Gas Law Short Course
October 19–23, 2015 ● Westminster, Colorado

The Endangered Species Act: Current and Emerging Issues
November 4–5, 2015 ● Westminster, Colorado

Human Rights and the Extractive Industries
February 18–19, 2016 ● Panama City, Panama

Oil & Gas Agreements: Purchase and Sale Agreements
May 12–13, 2016 ● Santa Fe, New Mexico

For additional information, contact the Foundation:
Tel (303) 321-8100 ● Fax (303) 321-7657 ● Email info@rmmlf.org

Rocky Mountain Mineral Law Foundation
9191 Sheridan Blvd., Ste. 203
Westminster, Colorado 80031
www.rmmlf.org

Volume XXXII, Number 2, 2015
ISSN 0897-6694